IEEE Power & Energy Society

April 2020

TECHNICAL REPORT

PES-TR77

Stability definitions and characterization of dynamic behavior in systems with high penetration of power electronic interfaced technologies

PREPARED BY THE
Power System Dynamic Performance Committee
Task Force on Stability definitions and characterization of dynamic behavior in systems with high penetration of power electronic interfaced technologies

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TASK FORCE ON

STABILITY DEFINITIONS AND CHARACTERIZATION OF DYNAMIC BEHAVIOR IN SYSTEMS WITH HIGH PENETRATION OF POWER ELECTRONIC INTERFACED TECHNOLOGIES

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KEYWORDS

Converter-driven stability, electric resonance stability, frequency stability, power system stability, small-signal stability, transient stability, voltage stability.

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1. INTRODUCTION

1.1 Background

A task force set up jointly by the IEEE Power System Dynamic Performance Committee and the CIGRE Study Committee (SC) 38, currently SC C4 – System Technical Performance, had addressed in [1] the issue of stability definition and classification in power systems from a fundamental viewpoint and had closely examined the practical ramifications. At the time this document was published in 2004, the dynamic behavior of power systems was predominantly determined by the dynamic performance of synchronous generators and their controls as well as the dynamic performance of the loads. Consequently, [1] primarily dealt with fairly slow, electromechanical phenomena, typically present in power systems dominated by synchronous machines, while fast transients related to the network and other fast-response devices were considered out of scope and thus neglected. Thus, for the purposes of stability analysis in the bandwidth of interest, all fast-electromagnetic transients are neglected as they typically decay rapidly [2].

Since the publication of [1], however, electric power systems worldwide have experienced a significant transformation, which has been predominantly characterized by an increased penetration of power electronic converter interfaced technologies. Among these new technologies are wind and photovoltaic generation, various storage technologies, FACTS devices, HVDC lines, and power electronic interfaced loads.

With significant integration of converter interfaced generation (CIGs), loads, and transmission devices, the dynamic response of power systems has progressively become more dependent on (complex) fast-response power electronic devices, thus, altering the power system dynamic behavior. Accordingly, new stability concerns have arisen which need to be appropriately characterized, classified, and defined.

This report focuses on CIG, while the effects of converter connected loads on stability are briefly discussed, where relevant.

1.2 Time Scales of Power System Dynamic Phenomena

Fig. 1 depicts the time scales for various classes of dynamic phenomena in power systems. It can be seen that the time scale related to the controls of CIGs ranges from a few microseconds to several milliseconds, thus encompassing wave and electromagnetic phenomena. Considering the proliferation of CIGs, faster dynamics will gain more prominence when analyzing future power system dynamic behavior compared to the phenomena within the time scale of several milliseconds to minutes. Focusing on the time scale of the electromechanical transients enabled several simplifications in power system modeling and representation, which significantly aided the characterization and analysis of the related phenomena. A key aspect of these simplifications is the assumption that voltage and current waveforms are dominated by the fundamental frequency component of the system (50 or 60 Hz). As a consequence, the electrical network could be modeled considering steady-state voltage and current phasors, also known as a quasi-static phasor modeling approach [3]. With this modelling approach, high-frequency dynamics and phenomena, such as the dynamics associated with the switching of power electronic converters, are only represented by either steady-state models or simplified dynamic models, meaning that fast phenomena, like switching, cannot be completely captured. Considering the CIG related time scales of operation mentioned previously, there is a need to extend the bandwidth of the phenomena to be examined and include faster dynamics within electromagnetic time scales when the faster dynamics is of importance and can affect overall system dynamics.

This document focuses on two time scales, namely, that of "electromagnetic" and "electromechanical" phenomena. Electromechanical phenomena are further divided into "short-term" and "long-term" as introduced in [1]. For short- and long-term dynamics, a phasor representation is usually implied, allowing the use of phasor (or quasi sinusoidal) approximation in time-domain simulations. However, this representation is not directly suitable for the study of electromagnetic phenomena.

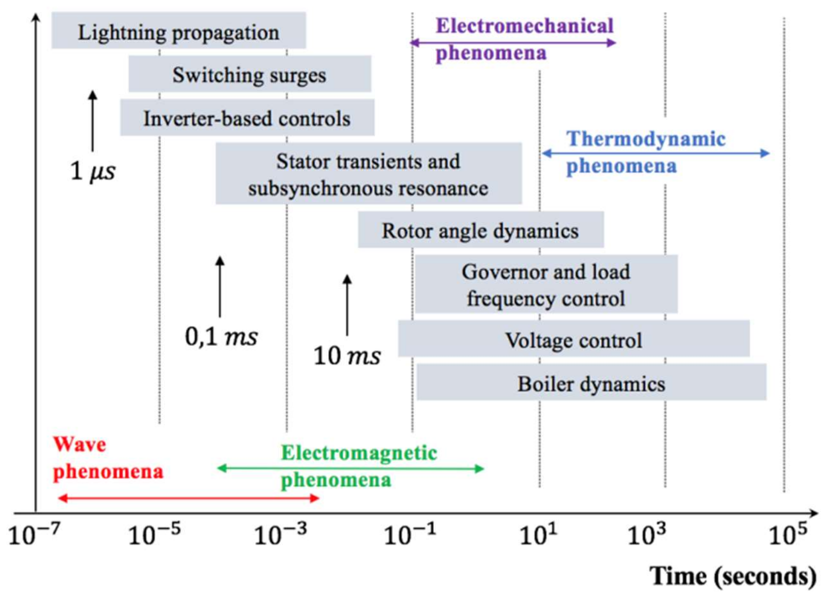

Fig. 1. Power system times scales.

1.3 Scope of this Work

This report focuses on classifying and defining power system stability phenomena, including additional considerations due to the penetration of CIGs into bulk power systems. The classification is based on the intrinsic dynamics of the phenomena leading to stability problems. The classification into time scales refers to components, phenomena, and controls that need to be modeled to properly reproduce the problem of concern.

The impacts of distributed resources, connected at the distribution level, on the transmission system are addressed in [4] and hence are not dealt with in this document.

Furthermore, the report does not address: i) cases where an incorrect control setting causes a local instability, ii) cases when the instability of a control loop can be directly characterized without modeling the power system, iii) stability issues associated with microgrids (this topic is addressed in [5]), iv) electromechanical and electromagnetic wave propagation phenomena [6]-[10].

2. CHARACTERISTICS OF CONVERTER-INTERFACED GENERATION TECHNOLOGIES

2.1 Introduction

The increasing share of CIGs in power generation mix leads to new types of power system stability problems. These problems arise due to the different dynamic behavior of CIGs compared to that of the conventional synchronous generators. The stability issues arise due to interactions between CIG controls, reduction in total power system inertia, and limited contribution to short circuit currents from CIG during faults [11], [12].

2.2 Characteristics of CIGs and Associated Controllers

This section briefly discusses some of the main characteristics of CIGs and their controllers to facilitate better understanding of their potential impact on the dynamic performance of power systems and the possible interactions with other equipment and components of power systems. A comprehensive coverage of CIG controls, which is beyond the scope of this report, can be found in references such as [11], [12].

The CIGs are fundamentally different from synchronous generators. CIGs include a variety of energy sources ranging from wind-turbine generators to photovoltaic-cell arrays to batteries and other emerging technologies (e.g. wave generation systems). Hence, the source of energy is not necessarily a mechanical turbine-generator that is converting rotational kinetic energy to electrical energy. Even in the case of wind-turbines, where this is true, modern wind-turbine generators operate at variable speed and asynchronously with the network[1]. Thus, the traditional concept of rotor-angle stability does not apply directly to CIGs.

The overall performance of CIGs is dominated by the control systems and the strategy used to control the power electronic converter interface between the energy source and the electric grid. The vast majority of large-scale CIGs use voltage-source converters [11], [12], or some derivative thereof, allowing designs that offer full four-quadrant control. In that case, the converter is fully capable of independently controlling active and reactive current that is being exchanged with the grid, as long as the total current remains within the rated capability of the power electronic switches. This allows for fast and accurate control of active and reactive power in most circumstances. Therefore, CIGs present both

[1] Older wind turbine generators used fixed-speed induction generators. However, such wind turbine generators are no longer manufactured, although some significant amounts do still exist in power systems around the world. Even such older wind turbine generators, are still asynchronous.

a challenge and a greater opportunity for hitherto unprecedented flexibility in control of energy sources. For example, with energy sources such as photovoltaic (PV) systems and battery energy storage systems (BESS), very fast and sustained frequency response is technically feasible [13], [14].

