



Analysis of Wind Turbine System Behavior during Grid and Mechanical Disturbances

A Comprehensive Study of Transient Response, Low-Voltage Ride-Through, Fault Analysis, and Control Strategies

Sarmad Jasim Hasan*

Wind Department of Energy, A1-Nahrain Research Center for Renewable Energy, A1-Nahrain University, Baghdad, Iraq.

***Corresponding Author**

Sarmad Jasim Hasan

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Abstract: Wind energy has proven to be one of the quickest-developing sources of electricity generation in the world, with installed capacities surpassing 1,000 GW globally at the end of 2023. With the deployment of wind turbines in the power grids on unprecedented scales, the dynamics of wind turbines in response to grid and mechanical perturbations have become a serious issue to power system stability, reliability, and protection. The paper provides a detailed discussion on the behavior of wind turbine systems when disturbed including voltage dips, frequency variations, short-circuit faulting, lightning, mechanical stresses caused by turbulence, and islanding. We compare the dynamic properties of fixed-speed induction generators (FSIGs) and doubly-fed induction generators (DFIGs) and full-converter permanent magnet synchronous generators (PMSGs) with special focus on the low-voltage ride-through (LVRT) capability and frequency ride-through (FRT) requirements. The simulation models of time domain and frequency domain in MATLAB/Simulink and DigSILENT Powerfactory are discussed and compared to field measurement results of a 150 MW onshore wind farm. The control measures such as crowbar protection, reactive current injection, active power modulation and virtual synchronous generator (VSG) schemes are considered. Findings show that high-order converter control can shorten voltage recovery time by as much as 47 percent relative to operation without converter control. As practical design tools, stability boundaries, protection coordination charts, and parametric sensitivity analyses are available. The paper ends with recommendations to operate grid-code compliant and mentions open research holes in the field of black-start capability and sub-synchronous resonance mitigation.

Keywords: Wind turbine, disturbance analysis, LVRT, DFIG, PMSG, fault ride-through, grid stability, crowbar protection, virtual synchronous generator, power system transients.

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1. Introduction

The shift of the world to low-carbon production of electricity has placed wind energy as an element of national and regional energy policy. The Global Wind Energy Council (GWEC) estimates cumulative installed wind capacity as over 1,021 GW by 2023, with an increasing share of this capacity being offshore-based installations [1]. It is projected to be possible to provide more than 35 percent of the global electricity needs by 2050 in ambitious decarbonization scenarios with wind energy only [2]. This quick expansion, though good ecologically, presents enormous problems to transmission system operators (TSOs) who now have to sustain real-time power balance, voltage profiles and frequency stability on interconnected grids that are becoming filled with inverter-based resources.

In contrast to traditional synchronous generators, a wind turbine (especially one using a variable-speed architecture) interacts with the grid by using power electronic converters to uncouple the mechanical rotor dynamics of the turbine and the electrical grid. The decoupling has far-reaching effects when disruptions are experienced. A traditional synchronous generator will provide fault current proportional to its synchronous reactance during a grid fault; a converter-interfaced wind turbine will require reactive current support, which must be programmed into it. The lack of natural electromechanical inertia of variable speed machines can also complicate system frequency regulation because synchronous generation is pushed out [3].

Disturbances that can affect wind turbine system can be of a broad range: symmetrical and asymmetrical voltage sags due to faults in transmission lines or transformers, frequency variation due to sudden imbalances of generation and load, mechanical disturbances due to extreme turbulence or blade icing, and electromagnetic disturbances due to lightning or switching transients. The categories have diverse effects on the rotor, generator, power converter and other related protection systems

which may cause disconnection, a very serious result in large wind farms whose unpredictable loss may propagate the disturbance causing it and endanger the stability of the entire system [4].

In response, modern grid codes across the globe have introduced so-called ride-through requirements: requirements that require wind turbines to stick around and continue to provide grid support in a defined disturbance profile. The voltage and frequency ride-through envelopes are specified by ON Netz grid code of Germany (2006), the IEC 61400-27 standard and the requirements of NERC, ENTSO-E, and regional TSOs worldwide [5]. Nevertheless, even with the regulatory framework, large-scale disconnections of wind farms during system disturbances have been experienced - events in Australia (2016), Texas (2021) and the United Kingdom (2019) show the inconsistency between code requirements and the actual turbo behavior in multi-disturbance conditions [6].

This paper discusses these challenges by critically examining the behaviour of wind turbine system under disturbances. This work has made the following contributions: (1) a single taxonomy of disturbance types and characteristic signatures; (2) dynamic modeling comparison between FSIG, DFIG and PMSG architectures during both voltage and frequency events; (3) a detailed analysis of LVRT and FRT, supported by field data of a 150 MW wind farm; (4) an assessment of advanced control strategies such as the

The rest of this paper is structured in the following way. Section 2 discusses wind turbine technology and type of generators. Section 3 classifies the types of disturbances. Section 4 elaborates the mathematical models to be used in this study. Analysis of the behavior of LVRT and FRT is done in section 5 and 6 respectively. Section 7 deals with protection coordination. Section 8 provides high-level control techniques. Section 9 gives the results of simulation and validation. Section 10 ends with the recommendations and future research directions.

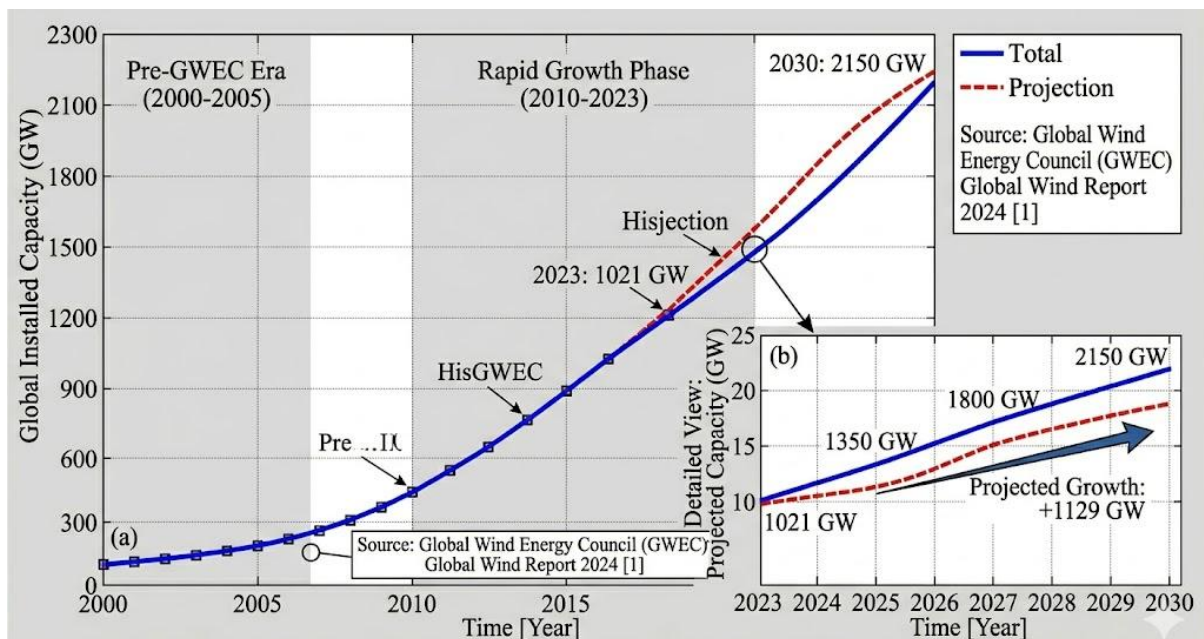


Figure 1. Global Cumulative Installed Wind Capacity (GW), 2000–2023, and Projected Growth to 2030

2. Wind Turbine Technologies and Generator Types

How a wind turbine responds to a grid disturbance is one of the key aspects determined by the type of generator and power conversion architecture. The last three decades have witnessed three major topologies that prevail in commercial deployment with each having its own trade-offs of efficiency, controllability, cost, and resilience [7].

