September 2023

Meeting the Challenge of Reliability on Today's Electric Grids: The Critical Role of Inertia

Executive Summary

As the calendar year changed to 2000, the US National Academy of Engineering was asked to declare the most important engineering innovation of the previous century. The answer of the world's most prestigious society of engineers: the electric grid. Over the century, the provision of electric power had modernized every major economy. Because electricity was clean and flexible—and increasingly affordable—it altered how households and firms used energy. Careful economic histories point to electricity, first and foremost, as the source of a century of sustained economic growth.[1]

Electricity mattered because it was highly reliable. Today many of the world's largest electric grids are facing new challenges in sustaining the levels of reliability that made electrification indispensable.[2] In addition to those physical challenges of reliability have been challenges of imagination and policy. In the past, reliability often turned on the question of what happened if a key power plant or power line unexpectedly failed. The rapidly increasing share of power supply from sources such as wind and solar plants, and the build-out of interconnections between different grid regions, countries, or even continents using high voltage direct current (HVDC) cables introduce new reliability considerations related to weather conditions and faults in control software that need our careful attention.

For the last century nearly every modern grid has depended on large, centralized power plants with spinning turbines—fired with fossil fuels and, in some cases, large nuclear and hydro plants. Those turbines generate prodigious quantities of electricity along with huge amounts of inertia, helping to stabilize the grid. The bigger the volume of electricity supplied from such sources, the larger the inertia.

[1] Benn Steil, David G. Victor, and Richard R. Nelson, *Technological Innovation and Economic Performance* (Princeton, New Jersey: Princeton University Press, 2021); Robert J. Gordon and Michael Butler Murray, *The Rise and Fall of American Growth*, Unabridged Edition (Webster, Texas: Audible Studios on Brilliance Audio, 2016), https://www.amazon.com/Rise-Fall-American-Growth-Princeton/dp/153661825X; and Bob Somerville and George Constable, *A Century of Innovation: Twenty Engineering Achievements That Transformed Our Lives* (Washington: Joseph Henry Press, 2003), http://www.greatachievements.org/.

[2] David G. Victor, David Fedor, and Rob Buechler, "Transformation of the American Electric Grid," George P. Shultz Energy Policy Working Group, Hoover Institution Essay, August 31, 2022, https://www.hoover.org/research/transformation-american-electric-grid-unmet-agenda; National Grid Energy System Operator (ESO) Staff, "Operability Strategy Report," Annual Operability Strategy Report, United Kingdom, December 2021, https://www.nationalgrideso.com/; PJM Energy Market Staff, "Energy Transition in PJM: Resource Retirements, Replacements & Risks," February 24, 2023, https://www.pjm.com/-/media/library/reports-notices/special-reports/2023/energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx; and Texas Public Utility Commission (PUC) Staff, "E3 Report, Staff Memo and Updated Questions," November 10, 2022, https://interchange.puc.texas.gov/search/documents/?controlNumber=54335&itemNumber=2.

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Because grids with a lot of inertia can ride through shocks and disruptions, they are a lot more reliable than grids that depend on fewer spinning turbines.

In many countries, there are policy and technological pressures to reconfigure electric grids in ways that will lessen the role of large spinning turbines. Those changes include more decentralization of electric supply—such as through a shift to microgrids and rooftop photovoltaics that operate locally. In tandem, many grids are shifting to wind and solar supplies that typically don't provide inertia. Wind turbines, while spinning, are rarely synchronized with the grid and thus don't offer inertia that stabilizes grids. Solar photovoltaic systems provide electricity via electronic processes that involve no turbines and no inertia. These two trends—decentralization and much bigger roles for renewables—have also led many grid operators to install growing numbers of battery storage systems, which are electronic devices that also don't intrinsically provide inertia.

New technologies and procedures are emerging to replace some of services that turbine inertia used to provide. For example, electronic devices that can help stabilize grid voltage and frequency. But reliability remains the watchword for modern grids. And how these new electronic systems will perform at scale is still hard to fathom. Inertia remains essential.

Around the world some grid operators are now beginning to grapple with the consequences of declining inertia. In this Energy Insight, we look at this issue with a focus on the experiences of grid operators in Britain as well as in the Nordic regional group. The British grid is of special note because it has seen the most rapid shift to a more decentralized grid and toward much greater roles for intermittent renewable power (mainly wind, but solar as well). In the case of the United Kingdom, policies that decreased the use of generators and favored intermittent renewables pushed the grid in the direction of declining inertia. The loss of inertia was a somewhat unexpected and completely unintended byproduct of those market designs and policies.

The British experience is an important case study for other grid authorities and a reminder that policymakers can pursue new technologies for important reasons: the British shift to renewables has lowered pollution from coal and other fossil fuels. But in the case of the UK, reconfiguration with abundant intermittent power and other actions, including international interconnections and not adding synchronous-turbine-driven new generation, impact grid inertia negatively.

Many other grid operators—in the Nordic nations, parts of the United States such as California, and elsewhere—are facing similar challenges.[3] In the Nordic grid (which comprises Sweden, Norway, Finland, and half of Denmark), premature retirement of nuclear units alongside the expansion of wind power have lowered system inertia and, as a result, forced grid operators to develop and fund an entirely new type of supporting market, offering at the very least an interim mitigating action. The Nordic experience also suggests the need for much clearer system-wide awareness of how digitalized parts of the grid system can fail or affect reliability in ways that were previously unexpected.

These experiences suggest an agenda for many other countries that may be on the cusp of similar ones. Grid systems that move away from power plants with synchronous spinning turbines need a strategy for addressing the loss of inertia. Better situational awareness can help, as can incentives to encourage the retention and production of inertia. This paper looks at those experiences and responses, and outlines what to watch for—so that the coming century, like the last one, is marked by a central role for reliable electric supply.

[3] Victor, Fedor, and Buechler, "Transformation of the American Electric Grid."

1. How Inertia Improves Reliability

The grid frequency is the speed of rotation of the rotating parts of the power system and is measured in Hertz (Hz), i.e., oscillations per second.[4] Synchronous areas, meaning areas that share a grid frequency and thus also share the task of maintaining that frequency, often do not align with country borders or even the jurisdiction of electricity trading systems. For example, the US grid is split into three synchronous grids (or “interconnections”). By contrast, twenty-four nations across continental Europe share a common synchronous grid.

The design frequency of all global power grids is either 50 Hz[5] or 60 Hz.[6] To maintain the frequency at this predetermined stable level, a precise balance between production and consumption across the system is required. The objective for "normal operation" is that the frequency should be kept within ± 0.1 Hz from its nominal value. If the frequency deviates outside the range ± 0.5 Hz from the nominal level, in most grids the system enters "emergency operation mode" and can suffer partial blackouts, both planned and unplanned. If the deviation becomes even more serious it may cause a system failure and breakdown, with a complete loss of power supply. Such a situation can take significant time to restore, with extreme consequences both economically and to human well-being.

