ELECTRIC POWER
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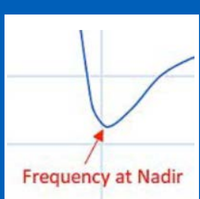
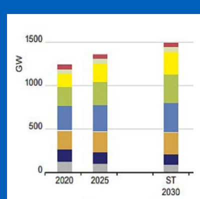
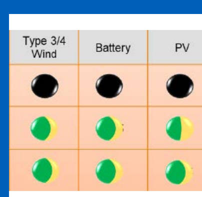
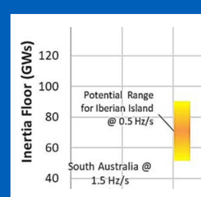
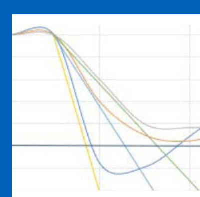
MEETING THE CHALLENGES OF DECLINING SYSTEM INERTIA

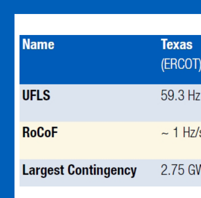












Name	Texas (ERCOT)
UFLS	59.3 Hz
RoCoF	~ 1 Hz/s
Largest Contingency	2.75 GW

April 2019

Abstract

As power systems worldwide shift their generation resource mix from conventional power plants to a high proportion of renewable resources, new issues arise for ensuring stable system operation. Traditionally, spinning conventional generators have provided system synchronous inertia. However, with increasing penetration of asynchronous resources, inertia declines. Synchronous inertia supports grid operation by supporting the balancing of supply and demand during normal operations and by stabilizing the grid as a whole during disruptions. EPRI has surveyed the technical and economic issues that arise from operation under reduced inertia. The industry needs new analytical tools, as well as high-quality real-world data on the effects of reduced system inertia during disturbances. In the meantime, new techniques for supporting system inertia require study to establish their value and effectiveness in supplementing or replacing synchronous inertia. These techniques include markets for frequency services and technological approaches to emulate the effects of inertia. This white paper reviews the nature of synchronous inertia, addresses the factors leading to declining inertia, and examines options for ensuring stable system operation. The paper also highlights areas where additional research will be most beneficial.

Executive Summary

Governments and policy makers in Europe and around the world are pursuing ambitious targets for renewable energy generation, as a part of the move towards decarbonization of the electricity, transportation, and heating sectors. These efforts have resulted in solar, wind, and other renewable resources providing a steadily increasing share of global generation throughout the world. However, this new resource mix comes with a reduction in the amount of online synchronous resources, and in particular in relation to the focus of this paper, a reduction in synchronous system inertia. This can lead to several challenges for system operations; here we focus on the challenges related to the impact of low inertia operations on system frequency performance. Inertia helps support system frequency during events on the system. Traditionally, large conventional thermal power plants have provided that stability, through the mechanical inertia of their spinning generators. However, asynchronous generators such as solar PV cannot provide that kind of support, and when they displace traditional synchronous resources, result in declining system inertia. Changes may be needed to support system stability in this new environment.

As system inertia decreases, transmission system operators face new challenges in planning, operating, and protecting transmission systems and electricity markets. Smaller or islanded electricity systems with large renewable energy capacities around the world have already identified concerns related to inertia-related issues, and they have been developing innovative solutions for real-time operation and markets. In the future, changes can be expected not only in how large thermal generation plants are operated, but also how generators are compensated for providing inertia to interconnected systems. Promising new options include methods that utilize the controls of inverter-based resources to support frequency control through electronic controls during disruptions.

In 2018, EPRI and one of its members collaborated to study in detail the issues arising from a power system operation with reduced synchronous inertia, considering both technical and economic viewpoints [1]. Here, EPRI provides a high-level discussion of the project findings. The study revealed a strong need for quality data, new analytical tools, and focused studies of the dynamic performance of the electricity system with this evolving resource mix. New capabilities from inverter-based resources are promising, but these need to be demonstrated at scale. At the same time, new market products, including frequency control services, need to be studied for their potential to supplement the need for synchronous inertia. Each of these elements will support transmission system operators (TSOs) in their efforts to ensure that the electricity system remains stable and reliable for electricity customers.

This technical brief examines the challenges that TSOs face, describes established and novel technical solutions, and considers the market and regulatory mechanisms that can mitigate low inertia's effects on electricity systems. This issue is highly relevant at present in the European system, so to some extent European perspectives and terminology are highlighted; however, the document as a whole is intended to address problems and solutions in systems worldwide. In the first few sections, the nature of inertia, its role in system stability, and critical operational factors are reviewed. Then, the solutions at hand are discussed, including technology solutions and new operational techniques. The experience of several system operators conducting early tests of some measures adds perspective and underscores economic and regulatory factors in planning for low-inertia systems. The document concludes with a summary of the most critical technical and economic choices that power systems face in anticipation of low-inertia operation.

Acronyms and Abbreviations

AC	alternating current
AEMO	Australian Energy Market Operator
CAES	compressed air energy storage
CE	Continental Europe
DC	direct current
DER	distributed energy resources
DG	distributed generation
ENTSO-E	European Network of Transmission System Operators for Electricity
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
EUCO	European Commission
FCR	frequency containment reserve
FRR	frequency restoration reserve
GCA	global climate action
HVDC	high-voltage direct current
LSI	largest single infeed
PV	photovoltaic
RoCoF	rate of change of frequency
SIR	synchronous inertial response
ST	sustainable transition
STATCOM	static synchronous compensator
SVC	static VAR compensator
TSO	transmission system operator
UFLS	under-frequency load shedding

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This white paper was prepared by EPRI.

Inertia as a Factor in System Operations

An Introduction to Inertia and Frequency

In an interconnected alternating-current (AC) system, generators and motor loads spin at speeds proportional to system frequency, or frequency. In any system, the combined rotational inertia of all of these heavy, spinning objects translates to a quantity termed system inertia, which contributes to the ability of the system to resist changes in system frequency. If one generator drops off-line (or one motor adds a new load to the system), the kinetic energy stored in all of the remaining generators is immediately tapped, to compensate for that difference between supply and demand. That energy drain works like a brake, slowing those generators and thereby reducing the system frequency. The amount of total system inertia, as well as the size of the generator (or motor) dropped off-line, defines the rate at which the frequency decreases. If inertia is sufficient, frequency decrease is slow, and the frequency will not decline excessively before generators sense the change in frequency and respond automatically through governor control or system operators take manual action. As described in more detail later, if the system has insufficient inertia, frequency performance may suffer with frequency declining too quickly and resulting in load shedding. Knowing the system inertia also allows operators to plan for the other frequency response mechanisms they employ. The reason is that system inertia sets the rate of change of frequency, and thereby affects the nadir. Figure 1 presents a simple analogy to the effect that the amount of inertia has on swings in system frequency: compare the results of applying identical forces to an empty bucket and one filled with sand. The heavy bucket—the one with high inertia—is more difficult to put into motion. Once swinging, the heavier bucket will have a smaller magnitude of oscillation and will also be more difficult to disturb or stop.

Transmission system operators (TSOs) endeavor to ensure that any frequency excursions are first prevented from becoming excessive and are then corrected in a controlled manner to return the system to its nominal frequency. The nominal frequency is 50 Hz in some regions, including all of Europe, while 60 Hz is used elsewhere, such as in North America. However, in any managed system, the goal is to maintain a steady system frequency.

Frequency is therefore the touchstone for describing the overall health of an interconnected AC system—its ability to balance supply and demand instantaneously and provide the promised service to customers. A characteristic of a synchronous AC grid, frequency crosses national and state jurisdictions. It can involve multiple TSO control areas unless confined to a physical or effective island isolated from other systems. Therefore, frequency stability across a synchronous area is usually managed through the joint efforts of TSOs and regional security coordinators.