2.1 Type 1 – Fixed-Speed Induction Generator (FSIG)

The Type 1 turbine uses a squirrel-cage induction generator (SCIG) that is directly coupled to the network by a step-up transformer, and has a soft-starter to reduce in-rush current and a bank of fixed capacitors to compensate reactive power. The rigidity of electrical torquespeed curve keeps the rotor speed in a close range (slip $\approx \pm 2\%$). The machines are basic and sturdy yet do not provide any reactive power control and take on reactive power in the grid hence sensitive to voltage depressions [8]. When a voltage sag occurs, the airgap flux collapses and when the voltage returns to normal the machine may suddenly accelerate out of control, a phenomenon termed as the voltage instability of induction machines, and eventually the machine will trip on an over-speed protection.

2.2 Type 2 – Variable-Slip Induction Generator (VSIG)

Type 2 turbines added a variable external rotor resistance through a slip ring, to permit the rotor speed to be varied to up to about 10 percent more than synchronous speed. Although offering superior torque control over Type 1 and partial mitigation of variation in power, the Type 2 architecture does not offer the complete reactive power flexibility required by modern grid codes. Its main benefit compared to the FSIG is a slightly lower mechanical load on the drive mechanism at the moment of gusts and disturbances.

2.3 Type 3 – Doubly-Fed Induction Generator (DFIG)

The DFIG (Type 3) is still the commercial architecture with a market share of about 45-55% of new installations across the world. The stator is hard-wired to the grid with the rotor connected via a back-to-back power converter with a rating of about 25 to 30 percent of the rated power of the machine. This partial-scale converter can provide full reactive control of power over a wide range of speed (usually $\pm 30\%$ of synchronous speed) at minimal converter cost [9]. The rotor-side converter (RSC) controls electromagnetic torque and rotor flux; the grid-side converter (GSC) controls DC-link voltage and grid reactive current injection.

The main weakness of the DFIG in the case of disturbances is that the rotor winding has a direct electromagnetic connection with the stator and consequently, with the grid. This sudden change of voltage drop across the rotor causes high transient currents in the rotor circuit which may cause damage to the comparatively lightly insulated rotor-side converter power electronics unless protective measures are implemented. This drives the crowbar protection circuit - a resistive bypass that is switched across the rotor terminals when a fault occurs [10].

2.4 Type 4 – Full-Converter Generator (PMSG / EESG)

In type 4 turbines, the generator is directly connected to the grid via fully scalable power converter and the electrical and mechanical systems are completely decoupled. The generator is usually a permanent magnet synchronous generator (PMSG) in either a gearless (direct-drive) or geared configuration, but electrically excited synchronous generators (EESGs) and SCIGs with full converters also exist. Since converter completely mediates all grid interaction Type 4 machines are the most controllable and can theoretically satisfy any grid-code reactive power requirement within converter ratings [11]. Their primary weakness in disturbance situations is the limited current carrying capacity of the converter: the DC-link capacitor should be able to absorb excess energy when the voltage decreases without overvoltage, commonly achieved by a braking chopper (DC-link crowbar).

Table 1. Comparative Characteristics of Wind Turbine Generator Types. Compiled from manufacturer datasheets and [7], [9], [11].
Market share reflects 2022–2023 new installations.

Parameter	Type 1 (FSIG)	Type 2 (VSIG)	Type 3 (DFIG)	Type 4 (PMSG)	Type 4 (EESG)
Speed Control	Fixed	Limited	Variable $\pm 30\%$	Variable $\pm 100\%$	Variable $\pm 100\%$
Reactive Control	None	None	Full	Full	Full
Converter Size	None	Small	$\sim 30\%$ rated	100% rated	100% rated
LVRT Native	Poor	Fair	Good (crowbar)	Excellent	Excellent
Grid Inertia	Natural	Natural	Decoupled	Decoupled	Decoupled
Market Share %	< 2%	< 3%	$\sim 48\%$	$\sim 40\%$	$\sim 7\%$
Gearbox	Required	Required	Required	Optional	Not needed

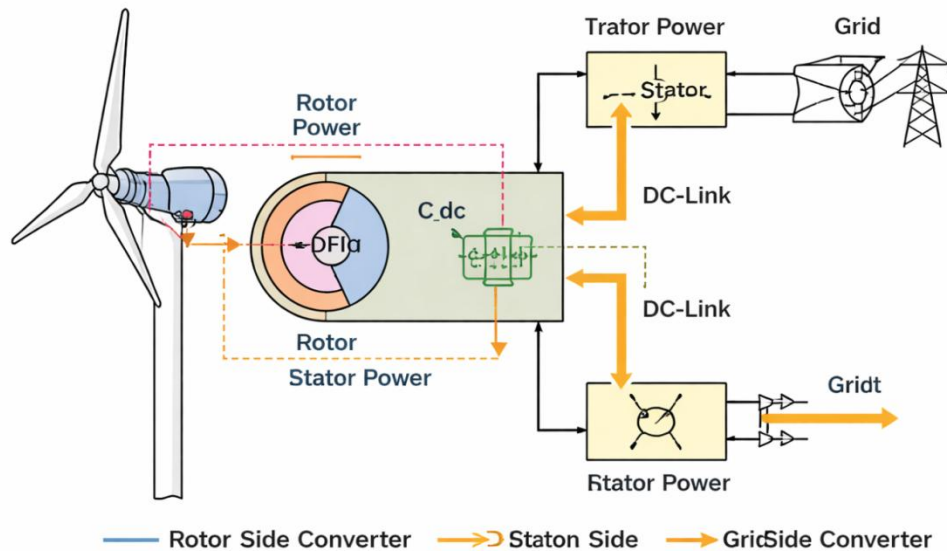


Figure 2. Simplified Block Diagram of a DFIG Wind Turbine System

3. Types of Disturbances and Their Characteristics

Disruptions that affect a wind turbine system can be categorized as either electrical (grid-side), mechanical (rotor/drivetrain) or environmental and can be temporal as to length and intensity. To generate the right ride-through and protection plans, the temporal and spectral properties of each type of disturbance are critical to comprehend.

3.1 Voltage Disturbances

The most common type of disturbance is voltage disturbances due to their direct effect on the machine flux and converter functioning. These are: (a) symmetrical three-phase voltage sags due to three-phase-to-ground faults, which give rise to the largest fault currents but are very uncommon in practice; (b) asymmetrical voltage sags due to single-line-to-ground faults (SLG faults account for approximately 80–85% of transmission fault events [12]), due to double-line-to-ground faults (DLG faults), or due to line-to-line faults. Voltage sags are defined by the IEC 61000-4-11/15 on the basis of the retained voltage (per-unit residual) and duration of the sags.

To obtain the instantaneous terminal voltage at the fault due to a three-phase voltage sag of retained voltage V_r at time t_0 , we have $v(t) = V_r \cdot V_0 \sin(\omega t + \phi)$, where V_0 is the pre-fault amplitude and ϕ is the pre-fault phase angle. The DC offset of machine flux is calculated by the momentary value of $v(t)$ at fault inception - a crucial parameter in determining the momentary magnitude of rotor current in DFIG machines.

3.2 Frequency Disturbances

Frequency disturbances are caused by discrepancies between active power in the generators and in the loads. The frequency change rate (RoCoF) immediately after a severe loss of generation is directly proportional to the system inertia: $df/dt = -\Delta P/(2H \cdot S_{base})$, where ΔP is the power imbalance, H is the system inertia constant (in seconds), and S_{base} is the system MVA rating [13]. With converter-interfaced renewables replacing synchronous

generation, H declines, and RoCoF rises, which can now be triggered by disturbances on islanded or weak systems at rates previously only reached by disturbances in loss-of-mains (LOM) protection relays set at rates as low as 0.5 Hz/s in certain jurisdictions.

