Grid-Forming Technology in Energy Systems Integration

Report by the Energy Systems Integration Group's High Share of Inverter-Based Generation Task Force

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COVER PHOTO

Hornsdale Power Reserve, a transmission-connected battery energy storage system where field tests of a GFM inverter were carried out (photo courtesy Neoen Australia)

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High Share of Inverter-Based Generation Task Force
Reliability Working Group of the Energy Systems Integration Group

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Contents

Abbreviations

AEMO	Australian Energy Market Operator
BESS	Battery energy storage system
CNC	Connection network code (Europe)
DER	Distributed energy resource
EMT	Electromagnetic transient
eSCR	Effective short-circuit ratio
ESCRI	Energy Storage for Commercial Renewable Integration (Dalrymple BESS in Australia)
FACTS	Flexible alternating current transmission systems
GB	Great Britain
GET	Grid-enhancing technology
GFL	Grid-following
GFM	Grid-forming
GW	Gigawatt
H	Inertia constant
HVDC	High-voltage direct current
Hz	Hertz
IBR	Inverter-based resource
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers
kV	Kilovolt
MVA	Mega-volt ampere
MVAr	Mega-volt ampere reactive
MW	Megawatt
NEM	National Electricity Market (Australia)
NGESO	National Grid Electricity System Operator (Great Britain)
PLL	Phase-locked loop
POI	Point of interconnection
PPM	Power park module
PV	Photovoltaic
RoCoF	Rate of change of frequency
SCR	Short-circuit ratio
STATCOM	Static synchronous compensator
SVC	Static VAR compensator
VMM	Virtual machine mode
VOC	Virtual oscillator control
VRT	Voltage ride-through
VSM	Virtual synchronous machine
VSM0H	Virtual synchronous machine with zero inertia

Executive Summary

As rising numbers of inverter-based resources (IBRs) are deployed in power systems around the world, their role on the grid is changing and the services needed from them have evolved. In order to maintain grid stability and reliability, IBRs need to provide some of the services currently (or formerly) provided by synchronous generators. Interconnection standards already include requirements for IBRs to have the capability to provide some of these services—such as frequency and voltage support—and the procurement and deployment of the services can be implemented either as mandatory interconnection requirements or as market products.

Nearly all of the IBRs deployed today are grid-following (GFL), and essentially read the voltage and frequency of the grid and inject current to provide the appropriate amount of active and reactive power. The fundamental GFL IBR design assumption is that there is still a sufficient number of synchronous generators on the grid to provide a relatively strong and stable voltage and frequency signal, which GFL IBRs can "follow." But since levels of GFL are increasing, there will be a limit to how far GFL controls can be pushed, and, at some point, new advanced inverter controls (termed grid-forming (GFM)) will be needed to maintain system stability. GFM IBRs will also be needed to establish voltage and frequency during operating conditions when there are zero synchronous machines (100 percent IBR penetration).

The Technological Leap

Power systems around the world are at the point of now needing to make this technological leap; however, system operators and planners, equipment owners, and manufacturers today are facing a circular problem regarding the deployment of advanced IBR controls (Figure ES-1, p. 2). Which comes first, the requirement for a capability or the capability itself? How do grid operators know what performance or capability is possible from new equipment (and therefore what they could conceivably require)? How can they evaluate costs and benefits of having such equipment on the grid? What drives manufacturers to invest in new technology without its being mandated for interconnection to the grid or otherwise incentivized by the market?

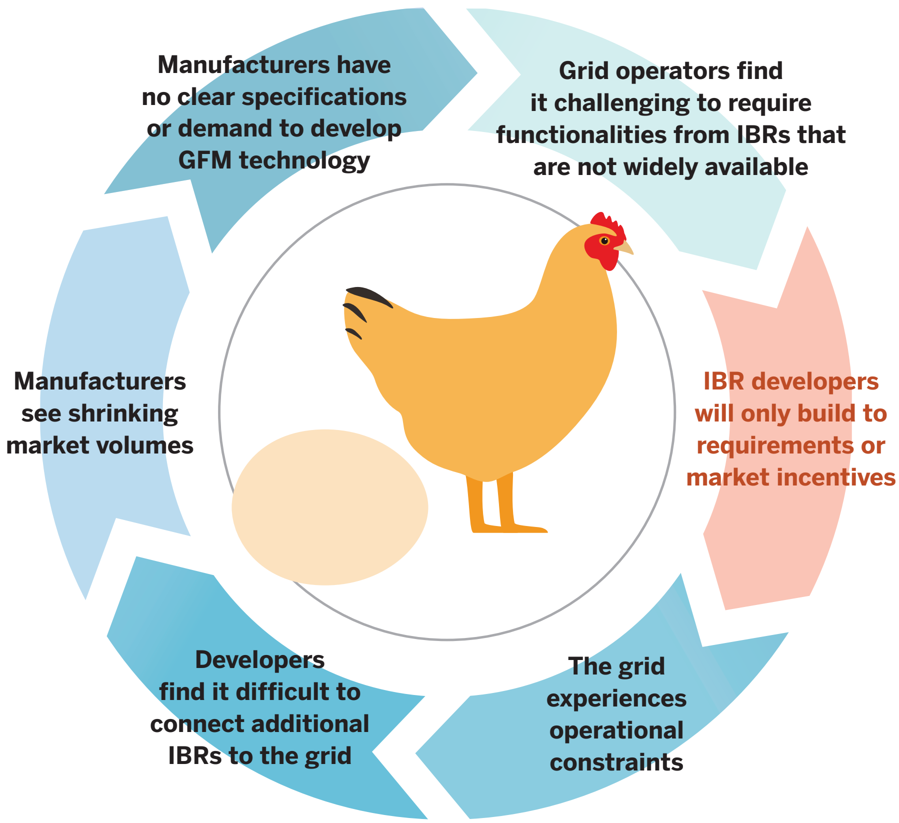
System operators and planners, equipment owners, and manufacturers are facing a circular problem today regarding the deployment of advanced IBR controls. Which comes first, the requirement for a capability or the capability itself?

The Cost of Inaction

Failure to break the cycle may have far-reaching negative consequences, hindering our ability to meet energy transition targets and increasing the costs of this transition. The cost of inaction today could be very high. Interconnection queues around the world have hundreds of GW of IBRs. Among those, battery storage is particularly low-hanging fruit for the deployment of GFM capability. This is a commercially available technology that has few trade-offs around design and implementation. However, in the absence of clear requirements and market incentives, all of these resources will be built as GFL, further increasing the number of GFL IBRs in power systems

FIGURE ES-1

The Circular Problem of Requirements and Deployment of Advanced IBR Controls



A self-reinforcing "chicken-and-egg" cycle exists today that prevents the widespread availability of IBRs with the new advanced functionality needed to support a high-renewables grid. The orange text shows the key element of the chicken-and-egg cycle that limits the deployment of GFM technology today.

Source: Energy Systems Integration Group.

and, consequently, increasing those systems' needs for additional reliability support.

However, with clear requirements and market mechanisms providing incentives, a significant proportion of these battery storage resources could be equipped with GFM functionality today, avoiding the costs of installing much larger additional grid-supporting devices or additional grid reinforcements in the future.

Breaking the Cycle Through Adoption of a System Needs Perspective

Rather than being locked in the chicken-and-egg problem between GFM capability and requirements for that capability, we need to approach the problem from the perspective of evolving system needs, using the following steps as a guide (see Figure ES-2, p. 3):

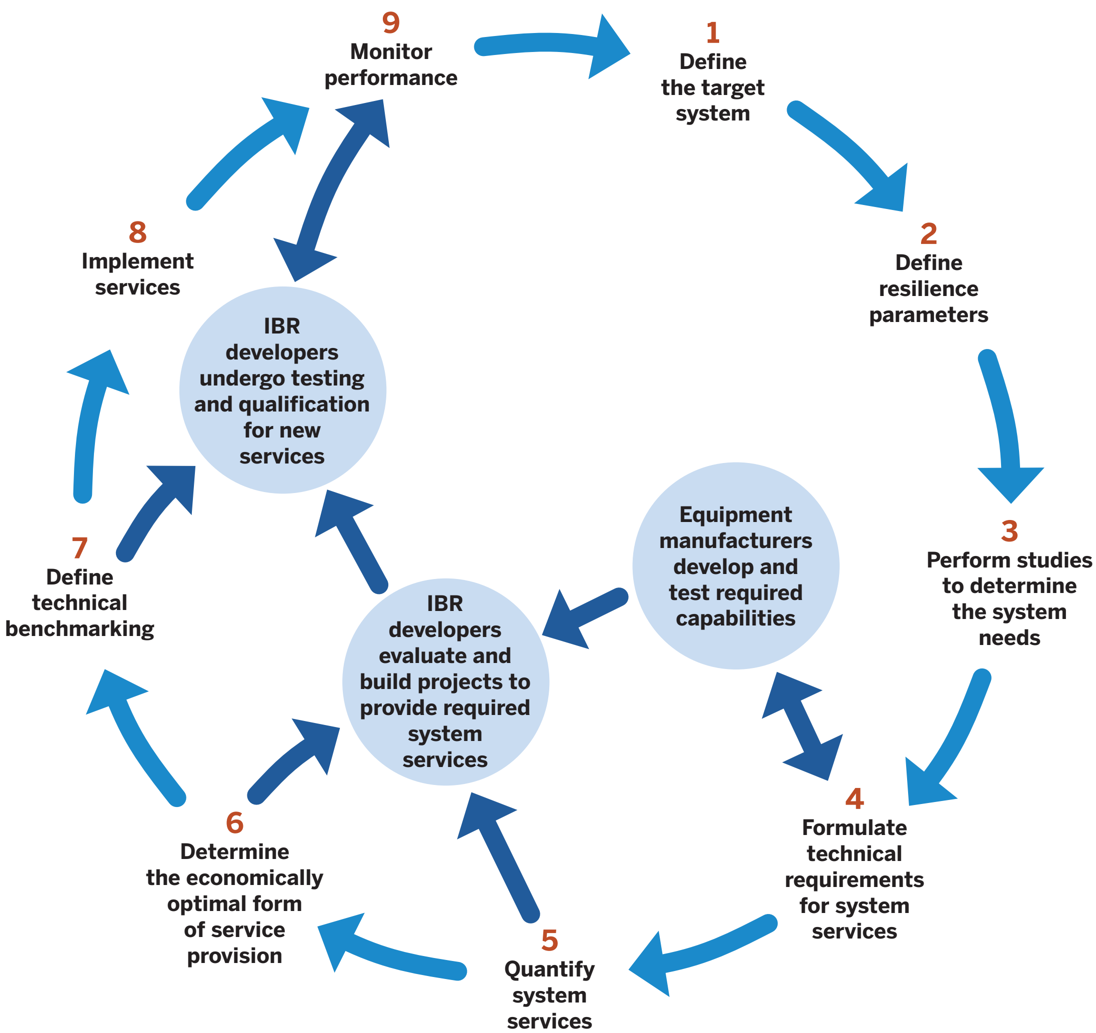
1. **Define the target system.** The target system is defined in terms of energy quantities, expected shares of the different power sources including storage, and expected sinks (loads (including electrification of transportation and heating), storage). If necessary, different scenarios for several points in time with key data may be specified based on policy goals.
2. **Define resilience parameters.** Desired resilience against certain disturbances is defined in terms of resilience parameters with which the target system should be able to cope without any (or with limited) impact on security of supply. The maximum amount

of load shedding permitted during low-frequency, high-impact system disturbances is also defined. The trade-off between costs to the grid and costs to resources to conform with defined resilience parameters is considered. This is a policy-driven decision.

3. **Perform studies to determine the system needs.** Studies are conducted to determine the type and scope of the minimum system needs in order for the system to be able to operate within the defined resilience parameters.

FIGURE ES-2

Proposed Process for Deploying New Grid-Forming Capabilities



In the proposed process for deploying new GFM capabilities to serve system needs, the outer circle follows steps 1 through 9 as discussed in the text, while the three inner elements show how the nine steps relate to IBR equipment manufacturers and project developers and owners. Steps 1 through 9 are not set in stone and will likely need to be an iterative loop as systems and technologies continue to evolve.

Source: Energy Systems Integration Group.

4. **Formulate technical requirements for system services.** Technical performance requirements are defined for necessary system services based on the identified system needs. This will inform the design, dimensioning, and, consequently, costs of the equipment providing the services. The objective is to enable as many system users as possible to provide system-supportive services, since the provision of grid services tends to become more economical for grid operators if there are several alternative providers.
5. **Quantify system services.** For each service, a methodology to quantify amounts is developed. For increased efficiency and reduced costs, varying quantities of services are procured, where practical, based on system conditions.
6. **Determine the economically optimal form of service provision.** The most efficient way to meet the demand for each of the services is decided. The appropriate trade-off between market-based solutions and mandatory requirements established by connection rules needs to be arrived at from technical and economic perspectives.
7. **Define technical benchmarking.** For both approaches above (market-based solutions and mandatory requirements established by connection rules), detailed technical benchmarking is developed and specified to verify performance at the commissioning stage of service providers and in their operation.
8. **Implement services.** The dates of the implementation of new services and any transitional arrangements are determined. Tender or other selected market forms for the procurement of market-based services are executed.
9. **Monitor performance.** For both approaches, performance is monitored during service delivery and compliance with technical performance requirements verified on an ongoing basis.

Early Adopters

The paradigm shift from a power system dominated by synchronous generators to one dominated by control-driven IBRs can only be achieved with close cooperation between system operators, equipment manufacturers, and equipment owners. This collaboration is critical in defining system needs, understanding equipment capabilities, and developing requirements and mechanisms to deploy new advanced control technology in coordination with existing systems.

Some power systems, such as those in Great Britain, Germany, Hawaii, and Australia, are experiencing high shares of IBRs, and are already on the path of reforming grid services and incentivizing their provision by IBRs with advanced controls, while others are just starting the journey. Successful GFM IBR pilots in Australia and Great Britain are a clear enabler to gain knowledge and experience with this new technology and are already providing valuable feedback into the deployment process.

Tools and Models

The process of defining and deploying new system services requires detailed engineering and economic studies. As the generation mix continues to evolve toward higher shares of control-driven IBRs (both GFL and GFM), simulation tools also need to evolve. While phasor-domain simulations remain at the center of stability assessment, they increasingly need to be supplemented with electromagnetic transient studies and small-signal analysis. In addition, since studies are not only being used for overall stability assessment but also in lieu of IBR testing, the accuracy of IBR models becomes paramount to ensure reliability. And lastly, there is a need for tighter integration of various study processes tying stability studies more closely to other analytical and economic assessments, to ensure that study assumptions are realistic, are consistent throughout, and capture stability risks under all relevant grid conditions.

This report discusses GFM IBRs and their role in a modern grid. The report is aimed at a technical audience and complements the recent *IEEE Power and Energy Magazine* article "A Future with Inverter-Based Resources" (Matevosyan et al., 2021), which outlines the challenges of operating with high shares of IBRs in grids with low system strength and low inertia and discusses potential mitigation options, including GFM technology. In this report, we discuss the differences between GFM and GFL IBRs, the fundamental system needs which must be met to maintain reliability, global experiences in formulating GFM requirements, characterization and testing of GFM IBRs, and the key modeling and simulation tools needed by system planners and operators to rigorously study grid stability in a high-renewables future.

1 Introduction

As growing numbers of inverter-based resources (IBRs) are deployed—including wind turbines, solar photovoltaic (PV) arrays, and batteries—their role on the grid is changing, and the grid services needed from them have evolved. IBRs differ from conventional synchronous generators in that they are not physically synchronized to the grid but rather are interfaced through power electronics. As a result, IBRs do not inherently respond to disturbances on the grid, as synchronous machines do. This poses both challenges and opportunities to a grid that was historically designed around synchronous generators.

Evolution of IBRs to Date and Remaining Challenges

Two decades ago when IBRs were scarce, they were allowed—or even required—to cease operation during disturbances on the grid. But gradually, as shares of these resources began to increase, such behavior exacerbated the severity of system disturbances. Consequently, interconnection standards for IBRs evolved to ensure that they are able to ride through certain types of frequency and voltage disturbances without disconnection and can also contribute to fault recovery.

Increasing levels of IBRs have also led to the decommitment and, in some cases, retirement of synchronous generators that were providing system services to support voltage and frequency, either inherently, mandatorily, or through market products. In order to maintain grid stability and reliability, IBRs need to provide some of these services such as frequency and voltage support. Requirements of capability for these services are now being included in interconnection standards, and the rules for their procurement and deployment can be implemented as mandatory interconnection requirements or market products.

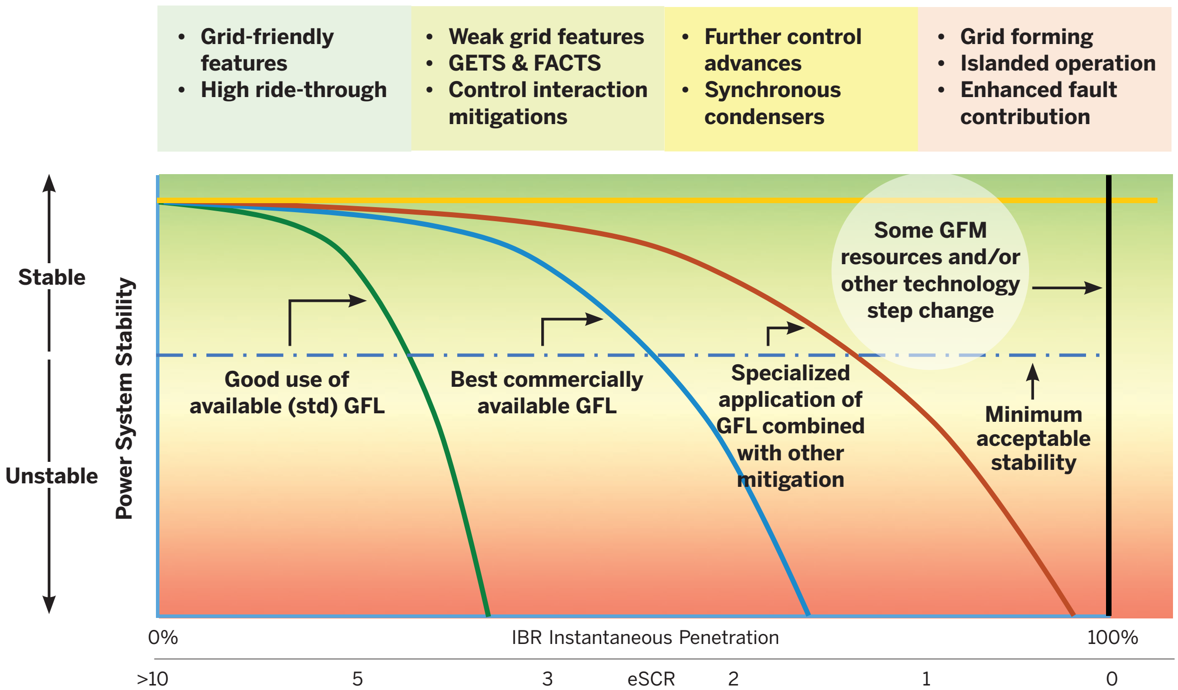
With higher shares of IBRs and retirements of synchronous generation, system needs that were previously served by synchronous generators need to be served by IBRs.

However, even with ride-through and the implementation of additional functionalities, there is a need for IBRs to provide additional reliability support as shares of IBRs continue to increase. Nearly all of the IBRs deployed today are grid-following (GFL); they essentially read the voltage and frequency of the grid and inject current to provide the appropriate amount of active and reactive power. The fundamental GFL IBR design assumption is that there is still a sufficient number of synchronous generators on the grid to provide a relatively strong and stable voltage and frequency signal for these inverters to "follow."

