Report

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System stability in a renewables-based power system

prepared for:

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Definitions and Abbreviations

AC	Alternating Current
aFRR	Automatic frequency regulation reserve. ENTSO-E term for the secondary frequency control reserve
Angle Stability	Term, which is often used to describe Rotor Angle Stability or to describe the Voltage Angle Stability. The term Angle Stability does not form part of the stability definitions and classification of the joint IEEE/CIGRE task force [1], which is the most widely accepted classification of stability terms referring to power systems. The stability definitions of this report do not use the term “Angle Stability”.
Artificial inertia	Control concept, which injects additional active power in proportion to the rate of change of frequency (analogously to “real”, physical inertia).
Automatic load shedding	Automatic load shedding: In case of a very severe frequency drop, which cannot be managed by the available Operating Reserve, underfrequency relays automatically disconnect a part of the load to re-establish the active power balance. Automatic load shedding must be well-co-ordinated to ensure that frequency stability will be re-established following load shedding actions
CE	Continental Europe
Converter	Electronic device to transform alternating current (AC) into direct current (DC) or vice-versa. The term can also be used for electronic devices transforming alternating current (AC) at a frequency F1 into alternating current (AC) of a different frequency (F2), in which case it is a “Frequency Converter”.
Damping power	Damping torque multiplied by speed (frequency).
Damping torque	Torque, which is in proportion to speed (or frequency) and which contributes to the damping of power oscillations
DC	Direct Current
Dynamic system security assessment	System Security Assessment, which is not only based on load flow calculations but also dynamic simulations.
E-STATCOM	STATCOM with an energy storage system linked to it (at its DC-side) and grid-forming converter control. Depending on the energy storage capacity, an E-STATCOM can provide inertia (time frame of several seconds, e.g. using super-capacitors) or even operating reserve (when using batteries).
Fast Frequency Control	Injection of active power in proportion to the frequency deviation (from nominal frequency). Fast frequency control is analogous to

	primary frequency control but acts within substantially shorter time frames (e.g. between 500ms and 2s).
Frequency stability	Frequency stability problems occur as a result of an imbalance of active power in a power system. An active power generation deficit leads to a frequency drop, active power generation excess leads to a rise of frequency.
FSM	Frequency Sensitive Mode. Term of the RfG to describe that a component responds to frequency changes within the normal frequency band of operation.(same as primary frequency control).
FCR	Frequency containment reserve. ENTSO-E term for primary frequency control reserve
	mFRR/aFRR: Manual/automatic frequency regulation reserve, also named secondary and tertiary frequency control reserve FCR: Frequency containment reserve, also named primary frequency control reserve
GF	Grid Forming
Grid following converter	Power electronics converter using a controller that regulates the current such that there is a well-defined phase angle between voltage and current (or well-defined active and reactive currents). A grid following converter measures the voltage angle so that the current angle can “follow” the voltage angle, and the converter remains in synchronism.
Grid forming converter	Power electronics converter that defines a voltage angle and synchronizes itself with the rest of the system by adjusting its voltage angle in function of the active power exchange with the grid. The converter remains in phase synchronism because it’s control strategy exchanges “synchronizing power” with the grid (similar to a synchronous machine).
HTLS conductor	High Temperature Low Sag conductors can carry a higher current than normal conductors.
HVDC	High-voltage-direct current: Power transmission at continuous currents (DC-direct current) instead of AC (alternative current)
HVRT	High Voltage Ride Through: Ability of a converter or a generator to remain connected with the network in the case of temporary overvoltages.

Inertia	The inertia defines the rate of change of frequency at a given active power imbalance (excess or deficit). The larger the inertia, the lower is the rate of change of frequency following an active power imbalance (the larger the inertia, the "slower" is a frequency rise or drop).
Inverter	Electronic device to transform direct current (DC) into alternating current (AC). An Inverter is a sub-category of a Converter.
LBO	Lean blow out – In gas turbines (or gas engines) lean flame blowout (LBO) is the phenomenon of flame extinction due to the reduction of the fuel-air ratio.
LFSM-O	Limited Frequency Sensitive Mode – Overfrequency: Term of the RfG to describe that a component responds to frequency changes outside the normal frequency band of operation, in the high-frequency range (overfrequencies).
LFSM-U	Limited Frequency Sensitive Mode – Underfrequency: Term of the RfG to describe that a component responds to frequency changes outside the normal frequency band of operation, in the low-frequency range (overfrequencies).
Load shedding	Disconnection of load, either to avoid grid congestions or to re-establish the active power balance of a system. We can further distinguish planned and automatic (unplanned) load shedding.
LVRT	Low Voltage Ride Through: Ability of a converter or a generator to remain connected with the network in the case of severe voltage dips.
mFRR	Manual frequency regulation reserve. ENTSO-E term for the tertiary reserve (manually activated active power reserve).
MSCDN	Mechanically Switched Capacitor with Damping Network. Component to provide reactive power in steady state.
Non-synchronous generator	Term, that is predominantly used in the U.K. for all types of generators, which are not synchronous generators (e.g. based on power electronic converters, asynchronous machines etc.). In this report, generators with grid following converters are non-synchronous. Generators with grid forming converters are synchronous.
Operating reserve	Active power reserve needed to operate a power system. Operating Reserve is needed to balance active power variations in the time frame of seconds up to several minutes, until the market takes over balancing. Operating Reserve is controlled by the TSO in charge, who procures it via ancillary service markets.

Operational Planning	Operational planning typically includes all planning activities up to one year ahead (sometimes even longer). Operational planning mainly focuses on - Outage planning (schedule of maintenance activities/planned outages at monthly, weekly, daily timescales) - Day-ahead planning (system security assessment, identification of required redispatch measures, securing the required operating reserve etc.) - Intra-day planning (same activities as in day-ahead planning but at intra-day time scales)
Ordinary Contingency	According to the ENTSOE SGOL [2] Ordinary Contingency means the occurrence of a contingency of a single branch or injection
Oscillatory Stability	Term, describing the stability of rotor angles of synchronous machines in the case of small disturbances (e.g. resulting from switching actions or small load changes). Each disturbance in a power system excites rotor angle oscillations. If these oscillations are sufficiently well damped, they are almost not visible. If they are only weakly damped, undamped or if the damping is even negative, oscillations with increasing amplitude can occur finally leading to loss of synchronism and system separation (system split).
Oscillatory stability	Stability of the rotor angle of synchronous machines (individual synchronous machines or coherent groups of synchronous machines) subsequent to small grid disturbances (e.g. switching actions, load changes etc.). In case of an oscillatory instability, even small disturbances excite oscillations which are weakly damped, undamped, or even with rising amplitude (“negative damping”).
Out of Range Contingency	According to the ENTSOE SGOL [2] Out-of-Range Contingency means the simultaneous occurrence of multiple contingencies without a common cause, or a loss of power generating modules with a total loss of generation capacity exceeding the reference incident;
Phase shifting transformer (PST)	Special transformer, which does not only allow varying the ratio of voltage angles but also the difference of voltage angles between their primary and secondary side by modifying the tap position. Can be used to control active power flows through individual network branches.
Planned load shedding	Load shedding, which is announced (e.g. at day-ahead timescales). Planned load shedding is a measure to ensure the active power balance in the case of a foreseeable active power

	imbalance (lack of generation).
PV	Photovoltaic
PV Inverter	Inverter to connect PV modules to the grid.
Rectifier	Electronic device to transform alternating current (AC) into direct current (DC). A Rectifier is a sub-category of a Converter.
Redispatch	Modification of the market-driven generator dispatch to resolve network constraints (grid congestions, voltage constraints or other constraints like stability constraint, export/import limits). Redispatch is within the responsibility of the TSO.
Redispatch cost	Cost associated with re-dispatch measures. This includes direct costs and indirect costs. Direct costs incur because the power of more expensive power plants must be increased and less expensive power plants are decreased. Indirect costs incur because generators, which, according to the market, have the right to generate, are compensated for the energy not delivered (minus variable generation cost).
Reliability	“Reliability of a power system refers to the probability of its satisfactory operation over the long run. It denotes the ability to supply adequate electric service on a nearly continuous basis, with few interruptions over an extended time period” [1]
RoCoF	Rate of Change of Frequency - Time derivative of the frequency (df/dt). The RoCoF is an important index relating to the frequency stability of the system.
Rotor Angle Stability	Term, describing stability phenomena in power systems referring to the synchronism of rotor angles of electric machines (synchronous machines). More specifically, Rotor Angle Stability includes “Oscillatory Stability” (or “small disturbance rotor angle stability) and “Transient Stability” (or “large disturbance rotor angle stability) phenomena. Rotor Angle Stability phenomena are always relating to electro-mechanical interactions.
Security	“Security of a power system refers to the degree of risk in its ability to survive imminent disturbances (contingencies) without interruption of customer service. It relates to robustness of the system to imminent disturbances and, hence, depends on the system operating condition as well as the contingent probability of disturbances.” [1]
Series compensation	Reactive power compensation devices, which are connected in series to a line (between two nodes/bus bars).
Short circuit	Fault, during which two or more phases are either connected between each other, or one or several phases are connected to ground by a very low impedance causing a very high current to

	flow.
Short circuit current	Current that occurs during a short-circuit
Short circuit impedance	Equivalent impedance of the electrical network, which is effective during a short circuit. The lower the short circuit impedance the higher is the short circuit current.
Shunt compensation	Reactive power compensation devices, which are connected to a single node (bus bar).
SPGM	Synchronous Power Generating Module (power plant using a synchronous generator)
Stability	"Stability of a power system, as discussed in Section II (of [1]) refers to the continuance of intact operation following a disturbance. It depends on the operating condition and the nature of the physical disturbance." [1]
STATCOM	Static Synchronous Compensator: Reactive power source, which is continuously variable, and which can be controlled very quickly, based on self-commutating power electronic converters ("static", non-rotating, typically using IGBTs or other types transistors). Standard STATCOMs are equipped with very small energy storage (module capacitors), which are needed to balance the DC-voltage. The storage is too small to provide any kind of active-power related service to the system. STATCOMs with larger energy storage at their DC-side (e.g. supercapacitors or even battery energy storage), which can be used to provide inertia or even primary frequency reserve to the system are named E-STATCOM in this report.
Sub-synchronous (frequency)	Frequency range below nominal frequency (e.g. below 50Hz or 60Hz)
Super-synchronous (frequency)	Frequency range above nominal frequency (e.g. below 50Hz or 60Hz)
SVC/SVS	Static var compensator/Static var system: thyristor based, controllable reactive power compensator comprised of switched capacitors and a thyristor-controlled reactor, with similar applications as STATCOMs.
Synchronous Condenser	Synchronous machine without turbine (therefore operates as a motor), which is used to provide reactive power (voltage control) and inertia.
System security assessment.	Network calculations to ensure that the planned generator dispatch will not lead any grid congestions or any other constraint

	violation (e.g. voltage constraint, minimum inertia, etc.). Usually, system security assessment is based on load flow calculations to analyse all relevant operating conditions ("N-1" cases), but also "exceptional contingencies" will be analysed. In the case of constraint violations, the system operator will define the required re-dispatch measures to mitigate it.
Synchronizing torque	Torque in proportion to the difference of the rotor (or voltage) angle between two synchronous machines. Synchronizing torque acts on the drive train of synchronous machines and synchronizes all synchronous machines of an AC-interconnected power system. Synchronizing torque is analogue to the force of a mechanical spring, which is in proportion to its displacement. The factor of proportionality of a spring is the spring constant. The synchronizing torque of a synchronous machine is in function of rotor angle. For small angle variations it is also in proportion to it. The equivalent of the spring constant is the synchronizing torque coefficient.
Synchronizing power	Synchronizing torque times speed (essentially the same as synchronizing torque but expressed as power).
System Split Event	System disturbance that leads to the separation of an interconnected power system.
Tap Changers	Mechanical devices allowing modifying the winding ratio of a transformer or variable shunt reactor (see VSR). On-load tap changers can be operated while the transformer is under load (current is flowing) whereas off-load tap changers can only be operated while the transformer is disconnected. On-load tap changers are used to control the voltage in power grids.
Transient Stability	Term, describing the stability of rotor angles of synchronous machines in the case of large disturbances (e.g. resulting from short-circuits or other major faults in a power system). Based on location, and duration of the fault, a single synchronous machine or a group of synchronous machines may re-synchronize with the rest of the system after the fault has been cleared (stable behaviour) or they may lose synchronism (unstable behaviour).
Voltage Angle Stability	Term, which is often used to describe stability phenomena in power systems referring to the voltage angle between different nodes in a power system. The term Voltage Angle Stability does not form part of the stability definitions and classification of the joint IEEE/CIGRE task force [1], which is the most widely accepted classification of stability terms referring to power systems. In this report, the term "Voltage

	Angle Stability" is not used. Corresponding phenomena are covered by the term "Voltage Stability".
Virtual Synchronous machine	Other expression for a generator with grid forming converter
Voltage Angle / Voltage Angle Difference	The angular difference between the sinewaves representing the voltage at two different nodes in a power system.
Voltage collapse	Sudden decrease of the voltages (down to very low values or even zero). A voltage collapse usually leads to a loss of synchronism (instability of the voltage angles) and consequently to a system split or even black-out (complete loss of power supply).
Voltage Magnitude	Peak value of the sinewave of an alternating voltage. In power systems, the voltage magnitude is expressed by the equivalent "RMS-value", which is equal to the voltage magnitude divided by the square root of two.
Voltage Stability	Term, describing the stability of the voltage magnitude at all nodes of a power system. Because the stability of voltage magnitude implies that voltage angles are stable too, the term Voltage Stability includes the stability of voltage magnitude and angle, which is essentially the same. In most cases, a voltage instability is related to the inability of the system to provide sufficient reactive power to cover the reactive demand. However, because reactive power demand of inductive elements (lines, transformers, etc.) highly depends on the active power flow across these components, voltage instability is very often caused by very large active power flows across long transmission lines.
VRE	Variable Renewable Energies (wind and PV generation).
VSC - Voltage Sourced Converter	Converter with a DC-voltage intermediate circuit, which is stabilized by a capacitor. VSCs are equipped with self-commutating converters (typically IGBTs or other types of transistors).
VSR	Variable Shunt Reactor: Shunt reactor with on-load tap changer allowing modifying its inductance and consequently its reactive power absorption. Can be used to control reactive power in the time frame of some seconds seconds up to a few minutes. The reactive power control by a VSR is in steps but because there are typically many steps (e.g. 33 steps), it is a quasi-continuous control.
WTG	Wind turbine generator

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1 Executive Summary

Maintaining system stability is key to the secure operation of power systems. Global instability can lead to system separation and consequently to partial or total system collapse (black-out).

There are three main areas of power system stability (compare also [3]):

- Frequency stability, which is associated with the active power balance of the system.
- Stability associated with the secure power transfer across transmission lines (voltage stability, oscillatory stability and transient stability)
- Stability associated with the correct performance of controllers (resonance stability, controller inter-action).

This report analyses the question how system stability can be maintained in a power system that is dominated by VRE with inverter-based generators without any short-term storage capability, in contrast to a conventional power system which is dominated by directly coupled synchronous machines providing short-term storage through their rotating masses. This report aims at creating an understanding of the different elements of stability, and how they are affected by the change in generator technologies. In addition to this, this report also analyses the impact of the massive integration of VRE on system stability resulting from increased power transfers across relevant transmission corridors, enabled by the use of HTLS[1] conductors, which drives the system closer to its stability limits.

This report further discusses future system service requirements and strategies to provide those services (e.g. mandatory requirements, auctions, market-based, etc.).

Stability constrained transfer limits

Voltage stability and rotor angle stability restrict the maximum power transfer across a line or a set of lines (transmission corridor). In the case of meshed systems, it is not easy to identify relevant transmission corridors. Therefore, it is common practice to introduce boundaries between areas that have long interconnections. Transmission lines, which cross the boundaries represent the transmission corridor in this case.

In general, there are three types of limits, against which transmission lines or a set of transmission lines defining a transmission corridor must be secured:

- Thermal limits
- Voltage constrained transfer limits
- Stability constrained transfer limits

In Europe, the transmission system is typically highly meshed, and lines are relatively short, so that stability limits are usually above thermal and voltage limits and it is sufficient to secure the system against thermal limits (maximum currents) and voltage limits (see Figure 1, left side/blue box).

However, with the introduction of HTLS[1] conductors, thermal limits of transmission lines can be increased increased but unfortunately not the voltage and stability constrained power transfer limits

[1] *HTLS: High Temperature Low Sag*

because stability and voltage constrained transfer limits depend on the line reactance, which predominantly depends on the tower geometry (external magnetic field) and not on the conductor type. Therefore, in the case of longer lines, it can happen that thermal limits are above voltage and stability constrained transfer limits (see Figure 1, right side/orange box).

Consequently, if lines should be loaded up to their thermal limit, it is necessary to take measures to increase voltage and stability constrained transfer limits too (e.g. installation of STATCOMs or series compensators). It is very important to increase both, voltage and stability limits and to ensure that there remains a sufficient margin between these and the thermal limits.

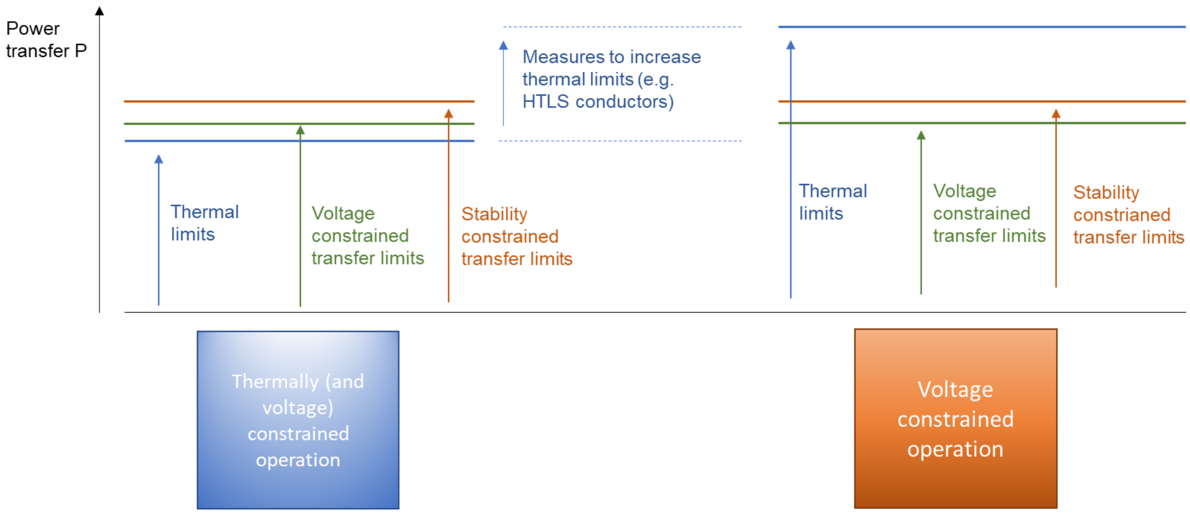

Figure 1: Thermally constrained and stability constrained operation

Measures that support the voltage only, without increasing stability constrained transfer limits (or not increasing them sufficiently) can be dangerous too. For example, the extensive use of passive shunt compensation (e.g. MSCDNs) supports the voltage but has only a small impact on the voltage stability constrained transfer limit. Consequently, it may happen that the voltage stability constrained transfer limit is reached even if the voltage is still within the normal band of operation. This can be very dangerous because in such a configuration, the voltage does not indicate that a power transfer is close to the voltage stability constrained transfer limit and it is possible that the system collapses, even if the voltage is still within the normal band of operation (see also Figure 2).

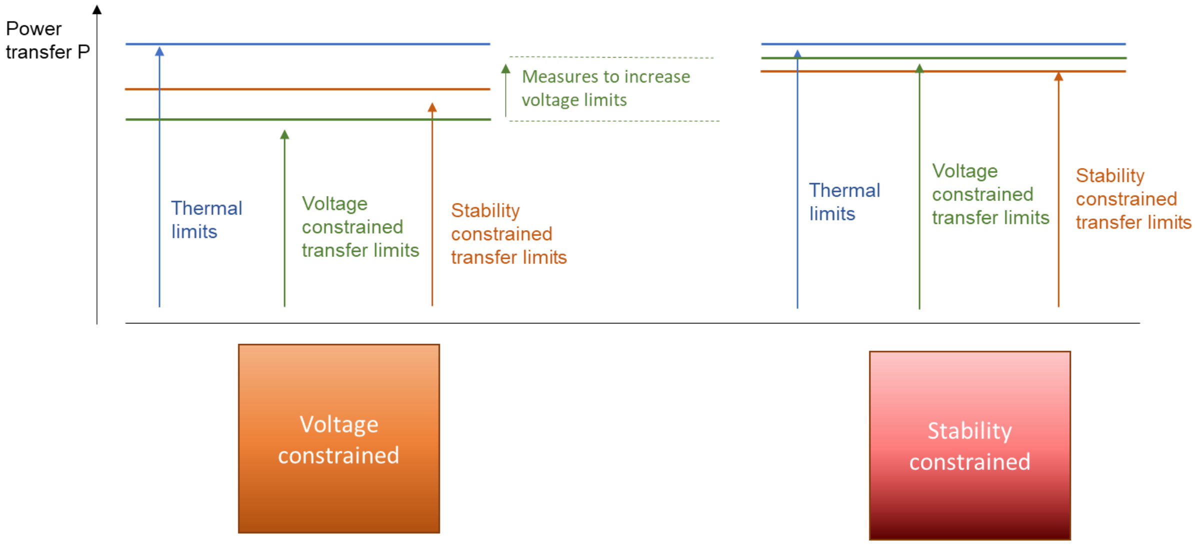

Figure 2: Stability constrained system (Stability limits below thermal and voltage limits)

Ideally, measures are taken (installation of STATCOMs and/or series compensators) to bring the limits into the original order again, meaning that thermal or voltage limits are clearly below any stability limit (see Figure 3, right side/blue box).

The longer the lines of a transmission corridor, the more restricted is the maximum stable power transfer across these lines. Therefore, in countries with very long lines (e.g. Australia, USA, Latin America, South Africa, etc.) it is common practice to operate the system with stability constraints, meaning that stability constraints must be well known because they can be below thermal or voltage constraints. Stability constraints are then calculated using offline simulation tools (see section 7.2) or online, as part of the operational planning or even the real-time operational processes (Dynamic security assessment, see section 7.3)

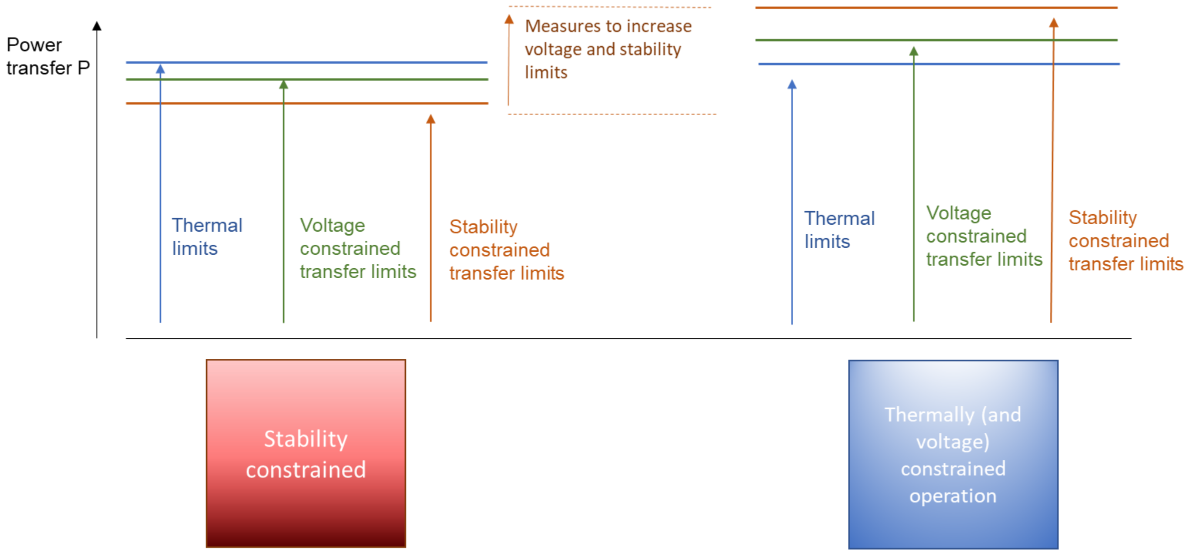

Figure 3: System with increased thermal, voltage and stability limits.

System split events

If a voltage or oscillatory instability occurs across an important transmission corridor, e.g. resulting from a series of "cascading events", it may happen that the power system loses synchronism and must be separated by a planned protection scheme (see also Figure 4).

As described in section 3.1.2, system split events always lead to an active power imbalance in each of the resulting islands and consequently to potential frequency stability issues (either low- or high-frequency issues). The larger the area exchange flow prior to the separation of the system, the larger is the imbalance right after separation and the higher is the risk of a consequential frequency instability.

Depending on the active power imbalance, the available inertia and the primary control reserve in each island, the sequence of events can lead to one of the following results:

- Frequency in each island can be restored without any load disconnection.
- Frequency in each island can be restored with the support of load disconnections (under-frequency load shedding).
- The frequency in some islands collapses and some islands survive, resulting in a "partial blackout".
- The frequency in all islands collapses resulting in a collapse of the entire, interconnected power system ("total blackout")

Besides the active power balance, also the reactive power balance of each island can be disturbed by a system spit resulting in voltage stability problems (either over- or under-voltage problems) after a system split has occurred.

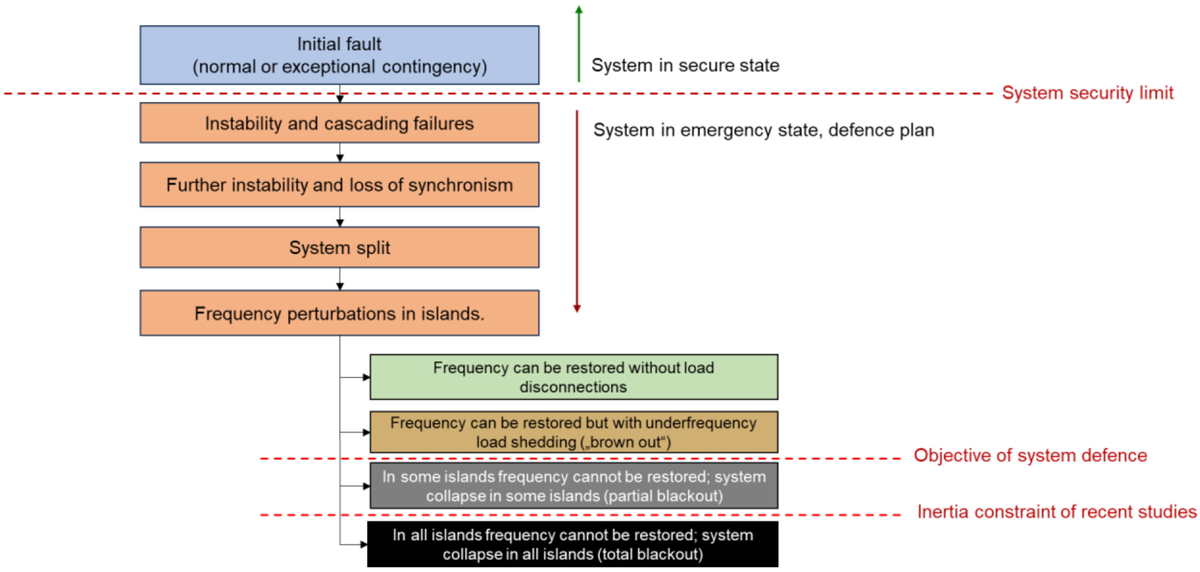

Figure 4: Series of stability events that can lead to major outages or system collapse.

Therefore, to ensure system security, it is important to:

- Ensure that no stability problems occur in the case of Normal or Exceptional Contingencies. Normal and Exceptional contingencies must not cause cascading events and instability resulting in system splits (system security requirement according to [2]).
- Ensure that no other causes trigger cascading events (thermal overload, protection failure, etc.)

In the case that a system split occurs:

- Ensure that "islands" resulting from system split events can "survive", ideally without wide-area load disconnections.
- Avoid a total black out (all islands collapse) if possible.

In the case of a partial or a complete black-out:

- Ensure that there are enough power plants with black-start capability to restart the system.
- Ensure that operator's staff are sufficiently well trained to be able to restore the system as quickly as possible.

To ensure that islands "survive" a system split without collapsing, the following is required:

- There must be sufficient inertia in each island.
- The power imbalance (resulting from power transfers across opened corridors prior to the system separation) is within acceptable limits.
- There is an effective and selective underfrequency load shedding scheme in place.
- Generators reduce their active power output sufficiently quickly to avoid uncontrolled over-frequency disconnection of generators.

- There is sufficient reactive power available in each island to maintain the voltage within the permitted limits.

Impact of VRE on power system stability

Variable renewable energies (VRE, wind and PV generation) can have a considerable impact on system stability as it has been studied and discussed by the literature for many years (compare e.g. [4] [5]):

- The generator technology of (grid following) VRE is different compared to generators of large conventional power plants (converter-driven generators instead of large, directly coupled synchronous machines)
- VRE is typically installed remote from load centres and at lower voltage levels (132kV and below) than large conventional power plants.

Based on this, the impact of VRE on system stability is the following:

- Reduced system inertia.
- Reduced voltage control capability to maintain voltage in the highly loaded areas of the transmission system (reduced reactive capability)
- Larger area exchange flows moving boundary flows closer to stability limits and increasing the active power imbalance in the case that a system split occurs.

It should be noted that the impact of VRE on system stability can be both, positive or negative as e.g. outlined in [4]:

Positive:

- Increased oscillatory stability constrained transfer limits due to the installation of VRE in exporting areas.
- Increased transient stability constrained transfer limits due to the installation of VRE in exporting areas.

Negative:

- Reduced voltage stability constrained transfer limits due to the installation of VRE in importing areas.
- Reduced oscillatory and transient stability constrained transfer limits due to the installation of VRE in importing areas.
- Increased power transfers driving the system closer to its stability limits.
- Increased RoCoF in the case of system splits resulting from reduced inertia.

In addition to the impact of VRE, the following aspects have a negative impact of the stability of the Continental European System leading concerns about the stability of the future CE system:

- Higher loading of long transmission lines enabled by HTLS conductors.
- Larger power transfers resulting from increased international energy trading within Europe (which is also linked to the increased use of renewable energies).

System services to ensure power system stability

To maintain the stability of the CE system in future, additional system services are required to support voltage and synchronizing power and to increase the inertia of the system. These system services can either be provided by power plants (conventional or VRE) or by additional components (like STATCOMs, synchronous condensers, battery energy storage systems etc.), which can either be operated by the TSOs or by independent service providers.

The term “system service” describes a physical behaviour independent from the technical component providing it. System services can therefore be defined differently. The definitions used in this report are the following:

Active power based services:

- mFRR/aFRR:
  Manual/automatic frequency regulation reserve, also named secondary and tertiary frequency control reserve
- FCR:
  Frequency containment reserve, also named primary frequency control reserve
- Frequency-sensitive demand response:
  Automatic disconnection of demand in function of frequency. It is similar to frequency-sensitive load shedding but it operates in the normal frequency band of operation and is usually a paid service.
- Artificial inertia/Fast frequency control:
  Active power control in function of frequency or frequency gradient in a short time frame of less than one second or even less than 500ms.
- Synchronizing inertia (phase jump power and inertia):
  Inertia, which is activated through voltage angle variations (and not by frequency). It contributes synchronizing power to the system and instantaneously activated inertia.

Reactive power based services:

- Static voltage support:
  Reactive power provision in steady state. Is usually not controllable but can only be switched on and off (typically realized by capacitor banks / MSCDNs)
- Dynamic voltage support:
  Reactive power provision in the time frame of milliseconds. Must be automatically controlled at high resolution (continuous variation of reactive power).
- Short circuit current:
  Reactive current support in response to a voltage dip (fault). Is activated in less than a few millisecond (e.g. 30ms). Includes “true short circuit current” (instantaneously activated), as provided by synchronous machines and “reactive current support”, as provided by converter-driven generators and storage.

System restoration:

- Black start capability:
  Capability of a generator to start itself without any grid and to operate an island without support from any other generator

This list includes the most important system services with a focus on system stability.

"Grid forming capability" as a service

During the past years, the discussion around "Grid Forming Capability" as a service (and as a technology) came up in many countries. "Grid Forming Capability" mainly describes a combination of the following active- and reactive power based services:

- Synchronizing inertia (phase jump power and inertia):
- Dynamic voltage support
- Short circuit current

Additionally, "Grid Forming Capability" is often combined with additional requirements regarding resonance stability aspects ("passivity requirements") or operation under phase unbalance.

It should be noted that dynamic voltage support and short-circuit current (reactive current support during grid faults) can also be provided by grid following converters. However, dynamic voltage support, which greatly supports both voltage and rotor-angle stability is usually not required from VRE with grid following converters and therefore not provided neither.

Different technologies can provide different combinations of different system services (see chapter 5) at different cost. Active power based services always require an energy source, which can either be a primary energy source (fossil fuel, wind, solar irradiation, etc.). In the case of short-term services it is possible to use storage components (e.g. battery energy storage, super-capacitors) to provide the required energy. It should be noted that providing active power based services using the primary energy source of a power plant requires the generator to operate with an active power reserve. This can be very expensive in the case of variable renewable energies and therefore, we assume that longer-term active power based services (FCR, aFRR/mFRR) will more and more be provided by storage components, in particular BESS, as it is already the case for FCR (primary frequency control reserve) in Germany.

The provision of synchronising inertia however (phase jump power and inertia), which is the "key-service" of any Grid Forming Capability, can best (at lowest cost) be provided by synchronous machine power plants and synchronous condensers and possibly by utility-scale BESS combined with a grid forming converter.

The provision of Grid Forming Capability from wind and solar plants (power park modules) would be much more expensive (see e.g. [6]) because it requires a considerable re-design of the systems. One option would be to add energy storage components, like super-capacitors or battery energy systems. In this case, the inertia comes effectively from the storage components. In the case of wind turbine generators, it would also be possible to use the energy stored in the rotating masses of the drivetrain and the turbine (blades). However, this requires strengthening the mechanical system of a wind turbine considerably (especially the drivetrain but also the blades and even the tower), because it will be exposed to heavy power surges when being coupled to the electrical system. Both options require a considerable re-engineering and increase the cost of wind and PV power plants considerably.

To ensure that synchronous machine based peaking plants (e.g. H2-gas-turbines) will provide the required Grid Forming Capability, also when they are not generating, they must be equipped with self-synchronizing clutches (SSC) and potentially additional flywheels to enhance their inertia. These are mature technologies that can be provided at relatively low additional cost. In addition to this, these large power plants are directly connected to the transmission level, where synchronizing power and dynamic voltage support to support the stability of the system is most needed.

Quantifying future system service requirements

To assess future needs of system services, there are several studies under way at national and European level. As explained above, the need for stability services and components to provide these services will increase in future because of the following reasons:

- Increased area exchange flows
- Reduced level of synchronous generation (replaced by VRE)

Increased area exchange flows will require appropriate measures to keep the probability of instability resulting in system splits at the same (low) level as in the past. Over the past years, European TSOs have more and more started increasing the thermal rating of transmission lines using HTLS[2] conductors. With higher thermal ratings of transmission lines (higher current ratings), voltage and stability limits must be increased too to enable higher power transfers. This requires the increased provision of reactive power based services that can be delivered by STATCOMs, synchronous condensers or series compensation.