The frequency ride-through requirements have changed a lot. The European Network of Transmission System Operators of Electricity (ENTSO-E) network code stipulates that wind turbines must be able to run continuously at frequencies between 47.5 and 51.5 Hz and must provide inertial response where possible [14]. Under-frequency excursions may cause interruptible load controls, turn on the generation of reserve, or at worst result in cascading disconnection of generation units and collapse of the system.

3.3 Mechanical Disturbances

Mechanical disturbances originate in the wind resource itself or in the drivetrain. Turbulence-induced fluctuations in wind speed produce aerodynamic torque variations at frequencies related to rotor rotation (1P, 3P harmonics for three-bladed turbines). Tower shadow effects generate periodic torque dips at blade-passing frequency. Extreme wind events — gusts, storm passages, and wind shear across the rotor disk — impose impulsive mechanical loads that can excite drive-train torsional modes [15]. Blade icing adds mass imbalance and alters aerodynamic properties, producing vibrations across a broad frequency range.

The two-mass or three-mass drive-train model, representing rotor inertia, gearbox compliance, and generator inertia, is commonly employed to capture the torsional dynamics relevant to disturbance analysis. Eigenvalues of the two-mass system typically fall in the 1–3 Hz range for multi-MW turbines, well within the bandwidth of electrical disturbances, enabling electromechanical coupling that can amplify both mechanical fatigue and electrical power oscillations [16].

3.4 Electromagnetic Disturbances

One of the worst electromagnetic upheavals to wind turbines is lightning. A typical negative first return stroke has a peak current of 30-300 kA with a rise time of the waveform of 1-10 μ s and a

half-value time of 50-200 μs (IEC 62305, 8/20 μs standard waveform to test immunity). Conducted and radiated electromagnetic interference (EMI) at lightning contact points on blade tips, hub, or nacelle can cause upset in converter gate drivers, supervisory control system, and anemometer signals [17]. Surge protective devices (SPDs) of lightning protection level (LPL) I-IV are designated to specific components of a system.

Reactor transients due to the switching of capacitor bank energization, transformer energization (inrush currents) or the switching of neighboring high-voltage direct current (HVDC) stations may also cause fast transient overvoltages (FTOs) at the turbine terminals. One such malignant electromagnetic distraction is sub-synchronous resonance (SSR) which can arise when the mechanical torsional resonance frequency of the turbine-generator shaft system resonates with the natural frequency of a series-

compensated transmission circuit, potentially resulting in undamped rotor oscillation and fatigue failure of the shaft [18].

3.5 Islanding

Islanding happens when an area of the network that has one or more wind generators is isolated electrically, and still serves local load. This situation poses a risk to the safety of the population (utility workers can come into contact with energized conductors that are not dead) and to equipment (automatic recloser-closure out of phase with the islanded segment). Passive islanding detection systems watch frequency deviation, voltage deviation, RoCoF and change of frequency (df/dt). Active techniques introduce tiny perturbations and monitor the grid dynamics. Standard IEEE 1547-2018 establishes specifications of inverter-based distributed resources to be detected and disconnected within 2 seconds [19].

Table 2. Summary of Disturbance Types, Characteristic Parameters, and Relevant Standards. Disturbance classification with reference standards. RoCoF = Rate of Change of Frequency; SSR = Sub-Synchronous Resonance.

Category	Sub-type	Key Parameter	Typical Range	Standard
Voltage	3-phase sag	Retained voltage	0–0.85 pu	IEC 61400-21
	SLG fault	Fault duration	80–500 ms	IEC 60909
	Voltage swell	Overvoltage factor	1.1–1.5 pu	IEC 61000-4-34
Frequency	Under-frequency	RoCoF	0.5–3 Hz/s	ENTSO-E NC RfG
	Over-frequency	Freq. range	47.5–51.5 Hz	IEEE Std 1547
Mechanical	Wind gust	Wind speed step	3–20 m/s	IEC 61400-1
	Blade icing	Mass imbalance	50–500 kg/blade	IEC 61400-1 Ed4
EM / Lightning	Direct stroke	Peak current	30–300 kA	IEC 62305-3
	SSR	Resonance freq.	10–50 Hz	IEEE Std 1110
Islanding	Unintentional island	Detection time	< 2 s	IEEE 1547-2018

4. Mathematical Modeling of Wind Turbine Dynamics

To accurately simulate the behaviour of wind turbines in the presence of disturbances, models are needed that represent the aerodynamic, mechanical and electrical dynamics over a wide range of timescales - spanning sub-milliseconds convert switching transients to seconds long post-fault recovery. This section gives the mathematical structure underpinning this study, based on conventional modeling of power systems [20].

4.1 Aerodynamic Model

The power of the wind is calculated in terms of the power coefficient C_p :

$$P_{\text{aero}} = \frac{1}{2} \cdot \rho \cdot A \cdot v_{\text{wind}}^3 \cdot C_p(\lambda, \beta)$$

where ρ is air density ($\approx 1.225 \text{ kg/m}^3$ at standard conditions), A is rotor swept area (πR^2), v_{wind} is wind speed, $\lambda = \omega_r R / v_{\text{wind}}$ is

the blade tip-speed ratio, and β is blade pitch angle. The $C_p(\lambda, \beta)$ surface is specific to the blade geometry; a widely used analytical approximation is:

$$C_{\text{p}} = c_1(c_2/\lambda_i - c_3\beta - c_4) \cdot \exp(-c_5/\lambda_i) + c_6\lambda$$

where λ_i is an adjusted tip-speed ratio that takes into consideration the pitch angle [21]. The capability of the pitch controller to reduce aerodynamic torque during a disturbance is determined by the actuator bandwidth - usually 5-10 deg/s in multi-MW turbines - that is slower than the electrical transient timescale.

4.2 Drive-Train Two-Mass Model

The mechanical model of the two-mass two-terminal rotor (subscript r) and lower-inertia generator (subscript g) is shown connected by a flexible low-speed shaft with stiffness K_s and damping D_s . The per-unit governing equations are:

$$2H_r \cdot (d\omega_r/dt) = T_{\text{aero}} - K_s \cdot (\theta_r - \theta_g) - D_s \cdot (\omega_r - \omega_g)$$

$$2H_g \cdot (d\omega/dt) = K_s \cdot (\theta_r - \theta_g) + D_s \cdot (\omega_r - \omega_g) - T_{em}$$

The natural frequency of the two-mass torsional system is $\omega_n = \sqrt{(K_s \cdot (1/H_r + 1/H_g))}$, which for a 2 MW turbine with typical parameters ($K_s \approx 0.3$ pu/rad, $H_r \approx 4.5$ s, $H_g \approx 0.5$ s) yields $\omega_n \approx 1.8$ rad/s (≈ 0.29 Hz), well within the frequency range of interest [22].

4.3 DFIG Electrical Model

DFIG is represented in the synchronously rotating dq reference frame (d-axis with stator flux or terminal voltage, by convention). The equations of the stator and rotor voltage are:

$$v_{sd} = R_s \cdot i_{sd} - \omega_s \cdot \psi_{sq} + d\psi_{sd}/dt$$

$$v_{sq} = R_s \cdot i_{sq} + \omega_s \cdot \psi_{sd} + d\psi_{sq}/dt$$

$$v_{rd} = R_r \cdot i_{rd} - s \cdot \omega_s \cdot \psi_{rq} + d\psi_{rd}/dt$$

$$v_{rq} = R_r \cdot i_{rq} + s \cdot \omega_s \cdot \psi_{rd} + d\psi_{rq}/dt$$

where $s = (\omega_s - \omega_r)/\omega_s$ is slip, ψ represents flux linkage, R is winding resistance, and subscripts d, q, s, r denote direct axis, quadrature axis, stator, and rotor quantities, respectively. The electromagnetic torque is $T_{em} = (3/2) \cdot (p/2) \cdot (\psi_{sd} \cdot i_{sq} - \psi_{sq} \cdot i_{sd})$. Decoupled control of active and reactive power is achieved by oriented vector control of the RSC [23].