But as grid strength declines due to declining levels of synchronous machines, the grid becomes more susceptible to transient voltage instability risk, and GFL IBRs become more susceptible to converter instability risk. Enhanced controls and parameter-tuning of GFL IBRs have helped to reduce these risks as GFL IBRs have been refined to work in systems with lower and lower grid strength. However, there will be a limit to how far GFL controls can be pushed, and at some point new advanced inverter controls (termed grid-forming (GFM)) will be needed to maintain system stability. GFM IBRs will also be needed to establish voltage and frequency during operating conditions when there are no synchronous machines (when we get to 100 percent IBR penetration).

FIGURE 1

Technology Enablers to Promote the Shift to a 100 Percent Renewable Future



The left side of the figure shows that while instantaneous levels of IBRs are low and system strength is relatively high, available "off the shelf" GFL IBR solutions are sufficient. In the center of the figure, IBR levels are rising and more IBRs are interconnected in areas with low system strength. Here, the controls of GFL IBRs need to be enhanced, or additional equipment to improve system strength needs to be installed. The right side of the figure shows that to go beyond levels of 75 to 80 percent, the development of new GFM controls is needed on IBRs and other FACTS devices.

Note: eSCR = effective short-circuit ratio; FACTS = flexible alternating current transmission systems; GETs = grid-enhancing technologies; GFL = grid-following; GFM = grid-forming; IBR = inverter-based resource. System strength on the second x-axis is shown in terms of effective short-circuit ratio, the short-circuit ratio of an equivalent local area with high shares of IBRs.

Source: GE and HickoryLedge.

Figure 1 illustrates the stages of this paradigm shift. The two stages on the left represent where we have been: making the most of incremental updates to existing equipment and controls to maintain stability in areas of the grid with high levels of IBRs. The use of enhanced controls of existing GFL IBR technology to the maximum extent possible has been very successful in enabling relatively high instantaneous levels of IBRs, system-wide or locally. However, to move beyond this, a more fundamental shift is needed, shown toward the right side of the figure. This is where a keen focus is needed on the development of new advanced inverter controls and the deployment of other mitigation measures (such as synchronous condensers, GFM static synchronous compensators (STATCOMs), etc.). GFM controls are relatively new and still being researched and developed; however, there are already GFM IBRs installed by equipment vendors in both microgrids and larger grids around the world. Though not depicted in Figure 1, it is important to note that in parallel with the evolution of inverter controls and capabilities, requirements for IBR models and study tools have also been advancing, with the growing demands on model accuracy and detailed, computationally intensive simulation tools.

The Technological Leap

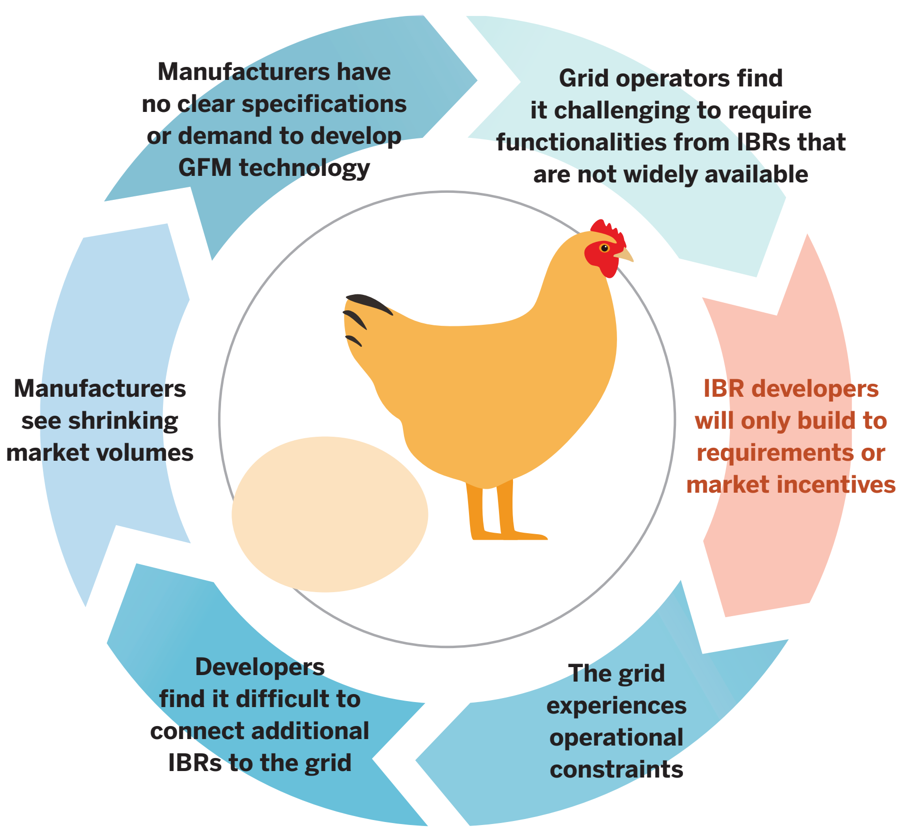
Power systems around the world are at the point now of needing to make this technological leap. Figure 2 (p. 7) describes a circular problem that system operators and planners, equipment owners, and manufacturers are facing today regarding the deployment of advanced IBR controls. Which comes first, the requirement for a capability or the capability itself? How do grid operators know what performance or capability is possible from new equipment, and therefore what they could conceivably require? How can they evaluate costs and benefits of having such equipment on the grid? What drives manufacturers to invest in new technology without its being mandated for interconnection to the grid or otherwise incentivized by the market?

With higher shares of IBRs and retirements of synchronous generation, system needs that were previously served by synchronous generators need to be served by IBRs. However, system operators are finding it challenging to procure or mandate services from IBRs to serve system needs without fully understanding IBRs' capabilities—existing or potential. This leads to operational constraints in which system operators keep a certain amount of synchronous generation online to serve system needs, and curtail IBR output. As a result, it becomes more difficult and less economical to connect more IBRs, which in turn leads to shrinking markets for manufacturers and diminished opportunities to deploy advanced IBR control technologies. Simultaneously, manufacturers are unable, or unincentivized, to deploy new advanced IBR controls because they lack clear technical specifications on what is required from IBRs to serve system needs.

Figure 2 specifically calls out the deployment of GFM technology, but the dilemma applies generally to many

FIGURE 2

The Circular Problem of Requirements and Deployment of Advanced IBR Controls



A self-reinforcing "chicken-and-egg" cycle exists today that prevents the widespread availability of IBRs with the new advanced functionality needed to support a high-renewables grid. The orange text shows the key element of the chicken-and-egg cycle that limits the deployment of GFM technology today.

Source: Energy Systems Integration Group.

Hundreds of GW of battery storage are in interconnection queues that, in the absence of clear requirements and market incentives for advanced inverter technologies, will be built as GFL resources, consequently, increasing systems' needs for additional reliability support. However, with clear requirements and market mechanisms providing incentives, a significant proportion of these battery storage resources could be equipped with GFM functionality.

new technological capabilities for IBRs. IBR capabilities, such as fault ride-through, frequency response, or enhanced inverter controls in weak grids, have initially experienced limited adoption in the absence of specific technical requirements or market incentives to deploy them. Just because manufacturers develop new capabilities does not guarantee they will be successfully deployed: since the purchasers of generation equipment are not the direct benefactors of the advanced grid-friendly technology, they may often opt not to invest in it in the absence of additional incentives.

To break the chicken-and-egg cycle it is imperative that researchers, manufacturers, equipment owners, system operators, and policymakers work together to: (1) cohesively develop requirements, standards, technologies, and deployment mechanisms that reflect evolving grid reliability needs; and (2) identify practical capabilities of equipment to effectively address those needs. System reliability needs should be translated into clearly defined reliability services that may be sourced from new transmission assets (e.g., GFM STATCOMs), either obtained through mandatory interconnection requirements established by the system operator, procured through market mechanisms, or incentivized in other ways, for example, by reducing curtailment.

The Cost of Inaction

Failure to break the cycle may have far-reaching negative consequences, hindering our ability to meet energy transition targets and increasing the costs of this transition. For example, the energy policy target of the European Union is to achieve carbon neutrality by 2050. This can be achieved only if the electricity sector relies on renewable energy sources, which are typically IBRs. Such a system would regularly operate at very high instantaneous levels of IBRs, and system stability can be ensured only with a sufficient level of GFM assets. The cost of inaction can also be observed in the United States and elsewhere, where there are hundreds of GW of battery storage in the interconnection queues that, in the absence of clear requirements and market incentives for advanced inverter technologies, will be built as GFL resources. This will further increase the number of GFL IBRs in power systems and, consequently, increase those systems' needs for additional reliability support. However, with clear requirements and market mechanisms providing incentives, a significant proportion of these battery storage resources could be equipped with GFM functionality. Installing a GFM resource today will help to avoid the costs of installing much larger additional grid-supporting devices or additional grid reinforcements in the future, as illustrated with the example given in the appendix.

The goal of this report is to clarify the need for, capabilities of, and deployment mechanisms of GFM technology to enable the power system transformation necessary for a decarbonized future. The report complements a recent *IEEE Power and Energy Magazine* article, "A Future with Inverter-Based Resources" (Matevosyan et al., 2021), which details the challenges of operating high shares of IBRs in grids with low system strength and low inertia, and discusses potential mitigation options. The report provides references to relevant publications throughout and more specifically builds on earlier work that explored capabilities and needs for GFM technology including the National Renewable Energy Laboratory's *Research Roadmap on Grid-Forming Inverters* (Lin et al., 2020) and the North American Electric Reliability Corporation's white paper "Grid Forming Technology, Bulk Power System Reliability Considerations" (NERC, 2021).

This report is intended primarily for power system operators, network owners, regulatory bodies, equipment developers, and equipment owners, as we believe that a top-down approach extending from broad system needs to specific equipment capabilities will most efficiently accelerate the commercial deployment of IBRs with GFM capability.

First, the report provides an introduction to GFM controls, discusses the differences between GFM and GFL inverters, and briefly introduces several GFM control implementations. It then starts on one side of the chicken-and-egg problem—the system needs—and discusses those needs that were previously served solely by synchronous generators (either inherently or through defined services) but that increasingly need to be provided by IBRs or other technologies. The report then moves on to a discussion of system services that need to be clearly defined in the grid codes and mandated or procured through market products in order to meet system needs in a high-renewables grid. It provides recommendations on the best practices for breaking the chicken-and-egg problem by clearly specifying new system services, and discusses various initiatives around the world.

To address the other side of the chicken-and-egg problem, the report then discusses the capabilities of GFM inverters to serve grid needs. It offers guidelines for how these capabilities can be tested and demonstrated in a lab environment and through simulation studies, and describes the field performance of two GFM projects in Australia during actual grid disturbances.

As with any new technology, new simulation models and tools are required to evaluate impacts of GFM inverters on power systems as well as to determine the types and amounts of reliability services needed. To this end, the report gives an overview of the tools and modeling needs for power systems with increasing shares of GFL and GFM IBRs. The final section of the report presents conclusions and recommendations and identifies future research and development needs for the wider deployment of GFM technology.

2 Grid-Forming vs. Grid-Following Inverter-Based Resources

Most inverter-based resources (IBRs) today use grid-following (GFL) inverter controls. Due to the popularity of these inverters and rising installed capacity levels, it is critical to understand their properties, dynamic behaviors, and potential to contribute to grid reliability. This is an area of active research in academia and industry. In addition, grid-forming (GFM) IBRs are beginning to gain traction, with several pilot projects underway and commercial products for GFM battery storage already available.

Definitions and a Brief Comparison

The primary objective of both GFL and GFM IBRs' controls is to supply active and reactive power to the grid; however, GFL and GFM behavior in the transient time frame—during and immediately after a system disturbance—is fundamentally different.

Grid-Following

A GFL IBR maintains active and reactive components of its output current at a constant value during the transient time frame. To do this, the GFL IBR relies on a fast-acting synchronizing function typically using a phase-locked loop (PLL) that determines the angle of the grid voltage at the IBR's point of connection. The inverter uses this measured angle to tightly control the active and reactive components of the current it supplies. In other words, the controls "follow" the measured grid voltage. If the controller cannot accurately and quickly track the external voltage, a GFL IBR cannot maintain controlled, stable output.

In the transient time frame, GFL IBRs appear to the grid as constant current sources. Most IBRs in service today are GFL.

Grid-Forming

A GFM IBR maintains an internal voltage phasor in the transient time frame, with the magnitude and frequency set locally at each inverter. GFM IBRs can be controlled to operate in an electrical island ("forming" the grid voltage and frequency). They can also be controlled to synchronize to an external grid. This allows GFM IBRs to immediately respond to changes in the external system phase angle, providing additional active and reactive power in the transient time frame as necessary. If properly configured, this can provide stability in the controls during challenging network conditions and can be further enhanced with supplemental controls and equipment. In certain adverse grid conditions, however, synchronization may still be lost.

A GFM IBR maintains an internal voltage phasor in the transient time frame, with the magnitude and frequency set locally at each inverter.

In the transient time frame, GFM IBRs appear to the grid as voltage sources, as long as the resulting currents remain within inverter current limits and an energy buffer is available.

There are many variations of both GFM and GFL inverter controls, as briefly described in the next subsection. Both types of controls are subject to physical equipment constraints including voltage, current, and energy limits; mechanical equipment constraints (on wind turbines); and external power system limits.

TABLE 1

Comparison of Grid-Following and Grid-Forming Controls

Inverter Attribute	Grid-Following Control	Grid-Forming Control
Reliance on grid voltage	Relies on well-defined grid voltage, which the control assumes to be tightly regulated by other generators (including GFM inverters and synchronous machines)	Actively maintains internal voltage magnitude and phase angle
Dynamic behavior	Controls current injected into the grid (appears to the grid as a constant current source in the transient time frame)	Sets voltage magnitude and frequency/phase (appears to the grid as a constant voltage source in the transient time frame)
Reliance on PLL for synchronization	Needs PLL or equivalent fast control for synchronization	Does not need PLL for tight synchronization of current controls, but may use a PLL or other mechanism to synchronize overall plant response with the grid.*
Ability to provide black start	Not usually possible	Can self-start in the absence of network voltage. When designed with sufficient energy buffer and over-current capability, it can also restart the power system under blackout conditions. (Only a limited number of generators on a system need to be black start–capable.)
Ability to operate in low grid strength conditions	Stable operation range can be enhanced with advanced controls, but is still limited to a minimum level of system strength	Stable operation range can be achieved without a minimum system strength requirement, including operation in an electrical island. (GFM IBRs will not, however, help to resolve steady-state voltage stability for long-distance high-power transfer.)
Field deployment and standards	Has been widely used commercially. Existing standards and standards under development define its behavior and required functionalities well.	Has been deployed in combination with battery storage primarily for isolated applications. Very limited experience exists in interconnected power systems. Existing standards do not yet define its behavior and required functionalities well.

* A GFM inverter also needs a synchronization mechanism when it has reached its current or energy buffer limits. If it reaches these limits, it will temporarily fall back to GFL operation and will need to track the grid voltage phasor.

Source: Energy Systems Integration Group.

Basic Principles of Grid-Following and Grid-Forming Inverter-Based Resources' Operation

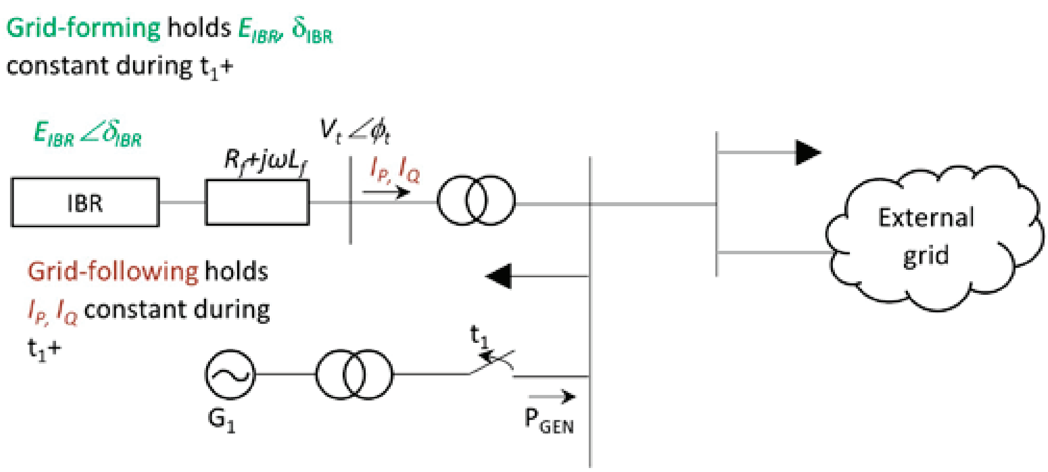
Conventional synchronous generators possess an internal voltage or electro-motive force through electromagnetic induction and appear to the system as a relatively strong voltage; that is, they are a voltage source of a steady magnitude with a relatively small series impedance. Most IBRs are configured with a large capacitor on the DC side that defines the DC-side voltage. This voltage is chopped or modulated by the semiconductors to produce AC output. That AC output is entirely the creation of the control loops and modulators of the inverter but is subject to the limits of that available DC voltage, the power available at the DC side, and the current rating of the semiconductors. IBRs typically have multiple control loops arranged in a hierarchy, the highest level of which is the power control. For GFL IBRs, the power control has the objective of exporting power equal to a dispatch instruction or tracking maximum available power of the resource. For GFM IBRs, in contrast, power control has the objective of drooping frequency and voltage according to the measured real and reactive power flows into the grid.

At a basic level, the power control establishes either a current source or a voltage source. A GFL IBR injects current into an existing grid voltage to which it must synchronize. In contrast, a GFM IBR creates a voltage source, from which current can flow into a grid voltage and to which it will synchronize. A GFL IBR follows a current reference, derived from the power control, and the AC-side voltage (magnitude and phase) is adjusted to force the AC current to follow the reference. For GFM IBRs, the DC voltage is modulated to form an AC voltage directly, or to force the voltage across a filter capacitor to follow an AC reference.[1] Figure 3 (p. 12) illustrates the differences between GFL and GFM principles.

1 This method is called a single-loop GFM. There are other GFM control methods that use a multi-loop in which a middle-level control generates voltage across a capacitor while an inner current-control loop controls the injected current.

FIGURE 3

Grid-Following vs. Grid-Forming Behavior



The figure illustrates the difference between GFM and GFL behavior of an IBR, when generator G_1 disconnects at t_1. In the transient time frame t_1+ the GFM IBR will hold the magnitude and angle of its internal voltage, E_{IBR} and δ_{IBR}, constant. In the transient time frame immediately after the disturbance, this results in the GFM IBR providing necessary current to the grid (within inverter limits). Such behavior may enhance the overall grid stability margin. In contrast, in the transient time frame t_1+ the GFL IBR will be trying to hold active and reactive components of its output current, I_P and I_Q, constant. The grid thus cannot source current from the GFL IBR immediately after the disturbance. This behavior in certain system conditions and under high shares of IBRs may deteriorate the system's stability margin.

Source: Isaacs (2021).

Both types of inverters have an internal AC voltage, $|E_{IBR}|\angle\delta_{IBR}$, that is separated from the voltage at the grid connection point, $|V_t|\angle\phi_t$, by a mostly inductive impedance (formed by the interface or filter inductor), $R_f + j\omega L_f$. The current that flows is:

$$I\angle\phi = \frac{|E_{IBR}|\angle\delta_{IBR} - |V_t|\angle\phi_t}{R_f + j\omega L_f} \qquad (2.1)$$

This current can be viewed as current flowing as a result of E_{IBR} being established (for inverters that are GFM) or current being controlled to follow a current reference by manipulating E_{IBR} (for inverters that are GFL).