In the case that a system separation (system split) occurs, increased power exchange flows (prior to the split) increase the risk of severe frequency instability resulting in wide-area disconnection of load or even system collapse (“black-out”). Therefore, additional system inertia is needed to make power systems more robust in case of system splits. However, when adding inertia, there is always the risk that the damping of rotor angle oscillations decreases and the risk of severe system splits resulting from oscillatory instability increases.

Therefore, to maintain system security at the same level as in the past, TSOs must ensure that the required amount of system services will be available to stabilize the grid. These services should ensure both:

- that the probability of instabilities resulting in system splits remains at the same level as in the past, meaning that no global instabilities or cascading events occur in the case of Ordinary or Exceptional contingencies, as required by the EU guideline [2].
- That the system is sufficiently robust in in case of system splits.

TSOs can either achieve this through the installation of additional components like STATCOMs, synchronous condensers or series compensation or by procuring the required services from independent service providers (operators of generators, storage plants or independent operators of compensation equipment), as done in GB, through the Pathfinder programme [7].

The amount of additionally required reactive power based services is usually identified at national level, as part of the network development plans.

[2] *High Temperature Low Sag*

The amount of additionally required inertia (requiring grid forming capabilities if provided as synchronizing inertia) and other active power based services, however, must be defined at system level (per synchronous area, e.g. Continental European System).

Several studies have been executed to identify the required amount of inertia of the future CE-system. Based on the most recent study of the ENTSO-E [8], 455 GWs of additional inertia will be required in the CE-system to eliminate all “Global Severe Splits”[3] in the NT2030 scenario and to reduce the number of “Global Severe Splits” to very low values (e.g. 0.15 % of all relevant splits) in all other scenarios studied for 2040. This would be equivalent to around 91 GW of synchronous machine power plants (assuming an equivalent acceleration time constant Ta of Ta=10 s/H=5 s) or around 46 GW/GVA of BESS storage or dedicated synchronous condensers (with Ta=20 s/H=10 s). The distribution of the overall required inertia between the different CE-member states will have to be identified by additional studies.

Summary and Recommendations

Based on already available studies about the future development of generation to ensure CO_2-free power systems (e.g. [9]), the amount of planned synchronous machine power plants, synchronous condensers and utility-scale BESS would be sufficient to provide the required synchronizing inertia providing they are suitably specified. In fact, just the amount of planned H_2-gas-power plants (around 200 GW until 2050) would suffice to cover the additional inertia needs reported in [8] provided they are will be able to operate in synchronous condenser mode with a clutch and a flywheel.

However, the available studies about future needs of system services, especially Grid Forming Capability, are very high level (e.g. based on generic models and not on actual models of the CE-system) and indicate a relatively moderate need for additional system services.

Therefore, we recommend the following way forward:

- Carry out additional studies based on a dynamic model of the actual CE-system (in-line with the network development plans until 2045) to analyse system stability and the need for additional system services (especially Grid Forming Capability).
- Analyse the level of system services that can be provided by existing, well-established technologies at no or very low additional cost.
- Organizing technology-neutral auctions to close the gap at lowest possible cost (CAPEX and OPEX).
- Only in the case that a market-based procurement cannot close the gap, the introduction of mandatory requirements can be justified.

Based on studies and data available today, a market-based procurement of Grid Forming services (e.g. technology-neutral auctions) should be sufficient to cover future system service needs. The introduction of mandatory requirements for all power park modules to provide Grid Forming Capability does not seem to be required, increases the cost of electricity production and could even lead to new stability risks (e.g. reduced frequencies and damping of inter-area oscillations) if not appropriately specified and designed. Instead, dynamic voltage support should become a requirement for all power park modules. This is a well understood technology, could be made available within very short time at

[3] *System splits that can result in a complete black-out of the CE-system*

very low or no additional cost, and would resolve most (but not all) stability issues of the future CE system.

However, securing the stability of the future CE-system should not be limited to system services. It is as important to adjust the operational procedures (operational planning and real time operational procedures) to future system needs and to include procedures and guidelines to operate transmission corridors close to their stability limits. At present, the operational security limits according to Article 25 of the SOGL [2] just define voltage limits, short-circuit current limits and thermal limits (current limits) of transmission lines. Stability limits, which are defined by active power limits, are not explicitly addressed as part of the operational security limits listed in Article 25 of the SOGL.

Stability constraints are addressed by Article 38 and 39 of the SOGL [2], which foresees a three-stage approach:

1. TSOs shall execute a dynamic stability study at least once per year.
2. In the case of planned outages, if stability limits and steady state limits are close or stability limits are even below steady state limits, dynamic stability studies should be executed as part of the day-ahead planning process.
3. If stability limits are below steady state limits in the N-state (all components are available), stability studies should be executed as part of all operational planning processes and in real time operational timescales.

We recommend reviewing this three-stage approach and assess whether it would not better to include dynamic security assessment in the day-ahead or even intra-day operational planning processes (introduction of Dynamic Security Assessment as a mandatory requirement).

Additionally, the SOGL [2] should include clearer guidelines about the identification and the management of stability constrained transfer limits:

- Stability constraints should be expressed by active power limits and not by current limits (in MW instead of Amps) and directly addressed by Article 25 of the SOGL [2].
- Because of the limited accuracy of the models used to identify stability constrained transfer limits, the SOGL [2] should not only address the execution of stability studies to identify stability limits but also define required stability margins.
- Article 39 of the SOGL [2] should not only address transient stability issues (critical fault clearing time) and inertia requirements but also voltage stability constraints, as it could be found in Policy 3 of the old ENTSOe Operation Handbook, especially in Annex 3 to Policy 3 [10]. Corresponding requirements should include:
    - Systematic analysis of the “critical voltage”
    - Definition of upper limits to the “critical voltage”
    - Definition of stability margins (power transfer margins).
- Curative congestion management (“post-fault actions”) should generally not be permitted if a transfer limit is stability constrained and not thermally constrained (in case of a stability constrained transfer limit, there is usually no time to react if the system becomes unstable following a contingency).

By improving the relevant operational processes, it will be possible to maintain system security at the same high level as today, even if the system will operate closer to its stability limits. The required tools and processes are available today. However, the accuracy of these tools always depends on the models used to execute the simulations and we highly recommend not to overestimate it. Stability assessment tools should not only tell whether a power system is stable or not at a given moment in time but should also calculate stability limits and estimate stability margins to account for the limited accuracy of the models and other uncertainties.

2 Introduction

2.1 Background

Stability is a physical property of a system and is defined by the “ability of a system to return to a steady state after having been subject to a disturbance” [1]. In the case that the stability of a power system is lost, wide-area load shedding or even a complete system collapse can be the consequence that can last for several hours or even for more than a day.

The probability of occurrence of such catastrophic events is addressed by the term System Security. Most wide-area interruptions (“Black Outs”) are caused by a global system instability, which brings down the entire system or large parts of it. In the case of a complete “Black Out” (or “system black event”), all power plants are stopped and there is no electricity anywhere in the system (except from local supply by small emergency generators). In case of a “Partial Black-Out”, a large part of the system is down but there are still areas in the system, which remain in operation. Partial “Black-Outs” are usually of much shorter duration than total “Black-Outs” because system restoration is easier if there are areas, which are still in operation.

However, not every instability leads to such catastrophic outages. Only so-called “global stability problems” that span across the whole or at least large parts of a power system may cause a catastrophic wide-area system outage. But there are also smaller, “local stability problems”, which may only lead to the disconnection of a single generator and/or a small number of customers. Therefore, when discussing System Security, the focus is on “global stability problems” that have the potential to drive the system into a global or partial “Black-Out”.

Because of the severe consequences of a power system instability, maintaining the stability of a power system is key to its reliable operation.

However, reliability is not only defined by the stability of a power system. Most customer interruptions are caused by local outages, like transformer or line outages that lead to customer interruptions in a limited area for a limited duration. These local outages have nothing to do with the stability of a power system but mainly define the reliability of a power system, which is usually measured in terms of “number of average annual customer interruptions” or “average customer outage duration”.

In some countries, generation adequacy is an issue, either because of insufficient generation capacity (number of available power plants is insufficient) or because of fuel supply problems (energy problems) and has an impact on the reliability of supply. In those countries local customer interruptions also occur because of planned load shedding due to insufficient generation. In this case, the system operator periodically disconnects customers to reduce the load so that the system can be operated without any risk of system instability. Those interruptions usually occur in the form of “planned load shedding”, meaning that the system operator plans at day-ahead (or “several hours ahead”) time scales, which customers will be disconnected during which period. Ideally, these planned load disconnections are communicated to the concerned customers, so that they can prepare themselves and reduce the consequences of power failures.

Consequently, the reliability of a power system depends on several aspects:

- Generation adequacy (sufficient generation capacity and availability of fuels to drive it)
- Network reliability: High availability of the network components at transmission and distribution levels.

- System stability and system security (defining the risk that the system can survive a large disturbance).

Proper definitions of the terms Reliability, Security and Stability (with reference to power systems) can be found in the report of the joint CIGRÉ-IEEE task force on stability terms and definitions [1].

These definitions are repeated below:

"*Reliability* of a power system refers to the probability of its satisfactory operation over the long run. It denotes the ability to supply adequate electric service on a nearly continuous basis, with few interruptions over an extended time period.

Security of a power system refers to the degree of risk in its ability to survive imminent disturbances (contingencies) without interruption of customer service. It relates to robustness of the system to imminent disturbances and, hence, depends on the system operating condition as well as the contingent probability of disturbances.

Stability of a power system, as discussed in Section II (of [1]) refers to the continuance of intact operation following a disturbance. It depends on the operating condition and the nature of the physical disturbance."

Reliability

A satisfactory degree of Reliability represents the overall objective of the design and operation of a power system. Reliability Indices measure the frequency and duration of supply interruptions at the customer side. A high degree of system Reliability is equivalent to a high availability of the electricity supply service.

The Reliability of a system is further measured in terms of

- Generation Adequacy: The ability of the available generation capacity to supply the energy demand of the system adequately during all times.
- *Network Reliability*: The ability of the grid to transmit and distribute the generated energy to the end-customer.

In case of inadequate generation (meaning that the available generation capacity is insufficient to supply system demand) the system operator manages the problem by executing planned load shedding, meaning that customers are informed about time and duration of service interruptions. Generation Adequacy problems are quite common in developing and emerging countries, if the required expansion of generation cannot follow the increase of demand and consequently generation is insufficient to supply the load.

Because there is adequate generation in Europe, the Reliabiltiy of power systems in European countries usually depends mainly on the failure frequency of components in the distribution grids and the required time to restore electricity supply after the occurrence of an outage.

Reliability is measured by various reliability indices. The most important indices are:

- System Average Interruption Duration (Index) - SAIDI: The average duration of customer outages per year (cumulative, all events per year observed by an average customer)
- System Average Interruption Frequency (Index) - SAIFI: The average number of outages per customer per year (Average number of outages per year that a customer will observe)

In European countries, SAIDI typically ranges between 0.2 hours/year (e.g. Switzerland, Germany in 2019 [11]) and around 3.3h/year (e.g. Romania in 2019 [11]). These numbers typically characterize the system's reliability in terms of "regular events" not considering long duration outages resulting from exceptional events.

Security

The term System Security refers to the degree of risk in the ability of a power system to continue unrestricted operation or operation with low restrictions following a disturbance. Hence, it refers to the robustness of a power system to withstand unexpected events having severe consequences.

Customer interruption can occur because of:

- Insufficient active power reserve requiring load shedding.
- Grid congestion (overloaded lines) that require the disconnection of loads to avoid cascading faults.
- Bus bar voltages are out of permitted ranges leading to load disconnection.
- The system runs into stability problems (Frequency stability, voltage stability, transient stability, oscillatory stability or combinations of several phenomena) leading to wide area load disconnections or even a black-out (exceptional events with long duration).

System Security assesses "risk", which means that both, the probability of contingencies and the consequences of contingencies are considered.

In contrast to System Reliability, which is a long-term attribute of a power system, System Security is a time varying attribute (likewise stability) because the Security of a power system highly depends on its operational conditions. Therefore, system security assessment is not only carried out at planning time scales but also as part of system operation (e.g. "day ahead congestion forecast", "contingency analysis", etc.).

It is an important task of system operators to carry out system security assessment on a continuous basis, as part of the short-term operational planning. In the case that a threat to system security is identified (e.g. grid congestions, low active power reserve etc.) the system operator must initiate suitable preventive mitigation measures to ensure system security, ideally without disconnecting customers. Possible mitigation options without customer interruptions are:

- Additional reserve allocation
- Generator re-dispatch
- Re-switching of lines
- Reactive power re-dispatch (capacitor switching)

In the case that quad-boosters (phase shifting transformers) are available (e.g. in the U.K.) a system operator can also adjust the quad-booster tap settings to mitigate grid congestions.

In the case that a prospective security problem cannot be resolved, a system operator must initiate load disconnections (planned load disconnections).

The term System Security is usually only used in the context of power transmission systems, because only severe events in the transmission system can have consequences spreading over large areas and can therefore lead to the disconnection of large amounts of customers[4].

We can also say that the term System Security mainly refers to the risk of the occurrence of exceptional events causing the wide-area disconnection of customers and a long outage duration, whereas the term Reliability mainly refers to regularly occurring customer outages (with short duration).

Stability

The term Stability is a general term of systems theory (see e.g. [12]). In physical systems, the term Stability is generally used for the ability of a system to return to a steady state following a disturbance.

This general definition also applies to power systems [1]. However, power systems have been studied extensively and typical stability phenomena in power systems have been identified and classified (see chapter 3).

In contrast to Reliability and Security, which characterize the long term or short-term risk of customer interruptions, the term Stability refers to a physical property of the system. Stability issues may or may not lead to customer interruptions, but they have a strong impact on System Security because stability problems increase the risk of customer interruptions and reduce the degree of the reliability of supply.

2.2 Objectives and structure of this report

Historically, rotor angle and frequency stability have been the focus of the industry. However, larger interconnections, the higher loading of transmission lines, the use of more advanced controls and the increased penetration of converter-based generators lets other stability aspects emerge.

This report analyses the question, how system stability can be maintained in a power system that is dominated by VRE with inverter-based generators without any short-term storage capability. It aims at creating an understanding of the different elements of stability, and how they are affected by the change in generator technologies and by increased power transfers across transmission lines enabled by HTLS[5] conductors.

Chapter 3 introduces the main definitions and concepts of power system stability. The presentation of power system stability aspects is in-line with the classification and definitions of the joint IEEE/CIGRE working group on power system stability [1].

Chapter 4 describes the impact of VRE on the different stability phenomena and identifies the main impact on power system stability resulting from the massive integration of VRE.

Chapter 5 introduces the concept of system services to ensure the stability of the power system and presents technologies to provide those services. A special focus of this chapter is on “Grid Forming Capability” as a specific service (or a group / ”package” of services), which currently draws a lot of attention in the industry.

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[4] *No rule without exception: The most relevant exception from this was the so-called “50.2Hz-problem” of rooftop PV in Germany and other European countries: Until several years ago, rooftop-PV-installations were asked to disconnect if the frequency exceeded 50.2Hz (or fell below 49.5Hz). This rule caused a high risk of wide-area disconnection of rooftop PV in case of a frequency excursion (e.g following a system split event) and represented a permanent system security issue.*

[5] *High Temperature Low Sag*

Chapter 6 discusses different strategies to enable the required services, including options with and without remuneration. A special focus of this chapter is on the questions whether it can be justified to introduce “Grid Forming Capability” as a mandatory requirement.

Chapter 7 finally presents an overview of processes and tools that system operators require to securely operate a stability constrained power system. This includes specific procedures to deal with stability constrained transfer limits (in contrast to thermally constrained transfer limits) and tools like DSA (dynamic security assessment) and WAMS (wide-area monitoring systems) and their integration into the relevant operational procedures.

3 Power system stability

The term Stability is a general term of systems theory (see e.g. [12]). In physics, it is generally used to describe the ability of a system to return to a steady state following a disturbance (see also [1]).

The general definition also applies to power systems. However, power systems have been studied extensively and typical stability phenomena in power systems have been identified and classified. The problem of power system stability came up when the first interconnected power systems were built and is studied since then (see e.g. [13] [14]). The classification from 2004 according to [1] is the most referred classification of power system stability phenomena nowadays.

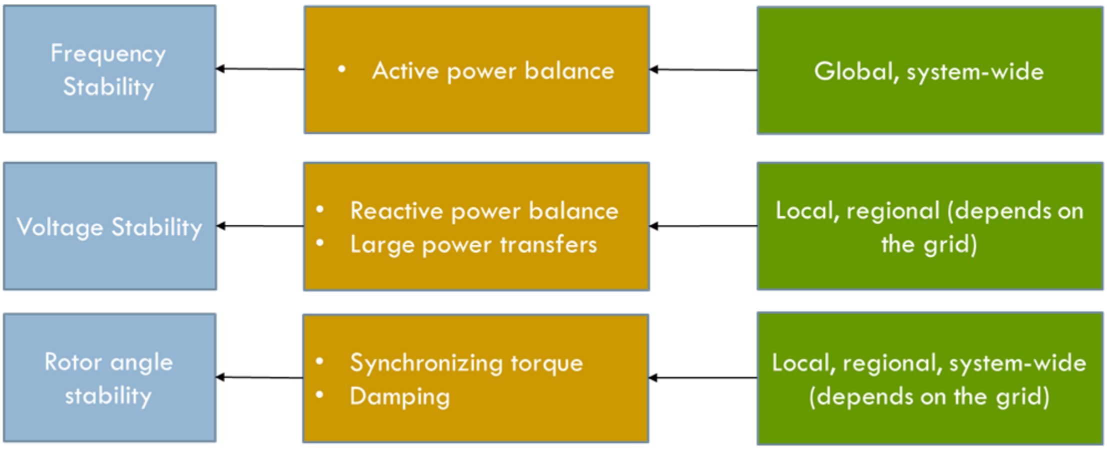

Figure 5:Most important stability phenomena in power systems according to CIGRE/IEEE [1]

This classification considers the following main criteria:

- The physical nature of the resulting mode of instability as indicated by the main system variable in which instability can be observed.
- The size of the disturbance considered which influences the method of calculation and prediction of stability.
- The devices, processes, and the time span that must be taken into consideration to assess stability.

Based on these considerations, the following power system stability phenomena are defined:

- Frequency stability: Ability of a power system to balance active power (generation – load) and to maintain frequency.
- Voltage stability: Ability of a system to maintain a steady state voltage at all bus bars following a disturbance.
- Rotor angle stability: Ability of the synchronous machines in an interconnected power system to remain in synchronism after being subjected to a disturbance.

Besides this classification according to the main variable indicating a stability problem, stability issues in power systems can be classified in terms of:

- Local stability
- Global stability

For example, a local stability issue would be the loss of synchronism of an individual generator (with subsequent trip) or the inability of an individual wind farm to remain connected in the case of a voltage dip (LVRT problem)

A global stability problem would be the loss of synchronism of one area of an interconnected power system, or a voltage collapse that extends over the whole grid.

Frequency stability issues (imbalance between generation and load) are always of a global nature because frequency is generally a global variable. However, this does not mean that the allocation of inertia and other frequency support within a synchronous area is not of any relevance: to ensure that there is sufficient inertia and frequency support in each resulting island after a system split, the distribution of inertia and other frequency support mechanisms is important and must be well thought through.

Rotor angle and voltage stability issues can be both, global and local.

Because the consequences of global stability problems are by far more severe than consequences of local stability issues, global stability problems are by far more relevant to System Security and will therefore be in the centre of interest of the following sections.

Besides the main stability phenomena – frequency stability – voltage stability – rotor angle stability there are other stability issues in power systems, which either occur far less often or which became more important over the recent years (since 2004), due to the wide roll-out of power electronics converters in power systems. These are:

- Sub-synchronous resonance: Series compensated lines tend to interact with the torsional modes of long drive-trains of generator-turbine sets leading to oscillations with low or even negative damping in the sub-synchronous frequency range (frequency range below the fundamental frequency). In case of resonance, torsional oscillations can occur which, in the extreme case, can lead to increased fatigue or even destruction of turbine shafts.
- Sub-synchronous controller interaction: Like sub-synchronous resonance, turbine-generator shafts can also interact with the controllers of power electronic converters. Sub-synchronous controller interactions can have the same consequences as sub-synchronous resonance of series compensated lines.
- Controller instability (super-synchronous or sub-synchronous): Because the controllers of power electronic converters have a very wide bandwidth, they can interact in the whole frequency range. Therefore, undamped oscillations resulting from controller interaction can occur.

More details on sub-synchronous resonance, sub-synchronous controller interaction and controller instability are provided in section 3.4.

In 2014, an IEEE working group has extended the classification of stability phenomena in power systems (see [3]). This extension mainly includes various types of controller instabilities associated with the operation of power electronic converters and the inclusion of sub-synchronous resonance issues resulting from the interaction of series compensated lines and the drive train of large turbine-generator sets. However, the concept of characterizing a stability phenomenon by the “variable with which it can be best observed” got a bit lost in this extension and therefore, this updated classification of stability phenomena in power systems is not as well accepted by the industry as the classification according to [1] from 2004.

Besides the IEEE/CIGRE classifications according to [1], there are other classifications and definitions of power system stability phenomena around using older terms, which were particularly used in Europe, like “Static Stability” and “Dynamic Stability”, whereas “Static Stability” usually refers to small disturbance and “Dynamic Stability” to large disturbance stability phenomena (resulting from faults).

The publication [15], which was written by some of the most recognized German stability experts at the time (mid of the nineties) uses the terms:

- Short-term stability:
    - Static stability: used in the same sense as Oscillatory Stability according to [1]
    - Transient stability: used with the same meaning as in [1]
- Primary control (time frame between seconds and minutes):
  Frequency stability and low-frequency inter-area oscillations
- Voltage stability (minutes to hours):
  same as “long-term voltage stability” according to [1]

Even today, the term “angle stability” is used quite often, especially in Europe. “angle stability” can have a different meaning than “rotor angle stability”: whereas “rotor angle stability” always refers to electro-mechanical interactions, the term “angle stability” refers to the voltage angle only. In fact “angle stability” can be both “rotor angle stability” or “voltage stability”.

This report uses the terms and definitions of the CIGRE/IEEE working group of 2004 [1] because it represents the most widely accepted set of power stability definitions.

3.1 Frequency Stability

The frequency in a power system indicates whether there is an excess of generation (more generation than demand) or a generation deficit (less generation than demand) in the system. In the case of an excess of generation, the frequency rises, in case of a generation deficit, the frequency drops.

However, it is not directly the frequency that indicates whether there is a generation deficit or excess of generation but it’s the rate of change of frequency that shows it: The rate of change of frequency (ROCOF) is in proportion to the generation excess/deficit and in proportion to 1/J, with “J” being the inertia of the system.

“Inertia” essentially quantifies the rotating masses in the system: The higher the rotating masses the lower is the rate of change of frequency resulting from an active power disturbance.

Frequency stability always refers to the average frequency[6] of a system (or centre of frequency). Right after a disturbance, local frequency measurements will show the superposition of the average frequency and oscillations resulting from rotor angle transients (see Figure 6). The description of these oscillations (frequency of oscillation, damping etc.) is characterized by rotor angle stability phenomena (see section 3.3).

[6] *More precisely, it’s the weighted average of the speed of the generators, also named “center of frequency”. The weighting factors are the inertias of the generators.*

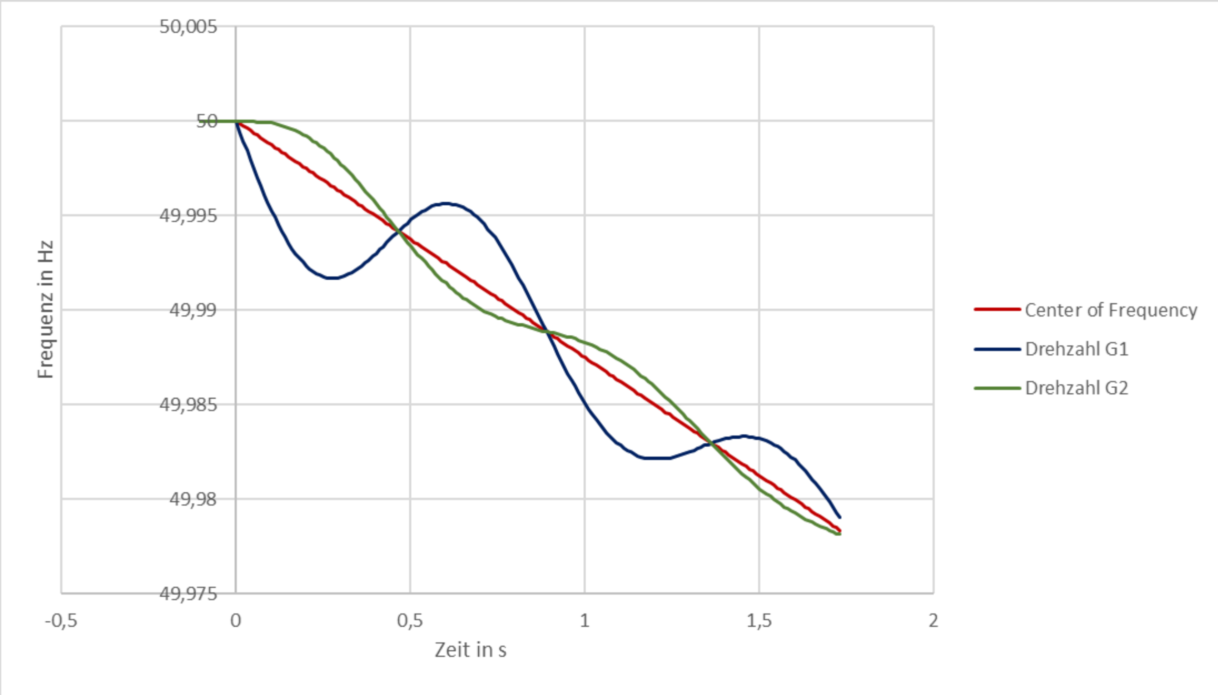

Figure 6: Centre of frequency with superposition of the local frequency at two different generator nodes.

Assuming that all generators of a system are synchronized, the total inertia (or system inertia) is the sum of the inertias of all individual generator-turbine-sets of the system. Consequently, frequency stability is always a global stability phenomenon that applies to a complete synchronized area of a power system (e.g. the complete continental European synchronous area).

Different frequency control mechanisms are in place to re-establish the power balance and to bring back frequency to its nominal value (50Hz in the ENTSO-E-network) after a disturbance:

- Frequency Containment Process (FCP, primary frequency control): The Frequency Containment Process is a decentralized frequency control mechanism. The turbine of each individual generator that participates in Frequency Containment increases its power generation in proportion to a frequency drop (or decreases it in proportion to an increase of the frequency). This ensures that frequency stops dropping/rising and is driven back into a band of typically +/-200mHz around nominal frequency (50Hz). Frequency Containment typically operates in a time frame of several seconds (e.g. 30s to activate the Frequency Containment Reserve).
  To be able to increase active power in case of a frequency drop, generators participating in the FCP cannot operate at full power but must keep an active power reserve (FCR, Frequency Containment Reserve).
- Automatic Frequency Restoration Process (aFRP, Secondary frequency control): The Automatic Frequency Restoration Process is a centralized control mechanism, which brings back frequency to its nominal value and which re-establishes the scheduled area exchange flows of an interconnected power system. Classically, there is one secondary controller in each control area of an interconnected power system that sends signals to those generators that participate in the aFRP (Secondary Frequency Control). The aFRP operates in the time

frame of several minutes (e.g. five minutes to fully activate Automatic Frequency Regulation Reserve) and de-loads the Frequency Containment Reserve (FCR) so that it is available again to compensate another disturbance.
To be able to participate in the aFRP, generators must keep an active power reserve (aFRR).

In addition to FCP and aFRP, there is the tertiary frequency control (Manual Frequency Regulation), which is not really a frequency control mechanism but rather a re-optimization of the use of active power reserves needed to re-establish the power balance after a disturbance. mFRR is manually activated by the transmission system operator (by remote control signals or even telephone). mFRR must be activated within around 15min (slightly different in different parts of the ENTSO-E network).

Besides the above-described control mechanisms, the load supports the frequency stability of the system too: System demand is frequency-dependent, meaning that demand drops with decreasing frequency and increases with rising frequency.

Assuming that sufficient frequency control reserve is available, frequency stability mainly refers to the initial seconds following an active power disturbance, which is defined by the available inertia and the speed of activation of FCR.

3.1.1 Frequency stability in case of a generator outage

In the case of an unplanned disconnection of a generator (e.g. resulting from a fault), the active power balance of the system is disturbed, and the system experiences an active power deficit. As a result, frequency drops in proportion to the power deficit and in proportion to 1/J (one over inertia), meaning that:

- The larger the active power deficit the larger is the rate of change of frequency (ROCOF)
- The higher the inertia of the system, the smaller is the ROCOF.

This is visualized by Figure 7, in which frequency following a generator outage is shown for two different values of the system inertia (which is expressed by the equivalent acceleration time constant). As shown by these diagrams, the initial frequency rate of change (ROCOF) increases with decreasing inertia and the minimum frequency (frequency-Nadir) decreases with decreasing system inertia.

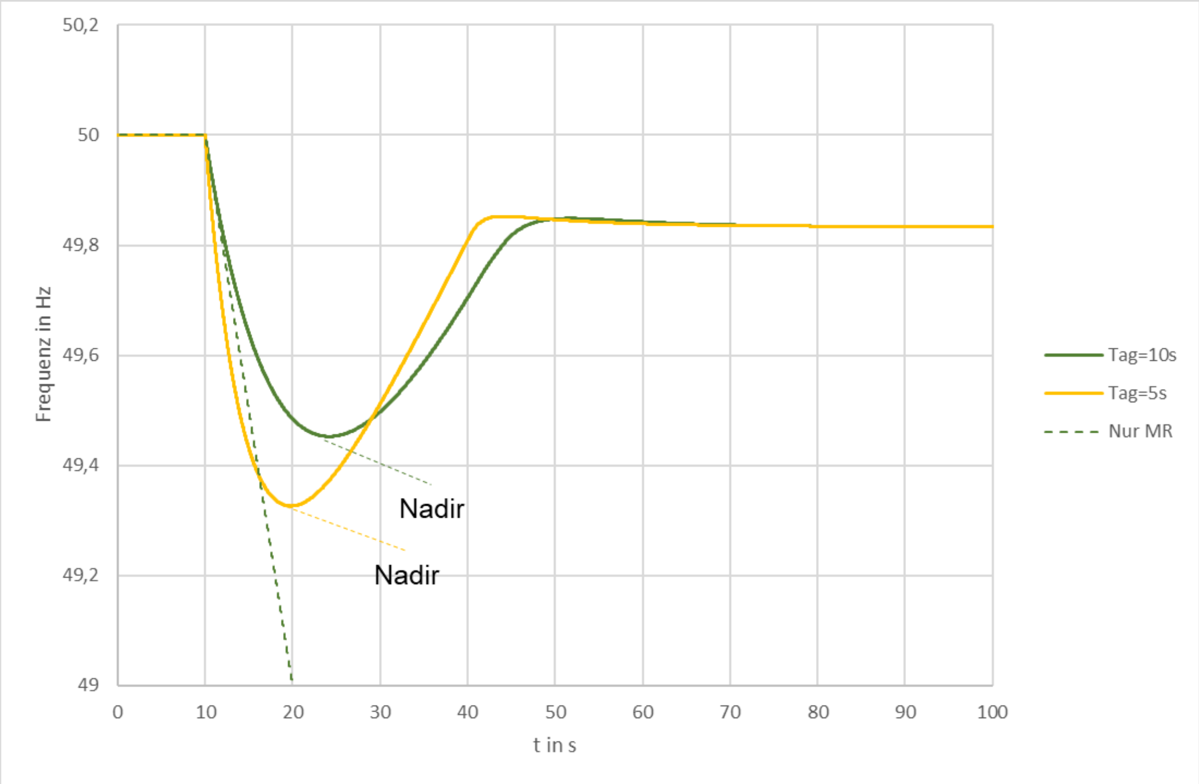

Figure 7: Frequency drop following a generator outage in function of system inertia (equivalent acceleration time constant): green: larger inertia, yellow: small inertia

If system inertia is too low and the activation of the available FCR is too slow to effectively maintain frequency above 49 Hz, the first load shedding stage will be triggered, meaning that a part of the load will automatically be disconnected[7]. This is an emergency measure which is required in situations, in which the available FCR is not able to compensate a generation deficit.

In the Continental European system, FCR should always be equal to 3000MW so that the simultaneous outage of two large nuclear power plants can be compensated by the available FCR without load shedding ("design event"). In this "design-event", the frequency must remain above 49,2 Hz so that the first load shedding stage at 49 Hz is not yet triggered.

3.1.2 **Frequency stability in the case of system separation**

Frequency stability problems can also occur if an interconnected network separates into two or more islands (system split event). According to the EU commission regulation [2], a system split may not occur in the case of ordinary or exceptional contingencies. Only in the case of a very unlikely event, which is not considered by the regular system security assessment of the TSOs a system separation may occur. Because the probability of system splits is therefore very low, it is permitted that frequency excursions resulting from system split events are managed with the support of automatic load shedding.

Figure 8 shows the example of an interconnected system with two areas. Prior to the separation of the systems, area A1 exports power and area A2 imports power. Consequently, area A1 will experience a

[7] *49 Hz is typically the first load shedding stage in the CE-system. In other system, frequency setpoints for underfrequency load shedding may be different.*

power excess and area A2 will experience a power deficit following the opening of the interconnector. As a result, the frequency in area A1 will rise and the frequency in area A2 will drop (see Figure 9). It is interesting to note that this not only happens in the case of synchronously interconnected areas but also in the case of HVDC-connected areas.