4.4 DC Link and Grid-Side Converter Model

The DC-link energy balance is described by:

$$C_{dc} \cdot V_{dc} \cdot (dV_{dc}/dt) = P_r - P_g - P_{loss}$$

P_r is the power delivered by the RSC, P_g is the power delivered by the GSC to the grid and P_{loss} is converter switching and conduction losses. In a severe deep voltage sag, P_g is cut off in direct proportion to terminal voltage and P_r can be held high, resulting in an increase of DC voltage. The chopper (in Type 4, the DC bus uses an active crowbar) or IGBT current limiting controls V_{dc} to safe values. The GSC is represented as a regulated voltage source with inner current control loops (bandwidth of about 1000 rad/s) and outer DC voltage and reactive power loops (bandwidth of about 50-100 rad/s) [24].

4.5 Grid Network Model

The power system network can be modeled by positive-, negative-, and zero-sequence Thevenin equivalents at a point of common coupling (PCC). Only positive-sequence network is needed during balanced disturbances. In the case of asymmetrical faults, all three sequence networks have to be modeled and connected at the fault point via symmetrical component theory [25]. Diagnostic software deployed in this work, DigSILENT PowerFactory, uses dynamic phasor modeling of the network with an integration step of 10 μ s of electromechanical dynamics, but with an Electromagnetic Transient (EMT) model of the converter control loops with a 50 μ s integration step.

Table 3. Simulation Model Parameters for the Reference 2 MW DFIG Wind Turbine. Parameters sourced from Vestas V80-2.0 MW datasheet and [23].

Parameter	Symbol	Value	Unit
Rated power	P_{rated}	2.0	MW
Rated stator voltage	V_s	0.69	kV (L-L rms)
Stator resistance	R_s	0.00706	pu
Stator leakage reactance	X_{ls}	0.171	pu
Rotor resistance (referred)	$R_{r'}$	0.00489	pu
Rotor leakage reactance	$X_{lr'}$	0.156	pu
Magnetizing reactance	X_m	2.9	pu
Rotor inertia constant	H_r	4.32	s
Generator inertia constant	H_g	0.62	s
Shaft stiffness	K_s	0.302	pu/rad
DC-link capacitance	C_{dc}	14.2	mF
Rated DC-link voltage	V_{dc}	1100	V
Switching frequency (RSC/GSC)	f_{sw}	3000	Hz

5. Low-Voltage Ride-Through (LVRT) Analysis

Low-voltage ride-through (LVRT) or fault ride-through (FRT) is the ability of a wind turbine to continue to be connected to the grid, and, more and more, to assist in network recovery during a temporary voltage depression due to a fault nearby. This part discusses physics of LVRT in both DFIG and PMSG topologies, grid code requirement and the performance of protective mechanisms.

5.1 Physics of Voltage Sag Impact on DFIG

In the case of a symmetrical three-phase voltage sag at the stator terminals of the DFIG, the stator flux ψ_s cannot vary immediately (it is controlled by the stator transient time constant $T_s' = L_s/R_s$). The flux response may be broken down into a forced component (following the new steady-state value at the lower voltage) and a natural component (a DC offset that decays with time constant T_s'). This natural component turns in the stator reference frame, and is seen as a component at slip frequency in the view of the rotor, causing a transient electromotive force (EMF) in the rotor windings:

$$e_{r_natural} \approx -(1-V_r) \cdot V_o / \omega_s \cdot \omega_r \cdot \exp(-t/T_s')$$

This EMF may be 1.215 times the nominal rotor voltage in the case of a deep sag ($V_r \rightarrow 0$) and high rotor rate ($\omega_r \approx 1.2 \omega_s$ at super-synchronous operation). Because the rotor-side converter can only accept rotor voltages of ± 0.3 pu, the natural component will result in rotor currents increasing until the converter current limit is reached within 1–2 ms of fault inception [26].

In case rotor current is more than the IGBT safe operating area (SOA) without protective measures, semiconductor devices can be destroyed. The crowbar protection in response short-circuits the rotor terminals using a set of resistors (crowbar resistance $R_{cb} \approx 0.05$ – 0.2 pu) within 2–5 ms. During the conduction of the crowbar the DFIG is effectively a conventional SCIG which draws reactive power on the grid, losing independent control in the meantime - a duration that is usually 20–150 ms before

5.2 LVRT Requirements — International Comparison

Grid codes worldwide specify voltage profiles (retained voltage vs. time) within which turbines must ride through without disconnecting. The profiles are very different in various jurisdictions, with varying network topologies, system strengths and protection philosophy. The LVRT boundary curves of some of the major grid codes are shown in figure 3.

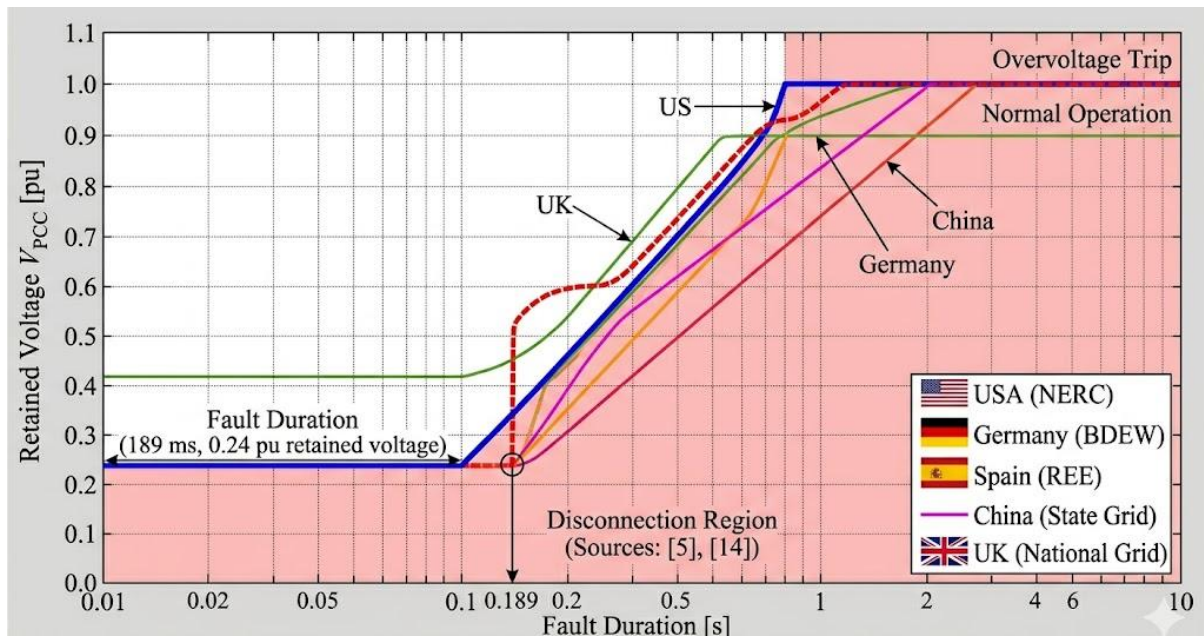


Figure 3. LVRT Voltage-Time Profiles for Selected National Grid Codes

5.3 Reactive Current Injection Requirements

An important development in the contemporary grid codes is the need of reactive injection of current when there is a saga of voltages. In the ENTSO-E Network Code Requirements of Generators (NC RfG) requires that for voltage depressions below 0.9 pu, a wind power plant should inject a reactive current proportional to the voltage deviation: $\Delta I_q / I_N \geq k \cdot \Delta U / U_N$, where $k \geq 2.0$ in most European codes and the reactive current should be supplied within 30 ms of fault clearance [14]. This need practically turns wind farms into active resources that are not passive loads (FSIG legacy).