Maintaining control and controllability over grid frequency is therefore paramount in any power system. Control starts with generators. Electric power production units can either be synchronously or asynchronously connected to the power system. Turbines and generators of synchronously coupled generation units rotate at the same speed within a system, which corresponds to the frequency of the system. Their rotational energy is, in effect, a kind of storage. It gives the system an "inertial buffer" against changes, which makes it resistant to disturbances that may affect frequency. If, for example, a large consumer, a production facility, or an interconnecting cable is lost, a momentary imbalance arises. Big interruptions like these can be on the order of 1 to 1.5 gigawatts (GW)—the size of some of the world’s largest nuclear or coal plants.

Because electric supply must always equal consumption—that’s how grids operate, by connecting suppliers and users literally at the speed of light—the grid must respond to this loss. The lost supply is compensated for by the slowing down of the rotation of all synchronous units connected to the system (thus, the frequency is reduced), and the drained energy from this slowdown is released to the grid in the form of electrical production that compensates for the loss of supply. The greater the inertia of a system, the slower and smaller the frequency change for any given disturbance. Inertia therefore creates time for the system's active power regulation to respond and stabilize following disturbances.

A mental model describing system frequency and the role of inertia according to real physical principles can be presented via a “bathtub analogy,”[7] as seen in figure 1. Here, power production corresponds to the addition of water into the tub from the tap at the top, while consumption is the flow out of the drain at the bottom. In this model, the water level represents the grid frequency, which remains stable as long as the flow in (production) and flow out (consumption) are equal. Any disturbance, meaning an increase or decrease in flow in either direction that causes the rates of the two to differ, will cause the water level (or frequency) to start changing. If there’s a blockage in the drain (i.e., falling consumption), the water level (and frequency) will start to rise. If the water pressure falls and the tap at the top starts supplying

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[4] The frequency corresponds to how often the voltage goes from its highest point to its lowest point and back to its highest point. If the mains frequency is ~50 Hz, this means that the electrons in the power lines go back and forth fifty times in a second, or that the voltage goes from 325 V down to -325 V and back to 325 V fifty times per second in your electrical outlet. The so-called effective mean voltage in such a system is 325 V/√2 = 230 V.

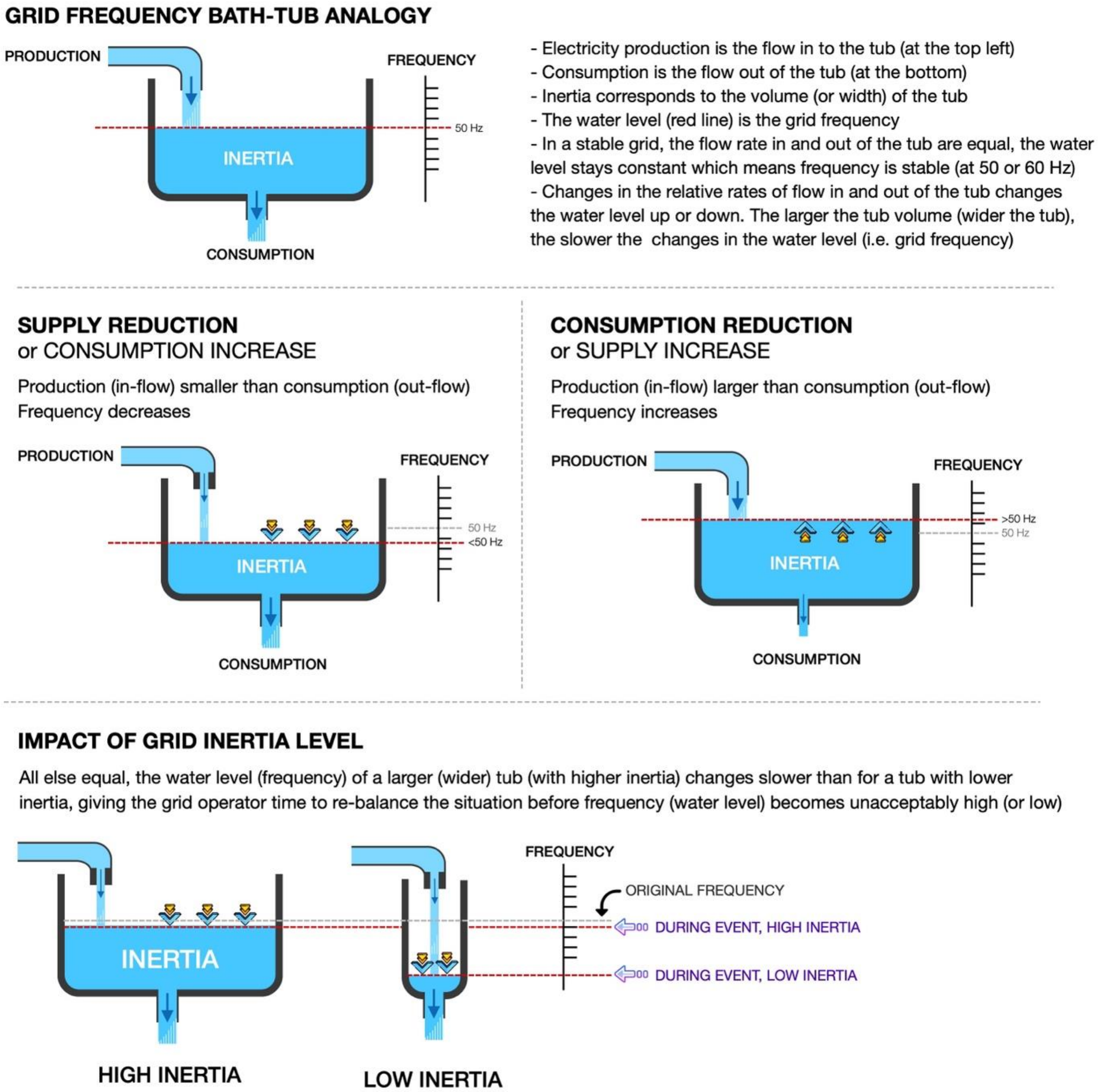
[5] Grids with 50 Hz include all of Europe, Africa, the Middle East (with the exception of Saudi Arabia), and Asia (with the exception of the Philippines, Taiwan, South Korea, and western Japan), and South America south of Bolivia.

[6] Grids with 60 Hz include the United States, Canada, Mexico, Central America and the Caribbean, and northern South America (i.e., Brazil and Peru).

[7] Joseph Eto et al., *Frequency Control Requirements for Reliable Interconnection Frequency Response*, Energy Analysis and Environmental Impacts Division, Lawrence Berkeley National Laboratory, 2018, https://gridintegration.lbl.gov/publications/frequency-control-requirements.

less water, the water level (and frequency) will start falling. The larger the tub, the slower and smaller the change in water level for a given imbalance. The volume of water in the tub is analogous to the inertia of the power system.