Figure 2 depicts the converter interface and controls associated with most CIGs. There are essentially four system components:

1. The main circuit which constitutes the direct-current bus (e.g., fed by a BESS, PV cells or arrays, or the generator side rectifier for a type-4 wind turbine generator [11], [15]) and the electronic power converter[2] bridge that converts the dc current to ac for injection into the network.
2. The inner current control loops, which regulate the active and reactive current to be injected into the network based on the commands issued by the high-level controls.
3. The phase-locked loop (PLL), which locks onto the network fundamental frequency voltage and thus keeps the converter synchronized with the network. It provides the reference angle for the transformation of variables between the high-level controls and the current to be injected into the grid. The PLL is currently the dominant method used by vendors for synchronization of the CIG to the grid. Still, there is on-going research and development considering other alternatives, see for example references [16], [17].
4. The high-level inverter controls include all the essential control functions such as voltage/reactive control, active power control, ride-through functionality, frequency response, among other functions. Typically, these controls are significantly slower than the inner-current controls, with the exception of fault ride-through controls which tend to be fast acting controls.

[2] The most common types of power electronic devices used in the converter bridge are insulated-gate bipolar-transistors (IGBTs)

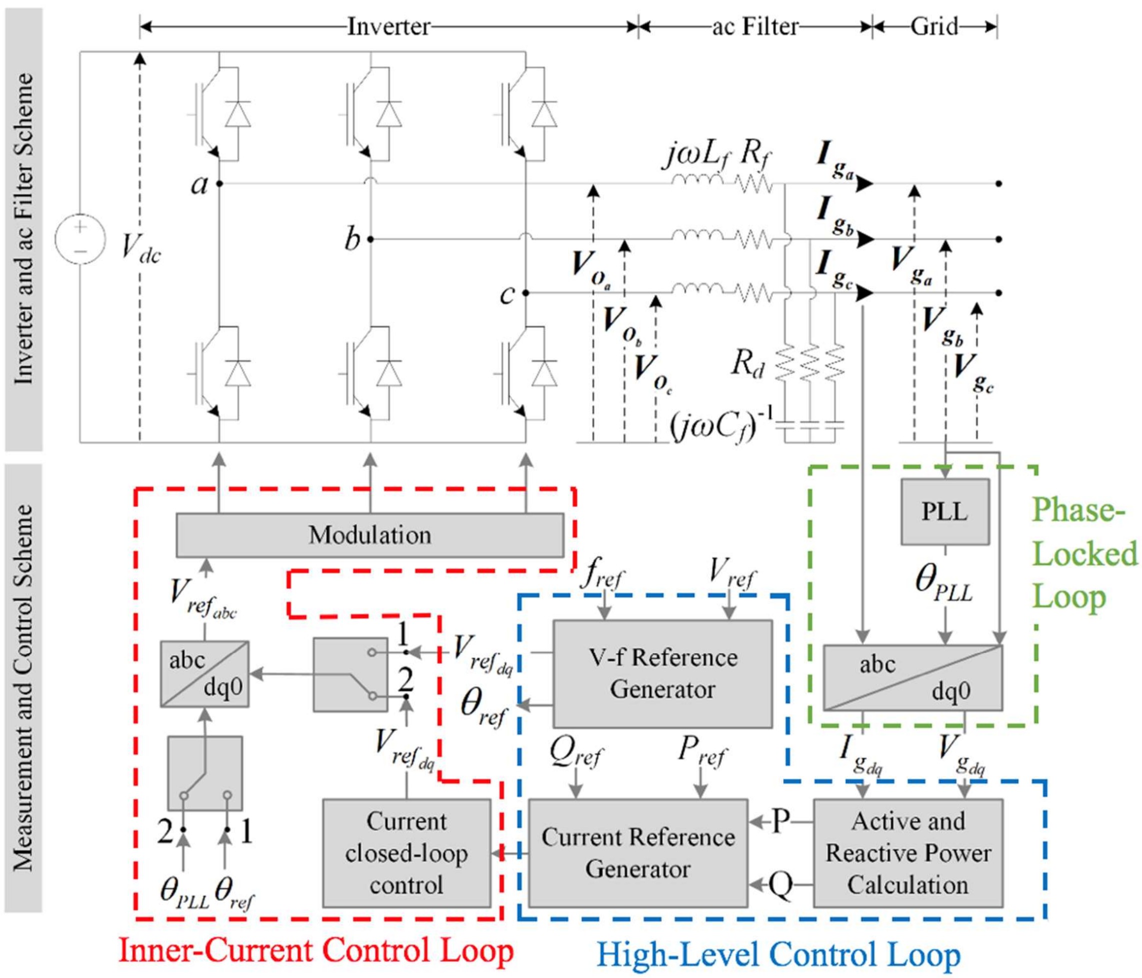

Fig. 2. Diagram of a typical the converter interface and its controls (based on Fig. 2 in reference [5], IEEE© 2018).

Thus, the ability of CIGs to ride-through electrically close large voltage and frequency disturbances, to control voltage, active/reactive power, and contribute to frequency response, is all driven by the stable operation of these basic controls. The key attributes that need to be considered when evaluating the impact of CIGs on system dynamic behavior are:

1. CIGs can provide limited short-circuit current contributions, often ranging from 0 (converter blocks for close in bolted 3-phase faults) to 1.5 $p.u.$ for a fully converter interfaced resource [18]. Type-3 wind turbine generators [18], i.e., double fed induction generators, can contribute more short circuit current though, as their stator is directly coupled to the grid.
2. The PLL and inner-current control loop play a major role in the dynamic recovery after a fault. For connection points with low-short circuit ratio, the response of the inner current- control loop and PLL can become oscillatory. This is due to the PLL not being able to quickly synchronize with the network

voltage, and also due to high gains in the inner-current control loop and PLL. This can potentially be mitigated by reducing the gains of these controllers. The exact value of the short circuit strength at which this may occur will vary depending on the equipment vendor and network configuration. A typical range of short-circuit ratios below which this may occur is 1.5 to 2.

3. The overall dynamic performance of CIGs is largely determined by the dynamic characteristics of the PLL, the inner-current control loop, and the high-level control loops and their design.

With the switching frequency of the power electronic switches typically in the kilo-hertz range, and the high-level control loops typically in the range of 1 to 10 Hz, similar to most other controllers in power systems, CIGs can impact a wide range of dynamic phenomena, ranging from electromagnetic transients to voltage stability, and across both small- and large-disturbance stability.

In summary, with proper design of both the main circuit and the converter controls, CIGs can contribute to power system control and provide the vast majority of the services traditionally provided by conventional generation such as (i) voltage/ reactive power control, (ii) active power control and frequency response, and (iii) ride-through for both voltage and frequency disturbances. In this context, there has been, and continues to be, significant advances and learning of how best to achieve these objectives. Furthermore, due to the significant differences in the physical and electrical characteristics of CIGs compared to synchronous generation, CIGs do not inherently provide short-circuit current nor inertial response, and so these aspects will continue to present some challenges [18]. It should be noted, however, that CIGs are governed by the power electronic controls that present significant opportunities for greater speed and flexibility.

3. DEFINITION OF POWER SYSTEM STABILITY

3.1 General Comments

In this section, the formal definition of power system stability from [1] is presented. The intent in [1] was to provide a physically based definition which, while conforming to definitions from system theory, can be easily understood and readily applied by power system engineering practitioners. For the system transformation resulting from connection of converter interfaced generation and load power- electronics based control devices, described in Section I, the definition in [1] still applies and hence, it remains unchanged.

3.2 Formal Definition

Power system stability is the ability of an electric power system, for a given initial operating condition, to regain a state of operating equilibrium after being subjected to a physical disturbance, with most system variables bounded so that practically the entire system remains intact.

3.3 Discussion and Elaboration

As in [1], the discussion here applies to all aspects of the dynamic performance of interconnected power systems, including synchronous machines and conventional individual components. Of particular interest, though, is the application of the definition proposed in [1] in characterizing stability performance related to CIGs. Akin to the case of a single remote synchronous machine losing synchronism without causing cascading instability of the main system, the stability behavior of a single remote CIG interconnected to the system has identical stability implications. As long as the dynamic response to a disturbance only affects the individual CIG without causing the cascading instability of the main system, the definition provided in [1] still applies.

3.4 Conformance with System - Theoretic Definitions

Section V of reference [1] provides details of the system-theoretic foundation of power system stability. It provides an introduction to differential-algebraic equations forming mathematical models of power systems. This is then followed by specific definitions from system theory. These include stability in the sense of Lyapunov, uniform stability, asymptotic stability, exponential stability, and instability [19]. Furthermore, definitions for input/output stability and stability of linear systems, as well as an illustration of a typical analysis scenario are also provided. These definitions still apply to systems governed by differential-algebraic equations. With the inclusion of power electronic inverters and the possible need to model protection systems, however, there is also a need to provide similar definitions for hybrid systems.

3.5 Stability Definition and Theory of Hybrid Systems

Hybrid dynamical systems are characterized by interactions between continuous dynamics and discrete events. Consider, for example, the non-windup integrator of Fig. 3 (a). When the integrator state x is less than its upper limit x_{max}, the value of x evolves smoothly according to the differential equation $\frac{dx}{dt} = Ku(t)$. However, if $x(t)$ encounters the limit x_{max} and the input is non-negative, $u(t) \geq 0$, then x will remain constant at $x(t) = x_{max}$. This condition will continue unless the input changes sign, $u(t) < 0$, in which case $x(t)$ will evolve away from the limit value x_{max} under the influence of the original differential equation. The events that occur when $x(t)$ encounters and departs the limit clearly influence subsequent dynamic behavior of the system.