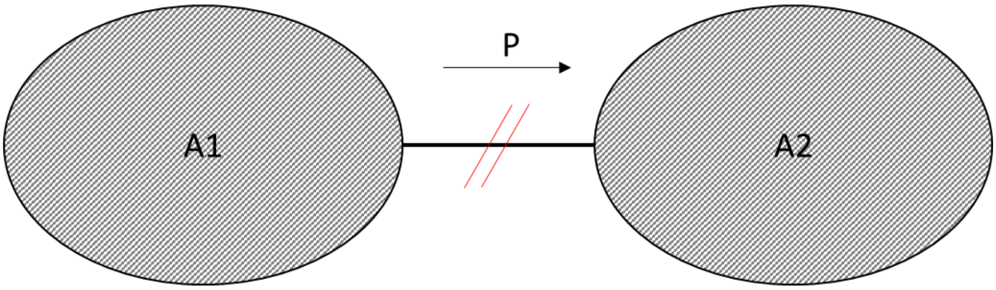

Figure 8: System split of a two-area network

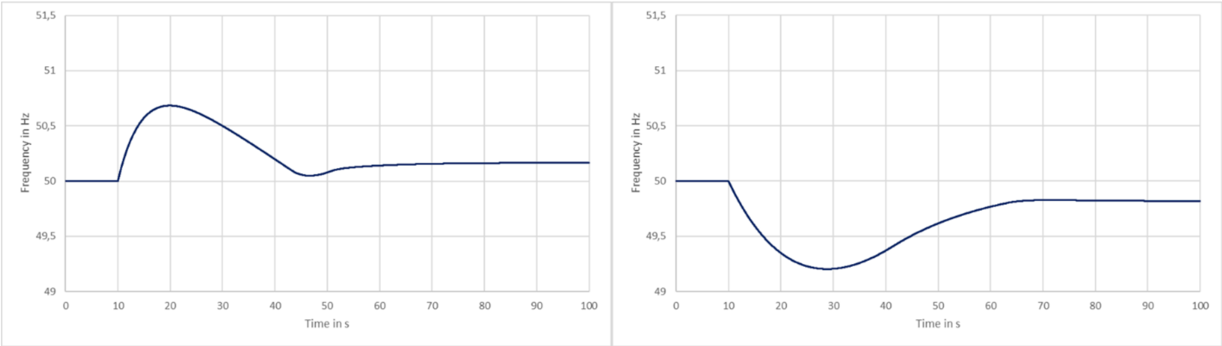

Figure 9: Frequency in area A1 (left) and area A2 (right) following a system split during a power transfer from A1 to A2

Whereas a frequency decline can generally well be managed by automatic load shedding, a frequency rise is more critical because it may trigger the uncontrolled disconnection of generators. Consequently, there is a high risk that too much generation is disconnected because of high frequency, resulting in a large active power deficit and a wide-area disconnection of load (“brown-out”) or even a system collapse (“black-out”).

To ensure that the two-area network according to Figure 8 remains stable in case of a system split, a system operator must ensure the following:

- There must be sufficient inertia in both areas, A1 and A2.
- The area exchange flow P must remain below a critical value so that, the power deficit/power excess following a system split remains in a range that can be managed by A1 and A2.
- To be able to manage the active power imbalance, the exporting area A1 requires sufficient amount of LFSM-O (generators with high-frequency response) and the importing area will mainly use load shedding (supported by FSM and LFSM-U (low-frequency response) and possibly frequency-sensitive demand response).

Consequently, when securing the system against system-split events, additional operational constraints must be considered (inertia, availability of LFSM-O and maximum area exchange flows).

In case of the Continental European system, this is quite complicated because it is not clear, at which points in the network the system may potentially separate. Therefore, it is also unclear, which power exchange flows should be limited and how system inertia should be distributed. Most studies about frequency stability refer to past events, like the European system split event in 2006 (see Figure 10). This event caused the CE system to separate into three areas, whereas two areas were running in under-frequency and the north-eastern area experienced an over-frequency following the system split.

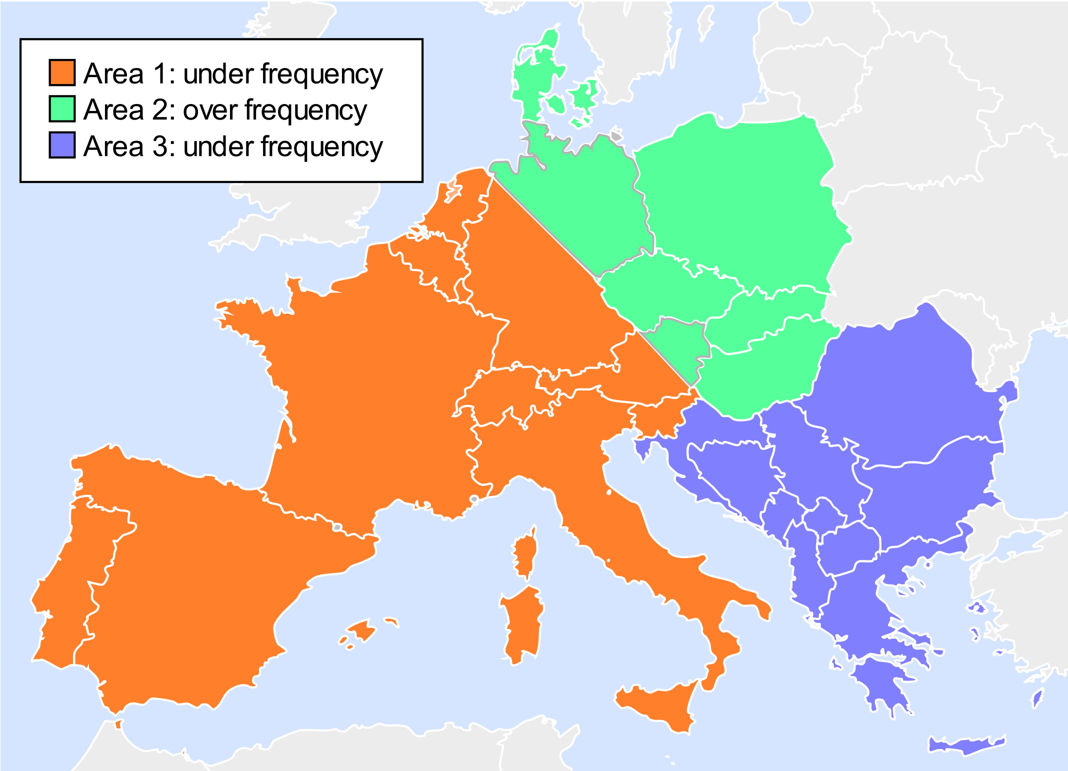

Figure 10: System split in Europe in 2006[8]

Recent work at ENTSO-E-level [8] and in the context of the German network development plan [16] address this issue and identify additionally required inertia (kinetic energy) in function of various possible system splits across the CE-system.

The two criteria, which mainly define whether a system split is manageable in each of the areas after the split (using load shedding in the importing and LFSM-O in the exporting area) are the following[9]:

- RoCoF is below 1 Hz/s: -1 Hz/s< RoCoF <1 Hz/s
- Frequency remains within the following band: 47,5 Hz < F < 51,5 Hz

According to ENTSO-E policies (see e.g. [8]), the objective is to secure the system against so-called Global Severe Splits. A Global Severe Split is defined by a system split into two areas, which is not manageable in both islands so that there is a highly increased risk of a total black-out of the RG CE system.

[8] *Picture is from* [37]

[9] *Load shedding is supported by primary frequency control/FSM and LFSM-U.*

Events, which drive only one of the two islands into a collapse (partial black-out) are tolerated by these studies. Partial black-outs are considered to be far less severe than a total black-out because less customers are interrupted and the system restoration time is considered to be considerably shorter.

The ENTSO-E-report [8] identifies an additionally required system inertia of 445 GWs (kinetic energy) for the scenario NT-2030, which corresponds to 255 synchronous condensers with a rating of 250Mvar each and an acceleration time constant Ta=14 s to be installed in the RG CE system (or around 237 E-STATCOMs with a rating of 300 Mvar/150 MW each and Ta=25 s).

The German network development plan identifies the need for more than 1000 GWs of additional inertia (kinetic energy) to be installed in Germany until 2037 (80 Gvar of installed E-STATCOM capacity with Ta=25 s or 532 E-STATCOMs with a rating of 300 Mvar/150 MW) [16]. This is substantially more than in the ENTSO-E-analysis, especially when considering that this is only in Germany. However, the German analysis refers to the year 2037 with considerably more VRE than in 2030. Secondly, the methodology to identify the additionally required inertia is different from the methodology applied in [8] and seems to be extremely conservative.

3.2 Voltage Stability

Voltage is the parameter in a power system that indicates a reactive power imbalance. In contrast to frequency, which is a global variable, voltage can vary considerably between different areas or nodes. Unlike active power, reactive power cannot be transferred across large distances and therefore, reactive power must be provided locally, in the same area or node where it is needed. Depending on the source of the reactive power problem, this should be next to a highly loaded transmission line or a very large load.

Even if voltage stability mainly depends on the reactive power balance, there is a strong link between active power flows and voltage stability: Because the reactive power demand of transformers and transmission lines highly depends on the current flowing across it, voltage stability depends on the active power flows too. The larger the reactance associated with the branch component, the larger is its reactive power demand. Therefore, especially in the case of long transmission lines, a voltage instability is usually initiated by large active power flows resulting from unplanned line disconnections and a lack of reactive power support.

The term “voltage stability” is used for different phenomena in power systems, which have in common that voltage cannot be maintained within the permitted limits. It is used for small disturbances resulting from a lack of voltage control capability or for large disturbance instabilities resulting from line disconnections or generator outages. A voltage instability can express itself by an under- or an overvoltage.

A voltage collapse occurs if the required active power flow across a long transmission corridor exceeds its stability constraint transfer limit. In case of a voltage instability, the voltage at one or both sides of a highly loaded transmission corridor goes down to very low values and finally, the synchronism between the interconnected areas gets lost. A voltage-stability constraint transfer limit is an active power limit defining the maximum power that can be transferred across a transmission corridor while maintaining stability.

Above the voltage-stability constrained transfer limit, there is no steady-state solution of the power flow problem (see Figure 13 and Figure 14). Therefore, the system collapses: voltages go down to almost zero and synchronism is lost. Because a voltage collapse always leads to a loss of synchronism too, corresponding instabilities are often also named “rotor angle instability” or just “angle instability”. Especially in Europe, it is very common to name corresponding instabilities “dynamic instability” or “angle instability” (see e.g. [17] or [18]), or even “transient stability” (for short-term voltage instability, see [16]), whereas outside of Europe, the term “voltage stability” is used consistently with the same meaning as in this report (see e.g. [19] or [20]). However, we do not want to discuss, which definitions are “right” or “wrong” but we would like to highlight that these stability definitions are not applied consistently, which can lead to misunderstandings.

In this report, a voltage instability is an instability that results from the fact that the steady state transfer limit of a reactance (whether it is a line, a transformer or a complete transfer corridor) are exceeded leading to both, a collapse of voltage magnitude and voltage angle (loss of synchronism).

In contrast to the violation of a thermal constraint (exceeding the current limit of a transmission line), which can be tolerated for up to around 15 minutes (can also be shorter or longer, depending on the degree of overload), a voltage collapse develops within seconds or even milliseconds once the voltage stability constraint transfer limit is exceeded. Therefore, it is not acceptable to tolerate the exceedance of a voltage stability constraint transfer limit, event not for short periods of time. Also, managing voltage stability constraints by post-fault actions (e.g. automatic inter-tripping or automatic run-back schemes) is very risky because it requires very fast and reliable schemes to avoid a voltage collapse once the transfer limit has been exceeded.

When analysing voltage stability, the analysis usually focuses on “boundaries” that split the system into two or more areas (see Figure 11 and Figure 13). The lines crossing these boundaries define a transmission corridor.

A voltage stability constraint transfer limit depends on the following quantities:

- Equivalent impedance of the transmission corridor: the higher the equivalent impedance, the lower is the voltage-stability constraint transfer limit (maximum active power flow).
- Reactive power reserves at both sides of the transmission corridor: the higher the voltage control capability (reactive power capability) at both sides of the corridor, the higher is the transfer limit.

In the short-term, e.g. after the sudden disconnection of a line, the “Equivalent impedance” highly depends on power sources and sinks. In the time frame of a few hundreds of milliseconds, “sinks” are formed by grid forming components, like synchronous machines or generators with grid forming converters, which maintain a “stiff” voltage angle in this time frame and absorb or inject active power as required. In other words: the more “grid forming components” there are, the lower are the equivalent impedances of the relevant transmission corridors in the very short-term (few hundreds of milliseconds).

The voltage stability constrained active power flow limit can best be visualized using so-called P-V-curves (see Figure 13). The P-V-curves in this diagram show voltage in function of active power for two cases:

- N-0 case (orange): all lines of the transmission corridor in operation.
- N-1 case (red): one line of the transmission corridor out of operation.

The displayed node is voltage controlled and therefore, the voltage is equal to 1 p.u. (nominal voltage) if the reactive power reserves at this node are sufficient to control the voltage. As soon as the reactive power limit at this node is reached, the voltage starts decreasing.

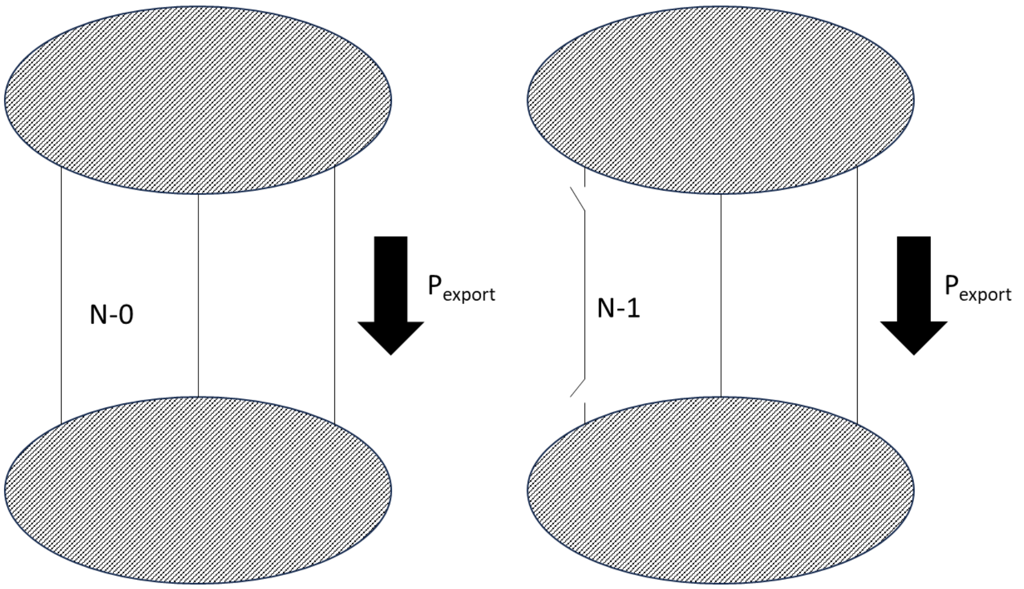

Figure 11: Area exchange flow

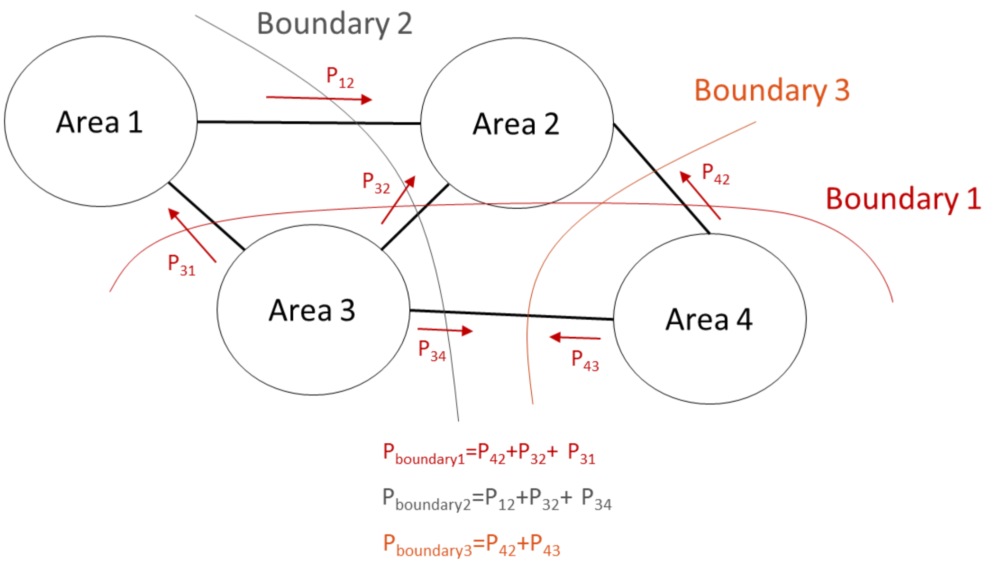

Figure 12: Definition of boundaries and transmission corridors crossing these boundaries.

As shown by the diagrams of Figure 13, there is a maximum active power flow ("Plim N-0" and "Plim N-1") that can be transferred across the transmission corridor. A steady state active power solution is always represented by the crossing between a vertical line representing the intended active power transfer and the red or orange curves representing the network characteristics. Above the limits (Plim N-0 or Plim N-1), no such crossing is possible meaning that there does not exist any steady state solution above these limit values. If, because of the load or by means of controls, the system tried to transfer more active power across the transmission corridor than possible (above Plim), the system would become unstable und would run into a voltage collapse.

Because of voltage constraints (in this case, the minimum permitted voltage is assumed to be equal to 0.95 p.u., which would be 380 kV in a 400 kV grid), the maximum power that could be transferred across the boundary would be equal to around 2700 MW (shown by the blue line, labelled “Pmax N-1”), which would be around 900 MW below the voltage stability constrained transfer limit of 3600 MW (shown by the dashed red line “Plim N-1”). The critical voltage ($Ucrit_{n-1}$ and $Ucrit_{n-0}$) is well below the minimum value of 360 kV (0.9 p.u.) under n-0 and n-1 conditions

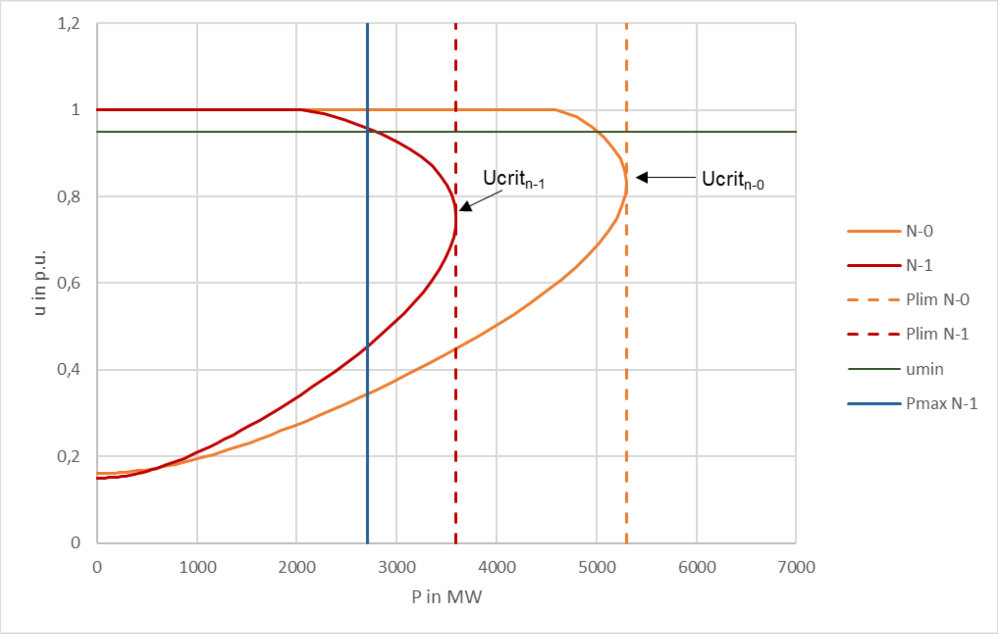

Figure 13: P-V-curves and voltage stability limits

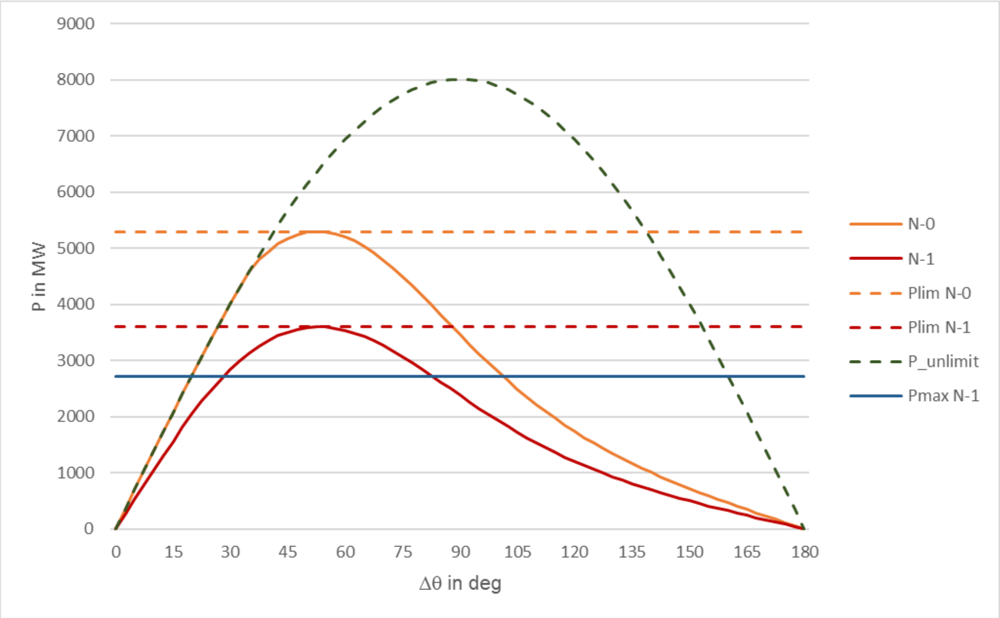

Figure 14: P-ΔΘ-curves and voltage stability limits

Figure 14 shows active power against the voltage angle difference between both ends of the transmission corridor. The green dashed curve (“P_unlimited”) shows the sinusoidal transfer characteristic of the transmission corridor for constant voltages at both ends of it (unlimited reactive power capability). The orange and red curves show the corresponding curves with limited reactive power capability (and voltages according to Figure 13).

When comparing the maximum value of the green dashed line (unrestricted reactive power) with the maximum values of the orange and red curves (restricted reactive power) it can be seen that the limit of stable power transmission is considerably reduced due to reactive power limitations. At the same time, the curves according to Figure 14 show that it is plausible that both, voltage magnitude and voltage angle “collapse” in the case of a voltage instability.

In the case of synchronous machines, the rotor angle of the generators would lose synchronism if the power generated by the turbine exceeded the transfer limit. In the case of converter-driven generators, the PLL (phase locked loop, device to measure the voltage angle) would lose synchronism and the converters would run out of step.

To increase the voltage stability constrained transfer limit, additional reactive power compensation can be installed so that the voltage can be controlled in a wider range. As shown by Figure 15, the transfer limit increases due to the increased reactive power range (from around 3000MW to around 4000MW in this example). However, the limit of voltage instability moves at the same time to higher voltages. As shown by the diagram according to Figure 15, maintaining the voltage above 0.95 p.u. under N-1 conditions means in this case, that the system is operated right at the limit of voltage instability.

Figure 15 shows the impact of a larger reactive power capability on the voltage stability constraint transfer limit: When extending the reactive power capability, the stability limit (expressed by the maximum possible active power transfer) moves to larger values. However, the diagram according to Figure 15 also shows that with the higher reactive power capability, the limit of voltage instability moves into the normal voltage band of operation. This can be dangerous because the voltage does not indicate any more that the system is close to its stability limit: the operator may think that the system operates in a secure state, but in reality, it is at the edge of voltage stability: just a minor increase of the active power transfer would drive it into a voltage collapse.

Therefore, it is important to ensure that the limit of voltage stability is always in a voltage range that is out of the permitted voltage band of operation. This can be achieved by appropriately defined control characteristics of the STATCOM controllers (e.g. sufficiently large droop of the voltage control characteristic) or by the installation of series compensation instead of shunt compensation (see section 5.3.11) to enhance the stability of a transmission corridor.

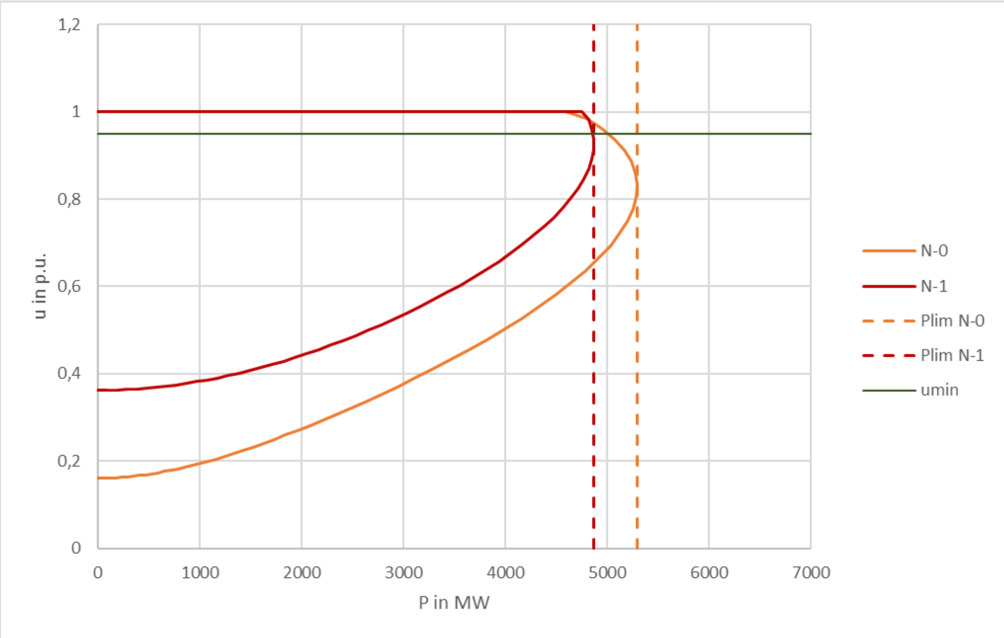

Figure 15: P-V-curve: high reactive power capability

3.2.1 Long-term voltage stability

A long-term voltage instability develops over a timeframe of minutes or even hours. Usually, it is initiated by a series of events, very often by cascaded line disconnections and/or generator outages in the importing area. Resulting from cascading events, a power system can be driven slowly, within a time frame of minutes or even hours, into a voltage instability (therefore the name “long-term” voltage instability).

The examples according to Figure 16, Figure 17 and Figure 18 demonstrate how a long-term voltage instability typically develops.

The example according to Figure 16 shows the development of a voltage instability by a series of events, which increase the power transfer across a line (e.g. several generator outages in the importing area). As soon as the power transfer exceeds the stability limit (red line) the system collapses.

In Figure 17, the voltage instability is initiated by a reduction of the stability limit while the power import remains constant. Such a reduction of the stability limit can be caused by a series of line outages in a transmission corridor (cascaded line outages). When the stability limit drops below the power import, the system collapses.

Figure 18 shows an example, in which the instability is initiated by both, a reduction of the stability limit and an increased power transfer. In most cases, a voltage instability is a combination of both, cascaded line disconnections and generator outages in the importing area. When the voltage starts dropping, generators may disconnect because of undervoltage, which increases the power import, reduces the reactive power control capability of the importing area and accelerates the development of a voltage collapse.

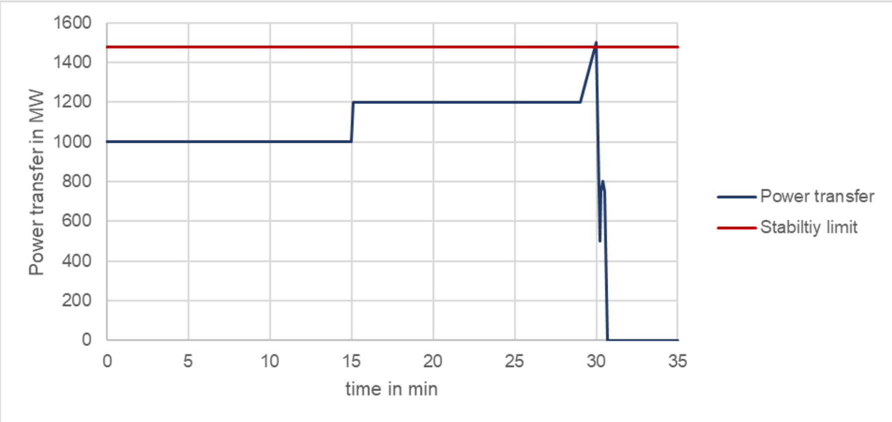

Figure 16: Long-term voltage instability caused by increased power transfer (generic example).

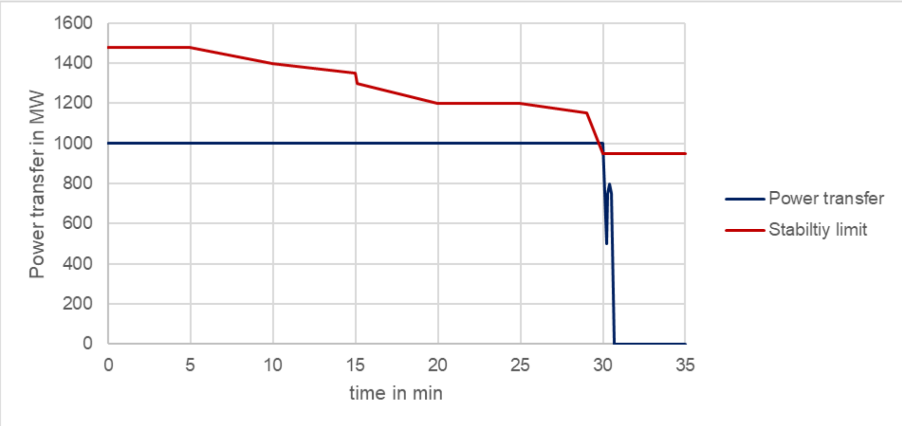

Figure 17: Long-term voltage instability caused by a reduced transfer limit (generic example).

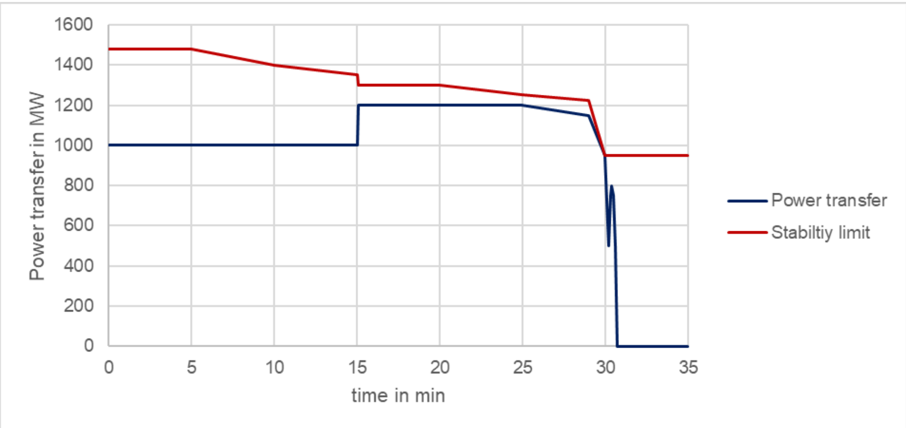

Figure 18: Long-term voltage instability caused by increased power transfer and reduced transfer limit (generic example).

Long-term voltage instability is the most frequent cause of system splits and black-out events in power systems. Well-known examples are:

- System black event in South Australia in 2016 [20]
- Black-out in Italy in 2003 [21]
- Northeast black-out in USA 2003 [19]

More recent system split events in the Continental European System were caused by long-term volage instability too (even if the term “voltage instability” is not used in the reports analysing these events):

- Separation of the Spanish and Portuguese systems from the rest of the CE-system in 2021 [17]
- System split in Turkey in 2015 [18]

Figure 19 shows the voltages at several nodes of the South Australian grid, right before the system black event in South Australia in 2016. The red line shows a voltage in Heywood, the Victorian side of the Heywood interconnector (interconnector between South Australia and the rest of the NEM-system), which remained in operation during this event. All other lines show voltages at the South Australian side of the Heywood Interconnector.

In this event, the voltage collapse was initiated by the disconnection of several wind farms in South Australia resulting from multiple voltage dips within several minutes caused by very severe weather conditions (see Figure 20). The loss of generation in South Australia led to an increased power import into the South Australian transmission grid which finally exceeded the voltage stability constrained transfer limit between South Australia and the rest of the NEM-system. This sequence of events finally caused a voltage collapse as shown by the curves according to Figure 19.

While the voltage collapsed, the frequencies (and consequently also the voltage) in the South Australian system and the rest of the NEM-system drifted apart, as shown by Figure 21.

Finally, the Heywood Interconnector opened because of “loss of synchronism” and the NEM-system split into two areas. Because the inertia in the South Australian Island was extremely low and the power deficit was very high at the time of the system separation, the South Australian system experienced a frequency collapse when being islanded (as explained in section 3.1.2).

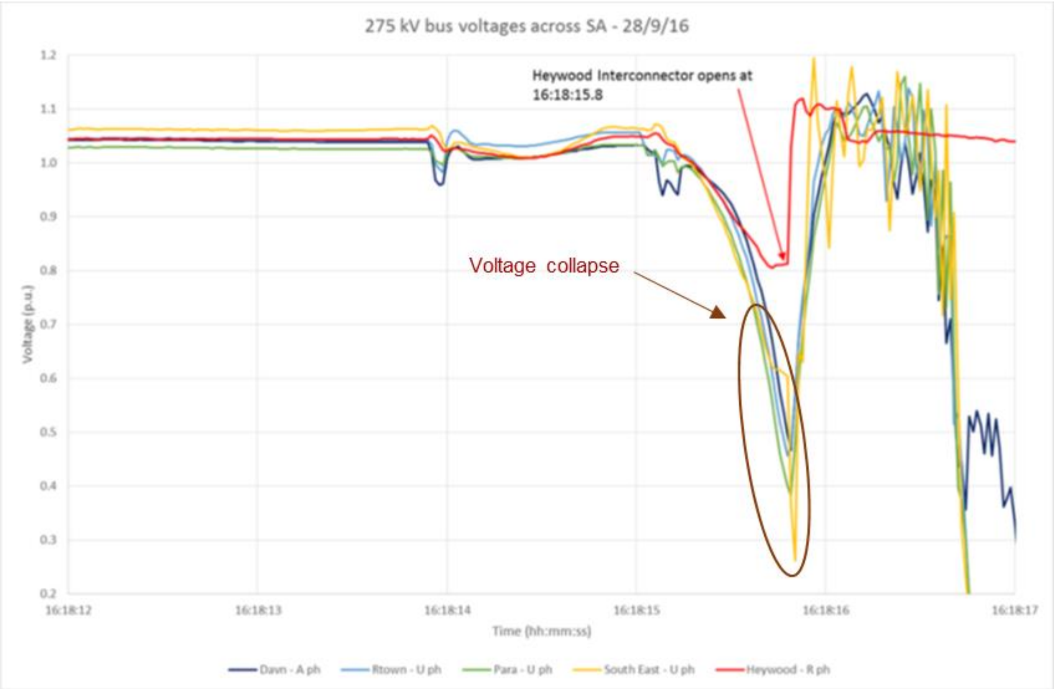

Figure 19: Voltages around the Heywood Interconnector/Australia, during the system black event in 2016 (taken from [20])

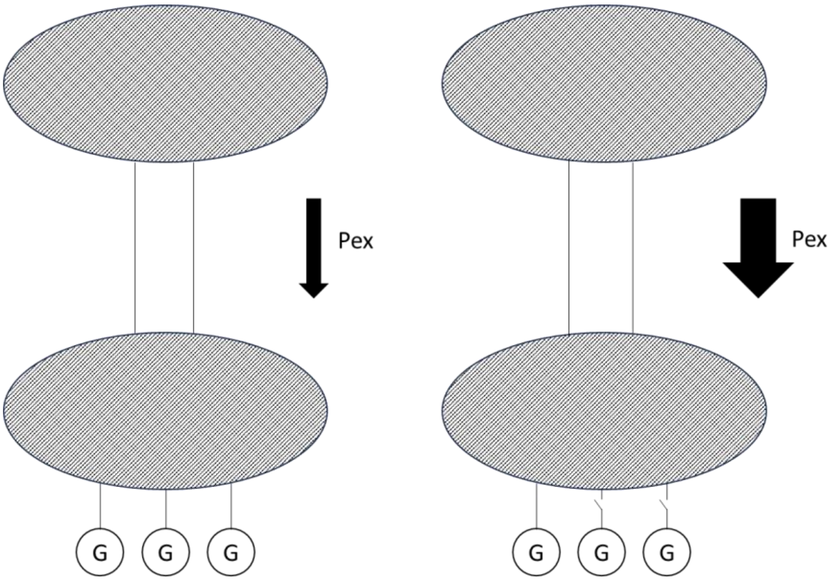

Figure 20: Disconnection of generators in an importing area resulting in increased power exchange.

