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C2 Power system operation and control
PS2 Maintaining operational reliability through flexibility**Strategies for Inertia Assessment and Provision in Power Systems
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The global power sector is undergoing a profound transformation driven by decarbonization targets and the rapid expansion of renewable energy sources. The increasing replacement of large synchronous generators by Inverter-Based Resources (IBRs) has significantly reduced system inertia and altered frequency dynamics, introducing new operational challenges for System Operators (SOs). In low-inertia power systems, frequency deviations occur faster and with a higher Rate of Change of Frequency (RoCoF), reducing the available time for corrective actions and increasing the risk of widespread disturbances [1], [2]. At the same time, the dynamic behavior of IBRs differs fundamentally from that of synchronous machines, motivating the expansion of classical power system stability classifications to include converter-driven and resonance-related phenomena [3], [4]. Several real-world events highlight the need for new operational frameworks [5]–[8]. This paper proposes an integrated framework for inertia assessment and provision, combining analyses of real-world low-inertia disturbances, a structured review of inertia assessment methodologies, evaluations of technological solutions for inertia provision, and discussions of ancillary service mechanisms and market designs. By bridging scientific advances and operational practice, the proposed framework supports the development of secure, resilient, and sustainable power system capable of maintaining frequency stability in converter-dominated grids.

KEYWORDS

Inverter-based resources, Fast frequency response, Synthetic inertia, Grid-forming converters, Ancillary services; Frequency stability; Wide-Area Monitoring.

1 Introduction

The global power sector is undergoing a transformative transition driven by sustainability targets and the rapid expansion of Renewable Energy Sources (RES) [1], [2]. The recent global climate discussions at the COP30 conference, held in Brazil in November 2025, reaffirmed the international commitment to clean and renewable energy as a central pillar of decarbonization strategies. This evolving context underscores the urgency of preparing electric power systems for high penetration of IBRs, whose reduced inherent inertia demands new approaches to control, monitoring, and stability provision. As synchronous machines are progressively replaced by geographically dispersed IBRs, power system dynamics are being reshaped, resulting in increased operational uncertainty, reduced inertia, and new layers of complexity across multiple stability domains [3]. Although voltage stability, converter-driven stability, and resonance-related phenomena are increasingly crucial in IBR-dominated grids, this paper focuses primarily on the challenges associated with frequency stability. The shift toward low-inertia operation has increased the occurrence of complex perturbations and reduced overall grid flexibility. Conventional power systems relied on the inherent rotational inertia of synchronous machines and on the programmability of large generating units to maintain frequency stability. In contrast, modern systems must rely on heterogeneous, distributed renewable units whose contributions to frequency control arise from advanced converter control strategies rather than from inherent physical properties. Therefore, achieving frequency stability in converter-dominated systems requires new methodologies, enhanced situational awareness, and tools capable of capturing fast and coupled dynamic interactions. The increasing integration of distributed and IBRs must therefore be accompanied by enhanced monitoring technologies, improved situational awareness, and advanced decision-support tools for SOs, including Wide-Area Monitoring, Protection, and Control Systems (WAMPACS) [9]. Ensuring secure and reliable operation now requires a coordinated approach to frequency control, voltage regulation, and overall system resilience. Renewable energy sources, distributed generation, and demand response introduce new dynamics into stability assessment; when properly monitored and characterized, they can support system operation, but when insufficiently mapped, weakly coordinated, or poorly understood, they introduce uncertainties that may degrade situational awareness and compromise secure operation. The operational landscape is further challenged by the need to coordinate multiple heterogeneous energy assets—ranging from distributed renewable resources to storage systems and flexible loads—to maintain stability amid fluctuating generation patterns and evolving transmission constraints. This requires that, in addition to SOs adopting new methods for inertia assessment and estimation, technologies capable of providing fast and effective frequency support be available, and that market mechanisms for inertia-related services suitable for converter-dominated power systems be used. In this context, comprehensive frameworks are needed to bridge the gap between scientific advancements and operational requirements. Accordingly, this paper proposes an integrated approach structured around three key dimensions. A review of real-world low-inertia disturbances to derive practical insights into instability mechanisms. Advanced inertia estimation techniques—both offline and online—can capture the dynamic behavior of RES-rich systems. Evaluation of technological solutions for inertia provision, including synchronous, synthetic, and hybrid sources, and the development of ancillary service mechanisms that align market incentives with system stability needs. By combining these three dimensions within a unified framework, the paper aims to contribute to the secure, resilient, and sustainable operation of power systems that can withstand the challenges posed by the global energy transition. This paper is structured as follows: Session 2 presents the role of inertia in modern power systems; Session 3 presents methodologies for assessing inertia; Session 4 presents strategies for providing inertia; and Session 5 presents the conclusions.