Figure 1: The Role of Inertia in Managing Grid Frequency: a Bathtub Analogy



Source: QuantifiedCarbon

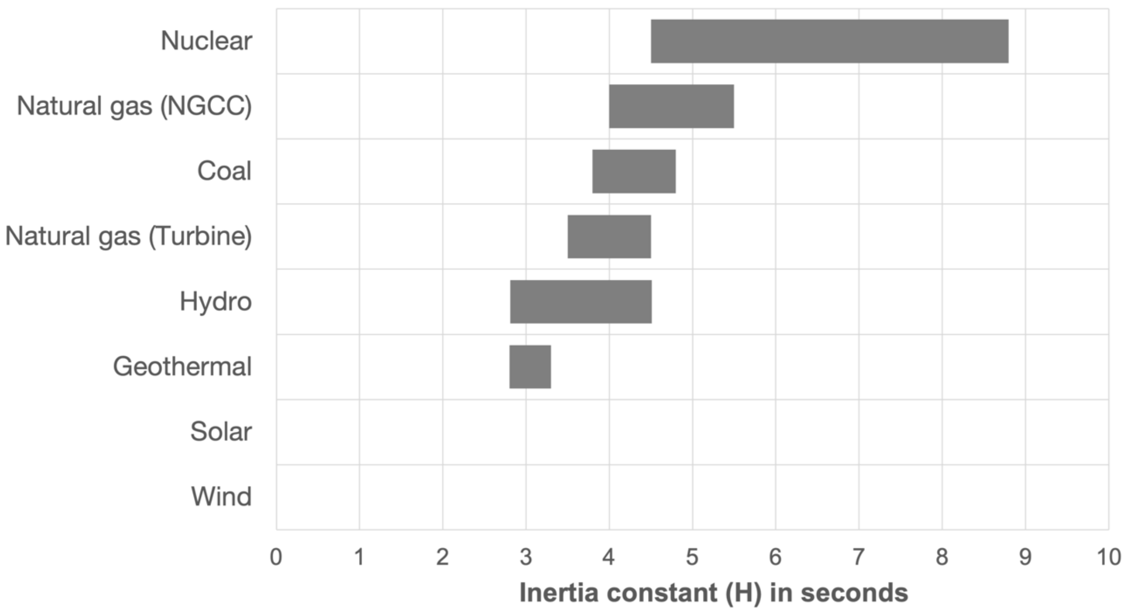
The inertia of a grid, overall, is measured in the unit of gigawatt-seconds (GWs). Each single production unit's ability to add rotational energy to the system is measured by an inertial constant (H) in the unit of seconds—shown in figure 2.[8] Only synchronously connected production units that spin with the frequency of the grid can contribute to the system inertia directly. Moreover, they typically only contribute when in operation and supplying power to the grid, which is one reason why grid operators

[8] The inertial constant is defined as the unit's rotational energy (GWs) divided by its production capacity (GW). A power plant supplying the grid with 0.5 GW of power with 3 GWs of rotational energy therefore has an inertial constant of 3/0.5 = 6 seconds.

who are worried about grid stability often order extra generators to be synchronized and generating power, even if all that additional power is not needed at that moment.[9]

Synchronized units, which are the only ones that can add inertia to a grid, typically include larger thermal power plants that make use of steam and gas turbines (nuclear, coal, natural gas, oil, biomass, waste, and geothermal), as well as the turbines in hydroelectric power plants, and pumped hydro power storage plants. Wind turbines have inherent rotational energy—after all, they work when enough wind is available to rotate the blades—but today's wind technologies don't involve synchronously connecting the units to the grid.[10] Solar photovoltaics completely lack rotating parts and stored energy. Neither wind nor solar power therefore make any natural contribution to the system's inertia; at the extreme, a synchronous power system fed entirely by solar and wind generation, without any other compensatory measures, would therefore have zero inertia, be extremely sensitive to any disturbance, and probably be highly unreliable.

Figure 2: Typical Magnitudes of the Inertia Constant (H) for Different Types of Power Generation



Source: QuantifiedCarbon

Figure 2 reflects that the heaviest rotating masses on any grid, which often provide the highest inertia both in relative and absolute terms, are the steam turbine sets of large nuclear power plants. For the largest individual nuclear units with a power rating above 1200 megawatts (MW), the shaft string with its turbines and generator rotors can be up to 70 meters long and have a total rotating mass exceeding 1100 tons. Turbines this large operate at "half speed," meaning this mass is rotating at half the frequency of the grid (1500 revolutions per minute for 50 Hz grids, 1800 for 60 Hz grids), to limit tensile stress. It takes a huge amount of energy to either speed up or slow down such a heavy component, which is the intuition behind the dampening effect such a turbine has on any disturbance in the grid. Detailed calculations of inertia contributions for individual plants are relatively rare in the public domain,

[9] Some turbines are designed for operation as "synchronous condensers," which is an operational mode where they provide inertia but no active power production.

[10] Through blade pitch control, a type of delayed synthetic inertial response can be provided by certain turbines. But this is still an evolving technology and, for most wind turbines in operation today, adding synchronicity requirements would constrain operations in ways that probably would lower the ability of wind turbines to provide raw power to the grid. Today most wind turbine policies focus on power, not inertia.

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however; for example, the Swedish Oskarshamn-3 reactor, currently the world's most powerful boiling water reactor, contributes up to 13.25 GWs with a corresponding inertia constant of about 8 seconds.[11]

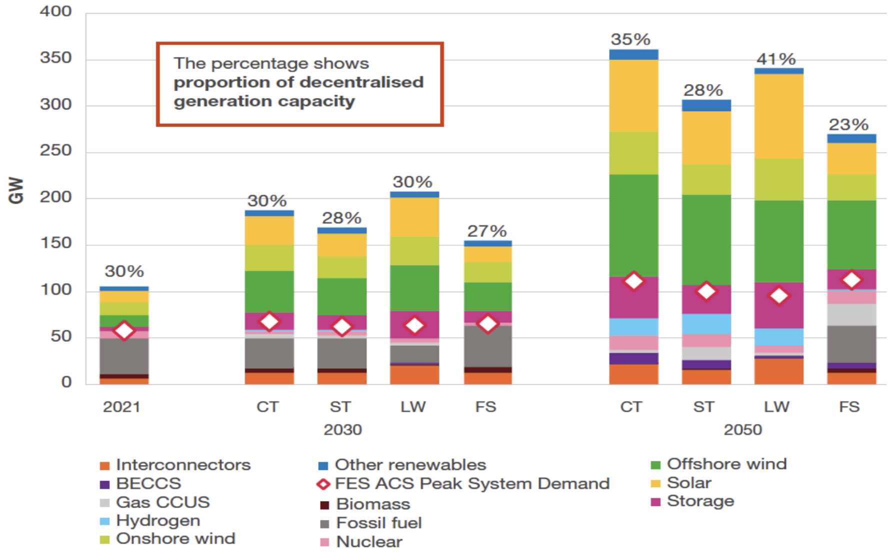
A power system must be able to cope with a loss of the largest single component while staying within limits for total frequency deviation.[12] It is interesting to note that inertia requirements are independent of the size of the power grid as a whole and depend only on the size of the maximum disturbance the grid should be able to handle. The most challenging future frequency management situations will therefore arise in smaller isolated power systems that are planning to transition to a large fraction of zero-inertia power generation (i.e., solar PV and wind) while maintaining large possible individual faults, such as major interconnecting cables and offshore wind farms in the UK and Ireland (1400+ MW faults in small, isolated grids), or large solar PV farms in smaller grids in the Middle East.