The power that flows into the grid can be found from the conjugate of the current, I^*, as:

$$P + jQ = V_t I^* \qquad (2.2)$$

If R_f is small, we can approximate the real power transfer as:

$$P = \frac{|E_{IBR}|\,|V_t|}{j\omega L_f}\sin(\delta_{IBR} - \phi_t) \qquad (2.3)$$

And reactive power transfer as:

$$Q = \frac{|E_{IBR}|^2}{j\omega L_f} - \frac{|E_{IBR}|\,|V_t|}{j\omega L_f}\cos(\delta_{IBR} - \phi_t) \qquad (2.4)$$

For a GFL IBR, the real and reactive power flows are enforced by setting a current reference from the power references (the dispatch instructions or the maximum power point tracking of the resource):

$$(I\angle\phi)_{ref} = \frac{P_{ref} - jQ_{ref}}{|V'_t|\angle\phi'_t} \qquad (2.5)$$

Here, $|V'_t|$ and ϕ'_t are the measured magnitude and angle of the voltage at the connection point as evaluated by the synchronization function of the GFL IBR (typically a phase-locked loop (PLL)). During a large disturbance (for example, loss of G_1 in Figure 3), the PLL may temporarily lose track of an external voltage reference, and a GFL IBR will be keeping current constant in the transient time frame.

For a GFM IBR, the power exported is not fixed directly by a constant reference but is instead a point on a droop characteristic. During a disturbance (for example, loss of G_1 in Figure 3), a GFM IBR will keep the voltage magnitude E_{IBR} and angle δ_{IBR} constant in the transient time frame. As a result of the synchronizing action of the droop controller, the angle difference $(\delta_{IBR} - \phi_t)$ will settle at a value at which the power export gives a frequency ω_E for E_{IBR} that matches the grid frequency ω (a synchronization process similar to that of a synchronous generator), but which also satisfies the droop equation (similar to the speed governor of a synchronous machine):

$$\omega_E = \omega = \omega_0 - m_P (P - P_0) \qquad (2.6)$$

where m_P is the droop coefficient (or slope), ω_0 is the nominal value of grid frequency, and P_0 is the setpoint of power export at the nominal frequency.

The power export is therefore:

$$P = P_0 + \frac{\omega_0 - \omega}{m_P} \qquad (2.7)$$

The setpoints and droop coefficient can be configured to determine the power export from the GFM IBR, but the power export is also subject to variation as frequency changes, within IBR design limits. This variation is central to how IBRs that are GFM contribute to supply-demand balancing, and the droop coefficient sets how the sharing of that duty is determined among all of the GFM IBRs and governor-fitted synchronous machines on the grid. In contrast, GFL IBRs maintain a constant power export with respect to frequency, and therefore do not contribute to supply-demand balancing unless a supplemental frequency control function has been added. In this case, a change in system frequency has to be measured first, and then the GFL IBR responds with a proportional change in active power export, according to its droop characteristic.

Alongside a frequency-power droop, a GFM IBR normally has a voltage-reactive-power droop:

$$|E_{IBR}| = E_0 - m_Q (Q - Q_0) \qquad (2.8)$$

where m_Q is the droop coefficient (or slope) for reactive power, E_0 is the nominal value of voltage, and Q_0 is the setpoint of reactive power export at the nominal voltage.

If $|E_{IBR}| \approx |V_t|$, then the reactive power is:

$$Q = Q_0 + \frac{E_0 - |V_t|}{m_Q} \qquad (2.9)$$

Thus, GFM IBRs not only provide a voltage source characteristic themselves, but also share the duty of meeting the reactive power needs of the system according to their reactive power droop coefficient. Their unique characteristic is providing a voltage source, but not necessarily the droop function. Droop can also be used in the GFL inverter to coordinate voltage regulators used in those controls, even though the grid interface in the GFL inverter is regulating current.

It is important to point out that GFM IBR behavior described above is subject to IBR design limits (based on the inverter's current-carrying capability and available energy buffer). Immediately after a disturbance, the output current of a GFM IBR is not controlled. If the inverter's current rating is reached, it will enter current-limiting mode, maintaining its output current at or below the limit. Various methods are used for limiting the inverter output currents, for example, current control mode or high impedance mode, to protect the inverter hardware during a grid disturbance.

Brief Description of Grid-Forming Methods

Many proposed control concepts exist for GFM IBRs, both phasor-domain and time-domain control structures (Figure 4, p.14). These currently include virtual synchronous machine control (Liu et al., 2017), matching control (Arghir and Dörfler, 2020), droop-based control (Chandorkar, Divan, and Adapa, 1993; Liu, Miura, and Ise, 2016), and virtual oscillator control (both dispatchable and non-dispatchable) (Seo et al., 2019; Lu et al., 2019). All of these concepts are still being researched and developed, and there may be more options developed in the near future. There are already GFM IBRs that have been developed, built, and installed by vendors in both microgrids and larger grids around the world, some of which are discussed in the section "Advanced Characterization and Testing of Grid-Forming Resources" below.

Phasor-Domain Virtual Synchronous Machine Control and Matching Control

Both the virtual synchronous machine control and the matching control aim to mimic the behavior of a synchronous machine. In the former, some of the system-supporting characteristics of synchronous machines are emulated through mathematical implementation of the swing equation along with emulation of constant voltage behind an impedance. The advantage of a virtual synchronous machine compared to a synchronous machine is that a manufacturer can chose which synchronous machine characteristics are beneficial for a particular application. This type of control is currently the most commonly used in GFM IBR pilots, due primarily to its similarity to the familiar synchronous machine behavior. In the matching control concept, the synchronous machine behavior is emulated from the back-end DC side of an inverter, where the flow of current through the DC bus is controlled by making use of the energy transfer relationships between capacitor and inductor elements.

Phasor-Domain Droop-based Control

The droop-based control is a phasor-domain advanced control structure that repurposes well-known droop equations to control the output voltage and frequency of an IBR. This type of control is most commonly used today in microgrid applications. Here, the active power and reactive power output of the IBR is measured at its terminals and used as input terms to the droop equations (2.7) and (2.9) on page 13. The resultant values of frequency and voltage magnitude subsequently govern the nature of the sinusoidal voltage generated by the IBR. This structure has been denoted as Type A. The traditional well-known droop equations (Type B) can also be used to bring about the operation of an all-IBR network if the control loops are appropriately parameterized with a robust control structure to evaluate the frequency of the grid.

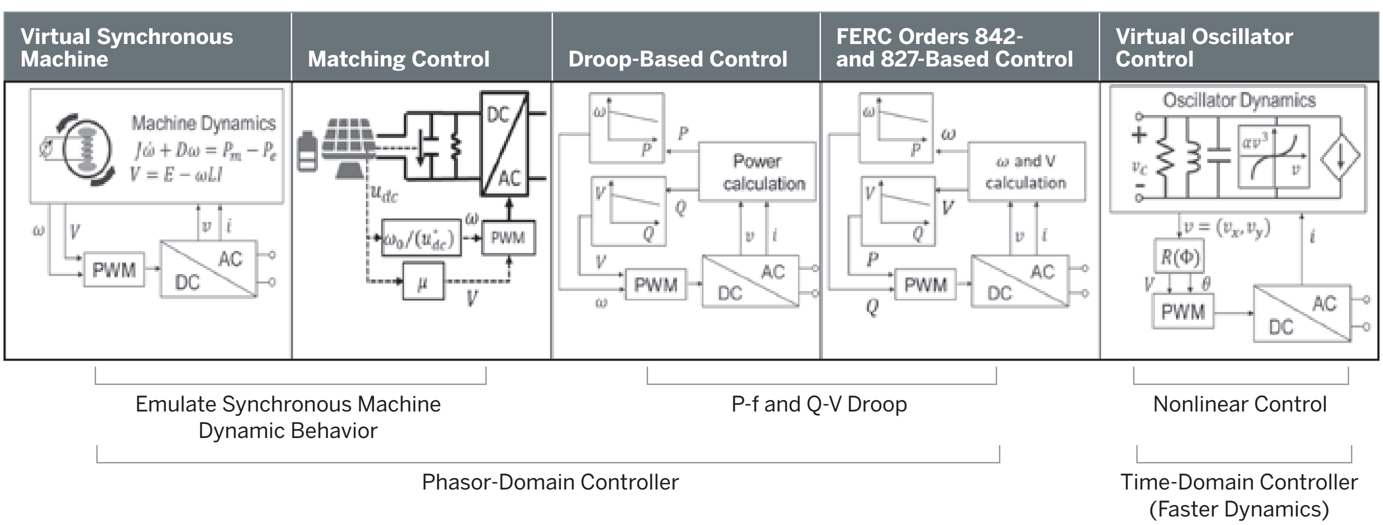
VSM control is currently the most commonly used in GFM IBR pilots, due primarily to its similarity to the familiar synchronous machine behavior.

Time-Domain Nonlinear Control

Lastly, time-domain nonlinear control methods have also been proposed in the research literature. An example is the use of virtual oscillator control in which electrical oscillator circuits are constructed based upon the principles of the Van der Pol equation or Andronov-Hopf bifurcation to generate limit cycles of a specified frequency and voltage magnitude. These limit cycles then serve as the "timing" mechanism of the IBR control structure governing the generated AC voltage.

FIGURE 4

Proposed Control Concepts of Grid-Forming IBRs



Source: Electric Power Research Institute (2020).

3 System Needs

Historically, power system reliability needs have been shaped by the development and deployment of synchronous machines. Those needs are changing with increasing shares of grid-following inverter-based resources (GFL IBRs) and declining shares of synchronous generation. To maintain grid reliability, it is critical to have voltage and frequency support during steady-state operation and under a multitude of disturbances, stability of controls for all individual IBRs, and interoperability across all resources. Grid-forming (GFM) inverters are well poised to meet many of these needs. This section on system needs draws from the report *System Needs and Services for Systems with High IBR Penetration* published by the Research Agenda Group of the Global Power System Transformation Consortium (Bialek et al., 2021). Additional discussion of the ways in which system needs are evolving with growing shares of IBRs can be found in the *IEEE Power and Energy Magazine* article "A Future with Inverter-Based Resources" (Matevosyan et al., 2021).

A Historical Perspective Centered on Synchronous Machine–Dominant Systems

The early history of electricity grids is inextricably linked to the alternators of the time, which we have come to know as synchronous machines. Speed control was achieved with a centrifugal governor, which helped support the operation of generators in parallel with a common system frequency. In a similar manner, automatic voltage regulators, protection relays, and a wide variety of other equipment was designed around the characteristics of the synchronous generators. An example of the co-evolution of synchronous machines and power systems is that protection relays and circuit breakers have been designed to work within the critical clearing time set by the acceleration of rotor of a synchronous machine under short-circuit conditions. Broadly speaking, some principles underpinning a traditional power system based on synchronous machines include the following:

- Generation resources present themselves as voltage sources behind an inductive impedance.
- The synchronization of a generator occurs through variation of power export with angle difference and the accompanying rotor acceleration/deceleration as expressed by the swing equation.
- Imbalances between supply and demand are indicated by changes in overall system frequency.
- Equivalent source impedance (combining line impedances and generation source impedances) at a node determines grid strength in terms of variation of node voltage with current. Short-circuit ratio (the ratio of three-phase short-circuit apparent power to rated power) is often taken as an indicator of grid strength, since it indicates the amount of equivalent impedance between a strong voltage source and a grid node.

Some of the features and design principles of power systems have been so deeply embedded for so long that their roots in synchronous machine properties are obscure. This applies to the "services" which are the capabilities that a system operator must make sure are

Many of the services today do not need to be explicitly procured or mandated, but are simply available as a consequence of the physical operation of a synchronous machine–dominated grid.

present so that the system reliably delivers to consumers the power quality and service quality expected, and that safety is ensured. Synchronous machines provide many of these services inherently. The services do not need to be explicitly procured, and they may not even be mandated, but they are simply available as a consequence of the physical operation of a synchronous machine–dominated grid. One example is inertia, where the kinetic energy of the rotating masses of synchronous generators reduces the rate of change of frequency (RoCoF) in case of sudden supply-demand imbalances; this inertia is a prerequisite for the effectiveness of countermeasures, such as frequency control.

IBRs have no intrinsic behavior; rather, their behaviors are dictated by their control systems. There is a large degree of freedom in the design of their control systems (subject to physical limits of the inverter), meaning that inverters can be designed to provide responses to all possible normal and abnormal system conditions.

Beyond that are services that might be explicitly procured, but that were defined around the properties of synchronous generators—for example, frequency response was defined around governor characteristics. The challenge now is to think through a set of operating principles and system needs that are technology-neutral and applicable to systems with few, if any, synchronous machines present.

An Inverter-Dominant Perspective

In a system in which most or all resources are inverter-based, we have an opportunity—and an obligation—to rethink how grid services are designed so that they continue to ensure system stability and reliability, without placing undue burden on IBR design and operation. IBRs have no intrinsic behavior; rather, their behaviors are dictated by their control systems. There is a large degree of freedom in the design of their control systems (subject to physical limits of the inverter), meaning that inverters can be designed to provide responses to all possible normal and abnormal system conditions.

A key challenge in an inverter-dominant system is that IBRs often face additional capital or operational costs in the provision of system services that are inherently available at no additional cost from synchronous generators today. One example stems from the physical limit on inverters' short-term over-current. The semiconductors within inverters have very little thermal mass, and their temperature rises very quickly. Their current limit is essentially instantaneous and strict. If an inverter is required to deliver additional current to provide grid services for even a short-duration event (for example, to allow existing over-current protection to detect system faults), that can be provided only by increasing the general current rating, and this substantially increases the IBR's cost.

Synchronous machines can provide additional power and energy through their short-term rating, because the prime mover, for example, a steam turbine, often has a short-term rating also. However, IBRs based on wind and solar resources are operating under maximum power point tracking and so cannot source additional power unless an energy buffer is added or the resource is operating below its available power.[2] Running a renewable resource at less than its available power foregoes revenue without saving on costs; therefore, IBRs' additional costs to serve these system needs would need to be recovered. A trade-off between market-based solutions based on technical prequalification criteria and mandatory requirements established by connection rules has to be found from a technical and economic perspective. Either way, from a system operator's view it is important to define and obtain services at a minimum cost, and that implies balancing the cost burden on the IBRs with the cost burden elsewhere in the system.

2 One exception here is inertia-based fast frequency response from wind turbines (sometimes called "synthetic inertia"). This control algorithm allows the extraction of kinetic energy from the rotating mass of a wind turbine and the rapid injection (in less than 1 second) of additional active power into the grid after detecting a change in system frequency. While this type of fast frequency response does not require the wind turbine to operate below maximum available power, the response can only be sustained for a few seconds, and the effectiveness of the response depends on wind conditions.

System Needs, in Brief

A system operator seeks services to satisfy a set of needs for a secure, stable, resilient, and well-regulated grid. Here we categorize those needs as ensuring stability, power quality, continuity of service and safety, and resource adequacy. These are discussed briefly here and in greater detail in the next section.

Needs

Stability and Power Quality

- **Synchronization and angle stability:** All generation resources need to synchronize and remain synchronized through grid disturbances.
- **Frequency regulation:** System frequency must be maintained close to nominal value, and frequency excursions following a sudden generation-load imbalance (e.g., due to a generator trip) need to be limited and corrected.
- **Voltage regulation:** Voltage magnitude must be maintained close to nominal and recover from adverse events, and unbalances, harmonics, and flicker need to be mitigated in order to maintain desired voltage quality.
- **Damping:** Oscillatory modes (sub- and super-synchronous) need to be positively damped and settle quickly.

Control stability has to be maintained to ensure that all generators operate stably without control interactions with other resources or grid devices, while providing stability and power quality services listed above.

Continuity of Service and Safety

- **Protection:** Faulty network equipment and resources must be detected and selectively isolated in a safe and timely manner.
- **Restoration:** Following a partial or system-wide loss of service, service must be restored in a safe and timely manner.

Resource Adequacy

- **Capacity:** Sufficient capacity needs to be installed and available to serve instantaneous electricity demand and ensure a desired level of security of supply.
- **Energy:** Sufficient energy has to be available at all times to continuously serve electricity demand and ensure desired level of security of supply.

While the resource adequacy needs are not influenced by whether or not resources are inverter-based per se, they are greatly influenced by the nature of the energy resource. Therefore, resource output variability and any weather dependencies and duration limits should all be taken into account.

In designing services to meet needs, the flexibility of the inverter can be exploited to great effect.

Designing Services to Meet System Needs

In designing services to meet needs, the flexibility of the inverter can be exploited to great effect. It may be possible to create services based on the wide latitude of inverters' functionality and meet system needs more effectively than through services offered by synchronous machines. It is important to recognize that there is not a one-to-one mapping between service and needs: one service might meet more than one need, and one need could be met by several services. As an illustration, consider the needs arising from a sudden loss of generation infeed. The frequency has to be contained, before it becomes so low that emergency measures are taken to protect vulnerable equipment, and then must be recovered to its normal range. This can be achieved by limiting the RoCoF, because that allows more time for other means of frequency control to respond and raises the frequency nadir. Several services, perhaps in combination, could cover this need:

- **Instantaneous active power response:** The response that starts instantaneously (within a few milliseconds) after a disturbance, provided inherently or through controlled active power injection proportional to RoCoF.

  While the response provided by synchronous machines through physical inertia is inherent and based on the physical machine design, active power injection provided by GFM IBRs is control-based, thus the magnitude and shape of the response are configurable.

- **Fast proportional frequency response:** Fast (less than one second) active power injection, proportional to measured change in frequency after a disturbance.

  This response is control-based; therefore, time, magnitude, and duration of response in IBRs is configurable and may be delivered with or without a frequency deadband. Even though a traditional synchronous machine's governor response starts as soon as frequency change (outside of a deadband) is detected, it may take 10 to 20 seconds to reach full response.[3] Therefore, only a small portion of governor response (anything delivered within one second or less) can be counted as fast frequency response. GFL and GFM IBR controls on solar and battery energy storage systems (BESSs) can be configured to deliver full response to a frequency deviation in less than one second, provided there is sufficient energy reserve available.[4]

- **Fast step frequency response:** Fast (less than one second) active power injection or reduction in load with a pre-set magnitude triggered when a measured change in frequency crosses a pre-set threshold after a disturbance.

  This response is control-based; therefore, time, magnitude, and duration of response is configurable. This service cannot be provided by synchronous generators, while both GFL and GFM IBR controls on solar and BESSs can deliver fast step frequency response in less than one second, provided there is sufficient energy reserve available.[5]

Additionally, the same loss of infeed may also cause a phase jump and a voltage drop, which present other needs to maintain angle stability and recovery of voltage magnitude. To mitigate these impacts will require services in addition to those listed above (such as instantaneous injection of active power in response to change in voltage phase angle, and fast reactive power injection in response to change in voltage magnitude). An IBR design question then becomes how these various services are prioritized within the limited over-current capability of inverters and limited size of available energy buffers.

System Needs, a Deeper Dive

Here we further dissect system needs in a technology-neutral fashion, applicable to networks dominated by synchronous machines or by IBRs. Some of the needs described below often appear as a composite need. For instance, a need could be defined as for "grid strength." This is a composite of a need for a low-impedance voltage source and the need for sufficient and stable voltage regulation, mitigation of harmonic distortion, and synchronization stability of IBRs' phase-locked loop (PLL). Because an inverter would need specific controls or physical features to address these different aspects of grid strength, they are kept separate here.

Angle Stability and Synchronization

Today's power systems are fundamentally synchronous systems and based on synchronous machines. This synchronism is the glue that enables synchronous machines to act together to maintain the integrity of the power system. Even though our aim in this section is to define all system needs in a technology-neutral fashion, this is hard to do when discussing synchronization, because there are two types of synchronization and each is applicable to one or more specific technologies: an angle-frequency-power feedback loop, as found in synchronous machines and some types of GFM IBRs that use frequency droop, and angle-voltage feedback within a PLL as used in GFL IBRs.[6] The first is a familiar need for synchronizing torque but one that needs to be re-examined for GFM IBRs. The second need, for PLL compatibility, has grown over the last two decades. Research is underway to establish a framework in which the two synchronization methods can be considered together under a single, technology-neutral heading of synchronization strength or synchronization power (Gu, Li, and Green, 2021; Harnefors et al., 2021; Li, Gu, and Green, 2021); however, it is not yet available.