2 The Role of Inertia in Modern Power Systems

Inertia plays a fundamental role in power system frequency dynamics by providing an immediate, inherent, and passive response to active power imbalances, acting in the first instant after a disturbance and before any control or protection mechanisms are activated. In conventional power systems dominated by synchronous generators, rotational inertia stored in turbine-generator shafts acts as the first line of defence following disturbances such as generation outages or sudden load changes, inherently opposing rapid variations in system frequency through electromechanical coupling. This inertial response limits the initial Rate of Change of Frequency (RoCoF), mitigates the depth of frequency excursions, and provides sufficient time for primary frequency control mechanisms—such as governor action and droop response—to activate and restore the system frequency toward acceptable operating limits [1], [2], [11]. From a physical perspective, system inertia is directly associated with the kinetic energy stored in rotating masses electrically coupled to the grid, which is released or absorbed as frequency deviates from its nominal value. Consequently, the aggregated inertia level strongly influences the initial frequency trajectory immediately following a disturbance and affects key stability metrics, including RoCoF, frequency nadir or zenith, frequency recovery time, and the likelihood of protection thresholds being reached [12]. Historically, high inertia levels ensured robust and predictable system behaviour, allowing interconnected power systems to withstand relatively large disturbances without compromising secure operation, triggering under-frequency load shedding, or causing cascading outages. However, the increasing penetration of IBRs—such as wind power plants, photovoltaic systems, and battery energy storage systems—has fundamentally altered this paradigm. Converter-interfaced generation is decoupled from grid frequency through power-electronic control systems and therefore does not inherently contribute rotational inertia to the system. As synchronous generation is progressively displaced, the total kinetic energy available in the system decreases, leading to faster frequency excursions, higher RoCoF values, increased sensitivity to disturbances, and reduced stability margins under both normal operation and contingency conditions. These effects are particularly pronounced in weak grids, low short-circuit ratio environments, and islanded or lightly interconnected systems. Beyond frequency-related impacts, the large-scale integration of IBRs has introduced additional stability challenges arising from their fundamentally different dynamic behaviour compared to conventional synchronous machines. These include fast control interactions, reduced natural damping, and the potential excitation of network resonances across a wide range of frequencies. As a result, the traditional stability concepts developed for synchronous-machine-dominated systems are no longer sufficient to fully characterize system behaviour. This evolution has motivated expanding the classical power system stability framework into a more comprehensive classification better suited to converter-dominated systems. Recently, aligned stability definitions developed by IEEE and CIGRE explicitly recognize, in addition to rotor angle, frequency, and voltage stability, other new classes such as converter-driven stability, resonance (electrical resonance), and DC-side voltage and transient stability, with further subcategories defined according to the relevant time scales and frequency ranges [3], [4]. Figure 1 summarizes the extended stability classification and highlights its main subtypes, with emphasis on converter-driven stability, including fast and slow interaction phenomena and resonance stability. This classification reflects the increasingly significant role of power-electronic inverters in power system dynamic stability and their interactions with the conventional legacy system dominated by synchronous generation, requiring a comprehensive understanding of both power electronics and traditional power system dynamics for engineers involved in system planning, power system studies, operation, protection, and control activities.