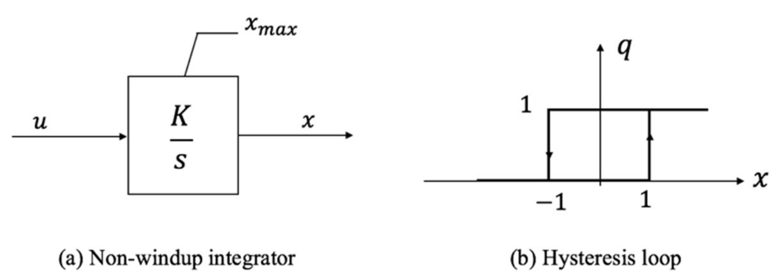

Fig. 3. Simple examples of hybrid dynamical systems.

Interactions between continuous and discrete states can be further illustrated by considering the hysteresis loop of Fig. 3 (b). Assume the discrete state q initially has value 0. Then if the continuous state x increases through the value 1, the discrete state q will jump from 0 to 1. Subsequently, if x decreases through -1, then q will jump from 1 to 0. When $x \leq -1$ or $x \geq 1$, the value of q is uniquely determined by the value of x. However, when $-1 < x < 1$, the value of q depends on prior information.

To illustrate potential complications that can arise from switching, consider the model for a non-windup proportional-integral block given by Figure E.7 in the IEEE Standard 421.5-2016 [20]. It is shown in [21], [22] that this model can encounter situations where upon switching, the model must immediately switch back, *ad infinitum*. This infinite switching sequence prevents the trajectory from progressing beyond that troublesome switching event. Such situations are referred to as *deadlock* or *infinite Zeno*, and cannot occur in real systems. This highlights the need for extra care in developing models that involve interactions between continuous dynamics and discrete events.

An actual event that was driven by hybrid dynamics is analyzed in [23]. The event began with an unplanned outage that weakened a section of sub-transmission network, resulting in voltage oscillations. The oscillations arose due to interactions between transformer tapping and capacitor switching, both of which caused discrete changes to the network. Furthermore, the voltage regulating controls of both the transformer and capacitor incorporated switching in the form of voltage deadbands and timers. Hence, hybrid dynamics played multiple roles in this event.

Simulation of hybrid dynamical systems, in particular event detection, also requires extra care. Generically, events do not coincide with the time-steps of the simulation process. Event triggering conditions must be evaluated at each time-step and compared with the corresponding triggering thresholds. For example, if zero crossing initiates an event, then a change in sign of the event indicator from one time-step to the next suggests an event should take place within that time interval. The simulator should backtrack to the actual event time, implement the event, and then resume forward progression of time. This event detection process is not foolproof, however, as it cannot detect situations where an event triggering threshold is crossed and then re-crossed within a single time interval, i.e. between adjacent time-steps.

In order to establish stability concepts for hybrid dynamical systems, it is first necessary to carefully define a hybrid system and its characteristics [24]. This is achieved using the concept of an autonomous hybrid automaton. An autonomous hybrid automaton consists of:

- A set of continuous states $\mathbb{R}^n$ and a set of discrete states $Q = \{q_1, q_2, \dots\}$, with the state of the hybrid automaton given by $(x, q) \in \mathbb{R}^n \times Q$.
- Initial conditions (x_0, q_0) for both continuous and discrete states.
- A vector field $\dot{x} = f(x, q)$ driving the continuous states.
- Event triggering conditions $s_i(x, q) = 0$ for each event i.
- Event reset relations $h_i(x, q) = (x^+, q^+)$ for each event i, where (x^+, q^+) refers to the state immediately following the event.

The evolution of a hybrid dynamical system makes use of the concept of a hybrid time set. A hybrid time set is a sequence of intervals $\tau = \{I_j\}_{j=0}^{N}$, such that:

- $I_j = [\tau_j, \tau_j']$ for all $j < N$,
- $\tau_j \leq \tau_j' = \tau_{j+1}$ for all $j < N$.

Evolution of a hybrid dynamical system is given by a hybrid trajectory (τ, x, q). Such a trajectory starts from an initial value (x_0, q_0) with the continuous state x flowing according to the differential equation $\dot{x} = f(x, q_0)$ where $x(0) = x_0$, and the discrete state remains constant at q_0. Continuous evolution will occur until an event i is triggered through satisfaction of the triggering condition $s_i(x, q) = 0$. At that point, the state will reset according to $h_i(x, q)$ giving new initial conditions (x^+, q^+) for the subsequent interval. The process then continues.

Stability: The concept of equilibrium extends naturally to hybrid dynamical system. As with continuous systems, the concept of stability of hybrid dynamical systems should capture the notion that if the continuous state x starts close to an equilibrium point then it should remain close, or converge to the equilibrium point. Lyapunov stability for hybrid dynamical systems is also conceptually similar to the requirements for continuous systems. However, hybrid systems require the additional condition that the Lyapunov function must exhibit non-increasing behavior at events.

Interactions between continuous dynamics and discrete events can result in non-intuitive behavior of hybrid dynamical systems. This is illustrated by the following example from [25] which consists of switching between two stable linear systems, $\dot{x} = A_1 x$ and $\dot{x} = A_2 x$, where:

$$A_1 = \begin{bmatrix} -1 & 10 \\ -100 & -1 \end{bmatrix}, \quad A_2 = \begin{bmatrix} -1 & 100 \\ -10 & -1 \end{bmatrix}.$$

In this system, x is the (2 dimensional) state of the system, and the A-matrix switches between A_1 and A_2. The state $x_e = 0$ is an equilibrium point. Furthermore, the eigenvalues of both A_1 and A_2 are $-1 \pm \sqrt{1000}$, so the continuous systems $\dot{x} = A_i x$ for $i = 1,2$ are both asymptotically stable. However, if the system is described by A_1 when $x_1 x_2 < 0$ and by A_2 when $x_1 x_2 > 0$, with switching occurring whenever $x_1 x_2 = 0$, then simulation reveals that $x_e = 0$ is unstable due to the switching. Interestingly, if the regions of state-space associated with A_1 and A_2 are flipped then $x_e = 0$ is stable.

4. CLASSIFICATION OF POWER SYSTEM STABILITY

4.1 Need for Classification

Figure 4 shows the classification of the various types of power system stability. With respect to the original classification presented in [1], two new stability classes have been introduced, namely “Converter-driven stability” and “Resonance stability”. Adding these two new classes was motivated by the increased use of CIGs. The traditional sub-synchronous resonance class, was not included in [1] because such phenomena were outside of the time scale originally considered in [1] (see Fig. 1). Due to the addition of the power electronic dynamics, however, the time scale of interest for power system stability extended down to electromagnetic transients.

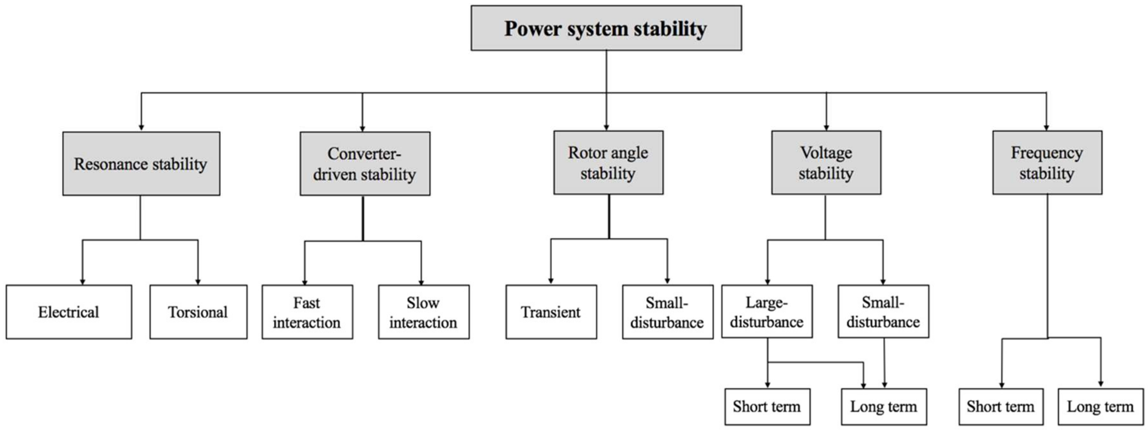

Fig. 4. Classification of power system stability

Note that all dynamic phenomena considered in the original classification presented in [1], are properly modeled using the "phasor (or quasi-sinusoidal) approximation". Most often though, this simplified modeling approach is not applicable to the converter-driven and electric resonance stability classes, with the possible exception of the "slow-interaction of converter-driven stability" (see Fig. 2).