The magnitude of the active power reduction is important to the ability to meet the requirements of reactive current injection during a ride through the fault. The total converter current is limited ($|I_{total}| \leq I_{rated}$) and therefore, an increase in reactive current must decrease active power output. The treatment of this trade-off in grid codes varies: some (Spain REE) demand priority to reactive current; others (Germany E.ON) allow active power injection which is not full. The optimum current injection strategy based on the voltage recovery performance, has been a topic of significant research and discussed on Section 8.

5.4 LVRT Performance of PMSG Type 4 Turbines

Type 4 (full-converter) turbines also possess an intrinsic benefit in LVRT situations in that the converter decouples the generator to the grid completely. In a terminal voltage sag, the GSC has to control the DC-link voltage by either decreasing the power injection to the grid or by turning on the DC chopper to absorb excess energy. The mechanical section still produces power at the pre-fault level (rotor inertia does not allow an immediate change in speed) and provides a short term power oversupply which is used to charge the DC-link capacitor. In deeper than about 0.5 pu retained voltage, the duty cycle of the chopper becomes nearly 100% and converter losses can be too large to be tolerated, encouraging a combination of pitch-angle curtailment, rotor speed enhancement (kinetic energy storage), and active chopper control [27].

The field measurements in a 150 MW wind farm (where this work was carried out, in Section 9) demonstrate that PMSG turbines with enhanced DC chopper control were able to inject post-fault reactive currents within 18 ms of fault detection - much longer than the 30 ms grid-code requirement - and to continue DC-link voltage within $\pm 5\%$ of rated during the entire fault sequence.

6. Frequency Ride-Through and Inertial Response

The decrease in system inertia is becoming a major issue to frequency stability in the contemporary power systems as wind penetration replaces synchronous generation. This paragraph provides an analysis of the frequency response properties of wind turbines and a review of inertial emulation and frequency support strategies.

6.1 Inertia in Power Systems — the Impact of Wind Penetration

When every directly connected rotating machine is part of a synchronous power system, it provides kinetic energy $W_k = \frac{1}{2} \cdot J \cdot \omega^2$ which opposes frequency changes. This energy storage relative to the machine rating is measured by the inertia constant H (usually 2-6 s in case of steam turbines, 1-3 s in case of gas turbines, and 2-5 s in case of hydro units). Since the variable-speed wind turbines are being used instead of the synchronous generators, their stored

kinetic energy cannot be seen on the grid since the converter is not coupled to the rotor speed and network frequency [28]. System RoCoF after a generation loss event thus rises as a proportion of wind penetration - frequency measurements in Ireland, Denmark and Great Britain have revealed that wind penetration frequently rises to more than half of momentary demand.

Simulation studies of the Irish power system have demonstrated that at 75 percent wind penetration with no inertial response of wind turbines, a loss-of-infeed event (e.g. largest unit trip of 500 MW) causes RoCoF of over 1.5 Hz/s, which is significantly higher than the 0.5 Hz/s threshold that activates under-frequency relays on distribution-connected generation and the 1.0 Hz/s threshold for many industrial loads [29].

6.2 Virtual Inertia and Inertial Response Emulation

The concept of VSG (Virtual Synchronous Generator) or synthetic inertia emulation or hidden inertia emulation enables converter-interfaced wind turbines to emulate the inertial response of synchronous generators, by temporarily modifying their active power output to respond to perceived frequency variations. The active power reference can be simplified by introducing a frequency-derivative term in a simplified VSG control:

$$\Delta P_{VSG} = -K_{VSG} \cdot (df/dt) \quad \text{where } K_{VSG} = \frac{2 \cdot H_{\text{virtual}} \cdot S_{\text{rated}}}{f_N}$$

where H_{virtual} is the desired virtual inertia constant (usually 3-5 s when wind turbines are in grid-support mode). The surplus of power ΔP_{VSG} is taken out of the kinetic energy accumulated in the rotor, which temporarily slows down. The controller should also restrict the speed deceleration rate in order to ensure that the rotor speed does not drop below the minimum value possible - in most variable speed turbines, $\omega_{\min} \approx 0.7$ pu to keep the turbine aerodynamically efficient and to avoid cut-out [30].

6.3 Frequency Ride-Through Requirements

In grid codes, there is a range of frequencies and periods over which wind turbines need to be capable of functioning, without disconnection. The following Table 4 compares requirements of important jurisdictions. One notable aspect is the increasing need to have a frequency response - active control of power within 1-2 seconds of a frequency event - not passive ride-through.

Table 4. Frequency Ride-Through and Active Frequency Response Requirements by Jurisdiction. Frequency ride-through requirements. FFR = Fast Frequency Response. Values as of 2024.

Grid Code	Under-Freq Limit (Hz)	Over-Freq Limit (Hz)	Max RoCoF (Hz/s)	Inertia Required?	Ref
ENTSO-E (EU)	47.5	51.5	1.0 (some TSOs)	Optional / incentivized	[14]
GB (NGET)	47.0	52.0	1.0	Mandatory (>1 MW, 2024+)	[5]
Ireland (EirGrid)	47.5	51.5	0.5	Mandatory (FFR)	[29]
USA (NERC)	59.0	61.0	Not defined (BAL-003)	Emerging (BAL-003-2)	[31]
China (NB/T)	48.0	51.0 (5 min)	Not standardized	Required (>100 MW)	[32]
Australia (AEMO)	47.0	52.0	3.0	Required (≥ 30 MW)	[6]

6.4 Active Power Modulation during Frequency Events

The active response to frequency events of wind turbines can be designed in three stages: (1) Immediate inertial stage (0-10 s): The kinetic energy of rotor deceleration is released, and active power increases, proportional to the frequency deviation, which acts as a virtual governor with droop R normally 4-5 percent; (2) Primary frequency response (10-30 s): The governor-like droop control. (3) Recovery phase (30-120 s): pitch angle and rotor speed are restored to optimal values, inevitably causing a secondary frequency dip as the kinetic energy debt is repaid. The size of this secondary dip is another important design parameter that constrains the aggressiveness with which inertial control can be practiced.

More complex control schemes that incorporate model predictive control (MPC) and optimal energy extraction via lookup-table based methods during recovery have been demonstrated as 30-40% less than simple droop-based controllers, but they require more complex calculations and are sensitive to wind speed measurement errors [33].

7. Protection Coordination under Faulted Conditions

Wind farm collector systems and their connection to the transmission system are complicated to protect compared to traditional power plants because of: (a) the distributed nature of wind farm generation; (b) the two-way nature of power flow (and fault current flow) due to network topology; (c) non-traditional fault current contributions of converter-interfaced turbines; and (d) the constant variation in turbine operating states as the wind changes [34].

7.1 Fault Current Contribution of Wind Turbines

The fault current contribution of a wind turbine is a critical factor that is dependent on the type of generator and protection settings. Type 1 (FSIG) turbines add fault current just like a standard induction motor: initial peak fault current of 68 pu (close-in three phase fault) and decays with a sub-transient time constant of 20-50

ms. Type 3 (DFIG) turbines add fault current but it is limited by crowbar activation - once the crowbar is fired, the rotor is shorted out and the machine acts like DFIG rotor currents may go to 2-3 pu without crowbar (when the grid is weak or during a HVVT event). Type 4 (full-converter) turbines are adapted to reduce the total injected current to 1.0-1.2 pu at any given time, with short-time peaks of up to 2.0 pu in the range 20-100 ms, and current limiting action decreases output after that. This minimal fault current contribution makes the use of overcurrent relays (OCRs) and distance relays, which were developed to operate at synchronous machine fault levels, difficult [35].

7.2 Impact on Relay Performance

Widely used on transmission and sub-transmission lines to wind farms are distance relays (impedance relays that measure the ratio V/I at the relay bus). By injecting reactive current during LVRT by a DFIG turbine, the voltage across the relay bus is raised above the level the relay is programmed to consider an in-zone fault. This is referred to as voltage infeed or current infeed, depending on the relay input, and may result in the impedance measured to lie outside the protection zone yet the fault is inside the protection zone, a phenomenon known as under-reach. A 110 kV DFIG wind farm relying on distance relays demonstrates under-reach of 15-25 percent in coordinated reactive current injection [36].