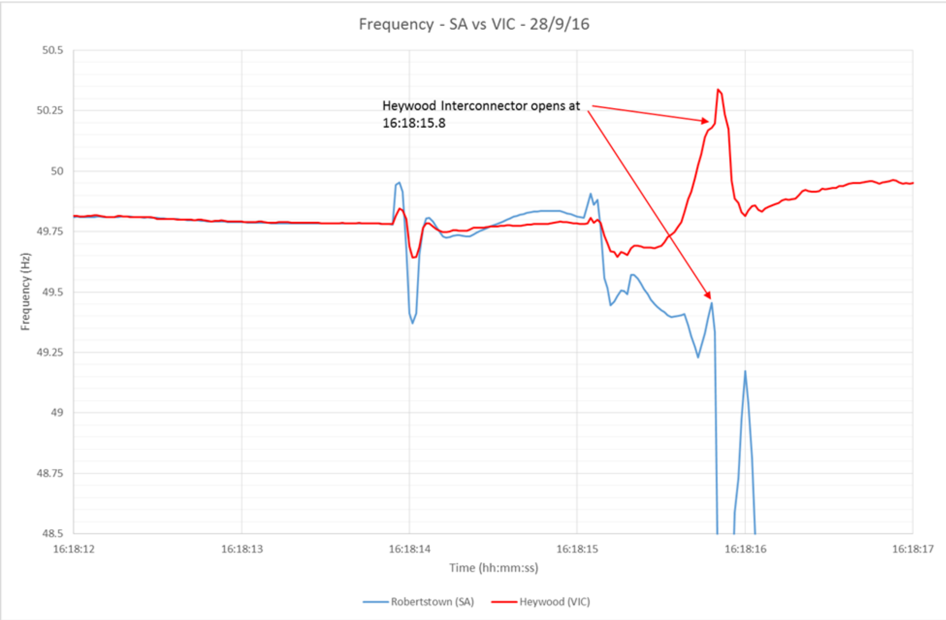

Figure 21: Frequency around the Heywood Interconnector/Australia, during the system black event in 2016 (taken from [20])

The South Australian example was a voltage instability that was initiated by the loss of generation (wind farms) in an importing area leading to increased power exchange between two areas. Insufficient dynamic reactive power reserve in the South Australian network had an additional negative impact on the voltage stability constrained transfer limit of the Heywood Interconnector.

However, a voltage instability can also be initiated by a reduced transfer limit resulting from cascaded line disconnections (see Figure 22).

This happened in Europe in 2003, when a highly loaded line in Switzerland tripped, causing overloads and consequential trips of other lines in Switzerland and between Austria and Italy. These cascading events finally resulted in a voltage collapse in Italy [21]. As a result of this voltage collapse, the Italian grid lost synchronism with the rest of the Continental European System, was disconnected from it, and finally collapsed because it could not survive as an island.

As a result of the cascaded line disconnections, the equivalent impedance of the transmission corridor between Italy and the rest of the Continental European transmission system increased and consequently the voltage stability constrained transfer limit dropped below the required import into the Italian system. In the event of 2003, measures to reduce the power import into Italy (e.g. stopping pumped storage plants etc.) failed and finally the Italian system collapsed resulting from a long-term voltage instability.

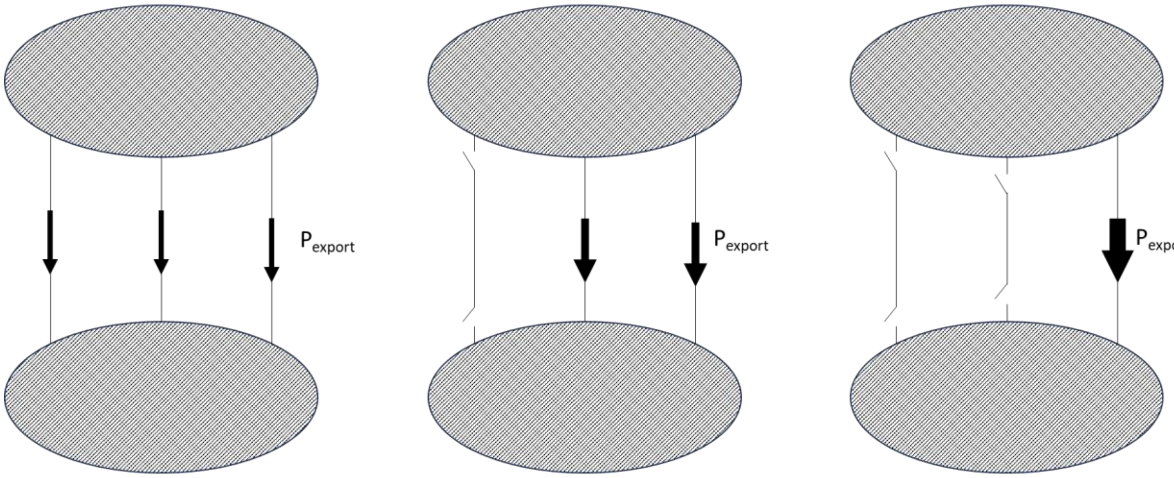

Figure 22: Cascading events

Impact of the load on voltage stability

In the short-term, the system load is strongly voltage dependent. Therefore, in case of a sudden voltage decrease, the system load decreases too, which may reduce the power transfer across a critical interconnector or boundary. In the longer term however, automatic tap changers may step up trying to restore the voltage at the secondary side of the distribution transformers (e.g. at the 20-kV-side of distribution transformers), which increases the power demand. Consequently, it can happen that with each tap action, the system is driven closer to the voltage stability constraint transfer limit and finally into a voltage collapse.

3.2.2 Short-term voltage stability

Especially with the introduction of fast-controlling power electronic devices, short-term voltage instability became more and more important. In contrast to synchronous generator-based power plants, which control active power in the time frame of several seconds, converter-driven generators (e.g. solar inverters, wind turbine generators with fully-rated converters / IEC-type-4, or doubly-fed induction machines / IEC-type 3) control the electrical active power within less than a second (typically within tens or hundreds of milliseconds). Consequently, a voltage instability can develop within a very short time frame, especially if the voltage is temporarily low, e.g. because of a fault.

This problem can be mitigated by reducing the active power of power electronics converters in proportion to the voltage. A reduced active power injection makes a short-term voltage instability much less likely. However, it must be ensured that active power is restored quickly after the voltage has been restored to avoid frequency stability issues. At the same time, the voltage must be well supported by the injection of reactive power after fault clearance so that the voltage recovers well, which improves the rotor angle stability of the system as well. This can be achieved by grid following converters with dynamic voltage support, which is a well-established concept, which is used by several wind turbine generators already, even if it is not a mandatory requirement of most grid codes.

Another approach to solve this problem is the use of grid-forming converters instead of grid following converters. Grid forming converters essentially “simulate” the behaviour of synchronous machines (also the term “virtual synchronous machine” is common), which means that in the short time frame (some hundreds of milliseconds), these converters present an almost “stiff” voltage angle to the power system and absorb or inject active power as required. However, because active power cannot be controlled if the voltage angle is “stiff”, wind and PV generators with grid forming converters require additional storage to provide the required synchronizing power. Additionally, grid forming converters must have a considerable thermal overload capability because otherwise, they must limit the delivered active power, in which case they lose their grid-forming properties, which makes them less effective. Both, short-term storage and thermal overload capability, increases the cost of the converters. Besides this, they can show similar “rotor-angle” stability problems as synchronous machines, especially when connecting them to weak networks. In other words: they avoid the short-term voltage stability problem, which is typical for grid forming converters, but they introduce rotor-angle stability problems to converter-driven generators. Therefore, benefits and risks of grid-forming converters must well be studied before introducing them into power systems. Especially in distribution grids, the benefits are not very large and therefore, we do not recommend using grid forming converters in distribution networks (132kV and below).

Besides voltage instability associated with low voltages, also high voltages can cause problems, especially in weak areas of a transmission system in which there are only very few voltage controlling components (synchronous generators, STATCOMs or wind/PV farms with voltage control capability). Especially after faults there is a risk of overvoltage in network areas with only very few synchronous machines. Such overvoltage can trigger the disconnection of generators and initiate a classical voltage instability (voltage collapse due to high power imports) or frequency instability.

Dynamic voltage instability

A special type of short-term voltage instability is the Dynamic Voltage Instability, sometimes also called “Induction Machine Instability”. Dynamic Voltage Instability is closely linked to the behaviour of (directly coupled) induction machines. Especially in countries with lots of air conditioners driven by directly connected induction machines, this type of instability can be a problem. In case of a voltage sag (e.g. resulting from a short-circuit), an induction motor decelerates and approaches its stalling point. After fault clearance, when the voltage comes back, the induction machines are re-accelerated. During re-acceleration however, they draw a large reactive current (“starting current”), which results in a much higher reactive power demand than prior to the voltage sag. In case of weak grids (low short circuit level), the very high reactive power demand of induction machines can drive a network (or a part of it) into a voltage collapse after the clearance of a short-circuit.

In the Continental European System, dynamic voltage instability resulting from air conditioners is not that much of a problem. Large industrial induction machines are more and more replaced by converter-driven variable speed drives, which reduces the risk of a dynamic voltage instability. However, during the early development of wind generation, when fixed-speed stall-controlled wind turbine generators were the dominant technology (“Danish concept”), a similar effect endangered the voltage stability of European distribution networks: In contrast to an induction motor, an induction generator accelerates during a voltage sag and approaches its super-synchronous stalling point (stalling point above synchronous speed). When the fault is cleared and voltage comes back, the induction generator is close to its stalling point and absorbs a high amount of reactive power (up to five times the reactive power demand during normal operation). Consequently, directly coupled induction generators can cause a dynamic voltage instability too (like induction motors). This is the main reason, for which distribution network operators in the late nineties (until mid of the 2000-years) explicitly required distribution network connected generators to disconnect in case of voltage sags. Only with increasing capacities of distributed generators and with advanced technologies, towards doubly-fed induction machines and wind turbine generators with fully rated converters (IEC-type-3 and IEC-type-4 WTGs), network operators realized that the frequency stability of the transmission grid would be endangered if distributed generators continued disconnecting during voltage dips. This initiated the introduction of LVRT (FRT) requirements in the Connection Conditions, as it is a standard requirement in practically all power networks nowadays.

In Germany, it is required to install a special protection relay, called Q(U)-protection, in the connection point of each wind or solar farm to prevent the absorption of reactive power during voltage recovery still today.

3.3 Rotor Angle Stability

Rotor angle stability is directly linked to the electromechanical behaviour of synchronous generators and therefore, it could also be named “synchronous machine stability”. Unlike voltage instability, which occurs if the power flows in a network exceed the steady state limits of a transmission corridor, rotor angle stability defines the stability of a power system at a given, steady state operating point (operating point below the voltage stability constraint transfer limit) and the electromechanical interactions at this point.

Rotor angle stability can further be subdivided into

- Small-disturbance rotor-angle stability (or Oscillatory Stability) and
- Large-disturbance rotor-angle stability (or Transient Stability)

Small-disturbance rotor-angle stability describes the behaviour of rotor angles in the case of small disturbances, as they are always present in a power system (like small changes of the load, switching actions, etc.).

Large-disturbance rotor-angle stability describes the behaviour of rotor angles in the case of faults (short-circuits) in the network.

3.3.1 Oscillatory Stability/Small disturbance rotor angle stability

Synchronous machines tend to oscillate around their steady state operating point. Due to their damping windings, these oscillations are usually well damped. However, not only individual synchronous machines can oscillate against the rest of the system but also groups of synchronous machines can oscillate against other groups of synchronous machines (inter-area oscillation).

Inter-area oscillations have usually lower frequencies than oscillations of individual synchronous generators and therefore, the damping windings are less effective resulting in a lower damping compared to local oscillations. Additionally, because of the lower frequency of inter-area oscillations, governor dynamics (primary control) have a considerably influence on frequency and damping on low-frequency power oscillations. In this frequency range, frequency and rotor-angle oscillations can overlap each other, and it is sometimes not possible to clearly distinguish both.

Besides inertia and damping windings of generators, frequency and damping of inter-area oscillations depend on the equivalent impedance (synchronizing power) and the active power transfer across a transmission corridor, whereas higher equivalent impedances (reduced synchronizing power) and larger active power transfers reduce the damping of inter-area oscillations. Consequently, there are oscillatory stability constrained transfer limits in a system, meaning that if the active power transfer across a transmission corridor (or boundary) exceeds the corresponding oscillatory stability constrained transfer limit, the damping becomes negative, and the amplitude of the oscillation gets larger.

This is visualized by the example according Figure 23 showing two areas with different exchange flows. In the first case (left), the power exchange is below the oscillatory stability constrained transfer limit and therefore, inter-area oscillations are well damped. In the right figure, the power exchange has been increased is now larger than the oscillatory stability constrained transfer limit. Consequently, the damping of the oscillation is negative (increasing amplitude). In such a situation, the amplitude of the oscillations increases until the two areas lose synchronism resulting in a system split and frequency stability problems in both islands A1 and A2 (see also section 3.1.2).

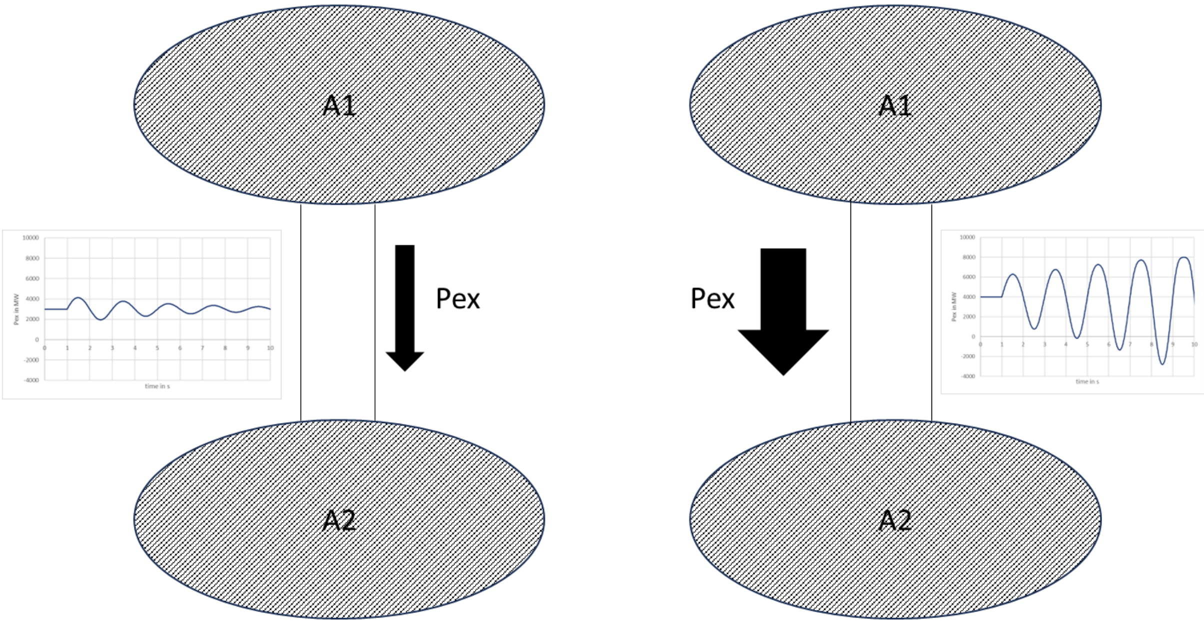

Figure 23: Inter area-oscillation with positive damping (left) and negative damping (right)

Besides equivalent impedance (synchronizing power), the voltage has a considerable influence on oscillatory stability as well. Because active power and reactive power are closely linked, especially in the case of highly loaded transmission lines, an active power oscillation triggers a reactive power oscillation and consequently a voltage oscillation. These voltage oscillations influence the active power demand in the two areas because the load is voltage dependent. Depending on the phase of these oscillations, the impact of the (voltage-dependent) load can have a damping or an un-damping effect.

To improve the damping of power oscillations, Power System Stabilisers (PSS) can be used. PSS are electronic devices, which modulate the excitation voltage of synchronous machines in function of their speed or power (or both) to improve their damping. However, it is important that a PSS is properly tuned (tuning is required for each individual site) because a badly tuned PSS can also have an adverse effect on the damping of synchronous machine oscillations. Therefore, in many cases, PSSs are disabled and not in operation.

However, even if PSS work very well to improve the damping of local and up to some extend also inter-area oscillations, they only have a minor impact on inter-area oscillations with very low frequency, as they can occur in the Continental European system. To improve the damping of inter-area oscillations (and to increase the oscillatory stability constrained transfer limit), Power Oscillation Dampers can be used. POD are electronic devices connected to the controllers of STATCOMs, SVCs or HVDC-VSC-converters and modulate the voltage so that the voltage-dependence of the load creates additional damping power. POD on HVDC converters can also modulate active power to dampen low-frequency oscillations. Similarly to PSS, PODs must be properly tuned.

An example of a major system disturbance caused by an oscillatory instability is the event in Europe in 2006, which led to a separation of the Continental European System into three islands (see Figure 10) and finally to wide area underfrequency load shedding. The starting point of this event was the opening of a line across the Rhine River and several operational issues, which finally led to cascaded line outages and an oscillatory instability (see Figure 24). At around 22:10:28h, the system was split into three areas because of loss of synchronism.

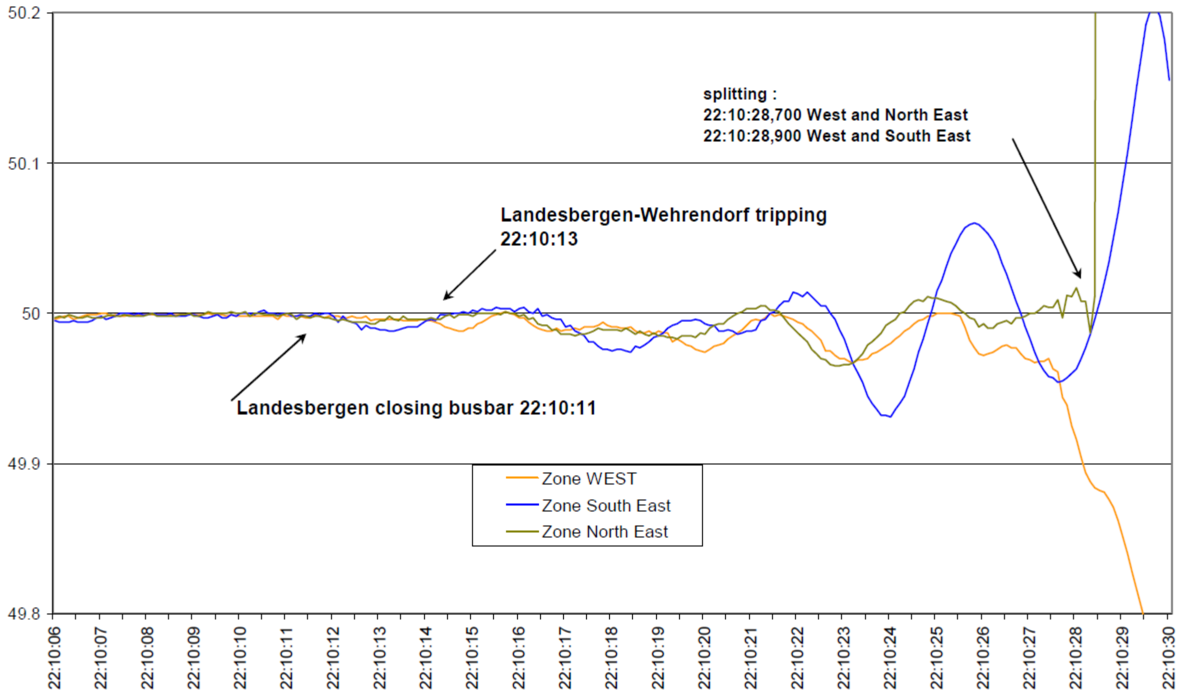

Figure 24: frequency recordings as retrieved by Wide Area Measurement Systems (WAMS) in the three areas from 22:09:30 to 22:20:00[10]

3.3.2 Transient Stability/Large disturbance rotor angle stability

Transient stability analyses the rotor angle stability following a severe disturbance, typically a short circuit in the network.

In contrast to Oscillatory Stability (small disturbance rotor-angle stability), which depends on the system characteristics and the operating point, the Transient Stability additionally depends on type and duration of the disturbance.

Figure 25, Figure 26, Figure 27 and Figure 28 show voltage, speed, rotor angle and active power of a group of synchronous generators in the case of a three-phase short circuit at the high-voltage-side of the step-up transformer for two different fault clearing times. As these figures show, the generators successfully re-synchronize with the grid in case of the shorter fault-clearing time (blue). If the fault clearing time is slightly higher, the generators fail to re-synchronize and synchronism is lost. This can be explained as follows:

[10] *Picture is copied from* [37]

During the fault, when the voltage gets down to zero (solid fault), also the generated electrical power gets down to zero (see Figure 28). This unloads the generators and as a consequence, they speed up (see Figure 29). Together with speed, also the rotor angle increases during the fault (see Figure 30).

After the fault, when voltage gets back to its pre-fault value, the electrical power increases and gets higher than the pre-disturbance power (which is equal to the mechanical power of the connected turbines), which causes the generators to slow down (speed is reduced, see Figure 26).

In the blue case (shorter fault clearing time, stable case), speed crosses the value of 1 p.u. before the electrical power gets below the mechanical power (green, dashed line in Figure 28) and the generators re-synchronize and remain stable.

In the red case however, when the fault clearing time is above the Critical Fault Clearing Time, active power gets below mechanical power (at around t=0,5s, see Figure 28) before speed has reached 1 p.u. (synchronous speed) and consequently, the generators re-accelerate before they could re-synchronize with the external grid. Consequently, the generators lose synchronism leading to very high currents and to the disconnection of the generators (disconnection is not shown in the figures below but in reality the generators would disconnect).

The maximum fault clearing time, at which a synchronous generator (or a group of synchronous generators) remain in synchronism after a fault, is named the Critical Fault Clearing Time. It is a general system requirement, that the Critical Fault Clearing Time is above the maximum fault clearing time that can be expected when clearing faults at major transmission levels conceptually (e.g. within the first zone of the impedance protection). In the Continental European System, it is generally required that critical fault clearing times remain above 150ms.

Besides the fault clearing time, the transient stability of a generator or a group of generators further depends on the following system variables:

- Active power generation: The higher the active power generation, the shorter is the Critical Fault Clearing Time.
- Voltage recovery after the fault: The higher the voltage during the voltage restoration process, the higher is the Critical Fault Clearing Time. Fast acting voltage regulators and excitation systems with a high dynamic range therefore improve transient stability.
- Equivalent impedance between the generators and the external grid: The higher the external impedance, the lower is the synchronizing power and the lower is also the Critical Fault Clearing Time.

In highly meshed systems, like the Continental European System, transient stability is mostly a local stability phenomenon. In case of a transient instability, only a single generator or maybe a group of generators operating in parallel may be disconnected from the grid. Only in areas with very low dynamic voltage support, a transient instability can extend into a global instability, in which case the instability behaves more like a short-term voltage instability.

Transient stability as a global instability is usually a risk in systems with long, individual interconnectors between different areas (e.g. the Australian NEM-system).

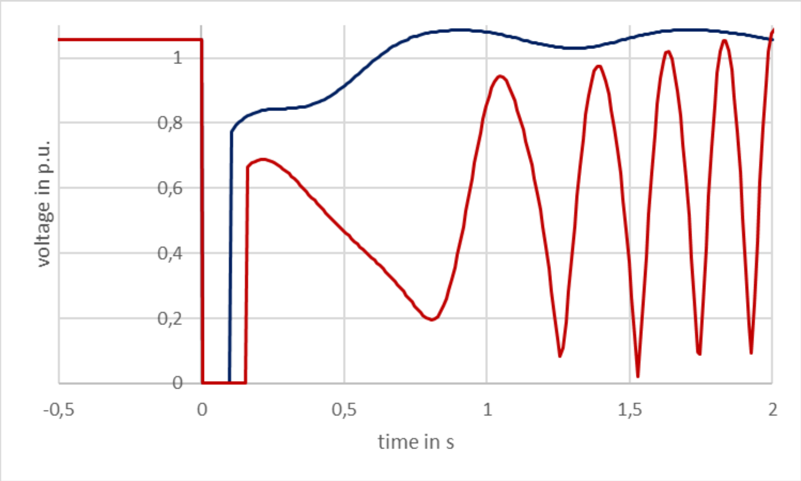

Figure 25: Voltage in p.u. (blue: stable, red: unstable)

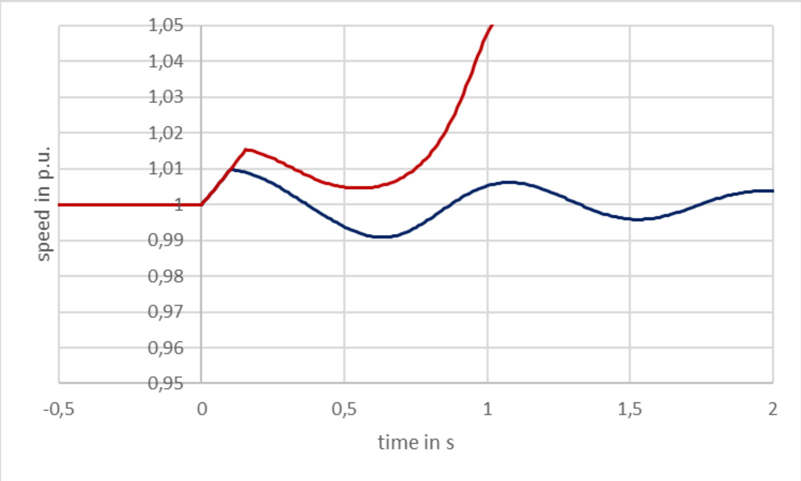

Figure 26: Generator speed (blue: stable, red: unstable)

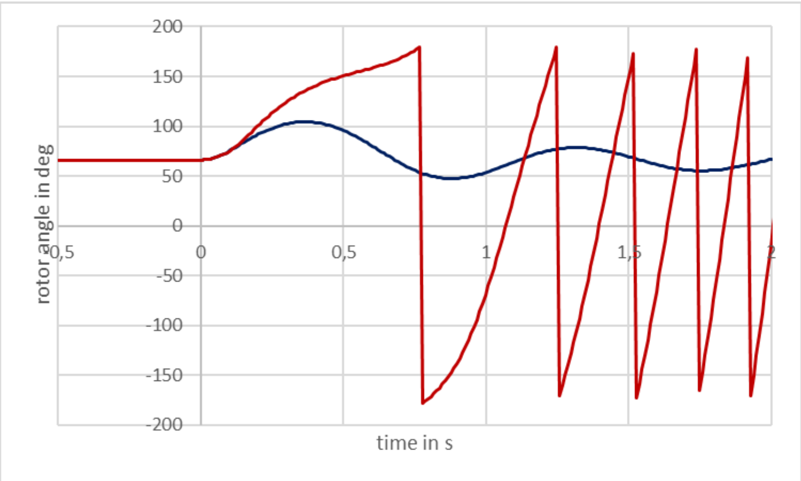

Figure 27: Rotor angle (blue: stable, red: unstable)

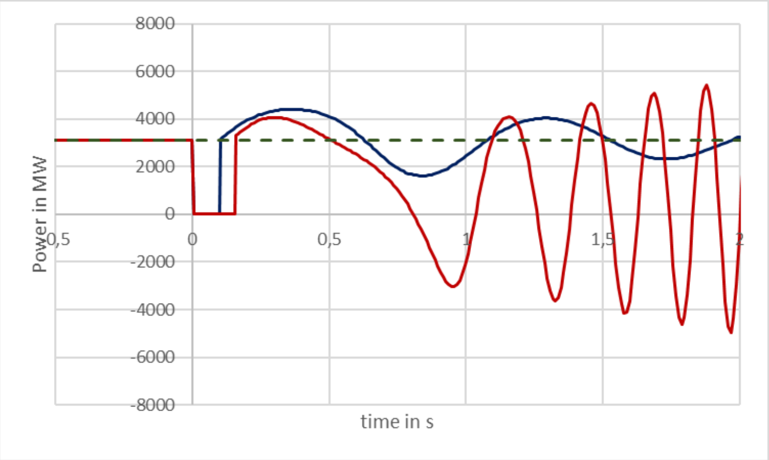

Figure 28: Power in MW (blue: stable, red: unstable)

3.4 Sub-synchronous resonance, self-excitation and resonance instability

Besides frequency, voltage and rotor-angle stability, there are other stability phenomena, which occur at other electrical frequencies than fundamental frequency, and which are usually rather local.

3.4.1 Sub-synchronous resonance in power systems with series compensated lines

In power systems with series compensated lines, there is a risk that the L-C-series resonances formed by series capacitors and network inductances excite torsional oscillations of the turbine-generator shaft system of thermal power plants or gas turbines. Those interactions can lead to accelerated fatigue of long drive trains of thermal power plants, or the shaft can even break.

However, modern series compensation, which is supported by power electronics and corresponding controllers, can mitigate the risk of sub-synchronous resonance and even provide additional shaft damping.

3.4.2 Resonance stability

Because of the large bandwidth of converter-driven components (e.g. PV-inverters, WTG-inverters, HVDC, STATCOM, etc.), instabilities can also occur at frequencies other than fundamental frequency resulting from interaction between controllers and the grid or between different controllers.

In case of a controller instability (or “resonance instability”), the amplitude of voltages and currents oscillates at a non-fundamental frequency and may increase exponentially and can finally lead to the disconnection of the component.

Usually, controller instability is a local stability issue. However, if a large HVDC-link is disconnected because of an unstable controller interaction, this may trigger other cascading events and develop into a global voltage or oscillatory instability as described in section 3.2 and section 3.3.

3.5 Summary: Power system stability

There are three main areas of power system stability:

- Frequency stability, which is associated with the active power balance of the system.
- Stability associated with the secure power transfer across transmission lines (voltage stability, oscillatory stability and transient stability)

- Resonance stability occurring in frequency ranges above or below nominal frequency (super- or sub-synchronous frequency range).

Frequency stability refers to the active power balance of a power system: Generated and consumed active power must always be well balanced in a power system. Active power unbalance is indicated by the frequency: In case of an active power excess, the frequency rises. In case of an active power deficit, the frequency drops. Because the electrical frequency of a power system is directly linked to the rotational speed of power plants, there are very stringent restrictions regarding the permitted frequency range of operation. If frequency gets out of this range or if the rate of change of frequency (RoCoF) is too large, there is a risk of load or generator disconnection, which is a threat to system stability. In the CE-system, frequency stability following the outage of a large power plant is not a big issue and will not be a big issue in future neither. More critical is the frequency stability following system separation: Right after a system split, there is either an active power excess or an active power deficit in each of the resulting islands. Depending on the power exchange between these islands right before the overall system was separated, there can be large frequency variations right after the system split. Whether it will be possible to manage the resulting frequency variations depends on the available inertia in each island, the active power flows between the islands before the system split has occurred and other parameters, like the frequency-dependence of the load and the control characteristics of the frequency control systems.

Voltage stability and oscillatory stability on the other hand restrict the maximum power transfer across a line or a set of lines (transmission corridor). Voltage stability, in the sense that this term is used in this report, refers to the steady state electrical power transfer limit of an equivalent reactance (line, transformer, etc.). If active power is injected, which is above the power transfer limit, the system becomes unstable, voltage collapses and the voltage angles lose synchronism. Because the maximum transfer limit of a reactance is voltage-dependent, the voltage stability limit depends on both, active power flows but also reactive power flows. Particularly in cases, in which there are reactive power shortages, the voltage gets reduced and therefore also the transfer limit of the line (therefore the term "voltage stability").

Oscillatory stability and transient stability are both terms, which are associated with electro-mechanical interactions between the electrical network and the mechanics of synchronous machines. Oscillatory stability is also named "small disturbance rotor angle stability", which means that it is possible that oscillations with very weak or even negative damping may occur, which final lead to loss of synchronism and system separation. Transient stability is also named "large disturbance rotor angle stability" and refers to the stability of synchronous machines (either a single machine or a group of machines) right after a major disturbance (typically a short-circuit in the network).

Stability phenomena in the super- and sub-synchronous frequency ranges ("resonance stability") can be associated with resonances between torsional modes of long drivetrains and the electrical network (especially in the presence of passive series compensation, also known as "sub-synchronous resonance/SSR") or they can be caused by controller interaction, either between controllers and the electrical grid or between different controllers. Those instabilities are usually rather local stability phenomena, which are important to study to ensure the stable operation of individual power plants or other active devices (e.g. dynamic reactive compensation equipment). By adjusting the parameters of the relevant controllers, it is usually possible to mitigate those problems.

4 Impact of variable renewable energies on power system stability

The difference between a conventional system being supplied by large thermal power plants and a system with large share of VRE is visualized by Figure 29 and Figure 30.

The conventional system (Figure 29) can be characterized as follows:

- Load is supplied by large synchronous generator power plants.
- Generation is connected to the main transmission level.
- Power flows are in the top-down direction (from high voltage levels to low voltage levels)
- Generation is usually close to load centres.

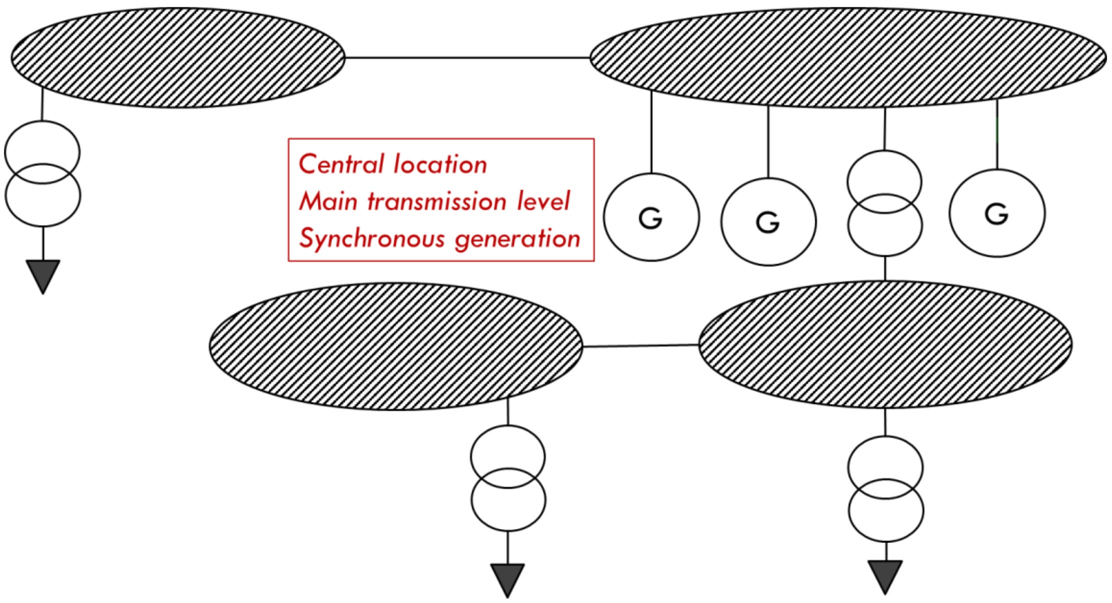

Figure 29: Conventional power system (supplied by large synchronous generators, which are close to the load centres)

With the addition of VRE, conventional generation is displaced by VRE (at least temporarily, during times of high wind and/or solar irradiation, see Figure 30). Therefore, the main differences of a system with high share of VRE compared to a conventional system are the following:

- Load is supplied by only few large synchronous generator power plants and by many distributed non-synchronous generators (usually interfaced with the system by power electronic converters).
- Only very few generators are connected to the main transmission level, the bulk of the generation is connected to HV and MV distribution levels.
- Power flows are in the top-down but also in the bottom-up direction.
- VRE-generation is often remote from the load centres.