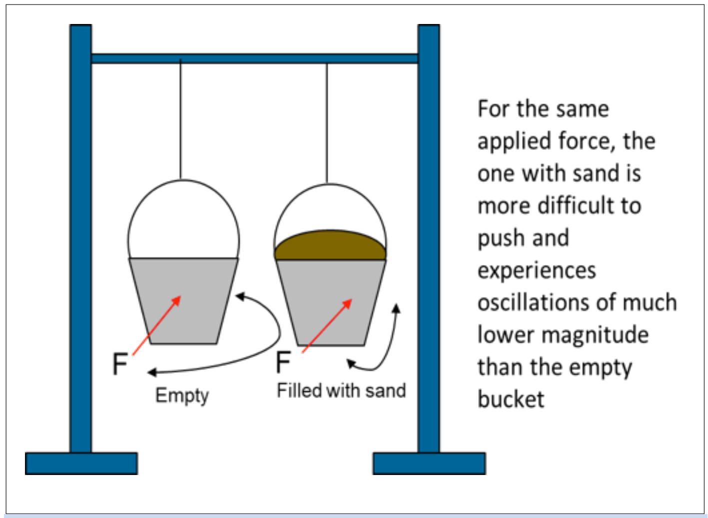


Figure 1. Simplified view of system inertia.

System operators expend significant effort and resources to ensure frequency stability. As a base requirement, operators ensure there is capacity above the minimum needed to meet demand, to ensure sufficient capacity is synchronized to respond when needed. During normal operations, there are constant small changes in both demand and generation, as customers continuously alter their consumption and generators respond to those changes. Because generator response cannot precisely match load shifts on a second-by-second basis, system operators perform continuous supply management by adjusting generation on this seconds-to-minutes time frame, either automatically or through economic dispatch. On longer time frames, operators are calling for generators to move on- or off-line as demand changes over the course of the day.

Sudden outages are a different matter. When a large generator trips offline, system operators need to ensure that the system can manage the resulting imbalance and then restore the system to nominal frequency by adjusting the supply-demand balance over a period of milliseconds to minutes. The need to be able to swiftly respond to sudden outages is a major factor in designing, planning, and operating interconnected systems.

A Sample Frequency Timeline

Figure 2 provides a simplified view of a frequency timeline before and after a disruption. Before the outage incident, during steady state conditions, automatic generation control manages the system's mi-

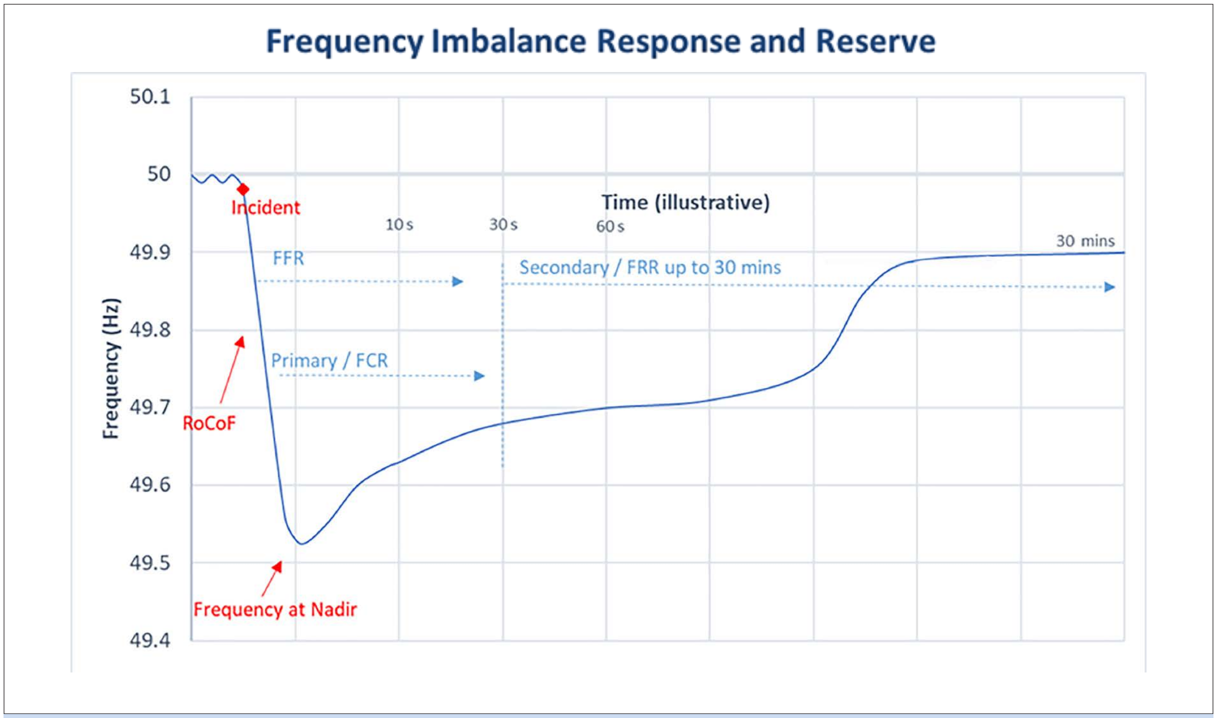


Figure 2: Graphical illustration of system frequency response over time.

nor variations in frequency. Abruptly, a large generator trips and the frequency drops, reflecting the shortfall of supply, initially declinging at a rate inversely proportional to system inertia. The minimum frequency reached (the nadir) is determined by the initial rate of change of frequency (RoCoF), the amount of frequency response provided, and the size of the generation trip. The amount of frequency response is based on how long it takes resources providing frequency response to respond, which is based on various generator settings including deadband—the frequency change required before it starts to respond, and droop—the rate of response and the system inertia.

Without additional measures, the system would tend towards a new, though somewhat lower, steady-state frequency. The recovery process proceeds in two stages. First, a portion of the already-synchronized generators automatically increase production in proportion to the frequency change through governor control, providing frequency containment reserve (FCR, also known as primary frequency response). This response begins during the initial frequency decline and continues after the nadir. These actions serve to restore the balance of supply and demand, reversing the frequency decline in a controlled fashion. Once the system is stable, operators bring online their manual frequency restoration reserves (FRR, or secondary frequency response) to return the system to nominal frequency, typically within approximately 30 minutes.

System operators are responsible for ensuring that sufficient frequency containment reserves are available, so that the frequency will not decline below the point at which under-frequency load shedding (UFLS) setpoints are reached. Among other concerns, these setpoints are established to avoid generators tripping offline which they would otherwise do, to avoid damage to their equipment. Most generators can only tolerate a limited range of frequency deviations. At these frequency levels, a portion of normal domestic and business load is shed on the system to help restore the balance between generation and demand. System operators seek to control and operate systems within applicable regulatory requirements intended to ensure that UFLS points are not reached, so that customers see only a slight, and temporary, change in frequency.

Traditionally, system operators have not needed to actively control the amount of inertia on the system, as conventional thermal and hydroelectric generators provide inertia naturally, and having generation capacity online to meet demand has always lead to sufficient inertia availability.

Inertia applies across the entire interconnected system, although there may be some locational need to ensure local stability. Hence, if inertia requirements are established and enforced in the future, this will likely apply, at least at first, at the regional level.

Impending Changes Affecting System Inertia

Shifting Generating Resource Mix

Figure 3 shows several projections for Europe's generating resource mix, based on four potential future energy scenarios [2]:

- Sustainable transition (ST)
- Distributed generation (DG)
- European Commission scenarios (EUCO)
- Global climate action (GCA)

Note that each scenario yields large increases in wind and solar resources. As these asynchronous energy resources constitute a larger share of the resource mix worldwide, the role of inertia as a power system characteristic is changing. Renewable energy resource penetration is expected to increase as cost reductions combine with policy choices targeting the low-carbon nature of these resources and as customer choice gains favor. On the load side, the increased prevalence of asynchronous power electronics-based loads is also creating a trend towards reduced inertia from the demand side.