The short- and long-term time scale sub-classifications of the original report [1] have been maintained here only when needed to distinguish between different phenomena which require different models for their analysis. As seen in Fig. 2, this is the case for voltage and frequency stability classes.

4.2 Categories of Stability

4.2.1 Rotor Angle Stability

Rotor angle stability is concerned with the ability of the interconnected synchronous machines in a power system to remain in synchronism under normal operating conditions and to regain synchronism after being subjected to a small or large disturbance [1]. A machine keeps synchronism if the electromagnetic torque is equal and opposite to the mechanical torque delivered by the prime mover. Accordingly, this type of stability depends on the ability of the synchronous machines to maintain or restore the equilibrium between these two opposing torques.

Synchronous machines maintain synchronism through restoring forces which act when a disturbance causes one or more machines to accelerate or decelerate with respect to the others [2]. In steady-state conditions, there is an equilibrium between the input mechanical torque and the balancing electromagnetic torque of each machine and the speed of all interconnected machines is maintained at a constant value. A disturbance in the system upsets this equilibrium and leads to torque unbalance which results in either acceleration or deceleration of the rotors of synchronous machines according to the law of motion of a rotating body. As a consequence, the rotor angle of a synchronous machine(s) can increase beyond a maximum value and the machine(s) lose synchronism or "falls out of step" with the rest of the machines. However, a significant increase in the speed of the machines may not necessarily lead to their loss of synchronism if all machines accelerate or decelerate together. The key factor in determining system stability is the angle difference between a machine or a group of machines and the rest of the system.

Loss of synchronism can occur between one machine and the rest of the system, or between groups of machines. In the latter case, synchronism may be maintained within each group after its separation from the others [2].

The change in the electromagnetic torque of a synchronous machine after a disturbance can be described in terms of two components: 1) a synchronizing torque component, in phase with the rotor angle deviation, and 2) damping torque component, in phase with the speed deviation [26].

Stable and well-damped response of the system can be ensured through the existence of sufficient positive synchronizing and damping torque components for each synchronous generator. Insufficient or negative synchronizing torque results in *aperiodic* or *non-oscillatory transient instability*, whereas lack of or negative damping torque will lead to *oscillatory instability* [1].

The synchronizing torque can be primarily controlled through the excitation system of the generator [26]. Another means used on large steam-turbines to enhance transient rotor-angle stability is to enact "fast-valving" which is aimed at reducing the mechanical torque immediately after a disturbance, through quick turbine-governor controls, in order to reduce the acceleration of the generator after a major fault [27].

Damping torque is an inherent property of synchronous machines largely affected by machine design parameters and generator loading. It is mainly provided by the damper windings of the rotating machines and to a lesser extent by the field winding. These rotor windings (damper and field) dissipate energy associated with the system oscillations, reducing their amplitudes [28]. The damping of rotor angle oscillations can be substantially enhanced through the application of power system stabilizers [28]-[30].

As shown in Fig. 4, rotor angle stability can be further classified into: Small-disturbance rotor angle stability and transient or large-disturbance rotor angle stability.

4.2.1.1 Small-disturbance Rotor Angle Stability

Small-disturbance (or small-signal) rotor angle stability is concerned with the ability of a power system to maintain synchronism under small disturbances, such as small variations in load and generation. Small disturbances are those changes arising in the system for which the deviations of the rotor angles of synchronous machines from the equilibrium point is so small that the system equations can be linearized around the equilibrium point without resulting in significant errors [29], [31]. The eigenvalues of the system state matrix and subsequent modal analysis then describe the different oscillatory modes of the system and characterize the small-disturbance rotor angle stability. The time frame within which rotor angle oscillations following a small-disturbance are expected to attenuate in under 20 seconds.

Small-disturbance instability can arise in the two forms: i) increase in rotor angle due to lack of, or negative synchronizing torque (*non-oscillatory or aperiodic instability*), or ii) rotor oscillations of increasing amplitude due to insufficient, or negative damping torque (*oscillatory instability*).

Most often, small-disturbance rotor angle stability is largely a problem of insufficient damping of electromechanical oscillations. The non-oscillatory stability problems have been largely eliminated by the use of continuously acting, high-gain, automatic voltage regulators (AVR). However, this problem can still occur when the AVR maintains constant field voltage due to the action of excitation limiters (field current limiters) [1].

As discussed above, rotor angle stability is clearly associated with synchronous machines, and the corresponding modes of rotor angle oscillations are electromechanical modes. Such modes can be broadly grouped into local-area modes (associated with a single synchronous generator or a small group of generators), which typically range in frequency from around 0.7 to 2.5 Hz, and inter-area modes (associated with large groups of machines across the system), which typically range in frequency from 0.1 to 1.2 Hz [2], [28]-[30].

4.2.1.2 Transient Rotor Angle Stability

Transient (or large-disturbance) rotor angle stability is concerned with the ability of a power system to maintain synchronism when subjected to severe disturbances, such as a short circuit on a transmission line, disconnection of large power plants, or disconnection of large loads. The system response involves large excursions of the rotor angles of the synchronous machines. Consequently, it is no longer appropriate to linearize the system equations as in the case of small disturbances, with the evolution of rotor angles typically analyzed using numerical integration methods [31]. Stability in this case depends on both the initial operating condition of the system and the severity of the disturbance. The post-disturbance steady state operation of the system will usually differ from the pre-fault operating point. The time frame of interest in transient stability studies is usually below 10 seconds following the disturbance, though in case of large interconnected systems this time frame could be extended to 20 seconds.

Loss of synchronism can occur either during the first swing or after a few oscillations. In the first case, the instability arises due to insufficient synchronizing torque and is commonly referred to as *first swing instability*. However, large power systems may not always experience transient instability at the first oscillation. Indeed, it is also possible that a generator maintains synchronism during the first few cycles of oscillations, but with the oscillations growing in amplitude. In this case, synchronism will be lost after a few cycles of oscillations. This form of instability generally arises due to insufficient damping and/or synchronizing torques and conflicting actions of the control systems [31].

4.2.1.3 Mechanisms leading to Rotor Angle Instability

Small-disturbance angle instability is characterized by a complex conjugate pair of relatively poorly damped eigenvalues of the linearized system state matrix moving from the left-half plane (stable) to the right half-plane (unstable) of the complex plane following a system disturbance or a change in the system topology [1]. This assumes that the system has an equilibrium point after the disturbance, so that its eigenvalues can be computed. Often in practice, the system evolves through a sequence of operating points until the "last" incident drives the system to instability. This was the case, for instance, during the blackout of WSCC (WECC) on August 10, 1996, where a series of 500 kV lines in the US North West tripped starting at 14:06:39. This reduced the damping of a heavily loaded system, until the last 500 kV line trip at 15:47:36 resulted in several generating units in Northern Oregon tripping in a few seconds. This final line trip resulted in slowly growing oscillations due to negative damping (a pair of complex eigenvalues moving to the right-half plane). Consequently, the Western US system separated into numerous areas, resulting in a major blackout [32]. This progressive weakening of the system damping can be illustrated on the system PV curves as the event slowly evolves. The last contingency forces the system to an unstable operating point beyond a Hopf Bifurcation[3] (HB) point on the final system's PV curve, as depicted in Fig. 5 and discussed in [32] and [33].

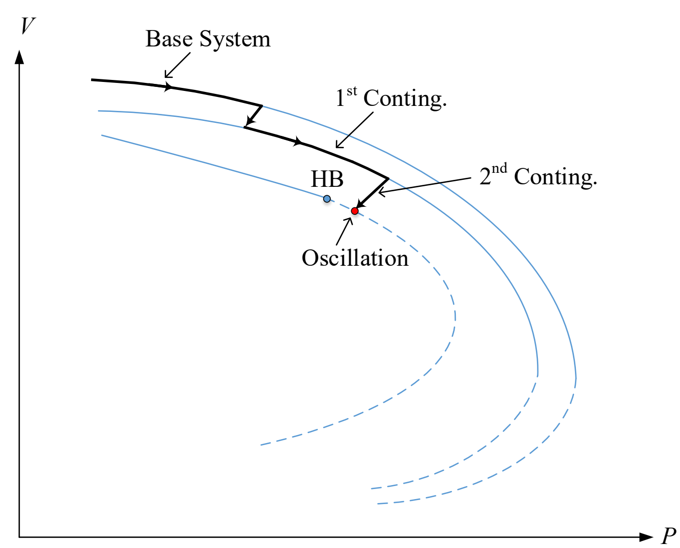

Fig. 5. PV curve evolution of a series of contingencies leading to an oscillatory instability associated with a Hopf Bifurcation (HB) for the last contingency.