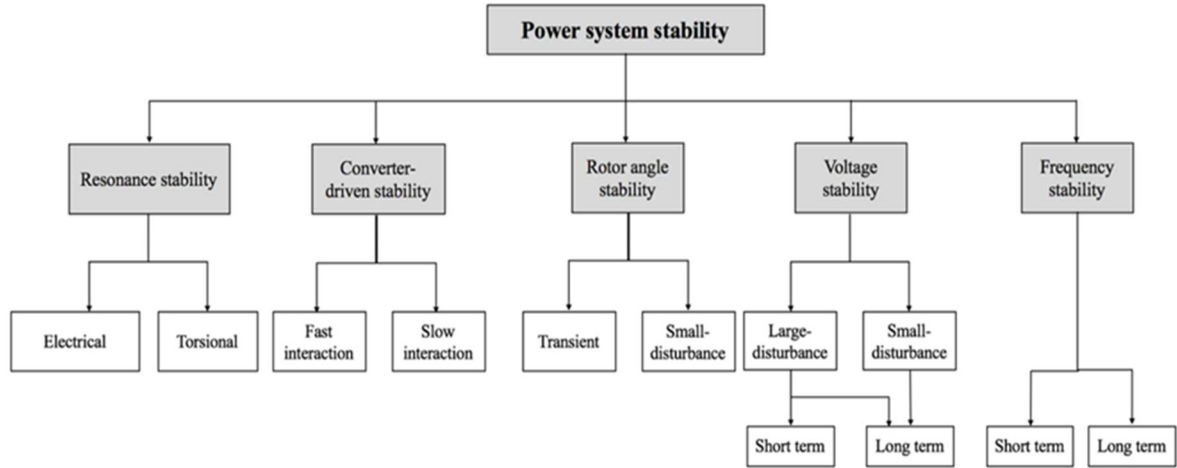


Figure 1 - Classification of power system stability phenomena in converter-dominated systems [3].

The practical relevance of this expanded stability framework has been reinforced by several real-world disturbances observed in power systems operating under high shares of non-synchronous generation, low-inertia conditions, and strong interactions among converter controls, protection systems, and network dynamics. A representative example was the 8 January 2021 separation of the Continental Europe synchronous area, which split the system into two asynchronous regions and resulted in significant frequency deviations, illustrating the sensitivity of large interconnected systems to cascading transmission events under stressed operating conditions [5]. Similarly, in Great Britain, the 9 August 2019 disturbance combined a transmission fault with the near-simultaneous loss of large generating units, causing frequency to fall sufficiently to trigger Low Frequency Demand Disconnection (LFDD) schemes and resulting in widespread customer interruptions [6]. Converter-dominated grids have also experienced events in which IBR control and protection behaviour played a central role. In Australia, the 28 September 2016 South Australia “black system” event demonstrated how severe weather, multiple transmission faults, and generator disconnections contributed to a system-wide collapse under limited interconnection strength, underscoring the need for coordinated protection schemes and dynamic response capabilities [7]. In North America, the February 2021 cold-weather event in Texas (ERCOT) demonstrated how the large-scale unavailability of generation can push system frequency close to critical thresholds, underscoring the importance of adequate frequency response and operational preparedness under extreme conditions [8]. More recently, the 28 April 2025 Iberian Peninsula blackout (Spain–Portugal) has become emblematic in the energy transition debate; official ENTSO-E analyses stress that the event must be interpreted through a multi-domain stability lens, where voltage dynamics, reactive power capability, protection coordination, and system conditions jointly shaped the outcome, rather than frequency behaviour alone [9]. Beyond large disturbance-driven frequency drops, power systems with high penetration of inverter-based and distributed generation are increasingly exposed to critical operating conditions under extremely low net-load scenarios. On 10 August 2025, during the Father’s Day holiday in Brazil, the Brazilian System Operator (ONS) recorded the lowest historical net-load value in the Brazilian Interconnected Power System (BIPS), reaching 35,306 MW, a reduction of 3,235 MW compared to the previous minimum observed in July 2025. On that day, for the first time, ONS determined to fully curtail wind and photovoltaic generation under its operational control. Thermal power plants were operating at minimum output levels due to inflexibility and unit commitment constraints, while limited hydropower reserves remained available, requiring a controlled hydropower ramp to supply the subsequent evening load increase.