The Impact of Aynchronous Resources

Asynchronous resources (including asynchronous AC machines, those not operating at the grid frequency) present an array of new issues. The output from these resources—especially for solar photovoltaics (PV) and wind—is both variable and uncertain. A substantial share of these resources is connected at the distribution system level in small capacity increments, often behind the meter. Viewed from a planning and operations perspective, these are quite different from traditional transmission-connected resources. In the context of inertia, the differences could not be more significant. Solar PV generation is a direct current (DC) resource and connects to the system using inverter technology. Wind generation may be AC, but it operates at a frequency not matching the grid. This means that wind generation typically involves a two-step conversion: first from the asynchronous AC to DC, and thence to grid-synchronous AC through an inverter. As seen from the grid, there is no spinning machinery that could contribute to system inertia.

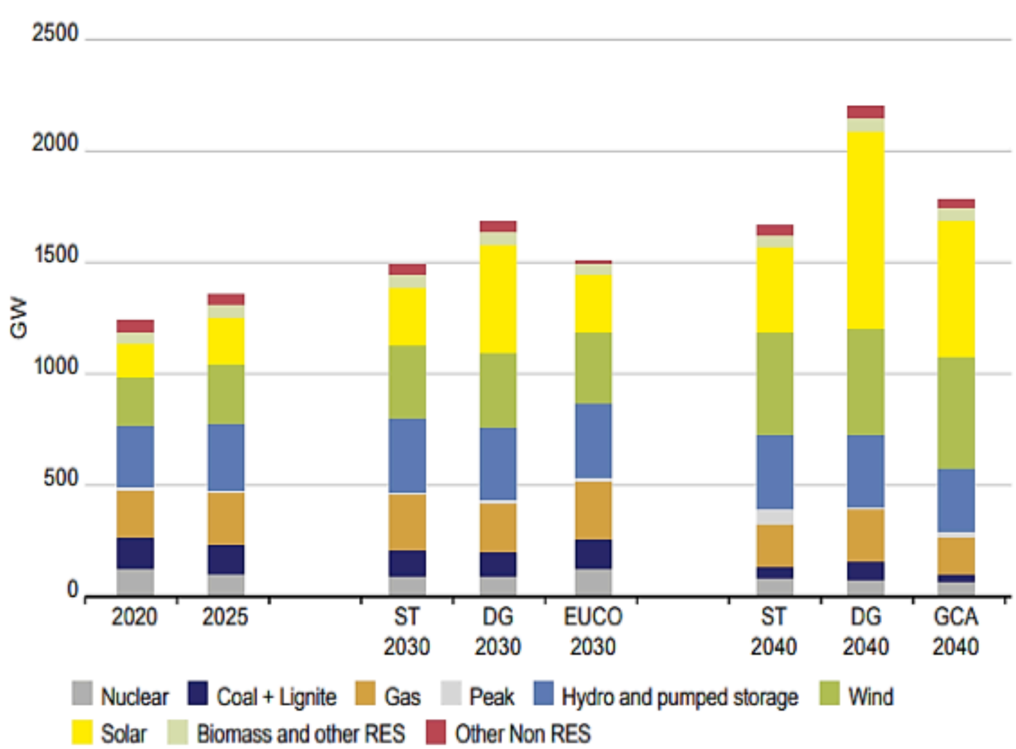


Figure 3: Projected installed capacity in Europe, by scenario and resource type. Used with permission from ENTSO-E.

To understand why this is an issue, a brief review of the function of inverters in grid-connected generation is useful. Inverters are a class of power electronic devices that convert DC to AC. Inverter-based resources are connected to the system asynchronously. In other words, the electrical power the unit generates is controlled only by the on-site power electronic converter's current control loops. Unlike traditional synchronized generators, these resources cannot inherently respond to disturbances in system frequency that disturbances in loads or power generation trigger. Instead, software installed in the power conversion system governs inverter behavior.

A similar concern arises for a high-voltage direct current (HVDC) link, which is a transmission connection that is becoming more widespread. Whether an HVDC line interconnection forms links between or within synchronous areas, it does not allow for transmission of inertia between the regions connected; this is particularly important when two regions not otherwise connected through AC transmission are connected with HVDC. Where all AC connections are replaced by HVDC, the net result is to separate regions into smaller pools for combining inertia, yielding a net reduction in system synchronous inertia. Both of these aspects become especially important if an area is meeting a large portion of its demand from a neighbor through an HVDC connection.

In summary, as more asynchronous resources are adopted, the number of rotating machines synchronized on the grid decreases, either in the form of conventional generation or motor loads. The new generation resources lack the rotational inertia that help a system maintain frequency stability in the event of an incident. The net result, without applying additional measures, is more-rapid frequency drops to deeper nadirs when system disruptions occur. This occurs because frequency containment reserves do not have time to be deployed in response to a frequency imbalance. Unless other actions are taken to manage system inertia and/or speed of frequency response, there may be direct consequences for the overall frequency stability of the bulk power system.

Fortunately, several technical solutions to the issue of low system inertia are emerging. Recent and ongoing research is developing understanding of the deployment, use cases, and associated issues and risks of these new technical solutions. Some techniques make use of the inverters themselves, others require deployment of new technologies, and some call for new applications of other existing technology. At the power system level, new operational strategies are likely to evolve as well. Understanding the outcome in terms of relative economics of different solutions requires further study. Similarly, the regulatory factors associated with these new approaches need to consider all potential impacts.

Power System Stability with Low Inertia

TSOs use layers of frequency control measures to ensure stability of the system. In ordinary operation, operators accomplish small-scale steady-state regulation in response to small load changes on the network using automatic and manual frequency restoration reserves (FRR). In contingencies, the system operator deploys frequency containment reserves (FCR). In larger systems, these are usually distinct from steady-state frequency control services. By managing the rate of change of frequency, the TSO seeks to:

- Limit load shedding due to large frequency deviations
- Avoid cascading outages that can lead to a blackout, if at all possible

At each level, system inertia plays a role in managing stability. Low inertia systems inherently present a greater risk of load shedding and potentially more severe consequences of instability.

A Brief Look at the Mathematics of Frequency and Inertia

A deep dive into the underlying mathematics of frequency and inertia is not necessary. However, a basic understanding of the relationships between key parameters is helpful. Each individual synchronous generator or motor load on the system has its own characteristic inertia constant, measured in seconds, that encapsulates the combined effects of the device's nominal rotational speed and its weight. (In its pure form, the inertia constant is measured in MW-second/MVA, which simplifies to seconds.) Typical generator inertia constants range from 2 to 12 seconds. The constant is the ratio of stored kinetic energy to the rated MVA size of the resource. This indicates the length of time for which kinetic energy stored in the spinning mass could allow for production at rated output of the machine. Total system inertia is then the sum of individual machine inertia, a fraction of total system power.

For practical reasons, the inertia can be expressed in terms of the total kinetic energy stored on the system, which is synchronous inertial response (SIR). This is measured in watt-seconds (or more typically GW-seconds, reflecting system size, abbreviated to GWs). For example, inertia floors, as described in the following subsection, are usually defined in terms of SIR.

The sensitivity of frequency to inertia is very strong. The rate of change of frequency (RoCoF) is directly proportional to the size of power disruption, and is inversely proportional to twice the system's synchronous inertial response (SIR).