4.2.1.4 Effects of CIGs on Rotor Angle Stability

The integration of CIGs does not change the fundamental definition of rotor angle stability presented in [1]. Still, as conventional synchronous generators are displaced by CIGs, the total inertia of the system will be reduced. This in turn has an impact on rotor angle stability and also on the electromechanical modes of the system [34]. The displacement of

[3] Such a bifurcation corresponds to a system operating condition where a complex pair of eigenvalues lies on the imaginary axis of the complex plane. The system becomes stable when the load (bifurcation parameter) is reduced, and unstable when the load is increased.

synchronous generation by CIGs, affects the rotor-angle stability of the remaining synchronous generators in the system by:

1. Changing the flows on major tie-lines, which may in turn affect damping of inter-area modes and transient stability margins [35], [36].
2. Displacing large synchronous generators, which may in turn affect the mode shape, modal frequency, and damping of electromechanical modes of rotor oscillations [35].
3. Influencing/affecting the damping torque of nearby synchronous generators, similar to the manner in which flexible ac transmission (FACTS) devices influence damping [29], [37]. This is reflected in changes in the damping of modes that involve those synchronous generators.
4. Displacing synchronous generators that have crucial power system stabilizers.

Given item 3 above, there may be future potential for designing supplemental controls for CIGs to help mitigate power oscillations, similar to the concept of power oscillation dampers on FACTS devices [29], [37].

Significant effort has already been devoted to understanding and describing the effects of CIGs on small-disturbance stability. However, results and conclusions obtained are to a large extent influenced by the test power systems used and their operating conditions [38]. Accordingly, there is no general consensus regarding the effects of increased penetration of CIGs on electromechanical modes and on the small disturbance rotor angle stability [34]. The effects can be both small and large, and the presence of CIGs beneficial or detrimental [35], [38]. The type of impact will depend on several factors, including the number of CIGs in the system, the type of controls applied, network topology and strength, the loading conditions in the system, and other similar factors.

In terms of transient rotor angle stability, lowering the total system inertia may result in larger and faster rotor swings thus making the system more prone to stability problems [34]. As before, studies have shown that increased penetration of CIGs can have both beneficial and detrimental effects on transient rotor angle stability depending on the grid layout, and the location, and control of CIGs [34], [35]. The effects of CIGs on transient rotor angle stability are also impacted by other factors such as the type of disturbance and its location with respect to the CIGs and the large power plants [39]. The control of the converters during and after the fault and their ride-through capability can also significantly influence transient rotor angle stability, as pointed out in, e.g., [39], [40].

4.2.2 Voltage Stability

4.2.2.1 Definition and Description of Phenomena

Voltage stability refers to the ability of a power system to maintain steady voltages at all buses in the system after being subjected to a disturbance [1]. It depends on the ability of the combined generation and transmission systems to provide the power requested by loads [41]. This ability is constrained by the maximum power transfer to a specific set of buses and linked to the voltage drop that occurs when active and/or reactive power flows through inductive reactances of the transmission network.

Long-term voltage instability usually occurs in the form of a progressive reduction of voltages at some network buses. A possible outcome of voltage instability is loss of load in an area, or tripping of transmission lines, and other elements by their protective systems, leading to cascading outages. Loss of synchronism of some generators may also result from these outages or from operating under field current limitation [41].

The term voltage collapse is also often used. It is the process by which the sequence of events accompanying voltage instability leads to a blackout or abnormally low voltages in a significant part of the power system. Stable (steady) operation at low voltage may continue after transformer tap changers reach their boost limit, with intentional and/or unintentional tripping of some loads. The remaining load is fed under abnormally low voltage, and the original load power is not restored to its pre-disturbance value.

The driving force for voltage instability is usually load dynamics. In response to a disturbance, power consumed by loads tends to be restored by the action of motor slip adjustment, distribution voltage regulators, tap changing transformers, and thermostats. In the attempt to restore their power, loads further depress transmission network voltages, and draw more reactive power from voltage-regulating sources, eventually exhausting their reactive reserves. This effect is more pronounced in case of loads that are less sensitive to voltage, e.g., constant power loads, compared to loads that are more voltage dependent, e.g., constant impedance loads. The onset of instability coincides with the maximum power transfer condition.

The dynamic behavior of loads, as seen from the transmission network, also includes the response to voltage disturbances of dispersed generation units connected at the distribution level. Proper representation of active distribution networks in voltage stability studies is thus of growing importance.

The time frame of interest for voltage stability problems may vary from a few seconds to tens of minutes. Therefore, voltage stability may be either a short-term or a long-term phenomenon as identified in the classification diagram shown in Fig. 4.

4.2.2.2 Short-term Voltage Stability

Short-term voltage stability involves dynamics of fast acting load components such as induction motors, electronically controlled loads, HVDC links and inverter-based generators. The study period of interest is in the order of several seconds, similar to rotor angle stability or converter-driven stability (slow interaction type). Accordingly, models with the appropriate degree of detail must be used. For short-term voltage stability, the dynamic modeling of loads is essential, and short circuit faults near loads are the main concern.

It is recommended that the term transient voltage stability should not be used, as already pointed out in [1].

- *Instability Driven by Induction Machines*

The most typical case of short-term voltage instability is the stalling of induction motors following a large disturbance by either loss of equilibrium (between electromagnetic and mechanical torques) or by lack of attraction to the stable equilibrium due to delayed fault clearing. During a fault, induction motors decelerate (due to decreased electromagnetic torque) which makes them draw a higher current and reactive power, causing further voltage depression. After fault clearing, electromagnetic torque recovers. If the motor has not decelerated below a critical speed, it reaccelerates towards a normal operating point. Otherwise, it cannot reaccelerate and stalls. Stalled motors can either be disconnected by undervoltage protection or remain connected, drawing a large (starting) current until they are disconnected by thermal overcurrent protection. In the latter case, voltage remains depressed for longer time, possibly inducing a cascade of similar events on nearby motors [42].

Single-phase capacitor start/run induction motors are often used in residential air-conditioner, certainly so in North America. Such motors are even more susceptible to stalling than large 3-phase induction motors [43]. The stalling of large numbers of such single-phase induction motors has been found, in North America, to lead to a phenomenon referred to as Fault Induced Delayed Voltage Recovery (FIDVR)[4]. Although, in most cases where FIDVR has been observed, the system did not succumb to voltage instability (due to the eventual tripping of the stalled motors), this can be another potential cause of cascading and/or instability depending on the network topology and nearby reactive resources.

The above description of short-term voltage instability applies to all induction machines (directly connected to the network), including generators. The difference is that induction generators accelerate (instead of stalling) during faults and, if unstable, they are disconnected by overspeed protection.

The CIGs fault ride through capability should be modelled, as the depressed voltages during motor stalling can lead to disconnection of CIGs, further exacerbating the problem [44], [45].

- *Instability Driven by HVDC Links*

Voltage stability problems may also be experienced at the terminals of HVDC links with line commutated converters (LCC) used for either long distance or back-to-back applications. They are usually associated with HVDC links connected to weak AC systems and may occur at rectifier or inverter stations, due to the unfavorable reactive power "load" characteristics of the converters. The HVDC link control strategies have a very significant influence on such problems, since the active and reactive power at the AC/DC junction are determined by the controls. The associated phenomenon is relatively fast with the time frame of interest being on the order of one second or less. On the other hand, the Voltage

[4] https://certs.lbl.gov/initiatives/fidvr

instability may also be associated with converter transformer tap-changer controls, which is a considerably slower phenomenon.

The use of voltage source converters (VSC) in HVDC converter stations has significantly increased the scope for stable operation of HVDC links in weak systems compared to LCC based HVDC links.

4.2.2.3 Long-term Voltage Stability

Long-term voltage stability involves slower acting equipment such as tap-changing transformers, thermostatically controlled loads, and generator current limiters. The maximum power transfer and voltage support are further limited when some of the generators hit their field and/or armature current time-overload capability limits.

The study period of interest may extend to several minutes, and long-term simulations are required for analysis of system dynamic performance.

This type of stability is usually not driven by an initiating fault, but by the resulting outage of transmission and/or generation equipment after fault clearing, and the consequent loss of long-term equilibrium. Long-term instability then occurs when load dynamics attempt to restore power consumption beyond the maximum power transfer limit. Instability may also result when remedial action is unable to restore a stable post-disturbance equilibrium in a timely fashion, thus convergence to an equilibrium is not possible.

Alternatively, the disturbance leading to instability could also be a sustained load buildup (e.g., morning load increase). Even though the load increase may take place slowly, the sequence of events, controls, and actions triggered (including LTC, switched reactive support and other controls) requires a dynamic analysis.

Long-term voltage stability is usually assessed by estimating a stability margin expressed in terms of load power increase from an operating point to the maximum power transfer (onset of instability). For this purpose, the direction of system stress has to be defined, including the load increase pattern and generation participation.

As stated in [1], linear and nonlinear analyses are used in a complementary manner. More specifically, the stability of an operating point can be assessed using linearized analysis (i.e. eigenvalues of an appropriate Jacobian matrix) while for stability margin assessment non-linear models are required. In this respect, the distinction between both small- and large-disturbance must be considered for long-term voltage stability. Furthermore, linearized analysis can identify the point of maximum power transfer and provide sensitivity information useful in identifying factors influencing stability. However, linearized analysis should be used with care, since it cannot account for nonlinear effects such as limits, deadbands, discrete tap changer steps, and (constant or variable) time delays.