3 Frequency response in this time frame is also referred to as primary frequency response.

4 Similar characteristics can be achieved in a wind turbine equipped with inertia-based fast frequency controls ("synthetic inertia") in combination with primary frequency controls, provided there is sufficient energy reserve available.

5 For example, the Electric Reliability Council of Texas (ERCOT) has recently implemented fast frequency response service with a step response to a frequency trigger, where full response is required within one-quarter of a second.

6 Here again, as in Table 1, it should be cautioned that the mere presence of a PLL does not automatically make an IBR grid following. GFM IBR control methods that use a PLL for synchronization are also possible.

TABLE 2

Needs Related to Angle Stability and Synchronization in the Power System

Need Related to Angle Stability and Synchronization	Reason for the Need
Synchronizing torque	Synchronous machines and IBRs must remain synchronized. Loss of synchronization from angle instability can arise in cases of low synchronizing torque. (This is also called synchronizing power.)
PLL compatibility	IBRs' PLLs must remain synchronized with the grid. PLL and control stability support address instability arising from high impedance (low system strength) at an IBR's point of interconnection.
First-swing mitigation*	Synchronization of the grid must be maintained during large voltage disturbances.
Phase-jump mitigation	Synchronization to the grid must be maintained following the abrupt change of voltage angle due to loss of infeed or loss of line.

* It is unclear to what extent GFL IBRs are prone to long-lasting loss of synchronism from a single large disturbance. The generic need to provide first-swing stability for all resources may in fact be a set of differing needs for different technologies (synchronous machines, GFL IBRs, and GFM IBRs). A technology-neutral set of detailed definitions may not be possible here.

Source: Adapted from Bialek et al. (2021).

Frequency Regulation

Supply-demand balance is a fundamental need, and power systems have been designed to use frequency as a surrogate for the supply-demand balance, since regulating the frequency achieves supply-demand balance over the near term. However, the need for frequency regulation in power systems is not set in stone. If supply-demand balance could be maintained without using frequency regulation as a surrogate, then the need for frequency regulation would be reduced or could be replaced. Further, while it has been necessary historically to keep frequency within a narrow band where synchronous generation and demand equipment operate safely,

The need for frequency regulation in power systems is not set in stone. If supply-demand balance could be maintained without using frequency regulation as a surrogate, then the need for frequency regulation would be reduced or could be replaced.

TABLE 3

Needs Related to Frequency Regulation in the Power System

Need Related to Frequency Regulation	Reason for Need
Regulation	Power fluctuations of generation or load causing drift of frequency need to be mitigated.
Containment within frequency limits	Loss of load/infeed causing a large increase or decrease of frequency to the outside of defined limits and causing equipment malfunction or loss of service needs to be mitigated.
Frequency ride-through	Inability to ride through frequency disturbances leads to tripping of generation and exacerbates frequency regulation problems.
Limitation of RoCoF	Loss of load/infeed causing rapid change of frequency and protection malfunction or unwanted triggering of protection needs to be mitigated.
Settling of frequency	Following a major event, frequency must be immediately contained and stabilized.
Recovery of frequency	Following a major event, after containment and stabilization of frequency, it must be restored in a timely manner.

Source: Adapted from Bialek et al. (2021).

TABLE 4

Needs Related to Voltage Regulation in the Power System

Need Related to Voltage Regulation	Reason for Need
Containment within voltage limits	Heavy line loading and/or absence of reactive power sources leads to voltage excursions outside of limits.
Mitigation of unbalances, harmonics, and flicker	Absence of mitigation (such as low impedance paths to shunt harmonics and unbalances) leads to poor voltage quality.
Voltage collapse mitigation	Sudden and large increase in line loading or grid impedance due to loss of a line causes nonlinear behavior and collapse of voltage beyond bifurcation point.
Voltage ride-through	Inability to ride through voltage disturbances leads to tripping of generation and consequent frequency regulation problems.

Source: Adapted from Bialek et al. (2021).

the use of inverters and other modern interfaces to an AC system means that large frequency ranges might be tolerated in the future. In addition, the central role of regulating frequency may be reduced as a result of the increased use of DC in generation, transmission, distribution, and end use. While in the longer term tight frequency regulation may not be needed, there is a clear need in the medium term (say, 10 to 15 years) to continue to regulate AC frequency within relatively narrow limits around a nominal value.

Voltage Regulation

Power systems are designed with multiple voltage levels, from very high voltage at the transmission level to very low voltage where the end user is served. Power system equipment and loads are also designed around certain operating voltage ranges. Hence, voltage needs to be regulated to ensure proper operation of the power system and the connected loads. In contrast to frequency regulation, which is a system-wide need, the need for voltage regulation is localized. The voltage profile itself should be within acceptable harmonic levels and be held sufficiently far from the point of voltage collapse (the nose of the voltage-power curve) to minimize the risk of collapse. (See Table 4.)

Damping

Power grids naturally have oscillation modes ranging from less than one Hz to thousands of Hz. These oscillation modes are introduced by the reactive components of lines/cables and the connected apparatus of generating resources and loads due to natural grid frequencies and amplified underdamped resonance conditions. Some of these modes are poorly damped and can become unstable (negatively damped) if excited by a small or large disturbance (for example, a change in a generator output or transmission line trip). A system operator is required to ensure that these oscillation modes are adequately damped and robust against changes in operating point of the power grid (Table 5).

TABLE 5

Needs Related to Damping in the Power System

Need Related to Damping	Reason for Need
Damping of sub-synchronous oscillations	Poorly damped local or inter-area oscillations or amplified resonances can cause instability or equipment damage.
Damping of super-synchronous oscillations and harmonic resonances	Control interactions between IBRs in network conditions with resonant amplification can cause instability in the high frequency range.

Source: Adapted from Bialek et al. (2021).

Protection

Protection systems detect, locate, and isolate faults (short-circuit paths) or other abnormal operating conditions so as to protect equipment and grid elements while allowing the remaining parts of the system to continue to function. Over-current protection modalities are based on the flow of large fault currents from synchronous machines during grid faults, and the presence of substantial over-current is used to locate and isolate faults by protection relays. There are other protection modalities that detect negative-sequence current, ground current, estimated electrical distance (impedance) to fault, or residual current differences between two measurements (called differential protection), but essentially the basis of detecting and locating faults is either the presence of large abnormal currents or characteristics of the ratio between (or differences in) voltages and currents throughout the grid. The overall objective of protection systems is to balance the following, as economically as possible: selectivity (protection systems should remove only the disturbed parts of the grid), security (they should operate only for disturbances and not for normal conditions), reliability (should always detect and isolate disturbances), and speed (should isolate disturbances quickly). As IBR levels rise, methods of detecting and isolating abnormal conditions will need to evolve, since the behavior of currents and voltages in IBRs is fundamentally different than in synchronous machines (Table 6).

One example is over-current protection. In a power system dominated by synchronous machines, fault current is normally much larger than maximum load current and also larger than temporary overloads. Over-current relay coordination depends on this large difference in current magnitude to distinguish a faulted condition from a normal operating condition. However, in grids with low fault current, distinguishing faults from other temporary overloads is more difficult. While synchronous machines provide three to five times their rated current during system faults, IBRs do not have a meaningful short-term over-current rating. Consequently, IBRs only provide 1 to 1.5 times their rated currents during faults. Therefore, in a system in which fault currents are primarily provided by IBRs, it will be difficult to differentiate between fault and normal system conditions based on current measurement alone. Where short-term current ratings are provided for IBRs, they are through oversized semiconductors and oversized cooling provision, both of which increase costs.

Abnormal operating conditions in grids with high levels of IBRs can be more effectively detected and protected against through the use of alternative or hybrid protection modalities in place of those using over-current, or even, in some cases, distance (impedance) protection. Modalities such as differential protection or deployment of communications-based transfer-trip or blocking schemes provide more selective and secure options for these grids and are not dependent on a fault-to-load current ratio or voltage-to-current ratio for fault detection. Protection in IBR-dominated grids must also be reliable, selective, and secure for non-fundamental frequency voltages and currents and during large current spikes and phase jumps, by appropriately measuring and interpreting frequency.

TABLE 6

Needs Related to System Protection

Need Related to Protection	Reason for Need
Detection of short-circuit faults	Rapid detection of short-circuit faults is needed for the safety of people and equipment. This was traditionally based on the flow of large fault current from synchronous machines.
Identification of fault locations	Fault location must be identified as accurately as possible so that the fault is safely cleared, while minimizing the section of network being disconnected. This traditionally uses the fault current magnitude or estimated fault impedance to locate the fault.
Isolation of faults	Faults must be isolated in order to ensure safety of people and equipment.*
Selectivity, security, and reliability	Protection modalities need to operate only where and when needed (during actual events) and avoid misoperation (tripping of equipment in absence of events).

* The need to isolate faults is not a service provided by synchronous machines or IBRs, but rather by circuit breakers, but is included here for completeness.

Source: Adapted from Bialek et al. (2021).

Restoration

System restoration is the ability to black start and restore the power system after a major outage. It requires self-starting of a generator to establish a voltage and synchronizing torque to which other generators can synchronize. It needs to energize the local system, at which point load (cold load pickup) is added to the system so that the generator providing black start can operate stably. Other generators and other blocks of load are then sequentially added to the system, ensuring that each step can be stably operated. Finally, individual islanded systems are reconnected to restore the full power system. It should be pointed out that voltage and frequency control are much more challenging to achieve during black start and restoration, and, consequently, system needs for voltage and

TABLE 7
Needs Related to System Restoration

Need Related to Restoration	Reason for Need
Cold load pickup and network re-energization	Voltage and frequency must be maintained and additional power flow provided during energization of network segments, including non-black-start generators and other network assets, being returned to supply.
Black start	After a blackout, the system needs to be up and running as soon as possible. This is accomplished when a generator is able to self-start and then: (1) establishes voltage to which other IBRs and synchronous machines can synchronize, (2) provides cold load pickup, and (3) synchronizes and closes onto adjacent areas.
Island operation and re-connection to main grid	Following a system split, core functions (frequency and voltage regulation) must be maintained within an islanded area so that it can continue independent stable operation supplying demand. The islanded area then needs the ability to synchronize to an adjacent area as in the case of black start.

Source: Adapted from Bialek et al. (2021).

TABLE 8
Energy and Capacity Needs in Power Systems

Need Related to Energy and Capacity	Reason for Need
Energy	Consumers rely on the electricity grid for life-supporting services such as heat, light, and many other services.
Installed generation capacity	Some minimum amount of generating capacity is required to be able to serve demand and maintain an agreed-upon level of security of supply.
Transmission capacity	A minimum amount of transmission capacity is required to be able to serve demand and maintain an agreed-upon level of security of supply.
Dispatchable capacity	A portion of generation capacity is needed that is able to quickly ramp up or down to meet changes in demand or changes in variable renewables that were not resolved through normal operation of the energy market.

Source: Adapted from Bialek et al. (2021).

frequency regulation during these processes are different from those discussed above (Table 7).

Energy and Capacity

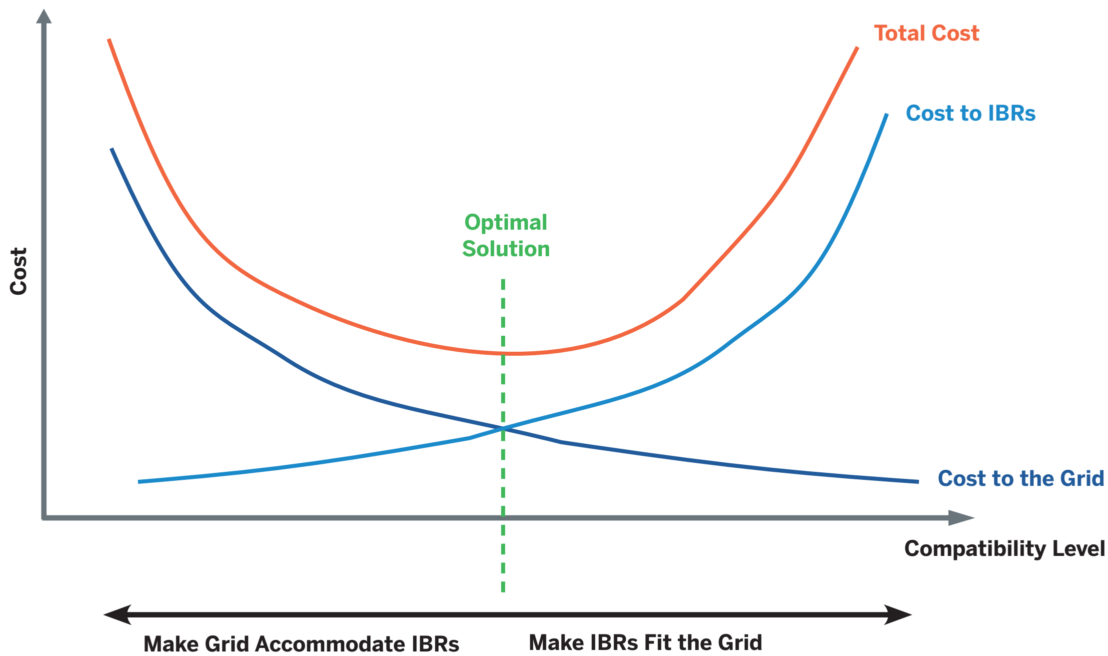
Last but not least, energy and capacity are fundamental needs for resource adequacy in order to maintain a required level of security of supply. Research is ongoing to better understand how energy and capacity needs are changing with the changing resource mix and how assessment methods need to evolve (RRATF, 2021). Although these two needs are not the main focus of this report, we include Table 8 for completeness.

Trade-Off Between the System Needs and Resources' Needs

It is important to understand that some of the grid needs discussed above can be seen from the point of view of the system or the resource, and can either constitute a joint need or present a trade-off. Needs presenting trade-offs have to be carefully navigated and can have implications for system costs or resource costs. For instance, the need to mitigate PLL instability is in part an issue of ensuring that PLLs maintain stability in the face of a certain amount of system strength (the system point of view) and is in part an issue of ensuring a sufficient system strength to allow PLLs to synchronize (the resource point of view). An optimal level of grid strength needs to be found that minimizes the sum of the burdens on the grid and PLL characteristics. A similar trade-off exists regarding the need for limiting the RoCoF. From the system point of view, it is better if RoCoF is limited to a smaller Hz/s value, as a RoCoF that is too fast can trigger protective devices on the grid or cause misoperation of protection. From the resource design perspective, providing active power injection that limits RoCoF requires faster controls and an energy buffer, both of which imply additional costs. Here, a trade-off has to be made regarding the optimal RoCoF that minimizes the sum of the burdens on the grid and on IBRs. This is a general principle that is illustrated in Figure 5 (p. 23), which shows that total system cost can be minimized by finding the right trade-off between making IBRs fit the grid and making the grid accommodate IBRs.

FIGURE 5

Total System Cost as Compatibility Burden Is Moved Between IBRs and the Grid



There is a trade-off between making IBRs fit the grid needs and making the grid accommodate IBRs. Total costs are driven by system policies: a system may absorb more costs to accommodate higher shares of IBRs, for example, in order to accelerate progress toward environmental goals, or, conversely, interconnection requirements that are too stringent may impose potentially unnecessarily high costs on IBRs. Both approaches are sub-optimal and lead to higher total costs compared to an optimal solution with the right trade-off between making IBRs fit the grid and making the grid accommodate IBRs.

Source: Adapted from Bialek et al. (2021).

4 System Services and Technical Requirements

From the perspective of a transmission system operator, sufficient volumes of reliability services must be present to meet all of the system needs, discussed in the previous section. As the proportion of inverter-based resources (IBRs) rises, more system services that were traditionally procured from synchronous machines (for frequency response and voltage support) need to be sourced from IBRs. This is already being done in some systems with high shares of IBRs (in Australia, Great Britain, Ireland, Texas) and technology maturity for provision of these services has been reached, subject to availability of an energy source on the DC side of the inverter.

Services that were previously provided by synchronous machines inherently, without explicit procurement (for example, to serve the need to limit rate of change of frequency (RoCoF) and the composite need of grid strength), are also becoming scarce. In order to prepare for the future system with few if any synchronous machines, these services need to be defined based on system needs and in a technology-neutral manner. To source these services from IBRs requires the development and implementation of advanced (grid-forming (GFM)) inverter controls. But implementing these advanced controls can do more than just replicate synchronous machines' provision of grid services: IBRs' broad flexibility means they will likely be able to provide newly defined services more efficiently than synchronous generators have historically.

While market mechanisms should be used where possible to procure these services, the codification of expected technical performance for GFM IBRs, as new technology, in grid codes and standards would allow harmonized performance expectations across the board and lead to more efficient deployment of GFM technology. At a high level these requirements include that the GFM IBR present a voltage source characteristic in the transient time frame at the point of connection, have the capability to synchronize to other IBRs and synchronous machines, provide instantaneous active power reserves, have the ability to ride through certain grid conditions, and others. Effective market designs need to be defined, and these will vary among power systems depending on system characteristics and legal and regulatory frameworks. These designs should include remuneration schemes, which may be based on tendered prices or regulated tariffs, could pay for capacity reservation or for deployment of service, and may be uniform within a system or vary regionally or locally.

While market mechanisms should be used, where possible, to procure system services, the codification of expected technical performance in grid codes and standards would allow harmonized performance expectations across the board and lead to more efficient deployment of GFM technology.

Breaking the Chicken-and-Egg Cycle

As discussed in the report's introduction, the development of grid codes and standards is often a circular problem in which it can be difficult to know whether the requirement or the capability of equipment comes first (see Figure 2, p. 7). Building upon VDE|FNN (2020b), below we outline a proposed path toward breaking the chicken-and-egg cycle by defining system needs, developing a set of requirements, and validating equipment performance. This path takes into account policy goals, power system security, and economic optimization.

1. **Define the target system.** The target system is defined in terms of energy quantities (seasonal peak load, seasonal energy consumption, etc.), expected shares of the different power sources (renewable energy resources, synchronous machines, storage), and expected sinks (loads (including electrification of transportation and heating), storage). If necessary, different scenarios for several points in time with key data may be specified based on policy goals.

2. **Define resilience parameters.** Desired resilience against certain disturbances is defined in terms of resilience parameters (such as maximum RoCoF in case of sudden load imbalances or after a system split), with which the target system should be able to cope without any (or with limited) impact on security of supply. Maximum amount of load shedding permitted during low-frequency high-impact system disturbances is also defined. The trade-off between costs to the grid and costs to resources to conform with defined resilience parameters is considered (discussed in the System Needs section above). This is a policy-driven decision.

3. **Perform studies to determine the system needs.** Studies are conducted to determine the type and scope of the minimum system needs—overall for the entire target system, as well as for regional and local needs—in order for the system to be able to operate in steady state and during contingencies with the desired voltage and frequency quality within defined resilience parameters.

4. **Formulate technical requirements for system services.** Technical performance requirements are defined for necessary system-wide/regional/local services based on the identified system needs, including system conditions under which the activation of a service is expected and conditions under which the provision of the service should be sustained. This will inform the design, dimensioning, and, consequently, costs of the equipment providing the services. The requirements are defined in a technology-neutral manner as far as possible, so that the services can be provided through quantifiable contributions by various individual system users (generators, loads, storage) or groups of them (e.g., aggregation of distributed energy resources or loads). The objective is to enable as many system users as possible to provide system-supportive services, since the provision of grid services tends to become more economical for grid operators if there are several alternative providers.