An Example of System Inertia and Frequency Response

Figure 4 illustrates frequency response that a model calculated by simulating a hypothetical system with three possible inertia levels providing 100, 200, and 300 GWs of synchronous inertial response (SIR). The lowest-inertia system (100 GWs) experiences a frequency nadir (less than 49 Hz) that would trigger load disconnections under some UFLS rules. For this hypothetical system, if the modeled event is the worst-case scenario for that system—the largest contingency—this study would indicate that an inertia floor (the minimum amount of inertia required at all times) of at least 200 GWs would be needed to protect against underfrequency load shedding (i.e., maintain system frequency higher than 49 Hz at all times). This assumes the same level of frequency response available in all cases for this illustrative system - in reality, this could also change, the point here is to illustrate reduction in inertia with all else being equal.

Until recently, the issue of low system inertia applied only to small power systems or those isolated from others (e.g., islanded systems). Larger power systems could rely on the close connectivity of large numbers of synchronous machines (both generators and motors) to help moderate frequency excursions. Large synchronous energy storage systems, such as pumped hydro storage and some newer technologies such as compressed air energy storage, also are synchronous resources. However, inverter-based resources do not contribute to system inertia. Without sufficient system inertia, frequency after disturbances in loads and generation must be contained faster as frequency excursions become more volatile.

The most problematic consequences of low inertia relate to the potential for shedding loads and tripping generators offline. Disconnecting customer loads is extremely undesirable. However, under low-inertia conditions, load-shedding setpoints may be reached before FCR can respond. On the generation side, interconnected equipment has its own constraints on acceptable operation, so low-frequency conditions may force generators to trip off-line. A new generator loss then presents a new challenge to system stability, which can create a cascading effect unless the disruption is brought under control. For any TSO, the worst-case scenario for a system with low inertia and faster RoCoF is the prospect of increased risk that a single event could lead to a partial or even a full system blackout.

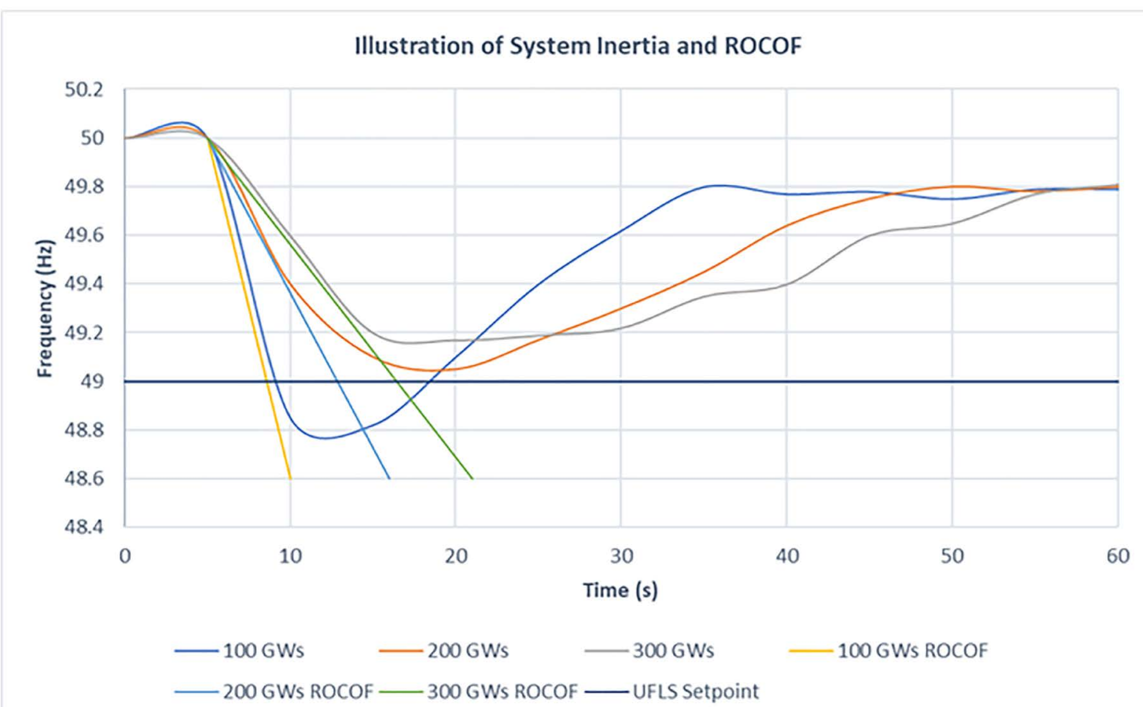


Figure 4: System frequency response as a function of synchronized resources and inertia.

Additional Consequences of Low Inertia

More complex consequences of low inertia require study and attention as well. Within a large interconnected system, electromechanical time constraints may come into play. This means that the RoCoF may be higher close to the loss of generation, compared to the RoCoF at more distant points in the system. As a result, locational aspects of system inertia and frequency disruption also need to be understood.

Islanding may also occur. Islanding is a condition in which a subset of a larger system disconnects and operates independently. Because the smaller, islanded subsystem now has an even lower inertia than the larger network, it may become even more difficult to control. On the smaller scale within distribution networks, there may also be an increased chance of islanding, together with the potential for increased system oscillations. Some small island systems have already built operating strategies to address low-inertia effects.

In a future with high shares of renewable, asynchronous generation, larger systems will no longer be able to rely only on the inertial protection of large numbers of synchronous generators to maintain equilibrium. These systems will need to learn how to manage system inertia without traditional sources of inertia. Recently, some relatively large but islanded systems such as Great Britain and the Texas grid have taken steps towards understanding the impact of renewables on system inertia. The Electric Reliability Council of Texas (ERCOT) is a synchronous system independent of the rest of the United States and Mexico. Britain's National Grid and ERCOT have begun recording the quantity of real-time inertia on their systems. In recent years, they have observed reduced inertia. They have attributed this to a relative reduction in synchronous resources, compared to inverter-based ones [3,4]. Very large systems, such as those in Continental Europe (CE) or the Eastern part of the United States can expect to see a reduction in inertia in future years. However, these systems still have sufficient synchronous inertia from traditional sources, so inertia is not expected to be a real-time system concern in very large systems for several years , other than in situations where those systems that could be separated during certain disturbances.

Assessing Impacts of Inertia and Frequency Regulation

Where inertia is declining, TSOs need to perform more rigorous and detailed assessments of their frequency regulation and containment needs. This is particularly important when considering potential needs under various generation portfolio forecasts. TSOs can no longer expect all new generators to naturally provide inertia and frequency control services. Ultimately, TSOs may need to require new resources to provide inertia-supporting services or to introduce new ancillary services markets to incentivize provision of frequency control services and inertia. In the European system, the EU Commission Network Code for Operation already requires TSOs to assess inertia on their system. In response, the Continental European TSOs have been conducting a joint project on the impact of inertia on the European system [5]. With an expected release in mid-2019, their report will contain a cost-benefit analysis of the introduction of an inertia floor in the CE system, as well as the benefits of potential mitigation measures.

Factors Relating Inertia, RoCoF, and Frequency Nadir

This section summarizes eight generation system characteristics and design factors that play roles in the behavior of systems under frequency disturbances. These affect decisions on managing systems for optimal stability.

Largest Contingency

The system design contingency, also known as the most severe system contingency or loss of largest single infeed (LSI), impacts system inertia and stability directly through the kinetic energy removed from the system if the largest credible contingency occurs. For example, this may be defined as the loss of a specific generator in a synchronous system, the loss of a major interconnection, or as a non-unit-specific figure representing a large outage. For example, in Continental Europe the largest contingency is 3 GW. Choice of the design contingency hinges on identifying the instantaneous resource loss that would lead to the maximum imbalance between demand and supply.