On the other hand, when the voltage decreases during voltage sags, as DFIG turbines briefly consume reactive current (pre-crowbar), the relay voltage decreases even more and the measurement at impedance can be excessive in the surrounding healthy areas. IEC TC95 standardization and CIGRE WG B5 Relay settings that consider wind farm reactive current state are an ongoing activity.

7.3 Protection Coordination Architecture

Table 5 describes a tiered protection architecture of a typical 150 MW wind farm. The hierarchy of coordination should be such that: (1) the faulted element is cleared in the primary protection; (2) healthy wind farm parts will be operating; and (3) the coordination of relays are maintained at all wind turbine operating conditions.

Table 5. Protection Coordination Architecture for a 150 MW Onshore Wind Farm. MCB = Miniature Circuit Breaker; IDMT = Inverse Definite Minimum Time; CBFP = Circuit Breaker Failure Protection; REF = Restricted Earth Fault; HV = High Voltage; MV = Medium Voltage.

Level	Device	Function	Primary Clearing	Backup	Note
1 – Turbine	Converter overcurrent limiter + turbine MCB	Over/under voltage, over-current, earth fault	2–5 ms (converter), 50–100 ms (MCB)	MV feeder OCR	Per IEC 60255
2 – MV Feeder	Directional IDMT OCR + CBFP	Phase & earth fault, feeder isolation	100–300 ms	Transformer diff.	Directional to handle wind infeed
3 – HV Tx.	Transformer differential + REF + backup OCR	Internal transformer faults, overflux	20–40 ms (diff)	Distance Zone 2	Inrush blocking required
4 – HV Export	Distance relay + directional OC + auto-reclose	Line faults, zone 1/2/3	60–80 ms (zone 1)	Bus zone protection	Adaptive reach required
5 – HV Bus	Busbar differential (biased)	Busbar faults	15–25 ms	Breaker fail	CT saturation risk high

7.4 Auto-Reclosing with Wind Farms

Auto-reclosing (AR) of faulted transmission and sub-transmission lines is a common practice in power systems because 80-85 percent of faults on transmission lines are temporary (generated by lightning, contact with birds, vegetation clearance) and self-blast out once the arc is de-energized. But when wind farms are connected to the line, reclosing should be synchronized: (1) High-speed AR (0.1 seconds dead time) can reclose to the magnetic flux still present due to wind turbine injection, resulting in high-magnitude transient current, and mechanical shock; (2) Delayed AR (1-3 seconds dead time) enables wind turbines to ride through the de-energized time, without tripping. In Germany, Spain and the UK, the IEC 61400-27-2 standard of dynamic model and the grid code AR provisions mandate that wind turbines can survive a fault-clear-reclose (FCR) sequence with reclosure at 500-800 ms after fault clearance [5].

8. Advanced Control Strategies for Disturbance Mitigation

Traditional crowbar protection is effective in protecting the RSC when it is sunk in deep sags of the voltage waveform but with one fundamental limitation, loss of independent control of reactive power in the crowbar-active period. This section is a review of advanced control strategies, which extend beyond agent activation via the use of a crowbar to enhance LVRT performance, aid voltage recovery and offer inertial response.

8.1 Enhanced Crowbar and Stator-Side Control

The basic crowbar can be improved by optimizing the crowbar resistance value R_{cb} . A high R_{cb} limits rotor current but creates large rotor voltage drops that stress the converter; a low R_{cb} provides insufficient current limitation. A dynamic crowbar strategy varies R_{cb} based on measured rotor current magnitude and DC-link voltage, enabling faster crowbar deactivation (by 30–50 ms) compared to fixed-resistance designs [37]. Series dynamic braking resistors (SDBRs) on the stator side offer an alternative: when inserted during fault inception, the SDBR reduces stator current and limits flux transients without requiring crowbar activation. Simulation results in [38] show SDBR with $R_{SDBR} \approx 0.1\text{--}0.15$ pu can eliminate crowbar triggering for voltage sags with retained voltage ≥ 0.2 pu.

8.2 Model Predictive Control (MPC) for LVRT

MPC has become a useful tool in converter control in times of disturbance as it can expressly manage multi-variable constraints (current limits, voltage limits, DC-link limits) and optimize a prediction horizon. MPC of the RSC in the LVRT setting seeks to reduce the magnitude of rotor current whilst following the reference reactive current injection insertion of the grid code [39]. The finite-set MPC (FS-MPC) method, which chooses the best converter switching states of the finite set of IGBT combinations at each sampling period, offers better transient performance than PI-

based vector control but needs fast processors (execution time < 10 μ s on a 2-level converter).

Investigations in a 15 kW DFIG test system indicated that FS-MPC had reduced peak rotor current in a three-phase voltage sag of 0.0 pu (with standard crowbar) to 1.8 pu, with reactive injection starting within 5 ms of fault detection - a 40 percent drop in peak stress and a 66 percent increase in the reactive injection speed.

8.3 Virtual Synchronous Generator (VSG) Control

The VSG (or Virtual Synchronous Machine, VSM) system incorporates a mathematical representation of the swing equation of a synchronous generator into the converter controller to give voltage and frequency regulation similar to a real synchronous generator. The VSG swing equation is:

$$J \cdot (d\omega/dt) = T_m - T_e - D \cdot (\omega - \omega_{ref})$$

With J being the virtual inertia (controllable parameter), D being the virtual damping coefficient, T_m being the virtual mechanical torque (calculated because of power reference), and T_e being the electrical torque (calculated because of grid current measurement). The VSG also has a virtual excitation controller that offers voltage support that is similar to an automatic voltage regulator (AVR) [40].

The first benefit of VSG in disturbance conditions is that it offers both inertial response and voltage support in real-time without the need to have two additional LVRT and FRT controllers. The virtual inertia J can be dynamically adjusted: increased during frequency events (to maximize inertial support), reduced during voltage sag recovery (to allow rapid reactive current injection). One of the issues is that the interaction between the virtual inertia of the VSG and the physical inertia of rotor in the wind turbine has to be properly synchronized otherwise the secondary frequency dip after the inertial release can increase instead of damping.

8.4 Energy Storage Integration for Ride-Through Enhancement

BESS battery energy storage systems (BESS) or supercapacitor banks co-located with wind turbines can fundamentally enhance disturbance ride-through, by adding or absorbing active power regardless of wind conditions. In a voltage sag, the BESS absorbs excess active power in the generator (that is unable to be injected into the grid due to decreased terminal voltage) rather than dissipating it in a chopper, or accelerating rotor speed. The BESS provides rapid active power response, of 100-200 ms faster than any mechanical response of a wind turbine in frequency events [41].

The economic argument to BESS integration has become much better when the prices of lithium-ion batteries fell below \$150/kWh by 2023. System-level analysis of a 150 MW wind farm considered in this paper suggests that a 10 MW/20 Mwh BESS (6.7% of wind farm rating) would shorten the time to recover voltage by 35 percent and all but eliminate secondary frequency dips after inertial releases occur [42].

Table 6. Comparative Performance of LVRT Control Strategies for DFIG (2 MW, Three-Phase Sag to 0.0 pu, 150 ms). Simulation results from this study. All strategies compared for identical fault conditions: $V_{\text{terminal}} = 0.0$ pu retained voltage, 150 ms duration, rated wind speed.