5. **Quantify system services.** For each service, a methodology to quantify amounts is developed. For increased efficiency and reduced costs, varying quantities of services are procured, where practical, based on system conditions.

6. **Determine the economically optimal form of service provision.** The most efficient way to meet the demand for each of the services is decided. The appropriate trade-off between market-based solutions based on technical pre-qualification criteria and mandatory requirements established by connection rules needs to be arrived at from technical and economic perspectives.

   Rules are also established for the market-based approach: the organizational (tender, periodic auctions/market executions, etc.) and remuneration form (price formation, payment based on capability and/or provision, etc.).

7. **Define technical benchmarking.** For both approaches above (market-based solutions and mandatory requirements established by connection rules), detailed technical benchmarking is developed and specified to verify performance at the commissioning stage of service providers and in their operation.

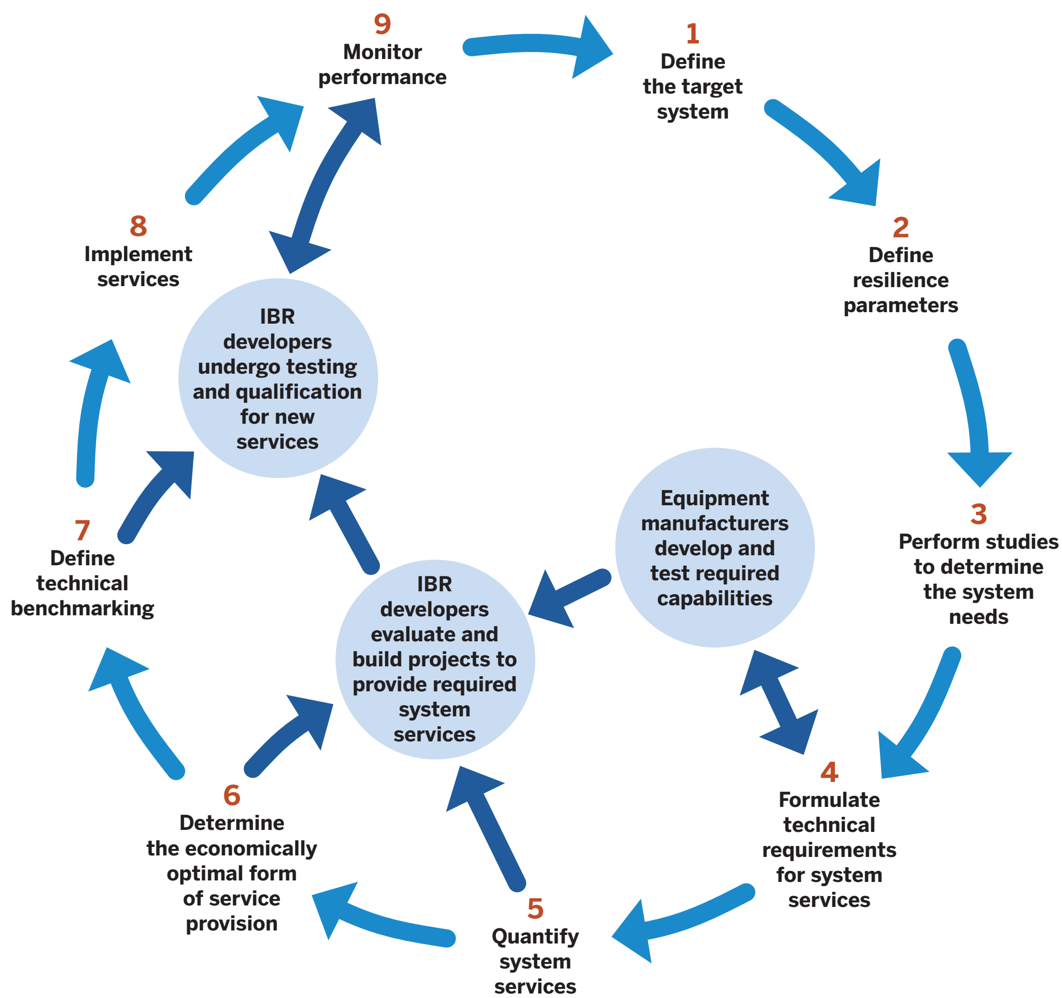
8. **Implement services.** The dates of the implementation of new services and any transitional arrangements are determined, as needed both for market-based and mandatory requirement–based approaches. Tender or other selected market forms for the procurement of market-based services are executed.

9. **Monitor performance.** For both approaches, performance is monitored during service delivery, and compliance with technical performance requirements is verified on an ongoing basis.

For a market-based approach, performance-based remuneration (or performance-based qualification for service) can be used, where practical, to incentivize continual good performance. For both market-based and mandatory requirement–based approaches, any non-compliance with new technical performance requirements is addressed through actionable mitigation to prevent future incidents.

FIGURE 6

Proposed Process for Deploying New Grid-Forming Capabilities



In the proposed process for deploying new GFM capabilities to serve system needs, the outer circle follows steps 1 through 9 as discussed in the text, while the three inner elements show how the nine steps relate to IBR equipment manufacturers and project developers and owners. Steps 1 through 9 are not set in stone and will likely need to be an iterative loop as systems and technologies continue to evolve.

Source: Energy Systems Integration Group.

Global Experiences with Interconnection Requirements and Services Incentivizing Grid-Forming Functionality

Some system operators are already working on the development of technical requirements for GFM capability. There are ongoing efforts in Great Britain, Germany, across Europe (through the European Network of Transmission System Operators for Electricity (ENTSO-E)), Hawaii, and Australia, summarized below.

Great Britain

Early on, National Grid Electricity System Operator (NGESO), the transmission system operator in Great Britain, established a proactive approach to determining system needs by carrying out a number of studies that investigated system performance with a large share of IBRs (all the way to 100 percent). This is consistent with steps 1 through 3 in Figure 6 (p. 26). The studies showed that operation of the system with 100 percent of the IBRs being grid-following (GFL) is not possible, and that a portion of inverters would have to be GFM in order for Great Britain's power system to operate reliably in steady state and under disturbance conditions within defined resilience parameters (as per step 2 above). As these studies were wrapping up, a pilot project was carried out in which an existing wind GFL IBR was equipped with GFM controls and operated with these controls on the Great Britain system for six weeks (Roscoe et al., 2021), with follow-up testing to demonstrate the ability of a wind-based GFM IBR to operate in an islanded condition and provide system restoration and black-start services (Roscoe et al., 2020). The pilot served as a proof of concept as well as provided valuable insights on GFM IBR capabilities and how these could be used to serve system needs.

NGESO then started working on performance requirements for GFM capability (to be procured as a service), consistent with steps 5 and 7 in Figure 6. At the same time, it launched a series of competitive tenders, called Stability Pathfinder, to procure new system services needed with the changing generation mix—specifically, system strength support and RoCoF mitigation. This is consistent with steps 5, 6, and 8 above. Along with evaluating the projects offering into Stability Pathfinder tenders, next steps will be to develop market-based services as well as performance evaluation requirements for those services, consistent with steps 8 and 9.

Below we discuss the development of non-mandatory grid code requirements for GFM capability and the Stability Pathfinder.

Grid Code Change GC0137

As a first step toward the development of technical requirements for GFM technology (which includes IBRs as well as synchronous generators) in NGESO,[7] the Virtual Synchronous Machine Expert Group was established in 2018 (NGESO, 2018). The group, made up of representatives from all relevant stakeholder groups (including equipment manufacturers, project developers, consultants, the system operator, and others), developed draft technical requirements for GFM technology in Great Britain (GB). The GB Grid Forming Working Group was established one year later to continue working on non-mandatory, high-level technical specifications for GFM capability and performance, and proposed grid code change GC0137 to the NGESO Grid Code (NGESO, 2019-2021). The GC0137 report was published in November 2021 (NGESO, 2021). GC0137 has been approved and was implemented into the Grid Code on February 14, 2022. As noted above, the requirements are non-mandatory, and the GFM capability will be procured as a market product.

Initial system studies indicate a need for (1) at a system level, a minimum volume of GFM capability in order to limit RoCoF; and (2) at a local level, a minimum volume of GFM capability to limit RoCoF, limit vector shift,[8] and ensure sufficient fault infeed to maintain an acceptable post-fault voltage profile. The volumes of GFM capability needed will vary over time based on operational conditions. In the Great Britain requirements, a GFM plant is subdivided into two types, synchronous and inverter-based, since some tests are not needed for

7 To account for technology differences between synchronous machines and IBRs, GC0137 clarifies, where relevant, whether specific details apply to only one of the technology types.

8 Loss of mains (anti-islanding protection) may use RoCoF or vector shift as a criterion to detect islanded conditions; therefore, where such protection is used, RoCoF and vector shift during normal operation should be maintained within the range in which anti-islanding protection would not be activated.

The interconnection requirements should be kept at higher level with an implementation guide providing more details on implementation and performance verification.

synchronous plants because their dynamic performance characteristics are well understood. Any resource that wishes to provide black-start service would also need to have GFM capability as defined in GC0137.

The GC0137 specification addresses GFM plant and equipment requirements, requirements for submission of data and models, and compliance simulation and testing. In parallel with the development of GC0137, the Great Britain Grid Forming Best Practice Group was established in the third quarter of 2021 with the aim of developing a GFM best practice guide. The GC0137 specification covers high-level requirements, while the best practice guide will offer detailed implementations, for example, analysis techniques, simulation tools, model requirements, and testing and monitoring necessary for the purposes of verification and validation (NGESO, 2019-2021). The intent is to keep the grid code requirements at a higher level while continually updating the best practice guide as more operational experience is gained with GFM technology.

Identification of Key Features of Grid-Forming Capability

GC0137 identified several key features of GFM capability that form the basis for a GFM IBR providing the same performance as that traditionally provided by synchronous machines in terms of supporting the grid during disturbances. GFM IBRs should be able to:

- Limit the RoCoF after sudden loss of generation or load
- Inject instantaneous active power at the time of a fault as a result of corresponding phase change
- Inject instantaneous fault current at the time of a fault as a result of corresponding voltage change
- Contribute to the damping of power oscillations
- Limit vector shift
- Contribute to synchronizing torque
- Contribute to maintaining an improved voltage profile during disturbed conditions (a fundamental prerequisite for fault ride-through for all resources)

GC0137 does not prescribe how much of each capability is required; rather, it simply states that a developer should declare a resource's capability in a data table. However, more quantitative requirements are provided with regard to various withstand capabilities.[9] GC0137 requires that a GFM resource operate in a range from 0 Hz to 1 kHz and comprise a synchronous internal voltage source behind a real impedance (i.e., not a virtual impedance), similar to a synchronous generator. GFM resources should be designed to withstand 2 Hz/s RoCoF, contribute to system inertia with Active Inertia Power, provide frequency response with Active Frequency Response Power and/or Active Control-Based Droop Power, and provide instantaneous contribution (within 5 milliseconds) to system disturbances with Active Phase Jump Power.[10]

GC0137 defines a phase-jump limit as a maximum phase jump at which a GFM resource is still able to inject Active Phase Jump Power without entering into a current-limiting mode, and a 60° Phase-Jump Angle Withstand, defined as the maximum angle change that a resource should ride through without tripping offline. The resource should also contribute to system damping with Active Damping Power, with a Damping Factor between 0.2 and 5.0. The GFM resource should independently control active and reactive power and respond within 5 milliseconds to phase jump in the AC grid voltage without actions being required in the control system. GC0137 requires GFM resources to be designed to alter the voltage and phase angle of the internal voltage source at bandwidths below 5 Hz to avoid control interactions and be capable of riding through faults and providing

9 Withstand capability refers to ability of a resource to stay connected to the grid during large disturbances resulting in high RoCoF, high voltage phase jump, etc.

10 For the definitions of GFM resources' performance characteristics given in the GC0137 report and discussed in this and the following paragraph, see https://www.nationalgrideso.com/industry-information/codes/grid-code-old/modifications/gc0137-minimum-specification-required.

Fast Fault Current injection as appropriate. GC0137 defines Voltage Jump Reactive Power as an instantaneous reactive power response to jumps in voltage magnitude, while Control Based Reactive Power is supplied by a GFM resource through controlled means based on manual or automatic operator adjustment of selectable setpoints.

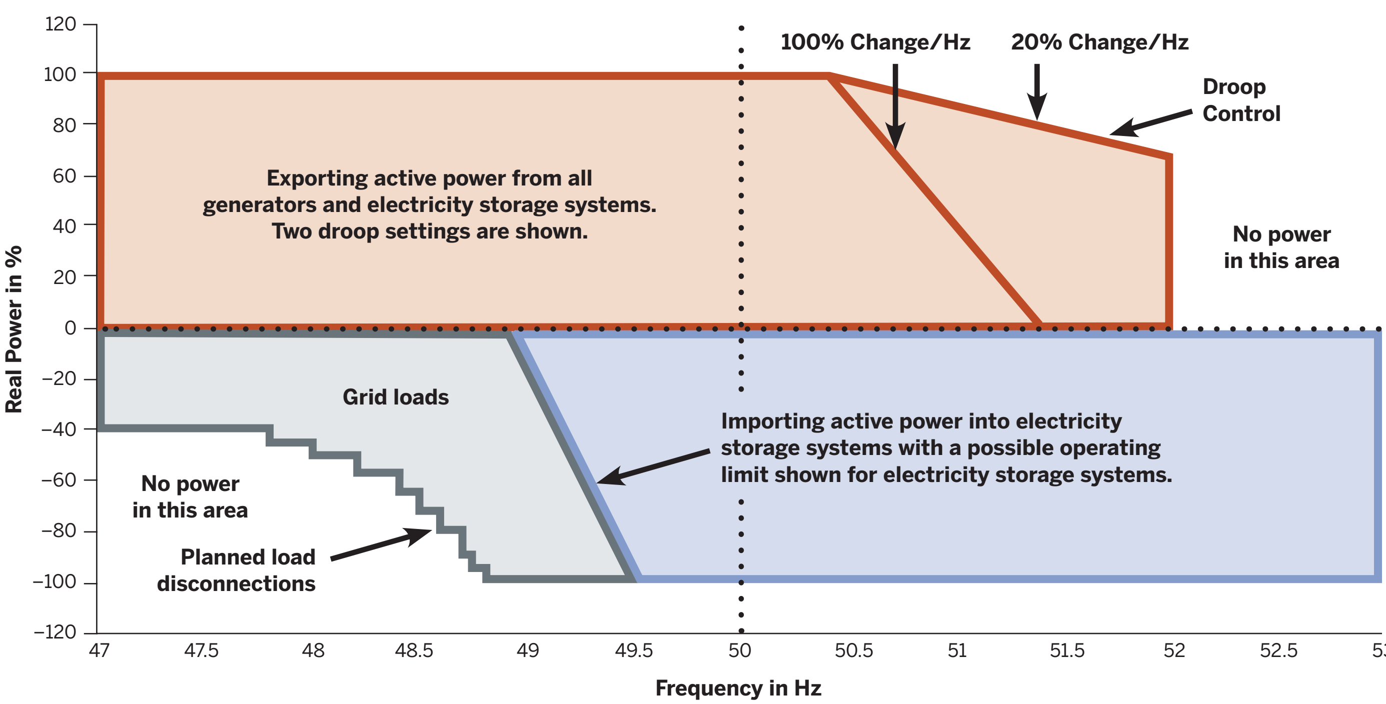
Additionally, GFM resources must be capable of operating at a minimum short-circuit level of zero MVA at the grid entry point with a power-frequency characteristic as specified in Figure 7. Resources must stably inject fault current for balanced and unbalanced conditions. The current injection must increase with the fall in the retained voltage, as per Figure 8 (p. 30), without exceeding the peak current rating of the inverter. Injected fault current must be above the shaded area shown in Figure 9 (p. 31). If the voltage falls outside of specified limits, the GFM resource is not required to exceed its transient or steady-state rating. In the case of unbalanced faults, the GFM plant should be able to employ a control strategy preventing transient overvoltage on healthy phases. GC0137 also specifies that simulation models and test results must be supplied by the IBR developer or owner so that the system operator can verify that the resource demonstrates the capabilities to declared levels.

Comparison of Technical Capabilities Across Technologies

Table 9 (p. 31) compares the capabilities of synchronous machines, GFM controls as defined by GC0137 for Great Britain, virtual synchronous machines with zero inertia, and conventional GFL controls. The table shows that the design specification of the GFM resource mimics that of a synchronous machine, particularly regarding inertia, frequency response, phase jump, response speed, and fault contribution.

FIGURE 7

Power-Frequency Operating Characteristics of Grid-Forming Resources

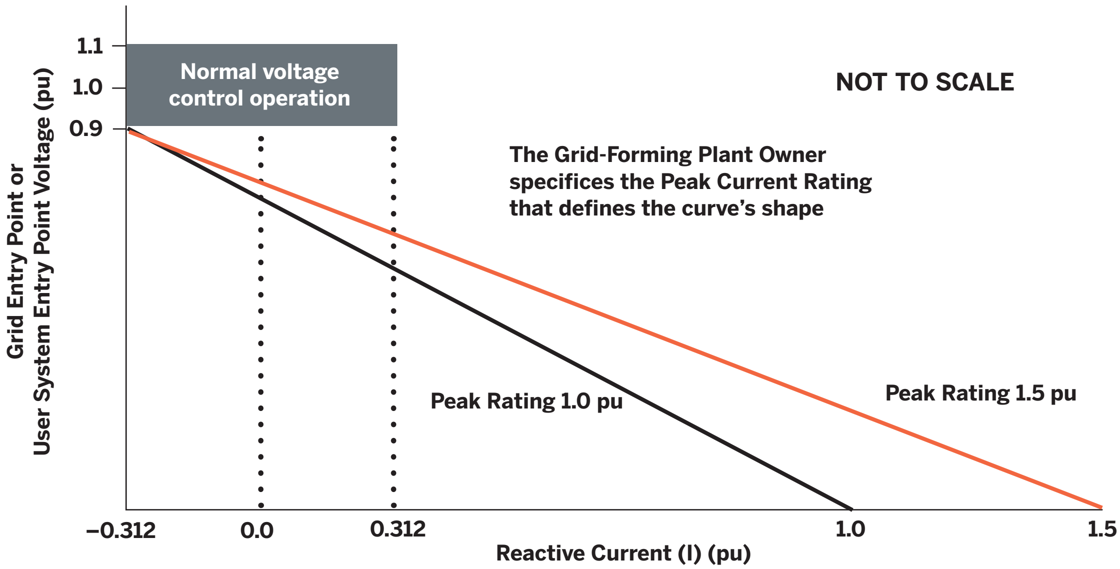


GC0137 requires that GFM plants with an importing capability mode of operation, such as HVDC systems and battery storage systems, have a pre-defined frequency response operating characteristic over the full import and export range that is contained within the envelope defined by the orange and purple lines shown. GFM plants that are only capable of exporting active power to the system are only required to operate over the exporting power region (orange shaded area).

Source: Adapted from data independently produced by Eric Lewis, director of Enstore.

FIGURE 8

Voltage-Reactive Current Injection Characteristic of Grid-Forming Controls Required by GC0137



In the GC0137, a GFM plant is required to inject a reactive current of at least its peak current rating when the voltage at the interconnection point drops to zero. For retained voltages between 0.9 and 0 pu at the point of interconnection, the injected reactive current needs to be on or above a line drawn from the bottom left-hand corner of the normal voltage control operating zone (shown in the rectangular gray shaded area) and the specified peak current rating at a voltage of zero at the interconnection point. The GFM plant is required to inject a reactive current that is no less than its pre-fault reactive current, and that must increase each time the voltage at the interconnection point falls below 0.9 pu, while ensuring that the overall rating of the GFM plant is not exceeded. Two examples of limit lines are shown: for a peak current rating of 1.0 pu where the injected reactive current must be on or above the black line, and a peak current rating of 1.5 pu where the injected reactive current must be on or above the orange line.