This event highlighted the emerging risk of loss of frequency controllability under minimum-load conditions driven by the accelerated growth of inverter-based and distributed generation. While the future connection of energy-intensive loads, such as data centers and green hydrogen facilities, may partially rebalance generation and demand, additional operational flexibility measures are required. These include energy storage deployment, fast-start and flexible thermal generation, coordinated control of Type III and distributed generation within the evolving Distribution System Operator (DSO) framework, and increased flexibility in hydropower and thermal operating constraints. At the same time, extreme reductions in centralized synchronous generation may result in very low inertia levels, thereby increasing susceptibility to frequency deviations and sustained overfrequency. In response, ONS is implementing the Regional Generation Shedding Scheme (ERAG), a protection mechanism analogous to underfrequency load shedding, designed to mitigate overfrequency conditions through controlled generation curtailment. At the same time, the transition toward converter-dominated power systems creates new opportunities for stability support. Advanced control strategies implemented in IBRs—such as synthetic inertia, virtual synchronous machines, and grid-forming control—can partially compensate for the loss of synchronous inertia and improve frequency behaviour. However, unlike physical inertia, these contributions are control-dependent, constrained by energy availability, and sensitive to measurement accuracy and coordination among multiple assets. Consequently, inertia can no longer be treated as a static parameter derived solely from generator data. Instead, it must be understood as a dynamic, system-wide attribute influenced by operating conditions, control strategies, network topology, and the interaction between synchronous and non-synchronous resources. This evolution highlights the need for advanced methodologies for inertia assessment, enhanced situational awareness, and coordinated operational strategies—topics addressed in the following section.

3 Inertia Assessment Methodologies

System inertia is a key indicator of frequency robustness in synchronous power systems, as it governs the initial frequency trajectory following active-power imbalances. Physically, inertia is associated with the kinetic energy stored in rotating masses coupled to the grid. For a given synchronous machine i , kinetic energy can be expressed as:

$$E_i = \frac{1}{2} * J_i \omega_m^2 \quad (1)$$

Where: J_i is the combined moment of inertia, and ω_m is the mechanical angular speed. A normalized representation widely used in power systems is the constant inertia:

$$H_i = \frac{E_i}{S_{n_i}} = \frac{J_i \omega_m^2}{2S_{n_i}} \quad (2)$$

Where: S_{n_i} is the rated apparent power of the unit.

These relationships underpin most inertia assessment approaches, ranging from model-based aggregation to measurement-based estimation and data-driven techniques [11].

3.1 Classification of inertia assessment approaches

Inertia assessment methods can be categorized in different ways (e.g., by data source, excitation type, or timescale). In this paper, we classify methodologies into five main groups: (i) synchronized-machine aggregation (SMM), (ii) disturbance-based (DBM), (iii) ambient-data-

based (ADM), (iv) probing-signal-based (PSM), and (v) artificial intelligence/machine learning based (AIM), including hybrid combinations (e.g., DBM+AI, ADM+AI, PSM+AI). This classification aligns with the growing operational need to estimate not only “synchronous inertia”, but also effective inertia contributions from load behavior and control-based fast frequency response.

3.1.1 Synchronized-machine aggregation methods (SMM)

SMM approaches compute inertia by aggregating the inertia constants of synchronized units connected to the transmission system, typically using SCADA/EMS information (breaker status, dispatch, unit parameters). A commonly used formulation is:

$$H_s = \sum_{i=1}^N S_{ni} H_i \quad (3)$$

Where : S_{ni} is the nominal power of i -th generator unit [VA] e H_i is inertia constant of the i -th machine [s].

This approach is widely adopted because it is simple, transparent, and easy to implement, and it provides a conservative estimate of inertia when contributions from loads and non-synchronous resources are excluded. For example, the Continental Europe TSOs have documented a continuous monitoring approach focused on inertia provided by synchronous generators as a practical operational indicator [13]. The Brazilian System Operator (ONS) has been evolving its operational toolset to enhance real-time observability of inertia and related stability margins, including initiatives and roadmaps to improve monitoring capabilities and integrate measurement-based approaches [14]. The current ONS real-time inertia monitoring system (SYNertia) calculates synchronized inertia by combining SCADA data with dynamic data from operating electrical machines. The obtained values parameterize the system security level based on the results of contingency simulations and the severity of impacts on the operation of the Brazilian Interconnected Power System (BIPS). To do it more broadly, the SYNertia needs to be complemented by PMU/WAMS-based estimation to capture effective inertia (including load effects and control-based responses) and to validate assumptions about the online generation mix. Strengths of SMM: straightforward implementation, low computational burden, easy explainability for control-room use. Limitations of SMM: does not inherently capture synthetic/virtual inertia from IBR controls, HVDC dynamics, or load-inertia-like behavior; accuracy depends on the quality of parameters and the observability of all relevant resources.