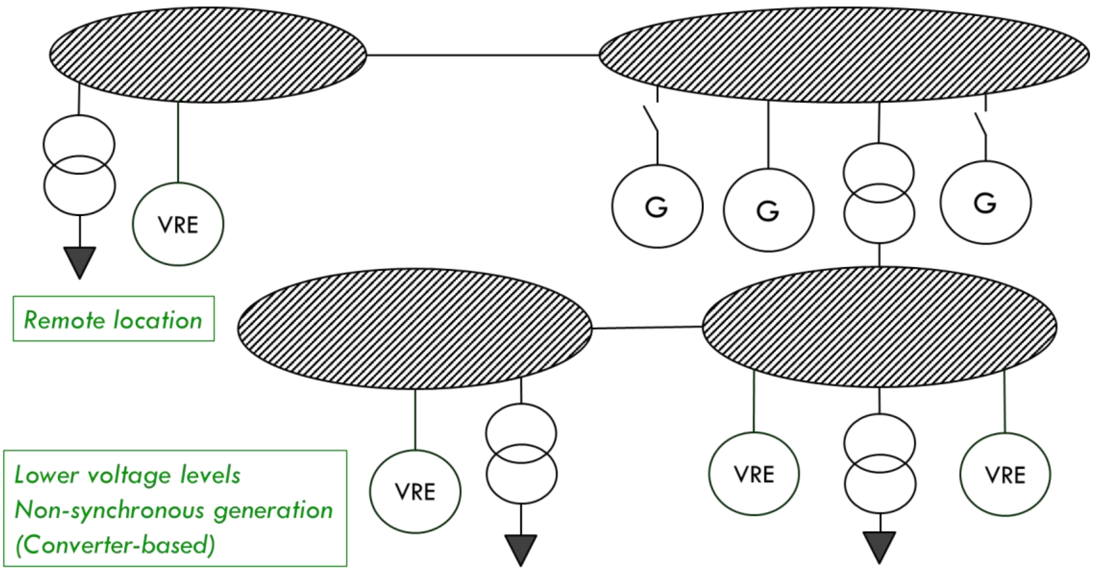

Figure 30: Power system with large share of VRE

Because wind farms must be installed in areas with high wind speeds and both, wind farms and larger PV farms require lots of space, VRE power plants are usually installed more remote from the load centres than conventional power plants.

Additionally, most wind and PV farms are connected to distribution networks (in Germany 110kV for larger and 20kV for smaller wind and PV farms. Rooftop-PV is connected to the LV-networks), which means that the “electrical distance”, which is characterized by the equivalent impedance between two nodes in the system is always large because impedances at lower voltage levels always appear to be larger seen from the higher voltage level.

Consequently, the main impact of VRE on system stability is defined by the following two aspects:

- Generator technology of VRE (non-synchronous generation compared to synchronous generation)
- Generation is remote from the load centres, which has an impact on load flows but also on other aspects, like the provision of reactive power and synchronizing power.

The generator technology (non-synchronous instead of synchronous generators) has the following impact on system stability:

- The contribution to short-circuit currents is reduced and therefore, voltage dips during faults are getting deeper and the region experiencing a considerable voltage dip gets wider (larger “voltage cones”).
- Non-synchronous generators do not contribute to system inertia. Therefore, replacing synchronous generators by non-synchronous generators reduces the inertia of a system.
- Non-synchronous generators do not provide any synchronizing power. On the one hand this also means that non-synchronous generators themselves are not prone to any rotor-angle stability problems (because there is no rotor angle). Regarding rotor-angle stability, non-synchronous generators behave similar to loads (but with negative power flows).

The impact of the generator location on system stability is the following:

- The level of reactive power control capability in areas with high load (and high reactive power demand) is reduced because reactive power transfer over long distances is very limited.
- Short circuit currents in areas with high load are reduced leading to more frequent and deeper voltage dips in these areas.
- Because the synchronizing power between two synchronous generators depends on the equivalent impedance between these generators (the higher the impedance the lower is the synchronizing power that these generators exchange), synchronizing power is reduced if generators are located remote from each other (large “electrical distance”).
- The modified location of generators has an impact on power flows. The network, which has been optimized for the conventional system may not be well adapted to the new power flow situations.

The various aspects described above are visualized by Figure 31 below. Their impact on the various stability phenomena is discussed in the following sections.

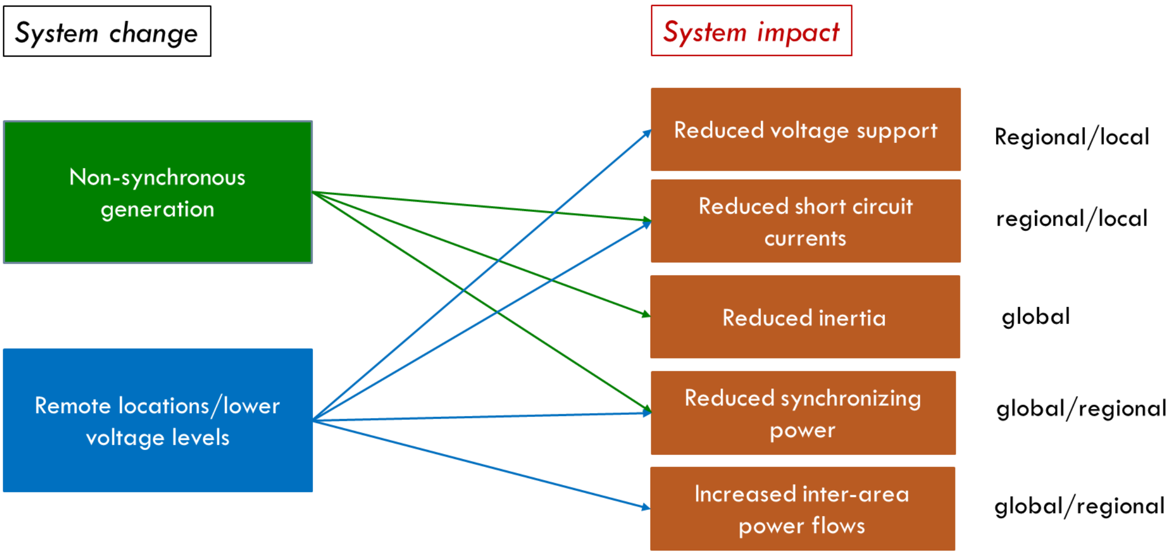

Figure 31: Impact of large share of VRE on system stability

4.1 Impact of VRE on frequency stability

Disconnecting synchronous machines and replacing them by non-synchronous generators weakens the inertia of a power system.

As a result of reduced inertia, the initial rate of change of frequency increases in case of an active power imbalance (e.g. resulting from the loss of a generator or a system split). This is visualized by Figure 32 showing the frequency following a generator outage in function of the equivalent system inertia, which is characterized by the equivalent acceleration time constant (Ta) of the system.

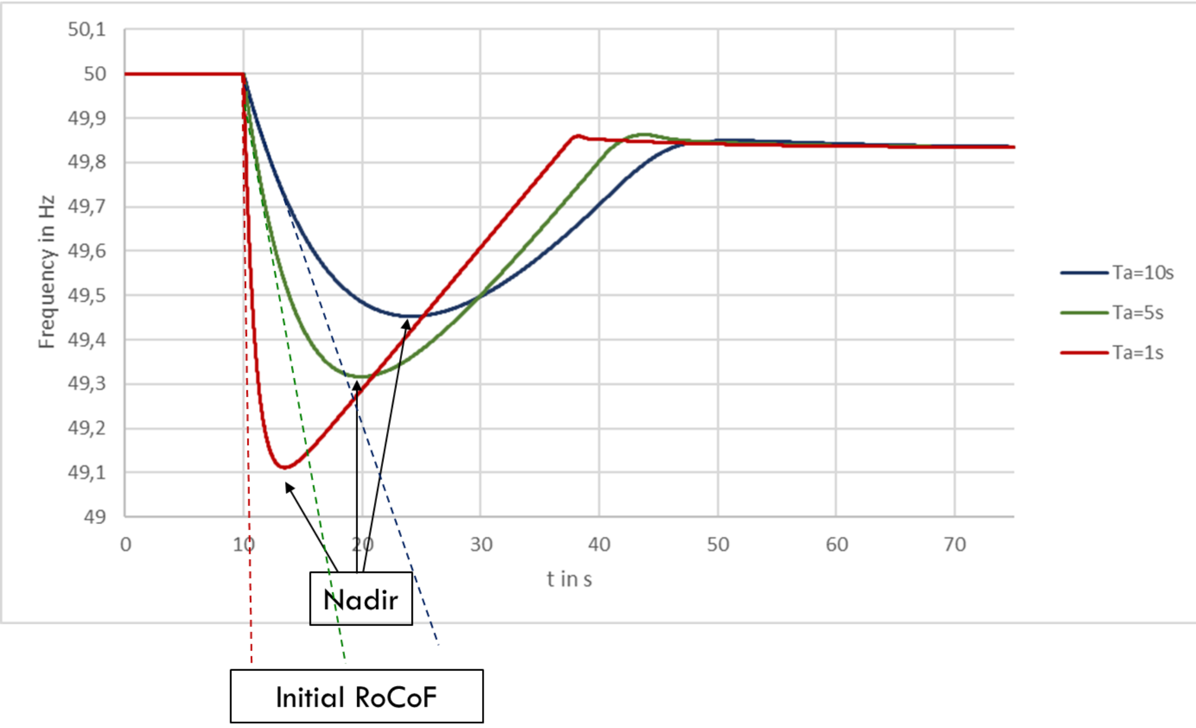

Figure 32: Frequency following a generator outage in function of the equivalent inertia of the system.

As shown by these diagrams, the transient minimum (Nadir) decreases and the maximum rate of change of frequency (RoCoF) increases with decreasing inertia.

In the case of system split events, it is also possible that a part of the system experiences a rapid increase of frequency. In the case of low inertia, frequency can rise so quickly that it is not possible to limit the frequency excursion by reducing the active power of generators. Consequently, the frequency can exceed the limit of 51,5Hz and generators disconnect because of over-frequency. In contrast to underfrequency load shedding, over-frequency tripping of generation is not selective and therefore, there is a high risk that the system collapses due to uncontrolled disconnection of generation if the frequency exceeds the limit of 51,5Hz.

The risks associated with low inertia are the following:

- High RoCoF:
  In the case of very high RoCoF it is possible that synchronous machine power plants disconnect because of the following reasons (see e.g. [22]).
    - Gas turbines experience a loss of flame or a lean blow out.
    - Synchronous machine power plants lose synchronism and disconnect.
    - System stabilizers (PSS) or Power oscillation dampers (POD) malfunction
    - Synchronous machines lose synchronism if the initial ROCOF gets too high.
- In the case of very large RoCoF, there is a risk that the underfrequency load shedding scheme does not operate selectively and reliably anymore, meaning that too much load is shed in case of an active power deficit, which can lead to a subsequent high frequency excursions and uncontrolled disconnection of generators.

- The frequency Nadir gets lower and lower with decreasing inertia and therefore, the risk of triggering underfrequency load shedding increases with decreasing inertia.
- In case of system splits, the frequency can rise very rapidly and the upper frequency limit of 51,5Hz can be exceeded leading to uncontrolled disconnection of generation.

To summarize the impact of VRE on frequency stability: Systems with large share of VRE have a lower inertia than systems with low share of VRE. The impact of VRE on system inertia is indirect: The reduced inertia is a result of the disconnection of synchronous power plants during times of high VRE generation. Therefore, the inertia of a power system with very large share of VRE must be strengthened by additional components, e.g. by the installation of synchronous condensers, STATCOMS with grid forming converter and energy storage, BESS with grid-forming converters or other components that can contribute to system inertia and fast frequency control.

Additional effects having an impact on the frequency stability of future power systems are:

- Larger inter-area power flows: Because VRE are usually installed remote from the load centres, area exchange flows are getting larger with increased penetration of VRE leading to higher active power deficits/active power excess in case of system split events making it more difficult to maintain frequency within the required limits.
- Reduced frequency-dependence of the load: Besides frequency control of generation, the frequency-dependence of the load helps maintaining the frequency within the required limits. Because more and more dynamic loads are equipped with frequency converters, the frequency-dependence of the load will probably decrease in future reducing the contribution of the load to frequency control.

4.2 Impact of VRE on voltage stability

4.2.1 Long-term voltage stability

Because VRE is predominantly installed at lower voltage levels than large thermal power plants and in areas, which are remote from the load centres, the reactive power control capability of a system with larger share of VRE is low compared to a conventional power system. Because reactive power cannot be transferred over long distances[11], the reactive power control capability of a system with large share of VRE is reduced even if VRE have a similar reactive power capability than large, thermal power plants.

Therefore, to maintain the voltage stability of a system with large share of VRE, it is necessary to install additional reactive power sources in areas, which are close to the load centres and in weak areas requiring additional voltage support.

Besides reduced voltage support, higher line loadings can usually be observed in systems with large VRE. Because highly loaded transmission lines have a much higher reactive power demand than lightly loaded lines, fast, dynamic reactive power compensation equipment (e.g. STATCOMs or synchronous condensers) must be installed in the proximity of highly loaded lines to ensure the voltage stability of the system in case of line outages.

[11] *understood as being the “electrical distance”, meaning that a VRE generator connected to a LV or MV grid is always “remote”*

4.2.2 Short-term voltage stability

In a conventional power system, voltage stability is mainly an issue in the longer time frame, when the synchronous machines of the system have synchronized because:

- During synchronization, synchronous machines stabilize the voltage angles and allow more or less free active power flows. Therefore, large active power flows exceeding the voltage stability limits of the system are not possible in the very short time frame (of a few hundreds of milliseconds).
- Synchronous machines have a large thermal overload capability and can provide large amount of reactive power in the short time-frame.
- In case of voltage dips, the load decreases and unloads the system. Only with the action of automatic tap changers, the voltage at the load comes back. Therefore, a load-driven voltage instability is linked to the time constants of automatic tap changer controls (time frame of minutes).

In the case of systems with large share of VRE however, short-term voltage stability can become highly relevant, which has to do with characteristics of converter-driven generators:

- Converter-driven generators (PV-inverters, wind turbine generators), HVDC inverters, etc. control the electrical active power in the very short time frame (between 0.01…0.1s). Therefore, it is possible that voltage stability constraint transfer limits are exceeded in the very short time frame.
- The reactive power capability of VRE is the same in the short-term as in the long term. The short-term thermal overload capability of VRE can (almost) be ignored.

This means that in systems with high share of VRE, voltage instability can occur in the very short time frame of a few hundreds of milliseconds because VRE-generators try to inject large amounts of active power, which may exceed the voltage stability constrained transfer limits of the system. In such a situation, the PLLs (phase measurement devices of the converters) lose synchronism and the corresponding generators trip.

In contrast to this, synchronous machines do not show this type of instability because they do not inject a controlled active power in the time frame of some hundreds of milliseconds. In this time frame they maintain the voltage angle and allow active power to flow freely. However, this does not mean that synchronous machines cannot become instable in this time frame: they “translate” this type of voltage instability into a rotor angle instability (transient instability, see section 3.3.2) instead, which is a stability phenomenon that cannot occur in the case of converter driven generators (see also section 4.3). In other words: both type of generators can become unstable in the very short time frame, but the type of instability is different.

In the new IEEE classification of power system stability phenomena [3], a new stability category has been introduced, which is named “Converter driven stability”. In the sense of this publication, the “short-term voltage stability” described above would be part of “Converter driven stability” (together with other stability phenomena like Converter instability in the super- and sub-synchronous range as described in section 3.4.2). However, this classification does not help understanding what the nature of this type of instability is and what could be done to mitigate it. Therefore, we do not use it in this report.

To mitigate this type of short-term instability, the following measures can be taken:

- Reduce active power in function of voltage during voltage dips.
- Introduce grid forming converter controls, where required.

In most Connection Conditions for VRE, the reduction of active power during voltage dips is a "can" and not a "must": power electronic converters can reduce active currents during voltage dips to prioritize the injection of reactive currents, which is required to support the voltage. However, transmission system operators usually overlook that this should be a "must" to avoid short-term voltage instability during voltage dips. Our recommendation is to require converter driven generators to reduce active currents in proportion to voltage if the voltage drops below 0.9 p.u. (active power reduces quadratically with the voltage). To avoid frequency stability problems after voltage recovery, it must also be required to re-establish active power quickly when the voltage gets back above 0.9 p.u., e.g. with ramping times of 0.5-1s (not faster than this, because a too sudden active power restoration can also adversely impact the stability of the system).

Another option is to introduce grid forming converter controls, in which case VRE behave similar to synchronous generators (with "fixed" rotor angle in the short time frame). Letting VRE behave like synchronous generators obviously avoids this type of short-term instability. However, grid forming converters must be specified with great care because all stability issues, which are typical for synchronous machines and which are avoided by grid following converters, can occur in the case of VRE with grid forming converters too. In particular, the following aspects must be considered when introducing grid forming converters to interface VRE with the network:

- Grid forming converters "fix" the voltage angle and active power is floating in the short time frame of some hundreds of milliseconds. This means that active power flows follow the network impedances (and not the capability of the converters behind) and may overload some converters in the short time frame (and make them disconnect).
- Because active power is floating in the short time frame, grid forming converter controls usually implement power limiters to avoid converter overload. However, as soon as active power is limited, the converter loses its grid forming capability and behaves like a grid following converter, which is unwanted. Consequently, grid forming converters must have a considerable thermal overload capability in the short time frame so that they are beneficial to the system. Such thermal overload capability comes at additional cost.
- "Floating" (or "free") active power means, that grid forming converters must be able to deliver more power than the turbine delivers in the short time frame. Synchronous machines use the energy stored in their rotating masses to do this. Wind turbine generators could also do so, but the interactions between the turbine's mechanical system (drivetrain, blades, tower) with the electrical grid requires strengthening the mechanical system, which has a considerable cost impact. PV inverters do not have any integrated storage, from which the required active power could be taken. Therefore, PV inverters would have to operate at reduced active power, which is very expensive (cost of the energy not delivered).
  Optionally, the installation of additional storage components, like battery energy storage or super-capacitors, would be required to allow wind turbine generators and PV-inverters to provide the necessary energy required for grid forming operation.

The above explanations show that the introduction of grid forming converter controls can mitigate stability problems associated with converter driven generators but can also create new challenges and problems which must be well studied before requiring grid forming converters for VRE.

In general, the benefits of grid forming converters increase with increasing voltage levels. At the same time, the additional problems caused by grid forming converters increase with decreasing voltage levels. Therefore, we recommend the following:

- Equip all BESS and VRE with dynamic voltage support (fast voltage control). Fast voltage control of grid following converters is a well-proven technology and can be made available by most manufacturers of wind turbines and PV-inverters almost instantaneously.
- Enable new synchronous machine power plants (e.g. H2-gas-turbine generators) to operate in synchronous condenser mode when not being dispatched. This can be achieved by the installation of self-synchronizing clutches between the generator and the turbine shaft of a gas- or steam-turbine.
- Require grid forming converters only for converter-driven components (BESS, STATCOMs, that are connected to the main transmission levels (220kV and above).
- VRE connected to distribution levels (132kV and below) should be equipped with classical, grid following converters to avoid new problems in the distribution networks. If required, VRE in distribution networks can be equipped with fast voltage and frequency control to provide additional voltage and frequency support.

4.3 Impact of VRE on rotor angle stability

As explained in section 3.3, rotor angle stability describes stability phenomena, which are linked to the electromechanical interactions between the electrical and the mechanical systems of synchronous machine power plants.

Because VRE with classical grid following converters either do not have any mechanical system (PV-inverters) or de-couple the electrical and the mechanical systems (variable speed wind turbines), there is no rotor angle and consequently no rotor angle stability problems associated with VRE (with grid following converters).

However, there is an indirect impact of VRE on oscillatory and transient stability when considering that VRE replace synchronous generation during times with high wind speed and solar irradiation:

- If synchronous machines are disconnected during times of high VRE generation, the equivalent impedance between the remaining synchronous machines increases. Consequently, the remaining synchronous machines exchange less synchronizing power, which drives the system closer to rotor angle stability limits.
- If synchronous machines in exporting areas are replaced by VRE, the equivalent inertia of this area decreases. As a result, the damping of rotor angle oscillations is improved, and transient stability constraint export limits are increased (see e.g. [4] and [5]). This is a positive impact of VRE on rotor angle stability.
- If VRE is added to exporting areas (without disconnecting the synchronous generators of the same area), the power flow on the exporting interconnector increases, moving the system

closer to the corresponding rotor angle stability limit. This is a negative impact of VRE on rotor angle stability.

- Very often, the level of dynamic voltage support decreases, if VRE replace large thermal power plants connected to the main transmission level. This can also have a negative impact on rotor angle stability, which, however, can be mitigated by the installation of STATCOMs in the proximity of the relevant interconnectors.

To summarize the impact of VRE on rotor angle stability we can state the following:

- VRE with standard, grid following converters do not show any rotor angle stability problems because they either do not have a mechanical system (PV-inverters) or their mechanical system is entirely de-coupled from the electrical system (variable speed wind generators). This also means that there is no rotor angle stability issue in a system with 100% converter-driven power plants ("rotor-angle stability" could also be named "synchronous machine stability").
- The indirect impact of VRE on the rotor angle stability of the synchronous generators in the system can either be positive or negative, depending on the system topology and the dispatch order.

When installing VRE with grid-forming converters, they can show the same rotor-angle stability problems as synchronous machines. However, because the corresponding "electro-mechanical" interactions are not real but "simulated" interactions, VRE with grid-forming converters can have a much better damping than real synchronous machines, especially for local modes.

However, if grid forming converter controls (or synchronous machines with very large inertia) are used to increase the inertia of the system above the levels of today, e.g. to secure the system against high RoCoF in the case of system split events, there is a considerable risk that the increased inertia reduces the damping of rotor angle oscillations leading to an increased risk of oscillatory instability. Therefore, inertia should not be increased unreasonably to ensure that oscillatory stability is always maintained.

4.4 Impact of VRE on resonance stability (controller interaction)

Especially in the case of weak grid connection points (areas of the network with a lower short-circuit impedance), power electronic converters can resonate with the surrounding network. In this case, voltages at sub- or super-synchronous frequencies are excited, which finally leads to the disconnection of the wind- or PV-farm.

Power electronic converters are equipped with very fast controllers (with time constants in the time frame of a few milliseconds). A classical power system can be described by passive electrical networks in the higher frequency range, which is always stable. With the introduction of fast controllers however, the power system is not just a passive network in the higher frequency domain, but instabilities can also occur in the higher, super-synchronous frequency range.

This problem can only be resolved, if only power electronic converters with low-bandwidth controllers are connected to the power system. However, the lack of thermal overload capability of power electronic converters requires them to use fast controllers to protect them from high currents. Therefore, lowering the bandwidth of the controllers means that they must have some dynamic overload capability to be able to handle over-currents for limited periods. This comes at additional cost. Therefore, it is very important to understand properly, what level of fast controlling converters can be tolerated without risking controller instability.

Ideal grid forming converter controls are “low bandwidth” and consequently not prone to controller instability in the sub-synchronous and super-synchronous frequency range. However, many so-called grid forming converter controls use fast current controllers to protect the converters against high currents. Those converters could still show resonance stability problems, even if they are sold as “grid forming”.

4.5 Summary: Impact of VRE on power system stability

The main impact of VRE on system stability is defined by the following two aspects:

- Generator technology of VRE (non-synchronous generation compared to synchronous generation)
- Generation is remote from the load centres, which has an impact on load flows but also on other aspects, like the provision of reactive power and synchronizing power.

The generator technology (non-synchronous instead of synchronous generators) has the following impact on system stability:

- The contribution to short-circuit currents is reduced:
  Therefore, voltage dips during faults are getting deeper and the region experiencing a considerable voltage dip gets wider (larger “voltage funnels”). This has an impact on the transient stability of synchronous generators.
- Non-synchronous generators do not contribute to system inertia:
  Because VRE do not contribute to inertia, replacing synchronous generators by non-synchronous generators reduces the inertia of a system. This has a considerable impact on frequency stability: Following an active power disturbance, the rate of change of frequency gets larger with decreasing inertia and frequency excursions are getting larger.
- Non-synchronous generators do not provide any synchronizing power.
  First of all this means that non-synchronous generators do not actively participate in neither oscillatory nor transient stability but behave passively, like (negative) loads regarding rotor angle stability.
  However, because non-synchronous generators control electric power they are prone to short-term voltage instability (in the time frame of some hundreds of milliseconds): if they inject more power than the electrical system behind can transfer without losing stability, the system runs into a short-term voltage collapse.

The impact of the generator location on system stability is the following:

- The level of reactive power control capability in areas with high load (and high reactive power demand) is reduced because reactive power transfer over long distances is very limited.
- Short circuit currents in areas with high load are reduced leading to more frequent and deeper voltage dips in these areas.
- Because the synchronizing power between two synchronous generators depends on the equivalent impedance between these generators (the higher the impedance the lower is the

synchronizing power that these generators exchange), synchronizing power is reduced if generators are located remote from each other (large “electrical distance”).

- The modified location of generators has an impact on power flows. The network, which has been optimized for the conventional system may not be well adapted to the new power flow situations.

Additionally, VRE can develop controller instability in the sub- and super-synchronous frequency range. However, this controller instability is usually a local instability and can be mitigated by appropriately tuning the converter controls.

Because of the impact of VRE on the various stability aspects, additional system services are required to support the stability of power systems with large share of VRE. This is discussed in the following chapter 5.

5 System Services and technologies to support system stability

Various technologies can be used to support the stability of a power system with high share of VRE. The most important technologies are:

- Technologies to improve voltage control, like HVDC converters with fast voltage control, STATCOMs, synchronous condensers and the converters of VRE themselves. However, because reactive power cannot be transferred over large distances, components to support the voltage must be available at the right places in the network and therefore, technologies, which are independent from the generators are usually more efficient.
- Technologies to increase the inertia of the system and which provide synchronizing power like synchronous condensers, E-STATCOMs[12], BESS with grid forming converter controls.
- Technologies that allow balancing power flows on parallel transmission connections like phase shifting transformers or UPFCs, controlled series compensation.
- Technologies to reduce the equivalent impedance of important transmission corridors like series compensation and, of course, additional transmission lines.

The upgrade of existing transmission lines by HTLS-conductors (High temperature low sag) or conductors with very large cross sections does not help to improve the stability of the power system because the stability is linked to the equivalent inductance of a transmission line, which is mainly defined by its geometry and not by the conductor material or cross section. HTLS-conductors allow higher currents on existing transmission lines, but these higher currents move the system closer to its stability limits so that the risk of instability increases. Therefore, to maintain system security, additional, voltage supporting components are required and advanced tools must be used, which allow operating the system closer to its stability limits while not deteriorating system security (see also chapter 7).

Technologies to improve the stability of the power system can either be installed by the TSO or by private investors, which build and operate components to support system stability, and which are remunerated by the TSO for the services that they provide. Those components can either be generators or specific component (as listed above) dedicated to support power system stability.

To enable the installation of those components by private investors, system services are usually defined, which are technology-neutral, and which can be quantified so that a remuneration is possible.

A “system service” is an abstract definition of a technical service that is required to support the stability of the power system. Additionally, a system service is:

- Independent from any technology (the same service can be provided by different technologies)
- It is possible to quantify the service so that it can be remunerated.

5.1 System services to support system stability

System services can be defined in different ways. In this report, we are trying to focus on the most relevant system services to support system stability and the required components and technologies to provide those services.

[12] *STATCOMs with short-term energy storage (time frame of seconds) and grid forming converter control.*

Figure 33 provides and overview about the services discussed in this report and their impact on the different stability phenomena.

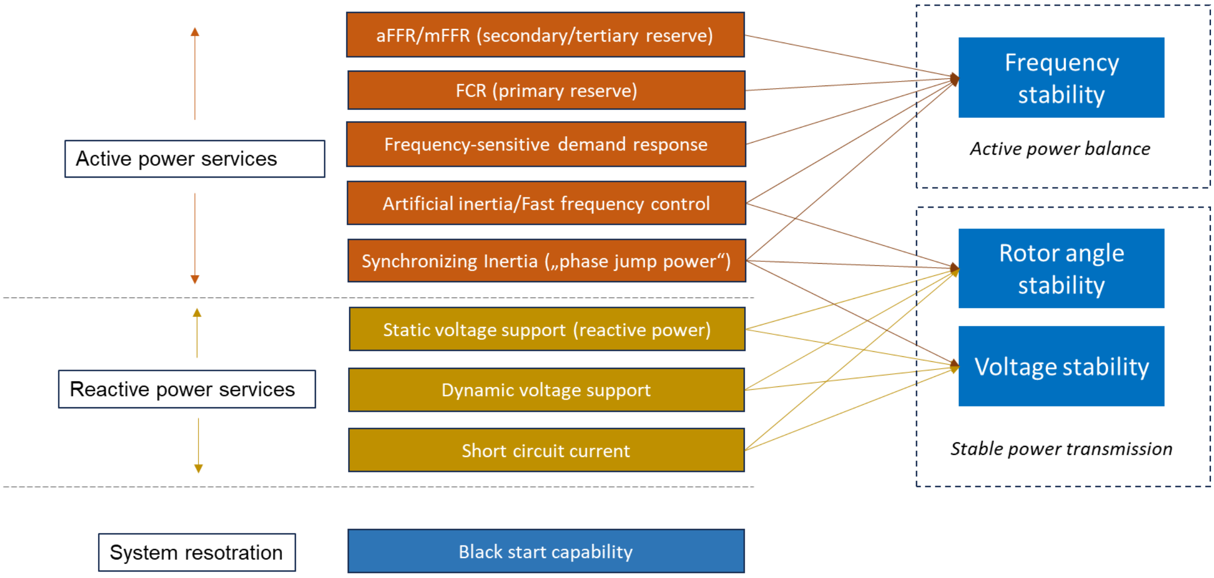

Figure 33: System services and their impact on different stability phenomena

The definition of those services and how they impact the different stability phenomena is described in the following sections.

5.1.1 Secondary and tertiary reserve (aFRR/mFRR)

Longer-term operating reserves like secondary reserve (automatic frequency restoration reserve) and tertiary reserve (or manual frequency restoration reserve, in Germany "minute reserve") is required to establish a balance between demand and supply in the time frame of 5-15 minutes. In Europe, the remaining mismatch between demand and supply, which is not compensated by the balancing responsible parties using the intra-day market and variations within a 15 minute-cycle is compensated by the TSOs using operating reserve (aFRR and mFRR). Because these are longer term reserves, which are activated in the time frame of minutes, they do not contribute to the short-term frequency stability but of course, sufficient operating reserve is required to maintain the frequency of the system within the permitted limits.

Secondary and tertiary reserve (aFRR/mFRR) support:

- Frequency stability in the longer run.
- Through area exchange control, Secondary control ensures that power plant outages are compensated by the control area, in which it has occurred.

5.1.2 Primary reserve (FCR)

Primary reserve (Frequency Containment Reserve / FCR) means that additional active power is delivered in proportion to a frequency deviation. The activation time of primary reserve (or Frequency Containment Reserve) is around 10s in the ENTSO-E systems. Conventional power plants can typically provide between 3% and 10% of their installed capacity as primary reserve because of dynamic constraints. Therefore, primary reserve must be distributed amongst many power plants in the system. Primary reserve is always spinning reserve (to be provided by generators, which are synchronized to the grid). Classically (before liberalization), primary reserve has been provided by practically all power plants in the system. Over recent years, a considerable change has happened regarding the provision of primary reserve: in Germany, between 80% and 90% of the overall required primary reserve is delivered by BESS. Because of the advantages of providing active power reserve using storage devices (which are permanently synchronized), we expect that within the next five to ten years, the overall required primary reserve will be delivered by BESS.

Besides frequency support, the dynamics of primary control systems also have an impact on oscillatory stability, especially low-frequency inter-area oscillations, which is not shown in the diagram according to Figure 33 because it is more a side-effect than a wanted impact.

Primary reserves support:

- Frequency stability (in the time frame of several seconds up to 5…15 min (when secondary control has been fully activated).

5.1.3 **Frequency-sensitive demand response**

To support frequency control, frequency-sensitive demand-response can be used as an additional system service. Technically, this is more or less the same as underfrequency load shedding but with the difference that frequency-sensitive demand response disconnects loads at higher frequencies and is not considered to be an emergency measure but a paid system service.

Frequency-sensitive demand response supports:

- Frequency stability (similar time frame as primary reserve)

5.1.4 **Artificial Inertia/Fast frequency control**

To support frequency stability, VRE can inject additional active power in proportion to the frequency gradient (ROCOF). This supports the frequency in a similar manner than true inertia from synchronous machines. However, the frequency measurement is associated with delays and therefore, such “artificial” inertia is not exactly the same as “true” inertia, which is triggered through the voltage angle.

Therefore, a distinction between “artificial inertia” and “true inertia” (or synchronizing inertia, as it is named in this report) must be made, whereas “true inertia” or “synchronizing inertia” activates the inertia through the voltage angle (see also section 5.1.5) and “artificial inertia” works with frequency measurements.

Standard, grid following converters can only provide “artificial inertia” whereas grid forming converters provide true inertia (or synchronizing inertia).

Similar to artificial inertia, there is a service named “Fast frequency control” (or Enhanced frequency response”), which is a paid ancillary service in Ireland and the U.K. Fast frequency control operates with similar activation times as artificial inertia but instead of providing active power in proportion to the frequency gradient, generators providing fast frequency control inject additional active power in proportion to the frequency deviation from its nominal value (e.g. 50Hz). In fact, Fast Frequency Control is the same as primary frequency control (Frequency Containment) but operating in much shorter time frames (time frame of around 1s only). With the help of Fast Frequency Control, much lower inertia can be tolerated.

Artificial inertia and fast frequency control also has a considerable impact on oscillatory stability. The provision of additional inertia is a wanted effect. However, depending on the frequency measurement time constants and control delays it also provides damping torque or can have an negative damping impact on rotor angle oscillations if it is not well designed.