RoCoF Protection Relay Settings

A RoCoF protection relay is an electrical safety device that automatically trips a generator when a greater than normal frequency change rate is detected, indicating that the local area, generally a portion of the distribution network, may have been islanded. A RoCoF relay is often installed with a DER that is synchronized with the grid, though this practice varies across the world. Overall, this means that when a disturbance causes islanding, all of the distributed generators within that island are safely disconnected from the system, avoiding islanding of that part of the grid. Different regions use different RoCoF settings for this purpose, with values ranging from 0.1 Hz/s to 1 Hz/s. Larger values are appropriate for small island systems; even in a normally stable island system, subsets of generation and load may become islanded within that system. In systems experiencing declining inertia, incorrect detection of islanding is more likely to occur, when RoCoF is relatively high due to low inertia. The result could be widespread, unnecessary tripping of DER by their protection relays. The near-term solution is to increase the RoCoF protection settings, thus preventing unwanted generator trips. The long term solution may be to determine other means to protect against islanding.

Under-Frequency Events and Conventional Generators

Unlike small DER, conventional synchronous generators—such as nuclear plants or combined-cycle gas turbines—rarely use RoCoF protection relays. In the past, operators have relied upon the natural inertia of these large generators to buffer the interconnected system from the effects of supply and demand disruptions. However, as the system evolves towards a low-inertia condition, these conventional units may be exposed to higher RoCoFs and deeper frequency fluctuations. Pushing the power system into previously unknown modes of operation may push conventional synchronous generators into untested modes of operation. When very large frequency imbalances and high RoCoF occur, these generators may not be able to respond adequately. Research is needed to explore this potential risk; some automatic protection relays may be needed for some conventional generators.

Under-Frequency Load Shedding Setpoints

When an imbalance event, such as a load surge or a tripped generation resource, occurs on an interconnected system, the system operator can choose from various available actions to maintain system stability. Under-frequency load shedding (UFLS) is a last-resort action, as the system is designed not to need these schemes for normal contingencies. However, to protect generators and customers, frequency levels are established below which loads will be shed, typically in stages of successively lower frequency levels. If the UFLS setpoint is high, too much load may be shed. Conversely, a lower UFLS setpoint may allow a deeper frequency nadir. These potential outcomes need to be considered when calculating inertia requirements. While operators seek to avoid dropping customer loads, lowering UFLS setpoints, or increasing the time for which low frequencies are observed before tripping, may allow the system frequency to shift further away from the normal operating range while corrective actions are being taken.

Fast Frequency Response from Inverter-Based Resources

Fast frequency response (FFR) is a fast power injection, triggered by frequency deviations, that is automatically self-deployed. It provides full response within the first half-second after the preset threshold frequency is detected. For example, inverter-based resources can be programmed to quickly inject power, which serves a similar but not identical function to inertia. The power injection can help slow the RoCoF, help stabilize the system, and avoid dropping loads. As for RoCoF relays, the setpoints used to trigger FFR will impact on the effectiveness of this fast response.

However, in order to provide this service, the available power production level for these inverter-based resources would need to be reduced, incurring an opportunity cost that needs to be taken into account. In certain cases, it may be economic to use this portion of capability for FFR, such as when there is already a large penetration of inverter-based power at the time, so that the value of frequency control exceeds the value of energy service.

Frequency Containment Reserve (FCR)

Increasing the amount of FCR on the system enables the system operator to call for active power generation from generators. While the addition of reserves online may not directly affect initial RoCoF, it might result in more online units and thus more synchronous inertia. Additionally, the FCR support can provide additional power injections within a few seconds, shortly after FFR comes into play. However, there is a cost to employing extra FCR as generators must be dispatched below their maximum power output levels to be able to respond. A side effect of this under-rating dispatch is that these units may also be performing below their most-efficient operating points. As a result, synchronizing more generators in this way, if done only to provide reserves, may be a suboptimal economic solution.

The Contribution of Load and Energy Storage

Considering load's contribution to stabilizing frequency is important. Load adjustment can provide quick frequency response without requiring additional inertia on the system. Various opportunities exist to utilize load to provide frequency response; for example, ERCOT already uses industrial load, with underfrequency relays responding to changes in frequency, to provide up to half of its responsive reserve service (a reserve used in ERCOT that is similar to FCR). With smart grid technology providing increased communications and control techniques, there is significant potential to use load in the future to support frequency after a large contingency.

Bulk energy storage, whether synchronous or not, may also be used to add or subtract load from the system. For example, if a pumped hydro facility, which as pointed out above provides inertia to the system, is actively pumping when a system disruption occurs, that load may be shed without consequences to customers. Alternatively, if adding load would improve system stability and a bulk storage unit is idle, activating a storage charging cycle would add a flexible, dispatchable load. Depending on the responsiveness of the particular storage system, a storage unit can effectively provide the sum of its charging and discharging capacities if switched from full charging to full discharging, or vice-versa.

System Protection Device Sensitivity

A significant reduction in system inertia may impact general system protective devices. These primarily include relays that automatically disconnect bulk power system components when a fault is detected, potentially causing equipment damage. For example, fault detection may respond to lightning strikes, equipment failures, or other issues. With a smaller proportion of synchronized power generation sources, the current that the protection relays need to detect faults and disconnect impacted components will be decreased.

Systems with declining inertia need to be modelled more accurately, accounting for the effects of DER supplying power to the system, but no inertia. To identify in advance any potential issues, coordination studies on power system protection should be conducted more frequently.

Considering Solutions to Low Inertia Operations

Assessing the Need for Inertia

TSOs need to first determine the levels of inertia required to maintain stability for a given system and then evaluate the technologies that could provide that inertia. This requires dynamic studies for current and future scenarios to assess the system design contingency and to accurately determine how much inertia is needed. If such studies demonstrate a shortfall of system inertia, then the TSO needs to supplement existing inertia with additional inertia sources or faster frequency response. Many solutions have been proposed to supplement system inertia, including synchronous and asynchronous options.

Synchronous Solutions

Synchronous solutions call for a mix of old and new approaches to support system inertia without constraining the share of renewables in the generation mix. The most direct synchronous solution involves imposing a minimum system inertia level, or floor, such that sufficient numbers of large synchronously connected generators must be placed on line. If there are constraints on generation from fossil resources, then synchronous storage resources may support the system. Pumped hydroelectric storage provides inertia to the system directly as a synchronous resource and may also be dispatched to add load (increasing demand) contingency. Compressed air energy storage (CAES) and synchronous flywheel storage provide the same services, without the siting constraints of pumped hydro.

Synchronous condensers, which are the original grid voltage regulation devices, declined in use when power electronics-based equipment, such as static synchronous compensators (STATCOMs) and static VAR compensators (SVC) became available for voltage regulation. However, synchronous condensers, like generators, contain rotating masses and so are now returning to favor as a valuable "new" technology to provide inertia while continuing to offer the voltage-related support they were originally designed for. Other technologies are under development, but storage and synchronous condensers are the most readily available and widely deployed technologies in this category. Inertial floors are an operational tool that can be used to keep existing synchronous resources online, while the largest credible contingency can also be dispatched down to reduce the size of the event for which the system needs to respond; both of these will have economic implications as discussed later.

Asynchronous Solutions: Synthetic Inertia and FFR

Asynchronous system solutions essentially exploit the inverter controls of power electronics to use asynchronous or DC resources to provide rapid power injections in response to events. This may be described as "synthetic" inertia or fast frequency response. Although these terms are often used interchangeably, a distinction may be drawn between synthetic inertia and FFR based on how the change in power injection is achieved. Wind turbines, where mechanical inertia does exist but is asynchronous to the system, can provide some synthetic inertia without having to be dispatched down. Conversely, solar PV, batteries, and other DC systems need to be dispatched down in order to be able to increase their output. Therefore, fast frequency response can come from wind or PV plants, battery energy storage systems, HVDC interconnectors, and other inverter-based resources. However, in some regions, synthetic inertia is defined only for wind generation. That said, FFR and synthetic inertia are quite similar in functional terms, and both can be considered solutions to issues related to low inertia operations.