3.1.2 Disturbance-based methods (DBM)

Disturbance-based inertia estimation exploits the initial system frequency response following a significant contingency (e.g., a generator trip, HVDC blocking, or significant load rejection). In the first instants following the event, primary controls are often assumed not yet dominant, allowing a simplified swing-equation relationship between power imbalance and RoCoF:

$$\frac{df}{dt} = \frac{f_0}{2HS_{base}} (P_m - P_e) \quad (4)$$

In initial moments, only P_e varies; P_m is considered constant, rearranging the Equation (4).

$$H_{eq} = \frac{f_0 \Delta P}{2S_{base} (df/dt)} \quad (5)$$

Where: f_0 = rated frequency (60Hz), ΔP = mismatch of power (MW) and df/dt = RoCoF, and ΔP is the net active-power imbalance and df/dt is the initial RoCoF estimated from frequency measurements.

In practice, DBM implementations follow a sequence: (i) event detection (SCADA/PMU), (ii) selection of a short analysis window (typically within ~ 0.5 – 2 s), (iii) robust RoCoF estimation (often requiring filtering/smoothing), (iv) estimation of ΔP from operational measurements, and (v) computation of H_{eq} , possibly with spatial aggregation from multiple PMUs. Because RoCoF estimation is highly sensitive to noise, smoothing techniques, such as Savitzky–Golay filtering, are commonly used in signal-processing pipelines to stabilize numerical differentiation. DBM refinements use estimation theory, such as Extended Kalman-filter (EKF) based approaches, to improve robustness to noisy measurements when estimating inertia. However, EKF-based methods may be sensitive to the assumed disturbance timing, motivating careful event detection and initialization strategies. Disturbance-based estimation has also been combined with identification models and probabilistic frameworks, including ARIMA/ARMAX [15] approaches and Bayesian inference to quantify uncertainty, particularly useful when system conditions vary rapidly, and measurements are imperfect. Strengths of DBM: conceptually simple; uses actual system events; supports post-event forensics and (with PMUs) regional inertia inference. Limitations of DBM: sensitive to measurement noise and to event characterization; depends on clear identification of ΔP and on selecting a window before primary control dominates; performance can degrade with overlapping events or complex IBR control/protection behavior.

3.1.3 Ambient-data-based methods (ADM)

Ambient data-based methods estimate inertia continuously by leveraging small natural fluctuations during regular operation (e.g., load variations, stochastic behavior of renewable sources, and low-amplitude frequency dynamics). Compared to DBM, ADM does not require significant events and is attractive for real-time monitoring in highly reliable systems where contingencies are rare. Recent literature emphasizes that inertia in low-inertia grids is time-varying and that continuous estimation/forecasting is increasingly essential for operational decision support. Data-driven ambient methods include frequency-gradient techniques for time-dependent inertia estimation. Another prominent direction is frequency-response-function tracking using PMU ambient measurements, enabling online estimation of both synchronous inertia and “virtual inertia” behavior in converter-based resources. Strengths of ADM: continuous estimation; non-intrusive; suitable for control-room situational awareness when supported by PMU/WAMS. Limitations of ADM: low signal-to-noise ratio; interactions with primary control and other dynamics may mask inertial signatures; results may require careful calibration across operating points.

3.1.4 Probing-signal-based methods (PSM)

PSM methods are active approaches: a small, controlled perturbation is deliberately injected into the system (e.g., via a Battery Energy Storage System (BESS), controllable load, or grid-forming converter control), and the measured response is used to identify inertial parameters. Because the excitation is designed, PSM can improve identifiability compared to ambient methods and avoid waiting for major events. In practice, PSM requires: (i) safe perturbation design (small amplitude, limited duration), (ii) synchronized high-resolution measurement (PMUs), and (iii) an identification/estimation algorithm to infer inertia (and potentially damping) from the response. PSM is particularly valuable for validating control-based inertia provision and calibrating models in experimental settings. Strengths of PSM: high repeatability;

improved identifiability; supports validation and commissioning. Limitations of PSM: require controllable resources and operational authorization; must ensure the injected signal does not trigger protections or adverse control interactions.