Source: Adapted from data independently produced by Eric Lewis, director of Enstore.

Great Britain Stability Pathfinder Programme

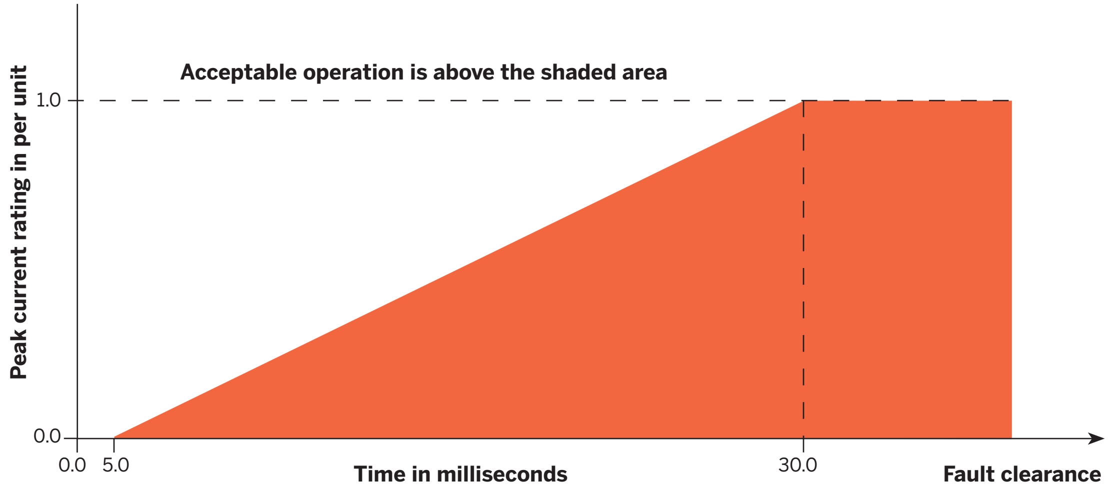
While NGESO was developing non-mandatory interconnection requirements for GFM IBRs (GC0137) but did not yet have a market product to incentivize GFM capability, it launched a parallel initiative with the objective of finding the most economic and efficient solutions for the support of grid strength in parts of the grid and system-wide inertia levels. These initiatives, falling under the Great Britain Stability Pathfinder Programme (NGESO, 2019-2022), are also exploring and testing the capabilities of new technologies to provide stability services in order to meet identified system needs. Stability Pathfinder consists of three consecutive tendering processes or phases. The understanding gained from each phase is used to shape the next.

Phase 1, initiated in November 2019, was to procure dynamic voltage support, short-circuit level, and inertia at 0 MW output across Great Britain to meet national inertia needs. Phase 1 was open only to proven synchronous solutions, favoring solutions with better dynamic voltage support capabilities and higher inertia contribution. The existing grid code requirements as well as specifications in the Draft Grid Code by the Virtual Synchronous Machine Expert Working Group were used to establish technical performance requirements for prospective solutions. Phase 1 concluded in January 2020, and 12 contracts were awarded to five providers of high-inertia synchronous condensers with total inertia of 12.5 GW·s.

Phase 2 and 3 are open to a broader range of technology types, including GFM IBRs; therefore, technical feasibility studies are carried out as part of the tender process to understand how non-synchronous technologies can meet system needs. Phase 2 is only using some elements of the requirements outlined in GC0137, while Phase 3 requirements are fully aligned with GC0137 as of November 2021. In both cases, compliance with other relevant grid code requirements is also expected.

FIGURE 9

Injected Fault Current Rating Requirement for Grid-Forming Resources Under GC0137



As specified in GC0137, a GFM plant is required to inject reactive current above the shaded area shown in the figure when the retained voltage at the point of interconnection falls to 0 pu. The injected current must be above the shaded area for the duration of the fault clearance time (up to 140 ms). Under any faulted condition, where the voltage falls outside the specified limits, there is no requirement for each GFM plant to exceed its transient or steady-state rating. Where the retained voltage at the point of interconnection is below 0.9 pu but above 0 pu, the injected reactive current component must be in accordance with Figure 8.

Source: Adapted from data independently produced by Eric Lewis, director of Enstore.

TABLE 9

Comparison of Grid-Forming Technologies

Capabiity	Synchronous Machine	GBGFC	VSM0H*	Traditional Converter**
Transient Impedance Value (TIV)	Yes	Yes	Yes	No
Active Phase Jump Power within 5 ms	Yes	Yes	Yes	No
Active Inertia Power	Yes	Yes	Very low	No
Active Damping Power	Yes	Yes	Very low	No
Active Control Based Power	Yes	Yes	Yes	Yes
Operates in Synchronism with the System	Yes	Yes	Yes	Yes
Contribution to Fault infeed	Yes – High	Yes, and value depends on the design	Yes, and value depends on the design	Yes – Limited
Bandwidth of optional control system features in normal operation	Below 5 Hz	Below 5 Hz	Below 5 Hz	Faster than 5 Hz

This table compares capabilities of synchronous machines, GFL inverters, and GFM inverters to provide various services as required in GC0137.

* VSM0H systems are a subset of GBGF Converter technology for supporting the Grid during system disturbances.

** The TIV defines the Grid's phase jump angle for a power transient. The PLL control of Traditional Converters gives a high TIV value and larger phase jump angles. The lack of Active Phase Jump Power gives lower power system stability.

Note: VSM0H = Virtual Synchronous Machine with zero inertia (similar to the Great Britain Grid-Forming Controls, except that it is lacking any volume of Active Inertia Power); GBGFC = Great Britain Grid-Forming Converter as defined by GC0137 for Great Britain (this term was chosen for GFM in Great Britain to distinguish it from other proposed GFM concepts); Traditional Converter refers to GFL inverters.

Source: Data independently produced by Eric Lewis, director of Enstore.

Phase 2 launched in June 2020 and is expected to conclude in March 2022. It is focused on increasing short-circuit levels by adding 8.4 GVA of short-circuit power contribution across eight locations in Scotland and increasing inertia by 6 GW·s across Scotland, with special emphasis on increased service availability.

Phase 3 is focused on increasing inertia and short-circuit levels in England and Wales. The requirement is for 15 GW·s of inertia and 7.5 GVA of short-circuit level. The tender of Phase 3 launched in December 2021 and is expected to conclude in November 2022.

Germany

An initiative is also underway in Germany to develop a concept for how requirements for GFM IBRs may be specified in future codes. The German VDE|FNN standard VDE-AR-N-4131, "Technical requirements for grid connection of high-voltage direct current systems and direct current–connected power park modules (PPMs)" (VDE|FNN, 2019), is a national-level implementation of the European network code (EC, 2016).[11] It is supplemented by the VDE|FNN guideline "Grid-forming behavior of HVDC systems and DC-connected PPMs," which introduces technical details with respect to dynamic frequency-active power behavior and dynamic voltage control without a defined reactive current injection (VDE|FNN, 2020a). This guideline aims at defining methods for compliance verification with regard to the specifications in VDE-AR-N-4131. It outlines verification test criteria adapted specifically for GFM voltage source converter with modular multilevel converter (VSC MMC) HVDC technology. The guideline is not intended to specify site-specific control strategies or any provisions for technical implementation; rather, the methods and verification procedures it introduces are understood as a representative model for the specifications of GFM inverters in general. Hence, they may also be used for GFM static synchronous compensator (STATCOM) systems, which are proposed by the German transmission system operators to further strengthen the grid on the path to higher levels of IBRs (GTSO, 2020).

The guideline defines system-level requirements, including management of a system split with regard to power imbalance, maximum permissible RoCoF, and minimum inertia conditions. It also defines the maximum voltage drop due to grid faults, aiming to ensure controller robustness and stable operations under small and large disturbances as well as stable parallel operation of HVDC systems.

Lastly, the guideline calls for extensive verification and definitions of test scenarios to validate the overall performance of GFM IBRs. This includes voltage, angle, and frequency performance during small and large disturbances and phase jumps. It also includes testing methodology for power quality, islanding (where an island includes a GFM resource and a synchronous machine), and impedance jumps during grid disturbances. The testing scenarios are given in Table 10 (p. 33).

HVDC systems and DC-connected PPMs, which exchange energy with the grid similarly to synchronous machines, would require a suitable amount of energy storage and current-carrying capability to support the grid under all feasible operating conditions. The provision of grid-supporting services will require further technical development, the nature of which will depend on the capabilities ultimately required of these devices. Requirements will apply to HVDC systems, DC-connected PPMs, or systems connected to the AC terminals thereof.

Hawaii

In 2019 Hawaiian Electric Company (HECO) issued a request for proposals that included numerous new utility-scale solar-plus-storage projects and new stand-alone storage projects being proposed through a competitive bidding process for integration into the Oahu, Maui, and Hawaii Island power systems. These new projects, along with very high shares of distributed energy resources and plans to reduce the operation of significant numbers of synchronous machines in the near term, are likely to introduce scenarios with nearly 100 percent of IBRs by 2023.

11 In the European network code, a power park module is a unit or ensemble of units generating electricity that is either non-synchronously connected to the network or connected through power electronics, and that also has a single connection point to a transmission system. VDE|FNN stands for Forum Netztechnik/Netzwerk im Verband der Elektrotechnik.

TABLE 10

Test Scenarios for Grid-Forming HVDC and DC-connected Power Park Modules

Scenarios to Be Examined for HVDC Systems	Scenarios to Be Examined for DC-Connected PPMs
• Phase angle step of network voltage • Linear frequency change in network voltage with initial phase angle step • Voltage magnitude step in network voltage • Presence of a negative-sequence component in the grid • Presence of harmonics • Presence of subharmonics • Change in the network impedance • Islanding with voltage source behavior under GFM control • Islanding with two devices with voltage source behavior under GFM control • Change in the network impedance with two parallel devices	• Phase angle step of network voltage • Linear frequency change in network voltage with initial phase angle step • Voltage magnitude step in network voltage • Presence of a negative-sequence component in the grid • Presence of harmonics • Presence of subharmonics • Change in the network impedance • Islanding with voltage source behavior under GFM control

Source: VDE|FNN (2019).

High-Level Requirements

In order to prepare for this future, HECO requested GFM functionality from all of the proposed projects that included battery storage. High-level performance requirements for GFM capability are in the project's power purchase agreement including (among others) the following:

> IBRs shall be capable of operating in grid-forming mode supporting system operation under normal and emergency conditions without relying on the characteristics of synchronous machines. This includes operation as a current-independent AC voltage source during normal and transient conditions (as long as no limits are reached within the inverter) and the ability to synchronize to other voltage sources or operate autonomously if a grid reference is unavailable (HEL, 2019).

In addition to these high-level requirements, a detailed set of tests was provided to prospective generators, which were to be applied to the models and used to ensure that the plants would provide the desired GFM performance.

HECO also commissioned an electromagnetic transient (EMT) study (performed using the PSCAD/EMTDC simulation tool) for all three islands (Unruh et al., 2021). The study's objectives included evaluating the ability of the projects with GFM controls to improve system performance and identifying potential risks in implementation of this new technology.

Recommendations

A number of findings and recommendations were made based on the PSCAD study with regard to GFM technology, including the following:

- Implementing commercially available GFM technology in battery projects provides significant improvement in steady-state performance and recovery after the studied system events. These improvements can

Implementing commercially available GFM technology in battery projects provides significant improvement in steady-state performance and recovery after system events.

only be achieved if the batteries have sufficient current and energy headroom to respond to system events.

- GFM controls implemented in the proposed projects are necessary to be able to stably and reliably operate the system with high shares of IBRs, as envisioned in 2023 scenarios. Synchronous condensers could be explored as a supplemental technology to assist GFM IBRs in stabilizing future scenarios with high levels of IBRs.
- GFM control technology should be required for all new batteries in future projects.
- Although a significant benefit is obtained by implementing GFM technology in battery resources for scenarios with very high levels of renewables, many of these scenarios also show oscillations in power and voltage quantities across the system. Undamped oscillations such as these may result in equipment damage or uncontrolled tripping of transmission elements. The source of undamped oscillations in GFM cases needs to be identified and mitigated, either through the use of external equipment or through control tuning in the battery projects.
- Since much of the GFM equipment is new, validation of the models will be useful as HECO gains operational experience with high-penetration scenarios. As faults and other events in the system take place, high-resolution recordings of these events will be very valuable for model validation and operational understanding. High-resolution digital fault recorders should be installed at key locations throughout the islands, and the data should be made available to planning, protection, and operations engineers.
- Future requests for proposals for GFM technology should improve clarity on technical requirements based on outcomes from the study.

Based on the study recommendations, the following details were added to the GFM requirements for the next round of requests for proposals (HEL, 2021), along with a supplemental list of model tests used to confirm performance:

- GFM resources must operate in a stable manner on low system strength grids (grids with a low short-circuit ratio or low inertia, an inertia-less system, etc.).
- GFM resources must set an internal voltage waveform reference and be able to either synchronize with the grid or operate independently of other generation.
- GFM resources must respond to changes in system frequency and voltage beyond the control deadband in a timely manner by contributing toward the subsequent recovery of system frequency and voltage to the pre-disturbance value, assuming that energy and power margins are available.
- GFM resources must have a damping control function that damps oscillations within the interconnection and other adverse interactions among GFM IBRs, GFL IBRs, and other power electronic devices.
- Upon the loss of the last synchronous machine in the power system, GFM resources should have the ability to operate autonomously if a grid reference is unavailable and be able to share the active and reactive power burden with other voltage sources without impacts on system stability.
- GFM resources must have the ability to transition from an electrical island to a grid-connected configuration without impacts on system stability.
- GFM resources must provide active low-order harmonics cancellation.
- GFM resources must provide black-start capability (as applicable, see below).
- A resource shall use GFM mode only as directed by the system operator. A GFM resource shall communicate to the system operator its parameters and settings pertaining to GFM mode.
- The GFM control block diagram must be submitted to the system operator for review, including initial settings for tunable controls parameters based on modeling. The initial control parameters may be modified based on field data and performance, subsequent system resource changes, or other factors to achieve acceptable system stability.

The following was added with regard to black-start capability for those specific projects that would be required to provide black-start functionality:

- The GFM resource must have sufficient short-term over-current capability to supply inrush currents during the energizing of transformers and distribution feeders and starting auxiliary motors of conventional power plants. Other inrush-current-mitigating solutions can be accepted as well, based upon results of the interconnection study.
- A GFM resource providing black-start services shall be configured to provide a ground reference for a black-start path during the black-start procedure (it must avoid energizing delta-delta transformer–connected paths, use switchable grounding transformers, or use wye-grounded transformers with dedicated black-start units).

The high-level GFM requirements set by Hawaiian Electric Company may be a suitable starting place for other system operators and policymakers looking to specify GFM capability at a high level in their jurisdictions where none currently exist.

These high-level GFM requirements set by HECO have been met successfully by commercial project applications, and early indications in studies show that the GFM plants are expected to provide significant stability enhancement to the future HECO grid. Thus, the simple list of objectives above may be a suitable starting place for other system operators and policymakers looking to specify GFM capability at a high level in their jurisdictions where none currently exist.

Europe

A coordinated effort among European stakeholders to define GFM capabilities for IBRs resulted in the technical report by ENTSO-E titled *High Penetration of Power Electronic Interfaced Power Sources and the Potential Contribution of Grid-Forming Converters* (ENTSO-E, 2020). The report elaborates on the potential contribution of GFM inverters to the secure operation of the power system where its generation is dominated by IBRs contributing between 60 and 100 percent of the total instantaneous power supply.

Seven system needs related to high levels of IBRs were examined in the report:

- Creating (forming) system voltage
- System fault level (short-circuit power)
- Contributing to system inertia (limited by energy storage capacity and the available power rating of the PPM or HVDC converter station)
- System survival to enable the effective operation of low-frequency demand disconnection for rare system splits
- Sink for harmonics and interharmonics in system voltage
- Sink for unbalance in system voltage
- Preventing adverse control system interactions

The report determined that advanced capabilities of IBRs, as listed above, are required to ensure stable system operation with up to 100 percent IBR levels in steady state and under disturbance conditions. When a system operator will be further specifying the capabilities, each of the above aspects could be treated in isolation or addressed in an integrated or holistic manner. Individual treatment may entail the risk that an IBR's positive contribution to one system need may be detrimental to another. Further research in this context is needed.

The report proposes a new class of IBRs, with GFM controls, that are capable of supporting the operation of the AC power system (from extra-high voltage to low voltage) under normal, alerted, emergency, blackout, and restoration states without having to rely on services from synchronous generators. This includes the capabilities for stable operation for the extreme operating case of supplying 100 percent of demand from IBRs (within IBR limits, such as short-term current-carrying capability and available energy buffer). Transient change to a current-limiting control strategy is allowed when inverter limits are reached, but immediate return to GFM control is required as soon as practicable.

The report also outlines a number of issues with regard to GFM technology and its implementation that still need to be solved:

- What proportion of IBRs need to have the seven characteristics identified; i.e., what percentage of the total installed IBR capacity needs to have GFM capabilities? Should all new IBRs be required to have GFM capability until the target percentage is reached?
- Where and when will the capabilities need to be available? In particular, how should GFM IBRs be spatially distributed in a large interconnected AC system like Continental Europe?
- Can some types of IBRs deliver GFM capability at lower cost than others? For example, small embedded units at the distribution level versus larger units connected at the transmission level?
- What kind of design decisions need to be made with regard to the most costly aspects of GFM, for example, regarding an energy buffer to provide instantaneous reserves or inverter short-term current ratings above nominal active power ratings?
- Do system operation and protection schemes such as, for example, loss-of-mains protection in distribution networks, need to be redesigned in order to be suitable for the systems with high shares of IBRs?

A follow-up paper from ENTSO-E, *Grid-Forming Capabilities: Towards System Level Integration*, recommends that GFM capabilities be described in European connection network codes (CNCs) to align the requirements throughout the European Union (ENTSO-E, 2021). It is envisioned that functionalities associated with GFM capabilities will be procured through market mechanisms; however, the qualification requirements for these services will be defined in CNCs as a pre-condition for grid connection of GFM IBRs and harmonized throughout Europe. ENTSO-E recommends non-exhaustive requirements in European-level CNCs to accelerate GFM specifications, with national implementation of these requirements depending on system characteristics and urgency in each member state. A similar approach is currently being followed in the CNCs for the requirements for primary frequency control (also called Frequency Sensitive Mode in the CNCs). The paper also recognizes that battery energy storage systems could play an important role in delivering GFM capabilities in the future.