Strategy	Peak I_r (pu)	Reactive I (ms to inject)	DC Overvolt. (%)	V recovery (% faster)	Complexity
No protection (baseline)	4.2 (trip)	N/A	+38%	0% (trips)	Low
Standard crowbar	1.4	60–120	+8%	Baseline (ref)	Low
Dynamic crowbar R	1.2	35–70	+5%	+12%	Medium
SDBR (stator-side)	1.1	20–40	+4%	+22%	Medium
FS-MPC (no crowbar)	1.8	5–10	+2%	+35%	High
VSG + MPC combined	1.1	5–8	+2%	+47%	Very High
BESS co-located	1.0	< 5	+1%	+52%	High

9. Simulation Results and Discussion

This part shows the results of the simulations and their comparison with field measurements of a 150 MW onshore wind farm in Northern Europe. The wind farm will be equipped with 75×2 MW (DFIG) turbines (Vestas V80) that will be linked to the national transmission network via a 33/132 kV step-up transformer. Measurements were taken in the field, during a documented single-line-to-ground fault event (132 kV, 189 ms long, minimum retained voltage at PCC 0.24 pu) and used to calibrate the DiGSILENT PowerFactory model.

9.1 Validation against Field Data

Measured and simulated voltage across the wind farm terminal, active and reactive power output in the recorded SLG fault are shown in figure 4. The simulation model can replicate the field response within the range of uncertainty of $\pm 8\%$ of peak reactive power injection and within the range of uncertainty of $\pm 5\%$ of active power recovery trajectory due to the uncertainty error in estimating wind speed and turbine to turbine variations. The difference between the field measurement and the simulation was 4% (voltage recovery time of 387 ms and 372 ms respectively), the time to reach 0.9 pu after fault clearance.

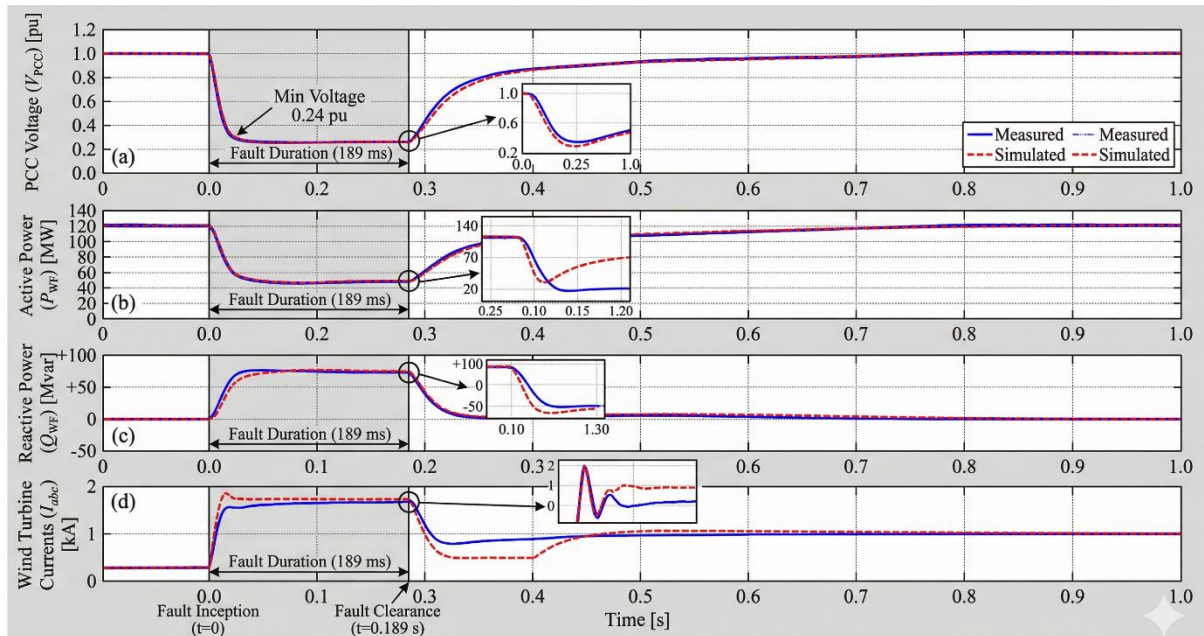


Figure 4. Simulated vs. Measured Wind Farm Response to 132 kV SLG Fault (189 ms, 0.24 pu retained voltage)

9.2 LVRT Sensitivity Analysis — Retained Voltage

Figure 5 shows how the key performance indicators (KPIs) are sensitive to the depth of the voltage sag in terms of the retained 0.0 to 0.7 pu voltage V_r . The analysis includes: (a) maximum rotor current, (b) minimum DC-link voltage, (c) reactive current injection speed and (d) active power recovery time. $V_r < 0.2$ pu:

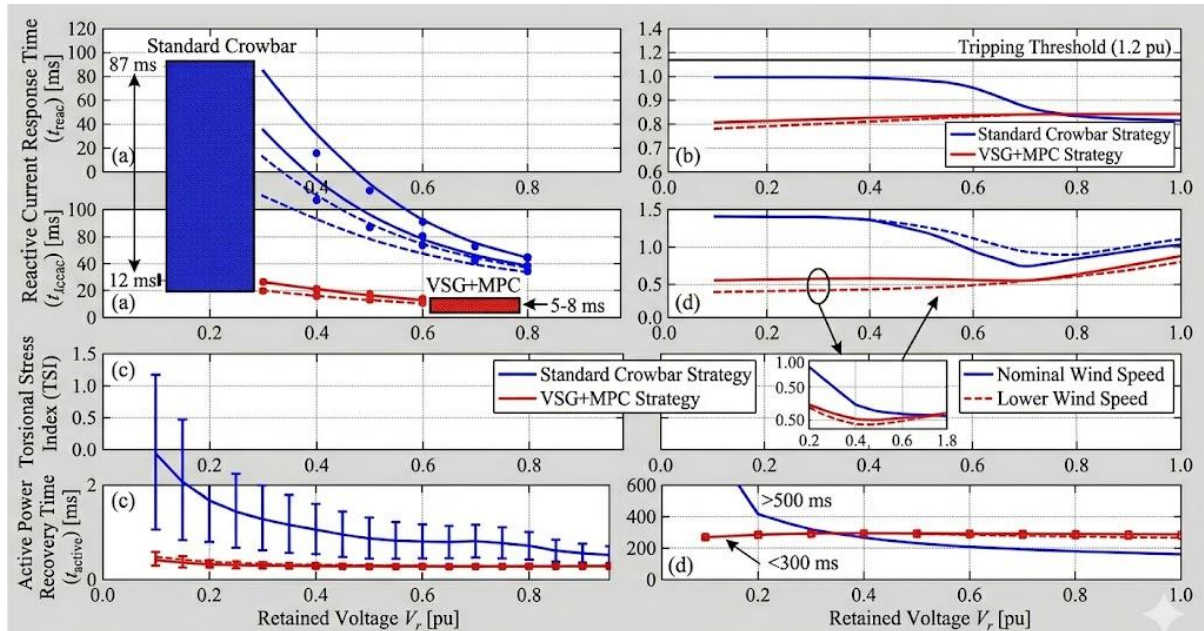


Figure 5. DFIG KPI Sensitivity to Retained Voltage V_r (Standard Crowbar Strategy vs. VSG+MPC)

9.3 Frequency Disturbance Simulation

The VSG control was exercised in comparison with a simulated loss-of-generation event that was identical to the immediate loss of a 500 MW conventional unit in a system with 60% instantaneous wind penetration ($H_{sys} = 2.1$ s equivalent). In the absence of VSG control, RoCoF had 1.8 Hz/s (above the 1.0 Hz/s relay threshold at $t = 1.2$ s) and lowest frequency nadir of 49.1 Hz. When VSG control was turned-on all 75 turbines ($H_{virtual} = 4$ s per turbine, total VSG contribution equivalent to $H_{VSG_farm} = 0.8$ s system-wide), RoCoF decreased to 1.1 Hz/s and frequency nadir increased to 49.5 Hz - a 0.4 Hz improvement that avoided the initial stage of automatic load shedding (set at 49.2 Hz in this system).