Artificial inertia and fast frequency control support:

- Frequency stability in the very short time frame of a few seconds (until primary reserve has been fully activated).
- Fast frequency control relaxes inertia requirements (allows tolerating lower inertia).

5.1.5 Synchronizing inertia ("phase jump power", "True Inertia")

To support frequency stability, short-term voltage stability and rotor angle stability both, synchronizing power and inertia is required. The service "synchronizing inertia" means two things:

- Provision of inertia
- Provision or requirement of "phase jump power" during a period that is relevant for synchronization (typically <1s).

In contrast to "artificial inertia", "synchronizing inertia", which is also named "true inertia" or "grid forming inertia", is activated without any delay because it responds to changes of the voltage angle and not to changes of frequency (or frequency gradient). Besides supporting frequency stability "synchronizing inertia" provides "phase jump power" during a relevant period (several hundreds of milliseconds up to several seconds) and consequently it supports the short-term voltage stability and the rotor angle stability of the system.

Synchronizing inertia supports:

- Frequency stability in the very short time frame of a few seconds (until primary reserve has been fully activated).
- Oscillatory stability (synchronizing power and inertia)
- Transient stability (synchronizing power and inertia)
- Short-term voltage stability (synchronizing power/"phase jump power")

5.1.6 Damping power/damping torque

Another requirement for the stable operation of a power system is that rotor angle oscillations are sufficiently damped. Synchronous machine power plants and grid forming converters tend to oscillate and therefore damping power (or damping torque) is needed to damp these oscillations.

Most of the damping is provided by the synchronous machines themselves. They provide damping through their damping windings. If this is not sufficient, they use additional controllers, named power system stabilizers (PSS), which act on the voltage control setpoint of the automatic voltage regulator of a synchronous machine.

Also, converters with grid forming control must be sufficiently damped to avoid that they oscillate and that they excite oscillations of other synchronous machines and grid forming converters.

However, the damping of synchronous machines is limited in frequency and does not work very well for very low frequencies as they occur in the case of inter-area oscillations, where many synchronous machine power plants (and in future also grid forming converters) are involved having a very large inertia.

Therefore, so-called power oscillation dampers (POD) can be used, which are controllers acting on the voltage setpoint of STATCOM-, SVC- or HVDC-converters. PODs provide additional damping, especially in the low frequency range.

HVDC converters can also provide damping by modulating active power directly.

Both, PSS and POD must be well tuned to the site-specific conditions. Otherwise, it may happen that they do not improve the damping of rotor angle oscillations but that they make it wors (or they provide positive damping in one frequency range but negative damping in other frequency ranges).

The provision of damping power by components, which do not oscillate themselves (all converters with grid following controls) should be seen as a system service and should also be remunerated.

However, because most of the damping is provided by components, which oscillate themselves, damping power has not been included into the list of system services according to Figure 34.

5.1.7 **Static voltage support**

Reactive power with an activation time in the range of minutes is required to maintain the voltage in the longer term. MSCDNs are typically used for this purpose. MSCDNs are essentially capacitor banks but with additional damping circuits to avoid any adverse impact in the higher frequency range.

To absorb reactive power during periods with high voltage, shunt reactors can be installed, which are mechanically switched and can be operated similarly to MSCDNs. If better voltage control is required, variable shunt reactors (VSR) can be installed. A VSR is a shunt reactor with an onload tap changer, with which it is possible to regulate its reactive power in a range between 40% and 100% of its rated capacity. With the help of more advanced tap changers (or two tap changers) a range of 20% and 100% can be achieved. Tab changers of variable shunt reactors operate in the same time frame as tap changers of transformers (between 5-10s per tap action).

Static voltage support is relevant to maintain the voltage stability in the long term.

Static voltage support contributes to:

- Long-term voltage stability (time frame of minutes and hours)
- Voltage maintenance: ensures that voltage can be maintained within the permitted limits

5.1.8 **Dynamic voltage support**

Dynamic voltage support (or fast voltage regulation) means a voltage regulation with an activation time of 10...100ms. Fast voltage regulation is provided, for example, by voltage regulators and the excitation system of synchronous machines or by power converters with fast voltage regulation (e.g. STATCOMs, HVDC-VSC-terminals or converters of some types of wind generators).

Dynamic voltage support positively impacts:

- Short-term voltage stability
- Long-term voltage stability
- Transient stability (accelerated voltage restoration)

It can also stabilize small disturbance rotor angle oscillations (oscillatory stability), especially if STATCOMs are equipped with so-called PODs (Power Oscillation Dampers), which are special controls that are designed to provide tamping torque to improve the damping of rotor angle oscillations.

5.1.9 **Short circuit current**

Practically all grid codes require VRE to inject reactive current into the grid in the event of a voltage dip and thus support the voltage. This limits the depth and spatial extent of short-term voltage dips resulting from network faults (limiting the “voltage funnel”). This is particularly beneficial regarding transient stability, as voltage support in the event of a fault keeps the “residual load” as high as possible and synchronous machines therefore experience lower acceleration. In addition, it also helps preventing a converter instability (short-term voltage instability of converter driven generators) during voltage dips.

Therefore, short-circuit current (reactive current support during grid faults) supports:

- Transient stability
- Short-term voltage stability (converter stability)

5.2 “Grid forming” (GF) as a system service

In many systems world-wide, “Grid forming” (GF) is introduced as a separate system service.

In fact, GF as a service combines several of the above listed services. The actual definitions of different system operators (or market operators) regarding GF as a service differ quite significantly. The following list shows the range of services, which are typically combined into “GF”:

- Synchronizing inertia (“phase jump power” and inertia)
- “Voltage jump reactive power”: very fast or even instantaneous reactive power response to changes in voltage magnitude. This is very close to the service “dynamic voltage support” according to section 5.1.8.
- Short circuit current

In addition to the above listed services, some grid codes require that grid forming converters avoid any kind of sub-synchronous or resonance stability (see section 3.4).

Recently, NESO (U.K.), AEMO (Australia) and the VDE/FNN (Germany, draft only) have issued documents specifying the technical properties understood by the term “grid forming”.

The definitions of ESO and AEMO and VDE/FNN refer to non-mandatory requirements and are used to define qualification criteria to participate in future stability markets (in the case of ESO, grid forming capability is already procured through the Stability Pathfinder program (see e.g. [7]), which has been initiated to gain experience about future long-term, mid-term and short-term stability markets).

ACER (E.U.) has issued a draft version of a new version of the Requirements for Generators (RfG 2.0 [23]), in which grid forming capability is a mandatory requirement for all generators (power park modules) and storage systems with grid connection at 110kV and above and MV connected power park modules that are directly connected to the secondary side of a HV substation. The new version of the RfG should be put in place in 2025 and foresees a three-years period to implement the RfG requirements in the national grid codes.

The following sections provide summaries of specifications for “grid forming capability”:

5.2.1 NESO (Great Britian)

In 2023 NESO, the transmission system operator of Great Britain, has introduced a service named “Grid Forming Capability” as a non-mandatory, paid service. Both the technical capability to provide the service and actual service delivery is non-mandatory. Grid Forming Capability is further subdivided into GBGF-I and GBGF-S, whereas “I” stands for “Inverter” and refers to the provision of grid forming capability of power electronic based converters (e.g. PV generators, wind generators, HVDC converter stations, BESS, STATCOMs). The “S” if for synchronous machines and refers to power plants with directly coupled synchronous generators and synchronous condensers.

The requirements for GBGF-I and GBGF-S are slightly different, mainly to account for the lack of thermal overload capability of inverter-based devices.

The main requirements of GBGF-I are [24]:

- In general: Behaviour like a Thevenin Equivalent (voltage source behind reactance)
- Impedance must be a real, physical impedance. The implementation by a “virtual impedance” is not permitted[13].
- Provision of Synchronizing Inertia up to the so-called “Phase Jump Limit” (typically 5 deg)
- Provision of Fast Fault Current Injection (Short circuit current)
- Provision of dynamic voltage support (“Voltage Jump Reactive Power” and “Control Based Reactive Power”)
- In case of high currents (e.g. due to faults or because the Phase Jump Limit is exceeded, the grid forming converter can switch over into an abnormal operating mode, in which it operates likes a grid forming converter.
- Controller bandwidth less than 5 Hz (to avoid resonance stability problems)

The definition of GBGF-I is very complete. A device operating according to these definitions is very similar to a synchronous machine with the exception that a synchronous machine has not “Phase Jump Limit” at which it changes its behaviour, and the provided short circuit currents are much higher.

5.2.2 AEMO (Australia)

In May 2023, AEMO has issued a document named “Voluntary Specification for Grid forming Inverters” [25] to inform users of the Australian system about AEMO’s expectations regarding grid forming converters. At present, grid forming behaviour is not required by the National Electricity Rules but the document [25] provides an outlook on potential future requirements in terms of grid forming converter control.

The main characteristics of grid forming converter control are:

- In general: Behaviour like a Thevenin Equivalent (voltage source behind reactance). The use of a “virtual impedance” is not explicitly excluded)
- Provision of Synchronizing Inertia
- Provisions of fast fault current injection

[13] *A “virtual impedance” is a controller function that behaves like an impedance.*

- Provision of dynamic voltage support
- The device can switch over to current control if its current limits are reached.
- Oscillations must be sufficiently damped
- Small signal impedance must be “passive” (resistive part >0) in a frequency band between 0 and 500Hz (to avoid resonance stability problems).

The guideline [25] is less precise regarding actual technical performance requirements than the National Grid Code [26] but in general, the requirements are very similar to the Great British requirements.

5.2.3 ENTSO-E

In response to ACER’s proposal to include grid forming capability as a mandatory requirement for most power park modules [27] [23], ENTSO-E published a draft technical guideline to specify the required grid forming behaviour with further detail [28].

Essentially, the requirements for Type B generators (“non exhaustive grid forming behaviour”) are:

- In general: Behaviour like a Thevenin Equivalent (voltage source behind reactance). The use of a “virtual impedance” is not explicitly excluded)
- Provision of Synchronizing Inertia
- Provisions of fast fault current injection
- Provision of dynamic voltage support
- The device can switch over to current control if current limits are reached.
- Oscillations must be sufficiently damped
- No requirements regarding controller bandwidth or passivity of the controllers.

In addition to the documents of ESO and AEMO, the ENTSO-E guideline [28] also includes requirements regarding the negative sequence response of grid forming converters.

5.3 Technologies (Components) to support system stability

Synchronous machine power plants can deliver all of the services described in the previous section. VRE power plants can only provide some of these services but not all of them.

Voltage support of VRE for example works very well, but as described in some of the previous sections, reactive power must be provided where it is needed and cannot be transferred over long distances. Because VRE is not always installed in areas, in which there is an increased reactive power demand, it is not possible to provide all of the required reactive power reserve using the VRE power plants only.

VRE can also deliver active power related services, like primary or secondary frequency control, but because VRE operate with very low variable cost (close to zero), the provision of active power reserves is very expensive for VRE.

The cost of active power reserve can roughly be estimated by the cost of energy not delivered minus variable generation cost (mainly fuel cost). This means that the higher variable generation costs are the less expensive is the provision of active power reserves. Therefore, there is a kind of “inverse merit order" for the provision of active power reserve: peaking plants having high fuel cost are the cheapest and baseload power plants having very low or no fuel cost are the most expensive resources to provide active power reserves. Therefore, because variable cost of energy from renewable sources is almost zero, cost of active power reserve from renewables is very expensive, even if it is technically feasible.

Therefore, in power systems with large share of VRE, many of the stabilizing services should be provided by additional components, like mechanically switched capacitors, STATCOMs, BESS etc. (see Figure 34 below).

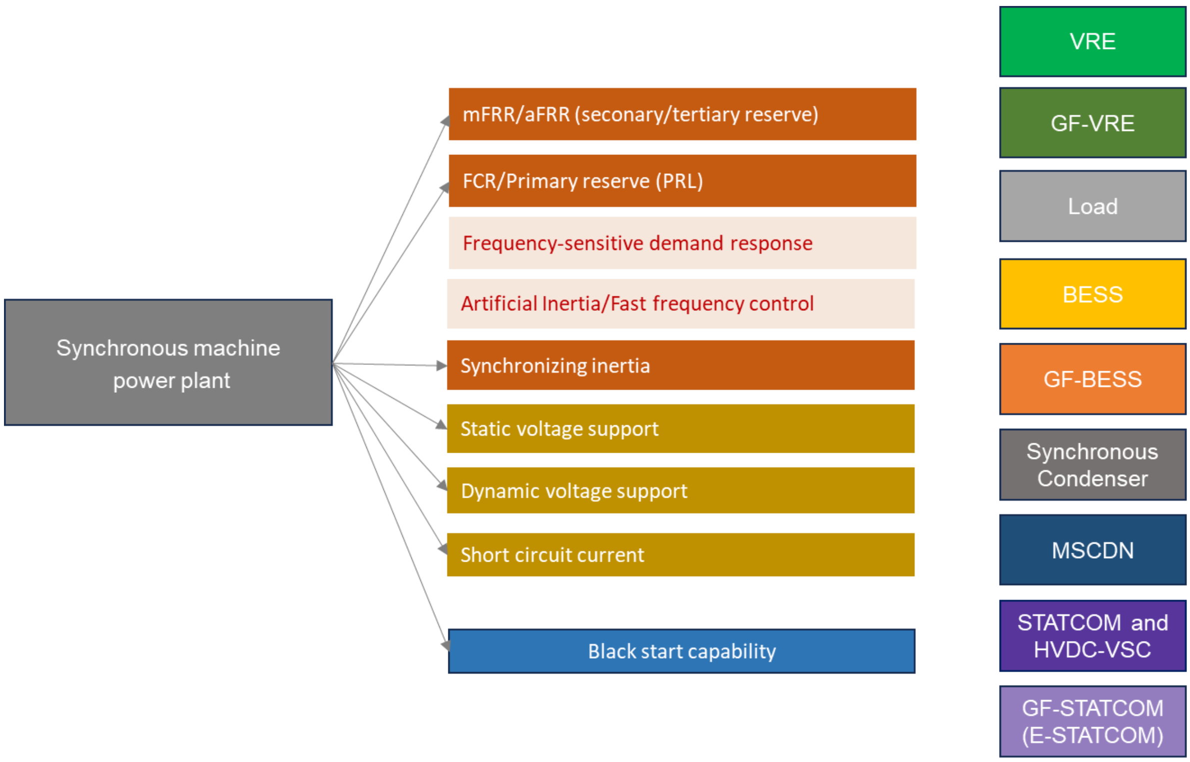

Figure 34: System services and components to deliver these services.[14]

In the following sections, the components that can provide the service described in the previous section are presented in more detail.

5.3.1 Synchronous machine power plants

As mentioned above, large conventional power plants using synchronous machines and a steam, gas or hydro-turbine can provide all relevant system services, as shown by Figure 34, maybe with the exception of fast frequency control services (activation times of FCR are typically in the time frame between 5s and 30s, whereas activation times of fast frequency response is more between 1s and 5s). However, conventional power plants can only provide these services during times, during which they are dispatched. With the increased penetration of wind and PV, there will be more and more time periods, during which only very few or even no synchronous machine power plants will be synchronized with the system. During these times, a synchronous machine power plant cannot

[14] *The arrows mean that the synchronous machine power plants can provide the corresponding service in principle. It does not mean that every synchronous machine power plant can provide the service (e.g. not every synchronous machine power plant can provide black start capability)*

provide any system service (which is in contrast to modern wind and PV farms, which can also provide reactive power and voltage control services during times of no wind/no solar irradiation). To enable a synchronous machine power plant to provide reactive power-based services and inertia also during times, during which it is not dispatched (does not generate energy), it must be enabled to operate in synchronous condenser mode. This can be achieved by installing a clutch between the generator shaft and the shaft of the turbine, which allows decoupling the turbine from the generator when the power plant is not dispatched so that the generator stay synchronized with the electrical network and provide system services. These clutches can be self-synchronized so that the generator does not have to be stopped and re-started when it is coupled with or de-coupled from the turbine.

5.3.2 Wind and PV generators (VRE-generators)

Variable renewable energies like wind and solar can provide most system services (see Figure 35). In fact, they can provide all stability-related services, except from synchronizing inertia and black start capability. The reason for which VRE cannot provide synchronizing inertia is the usually applied control concept, which is a so-called grid following control concept: The standard converter control concepts of VRE measure the voltage angle at the grid connection point of the inverter and control the injected currents so that there is a well-defined phase shift between voltage and current. Therefore, the injected current has a well-defined active and reactive component allowing controlling active and reactive power independently and with very short time delays.

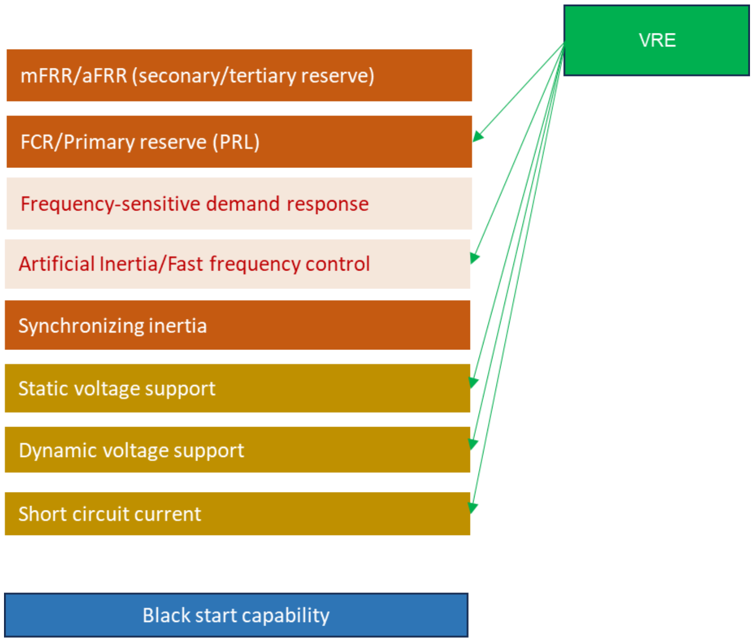

Figure 35: System services that VRE can provide

This control concept is very robust, maintains currents within the required limits, and allows the provision of most relevant system services. But there is no inertia and no synchronizing power exchanged with the system like synchronous machines would do it. In fact, VRE with grid following converters do not need much synchronizing power for being synchronized with the grid, but on the other hand, they do not help synchronizing other generators (synchronous and inverter-based generators) with the rest of the system neither. Regarding synchronization, we can say that they behave neutral (or passive).

5.3.3 VRE with Grid Forming Converter (GF-VRE)

The grid following concepts works very well, as long as there are enough synchronous machines in the system that actively help synchronizing all other synchronous machines and inverter-based generators. It should be noted that (grid-following-) inverter-based generators require much less synchronizing power than synchronous machines and therefore, also the need for components exchanging synchronizing power with the system reduces with reduced share of synchronous generation.

However, there is a minimum level of synchronizing power that is needed to synchronize inverter-based generators, and loads with the rest of the system and to keep voltage phase jumps resulting from faults and switching actions within reasonable limits.

By changing the control concept of the inverters (grid forming converter control) and by providing short-term active power reserves (time frame of some seconds), VRE can provide synchronizing inertia (synchronizing power/"phase-jump-power" and inertia), in a similar fashion to synchronous generators. As Figure 36 shows, VRE with grid forming converters can also be used to black-start a power system. However, black starting a power system with a varying primary energy source will always be impractical and would only work if the load is flexible. Therefore, Figure 36 shows a dashed arrow between GF-VRE and Black start capability.

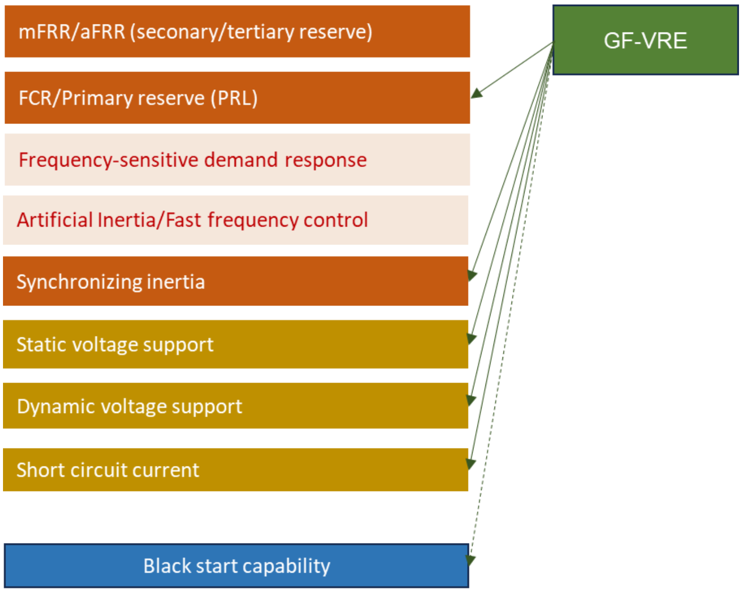

Figure 36: System services that VRE with grid forming converter can provide

But besides the mentioned advantages, there are risks associated with the grid forming control concept. With the addition of new, grid forming components, the need for synchronizing power increases too and therefore, grid forming converters can also cause new problems, like:

- Oscillatory stability problems (power swings at distribution levels, contribution to low frequency inter-area oscillations)
- Transient stability problems (loss of synchronism after faults in weak grids).

- Unpredictable impact on system stability if the converter loses its grid forming capability to avoid overload (high currents) or in the case of other unwanted controller interactions.

All these issues can be mitigated but need to be carefully studied. Very precise connection conditions specifying the required behaviour of grid forming converters during normal and abnormal system conditions are therefore of utmost importance.

Besides this, the cost impact on VRE with grid forming converters must be well understood.

For example, if WTGs are not allowed to release the required power from their rotating masses (because of aerodynamic interactions), WTGs will require additional storage components to support grid forming operation. Because the converter of modern WTGs is installed in the nacelle, there is no space for any additional storage component within the converter. Therefore, additional storage (super-cap or battery energy storage) including inverter and transformer would be required down in the tower. Optionally, centrally installed Energy-STATCOMs (STATCOM with grid forming control and storage) would be required in each wind farm. Both solutions would have a considerable cost impact.

Therefore, proper cost-benefit-risk analysis will be required to understand whether the benefits associated with the provision of synchronous inertia by VRE justify the associated risks and costs, especially if grid forming converter control should become mandatory for VRE.

5.3.4 Demand response

Active power based services can also be provided by the demand side. Reducing demand has the same effect as the injection of additional active power and therefore, loads can also contribute to active power based services.

Besides the classical underfrequency load shedding, which is not considered to be a system service but a measure to prevent system collapse (system defence), frequency-sensitive load disconnection, which acts in the normal frequency band of operation, can also be contractually agreed. Demand response can act in many different time frames and relax the requirements of other active power related services.

Contractually agreed demand response is applicable to all kinds of demand, for which the consequences of a short-term interruption have only a minor cost impact. This applies to all types of load with some storage capacity, e.g. thermal storage, like cooling houses, or heat pumps with associated warm water storage. Also loads driving any kind of fully automated production facility can be subject to contractually agreed demand response too (e.g. desalination plants, electrolysers etc.)

In most cases, demand-side-response is implemented by demand-interruption, which means that a load is completely disconnected when frequency support is required.

However, there are more and more continuously controllable loads connected to the grid, like electrolysers with controllable rectifiers, controllable heat-pumps or batteries (e.g. from electric cars or within domestic properties). Those loads can provide all active power based services like primary or secondary frequency control or even fast frequency control.

However, LVRT-operation is difficult to realise, even with loads that are interconnected through voltage-source-converters (VSC). In contrast to a generator with VSC, which use a chopper resistance to absorb the power, which is generated during a voltage dip, a load with VSC requires a storage component that can supply the load during the voltage dip, when the load cannot be supplied from the grid. Otherwise, they must be disconnected during a fault and can only ramp back with the usual start-up time of the process defining the electrical load. Therefore, requiring LVRT-capability with fast active power restoration from loads has a considerable cost impact on the load.

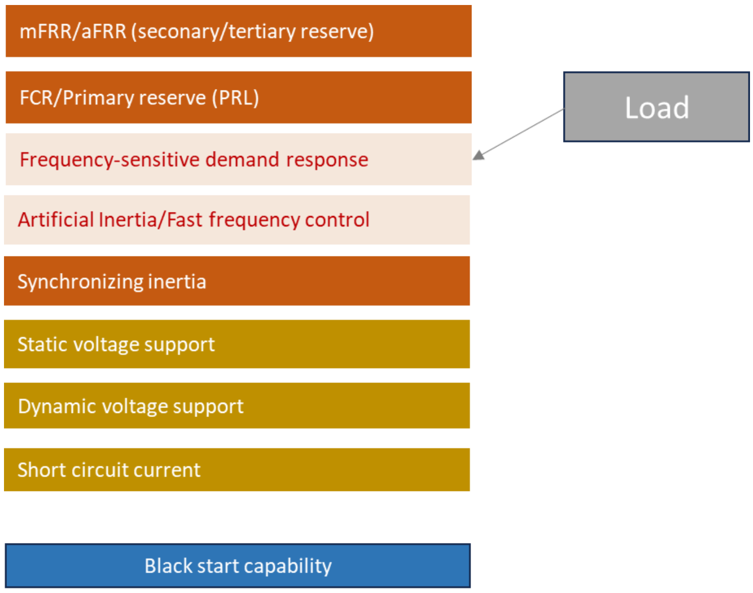

Figure 37: Demand response

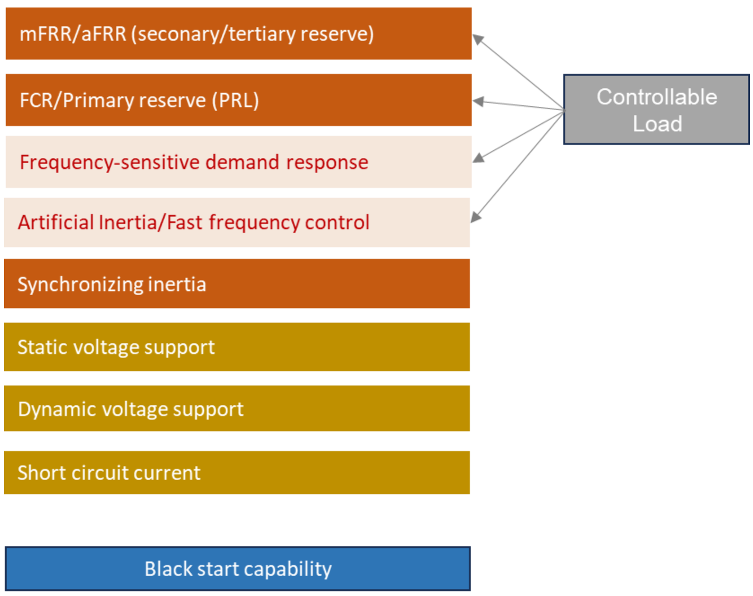

Figure 38: Possible demand-side services of controllable loads

5.3.5 Battery Energy Storage Systems (BESS)

Battery Energy Storage Systems (BESS) can provide a large variety of system services, depending on their energy to power ratio (E2P) and the converter controls with which they are equipped.

BESS systems with an E2P-ratio of <=1h are usually used for the provision of system services, like primary frequency reserve (FCR) or fast frequency control. BESS with larger E2P ratio (E2P>2h…4h) typically operate at the intra-day-market but they can also provide longer-term active power based system services like secondary and tertiary reserve (aFRR/mFRR).

In addition to this, they can provide the various types of reactive power based services, including dynamic voltage support.

As shown by Figure 39, BESS with standard, grid-following converters can provide all services, except from synchronizing inertia and black start capability. The provision of synchronizing inertia and black-star capability requires a grid-forming converter (see section 5.3.6).

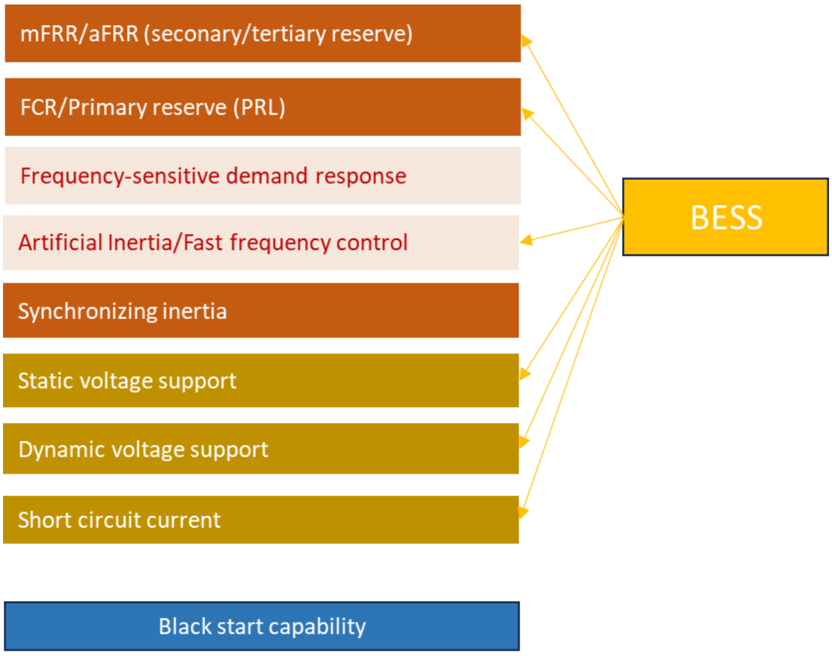

Figure 39: System services that BESS can provide

5.3.6 BESS with Grid Forming Converter (GF-BESS)

BESS with grid forming converter can provide the fully range of system services, like a synchronous machine, including synchronizing inertia (synchronous power and inertia) and black start capability. In terms of the contribution to system stability, a large GF-BESS with a grid connection point at the main transmission level is therefore fully equivalent to a large conventional power plant and is most effective regarding the provision of synchronising power (power associated with synchronising inertia).

However, like E-STATCOMs, BESS with grid forming converter do not have the same thermal overload capability as a synchronous machine. Therefore, the contribution to fault current and synchronizing power is limited by the converter capacity. Especially the limitation of synchronizing power of GF-BESS at the main transmission level can have negative impact on its contribution to power system stability.

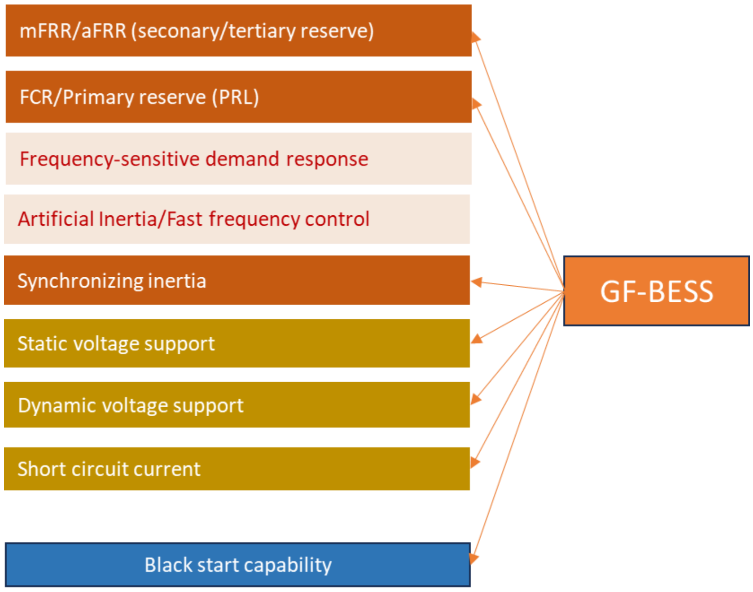

Figure 40: System services that BESS with grid forming converters can provide

5.3.7 Synchronous Condenser

A synchronous condenser is a synchronous machine without turbine. It can provide reactive power services and inertia (like an E-STATCOM, see section 5.3.10). Stand-alone synchronous condensers usually have additional masses connected to their shaft to increase the inertia that the synchronous condenser can provide. With these additional masses, acceleration time constants in the range of up to Ta=25s can be reached.

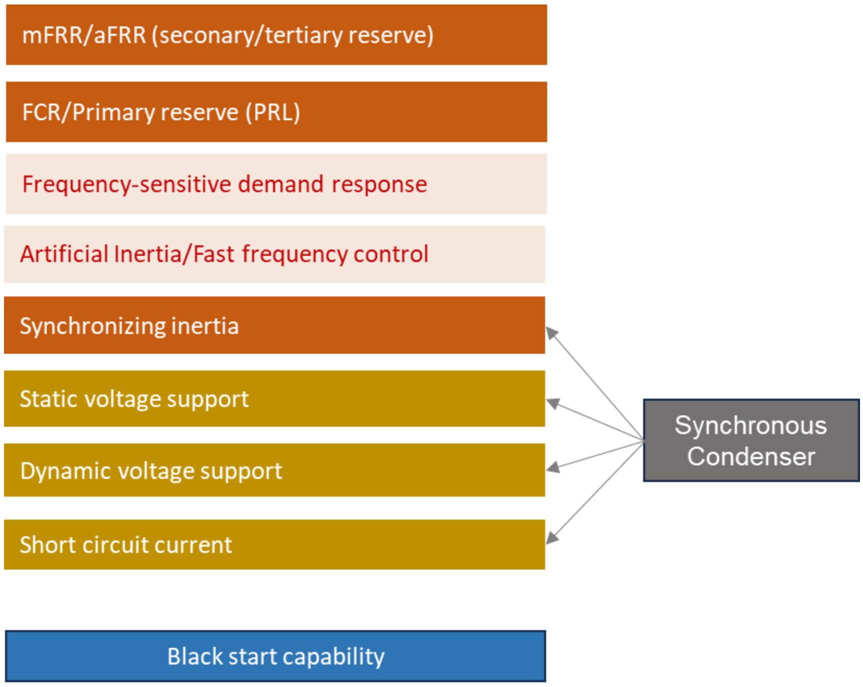

Figure 41: System services that synchronous condensers can provide

5.3.8 Mechanically Switched Capacitors (MSC/MSCDN)

Mechanically switched capacitors can help balancing reactive power in the long term. Capacitors connected to the transmission network are usually equipped with a damping network to mitigate any adverse impact on the system in the higher frequency range. The damping network is built by an additional capacitor, a filter reactor and a damping resistance.

MSCDNs are usually installed and operated by the TSOs and are more seen as an additional network component than a system service.