Australia

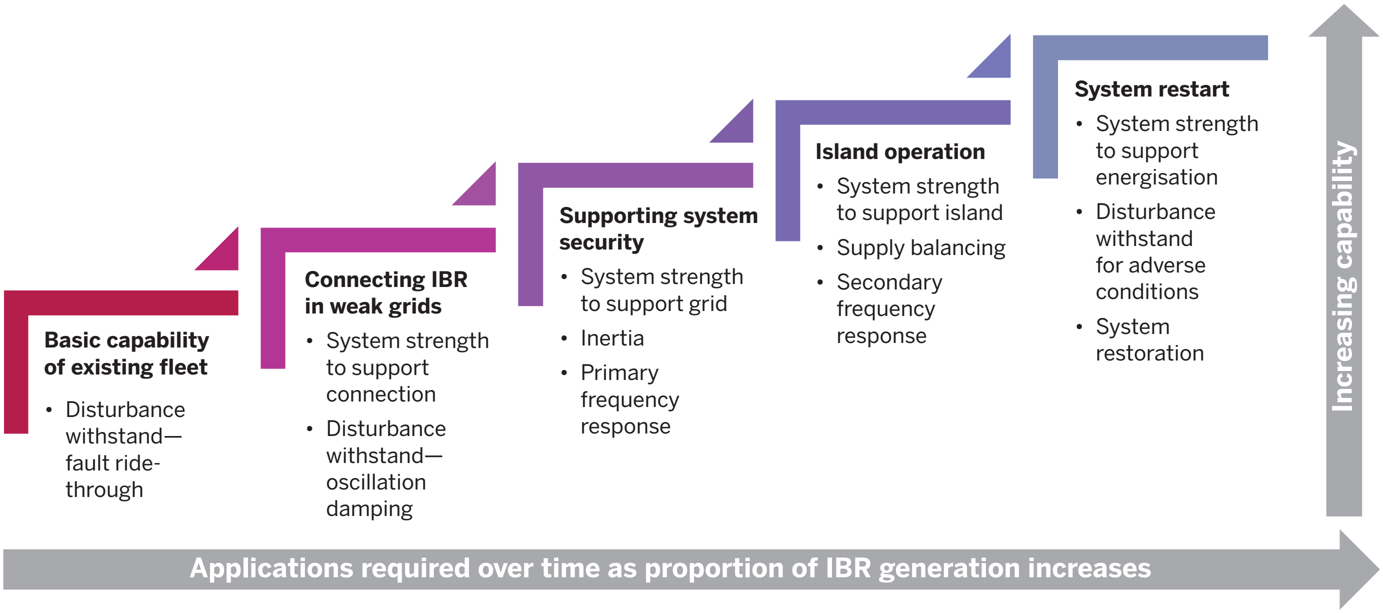
Several GFM battery energy storage systems are being installed or proposed for connection in various parts of the Australian National Electricity Market (NEM). These range from 30 MW to between 500 and 600 MW. The opportunity to tap into network support services is gradually becoming an important consideration for some of the IBR developers and network asset owners.

Market and regulatory bodies and government funding organizations including the Australian Energy Market Operator (AEMO) and the Australian Renewable Energy Agency have been working with stakeholders to understand the potential of GFM inverters to address many of the challenges facing the future power system. In August 2021, AEMO published a white paper titled "Application of Advanced Grid-Scale Inverters in the NEM" as an initial step in exploring advanced inverter technology (AEMO, 2021). The white paper described applications defined as relevant to advanced grid-scale inverters, with the focus on GFM inverters. Notably, AEMO is taking a gradual approach to the evaluation of IBR capabilities, where capabilities are expected to increase over time as the level of synchronous generation declines. The four applications are the following, and they increase in importance as the share of IBRs on the system rises (Figure 10, p. 37):

1. **Connecting IBRs in weak grids:** Advanced IBRs should be capable of maintaining stable operation in conditions of low system strength and of providing system strength and improved stability to nearby IBRs.
2. **Supporting system security:** Advanced IBRs should have capabilities that are predominantly delivered by synchronous generation today, such as capability to support inertia and system strength, to support the broader power system.
3. **Remaining stable in island operation:** Advanced IBRs should be able to maintain stability in a grid that becomes separated from the main synchronous system when operating under high levels of IBRs.
4. **Providing system restart:** Advanced IBRs should be capable of energizing the local network and/or assisting with the system restoration process after a blackout. This capability will become more relevant over time as the generation mix evolves and will only be needed from a subset of GFM IBRs.

FIGURE 10

Capabilities Required for Advanced Inverter Applications in the Australian Energy Market Operator



Source: Australian Energy Market Operator (2021).

The deployment of GFM capabilities is generally prioritized around grid-scale batteries in Australia's NEM, considering the availability of commercial GFM products from multiple manufacturers of battery energy storage systems. With the growing number of grid-scale batteries committed or proposed in Australia, there is an excellent opportunity to deploy GFM capabilities in the upcoming expansion of the battery fleet to support the transition to a grid with little or no synchronous generation. In this process GFM capabilities could be demonstrated and tested at scale. To facilitate this, the Australian Renewable Energy Agency has recently advised the market of its funding support for at least three different GFM projects across the NEM and the Western Australia grid accounting for 500 MW to 1000 MW of new large-scale batteries.

With the growing number of grid-scale batteries committed or proposed in Australia, there is an excellent opportunity to deploy GFM capabilities in the battery fleet to support the transition to a grid with little or no synchronous generation.

All of the examples in this section represent pathways to develop GFM requirements and capabilities. As requirements are being fully formed and ratified by each system operator, country, or region, it is important to undertake, in parallel, GFM pilot projects that are able to successfully meet those requirements. Where markets are used to deploy provision of new system services, these GFM IBR pilots should include the successful implementation of market mechanisms that compensate equipment owners for the investment in and provision of system services. Once GFM pilot projects demonstrate that the requirements and processes are successful in one location or region, GFM technology may be scaled in those and other areas that adopt the same framework.

Although GFM functionality today is most commonly found in battery energy storage systems, other technologies are not far behind, including flexible alternating current transmission systems (FACTS), such as static synchronous compensators (STATCOMs) and voltage source converter (VSC) HVDC technologies, and utility-scale solar IBRs. Solar inverters are similar to battery inverters and the same GFM controls can be implemented; however, as noted above, solar resources will need to forego some revenue from the provision of energy when they are providing grid services that require the availability of an energy buffer. It is more complex to implement GFM controls on wind-based IBRs, due to the participation of, and stress on, the drive train. If requirements for GFM capability are applied to wind-based IBRs, they should take into account the implications of drive train participation and stress for ride-through, frequency response, and damping during various disturbed and non-disturbed grid conditions.

To require GFM capability for proven GFM battery and FACTS technologies is low-hanging fruit and should be considered in all power systems experiencing growth of IBRs.

Several grids have already seen the successful deployment of GFM battery energy storage systems and voltage source converter (VSC) HVDC to provide grid voltage and frequency stability services as well as black start in some applications. To require GFM capability for these proven GFM battery and FACTS technologies is low-hanging fruit and should be considered in all power systems experiencing growth of IBRs.

5 Advanced Characterization and Testing of Grid-Forming Resources

In order to compare and define grid-forming (GFM) resources' performance requirements, uniform test procedures are necessary to characterize these resources' capabilities to serve various system needs. Most tests performed on grid-following (GFL) inverters are also required for GFM inverters, with additional tests also needed specifically for GFM inverters. This section describes advanced characterization and testing methods for GFM inverters, with the goal of serving as a guideline for developing test procedures.

Because the performance requirements for GFM inverters and inverter capabilities are still evolving, the experimental results presented in this section should not be construed as the maximum performance achievable from the tested inverters. Some of the GFM inverters used in this section to demonstrate test procedures employed control firmware that is still under development; hence, the test results do not represent the full range of their performance capabilities.[14]

How and When to Use the Various Tests and Models

The tests described in this section are recommended for inverter manufacturers as a part of product certification. In addition, demonstration of GFM resources' performance will likely be required by transmission system operators. Since it may not be feasible to do these tests for site-specific projects with parameters and control mode settings that differ from those of the certified product, we recommend first performing initial tests for product certification in a laboratory environment and using the test results to validate electromagnetic transient (EMT) simulation models. The validated EMT models can then be used for site-specific testing to demonstrate performance of GFM resources as required by transmission system operators. We recommend validation of EMT simulation models for all the tests described in this section, because each test captures different aspects of the dynamics of GFM inverters.

Assessing Voltage Source Behavior and the Current-Limiting Mode of Operation

The main objective of the tests for GFM inverters is to quantify their voltage source behavior and characterize the current-limiting mode of operation (Kersic et al., 2020; Denninger et al., 2020). The "stiffness" of the voltage source emulated by a GFM inverter depends on its control bandwidths: the magnitude and phase of the voltage of a GFM inverter tend to remain constant within the transient time frame following a disturbance if the bandwidths of the voltage control loops used for regulating the terminal voltage are kept sufficiently small (a voltage control loop with a smaller bandwidth generally corresponds to a longer rise time and settling time).[15] The performance of many of the system services from a GFM inverter depends on the stiffness of the voltage source it emulates.

14 Work discussed in this section of the report was authored in part by Alliance for Sustainable Energy, LLC, the manager and operator of the National Renewable Energy Laboratory for the U.S. Department of Energy under Contract No. DE-AC36-08GO28308. Funding provided by U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, Solar Energy Technologies Office and Wind Energy Technologies Office. The views expressed in this section do not necessarily represent the views of the Department of Energy or the U.S. government. The U.S. government retains and the publisher, by accepting this section for publication, acknowledges that the U.S. government retains a nonexclusive, paid-up, irrevocable, worldwide license to publish or reproduce the published form of the work described in this section of the report, or allow others to do so, for U.S. government purposes.

15 For example, Great Britain's GC0137 requirement for inverter terminal voltage control bandwidth is 5 Hz.

The stiffness of the voltage source emulated by a GFM inverter depends on its control bandwidths: the magnitude and phase of the voltage of a GFM inverter tend to remain constant within the transient time frame following a disturbance if the bandwidths of the voltage control loops used for regulating the terminal voltage are kept sufficiently small.

For example, if the bandwidth of the voltage magnitude control in a GFM inverter is designed to be low, then the inverter control will take some time to reflect a change in the voltage magnitude during a dip in the grid voltage magnitude. (This can be translated as the voltage appearing to be constant.) This behavior can subsequently induce a change in the reactive current response from the inverter. Similarly, a lower bandwidth of the control loop used for regulating the voltage phase angle will naturally induce a more aggressive active current response from a GFM inverter following a sudden change in the frequency of grid voltage or a phase jump. This means that GFM resources can maintain stability under low short-circuit ratio conditions and even "form" grid voltage when necessary. The absence of a phase-locked loop (PLL) for synchronization in a GFM resource can typically also help to mitigate sub-synchronous oscillations and harmonics by naturally acting against them. Caution should be taken to deploy inverter-based resources (IBRs) with controls that are appropriately tuned for the grid conditions (strong grid or weak grid), to avoid control interactions while providing required speed of response to meet grid needs.

Another aspect of the voltage source behavior of a GFM inverter is its equivalent Thevenin impedance. The impedance at the fundamental frequency determines the steady-state voltage regulation properties, whereas the small-signal impedance at other frequencies determines the dynamic properties including risks of unintended control interactions with other GFM and GFL IBRs, particularly during operation under low system strength conditions. It is important to note that GFM inverters can only maintain the voltage source behavior over a limited range of output currents, depending on the current rating of the power electronics hardware. Once the inverter's current rating is reached, the inverter will enter current-limiting mode, where output current is maintained at or below the limit. Different methods are used for limiting the inverter output currents, for example, current control mode or high impedance mode, to protect the inverter hardware during a grid disturbance. It is important to characterize a GFM inverter during operation in the current-limiting mode as well as during transition into and out of the current-limiting mode, as this shapes the behavior of the inverter during faults and other grid events. The way in which a GFM inverter remains synchronized with the grid and maintains stability during the current-limiting operation mode influences the duration and type of transient events it can withstand and ride through.

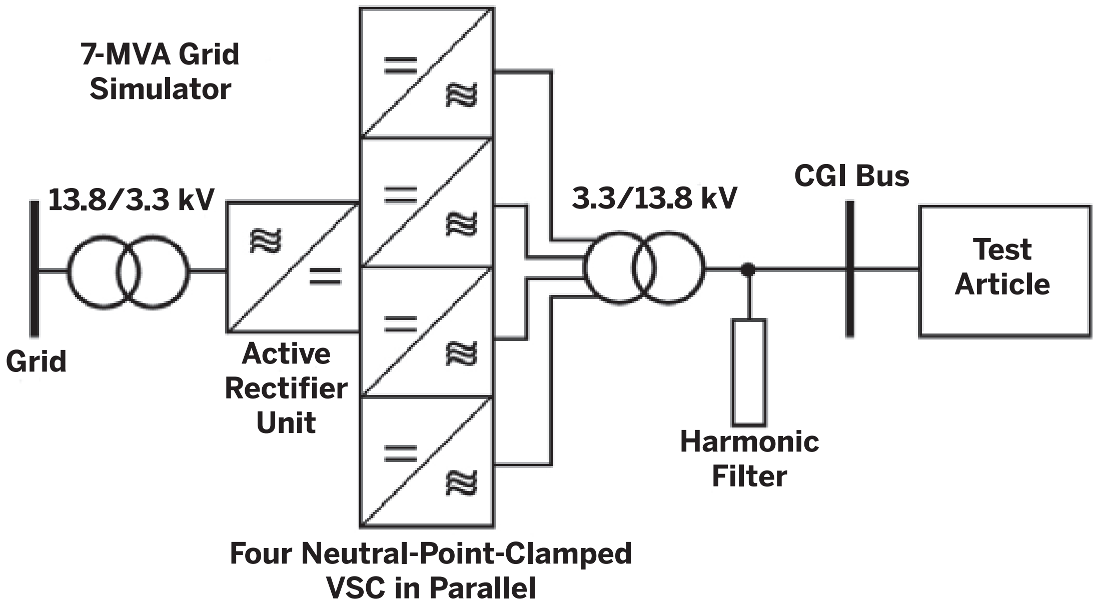
Once the GFM inverter's current rating is reached, it will enter current-limiting mode, where output current is maintained at or below the limit to protect the inverter hardware during grid disturbance.

Description of the Test System

Many of the tests in this section were performed on a 2.3 MVA inverter at the U.S. National Renewable Energy Laboratory (NREL). The inverter interfaces on its DC side with a battery energy storage system (BESS) rated at 1 MW/1 MWh. The transformer on the AC side was rated at 1 MW, and it stepped up the inverter output voltage to 13.2 kV (Figure 11, p. 41). The 2.3 MVA inverter at NREL is capable of operation in either the GFM or GFL mode. Unless stated otherwise, all of the test results presented in this section used the 2.3 MVA inverter and were performed when the inverter was operating in the GFM mode. Test results presented here were obtained by exposing the inverter to various disturbances using a 7 MVA/13.8 kV grid simulator.

FIGURE 11

Test Set-Up for the Advanced Characterization of a 2.3 MVA GFM Inverter



Schematic of the set-up at NREL that was used to test the 2.3 MVA inverter. The "Test Equipment" box included the 2.3 MVA inverter, a 1 MW transformer at the AC front-end of the inverter to step up the inverter voltage to 13.2 kV, and a 1 MW/1 MWh BESS on the DC side of the inverter.

Source: National Renewable Energy Laboratory.

Tests Applicable to Both Grid-Following and Grid-Forming Inverters

Voltage Ride-Through

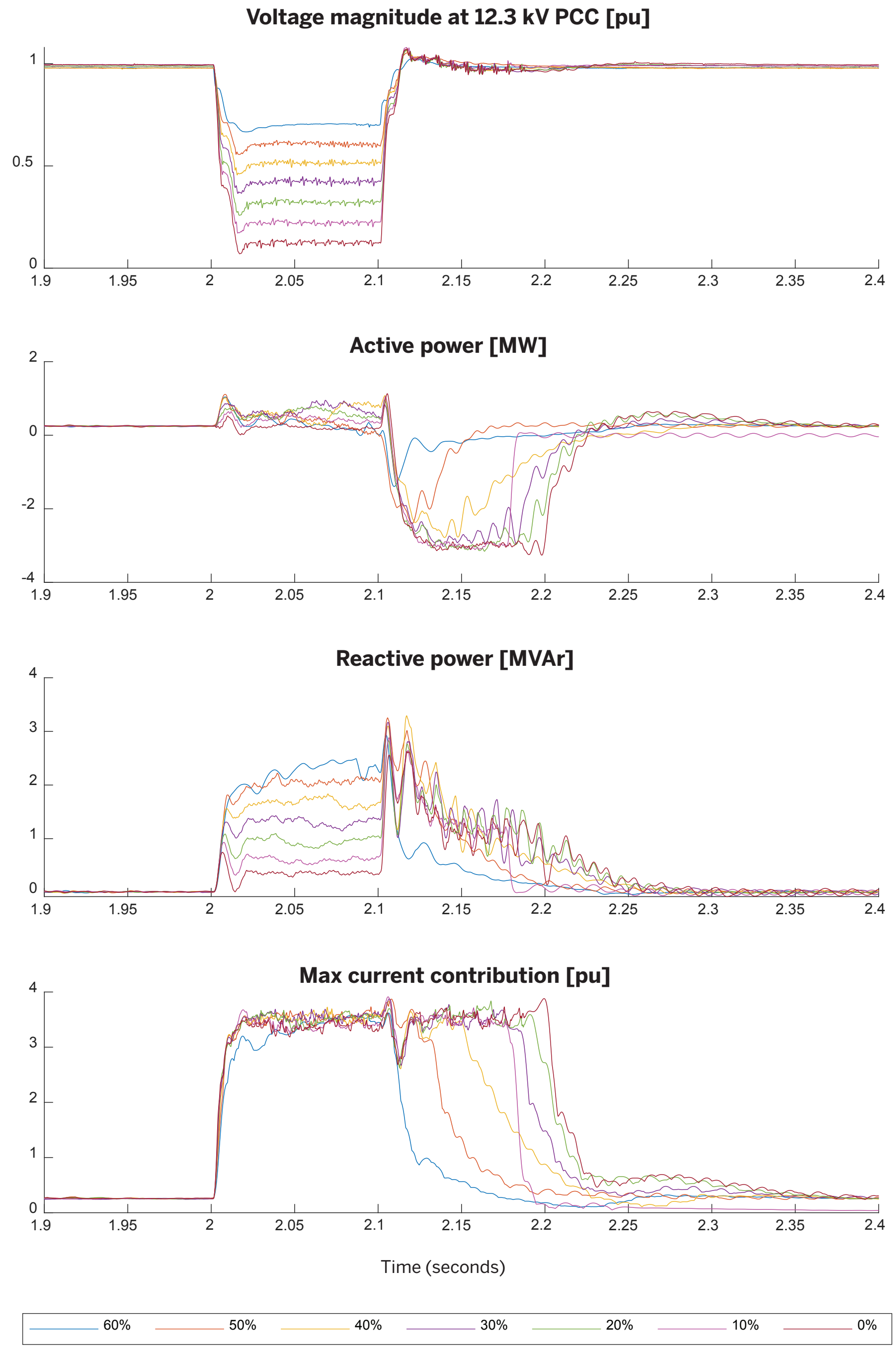
Figure 12 (p. 42) shows low-voltage ride-through (LVRT) test results for the 2.3 MVA GFM inverter (WGTF, 2007). During the voltage dip starting at 2 seconds for all of the LVRT events presented in Figure 12, the inverter quickly entered the current-limiting operation mode. The transition from the normal operation mode to the current-limiting mode was similar for all the LVRT events with different levels of the voltage dip. However, the transition from the current-limiting operation mode to the normal operation mode at the end of the voltage dip was different for all the LVRT events, and it depended on the voltage dip magnitude. The time the inverter took to return to the normal operation mode after the end of the voltage dip was proportional to the severity of the event. Moreover, the active power output of the inverter became negative following the voltage dip, with the duration and the magnitude of the negative active power response being dependent on the voltage dip level. In this case, this behavior could be a result of an integrator wind-up in an inverter controller. A longer and stronger negative active power response might result in an over-voltage condition at the DC bus and trip the inverter. The sizing of the battery, protection settings, and controller tuning determine the type of LVRT events that a GFM inverter can withstand and ride through.

Frequency Response

The time-domain tests for characterizing the frequency response of an inverter include emulation of rate of change of frequency (RoCoF) and a step change in the frequency of grid voltages using a grid simulator. The frequency response tests are important to determine what kind of frequency events an inverter can ride through and its active power response during these events. It may not always be possible to test an inverter using a grid simulator, either because of the inverter's size or because testing needs to be performed on an inverter operating in the field. Under such conditions, time-domain tests can be carried out by artificially manipulating control variables, so that the inverter behaves as if during a real frequency event.