2. The UK Grid: Context

Britain is on the forefront of grappling with loss of inertia and responses. As in most countries, Britain has adopted policies to promote renewable power, a source of electricity that is particularly intermittent. What's different is the speed at which the country has made the shift and is planning to continue its grid transformation. It is that speed of change that has sent grid operators scrambling to address looming shortfalls in inertia.

Figure 3 shows today's British grid, with about 100 GW of supply and a peak load of about 50 GW, comparable to California's grid. Half of Britain's supply capacity is renewable—roughly an equal mix of offshore wind, onshore wind, and solar. Britain is not sunny, but solar power is politically popular. Onshore wind is politically fraught because turbines and the powerlines that connect them to the grid are aesthetically unappealing to many voters. Offshore wind, however, is located at a considerable distance from shore in the North Sea and out of sight for most Britons—except for where power lines come ashore—its power can be brought to the grid with increasingly large, long-distance power lines.

Figure 3: Shifting to More Decentralized Generating Capacity



CT: Consumer Transformation; ST System Transformation; LW: Leading the Way; and FS Falling Short

Source: "Future Energy Scenarios," National Grid ESO (2023): 129, https://www.nationalgrideso.com/document/283101/download.

[11] John Edvardsson, "Kärnkraftens Bidrag Till Elkraftsystemets Stabilitet," 2019, https://www.uppsatser.se/uppsats/369d12cc13/

[12] RoCoF = Rate of Change of Frequency.

Every future scenario that British energy regulators have outlined as possibilities, shown in figure 3, forecast sizeable increases in renewables—especially offshore wind and solar. By 2050, the only spinning turbines left on the British grid from technologies that are known and can be deployed reliably today are the nation's nuclear plants and, possibly, some fossil plants. New gas turbines with carbon capture and storage (CCS), new hydrogen-powered turbines, and new bioenergy plants with CCS (so-called BECCS) could also provide inertia. So far, however, none of those futuristic plants operates on today's British grid.

Thus, inadvertently, British energy policy has created a significant challenge for grid operators: replacing lost inertia. The failure to anticipate this challenge early enough and to create the incentives to avoid the looming inertia crisis have left grid operators with fewer options and greater reliability risks.

In the past, inertia was provided "for free" because most British power came from coal and then from natural gas-powered turbines. By generating electricity, those turbines also automatically generated inertia. With the nation's coal fleet phasing down, that has left inertia mainly to a huge fleet of natural gas plants. That dependence has proved extremely costly to Britain as gas prices soared with the global economic recovery and the disruptions to energy markets caused by Russia's invasion of Ukraine.

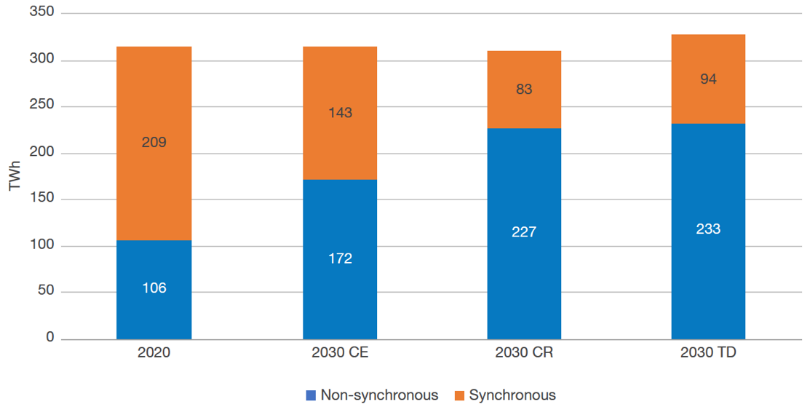
High and volatile gas prices have imposed an economic burden on Britons, as a share of the national gross domestic product (GDP), that is greater than energy crises in the past—including the energy crises of the 1970s.[13] Moreover, that inertia is set to disappear as the national plans to phase out its dependence on gas—although for the near term gas has become so expensive and also potentially unreliable in supply that the electricity system operator (ESO), National Grid, has contracted to keep five coal plants open to provide power when needed and also contribute to inertia.[14] The remaining nuclear plants will keep providing inertia, but they are a small part of the nation's generating capacity (about 15 percent of annual generation and 7 percent of installed capacity) and are not actually compensated for the inertia they generate. All existing UK nuclear capacity except for the Sizewell B reactor is to be retired before the end of the decade, with 3.2 GW of new capacity coming online at Hinkley Point C: the net result being about a halving of the total nuclear capacity in the near term.

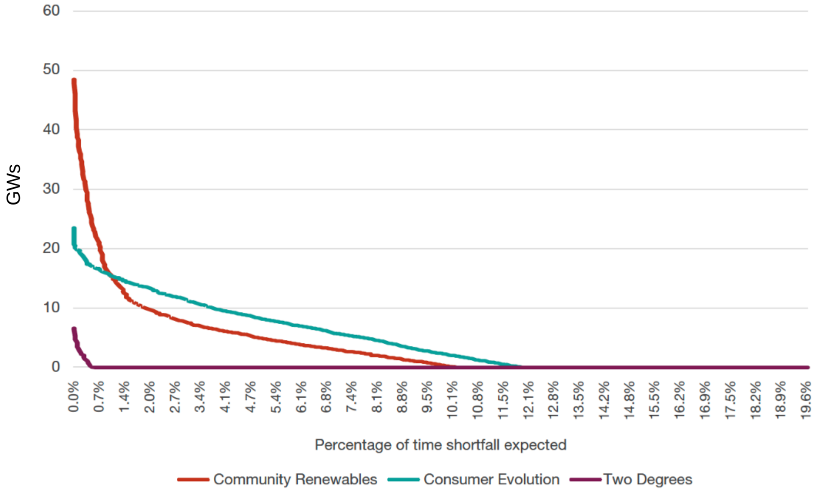
The challenge for grid operators can be seen by looking across three charts. Figure 4a shows the shift from synchronous spinning generators (i.e., generators that provide inertia) to nonsynchronized generators over the coming decade.

Most visions for the future of the UK grid are consistent with a doubling in unsynchronized generation and a proportional reduction in synchronized generation. This study, part of the British ESO's reliability planning system, looks only to the year 2030—when the shift in power supply is expected to be extensive, but total demand for electricity won't be much different from today. Beyond 2030, power demand is expected to rise as more end uses are switched from oil and natural gas to electricity. Nearly every study of deep decarbonization finds that decarbonization is least costly when it involves massive electrification.[15]

[13] Will Matthis, "Energy Crisis May Have Bigger Impact on Households Than 2008 Crash," Bloomberg, August 25, 2022, https://www.bloomberg.com/news/articles/2022-08-25/uk-energy-crisis-risks-squeezing-households-more-than-2008-crash.
[14] Fintan Slye and National Grid ESO Staff, *Winter Outlook Report ESO*, Strategy Report, October 6, 2022, https://www.nationalgrideso.com/research-and-publications/winter-outlook.
[15] Intergovernmental Panel on Climate Change, ed., "Energy Systems" in *Climate Change 2022-Mitigation of Climate Change: Working Group III Contribution to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change* (Cambridge: Cambridge University Press, 2023), 613–746, doi:10.1017/9781009157926.008.