3.1.5 AI/ML-based methods (AIM) and hybrid frameworks

AI/ML approaches are increasingly applied to inertia estimation and forecasting, leveraging large volumes of operational data (PMU/WAMS, SCADA/EMS, dispatch, weather, and network states). From an operator's perspective, CIGRÉ has explicitly recognized the growing role of ML/AI in power system operation and control, including decision-support applications that can complement classical physics-based methods. In inertia assessment, ML models can learn nonlinear mappings between features (e.g., frequency, RoCoF, nadir/zenith, power flows, renewable output patterns) and inertia indicators, enabling real-time estimation and short-term forecasting. Hybrid schemes are particularly promising: ML can enhance ADM (improved event detection and noise robustness), strengthen ADM (by extracting weak signatures from ambient data), and support PSM (by mapping-controlled responses to parameter estimates). A critical requirement is rigorous validation across operating conditions, transparency in uncertainty, and governance aligned with TSO operational practices. Strengths of AIM: excel at processing vast amounts of WAMS/PMU [16] data to identify non-linear patterns and provide accurate real-time inertia estimations and forecasts. By mapping complex relationships between variables such as frequency, RoCoF, and power dispatch. Hybrid AI approaches can refine existing estimation methods, significantly improving robustness to measure noise and overall computational efficiency. Limitations of AIM: high reliance on high-quality labeled data, which is often restricted by confidentiality or a lack of precise ground-truth inertia values for training. Real power systems are non-stationary, meaning models trained in specific scenarios may fail to generalize effectively to changing topologies or dispatch patterns. Table 1 shows an overview of inertia assessment methodologies in modern power systems.

Table 1 - Overview of inertia assessment methodologies in modern power systems

Method	Main inputs	Main outputs	Strengths	Limitations	Typical operational use
MMS – Synchronized Machine Summation	SCADA/EMS unit status, generator parameters ($H_i^{(1)}$, $S_{ni}^{(2)}$)	System or area synchronous inertia, kinetic energy (GW·s)	Simple, transparent, low computational burden	Does not capture synthetic inertia or load contribution	ONS (Brazil), ENTSO-E members, AEMO, ERCOT, EirGrid/SONI
MGD – Large Disturbance-Based	PMU/WAMS frequency & RoCoF, ΔP , event detection	Equivalent system or regional inertia	Physics-based, intuitive, real-event driven	Sensitive to noise and event clarity	Post-event analysis (Europe, GB, Australia, North America)
MDA – Ambient Data-Based	PMU/WAMS ambient signals, operational data	Continuous time-varying inertia	Works without major disturbances	Low signal-to-noise ratio	Pilot continuous monitoring tools
MSP – Probing Signal-Based	Controlled power/frequency injections, PMUs	Inertia and damping parameters	High precision and repeatability	Operational constraints and coordination	England, Australia, Japan
MIA – AI/ML-Based	PMU, SCADA, dispatch, topology, weather	Real-time inertia estimate or forecast	Captures nonlinearities, data fusion	Requires high-quality labeled data	Advanced decision-support systems

(1) H_i = inertia constant of the i -th synchronous machine; (2) S_{ni} = rated apparent power of the i -th synchronous machine.

4 Technologies and Strategies for Inertia Provision in Modern Power Systems

Historically, inertia in synchronous power systems has been inherently provided by rotating masses electrically coupled to the grid, including synchronous generators, synchronous condensers, and large industrial motors and drives. As power systems decarbonize and integrate growing shares of wind and Photovoltaic (PV) generation, High-Voltage Direct Current (HVDC) links, BESS, and other converter-interfaced resources (IBRs), frequency dynamics are increasingly shaped by control actions rather than by inherent electromechanical properties. Consequently, inertia adequacy must be addressed through a combination of (i) traditional synchronous inertia sources, (ii) Fast Frequency Response (FFR) and inertia-like controls from IBRs, and (iii) operational and planning measures that reduce exposure to high-impact contingencies.