As for short-term voltage instability, load modeling is important but the main focus is on distribution voltage restoration devices, typically load tap changers on distribution transformers. The interactions of both continuous and discrete controls and protection systems is also significant and must be considered.

Sometimes long-term voltage stability can be studied using static tools (based on algebraic equilibrium equations) to speed up computations. This does not mean that the problem is of static nature. In this respect, the use of the term "static voltage stability" is discouraged, as it results from a confusion of means and ends. In particular, where timing of post-disturbance corrective control actions is important, static analysis must be complemented by time-domain simulations.

4.2.2.4 Overvoltage Voltage Instability

While the most common form of voltage instability is the progressive drop of bus voltages, the risk of overvoltage instability also exists and has been experienced in a few cases [46], [47]. It is caused by a capacitive behavior of the network (e.g. EHV/HV transmission lines operating below surge impedance loading, shunt capacitors and filter banks from HVDC stations), as well as by under-excitation limiters preventing generators and/or synchronous compensators from absorbing the excess reactive power. In this case, the instability is associated with the inability of the combined generation and transmission system to operate below a minimum load consumption level. In their attempt to restore this load power, transformer tap changers cause long-term voltage instability.

This type of overvoltage instability can be related to the self-excitation of synchronous machines, associated with the capacitive overload of a synchronous machine, as discussed in [46], [48]. Negative field current capability of the exciter is a feature that helps limit self-excitation [1]. With CIGTs located electrically close to the loads, and with the ability to provide sufficient reactive power support with smart inverters, bulk transmission circuits connected to lightly loaded conventional generating plants have experienced high voltages during low load periods in the daily cycle.

4.2.2.5 On the Impact of Active Distribution Networks

More and more dispersed, converter-interfaced generating units exploiting renewable energy sources are in operation in distribution grids and have a growing impact on the dynamics of the combined transmission and distribution system [4]. The focus of this paper is on transmission systems. However, a proper modeling of active distribution networks in dynamic studies of transmission systems is important, although challenging. This applies to all short-term dynamic studies where the load response has an impact. It is also relevant to long-term voltage stability where the reactive power response of dispersed generation units may either improve or worsen the evolution of voltages in emergency conditions [4], [49]. Consideration of proper distribution equivalent feeder is also recommended for the cases with load unbalance and penetration of dispersed generation units [50].

4.2.2.6 Relations to other Stability Classes

- *Relation to Angle Stability*

As stated in [1], it is important to recognize that the distinction between rotor angle and voltage stability is not based on weak coupling between variations in active power/angle and reactive power/voltage magnitude. In fact, coupling is strong for stressed conditions and both rotor angle and voltage stability are affected by pre-disturbance active power as well as reactive power flows.

Progressive drop in bus voltages can also be associated with rotor angle instability. For example, the loss of synchronism of machines as rotor angles between two groups of machines approach 180° causes rapid drop in voltages at intermediate points in the network close to the electrical center [2]. Normally, protective systems operate to separate the two groups of machines and the voltages recover to levels depending on the post-separation conditions. If, however, the system is not so separated, the voltages near the electrical center rapidly oscillate between high and low values as a result of repeated “pole slips” between the two groups of machines. In contrast, the type of sustained fall of voltage that is related to voltage instability involves loads and may occur where rotor angle stability is not an issue.

Conversely, rotor angle instability may result from the degraded operating conditions caused by voltage instability. This holds true especially for field-current limited machines losing synchronism, thereby contributing to system collapse.

- *Relation to Frequency Stability*

Contrary to frequency instability, which is related to the system-wide active power balance, voltage stability refers to the power transfer from generation to specific load buses; generation may be available but at remote locations so that power cannot be transmitted to the loads. For voltage stability assessment, full representation of the transmission grid is essential.

4.2.3 Frequency Stability

In an interconnected power system that is dominated by synchronous generation, the system frequency control and stability are of paramount importance [51]. The most commonly studied events are those that cause a decline in system frequency. Fig. 6 depicts the three distinct periods during an event that causes decline in frequency and the related controls: (i) the initial inertial response of synchronous generators, (ii) the primary frequency response of generators and load damping, and (iii) automatic generation controls bringing the frequency back to its nominal value.

First, the *inertial response* of the system is an inherent physical response of synchronous generation to a sudden imbalance in generation and load. When there is, for example, the sudden forced outage of a large generator, in the instant that follows the loss of generation, the load (or demand) does not, and cannot, instantaneously change. As a result, due to basic physical principles and not controls, all the remaining synchronous generators will respond, in proportion to their electrical proximity, inertia and electrical rating, to provide a portion of the total lost power to continue supplying the load. Following this extremely fast electrical response, the extra electrical power delivered by each synchronous generator, from the stored rotational kinetic energy in generator rotors, will cause an imbalance between electrical and mechanical torque on the shaft of each generator, thus slowing down all generators, resulting in the initial decay of system frequency. This is the inherent inertial response of synchronous generators due to the laws of physics and not control actions. This uncontrolled frequency response is the first phase of the response shown in Fig. 6.

If one assumes that there were no controls on any of the generators, the system frequency would continue to decline until under-frequency load shedding schemes started to shed load and eventually other protection also started to trip generation, leading in extreme cases to a system blackout. To avoid these problems, an adequate number of generating facilities must carry some reserve power/fuel and operate below their maximum capability. These facilities respond by increasing their output power to replace the lost power and hence halt the decline in frequency and return the system to a new and proper equilibrium operating point. This reserve capacity is commonly referred to as spinning reserve. The control action is referred to as turbine-governor droop-response or frequency response [27], [51]. This controlled primary-frequency response is the second phase of the response shown in Fig. 6, namely where generators with available head-room provide frequency response based on their turbine-governor droop settings. It should be noted that load damping, i.e., the natural tendency of many loads to decrease by a small percentage (typically of about 1.5% or less per 1% change in frequency) as system frequency drops, also contributes to this primary-frequency response of the system [51], although it is a relatively small contribution. Finally, Automatic Generation Control (AGC) acts in the third stage to restore the system frequency back to its nominal value. This centralized controller operates on selected generators with head-room. For more details, see [51]. During this third stage of frequency response, there is further increase of the mechanical power of generators across the system. This provides the additional energy required to increase the kinetic energy of the rotating masses and thus restore system frequency.

The following factors determine whether the system frequency response is stable and well behaved:

1. The amount of active power spinning reserve available across generating units.
2. The speed and reliability of the response of the turbine-governors.
3. The total inertia of the system.
4. The amount of inherent load damping.

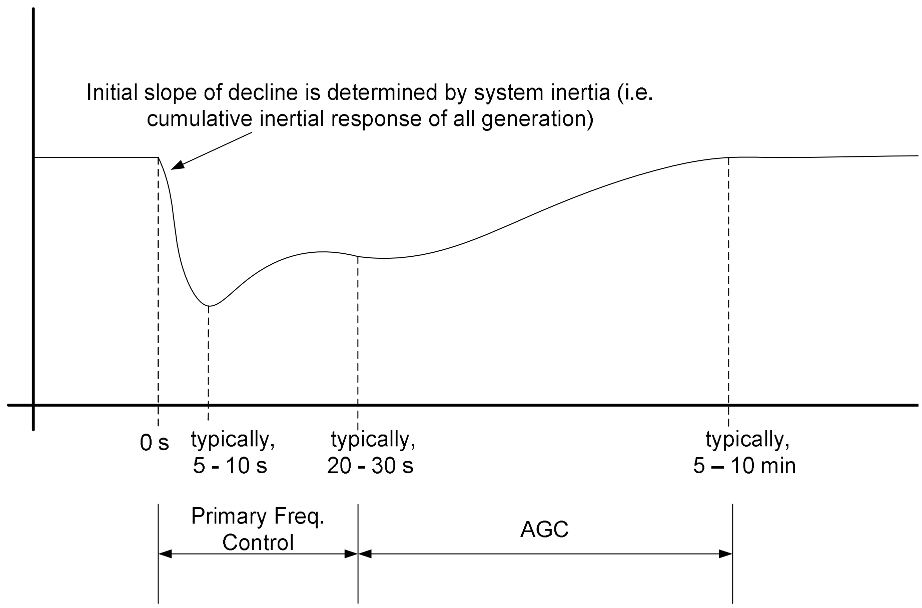

Fig. 6. An illustration of power system frequency response to a major loss of generation. (IEEE © 2013, reproduced from [27])

The total inertia available impacts the Rate of Change of Frequency (ROCOF) in the initial frequency drop. The total inertia will also determine the nature of the system response, i.e., whether an undershoot in frequency is observed, or if the overall system frequency response is slightly oscillatory. Fig. 7. illustrates the differences in the frequency response of three power systems to a significant loss of generation event for (a) a very large system (>400 GW), (b) a medium sized power system (between 100 to 200 GW), and (c) a small system (< 20 GW). Observe that the response for the very large system is overdamped, due to the massive inertia of the system; the second response, which is typically seen in most systems, is a damped response with an undershoot; and the last response for the small system exhibits some oscillations in frequency, inherent to systems with lower inertia.