Figures 4a and 4b: A Shift in Types of Generators and Rising Concerns about Inadequate Supply





Three scenarios: Community renewables (CR), Consumer evolution (CE), Two degrees (TD)

Source: National Grid ESO Operability Strategy report, Dec 2021,
"Operability Strategy Report," *Electricity System Operator for Great Britain* (2021): 40, https://www.nationalgrideso.com/document/227081/download.

3. The Strategic Importance of Grid Inertia

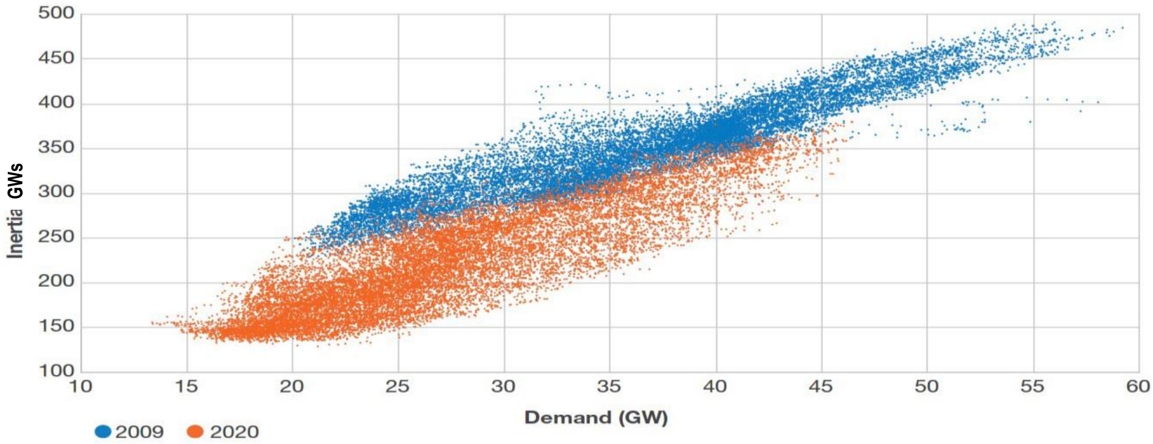
Ultimately what matters most for reliability is not the total volume of synchronous generation over a whole year—such as in the scenarios shown in figures 3 and 4—but the volume of turbines spinning at any given moment. In the middle of the night when power demand is low and wind output is high, inertia can fall to dangerously low levels—at which point nonsynchronous generators need to be curtailed, additional fossil generators with spinning turbines must be activated and, at times, the grid operator also deloads nuclear plants to stabilize their contribution to the grid. By contrast, inertia can be extremely high on a cold winter day with little wind and huge demand for electric heating—because under those conditions, nearly all power generated comes from gas turbines along with the nation's fleet of nuclear reactors.[16]

Figure 5 shows these instantaneous measures of inertia for every day in two different years: 2009, a representative year before the nation's huge shift to renewables, and 2020. During the later part of this period, British policymakers began exploring strategies to replace locally generated electricity, with spinning turbines fired with natural gas, by importing more power over long distance high-voltage direct current (HVDC) power lines. As that policy unfolds it will amplify the inertia-losing challenges because HVDC lines do not intrinsically add inertia along with generation. Over that period the ESO also pioneered methods for measuring inertia in real time. The typical inertia on the UK grid in 2020 was 200 GWs. Frequency on the 50 Hz grid is allowed to vary inside a band of +/- 0.5 Hz, and a typical imbalance between supply and demand is about 1 GW for a few seconds. That imbalance can be absorbed as torque on the grid's synchronous generators by drawing down about 4 GWs. These kinds of calculations lead the UK grid operators to demand that inertia not drop below 140 GWs (or below 130 GWs after a major imbalance), lest the grid be put in a condition where it could easily become destabilized.[17]

As shown in figure 5, there were already many moments in 2020 when the grid experienced the 140 GWs floor, and typical inertia on the grid that year was less than half the level of a decade earlier. Because of greater decentralization of energy supply, the demand for grid power shifted left, which also lowered inertia. An even bigger force in lowering inertia was the switch to renewables, which accounts for most of downward shift from the blue dots to the orange dots in figure 5.

That problem of inertial loss is set to get much worse without intervention, as shown in figure 6, which estimates [average national inertia] for four scenarios comparable with those in figure 3. Each one posits continued declines in inertia, and the earliest and fastest declines arrive with the "leading the way" scenario that envisions the fastest rate of decarbonization and the most profound shifts in how the society and energy systems are organized.

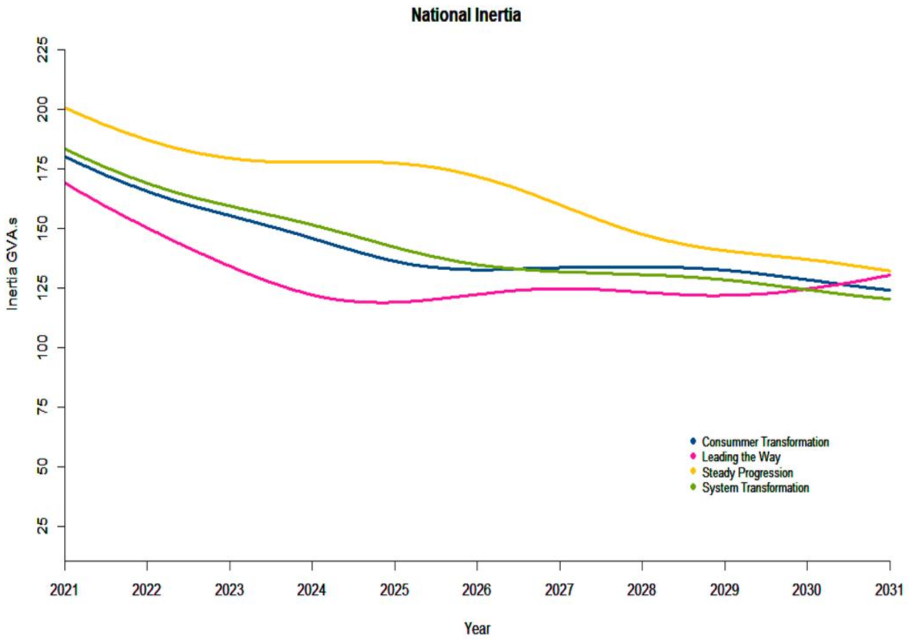
Figure 5: A Decline in Inertia on the UK Grid (2009 to 2020)



Source: National Grid ESO Operability Strategy report, Dec 2021,
"Operability Strategy Report," *Electricity System Operator for Great Britain* (2021): 26, https://www.nationalgrideso.com/document/227081/download.