4.1 System-level operational and planning strategies

Beyond asset-level solutions, system operators can reduce the risk of severe frequency events by addressing the largest credible contingencies and adopting network configurations that mitigate separation risks. In the BIPS, reinforcing transmission corridors interconnecting the Northeast subsystem—characterized by high wind and PV penetration—with other regions has increased transfer capability while reducing the likelihood of regional islanding under stressed operating conditions. In parallel, an approach already adopted in systems such as those in Australia and Great Britain, operational rules increasingly leverage real-time inertia indicators to trigger preventive constraints or activate fast-response support services when inertia falls below critical thresholds.

4.2 Synchronous-based inertia sources

Synchronous generators remain the most robust and predictable providers of inertial response in power systems. Their contribution is determined by the kinetic energy stored in rotating masses. It is typically characterized by the inertia constant H . Importantly, the inertial response is not directly linked to the dispatched active power level, but rather to the machine inertia constant and the rated apparent power. As a result, minimum inertia performance requirements have been proposed as a criterion for integrating new synchronous units into systems. Synchronous motors and large rotating loads may also provide a non-negligible contribution to total system inertia, even when connected on the demand side. Accounting for demand-side inertia improves the realism of inertia adequacy assessments and may reduce overly conservative operational actions in systems with high renewable penetration. Synchronous Condensers (SCs) are primarily deployed to provide dynamic reactive power support and system strength but also supply genuine electromechanical inertia. In areas with high IBR penetration, SCs can be specified not only for reactive capability but also for inertia requirements. Several manufacturers offer configurations in which flywheels are mechanically coupled to SCs, significantly increasing their inertial contribution and enhancing frequency robustness.

4.3 Converter-based fast frequency response

Wind power plants, PV plants, BESS, HVDC converters, and controllable loads are connected to the grid through power electronic interfaces and do not inherently provide rotational inertia. Nevertheless, they can support frequency stability through FFR, defined as rapid active power modulation in response to frequency deviations. The term “synthetic inertia” has been widely used to describe a subset of FFR controls, typically based on RoCoF-proportional active power

injection that emulates synchronous inertial behavior. In this paper, synthetic inertia is therefore treated as a specific implementation within the broader class of FFR services. The converter-based frequency support is control-dependent and has energy-limited. The design of them needs to have care to: (i) available energy buffers (e.g., wind turbine rotor kinetic energy, PV and BESS state-of-charge), (ii) measurement accuracy and filtering delays affecting frequency and RoCoF estimation, and (iii) coordination among multiple assets to avoid adverse interactions and oscillatory behavior.

4.4 VSC technology and the role of control: GFL versus GFM and Hybrid Converter Control

Voltage Source Converters (VSCs) dominate modern grid interfaces due to their fast and decoupled control of active and reactive power. Unlike synchronous machines, the energy stored in a VSC is primarily associated with the DC-link capacitor, resulting in an equivalent energy time constant typically on the order of a few tens of milliseconds. Grid-following (GFL) control remains the dominant paradigm for wind and PV plants currently connected to transmission systems. GFL converters behave as controlled current sources synchronized to the grid via a phase-locked loop (PLL), with cascaded current and power control loops. While additional control loops can provide frequency support, the overall dynamic response is influenced by PLL behavior and internal control delays, which may limit performance in weak-grid conditions. Grid-forming (GFM) control strategies, including droop-based control and Virtual Synchronous Machine (VSM) concepts, aim to establish local voltage and frequency references. By avoiding PLL-based synchronization, GFM converters can provide faster, more robust frequency response and are particularly suitable for weak, converter-dominated systems. Although their academic maturity is high, large-scale deployment is still progressing, supported by pilot projects [17]. However, neither GFL nor GFM, when applied in isolation, fully satisfies the combined requirements of modern power systems, which include accurate power tracking under Maximum Power Point Tracking (MPPT) operation, robust synchronization, effective frequency support, and stable operation across a wide range of grid strengths. This limitation has motivated the development of hybrid control strategies that combine the characteristics of GFL and GFM. Proposed approaches include parallel control architectures in which GFL and GFM controllers operate simultaneously [18], mode-switching schemes that transition between GFL and GFM based on grid conditions [19], and adaptive blending strategies that weight control contributions based on estimated grid strength [20]. These hybrid solutions are emerging for future systems that must simultaneously provide energy, stability, and flexibility.