4.2.3.1 Effects of CIGs on Frequency Stability

CIGs do not inherently provide inertial response, as described in the previous section. Furthermore, since CIGs are typically associated with renewable resources (wind, solar energy, wave energy), there are considerable economic consequences associated with the "spilling" of the incident resource in order to maintain a margin for reserve and thus provide primary-frequency response. These economic factors aside, it has been demonstrated that CIGs can contribute quite well and decisively to frequency response [13], [14], [52]-[59].

CIGs can provide primary frequency response faster and can have smaller droop settings (large response), since the limiting factor in many cases (e.g. solar PV and battery energy storage), is the response time of electronics/electrical equipment and not mechanical systems (e.g. boilers and turbines) [14], [27].

As the penetration of CIGs increases in power systems around the world, it is likely that the frequency response of power systems will tend towards the plot corresponding to smaller systems as shown in Fig. 7, which places a greater emphasis on the need for, and tuning of the controls associated with primary-frequency response. It should be noted that in the case of wind turbine generators, a form of inertial-based fast-frequency response is possible and provided by many vendors [13].

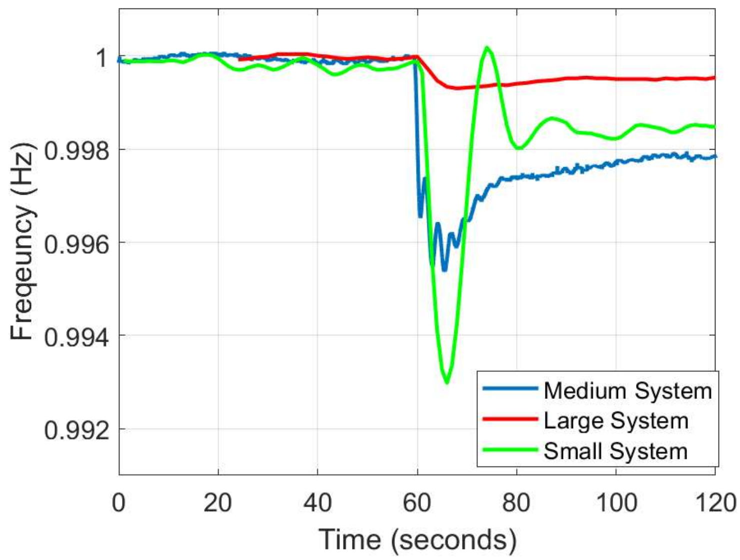

Fig. 7: Frequency response plots for a very large system (red), medium/large system (blue), and small system (green).

Due to the decreasing grid inertia resulting from the displacement of synchronous generators, frequency excursions become faster and therefore the likelihood of instability occurring earlier is increasing. This puts more emphasis on the need to design appropriate fast acting controllers to arrest frequency drops as soon as detected. High penetration of CIGs may not always result in a notable reduction of system inertia if the synchronous generators remain connected but de-loaded. For example, the Western Wind and Solar Integration Study [60] recommends a 2/3 de-commitment and 1/3 re-dispatch approach to balance a reduction in load, i.e., 2/3 to the reduction in load is balanced by disconnecting synchronous generators and 1/3 of the reduction is balanced by de-loading synchronous generators. In this case the effect on frequency response could be positive as more spinning reserve becomes available while the drop in system inertia may not be significant. The recent studies [61] and [62] have shown that the frequency response of systems with CIGs is a complex phenomenon which requires further investigation.

4.2.4 Resonance Stability

The term resonance stability encompasses subsynchronous resonance (SSR), whether it be associated with an electromechanical resonance or an entirely electrical resonance. The term SSR, as defined in the original publications related to this phenomenon [63], can manifest in two possible forms: (i) due to a resonance between series compensation and the mechanical torsional frequencies of the turbine-generator shaft, and (ii) due to a resonance between series compensation and the electrical characteristics of the generator. The first of these occurs between the series compensated electrical network and the mechanical modes of torsional oscillations on the turbine-generator shaft, while the second is a purely electrical resonance and termed Induction Generator Effect (IGE) [64], [65]. Hence, in Fig. 4 the resonance stability has been split into these two categories.

4.2.4.1 Torsional resonance

The SSR due to torsional interactions between the series compensated line(s) and the turbine-generator mechanical shaft are well documented in the literature, particularly as it pertains to conventional synchronous generation [63]-[67]. According to the IEEE working group [66], subsynchronous oscillations are mainly classified into subsynchronous resonance (SSR) and device-dependent subsynchronous oscillations (DDSSO). SSR involves an electric power system condition where the network exchanges significant energy with a turbine-generator at one or more of the natural sub-synchronous torsional modes of oscillation of the combined turbine-generator mechanical shaft [63], [66]. The oscillations can be poorly damped, undamped, or even negatively damped and growing [63], thus threatening the mechanical integrity of the turbine-generator shaft. DDSSO arise due to the interaction of fast acting control devices, such as HVDC lines, static VAr compensators (SVCs), static synchronous compensators (STATCOM), and power system stabilizers (PSS) with the torsional mechanical modes of nearby turbine-generators [63], [66]-[70]. It should be noted, however, that DDSSO are not always detrimental, in some cases the interaction can be beneficial and in fact improve torsional damping [71]. For this reason, in many cases devices such as SVCs may in fact be used as a means of providing a solution for SSR by improving torsional damping.

4.2.4.2 Electrical resonance

In the case of power systems with conventional turbine-generators only, the issue related to SSR is one of torsional interactions and resonance. The IGE [64] (or self-excitation [72]) has never been observed in real power systems with conventional synchronous generation. However, it was predicted as early as 2003 that variable speed induction generators used in DFIG wind-turbine generators would be highly susceptible to IGE self-excitation type SSR [73]. This is due to the fact that a variable speed DFIG generator is an induction generator directly connected to the grid, which makes such an electrical resonance between the generator and series compensation possible [72][5]. In this case, the self-excitation type SSR occurs when the series capacitor forms a resonant circuit, at sub-synchronous frequencies, with the effective inductance of the induction generator, and at these frequencies, the net apparent resistance of the circuit is negative.

The net negative resistance occurs due to the inherent negative resistance of the induction generator rotor, as seen on the stator side, and much more so because of the action of the DFIG controls governing the converter connected between the stator and rotor circuits.

[5] Older induction generator technologies such as type 2 WTGs (and possibly even type 1 WTGs on start-up), might also be susceptible to IGE SSR. These technologies are no longer manufactured for large wind power plants, however, some significant amounts of these older technologies still exist in some systems around the world.

Thus, if the total negative resistance resulting from these sources exceeds the positive resistance of the circuit at or near the resonant frequencies, self-excitation SSR occurs. The resultant resonance primarily leads to large current and voltage oscillations that can damage the electrical equipment both, within the generators and on the transmission system. It may also be possible that large perturbations in electrical torque, could result in mechanical damage to the turbine-generator assembly (e.g. gear box). This phenomenon was observed for the first time in the field in the Electric Reliability Council of Texas (ERCOT) in 2009 [68], [74]-[76]. Similar events, also including DFIGs and series compensation, have been observed in the Xcel Energy network in Minnesota [77].

The phenomenon leading to the subsynchronous oscillations in both incidents was termed subsynchronous control interaction (SSCI) in the literature [74], [78], [79] because the dominant factor in producing negative damping at the electrical resonant frequencies is the control action of the DFIG converter controls. This has been widely investigated and documented during the last ten years, [80]-[87], determining that the major cause of SSCI stability problems is the IGE [81]. It should be remembered that the underlying phenomenon is the purely electrical resonance between the series capacitor and the effective reactance of the induction generator (i.e. self-excitation [64], [72]) which becomes unstable once the resistance in the circuit becomes largely negative due to the effect of the converter controls. It is not only due to control interactions with the series capacitor. It has been shown that supplemental controllers added to the DFIG converter controls can help to mitigate and damp the resonant oscillations [88].

There are other electrical resonances that could potentially occur in the system. One such example is ferro-resonance, which occurs between the magnetizing reactance of a transformer and series capacitance.

4.2.5 Converter-driven Stability

The dynamic behavior of CIG is clearly different from conventional synchronous generators, due to the predominant voltage-source converter (VSC) interface with the grid [89]. As described in Section II, a typical CIG relies on control loops and algorithms with fast response times, such as the PLL and the inner-current control loops. In this regard, the wide timescale related to the controls of CIGs can result in cross couplings with both the electromechanical dynamics of machines and the electromagnetic transients of the network, which may lead to unstable power system oscillations over a wide frequency range [90]. Consequently, slow- and fast-interactions are differentiated as shown in Fig. 4, based on the frequencies of the observed phenomena. Instability phenomena showing relatively low frequencies are classified as Slow-Interaction Converter-driven Stability (typically, less than 10 Hz), while phenomena with relatively high frequencies are classified as Fast-Interaction Converter-driven Stability (typically, tens to hundreds of Hz, and possibly into kHz).