Each of these capabilities relies on control functionality first being enabled and then providing the desired response. Inverter controls provide significant added degrees of flexibility that can be exploited. Therefore, exploring methods to use these resources is worthwhile to not only maintain but also improve stability.

The various synthetic inertia and FFR techniques are currently at different levels of technical maturity. However, their capability to provide FRR offers considerable promise to contain frequency declines after disturbances.

Detection of RoCoF

For asynchronously-connected synthetic inertia solutions, the first element needed is detection of RoCoF, in order to activate the response. Measurement of RoCoF has an inherent time delay, based on the time window of the measurement. As a result, there are concerns about the potential delay before response activation. TSOs that have been on the leading edge of addressing low inertia operations have developed guidelines for acceptable measurement times, ranging from 100 ms to 500 ms. For example, EirGrid in Ireland has recently required that all conventional and renewable generation connected at transmission and distribution levels on the island be able to withstand RoCoFs of 1 Hz per second measured over 500 ms.

However, there is a trade-off between faster activation times and accuracy of measurements. By definition, RoCoF requires time to calculate, so an overly fast response may result in an inaccurate value of RoCoF. An inaccurate RoCoF may result in over- or under-shooting the needed level of change in inverter output.

Inertia Emulation: A Different Response than Synchronous Machines

Depending on specific operating conditions, inertia emulation is likely to exhibit a different response pattern, compared to synchronous machines. Consider the situation in which a wind turbine is set up to contribute to frequency support using synthetic inertia. If the turbine had been operating at maximum available power before the frequency drop, only the rotor's kinetic energy is accessible for frequency support once reduction in system frequency has been detected. This behavior is frequency response, and not an inherent provision of kinetic energy as in synchronous machines. Therefore, the frequency support cannot be sustained for more than a few seconds without risking a stall condition, as the process of extracting energy from the rotor decelerates it. Depending on the wind turbine's power electronic inverter ratings, its electronic controls would act to limit its capability to provide any additional power. In addition, as the rotor decelerates from its design point, the turbine's aerodynamic efficiency decreases, reducing active power until the unit is returned to normal operation. Because of this power drop, the wind turbine's speed recovery may then further interfere with overall system recovery.

In any event, the turbine's recovery process needs to be managed efficiently, including the power needed to re-accelerate the rotor after the energy extraction. This stage reduces the output of the turbine to below the pre-disturbance level, which may lead to a second system frequency dip. This does not happen if the wind turbine operates above rated wind speed. Note also that synthetic inertia effectiveness dramatically decreases if a wind turbine operates at less than 50% loading and is non-existent below around 20%.

"De-Loading" Renewable Resources

An alternative approach for using renewables, especially wind turbines, for frequency services involves operating them de-loaded. This allows capacity headroom for the desired services. In the case of frequency following (droop governor response), the service can provide positive and negative responses when the wind (or PV) system is operating under de-loaded conditions. Of course, choosing to operate renewables below full capacity implicitly reduces the total renewable energy in the resource mix. This may need to be addressed in the context of meeting regional objectives for renewables.

A Summary of Frequency Service Capabilities of Various Technologies

Table 1 summarizes how different technologies can contribute to inertia and frequency-related services. This qualitative assessment is based on the latest generally installed capability, is not a substitute for an in-depth planning study, and does not necessarily reflect every single installation and its potential capabilities. Green indicates a "perfect" score (i.e., a very effective capability to provide a given type of service in a mature technological fashion), while black indicates that the given type of technology essentially cannot provide that service. For example, all synchronized rotating devices score green for providing inertia, while asynchronous devices score black in that category. Many options, of course, fall in between perfection and complete unsuitability. Indicators with varying degrees of yellow describe resources that have some degree of capability, with an increasing fraction of green indicating a stronger ability to serve. For example, wind, solar, and batteries offer modest FFR and FCR capabilities. Note also that in practice these services are interrelated. For example, a technology can compensate for a lack of inertia, at least in part, using additional FRR. In this case, the various frequency services can act in concert to support system frequency stability. The final row of the matrix describes maturity level, encompassing the extent to which each technology has been tested and demonstrated for providing frequency services.

Table 1: Frequency service capabilities of synchronous and asynchronous resources.
Note this is a stylistic representation for discussion purposes and does not replace the need for detailed studies.

Services	Technology										
	Synchronous					Nonsynchronous					
	Fossil	Nuclear	Synchronous Condenser	Pumped Hydro	CAES	Asynchronous Flywheel	HVDC	Type 3/4 Wind	Battery	PV	Demand
Inertia (Instantaneous)	100%	100%	100%	100%	100%	0%	0%	0%	0%	0%	25%
FFR (Cycles)	0%	0%	0%	0%	0%	100%	100%	100%	100%	100%	75%
FCR (Seconds)	100%	25%	0%	100%	100%	50%	100%	100%	100%	100%	25%
FRR (Minutes)	100%	0%	0%	100%	100%	0%	100%	50%	25%	50%	0%
Maturity	100%	100%	100%	100%	75%	50%	75%	75%	75%	75%	25%

Key: 100% 75% 50% 25% 0%

Economic and Regulatory Considerations

Inertia and System Operation Today

At present, TSOs within a large synchronous area work together to provide frequency control. They ensure the availability of sufficient frequency containment, restoration, and replacement reserves. Each TSO within an interconnection is responsible for holding in reserve within their own control area their portion of the overall requirement for frequency control. For island systems, 100% of the requirement must be maintained on a system's own resources. Increasingly, system operators are also exploring ways to jointly procure reserves and to share frequency response across multiple areas in response to an event.

TSOs in low-inertia systems have access to a variety of methods to ensure stability. These include bringing synchronous generators online to provide additional inertia, enabling fast frequency response from inverter-based resources, and employing energy storage, as discussed above. To ensure that these responses are adequate, these regions need to perform assessments to determine whether there is sufficient capability to withstand a credible contingency. Some system operators in affected regions are already moving toward considering inertia in real-time operations. These are notably relatively large island regions, which typically serve several GW, as opposed to the small islands that have always needed to consider inertia issues. Today, inadequate inertia problems remain on the horizon for large continental-scale interconnected power systems, such as the Continental European, North American, and Chinese power systems, with their peak demands and generation capacities reaching hundreds of GW.

A Comparison of Five Power Systems

Table 2 summarizes recent information related to these issues for five power systems representing a range of sizes and islanding conditions. They each have set distinct under-frequency load-shedding points, with triggers at 0.7 to 2.4 Hz from nominal. The rate of change of frequency (RoCoF) ranges from 0.5 to 3.0 Hz/s, with Australia's National Energy Market showing the greatest RoCoF. The largest contingency ranges from 350 MW to 2.75 GW, while the peak demand ranges from 6.5 to 73 GW. Ireland's EirGrid has recently reached a target of 65% renewables on an instantaneous basis and is now aiming for 75% [6]. Each system has identified an inertia floor.

As shown, the inertia requirements differ for different systems, and are not closely related to their size in terms of capacity or peak demand. For example, compare the Great Britain and ERCOT systems, while are relatively similar in size. Even though ERCOT has a larger credible contingency, the inertia floor in Great Britain is higher. This is likely due to a blend of the effects of specific resource mix, the fact that ERCOT has a large amount of load providing fast (within 0.5 second) frequency response, and the two regions' distinct RoCoF values (i.e., ERCOT's RoCoF is twice that of Great Britain's). Other factors that affect determination of an inertia floor include region-specific design criteria and the preferences of decision-makers setting the requirements.