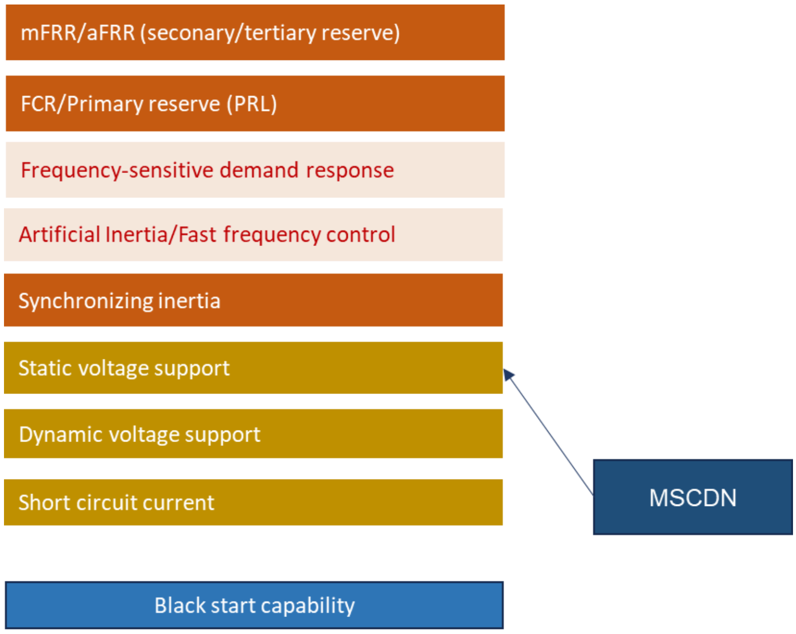

Figure 42: System services that MSCDN can provide

5.3.9 STATCOM (and HVDC-VSC)

STATCOMs (Static Synchronous Compensator) are dynamic reactive compensation devices built by power electronic converters (voltage-sourced converters/VSC) that act in the time frame of a few milliseconds. The typical capacity of a STATCOM at the main transmission level is in the range of some hundreds of Mvar (e.g. 100Mvar…300Mvar). As shown by Figure 43, a STATCOM can provide dynamic voltage support and static voltage support. The contribution of STATCOMs to fault currents (dynamic reactive current support during voltage dips) is usually very limited and therefore not shown by Figure 43. Because the storage capability of the internal capacitances is usually insufficient to cover STATCOM losses during grid faults, STATCOMs must be blocked if the voltage drops below a minimum threshold, which is in the range between 0.2 and 0.5 p.u. depending on the STATCOM manufacturer.

Besides the services shown by Figure 34, STATCOMs can also contribute to the damping of inter-area oscillations (rotor angle oscillations). This is achieved through the voltage dependence of the load. By modulating the voltage setpoint of the STATCOM via a Power Oscillation Damping (POD) control system, it varies the voltage slightly and through the voltage dependence of the load, also demand varies slightly. If this modulation is correctly tuned it can damp power oscillations effectively.

Because of the technical similarities between STATCOMs and VDC-VSC converters, the same type of services can be also provided by HVDC-VSC converters. In addition to the services shown by Figure 43, HVDC-VSC converters can also contribute to fault currents (fast reactive current provision) because they can cover converter losses through the other end of the HVDC link.

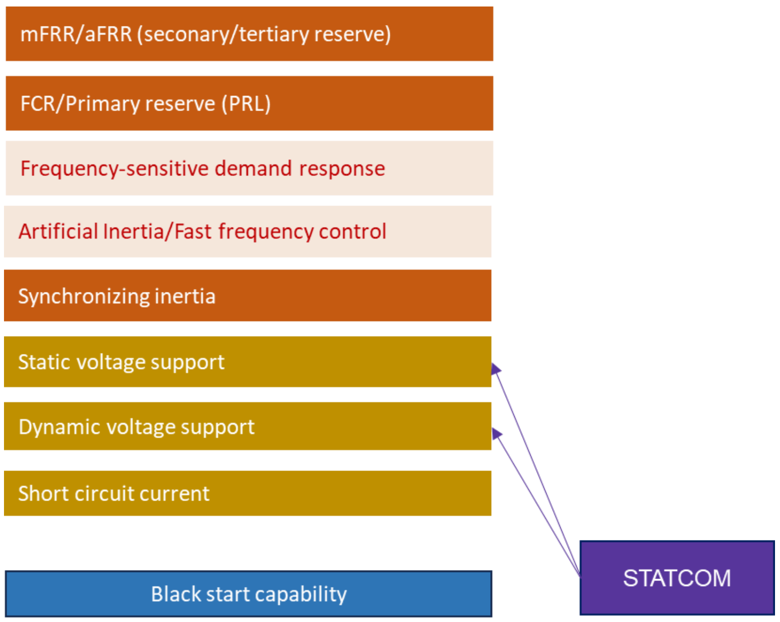

Figure 43: System services that STATCOMs can provide

5.3.10 STATCOM with Grid-Forming Converter and Energy Storage (E-STATCOM) and GF-HVDC

When combining a STATCOM with a grid forming converter and a static energy storage device (e.g. super-capacitors), it is possible to provide short-term active power services as well, like artificial inertia or fast frequency control. E-STATCOMs can also deliver short-circuit current (reactive current in response to voltage dips), even for voltages down to zero. With a grid forming converter, an E-STATCOM ("Energy-STATCOM") can provide synchronizing inertia and can help black-starting an island (together with a generator, which can be a converter-driven generator with grid following converter). It can therefore be fully compared to a synchronous condenser (see section 5.3.7).

An E-STATCOM is almost a full equivalent to a synchronous condenser but built by static (non-rotating) components. However, an E-STATCOM does not have the same thermal overload capability as a synchronous condenser (that can easily operate at five times the rated current for a short time frame) and therefore, E-STATCOMs require special controls to limit the current in the case of short circuits or in the case of large changes of the voltage angle. Because of the latter, the contribution to synchronizing power is more restricted in case of an E-STATCOM than in case of a synchronous condenser or comes at higher cost (when overrating the converter).

HVDC with grid forming converter can locally also contribute to the synchronization of the system. However, an HVDC-overlay connection, where both converter stations are in the same synchronous network, cannot contribute to system inertia because active power is always shifted from one end to the-other. It would therefore be required to connect a storage component (e.g. super-cap) to the DC cable so that inertia can be released from the storage component. In this case, an HVDC with grid-forming converter can fully contribute to the synchronizing inertia too.

An HVDC link that interconnects two asynchronous ac-grids can contribute to inertia without any additional storage component. Such HVDC interconnection can shift active power from one ac-network to the other. When assuming that a simultaneous frequency disturbance in both ac-networks is very much unlikely, this would be equivalent to a contribution to system inertia.

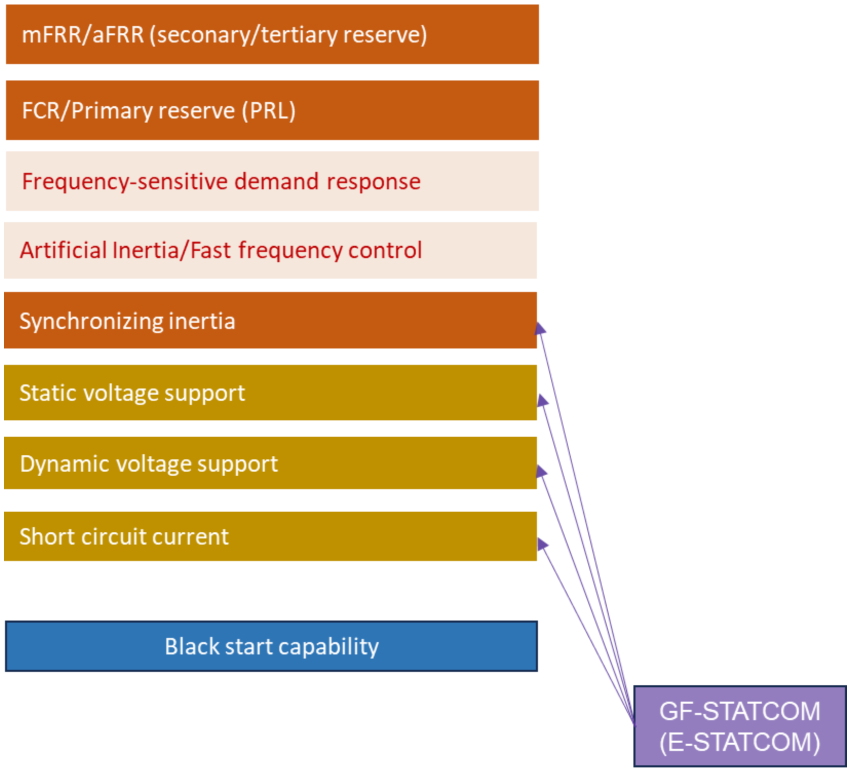

Figure 44: System services that E-STATCOMs can provide

5.3.11 Series compensation to enhance system stability

Besides system services aiming at the provision of active or reactive power in different time frames, the stability of the power system can be enhanced by balancing the load on parallel line corridors or by reducing the equivalent impedance of a transmission line using series compensation.

5.3.11.1 Static series compensator

Series compensation is a very efficient method to reduce the impedance of a line (or electrically "shortening" a line). The least expensive approach to series compensation is the installation of a capacitor in series to a transmission line, as shown by Figure 45.

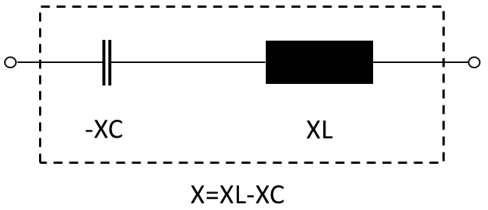

Figure 45: Static series compensator (passive, uncontrolled)

Because a capacitor has a negative reactance, it reduces the overall impedance of a transmission line. Electrically, the line looks as if it was shortened by the series capacitor. The reduced impedance increases the stability limit of power flows across the compensated line.

Besides increasing the stability constrained transfer limits of a line, series compensation can also help balancing power flows across different parallel transmission lines. Passive series compensation is a very cost-effective way to increase the stability of long or highly loaded transmission lines. Besides this, it is a very well understood concept (the first series compensated lines have been installed in the 1950s).

However, there are also risks associated with series compensation:

- Risk of torsional interaction or even sub-synchronous resonance: the series resonance introduced by the series capacitor may resonate with torsional eigenfrequencies of the drivetrain systems of large turbine-generator-sets. This may lead to accelerated fatigue of the shaft system or in case of a resonance to shaft destruction.
- Impact on impedance in meshed systems: the introduction of a series capacitor reduces the impedance of the corresponding branch. In a meshed system power flows use predominantly branches with lowest impedance. Reducing the impedance of an individual branch increases the power flow on this branch. Therefore, in meshed systems it is not sufficient to compensate only a single branch but branches on parallel corridors must be compensated too to re-balance the power flows between parallel transmission lines.

In central Europe, only few series compensation systems have been installed so far because there are not many long transmission lines, which would profit from it and because system operators have always been very much afraid of torsional interaction and sub-synchronous resonance.

Nowadays, with the use of HTLS-conductors allowing an increased thermal loading of transmission lines, series compensation could be a good solution to increase not only thermal limits but also the stability limits of transmission lines.

5.3.11.2 Thyristor-controlled series compensator (TCSC)

The risk of torsional interaction can be successfully managed by using thyristor controlled series compensation, which connects a thyristor-controlled series reactor in parallel to a series capacitor allowing controlling the impedance of the line and shaping the frequency response so that torsional interaction and synchronous resonance can be avoided (see Figure 46 below).

Thyristor-controlled series compensation is a well approved and well understood concept with many applications since the early 1990s.

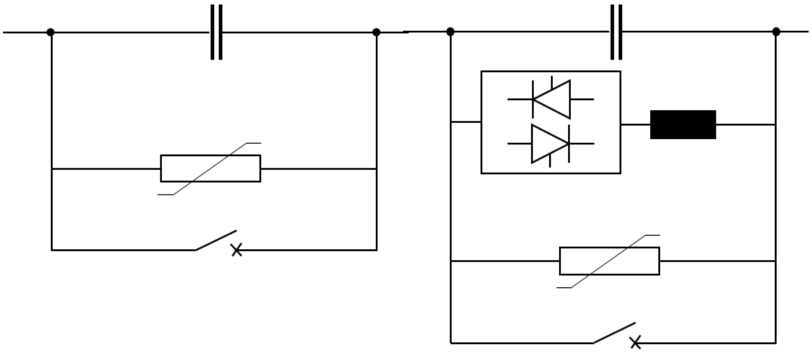

Figure 46: Thyristor-controlled series compensation (with protection equipment)

5.3.11.3 Static Synchronous Series Compensator (SSSC) and Unified Power Flow Controller (UPFC)

A SSSC is a STATCOM, which is connected in series to a transmission line. Essentially, it represents a controlled series compensator built by a static VSC-converter. Likewise classical series compensators, it allows injecting reactive power in series to a transmission line to reduce the equivalent electrical length of a transmission line and thereby increasing the stability constraints of that line. It exists in versions with transformer (see Figure 47), but also transformer-less devices have been introduced. Compared to static or thyristor-controlled series compensators, the SSSC is a rather new device, for which only very few installations exist today.

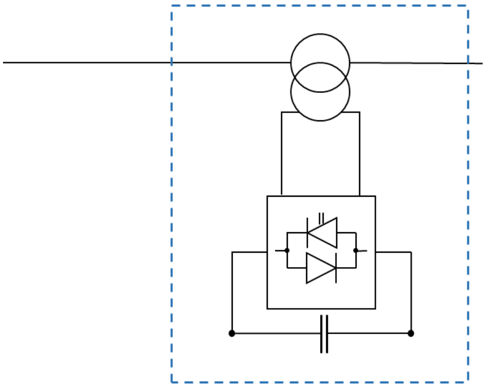

Figure 47: SSSC - Static Synchronous Series Compensator

When combining an SSSC with a STATCOM it is possible to not only inject reactive currents in series to a transmission line but also active currents. With such a device, not only the equivalent impedance of the transmission line can be varied (injection of reactive current) but also the equivalent voltage angle (by the injection of active currents) can be adjusted, which allows a direct control of the active power transfer across the line. The resulting component is named UPFC (Unified Power Flow Controller). It has been proposed in the beginning of the 90s but only very few installations have been realised since then.

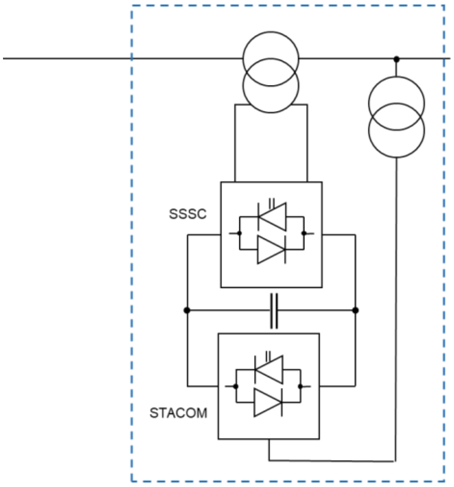

Figure 48: UPFC - Unified power flow controller

The main challenge associated with SSSCs (and UPFCs) is their protection against high short circuit currents, which requires converters with thermal overload capability and protective elements allowing bypassing the converter in the case of faults. Bypassing however means that the device temporarily loses its control capability when being bypassed.

5.4 Summary: System Services and technologies to enhance system stability

The term "system service" describes a physical behaviour independent from the technical component providing it. System services can therefore be defined in different ways. The definitions used in this report refer to the main services required to secure the stability of power systems, without any direct reference to actual system service markets.

<u>Active power based services:</u>

- mFRR/aFRR:
  Manual/automatic frequency regulation reserve, also named secondary and tertiary frequency control reserve.
  <u>Technologies</u>: mFRR and aFRR are typically provided by conventional power plants and pumped storage plants. In future, we will also see more and more BESS to provide mFRR and aFRR.

- FCR:
  <u>Technologies:</u> Frequency containment reserve, also named primary frequency control reserve. FCR is typically provided by conventional power plants but we see more and more BESS to provide FCR (in Germany, around 90% of FCR is provided by BESS already today).

- Frequency-sensitive demand response (FSDR):
  <u>Technologies:</u> Automatic reduction of demand in function of frequency. It is similar to frequency-sensitive load shedding but it operates in the normal frequency band of operation and is usually a paid service. FSDR is typically provided by large customers (industrial or commercial customers), especially by fully automatic production plant (e.g. desalination plants, etc.) or loads with inherent (thermal) storage capability (like cooling houses, etc.) where interruptions (in the time frame of minutes or up to an hour) have no or very low economic impact.

- Artificial inertia/Fast frequency control:
  Active power control in function of frequency or frequency gradient in a short time frame of less than on second or even less than 500ms.
  Technologies: In countries, in which Fast frequency control has been introduced as a paid ancillary service (e.g. Ireland or U.K.) we see predominantly BESS providing this service.

- Synchronizing power (or "phase jump power") and inertia:
  Inertia, which is activated through voltage angle variations (and not by frequency). It contributes to the synchronizing power and inertia.
  Technologies: The provision of synchronizing power and inertia is an inherent capability of synchronous machines (and was therefore not considered to be a "service"). Power electronic converters, which are equipped with grid forming converter control can also provide synchronizing power and inertia, if the converters have the required short-term thermal overload capability and short-term storage capability (time frame: up to around 10s) to provide additional power and energy.

Reactive power based services:

- Static voltage support:
  Reactive power provision in steady state. Is usually not controllable but can only be switched on and off.
  Technologies: Typically, static voltage support is provided by capacitor banks/MSCDNs.

- Dynamic voltage support:
  Reactive power provision in the time frame of some milliseconds. Must be automatically controlled at high resolution (continuous variation of reactive power).
  Technologies: Dynamic voltage support is provided by all synchronous machines (power plants and synchronous condensers). Static components, which are equipped with VSC-converters (like HVDC-VSC, STATCOMs, wind and PV generators) also provide short-term voltage support (as a mandatory requirement).

- Short circuit current:
  Reactive current support in response to a voltage dip (fault). Is activated in less than a few millisecond (e.g. 30ms). Includes "true short circuit current" (instantaneously activated), as provided by synchronous machines and "reactive current support", as provided by converter-driven generators and storage.
  Technologies: Short circuit current is provided by all synchronous machines (power plants and synchronous condensers) and dynamic loads (asynchronous machines, not connected via power electronic converters). But also VRE and HVDC-systems provide limited short-circuit current (up to rated current) as a mandatory requirement.

System restoration:

- Black start capability:
  Capability of a generator to start itself without any grid and to operate an island without support from any other generator.
  Technologies: Black start capability can be offered by all power plants that can operate an island (all power plants with synchronous machine or grid forming converter). Storage plants (pumped storage and GF-BESS) can in principle also provide black start capability but their

normal operation would be highly restricted in this case (must be sufficiently charge at any time).

Different technologies can provide different combinations of different system services at different cost.

Reactive power based services can be provided by static network components like MSCDNs or STATCOMs, generators (synchronous generators and converter-driven-generators) and HVDC-VSC converter stations. In future, also loads that are equipped with VSC (e.g. large electrolyser plants) will be able to provide static and dynamic voltage control services. However, in the case of reactive power service, the location of the component providing it is highly relevant because reactive power cannot be transferred over large distances.

Active power based services always require an energy source, which can either be a primary energy source (fossil fuel, wind, solar irradiation, etc.) or in the case of short-term services it is also possible to use storage for it (e.g. pumped water storage or battery energy storage for services in the time frame of up to several minutes, large capacitors or super-capacitors for short-term services in the time frame of seconds). It should be noted that providing active power based services using the primary energy source requires the generator to operate with an active power reserve. This can be very expensive in the case of variable renewable energies and therefore, we assume that active power based services will more and more be provided by storage components, as it is already the case for FCR (primary frequency control reserve) in Germany, which is predominantly provided by battery energy storage systems (BESS).

This also applies to grid-forming capabilities: Grid forming capabilities always include active-power based services (“active phase jump power” and inertia). This means that grid forming capability always requires:

- Thermal overload capability of the converter (to allow for higher than rated currents)
- Power source or energy storage.

In the case of wind generation, the required energy could be extracted from the rotating masses of the turbine. However, because of mechanical and aerodynamic constraints, it is usually not possible to make effective use of it. In the case of PV, using the primary energy source would mean that a reserve power would have to be kept permanently which comes at a high cost (cost of the energy not delivered, e.g. spot market price). Therefore, practically, wind and PV farms would have to be equipped with additional energy storage, which could be either battery storage or super-capacitors. Without thermal overload capability and without energy storage, a grid forming converter control permanently hits current or energy limits and effectively operates as a grid forming converter.

In addition to those system services, it is also possible to connect special devices in series to a transmission line to enhance the stability limits of this line (Flexible AC-Transmission Systems/FACTS). These devices can either reduce the equivalent impedance of the line (reduction of the “electrical length”) or allow controlling active and reactive power flows across the line. The most popular type of series compensation is the passive series capacitor. More advanced technologies are the thyristor-controlled series compensator, the Static Synchronous Series Compensator (SSSC) or the Unified power flow controller (UPFC), which allows controlling active and reactive power flows on a line. Passive series compensation and thyristor-controlled series compensation are well approved technologies, for which lots of operations experience exists for decades. SSSC and UPFC are also known for around thirty years now, but because of cost and protection issues, not many installations have been realized since then.

6 Strategies to ensure system security of future power systems

The EU guideline “establishing a guideline on electricity transmission system operation” [2] defines the following classes of contingencies:

- ‘ordinary contingency’ means the occurrence of a contingency of a single branch or injection;
- ‘exceptional contingency’ means the simultaneous occurrence of multiple contingencies with a common cause;
- ‘out-of-range contingency’ means the simultaneous occurrence of multiple contingencies without a common cause, or a loss of power generating modules with a total loss of generation capacity exceeding the reference incident;

According to these definitions, an ordinary contingency is a single component failure, like a line or a generator or the loss of generation with less than the reference incident. In the CE-system, the reference incident is defined by a loss of generation or load not exceeding 3000MW. In other European synchronous areas, the reference incident is essentially defined by the most severe loss of a single generator or other injection (e.g. HVDC terminal) or load.

An exceptional contingency refers to so-called common mode (or common cause) events, like the collapse of tower of an overhead with two or more circuits on it.

“Out of range” contingencies are those contingencies, whose probability is so low that securing the system against it would not be economic.

According to the operational guideline [2], the European TSOs are essentially asked to secure their systems against:

- Ordinary contingencies
- Exceptional contingencies if:
  - operational or weather conditions increase the probability of an exceptional contingency or
  - they have a high impact on their own or on neighbouring transmission systems.

Based on the above, we can conclude that system operators must secure their systems against instability resulting from ordinary and exceptional contingencies (because all exceptional contingencies leading to instability will have a high impact on the system).

“Securing” at operational time scales means that system operation must be verified at operational planning timescales and in real-time operations (based on simulation). In cases, in which system stability cannot be ensured, the system operator must carry out remedial actions (e.g. re-dispatch) to bring back the system into a secure state. With reference to Figure 49, this means that instabilities must be avoided so that the “red line” in Figure 49 will not be crossed in the case of ordinary or exceptional contingencies. Only in the case of out-of-range contingencies, there can be a remaining risk to cross the “red line” so that the system gets unstable and runs into a system split scenario.

If a system split occurs, the system is in an unsecure state (Emergency State) and it is always quite unpredictable what will happen.

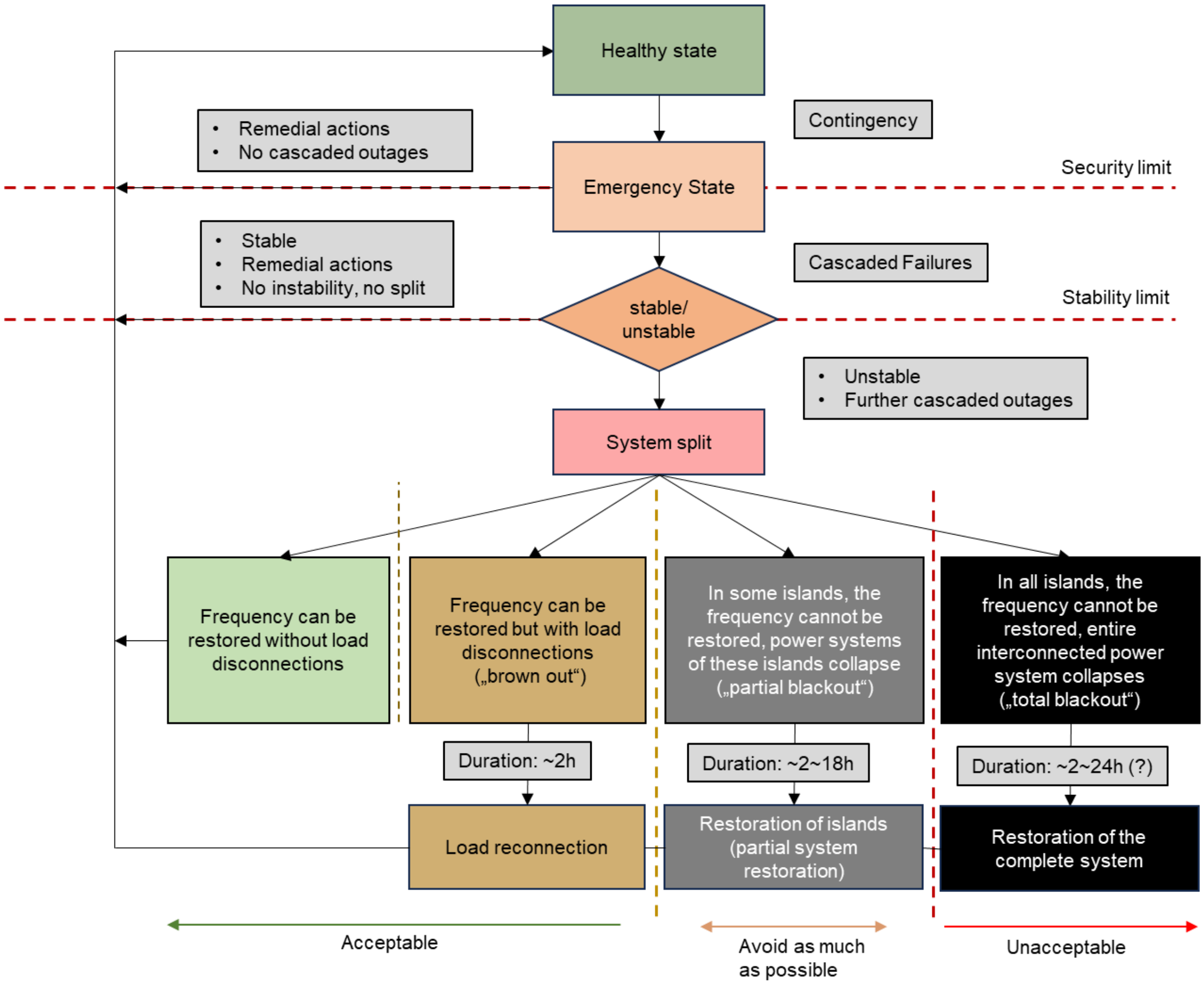

Figure 49: System security levels

As in explained in the previous chapter, the massive roll-out of variable renewable energies and the higher loading of transmission lines will require various additional components that can either:

- control power flows across transmission lines
- increase the stability limits of transmission lines or
- deliver system services (active and reactive power based services).

The preceding chapter has shown that technologies are available that can deliver those services and many of these technologies already exist for decades (e.g. synchronous condenser, series compensation of lines) and are very well approved.

In addition to the availability of components, the following key-questions need to be answered in order to achieve the overall objective, namely, to ensure system stability in a renewable-based power system without any unnecessary cost increase:

- Where in the grid is which service (and which component) required?
  The options are:
  - Mainly at the transmission level (top-down approach) or

  - At all voltage levels including distribution levels

- How should the delivery of the required services be enabled?
  The options are:
  - The system operator installs components that provide the required services (the "vertically integrated approach").
  - The system operator purchases services based on bi-lateral agreements (with generators or operators of stabilising components).
  - The system operator purchases services through markets.

The answer to these questions will depend on the actual service to be provided/component to be installed, especially, whether it is about:

- Active power based services (frequency stability, active power balancing)
- Reactive power based services (voltage stability, reactive power balancing)
- Components to control power flows or increasing stability limits of transmission lines

In the following sections, we will discuss the answers to these questions.

6.1 Regional distribution of system services

Due to physical constraints, active power can be transmitted over much larger distances than reactive power. Because the transmission of reactive power is always associated with significant voltage variations it is not possible to transfer larger amounts of reactive power over long distances. In addition to this, voltage is a local variable and voltage problems can occur in individual regions or even at individual bus bars. Therefore, especially in the case of fast voltage support, observability is key to the effective installation of STATCOMs (or other components supporting the voltage). In some cases. STATCOMs must be installed directly at a particular bus bar or close to a particular line so that it can mitigate a voltage stability problem effectively.

In the case of active power based services, the regional distribution is less critical: Frequency is a variable that can be observed globally. Apart from the first few seconds after a disturbance ("synchronization period"), the frequency in a synchronized power system is the same at every bus bar and at every voltage level. In addition to this, active power, which is needed to support the frequency, can be transferred over long distances.

The above statements apply to the classical, frequency-related active power services (primary- and secondary frequency control and inertia, as far as frequency stability is concerned). However, a reasonable distribution of inertia and primary frequency reserve is required to ensure that the network can transmit the associated power flows without violating any stability limits and that inertia and frequency control capability is well distributed in the case of a system split event.

The exchange of synchronizing power, which is needed to keep the voltage angles (rotor angles) in synchronism, follows the same principles as reactive power: the lower the equivalent impedance ("electrical distance") the higher is the synchronizing power that is exchanged between two generators (or grid-forming converters) at a given rotor angle difference.

Based on these physical constraints we can conclude:

- Reactive power based services and synchronizing power are most effective if provided locally.

- Active power services needed to ensure frequency stability can be allocated globally, in a wide area of the power system.

In addition to this, we must also take into consideration that the terms “near” and “far“ must be interpreted “electrically”, in a sense that a low impedance means “near” and a high impedance means “far”:

- The equivalent electrical distance depends on the impedance of a line (or underground cable) and the voltage level: Due to physical laws, impedances at a higher voltage level appear to be smaller at a lower voltage level (impedances transform with the square of the voltage levels between different voltage levels). This means that the “electrical distance” of a transmission connected component is reduced when seen from a distribution network and the “electrical distance” of a distribution component is increased when seen from the transmission network.
- Each transformer has an impedance and therefore, we must associate an electrical distance to each transformer too.

Consequently, all system services, which depend on network impedances, especially reactive power based services and synchronizing power, are more effective when being provided by transmission connected components than by distribution connected components.

Figure 50 summarizes the main outcomes of this section and visualizes, which services can be provided at global level, which services at regional and which services should be provided locally.

Note: the service “Synchronizing Inertia” has been divided into two parts in Figure 50. Whereas the exchange of synchronizing power must be provided locally, inertia is a service, which can be transferred over longer distances but should still be well distributed. Therefore, it is listed as a “regional service”.

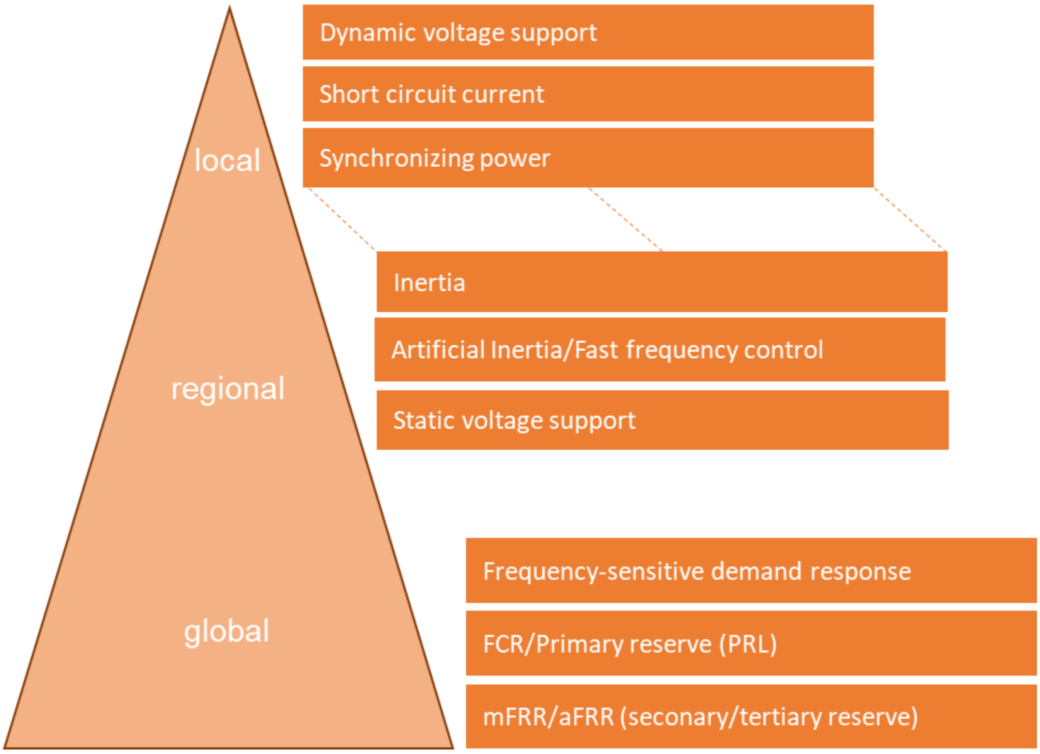

Figure 50: Global, regional and local provision of system services

6.2 Top down or bottom up?

As shown in the previous section, active power based services can be provided everywhere in the system, at any voltage level and at any location. Of course, the transmission capacity must be available to transfer the associated power flows to the required locations and therefore a reasonable distribution is still required, especially for the faster services like inertia and primary frequency reserve (FCR).

However, in the case of short-term services, like dynamic voltage support and synchronizing power, this is different. As explained in the previous section, they must be provided locally to be efficient. Additionally, we must understand that the faster a service is, the more important is the behaviour of the associated controllers, which must be able to observe the relevant quantities (e.g. voltage or voltage angle) to react correctly within very short delays so that the control system is stable.

Figure 51 and Figure 52 show two approaches for the allocation of fast ancillary services. In the "top-down-approach" according to Figure 51, components to provide the required services are allocated at the main transmission level only. The fast voltage control and synchronization requirements in networks at lower voltage levels are covered from the main transmission level. Essentially, this replicates the classical structure of power systems, in which the TSO is responsible for system stability. The components at distribution levels (132kV/110kV and below) would be passive in the short time frame, which means that their impact on system stability is very well predictable (passive). As stated above, frequency control services, like primary or secondary frequency control, could be provided at all voltage levels, including embedded generators and embedded battery energy storage.

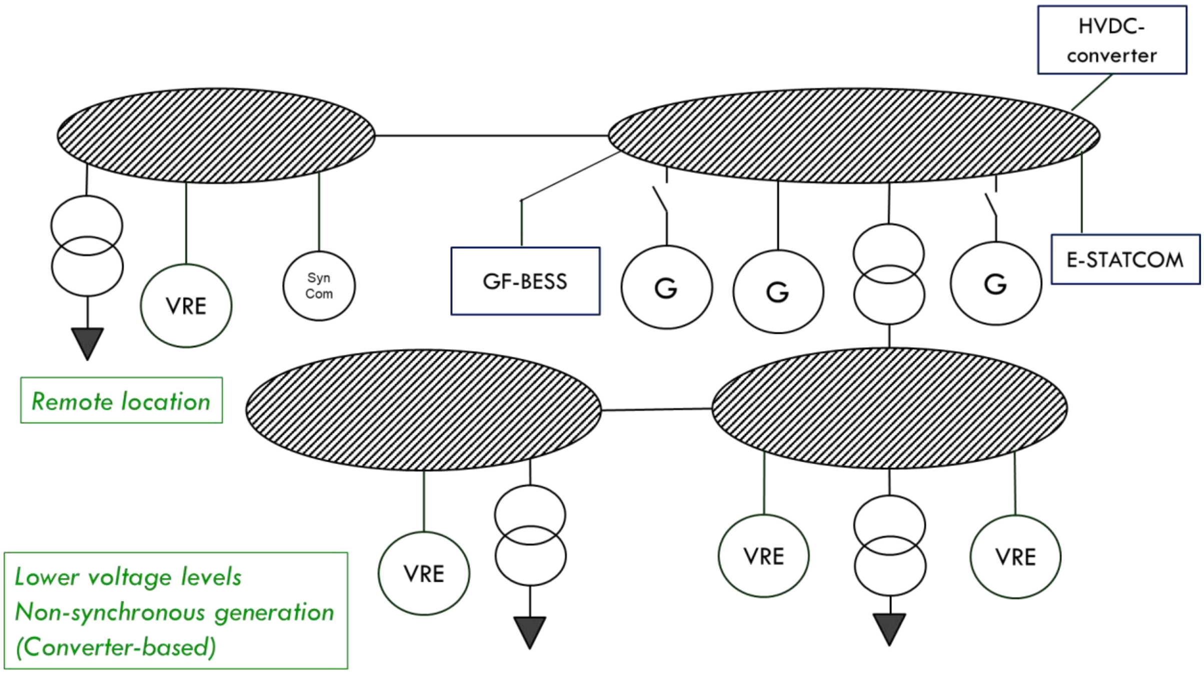

Figure 51: Strategies to ensure the stable operation of power systems - Top-down approach.