[16] At the extreme, of course, winter demand—which is when the UK grid sees its typical peak, unlike grids such as in California, where air-conditioning and summer cooling needs drive peak demand—can be so high that loads must be curtailed. That scenario now looms for extreme winters. See Todd Gillespie and Elena Mazneva, "UK Grid Warns of Winter Power Cuts in Tight Energy Market," Bloomberg, October 6, 2022, https://www.bloomberg.com/news/articles/2022-10-06/uk-grid-sees-risk-of-winter-power-cuts-in-tight-energy-market.
[17] Kathryn Porter, "Measuring Grid Inertia Accurately Will Enable More Efficient Frequency Management," *Watt-Logic* (blog), October 12, 2017, https://watt-logic.com/2017/10/12/inertia/.

Figure 6: National Inertia in Four Scenarios (2021 to 2031)



Note: The four scenarios in this graph (from the 2021 UK assessment) are the same as those in figure 3 (2023).

Source: "National Trends and Insights. A System Operability Framework Document," *Electricity System Operator for Great Britain,* (2021): 11, https://www.nationalgrideso.com/document/190151/download.

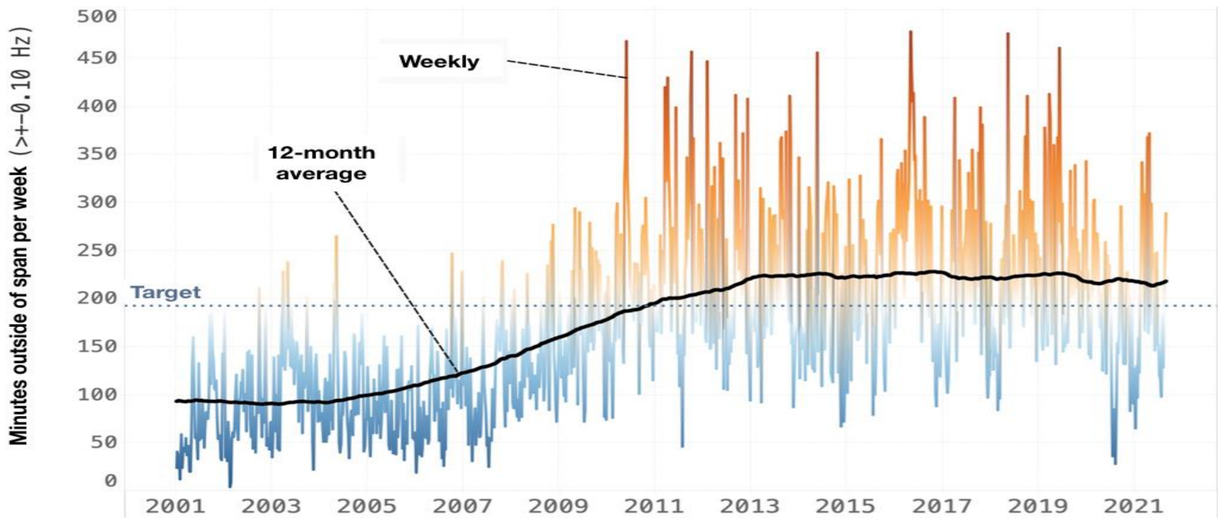
4. Stories That Rhyme: The Experience in the Nordic Synchronous Area

The Nordic synchronous area, which is a grid region with a common frequency encompassing Sweden, Norway, Finland, and half of Denmark, has been on a similar trajectory to that of the UK, with increases in both intermittent renewable power generation (mainly wind power) in absolute and relative terms, as well as an expansion of HVDC interconnectors. This development has led to a deterioration in grid frequency management in the Nordic synchronous grid, as can be seen in figure 7. This deterioration has been kept under control in part due to significantly higher spending on frequency control functions by the grid operators. Even so, operators have been unable to bring quality back below the set target of less than 200 minutes per week outside of the ±0.1 Hz frequency band. Costs to manage the situation rose by 400 percent from 2014-15 to 2021 (based on data from the Swedish grid operator specifically) and are projected to more than double again in the coming five years.

A downward trend in system inertia can already be observed in the Nordic system, with lower peak values, lower average values, and most critically, lower minimum values (see figure 8). In windy summer periods with low power demand, the Nordic power system now sees inertia levels approaching 100 GWs, as zero-inertia and zero-marginal-cost wind makes up a large proportion of total generation. The correspondingly depressed power prices mean the inertia-contributing hydroelectric fleet is idled, while nuclear plants typically shut down for scheduled maintenance during the summer.

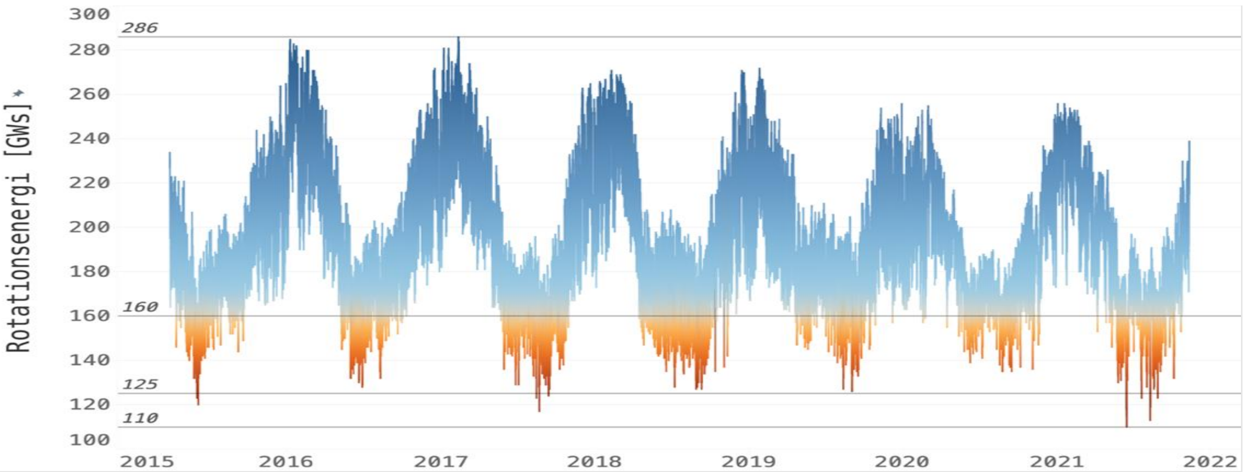
To improve stability, the Nordic power grid operators have recently introduced new national markets for fast frequency support services called FFR (fast frequency reserve). These are currently national markets, but they are to be merged into a common grid market at a later stage. When the operational conditions of low inertia and relatively high dimensioning faults coincide, the FFR market is activated in order to compensate for the lack of inertia. One such activation point for the Nordic FFR market is a grid inertia below 155 GWs and a dimensioning fault of 1450 MW, which is already a common situation throughout the summer months of the year. The resources in the FFR market consist of very quick production responses from, for example, ramping up hydropower turbines or batteries, or the rapid disconnection of consumption via electric boilers and furnaces. Modified wind power turbines could in theory also contribute to the FFR market, but none have so far qualified as suppliers.