While these developments show that operators are now considering inertia when operating power systems, experience with actually changing the operation of the system to ensure sufficient inertia has been limited. To EPRI's knowledge, of the five systems surveyed, only

Table 2: Inertial floors and underlying factors for several regions

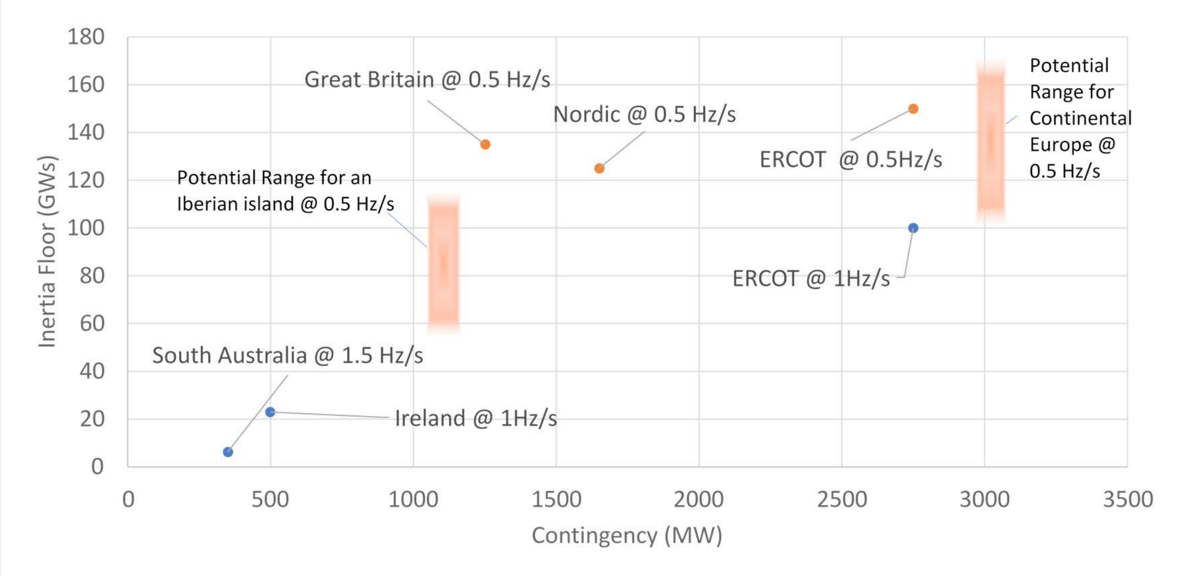
Name	Texas (ERCOT) [3]	Great Britain (National Grid) [7]	Ireland (EirGrid) [8]	Nordic system [3]	South Australia [9]
UFLS	59.3 Hz	48.8 Hz	48.85 Hz	48.85 Hz	47.6 Hz
RoCoF	~ 1 Hz/s	0.5 Hz/s	1 Hz/s	0.5 Hz/s	1.5-3.0 Hz/s
Largest Contingency	2.75 GW	1250 MW	500 MW	1.65 GW	350 MW
Peak Demand	~73 GW	~60 GW	~6.5 GW	~72 GW	~3.4 GW
Inertia Floor	100 GWs	135 GWs	23 GWs	125 GWs	6.2 GWs

(Note: The nominal frequency is 60 Hz in Texas and 50 Hz in the other systems.)

the Ireland and the Nordic system have modified the dispatch level of the largest contingency to maintain an inertia floor. Ireland also launched an ancillary service market to compensate resources that provide inertia to the system; this is still early in its development. Inertial support is procured annually and paid out depending on the resource's minimum generation and whether it is synchronous as agreed. However, this procurement process has not yet directly impacted operations. Today, the asynchronous limit that has been put in place in Ireland to ensure stability is more influential; while related to inertia levels, this constraint is not directly causing changes in dispatch to meet an inertial floor, but rather limiting instantaneous penetration to a pre-defined limit. Given the compensation provided, the cost to the system for the new ancillary service is presently very small, compared to other services procured. Hence, present costs directly associated with regularly providing inertia for systems with inertia floors are not significant.

Potential Ranges for Inertia Floor Application

Figure 5 places these systems in context with a few others for which inertia floors are under consideration. This chart is intended only to illustrate the broad potential ranges for inertia floor application. The



Source: EPRI 3002014970 [1]

Figure 5: Potential inertia floors as a function of design contingency and RoCoF limits.

values shown are based on extrapolation from existing studies. EPRI has not conducted additional studies to justify these particular values. As a result, care needs to be taken when viewing this information. Broad estimates of potential floors can be estimated for those systems that have not yet established them. Comparing the scale of ERCOT with Continental Europe suggests a likely range of inertia floors of 145-175 GWs for CE. The smaller Iberian system, similar in size to the Nordic system, might consider a floor of 50-90 GWs, if it was determined that there would need to be sufficient inertia available in the event it became islanded from the rest of the continental system.

Five Categories of Choices for System Inertia Adjustment

The following five categories of choices—each with its own potential value contribution—can be evaluated to resolve frequency stability concerns:

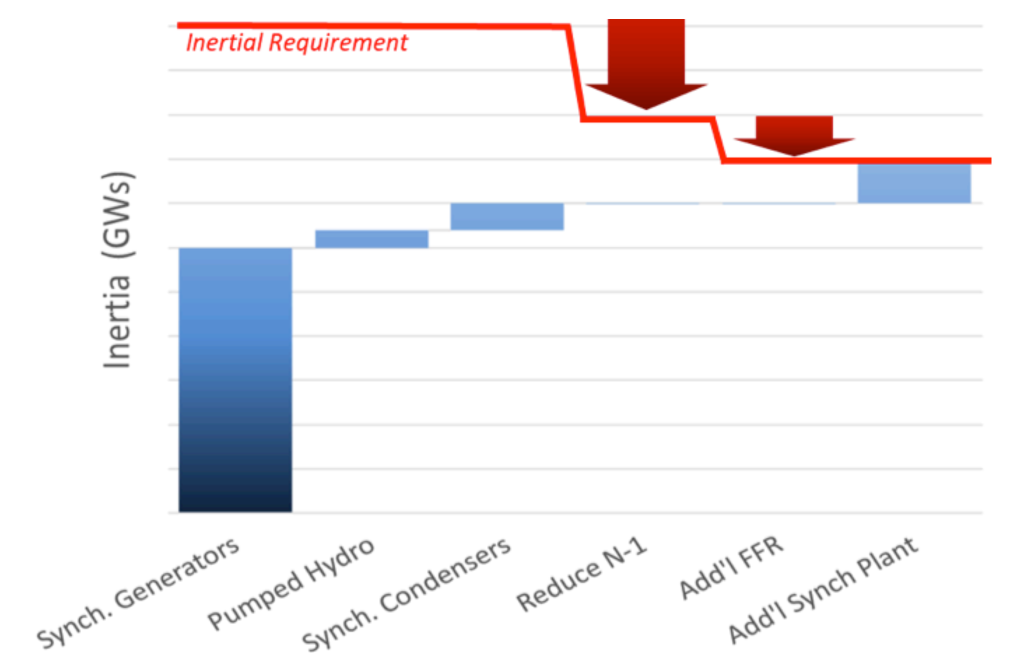
- Redispatch of the largest contingency to reduce frequency stability risk
- Increased procurement of fast frequency response service
- Commitment of more capacity, to bring additional synchronous plant capability on line
- Investment in new (or retrofit) synchronous condensers
- An increase in the inertia of load through pumped hydro storage in pumping mode

Figure 6 illustrates the interplay between these options, showing how each option either reduces the inertia requirement or increases the total system inertia. The levels shown are not intended to be precise but to indicate relationships between these interacting elements. For example, the most significant contributors in the near term are likely to be adding synchronous generators and reducing the size of the largest contingency ("reduce N-1").