In the bottom-up approach according Figure 52, also fast services like fast voltage support and synchronizing inertia would predominantly be allocated in distribution networks, typically linked to embedded generators or embedded storage systems.

Reactive power would also flow upstream to the main transmission levels to cover reactive power and synchronizing power requirements at the transmission level.

However, components connected to a lower voltage level are always "electrically far away" from the next higher voltage level and because reactive power services and synchronizing power depends on impedance (or "electrical distance"), such a bottom-up approach could not work without additional components, like STATCOMs, E-STATCOMs or GF-BESS at the main transmission level because only transmission-connected components would be in sufficient proximity to critical locations in the network requiring fast voltage support to remain stable. Distribution connected components would always be too far away (in terms of "electrical distance") to be able to effectively maintain the short-term stability of the transmission system.

Besides technical aspects, also organizational aspects should be considered: it is the TSO who is responsible for system stability. If the components ensuring system stability are predominantly connected at the distribution levels, it becomes very difficult to carry out appropriate system analysis to verify the stability of the system. At present, TSOs only model the main transmission networks in detail. Distribution networks are usually represented in simplified form in those models. Generators connected to distribution levels are usually just represented by generic and aggregated models not representing the actual, site-specific behaviour of the power plant. Already today, these stability models, which include the complete interconnected European transmission system, are very large and complex and simulation times are long.

In a scenario, in which the components that are most relevant to system stability are predominantly connected to the distribution levels, the accuracy of the models used to carry out stability studies would necessarily suffer or become over-complex, and it would be very difficult to predict whether the system is in a stable state or not. In other words, many stability-related aspects would be "in the dark".

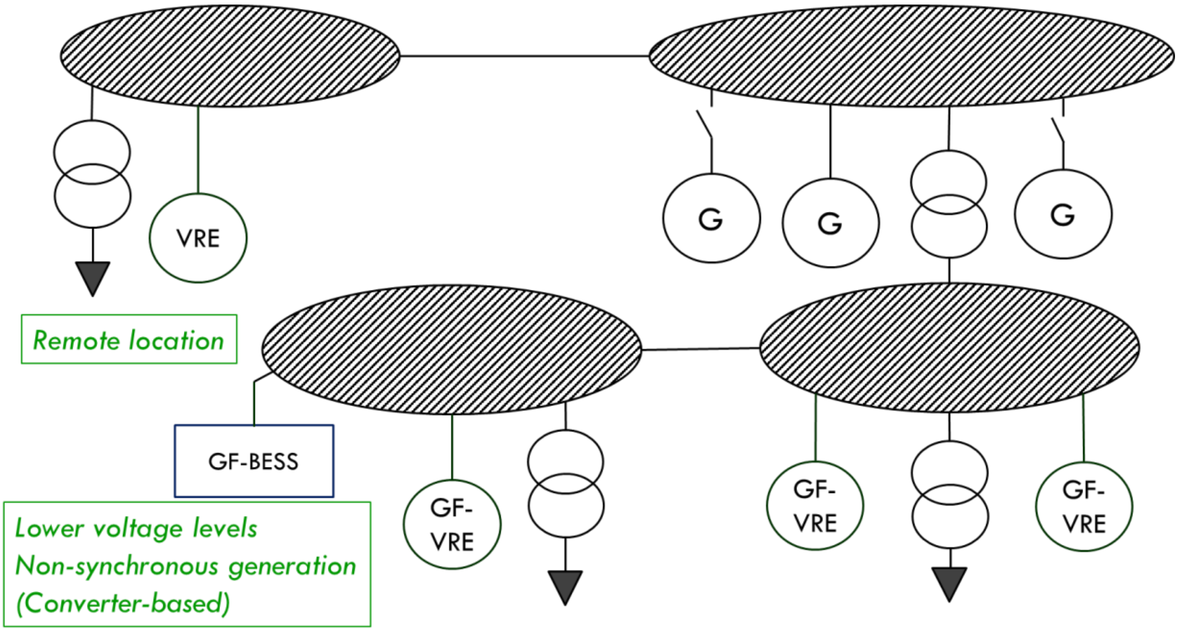

Figure 52: Bottom-up approach

This brings us to the "everybody does everything" approach, which is shown in Figure 53. In this approach, all services are allocated at all voltage levels.

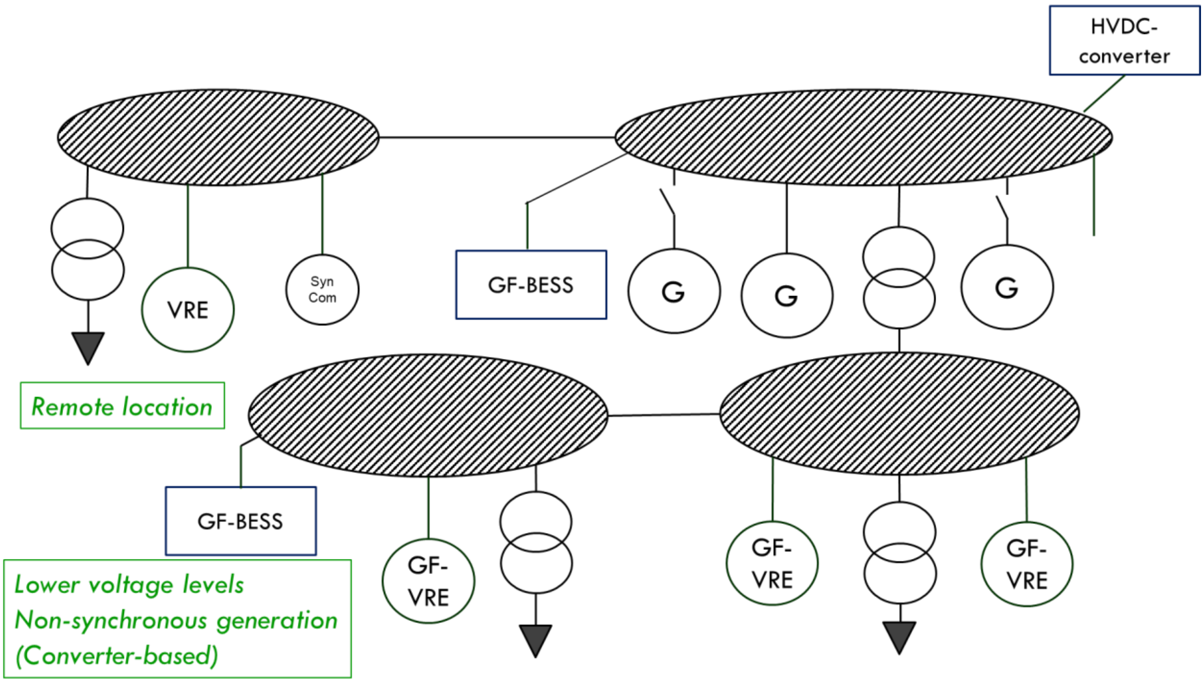

Figure 53: "Everybody does everything approach"

This is a scenario that usually develops if the provision of system services is mandatory, without any remuneration, as it is the case for most reactive power services in Europe. This can quickly lead to a scenario in which many technical capabilities are available, which will never be used and just represent stranded investments. For example, requiring fast voltage control from all VREs in a system (including transmission and distribution connected VRE) represents stranded investments for all those VRE installations, which are built in strong areas of the network, where fast voltage support is not needed.

In addition to this, the faster the response of distribution-connected assets to voltage variations and voltage angle variations, the more likely it is that stability problems also occur in distribution networks. Nowadays, distribution networks are predominantly passive in this sense (load and VRE with grid following converters and only very few synchronous generators) and therefore they are not prone to any stability problems. This could change if many grid-forming generators and storage systems would be connected to distribution networks. This would create numerous new stability problems in distribution networks, which must be properly being studied and understood.

6.3 Service provision by generators or storage?

In the classical, conventional power system, system services were generally provided by power plants (and some pumped storage plants). The reason is mainly that power plants with synchronous generators can provide all relevant system services and system services can be seen as a by-product of the generators. Additionally, battery energy storage was not available at reasonable cost until recently.

Only in power systems with very long transmission lines and areas, in which there are only few generators, additional dynamic voltage support had to be provided by SVCs.

Nowadays, battery energy storage is available and batteries for frequency control compete with synchronous generators about the provision of primary and secondary frequency control.

Compared to conventional power plants, there are key advantages when providing active power services using BESS:

- BESS is always synchronized and therefore, all system services provided by BESS are always available.
- During most times, when BESS does not deliver energy, frequency reserve (power) is available at no additional cost (no avoided cost of energy).
- BESS is extremely fast and can increase or decrease its active power output much quicker than conventional power plants (thermal power plants or gas turbines).

The advantages of BESS regarding the delivery of frequency-related services are confirmed by markets, in which BESS compete with power plants about the delivery of active power reserves. In Germany for example, BESS already provides more than 80% of the overall required primary reserve.

Besides primary and secondary reserve, BESS can also provide all reactive power services. However, as always, effectively providing reactive power services depends on the location of the component. Large BESS, which are connected to the main transmission level are therefore most effective and can provide all system services, including dynamic volage support and synchronizing inertia.

According to [29], between 73 GW and 119 GW of installed BESS can be expected in Germany until 2045. Out of these BESS, between 19 GW and 44 GW are predicted to be large, utility scale BESS power plants. These numbers show that the installed BESS capacity should be largely sufficient to provide the complete active power reserve of the German system (FCR, aFRR and mFRR). Once, these storage systems will be installed, they will likely completely dominate the frequency control markets and generators will not be able to compete with BESS.

In addition to planned BESS, there will be STATCOMs with short-term storage and grid forming control (E-STATCOMs) and synchronous condensers, which will be able to provide fast reactive power for voltage control and synchronizing inertia (see e.g. [30]).

If BESS, E-STATCOMs and synchronous condensers could provide all of the required system services, grid connection requirements for generators could be highly relaxed which would lead to reduced cost of generation. For example, gas turbines (fuelled by natural gas or hydrogen) could be built considerably cheaper when not having to comply with the dynamic performance requirements that are necessary to provide primary frequency response. Grid connection requirements could then be limited to basic requirements, which are needed to operate a power plant safely (e.g. LVRT-requirements, moderate reactive power capability to support the voltage in the surrounding area etc.).

On the other hand, the future, H2-ready gas turbine power plants should all be equipped with clutches and flywheels so that they can operate in synchronous condenser mode if they are not dispatched. According to [29], around 52 GW of installed Gas/H2 power plants can be expected in Germany until 2024. Because we assume that they will all operate with H2 by 2045, all turbines will be newly built turbines (partly new gas power plants, partly existing gas power plants where the turbine will be replaced by a H2-turbine). If all of these turbines were equipped with clutches and flywheels, most of the required inertia would be provided by these generators (during all times, including times of very high wind and PV generation). Together with utility-scale BESS (which would have to be GF-BESS in this case), there would be between 72 GW and 96 GW of capacity that could provide inertia during all times in the German grid. In terms of kinetic energy, assuming Ta=10 s for synchronous machine power plants and Ta=20 s for BESS, between around 450 GWs and 700 GWs could be provided just by gas/H2-turbines and utility scale BESS.

6.4 Strategies to enable system services

In a privatized, de-bundled power system, there are different options to enable the provision of system services. The most important are:

- Markets
- Compulsory services
- Auctions and bilateral contracts

In most European power systems, all stability-related system services, except from active power/frequency control services (FCR, aFRR, mFRR), which are procured via the ancillary market, are compulsory services that are defined by the grid connection conditions. In particular, this includes reactive power services and the contribution to short-circuit currents. Only in some countries, there are remuneration schemes in place for the provision of “reactive energy” (in kvarh, e.g. in Switzerland or. GB).

The advantages and disadvantages of the different procurement strategies are the following:

Markets:

Competitive markets are perfectly well suited to raise private capital. However, market prices are defined by offer and demand and therefore, they only work under the following conditions:

- There must be a sufficiently large market volume to initiate enough competition.
  If the market volume is too small, market prices can vary enormously. Therefore, especially "global" services, like most active power services are particularly well suited to be organized via markets (as it is the case today, where there are markets for FCR, aFRR and mFRR).
- Market rules must be very well defined to avoid speculation.
- To ensure system security, technical qualification criteria and conformity tests must be well established. Otherwise, system security would be at risk.

Besides this, it is important that there is a clear de-bundling between the system operator and the private entities offering a service and that the system operator is not allowed to install equipment to provide the corresponding services himself. Otherwise, there will be conflicts of interest between the system operator (or market operator) and the market participants.

At the same time, the required de-bundling can also be a disadvantage because it can prevent synergies from being used. From a technical point of view, it would be perfect to install large BESS at the main transmission level that support the voltage like a STATCOM and provide at the same time primary and secondary frequency reserve (FCR and aFRR). However, according to ENTSO-E regulations this is not possible because TSOs are not allowed to deliver FCR and aFRR. For a BESS operator however, it is not very interesting to connect onto the main transmission level to be able to effectively provide fast voltage control because there is no remuneration for it. BESS operators will rather try to get their connection points at lower voltage levels where connections are cheaper.

Optionally, TSOs could work with auction schemes to procure combined services (fast voltage control and synchronizing inertia) at well-defined locations in the transmission system, which would create business models for private investors to install BESS with grid forming capability (fast voltage control and synchronizing inertia) and to participate in intra-day trading and in ancillary service markets for FCR, aFRR and mFRR.

Compulsory services:

Generators and storage installations must comply with the grid connection conditions defined by the responsible TSO. The connection conditions of the individual European TSOs must comply with the technical framework defined by the Regulation 2016/631 (Requirements for Generators – "RFG" [31]) issued by the European Commission.

More precisely, the RFG does not define the provision of services but defines the minimum technical requirements for generators to ensure the stability of the system: the RFG defines technical capabilities and not service provision. For example, "Type C" and "Type D"-generators[15] must have the technical capability to participate in primary frequency control (operation in Frequency Sensitive Mode according to [31]). However, this does not mean that they must participate in the FCR market (or, if they participate in the market that they are able to submit competitive bids). In the case of wind and PV farms this usually means that all larger wind and PV farms (Type C/Type D) are equipped with FSM capability but because cost of primary frequency reserve (FCR) of wind and PV is considerably

[15] *generators connected to 110kV and above or having a rated capacity of 50MW or more*

higher than FCR of battery energy storage systems (BESS) or conventional generators, this capability will only be used under emergency conditions (e.g. in case of a system split).

This approach works very well in cases, in which the cost of a “technical capability” is rather low and the dominating cost is associated with the actual delivery of the service, as in case of active power services (FCR, aFRR, mFRR).

However, in cases, in which the dominating cost is with the “technical capability” (as in case of e.g. reactive power or fast current injection during faults), where the required technical installations are expensive but the cost associated with the delivery of the service is low, there is a high risk that this approach makes electricity more expensive because there is a lot of “technical capability” in the system, which is not needed (e.g. reactive power capacity at locations where it is not required) leading to stranded investments.

The support of system inertia by using grid forming converter technologies is currently under discussion within the ENTSO-E [6] [32] [33] [27]. The EU-regulation 2016/631 is currently under revision and the next version of it will foresee grid forming capabilities of PPM (power park modules), probably as a mandatory requirement, at least for Type B, C and D Power Park Modules [32] [27]. The report of the ENTSO-E Expert Group ACPPM [6] highlights that grid forming capability of power park modules (wind and PV farms) requires them to integrate either additional storage, keep some active power reserve or, in case of wind farms, release energy from the rotating masses of the turbine, which is not possible in all cases because of aerodynamic interactions. This can increase the cost of PV inverters or wind turbine generators significantly. In terms of remuneration schemes, a minimum technical requirement for grid forming capability of all generators and a remuneration for the provision of the actual service is the recommended option of the Expert Group [6].

In Germany, it has been decided that a market for inertial response will be introduced [34]. This market foresees a fix remuneration defined by the relevant TSO for either positive inertial response or negative inertial response (or both). The qualification criteria for this market are currently prepared by the FNN/VDE [35] (under consultation).

In the U.K. Grid Code [26], “Grid Forming Capability” is introduced as Non-Mandatory Service since 2023. The technical definitions are part of the Grid Code. The remuneration will be defined National Grid.

Auctions, bilateral contracts and fixed remuneration:

Auctions and bilateral contracts can always be used, where very specific services are needed, for example reactive power at a specific location with specific technical properties (e.g. dynamic reactive power response). In Great Britian for example, National Grid procures reactive power (shunt reactors, synchronous condensers, etc.) through auctions within the “Pathfinder” or similar projects.

Bilateral contracts are usually established if a network operator procures services from already existing plant or in cases, in which the service provision is only a by-product of an installation (e.g. enhanced reactive power capability exceeding the mandatory capability in case of a wind or PV farm).

In case of a “fixed remuneration” scheme, the network operator (or regulator) defines the price of a service and everybody who is interested can offer it at the given price. The operator will select the bidders based on a “first come first serve” approach, until the total volume of the required service is procured.

In Germany, the planned inertial response market will work in this way: TSOs will define price and region of inertial response and everybody who is interested to participate can submit an offer at the set price [34].

6.5 Case Study: System service requirements in the future European power system

Future power systems will be characterized by very large share of non-synchronous generation (generation, which is not based on directly-coupled synchronous machines, like wind and PV farms). Several publications (e.g. [36]) show that the share of true, synchronous/grid forming generation should be in the range of around 30% of the load. Otherwise, mainly voltage stability problems in different time frames are observed. However, we would like to point out that we consider the required percentage of 30% to be very conservative because related studies very often do not include the option “grid following converter with fast voltage control” in the analysis. We assume that with fast voltage control on grid following converters, the ratio of synchronous/grid forming generation could even be lower.

According to several scenarios, electricity demand of the Continental European System can reach up to 6000 TWh/year by 2050 (according to [9]), which is mainly supplied wind and PV (with the addition of some biomass plants, some nuclear plants and hydrogen-based gas turbines) with a renewable share of more than 95%. Assuming a load factor of around 70%, this is equivalent to a peak load of around 1000 GW in the Continental European System by 2050. Assuming that at least 30% of grid forming capability would be required to maintain the stability of such a system, an installed capacity of around 300 GW of synchronous generators and grid forming converters would be required in Europe until 2050. At transmission level, this could be covered by:

- Synchronous generators of nuclear power plants (36 GW until 2050 according to [9])
- Synchronous generators of hydro power plants (130 GW until 2050 according to [9])
- Synchronous generators of hydrogen fuelled gas turbines (in synchronous condenser mode while not operating, 192 GW until 2050 according to [9])
- Large BESS with grid forming converters (and connected to the main transmission levels): around 100 GW (estimate).
- Dedicated synchronous condensers (with increased acceleration time constant)
- E-STATCOMs with grid forming converters

Just considering the nuclear power plants and the H2-gas turbine generators operating in synchronous condenser mode, there would be around 266 GW of synchronous generation connected to the grid, which would be almost permanently be available. Together with grid forming BESS, the minimum required value of 30% would even be exceeded

In terms of inertia, we can assume the following acceleration time constants:

- Nuclear: Ta=10 s/H=5 s
- Hydro: Ta=6 s/H=3 s
- H2-gas turbine generators in synchronous condenser mode, with flywheel: Ta=10 s/H=5 s
- Large BESS with grid forming converter: Ta=20 s/H=10 s

Based on these numbers, we can calculate the following indices:

- All synchronous machines synchronized: 1530 GWs
- Nuclear plus H2-gas in syn. con. mode: 1140 GWs
- Nuclear plus H2-gas in syn. con. mode plus BESS: 2140 GWs
- All synchronous plus BESS: 2530 GWs

Today, there is between around 750 GWs and 2250 GWs[16] of inertia synchronized with the CE system, depending on the dispatch scenario.

As the numbers above show, the same amount of inertia could be provided by the still available synchronous machines plus BESS. When equipping the planned H2-gas-turbine generators with clutches and flywheels, 2530 GWs of inertia could always be available (considering an availability of 90% of these devices, it would be around 2300 GWs).

Based on this very high-level analysis we can conclude that the overall synchronizing inertia that could be made available by synchronous machine power plants and utility-scale BESS until 2045 is very large (kinetic energy of up to (2530 GWs) and will probably exceed the required inertia. It is therefore unlikely that additional inertia from other sources (dedicated installations like E-STATCOMs or synchronous condensers or from wind and solar farms) will be required.

The future need for system inertia is not clearly identified at present. The various studies at ENTSO-E level (e.g. [8]) and national level (e.g. [16]) lead to results that differ significantly from each other. The level of inertia, which will be required until 2045 should be determined by an appropriate methodology, which may be conservative but should not lead to over-conservative results ("over-conservative" in a sense that the estimated level of inertia exceeds the actual requirement by a factor of 2, 3 or 4). In particular, it is important to keep in mind that "more inertia" is not necessarily "more stability". Additional inertia improves the frequency-stability of a system but reduces the frequency and consequently the damping of inter-area oscillations and therefore has a negative impact on the oscillatory stability of the system. Inertia, synchronizing power (short-circuit level) and damping power must always be well balanced in a power system to ensure that all stability requirements are met.

6.6 Summary: Strategies to ensure the stable operation of future power systems

Recent studies at ENTSO-E-level (e.g. [8]) or national level (e.g. [30]) deal mainly with the stability of the system (or the "systems" in this case) after a system split has occurred. The required inertia is identified so that a total blackout can be avoided. Partial blackouts however can still occur. The sole criterion based on which the risk of a partial or complete blackout is evaluated is the rate of change of frequency (RoCoF) and the frequency limits. Other aspects like the voltage stability of each island are not analysed. However, based on the RoCoF criterion alone it is not possible to predict whether an island will be able to remain in operation or whether it will collapse following a system split. It is possible that islands collapse because of voltage instability even if the RoCoF is below 1Hz/s or it is possible that it does not collapse, even if the RoCoF is above 1Hz/s. However, it is certainly true that the higher the RoCoF the higher is the risk of a partial system collapse.

[16] *Based on a system load between 150GW and 450GW and an equivalent acceleration time constant of Ta=10 s*

Therefore, the prevention of system splits should have priority over defending the system in the case that a system split occurs. The concept, that each TSO must ensure that the system remains stable in case of Ordinary and Exceptional Contingencies, as required by the ENTSO-E guideline on transmission system operation [2] will ensure that the likelihood of system splits will not increase with increasing share of VRE. Only if the CE-system was not well secured against instability in the case of Ordinary and Exceptional contingencies, the likelihood of system splits would increase in future.

This requires the installation of synchronous machines and grid forming converter systems at the main transmission level, where they can provide synchronizing power and fast voltage support most effectively.

Great Britain has already started the introduction of Grid Forming Capability as a non-mandatory, paid system service through the Pathfinder projects. Most of these Pathfinder projects are synchronous condensers providing the full range of Grid Forming Capability. Some others are based on battery energy storage.

Other countries, like Australia have introduced guidelines about grid forming capability defining future requirements.

Germany is about to introduce an inertia market. According to the VDE/FNN guideline [35], the participation in the inertia market with converter-driven devices will require grid forming capability. The technical requirements defined by [35] are non-mandatory at present.

ENTSO-E is planning to introduce grid forming capability as a mandatory requirement for all storage systems, HVDC converters and power park modules with grid connection at 110kV and above (or at the secondary side of a 110kV substation). The idea behind may be that the technical capability to provide grid forming capability will be a mandatory requirement whereas the actual provision of the service will be market based. However, because grid forming capability has a considerable CAPEX and only a low OPEX, this approach will not lead to the most cost-effective solution because such a market-design would only reflect OPEX.

This leads to the question, which technologies are best suited to provide grid forming capability. The ENTSO-E expert group “Advanced Capabilities for Grids with a High Share of Power Park Modules” has published a quite extensive report in 2023 [6]. In chapter 8 of this report, the expert group listed existing capabilities and required measures of different technologies to enable them to provide grid forming capability. The overview distinguishes between different services and the provision of positive and negative power. The result of this overview is summarised by Table 1 and Table 2 below.

Table 1: Existing capability and upgrade cost to provide synchronizing inertia

Technology	positive		negative	
	Capability	Cost	Capability	Cost
SPGM	high	low	high	low
Syncon	high	low	high	low
BESS	medium	low	medium	low
HVDC	low/medium	medium	medium	medium
Wind	low	high	medium	medium
PV	no	high	medium	medium
STATCOM	no	high	no	high

Table 2: Existing capability and upgrade cost to provide phase jump power

Technology	positive		negative	
	Capability	Cost	Capability	Cost
SPGM	high	no	high	no
Syncon	high	no	high	no
BESS	medium	low	medium	low
HVDC	medium	medium	medium	medium
Wind	low	high	medium	high
PV	no	high	low	high
STATCOM	low	medium	low	medium

Based on this analysis, the expert group on "Advanced Capabilities for Grids with a High Share of Power Park Modules" comes to the conclusion that the required grid forming capability should be provided by those technologies that can provide it at lowest technical effort and that other technologies, especially power park modules should be designed to become more robust against large phase jumps in situation with low short circuit level so that the need for phase jump power can be reduced (see section 8.3 of [6]).

Therefore, the introduction of open markets to procure synchronizing inertia that reflect both CAPEX and OPEX of the offered technologies (which means that grid forming capability must not be mandatory) seems to be the way to ensure that grid forming capacity will be provided at most economic conditions. This would be in-line with the British approach.

The introduction of grid forming capability as a mandatory requirement for power park modules, as planned by ENTSO-E, could only be justified if there was a technical need for it. Such a technical need however is not stated in the report of the expert group [6] nor it is highlighted by any of the studies referred by [6]. Even in CO_2 emission-free European power systems, there will always be a considerable level of synchronous machine power plants synchronized with the grid that provide a large amount of grid forming capability:

- Several countries will retain or even expand their nuclear fleet.
- Some other countries (Austria, Switzerland) use a large amount of hydro power.
- Other countries, like Germany will have to install new H2-gas-turbines to ensure generation adequacy. When enabling these power plants to operate in synchronous condenser mode (by using self-synchronizing clutches (SSC) and additional flywheels), their grid forming capability will always be available, also during times, in which they are not generating.

Besides this, utility-scale BESS will be able to offer grid forming capability at competitive prices and will be rolled out at large scale to balance the variations of PV generation (arbitrage, incentivized by the intra-day market). Therefore, inertia markets should be introduced soon to provide incentives for large utility-scale BESS, which are under planning and construction today, to include the required grid forming capability that will enable them to participate in future inertia markets.

7 Processes and Tools to operate stability constrained power systems

7.1 Stability Constrained Transfer Limits

When using HTLS conductors the thermal limits of transmission lines increase but voltage and stability constrained transfer limits remain almost the same. Therefore, in the case of longer lines, thermal limits can move above voltage and stability constrained transfer limits and lines cannot be loaded up to their thermal limits.

With special measures (system services, installation of STATCOMs, etc.) voltage and stability constrained transfer limits can be increased too but, in most cases, power systems with highly loaded transmission lines operate closer to their stability limits than conventional power systems using traditional transmission line conductors.

To identify the stability limits of the various transmission corridors, stability studies with varying active power flows across relevant transmission corridors are executed (defined by lines crossing the "boundaries" (see also Figure 12).

Those stability studies are offline studies, which are executed at planning time scales (e.g. five or 10 years ahead) or operational planning time scales (day ahead, week ahead, in some cases up to one year ahead). With the help of these studies the required system services to maintain stability limits at the required level or the need of additional components to support system stability can be identified.

In contrast to thermal limits, which are defined by currents, stability limits are defined by active power flows. Usually, they are not defined "per line" but as an active power transfer limit across a transmission corridor consisting of several lines (or "boundary flow limit"). At planning time scales, the objective should be that stability constrained transfer limits are higher than thermal limits so that the lines of the transmission corridor can be loaded up to their thermal limits. In the case of long lines, this may not always be possible. In this case, stability limits should at least be above voltage limits (e.g. the voltage stability occurs at voltages outside the normal voltage band of operation) so that the voltage can indicate, whether the system is close to a stability limit or not.

Stability constrained transfer limits should be communicated to the system operator (integrated into models used for operational planning and real-time operations) and considered as additional constraints in the regular (steady state) system security assessment.

7.2 Dynamic Security Assessment (DSA)

Security Assessment is a process, which is executed at different operational planning time scales (e.g. several days ahead, one day ahead, a few hours ahead and close to real time, e.g. right before a switching action is executed).

The usual system security assessment is based on steady state load flow calculations. It analyses the (planned) normal operating condition (N-state) and the various N-1 states considering the predicted demand and generation of the moment to which analysis applies.

According to the EU guideline on system operation [2], the term "N-1" means all contingencies of a contingency list, which is defined and maintained by the responsible TSO. The contingency list should include all contingencies that can occur with a reasonable probability. Essentially, it includes all "ordinary" contingencies, which are mainly n-1 outages ("n-1" in the classical sense that one component is on outage) and Exceptional Contingencies, which are common mode (or common cause) contingencies. For example, the outage of two transmission lines because of a broken tower would fall into this category. The contingency list can vary over time. For example, in the case of adverse weather conditions the likelihood of some outages of higher order may increase and therefore, those contingencies must be included in the contingency list under these conditions.

Within the Security Assessment, each TSO carries out load flow calculations for all contingencies of the contingency list and verifies that the system can operate without violating any operational constraint. If this is not the case, the TSO must identify remedial actions (re-switching of lines or re-dispatch measures) which will be required to ensure that the system operates into a secure state.

Classically, it is sufficient to execute the Security Assessment using steady-state load flow calculation and to verify the system state against thermal (current) and voltage constraints. Also, a verification of active power flows against pre-defined stability constrained transfer limits (see section 7.2) can be part of this process.

In the case that power systems operate very close to their stability limits or in systems, in which voltage constrained transfer limits are very close to stability constrained transfer limits, steady state load flow calculations are not sufficient to validate the secure operation of the system at a given state. In this case, the system security assessment should be complemented by dynamic simulations and other tools like PV-curves (see e.g. Figure 13 or Figure 15), which allow identifying whether the system is stable at a given state and what the stability margins will be at the analysed states.

A full implementation of online dynamic security assessment tools should integrate the following functionalities:

- Steady state (load flow based) contingency analysis
- Voltage stability assessment (load flow based, PV-curves)
- Transient stability analysis (time domain simulations)
- Small signal analysis (eigenvalue analysis, to analyse oscillatory stability)

Dynamic Security Assessment came up in the 70^{s} and 80^{s}, mainly in the USA and Canada. At these times, special algorithms were used for online dynamic security assessment (e.g. using energy functions etc.), which were different from the methods used for offline stability analysis (for system planning).

Nowadays, dynamic security assessment is usually based on the same algorithms and models as in an offline environment and is implemented around standard simulation software packages like DIgSILENT PowerFactory or PSS/E. However, dedicated dynamic security assessment tools like DSATools of PowerTech (subsidiary of British Hydro), which is around since the late 80^{s}, are not only simulating individual system states but also calculate stability margins, which is very important when operating a power system close to their stability limits.

In Continental Europe, steady state security assessment was sufficient until recently because the European power system is highly meshed and the length of transmission lines is short compared to countries like Canada, USA, Australia or in Latin America.

Nowadays, with the higher loading of AC-transmission lines and the general trend to operate the system closer to its stability limits, DSA also becomes more popular in Continental Europe and European TSOs have started with DSA implementations.

7.3 Wide-Area Monitoring Systems (WAMS)

Wide-Area-Monitoring Systems are able to monitor system stability in real-time.

The basis of WAMS are Phasor Measurement Units, which are time synchronized and can measure power flows, voltages and voltage angles with a very high time resolution (the “reporting rate” of a PMU is typically in the range of one value per cycle).

Because of the time synchronization of PMUs, WAMS, which integrate many PMUs at various locations in the power system, can also measure and report the voltage phase difference between different nodes in the network at any time, which is a very important parameter to assess the stability of the system in real time. Advanced WAMS do not only monitor actual power flows, voltages and voltage angles, but also allow estimating stability margins in real time to enhance system security.

WAMS can be used just for monitoring purposes, but it is also possible to use PMU-measurements to implement smart control and protection algorithms, which do not only rely on local measurements but on measurements at different locations in the power system. For example, this can be used to split the system along well-defined boundaries in the case of instability.

7.4 Summary: Processes and tools to operate stability constrained power systems

To improve system security in stability constrained power systems, stability analysis should be executed at the various planning and operational time frames, which are typically:

- Up to 10-15 years ahead (network planning, network development):
  Offline stability analysis to identify stability issues at planning levels and required measures to mitigate those problems (required services, systems and components to improve system stability). Tools: standard offline power system analysis packages integrating the required steady state and time-domain analysis functions.
- One week up to one year ahead: Long-term operational planning/outage planning:
  As part of the regular outage planning processes (planning outages to carry out maintenance works etc.) the system should systematically be tested against potential stability issues. Tools: standard offline power system analysis packages integrating the required steady state and time-domain analysis functions.
- Day-ahead, intra-day (few hours ahead): Short-term operational planning:
  As part of the short-term operational planning, system security assessment is a standard process applied by every TSO. When operating a stability constrained power system, the standard, load flow based security assessment should be complemented by dynamic security assessment (DSA), allowing various additional steady state and time-domain simulations to assess the stability (including stability margins) for every analysed contingency. Tools: standard offline power system analysis tools with customized enhancements for DSA or specialized DSA-tools.
- Real-time:
  In the real-time environment, wide-area measurement systems (WAMS) can be used to improve the visibility of the system in real time. WAMS allow measuring power flows, voltages and phase angles in real time. Because PMUs are time-synchronized it is possible to monitor angular differences between different nodes of the network in real time or even implement

protection and control schemes, which use voltage and current measurements at different locations of the transmission grid.

Besides WAMS, also DSA can be used in the real-time environment: Based on an initial state estimation, DSA can execute N-1-simulations to identify potential stability issues in the case of n-1-outages or it can verify the stability of the system for a planned switching action, right before the switching action is executed (some minutes ahead of real time).

With the help of tools like DSA or WAMS, the visibility of stability issues in the power system can be improved, which contributes to system security. However, even if tools and measurement devices are constantly improving it should be noted that stability constrained transfer limits are physical constraints, which can only be increased by the provision of real system services delivered by generators or additional, dedicated components (e.g. STATCOMs, BESS, etc.). Therefore, while DSA and WAMS can be used to operate a power system closer to its stability limits, DSA and WAMS cannot influence the physical stability limits as such.

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