The following sections focus on defining and discussing both types of *Converter-driven Stability* from a bulk power system perspective. Accordingly, from the wide spectrum of stability problems reported with CIG, HVDC and FACTS, local instabilities caused by incorrect control settings or inappropriately tuned controllers, which can be characterized independently from the power system, are not considered.

4.2.5.1 Fast-Interaction Converter-driven Stability

These types of instabilities involve system-wide stability problems driven by fast dynamic interactions of the control systems of power electronic-based systems, such as CIGs, HVDC, and FACTS with fast-response components of the power system such as the transmission network, the stator dynamics of synchronous generators, or other power electronic-based devices. Instabilities in power systems due to fast converter interactions may arise in a number of different ways. For instance, interactions of the fast inner-current loops of CIG with passive system components may cause high frequency oscillations, typically in the range of hundreds of hertz to several kilohertz [91], [92]. This phenomenon has been referred to as harmonic instability in the power electronics community. It is a general term used for a wide range of phenomena resulting in high frequency oscillations, including resonance and multi-resonance issues, which can be prevented and/or mitigated by active damping strategies [92].

Several inverters in close proximity to each other may also generate interactions leading to multi-resonance peaks [93]. They can also be caused by high-frequency switching of CIGs that may trigger parallel and series resonances associated with LCL power filters or parasitic feeder capacitors [91], [94]. The resonance of an inverter filter can also be triggered by the control of the inverter itself or by interactions with nearby controllers [95]. The mutual interaction between the control loops of grid-connected converters may also lead to high frequency oscillations [96], [97].

Due to the very fast controls of the power converter in CIGs, interactions induced by the coupling between the converters and the grid are also possible [98]. High and very high frequency oscillations have been reported in the case of large-scale wind power plants connected to VSC-HVDC [99], [100] (i.e. between 500 Hz to 2 kHz). In another paper [101], it is argued that synthetic inertia controllers that sought to replicate swing equation inertial response, under high CIG penetration, may trigger super-synchronous stability problems due to converter control interactions. However, it is shown in [102] and [103] that a properly tuned virtual synchronous machine controller is less likely to induce these types of fast oscillations, in part due to their slower control response. These remain areas of active research.

Recently, some fast oscillation phenomena including sub- and super-synchronous interactions between STATCOMs and weak AC/DC grids have been detected in the China Southern Grid. The observed oscillations have frequencies of 2.5 Hz and 97.5 Hz [68], [104].

4.2.5.2 Slow-Interaction Converter-driven Stability

These types of instabilities involve system-wide instabilities driven by slow dynamic interactions of the control systems of power electronic-based devices with slow-response components of the power system such as the electromechanical dynamics of synchronous generators and some generator controllers.

This category of converter-driven instability can be similar to voltage stability, in the sense that maximum power transfer between the converter and the rest of the system, i.e., a weak system, can be the root cause of instability. The two mechanisms are different insofar as voltage instability is driven by loads, while converter-driven instability is associated with the power electronic converter controls.

- *Low frequency Oscillations*

Unstable low-frequency oscillations in power systems with CIGs can appear due to a variety of forms of interaction between the controllers of the converters and other system components. The outer (power and voltage) control loops and the PLL of CIGs can, for instance, lead to unstable low frequency oscillations [92]. System strength at the connection point of CIGs has a significant influence on the stability of low-frequency oscillations [105]-[109]. This has been observed in real events in Xinjiang (China), where the interaction between direct-drive permanent-magnet generator (PMG) wind turbines and weak AC grids has resulted in the system experiencing sustained oscillations since 2014. the oscillation frequencies range between 20 Hz and 40 Hz, depending on the system operating conditions [85], [110]. In power systems with low short circuit ratios (SCR), i.e. weak grids with SCR less than 2 [111], [112], the oscillations may become unstable and could lead to growing low-frequency oscillations in the PMG and the local grid.

Other factors affecting low-frequency oscillations in weak grids include the online capacity of CIG and the control strategies and parameters of the converters [105], [106]. Although a higher PLL bandwidth makes the system more stable when the converter is in power control mode, there are practical limitations related to the PLL gains and bandwidth, imposed by the low-pass filters used for eliminating noise and harmonics from the measured signals [106].

Unstable low-frequency oscillations in VSC-HVDC systems with weak grid connection have also been observed [108], [109]. In this case, system stability is mainly affected by the tuning of the outer loop parameters and the response time of the PLL [109], particularly at low SCR [108].

- *Weak System Stability*

The ability of the CIG PLL to synchronize with the grid in the case of nearby faults can be extremely challenging in weak networks [113], [114]. This phenomenon has been shown to be related to the PLL effectively introducing a negative admittance in parallel with the system input admittance [115]. When the PLL attempts to quickly track large changes in the angle during transients in weak networks, this effective admittance may lead to a high-gain PLL providing an erroneous value of angle to the inner current controller. Thus, the resulting current being injected by the CIG may be at the wrong phase, which could result in further voltage magnitude and angle degradation, thus leading to instability [114]. A variety of potential solutions may include tuning the PLL and inner-current control loops to lower their gains, considering other emerging control strategies, introducing other supplemental controls, or adding equipment to improve system strength (e.g. installation of synchronous condensers).

- *Stability Issues related to Power Transfer Limits*

Power transfer limits imposed on CIGs connected to weak networks may also result in stability problems. These are further discussed here. The test system of Fig. 8 represents a CIG connected to a Thévenin equivalent of the rest of the system and is considered here for illustration purposes. The system of Fig. 8 may correspond to a fault-on system if fault-ride through capability is tested, or to a system close to voltage instability. Since CIGs are usually connected to lower voltage levels, the effect of resistance on the impedance Z_T seen by the CIG is not negligible. This is represented by the loss angle $\beta = sin^{-1}(R_T/Z_T)$.

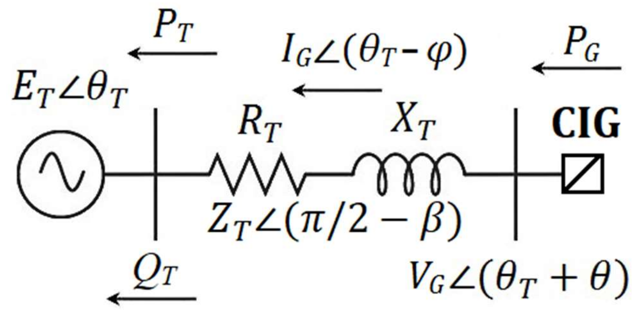

Fig. 8: A two bus system.

First the power transfer limit imposed by phase angle is investigated. This type of stability problem was first introduced in [116] as "transient stability of wind parks" but this terminology is discouraged to avoid confusion. The phase angle limit assuming constant voltage magnitude V_G is in this case $\theta - \beta = 90°$ due to the losses [117], [118]. In this case the delivered power P_T is less than the generated power P_G. However, in [116] the limit $\theta = 90°$ is considered as a conservative estimate of stability.

The stability mechanism implied is that the converter will keep its voltage magnitude constant and adjust its phase to export the generated power thus obtaining an equilibrium. If the generated power exceeds the maximum that can be transmitted, the equilibrium ceases to exist and the phase angle keeps increasing, as shown in the unstable responses recorded in [116], resulting in instability. This type of instability can be countered by dissipating the excess generation by a fault-ride-through scheme.

Another form of maximum power transfer limit can be encountered when the inverter hits its current limit, for instance, when trying to control its terminal voltage under deteriorated network conditions. Assuming a constant voltage E_T in Fig. 8 and a constant current, the maximum power that can be injected is that corresponding to unity power factor at the receiving end ($Q_T = 0$). The maximum generated power P_G is thus limited to $E_T I_G + R_T I_G^2$ as shown in [118]. Again, if the generated power is above this value, equilibrium is lost and instability will result unless the generated power is curtailed [119].

5. SUMMARY AND CONCLUSIONS

This report revisits the classic power system stability definition and extends the classifications of the basic stability terms, in order to cover the effects of the increasing penetration of fast-acting, converter interfaced generation technologies (CIGs), loads, and transmission devices in modern power systems. This extension was needed in order to incorporate new stability problems arising from CIGs' characteristics, which differ from those of conventional synchronous machines. Factors driving these new problems include potential decrease in system frequency response, notable reduction in total system inertia, and reduced contribution to short circuit currents. The formal definition of power system stability in [1] is shown to apply to the new conditions introduced by CIGs while conforming to definitions from system theory. An expanded classification is proposed in order to cover the effects of fast-response power electronic devices down to electromagnetic transients. The basic categories of "rotor angle", "voltage" and "frequency" stability are described focusing on the presence of CIGs. Next to these classic categories, two new stability classes are introduced, namely "Converter-driven stability" and "Resonance stability", also motivated by the increased presence of CIGs in modern power systems. It should be noted that the classification presented in this report is based on the intrinsic system dynamics (time constants associated with actual physical phenomena) and not on the scenario or disturbance initiating the instability.

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