At present, in locations within Europe where inertia issues are already binding constraints, the primary approach to resolving such issues has been through either generator redispatch or a technical-constraints resolution process. Meanwhile, new frequency control reserves are being pursued though contracts between resources and TSOs, and these reserves may be shared between control areas. As already mentioned, new incentives are in place in the Irish power system for those resources providing inertial capability. These take the form of a scarcity-adjusted availability payment for synchronous inertial response and for inverter-based resources to make fast frequency response available. Another example is the Nordic system, where a baseloaded nuclear power plant was recently redispatched to lessen the impact on domestic customers in case of loss of design contingency [6].

Market-Based Means to Maintaining Inertia

As redispatch or recommitment of generation to provide inertia becomes more frequent, the costs of providing inertia may become



Source: EPRI 3002014970 [1]

Figure 6: Multiple options combine to adjust system inertia for frequency stability

significant enough to justify a market-based means to maintaining inertia. Future needs may include:

- Keeping synchronous resources online when they otherwise would have been turned off (operational costs)
- Investing in new sources of inertia and frequency response, such as flywheels, synchronous condensers, or resources that provide synthetic inertia or FFR

Establishing a market value for inertia requires consideration of operational issues and investment decisions.

In the long run, the potential markets for inertial services are likely to interact with energy market operating costs and resource investment practices. When synchronous units are kept operating to satisfy inertia needs, not to minimize the marginal cost of dispatch, an operating cost of inertia service is created. If new components, such as synchronous condensers, are employed, there will also be up-front investment (or refurbishment) costs. However, operating costs could be lower than for committing additional capacity from a synchronous generator. Therefore, short-term market procurement mechanisms may be developed, such as Ireland's new ancillary service program. However, long-term mechanisms may also be needed to ensure that resources continue to provide services for system operators in the future.

There remain issues in designing an appropriate compensation scheme for inertia-support services. That process is likely to require a long-term outlook and be considered alongside other needs, such as reactive support and post-fault recovery support, as well as provision of energy and capacity. If the only need at hand was to provide inertia, then a synchronous condenser might appear to provide the best value. However, conventional generators and resources that provide fast frequency response also provide other services related to active power provision, and so may prove to be more valuable overall. These valuations and balancing factors need to be studied closely for each system under appropriate assumptions for operating conditions.

Ultimately, the size of a market for inertia services could reach the same scale as other ancillary services markets. Naturally, in each system the new market will have a small impact and only reach its ceiling volume once the challenge of inertia becomes significant enough to justify changes to the system commitment and dispatch process. As each TSO evaluates its needs through detailed study and testing, a combination of resources will emerge as useful and cost-effective methods to satisfy the need for inertia service or provide fast frequency response and similar services that reduce the need for inertia.

Looking Forward

Identifying Inertia Requirements

System operators and stakeholders should take into account the changing nature of the grid when building models of future systems, to reflect more accurately the behavior of loads and generation. As the contribution of DER rises, the constituents of the power system are transitioning from a centralized structure to a partly-decentralized one. Moreover, the electrical nature of the connected resources is shifting from a mostly-synchronous set of loads and generators to a mix of synchronous, asynchronous, and asynchronous elements. Both operational and investment practices will need refinement to adapt to this new arrangement. These refinements will require a deeper understanding of future inertial requirements, on both the planning and operational timeframes. Research needs fall into two categories: studies of system inertia, and development of analytical tools and detailed data.

Studies of System Inertia

Detailed studies on real-world systems are needed to identify the conditions under which inertia levels may complicate system operation. Focused research can help to determine the extent to which different solutions can provide relief for a particular system, depending on the characteristics of its loads and generation. For large interconnected systems, TSOs in neighboring regions need to work closely together to carry out such studies. Whether those studies recommend adding synchronous inertia reserves or developing markets for services such as fast frequency reserves, the resulting solutions need to be implemented in a coordinated fashion. Interconnected regions need to cooperate as they establish fair and transparent methods of assigning responsibility for providing sufficient levels of inertia to protect all involved parties—TSOs, customers, and independent power providers.

Need for Analytical Tools and Detailed Data

Operators need advanced analytical tools to study the effects of inertia, as well as detailed data to monitor the inertia on their systems in real time and looking forward. Effective operational decisions require a high level of accuracy in modeling and the ability to integrate information flow from moment-to-moment and over a time horizon of several days. Already, several TSOs across the world have implemented basic real-time monitoring capabilities, including the ERCOT and National Grid UK systems. Continuation of this process is needed to deepen detail in real-time data gathering and incorporate look-ahead capability to support efficient, reliable system operation.

Technological Solutions

As studies are completed, given the differences between various power systems, technical solutions appropriate for each will vary. However, these will likely involve a mix of technology investments and operational changes. Technologies that can help to meet this challenge include:

- Synchronous condensers
- Bulk energy storage
- Flywheels
- HVDC technologies
- Demand-side resources
- Inverter-based resources, such as wind, solar PV, and battery energy storage

The latter five, while not providing inertia themselves, can be controlled to provide fast frequency response. This reduces the impact of low inertia levels on the rate and depth of system frequency drops. Operational solutions include:

- Maintaining sufficient synchronous generation online (at lower output levels or by curtailing renewables)
- Reducing the size of the largest contingency
- Changing various power system setpoints, such as UFLS and droop response

Demonstrating new technologies is perhaps the most important research task at hand. While the asynchronous technologies are fairly well-understood at this time, the use of asynchronous sources to support system stability is largely untested. No single power system (as opposed a region within a larger interconnection) has yet demonstrated operations with 100% asynchronous generation. Inverter-based technologies, including grid-forming converters, offer strong potential for managing, or even mitigating the need for entirely, inertia at the point of DER operation. Demand-side technologies also need further study for their potential to support system frequency performance. The potential for HVDC interconnections to contribute to inertia support also requires real-world demonstration.

Alongside research on the capabilities of inertia-support technologies, the consequences of the actions of these technologies also require study. Some proposed measures have the potential to impact devices connected on the network. For example, protective relay switches may trigger unwarranted device tripping when sensing high rates of frequency change , even if those high rates of change can be managed through deployment of new technologies. Other protective devices may need to be adjusted for increased sensitivity to ensure that grid events are still correctly recognized even under new operating parameters.

Economic and Regulatory Considerations

As basic economics teaches, when a good becomes less available, its value increases. In today's evolving electricity grids, inertia response is becoming a scarce commodity, at least in comparison to its status in years past. When virtually all generation was provided by large rotating machines, system inertia was provided essentially as a free benefit. Now that specific measures are needed to ensure sufficient inertia, a new market paradigm is emerging.

Current electricity systems already operate markets for energy, power, and ancillary services such as spinning reserves. Adding markets for inertia services must be undertaken carefully to ensure sufficient system inertia, and the impact on overall frequency control needs to be understood, as systems continue to evolve in the future. Because there are multiple ways to manage frequency disturbances, the most likely result will be a blend of frequency-support and capacity-serving (i.e. long term) markets. For example, the mix of solutions may include long-term market mechanisms and contracts as well as short-term markets similar to, or a subset of, ancillary services markets. New generation could be required to contribute to system inertia, either directly or through the market. Where low inertia is a system-wide problem, specific incentives may be offered in the context of an organized market, to attract new participants to provide inertia-related services.

Provision of inertia services will not take place in a vacuum. New frequency control services and products may provide the needed system inertia support. However, a wide pool of resource types will need to deliver this support, in order to support the system's economic and reliability objectives as well. Fast frequency response from wind or solar, for example, may require keeping a unit operating below its maximum capacity, reducing its energy output, net efficiency, and overall contribution to system economics; however, this is also true for existing reserve products. This may affect investment decisions for new installations or planning objectives for capacity and reserves. In general, where any resource is providing more than one service, market design and remuneration of participants is needed to ensure that the services materialize as intended and that the benefits sought are fully realized.

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Meeting the Challenges of Declining System Inertia

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