4.5 Applied ancillary service and market perspective

As power systems become increasingly converter-dominated and inertia grows scarcer, inertia shifts from an inherent passive property of the system to an actively managed service provided by its operators. Ancillary services provide the procurement mechanisms needed to secure frequency stability across time scales, ranging from immediate inertial and FFR responses to primary, secondary, and tertiary reserve responses. Systems such as Dynamic Containment in Great Britain and Very Fast Frequency Control Ancillary Services (VF-FCAS) in Australia have been providing fast frequency response. In Brazil, inertia monitoring and evolving grid code requirements provide the foundation for a future framework that balances minimum performance obligations and market-based procurement. Table 2 presents a comparative analysis of inertia-provision technologies and strategies (indicative).

Table 2 - Applied comparison of inertia provision technologies and strategies (indicative).

Technology / Strategy	Mechanism	Typical activation	Typical delivery	Energy source / buffer	Key constraints	Operational notes
Synchronous generators	Natural inertial response	Immediate	Seconds	Rotor kinetic energy	Depends on synchronous commitment	Robust; well understood
Synchronous condensers (SC)	Natural inertia + reactive power + system strength	Immediate	Seconds	Rotor kinetic energy	CAPEX/OPEX; siting and integration	Supports voltage & short-circuit level; inertia
SC + flywheel	Enhanced natural inertia	Immediate	Seconds	Increased rotating mass	Mechanical integration; cost/space	Useful in weak/IBR-dominated areas
Demand-side inertia	Rotating load natural inertia	Immediate	Seconds	Rotor kinetic energy	Observability and uncertainty	Can reduce conservatism if quantified
Wind (synthetic inertia / FFR)	Temporary ΔP from rotor kinetic energy and/or control	<1–2 s	$\approx 5\text{--}10$ s (typ.)	Turbine rotor kinetic	Recovery period; impacts on MPPT	Requires careful tuning to avoid oscillations
PV (FFR via headroom)	Fast ΔP using curtailed headroom	<1–2 s	Seconds–minutes	Curtailed margin	Opportunity cost; irradiation variability	Requires careful tuning to avoid oscillations
BESS (FFR)	Fast power injection/absorption	<1 s	Seconds–minutes	Battery State of Charge (SoC)	Energy limits; cycling	High precision; very fast products
GFL converters + add-on loops	Supplementary frequency control on current-forming plant	<1–2 s	Seconds	Depends on asset type	PLL dynamics; weak-grid limitations	Common in existing fleets

5 Conclusion

The transition toward power systems with high shares of inverter-based renewable generation fundamentally changes the nature of frequency stability and the role of inertia. Inertia can no longer be regarded as a static property derived solely from synchronous machine data, but rather as a dynamic, system-wide attribute influenced by operating conditions, control strategies, network topology, and the interaction between synchronous and non-synchronous resources. The analysis of real-world disturbances confirms that low-inertia conditions amplify system vulnerability and that frequency stability must be addressed within a broader multi-domain stability framework. Accurate inertia assessment is therefore a prerequisite for informed operational decision-making. Measurement-based, model-based, and data-driven methods each provide complementary insights, and their coordinated use enhances situational awareness for system operators. From a technological perspective, no single solution can fully replace the inertia historically provided by synchronous generation. Instead, a portfolio approach combining synchronous machines, synchronous condensers, fast frequency response from inverter-based resources, and emerging grid-forming and hybrid control strategies is required. Ancillary service mechanisms and market designs play a key role in translating these technical needs into effective incentives, enabling new technologies—particularly battery energy storage systems—to support system stability. Overall, the integrated framework presented in this paper bridges the gap between advanced research and operational practice, supporting SOs in managing frequency stability under high renewable penetration and contributing to the development of secure, resilient, and sustainable power systems.

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