Figure 7: Frequency Deviations in the Nordic Grid System (in minutes per week)



Source: QuantifiedCarbon

Figure 8: Inertia in the Nordic Grid (2015 to December 31, 2021)



Source: QuantifiedCarbon

If the trend toward even lower inertia systems continues, simply backing the system up with larger FFR market volume is unlikely to suffice. A recent study that looked at a “100 percent renewable” Swedish power system estimated that the full suite of compensatory measures would also need to include a fleet of synchronous condensers equipped with large flywheels in addition to a greatly expanded FFR market in order for Sweden to provide its fair share of stability services. The analysis found that costs for this type of service would increase by a factor of twenty compared to a system with a maintained or expanded nuclear capacity.[18] In Australia, costs for frequency control have already risen by a factor of seven (since 2015), with batteries coming into use in an attempt to provide services that were, until recently, essentially provided "for free" by large synchronous generations.[19] The costs of compensating for reduced grid inertia are still relatively small compared to the overall costs of the power system, on the order of a few percent of total costs, but challenges are growing rapidly and need to be carefully and continuously reassessed.

While some studies have hailed the rapid transition to software-controllable components without inertia contributions as a potentially positive development for grid stability and controllability, real world practitioners have remained far more cautious, and software-based approaches can also bring new and severe challenges. In the Nordic power grid, the dimensioning fault has traditionally been a loss of its largest generating unit, the 1450 MW Oskarshamn-3 nuclear reactor mentioned above. A new software-based fault category has recently emerged with potential impacts that dwarf those conventionally considered. Software error in new high-voltage direct current interconnector terminals—which are critical in support of a more intermittent weather-dependent production system—can cause faults in both directions (oversupply and undersupply) of magnitudes far greater than the loss of any individual generator. On the February 17, 2023, the 1400 MW capacity HVDC link Nordlink that connects Norway and Germany was transmitting at 1372 MW flow from Germany (continental grid) to Norway (Nordic grid). A software error in the Nordlink control system then instantaneously shifted flow from near-maximum import to 348 MW of export (from Norway to Germany), causing an undersupply of 1720 MW in the Nordic grid. Frequency dropped by almost 0.6 Hz (to 49.4 Hz) before stabilizing, thankfully benefiting from the large inertia available from synchronous generators in wintertime (when demand and synchronous generation is at its highest for the Nordic system). A similar fault also occurred during testing of the HVDC system in 2020. The maximum possible fault of this type, an instantaneous supply balance change of 2800 MW, would cause unacceptably high frequency deviations in the Nordic grid system even with a very large share of synchronous generation available. Such emerging software-based errors, either in HVDC terminals, inverters, or other grid components, happening in a nonsynchronous-dominated grid with low inertia, would highly likely cause serious blackouts.

5. Challenges for Grid Authorities

The British grid operator has sounded alarms about the decline in inertia because it could affect the reliability of the grid. In its latest strategic assessment of grid operations, the authority identified five overlapping concerns—each of which influences reliability (table 1).

First and foremost, inertia affects frequency response for the reasons identified earlier. The sheer mass of spinning turbines: multiple turbines driven by steam or gas, linked to a rotating generator, all turning at 3000 rpm. (Turbines at nuclear plants—much bigger than typical fossil fuel generators and suppliers of even more inertia—spin at half that speed due to their large size and mass.) Related, and second, inertia confers stability on the grid—reducing the number and severity of frequency deviations in the first place.

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[18] Confederation of Swedish Enterprise, "Grid Support Services, Power System Scenarios until 2050," 2022, https://www.svensktnaringsliv.se/sakomraden/hallbarhet-miljo-och-energi/stodtjanster_1185903.html.
[19] Joel Gilmore, Tahlia Nolan, and Paul Simshauser, "The Levelised Cost of Frequency Control Ancillary Services in Australia's National Electricity Market," *The Energy Journal* 45, no. 1 (2024), https://doi.org/10.5547/01956574.45.1.jgil.

Table 1: Five Attributes Essential to Grid Reliability and Linked to Inertia

Grid Attribute	Why Inertia Matters	Responses
Frequency	Mass of spinning turbines allows frequency deviations to be converted to/from torque.	New devices that regulate and moderate frequency and contain frequency deviations. Reserves that offer quick (<60 seconds) and slow (<15 minutes) recovery and restoration of frequency.
Stability	Reduces the number and severity of frequency variations and other events.	Improved operations, allowing the grid to run reliably with lower inertia. New containment mechanisms (see frequency above) to prevent instabilities from propagating across the grid. New technologies—developed through the "pathfinder" program—that can simulate inertia.
Voltage	Generators that provided inertia also offered large amounts of "reactive power" that can be used to manage voltage levels. Decline in reactive power, as well, due to grid decentralization and more local generation that grid operators don't control.	Installation of new technologies designed to create and absorb reactive power and better controls to reduce needs for reactive power. Possible manipulation of EV charging and heat pumps—which requires closer cooperation with distribution grids and policymakers—could reduce reactive power needs.
Thermal	Because fuel for fossil plants was easy to transport, generators could be distributed in many locations, which reduced the number of critical paths on the grid—reducing the consequences that thermal limits or failures on any single power line would harm the grid as a whole. Shifting to renewables (and to more interconnectors with grids in other countries) will increase critical power flows: by 2030, some areas will see peak power flows 400 percent greater than current capabilities.	Better forecasting to identify thermal limits on the grid due to much greater usage of power lines along with options for dispatching power plants in new ways to avoid thermal limits; better coordination of transmission constraints, including for massive offshore wind farms. Redesign of boundary capabilities on the transmission system and more responsive demand loads. Building more power lines.
Restoration	High inertia units were also easy to utilize for a "black start" of a grid that had failed. Since 2021, new UK government policies have set stronger goals for restart capabilities to lower the odds of multiday grid failures.	New procurement mechanism for restoration services. New technologies that allow renewable and battery systems to provide black start capabilities; similar innovations, still to be tested at trials, that allow black start on distributed systems.

Source: Author analysis based on National Grid ESO Operability Report (2021).

The generators that supplied inertia also helped provide many other services that allow for grid stability. Those included voltage support—an attribute of alternating current (AC) grids that comes from injecting and removing "reactive power" from the grid so that voltages remain in narrow bands.

Similarly, the power generators being removed from the grid were also well-tested and reliable systems for restarting the grid after a massive failure—a so-called "black start" that works by restoring pockets on regional grids and then expanding and linking together synchronously these electrified systems back to a single national integrated grid. New technologies—some available, many others still being tested—make it possible in principle to provide reactive power and black start capabilities without conventional spinning turbines. But there is a world of difference between imagining how these technologies might work and actually deploying them with the degree of reliability to be expected on modern grids.