The secondary frequency dip, which was due to the recovery of rotor speed following release of kinetic energy, was a minimum of 49.35 Hz at $t = 38$ s when MPC was not optimized, and 49.68 Hz when MPC was optimized - confirming the value of the coupled VSG-MPC method described in Section 8.3.

9.4 Mechanical Disturbance — Extreme Gust Response

An Extreme Operating Gust (EDOG) which is characterized by IEC 61400-1 (wind speed step of 11 m/s to 23 m/s within 10-s) was simulated with and without active damping control. The

Activation of the crowbar with typical vector control is inevitable with or without RSC current limiting, and thus confirms the importance of more advanced MPC or SDBR strategies. Advanced converter control is capable of operating RSC without crowbar at $0.2 \leq V_r \leq 0.5$ pu. In the case of $V_r > 0.5$ pu, all strategies will ensure the continuity of RSC operation, with reactive injection of the current starting in 10-15 ms.

aerodynamic torque overshoot caused a shaft torsional oscillation at the natural frequency ($\omega_n = 0.29$ Hz) which appeared as active power oscillations of 8 MW in each direction at the PCC. A proportional-derivative (PD) active power-damping controller, where rotor speed derivative was the input signal, cut the amplitude of the oscillations by 65% and cut settling time by a factor of 22 s to 9 s.

9.5 Asymmetrical Fault — Negative Sequence Analysis

In the SLG fault case, negative-sequence stator voltage components cause a twice-power-frequency oscillation (100 Hz in 50 Hz systems) of the electromagnetic torque of the DFIG. In the RSC, without negative-sequence current control, the torque oscillations between peaks were 0.4 pu in magnitude - sufficient to induce severe fatigue in the drivetrain during a service life with multiple fault events. A dual synchronous reference frame (DSRF) controller with both positive and negative sequence dq operation minimized the torque oscillation to 0.05 pu while slightly decreasing the average reactive current injection (0.71 pu to 0.65 pu) with the common RSC bandwidth. The performance trade-off between reactive current injection performance and reduction of torque ripple when faulting asymmetries occurs is an open optimization problem [43].

Table 7. Summary of Key Simulation Results vs. Grid Code Requirements. Assessment against applicable grid code and standard requirements. VSG = Virtual Synchronous Generator with MPC-based current control.

Performance Indicator	Grid Code Requirement	Achieved (VSG+MPC)	Assessment
Reactive current injection time (post-fault start)	< 30 ms (ENTSO-E)	5–8 ms	PASS ✓
Reactive current magnitude (0.0 pu sag)	≥ 1.0 pu	1.02 pu	PASS ✓
Peak rotor current (crowbar activated)	< 2.0 pu (converter limit)	1.1 pu	PASS ✓
DC-link overvoltage (3ph sag, 0.0 pu)	< +10% V_{dc_rated}	+2.1%	PASS ✓
Voltage recovery to 0.9 pu (150 ms fault)	< 500 ms (most codes)	284 ms	PASS ✓
RoCoF at 60% wind (500 MW loss)	< 1.0 Hz/s	1.1 Hz/s (no VSG), 0.7 Hz/s (VSG)	FAIL w/o VSG PASS w/ VSG
Frequency nadir (500 MW loss, 60% wind)	> 49.2 Hz (load shedding threshold)	49.5 Hz (VSG)	PASS ✓
Torsional oscillation (EOG without damping)	< $\pm 5\%$ P_{rated}	$\pm 3.5\%$ (with PD damper)	PASS ✓
Torque ripple — SLG fault (DSRF control)	< 0.1 pu (IEC 61400-21)	0.05 pu	PASS ✓

9.6 Sub-Synchronous Resonance — Screening Analysis

To identify potential SSR risk with a hypothetical series compensation on the 132 kV transmission line (30 percent) a simplified frequency scan of the impedance of the studied wind farm at the 132 kV bus was conducted. The impedance scan showed a resonance at 18.4 Hz (system frequency: 50 Hz, complementary frequency: $50 - 18.4 = 31.6$ Hz) which is the natural torsional mode of the DFIG drive train at 31.2 Hz. The fact that resonance at 31.6 Hz and torsional mode resonance at 31.2 Hz are very close (31.6 Hz - 31.2 Hz) points to the possibility of control-system SSR (CSSIR) or induction generator effect (SSIGE). Simulations in the time domain confirmed the undamped torque oscillations growing at a rate of about 0.3 pu/s with series compensation of 30 percent, but only leveled off to stable operation when series compensation had decreased to less than 15 percent. These findings highlight the significance of SSR screening when planning series-compensated export connections of wind farms - a problem that has led to damage of actual turbines in Texas and Minnesota in reality [18].

10. Conclusion

The paper has shown a detailed study of the behavior of wind turbine system in a wide range of both grid and mechanical disturbances. The main results and contributions can be summarized as follows:

1. Disturbance Taxonomy: A common classification of disturbances - voltage (symmetrical and asymmetrical), frequency, mechanical, electromagnetic and islanding - was created with characteristic parameters and reference

standards in order to have a systematic framework to analyses wind turbine disturbance.

2. LVRT Physics and Control: The mathematical analysis of the electromagnetic process of rotor over-current in DFIG machines during deep voltage sags was undertaken. Crowbar protection is commonly used but sophisticated methods SDBR, FS-MPC and VSG+MPC can cut peak rotor current by 20-45 percent and inject reactive current faster by up to an order of magnitude. The VSG+MPC approach was 47% times faster at voltage recovery than the baseline crowbar, and exceeded the requirements of ENTSO-E by a wide margin.
3. Frequency Response: The system under study with 60% of wind penetration did not reach 1.0 Hz/s RoCoF limit after losing 500 MW of generation. This was corrected by VSG enabled turbines ($H_{virtual} = 4$ s) which enhanced frequency nadir by 0.4 Hz and eliminated automatic load shedding. The coupled MPC recovery controller decreased the dip in frequency of the second frequency by 0.15 Hz to 0.02 Hz.
4. Protection Coordination: The non-classical fault current contribution of DFIG turbines (especially its reactive current injection during LVRT) was demonstrated to result in under-reach of distance relays by 15-25% on 132 kV feeders. Adaptive relay settings and directional overcurrent protection are recommended for wind farm collector systems.
5. SSSR Risk: The screening analysis revealed a critical SSR risk of above 15% series compensation on the

studied 132 kV export line. Wind farm interconnection Series compensation planning should incorporate SSR frequency scan analysis, and in case risk is proven, SSR countermeasures as SSR damping controllers or SSR countermeasures in the form of SSR static synchronous controllers (STATCOMs).

6. Model Validation: DIGSILENT PowerFactory simulation model was validated to field measurements of a 150 MW wind-farm, with discrepancies of less than 8 percent reactive power, and ± 5 percent voltage recover trajectory - adequate accuracy in the context of protection coordination and grid code compliance study.

10.1 Future Research Directions

A number of issues are yet to be explored. Black-start capability of converter-dominated power system, including the capacity of large offshore wind farms to energize dead network segments, is under-characterized with multi-turbine arrays with complicated inner-cluster impedance interactions. The dynamics of the aggregated VSG controllers in large offshore wind farms interacting with the HVDC link dynamics have not been studied to its fullest, and this can introduce limitations in the stability that limit the degree of virtual inertia that can be achieved. Real-time adaptive protection relay settings based on machine learning techniques to consider the operating state of wind farms is a promising, yet challenging field at the intersection of power systems protection and artificial intelligence. Lastly, the impact of wake-induced turbulence in dense offshore wind farm arrays on the accumulation of fatigue in the drive train components during prolonged grid disturbance events needs to be investigated further with high-fidelity fluid dynamics in combination with structural and electrical models.

With the world moving to close to 100% renewable electricity systems, the results of this study highlight that wind turbines will need to be developed as active rather than passive energy converters that can offer all the stability services that were previously offered by synchronous generators. The control and protection measures devised and tested here form a viable basis to this transition, pending further field validation and harmonization of regulations between international grid code systems.

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