Because reliability of grids is a function of the system as a whole, there are even deeper insights that come from looking at how each of these five elements of grid reliability might interact. Difficulties in assuring frequency stabilization can interact with failures to stabilize voltage—and those interactions can be affected by thermal limits or even failures on critical large components of the transmission network. As studies of tightly coupled complex systems have shown, it is these kinds of correlated failures—often arising in ways that are hard for experts to predict fully—that lead to large system failures.[20]

6. Can New Technologies Save the Day?

Since renewables such as solar photovoltaics and wind power do not contribute directly to system inertia, a commonly proposed solution to handle grid stability, as well as the issue of intermittent supply, is the use of batteries. In this setting, batteries can supply what is known as "synthetic" or "virtual" inertia.

While fast-responding batteries can greatly improve grid stability by rapidly helping to restore and recover from failures, they do not provide an identical service to that of actual spinning synchronous machines. For example, conventional battery systems with grid-following inverters inevitably respond with some delay. This delay may allow faults to propagate and cause cascading failures through the system, from which grid operators may be unable to recover—in effect, assuming that batteries will be available to provide inertia may give grid operators false comfort until there is a lot more experience and probably a lot more demonstration of innovations under conditions of grid stress. By contrast, sufficiently available real inertia avoids such rapid-event risks. More advanced and costly battery installations with grid-forming (rather than following) inverters can in principle provide a service more akin to actual inertia. However, to what extent batteries and grid-forming inverters could take the place of conventional inertia in large power systems is an open question that is actively researched.[21]

The role of batteries today in real large-scale power grid operation is not to replace inertia, but more importantly to help restore the system over a span of seconds following a disturbance until slower-responding restorative power-generation resources become available.

7. Conclusions: Assuring Reliability While Learning New Strategies

The experiences in all these countries reviewed in this paper are warnings that the challenge of inertia will not automatically solve itself. As grids move rapidly to renewables and greater roles for interconnections what was once a prodigious supply of inertia—a byproduct of turbine power generation that few worried about—can change quickly. At least four lessons are emerging.

First, measurement and projections are essential. As UK planners realized they faced a decline in inertia, they needed to develop measurement systems and, crucially, link those systems to grid

[20] Charles Perrow, *Normal Accidents: Living with High-Risk Technologies*, Revised Edition (Princeton, New Jersey: Princeton University Press, 1999), https://press.princeton.edu/books/paperback/9780691004129/normal-accidents.

[21] See Paul Denholm et al., *Inertia and the Power Grid: A Guide Without the Spin*, National Renewable Energy Laboratory, NREL/TP-6120-73856, 2020, 35: "The costs (or need) to develop a system that can reliably operate under near zero-inertia conditions has yet to be analyzed in detail, particularly in comparison to maintaining the current synchronous-based system with sufficient modification to accommodate very high levels of VG penetration."

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operations so that they could devise appropriate limits for inertia while assuring reliability of the grid. Even more important were better forecasting systems so that the long-term trajectory of the grid (and inertia) could be projected, along with extreme stress tests. While very long-term forecasts were illustrative, the most important time horizons have been the next decade—the period relevant for transmission and operations planning. As many leaders say, organizations "manage what they measure." Inertia is no different.

Second, innovation and application of new technologies has been important, but great care is needed to match expectations for technology with proven realities. Around the world governments have funded innovation programs; where private investors have seen incentives to innovate, they have done more of that as well. Britain has created a "pathfinders" program that invests in inertia-replacing technologies and runs trials with real devices connected to the grid. There are pathfinder investments in technologies that synthesize many of the services that have been provided by inertia, such as containment of frequency events and synthetic reactive power.[22]

For the UK—a large industrial economy—these experiments could be justified by the technological advance of the country and the large benefits that would accrue at home. The country also has benefited from actively monitoring and participating in grid management technology experiments in other countries. For smaller grids and countries not operating at the global technological frontier, the lessons to be learned include the need to track technological progress in the rest of the world and to prepare to run experiments with proven technologies in the local context. Every country that faces the decline in inertia needs to identify its mix of local innovation and global sourcing of new technologies and strategies for managing the reduction in inertia and providing alternative supplies. In most countries—probably all—the global perspective will be extremely important. As with many technologies, the ability to source new ideas from a global market creates huge local benefits—in this case, benefits in the form of better management strategies for inertia and grid reliability.

Third, incentives and market design are important. Reconfiguration of the grid has been happening to no small degree because policy incentives and market design pushed the grid in this new direction. The loss of inertia was a somewhat unexpected and completely unintended byproduct of those market designs and policies. More participants in the market can search for solutions if there are incentives to do so. The new UK procurement for black start capabilities is a good example, as are new goals for needed procurement of reactive power. New modeling tools have made it possible to explore new configurations of power plants that could replace some or all lost inertia—for example, combinations of large nuclear plants with battery storage systems that can help provide frequency response.[23] Other examples include the Fast Frequency Reserve (FFR) market, launched in the Nordic countries in May 2020, that is designed specifically to handle low-inertia situations. Looking to the future, Australia will be launching similar markets in October 2023 to deal with the inertia problem; Australian policy makers are also exploring the creation of a spot market for procurement of inertia.[24] Australia is already facing an inertia shortfall in 4 out of 5 grid regions, a situation which is rapidly becoming more serious. The Australian grid operator AEMO states that in the relatively near term to manage a situation where 100% of the demand is met by non-synchronous generation (solar & wind), the country's grids will need resources beyond those envisioned from the new FFR markets – they will also need to install the equivalent of up to 40 new large-scale synchronous condensers fitted with flywheels to handle minimum inertia requirements.[25] AEMO expects a diversity of market incentives and new technologies to solve such challenges, but at present the pathways to a solution are not yet clear. Important "areas for innovation" include whether FFR markets could substitute for minimum inertia requirements, and what

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[22] Julian Leslie et al., "First Phase of Stability Pathfinders Delivered," National Grid ESO (website), April 5, 2023, https://www.nationalgrideso.com/news/first-phase-stability-pathfinders-delivered.

[23] Vincenzo Trovato, Agnès Bialecki, and Anes Dallagi, "Unit Commitment With Inertia-Dependent and Multispeed Allocation of Frequency Response Services," *IEEE Transactions on Power Systems* 34, no. 2 (March 2019): 1537–48, https://doi.org/10.1109/TPWRS.2018.2870493.

[24] https://aemo.com.au/initiatives/major-programs/fast-frequency-response

[25] This value is under the assumption that synchronous pumped hydro facilities are also available and contributing inertia – https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/operability/2022/2022-inertia-report.pdf?la=en

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role grid-forming technologies could and should play in the future system. The possibilities are hard to imagine today, and with the right incentives more actors will have incentives to seek them.

Fourth, and perhaps most important: be careful. Grid reliability is essential to electricity's role in the modern economy. Rapid loss of inertia can quickly create conditions that make it harder to assure reliability, even as new technologies and investments such as new power lines could, in time, allow new grids to be operated with high reliability. Loss of inertia prematurely can be dangerous. It also can, among other things, lead grid operators to take measures that run directly contrary to other national goals—such as prolonging the lifetime of older polluting power plants because new systems are not yet in place to assure reliability.

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