FIGURE 12

Response of a 2.3 MVA GFM Inverter During Low-Voltage Ride-Through Tests



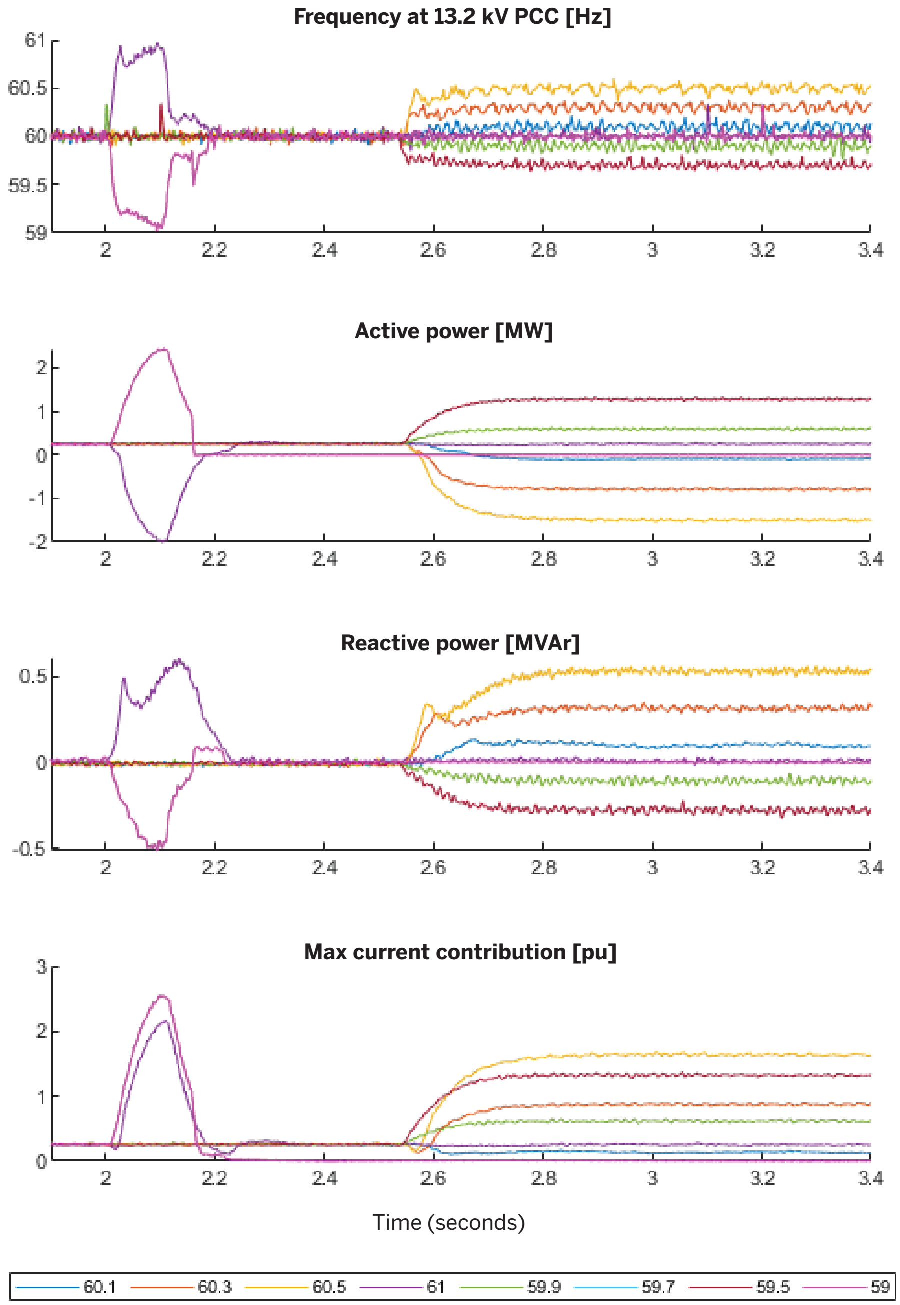
In LVRT tests used to evaluate transient performance of the inverter, during the voltage recovery phase the tested inverter exhibited negative active power response, with the magnitude proportional to the severity of the voltage dip. This behavior could be a result of an integrator wind-up of a controller inside the inverter. The inverter tripped for the event when the voltage at its terminal was reduced transiently to 0.2 per unit, as can be seen in the active power of the inverter going to 0.

Note: The percentages shown in the legend correspond to the voltage magnitude of the internal voltage source of the grid simulator during LVRT tests. The voltage at the point of common coupling (PCC) of the inverter (shown in the top plot) is higher during LVRT events than the grid simulator internal voltage because of the output impedance of the grid simulator.

Source: National Renewable Energy Laboratory.

FIGURE 13

Response of a 2.3 MVA GFM Inverter During Step Change in the Frequency of Grid Voltage

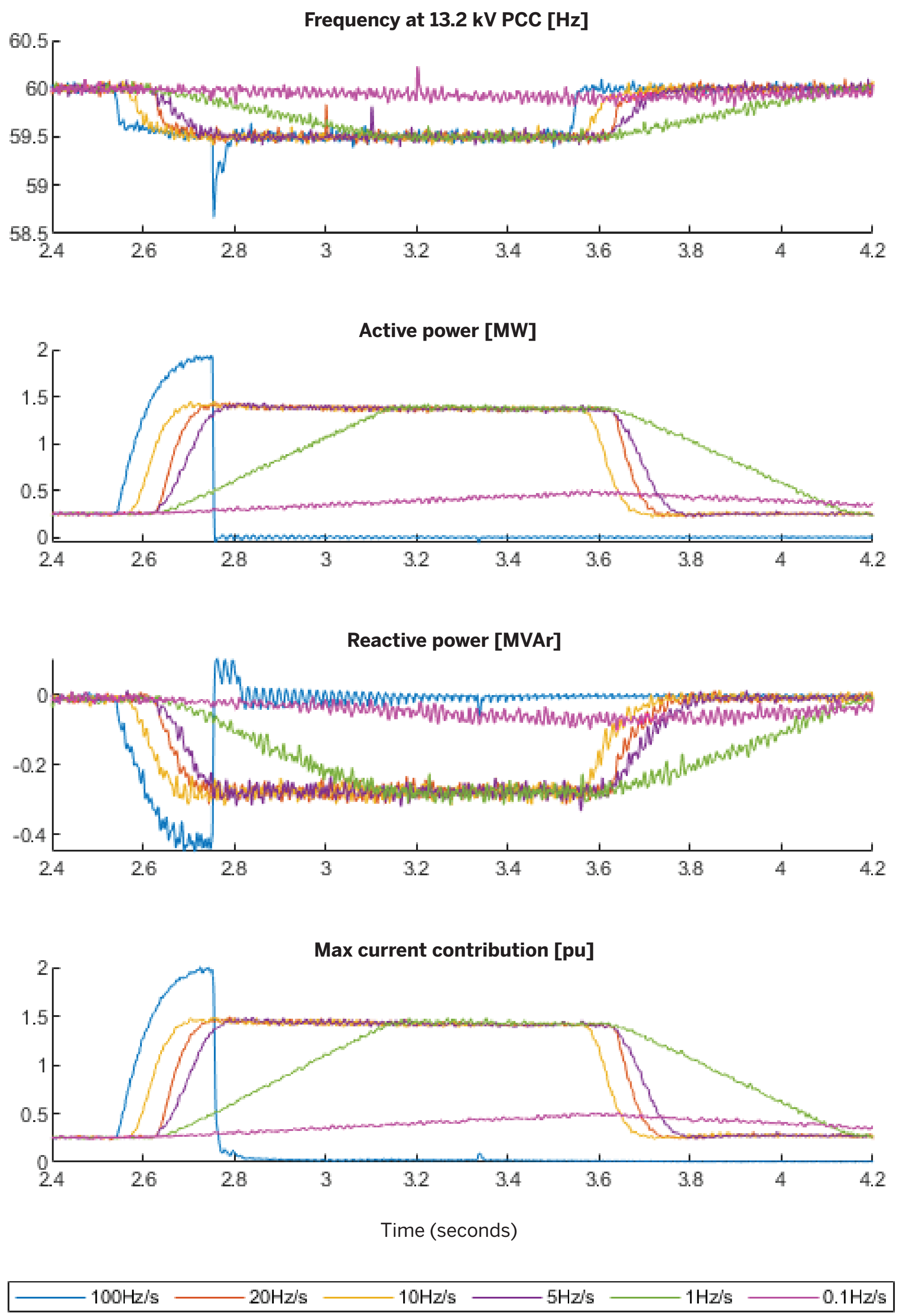


This figure demonstrates frequency step tests used to evaluate frequency response of the GFM inverter. The legend shows the new settling value of the fundamental frequency during frequency step tests. The per-unit values are based on 1 MW rating. The steady-state active power response of the inverter following a sudden change in the grid frequency is dependent on the droop setting. The inverter output power was limited to 1 MW because of the 1 MW rating of the BESS on the DC side. Because of this limitation, the frequency step events of magnitude 1 Hz were kept to a duration of 100 milliseconds, instead of 1 second duration used for events with smaller frequency steps, to avoid overloading the BESS.

Source: National Renewable Energy Laboratory.

FIGURE 14

Response of a 2.3 MVA GFM Inverter During RoCoF Tests



In RoCoF tests used to evaluate the frequency response of a 2.3 MVA GFM inverter, the tested inverter failed to ride through a RoCoF event of 100 Hz/s but was able to ride through RoCoF events of smaller magnitudes.

Source: National Renewable Energy Laboratory.

Figures 13 (p. 43) and 14 (p. 44) show results from time-domain frequency response tests. The frequency and voltage droop settings of the inverter were programmed at 1 Hz/2.2 MW (corresponding to a droop of 1.67 percent on 2.2 MW base power) and 0.05 pu (voltage)/1 MVAR, respectively.

Figure 13 shows the response of the inverter to step changes in the frequency of grid voltages. Here, the inverter tripped when the frequency was suddenly dropped to 59 Hz in a step manner (shown at approximately 2 seconds). The inverter rode through other frequency step events of smaller magnitudes (applied at approximately 2.5 seconds), and its active power output settled to a level depending on the droop setting. Figure 14 shows the response of the inverter to RoCoF tests. The inverter tripped for a very high RoCoF of 100 Hz/second (blue curve), but it was able to ride through less severe RoCoF events. The frequency step and RoCoF tests show that the ability of an inverter to ride through a frequency event depends on both the RoCoF of the event and the magnitude of the frequency change.

Frequency Scan–Based Characterization

GFL inverters are prone to dynamic stability problems during operation in areas with low system strength. Both GFL and GFM inverters are also prone to control interactions when in proximity to other inverters. It is therefore important to test their dynamic behavior for operation in areas with low system strength and to evaluate their interoperability with other GFL and GFM inverters from different manufacturers. Impedance measurements on actual hardware or impedance scans on vendor-supplied black-box EMT simulation models can be used to evaluate the dynamic behavior of IBRs, analyze risks of control interactions, and perform system stability studies (Shah et al., 2021a). The impedance responses of GFM inverters can also be used to quantify their participation in and impact on damping of wide-area oscillation modes.

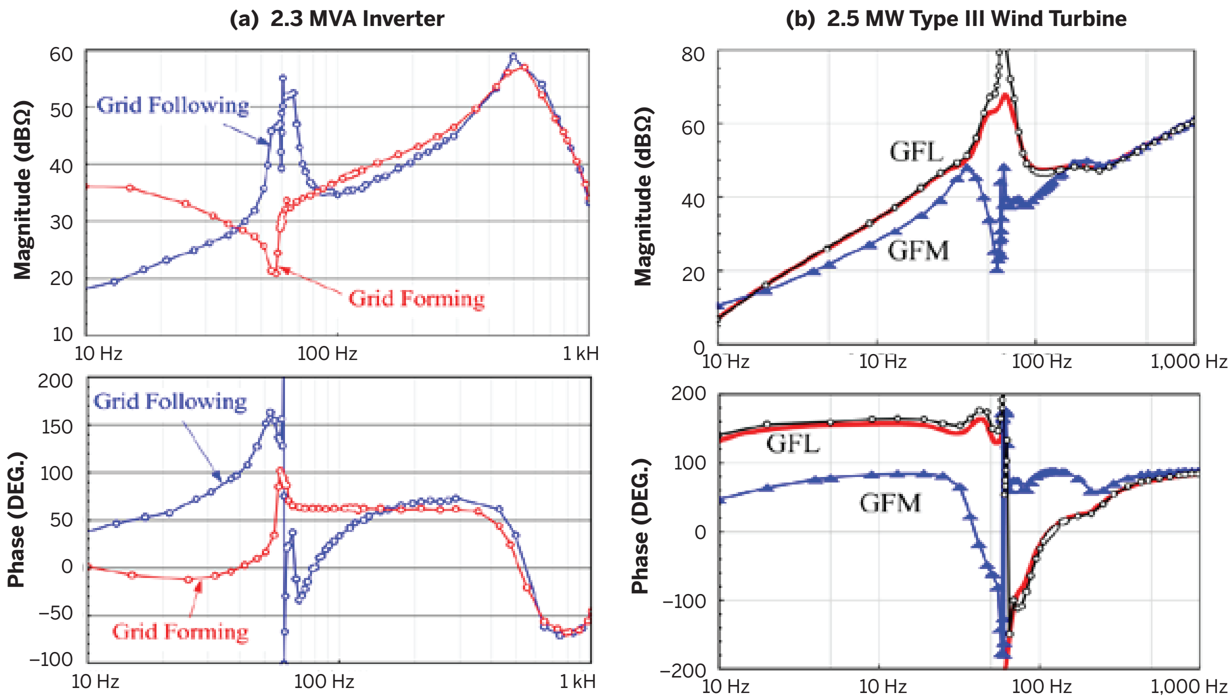
Figure 15 (p. 46) shows the positive-sequence impedance response of the 2.3 MVA inverter and a 2.5 MW Type III wind turbine (EMT simulation model), for operation in both GFL and GFM control modes. The impedance response of the 2.3 MVA inverter was obtained using a 7 MW grid simulator by injecting small-signal voltage perturbations at different frequencies superimposed on the fundamental voltage trajectory (Shah et al., 2021b). The magnitude of the impedance response, both for the inverter and the wind turbine, was significantly lower around the fundamental frequency for the GFM control mode than the GFL control mode. This is because the inverter and the wind turbine were emulating a voltage source behavior in the GFM mode at the fundamental frequency instead of a current source. The small-signal impedance response around the fundamental frequency can be used to quantify the voltage source behavior of GFM resources. The phase of the positive-sequence impedance responses in Figure 15 stayed within ±90 degrees for the entire frequency range, both for the inverter and the wind turbine, for the GFM control mode. This shows that GFM resources tend to provide positive damping over a broad frequency range, which can be quantified using impedance measurement tests.

In addition to the time-domain frequency step and RoCoF tests described in the previous sub-section, a frequency scan method can be used to test a GFM resource's frequency response. In the frequency scan approach, small, non-invasive perturbations of different frequencies are injected in the grid voltage frequency using a grid simulator at the terminal of a GFM resource, and its active power output is measured at the perturbation frequency. The objective of this test is to measure the transfer function from the active power output of a GFM resource to the frequency of the voltage at its terminal. For characterizing a frequency response of a GFM inverter, the frequency scan needs to be performed at low frequencies, up to a few tens of Hz (Dysko et al., 2020; Shah and Gevorgian, 2019). The response of the transfer function from the active power output to the frequency can be used to estimate the GFM inverter's inherent active power response (a response similar to that provided through a synchronous machine's inertia) and frequency response through the droop gain (similar to that provided from a synchronous machine's governor).

As an example, Figure 16 (p. 47) shows the results of frequency scan tests carried out on a simulation model of an IEEE 9-bus system and on a real 2 MW synchronous generator using a grid simulator. The DC gain of the transfer function at low frequencies gives the measure of primary frequency response of the tested system, and the capacitive response gives the measure of inertia (instantaneous active power response). The frequency scan

FIGURE 15

Positive-Sequence Impedance Measurement



This figure compares impedance characteristics of GFM and GFL resources, comparing magnitude and phase across a range of frequencies. The left plots under (a) show experimental measurements of the positive-sequence impedance magnitude and phase angle for a 2.3 MVA inverter for operation in GFL and GFM modes. The right plots under (b) show frequency scans of the positive-sequence impedance magnitude and phase angle performed on an EMT simulation model of a 2.5 MW Type III wind turbine for operation in GFL and GFM modes.

Source: Shah et al. (2021b); National Renewable Energy Laboratory.

method for characterizing a GFM resource's response during frequency events provides higher accuracy than the time-domain tests.

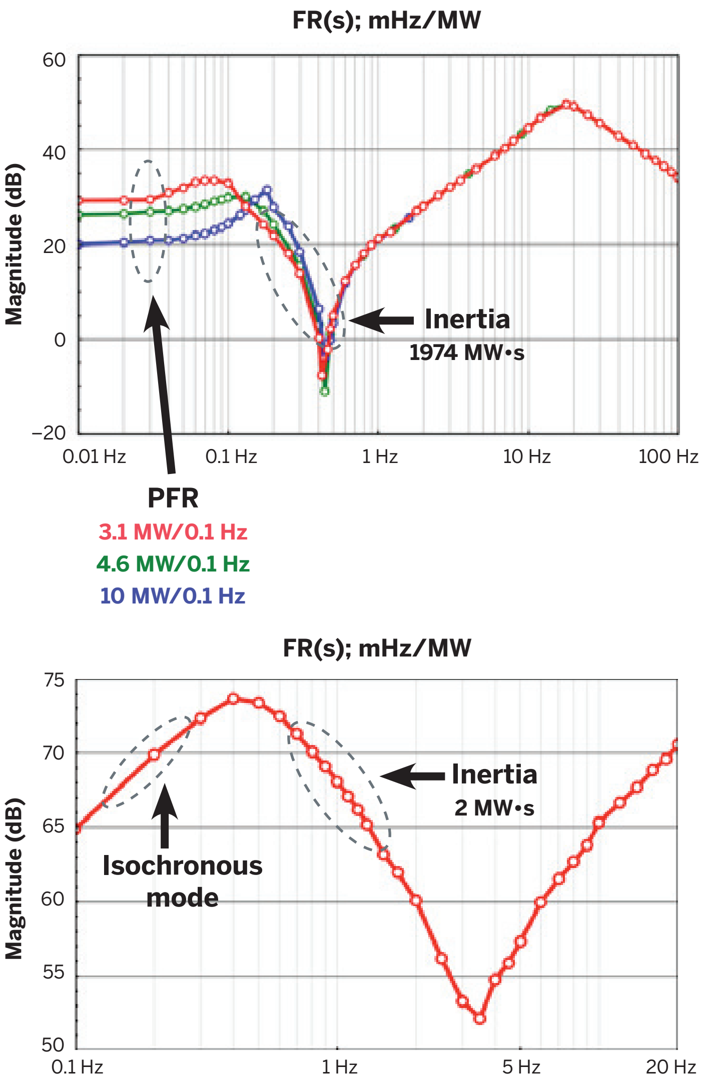
Phase-Jump Ride-Through and Response

Both frequency step and RoCoF tests, discussed above, can highlight an inverter's inherent active power response and fast frequency response behavior (along with primary frequency response behavior, if separated from fast frequency response). A phase-jump test highlights the inherent active power response behavior.

IBRs experience phase jumps in their terminal voltage during switching of major loads, reclosure or opening of transmission lines, operation of phase-shifting transformers, and fault events. The active power response is inherently provided by an inverter immediately after the phase jump, and the inverter returns to the pre-disturbance level after riding through the phase-jump event. Phase-jump tests are performed to determine the phase-jump events that an inverter can ride through without getting disconnected from the grid and to verify the inherent response provided by an inverter during the phase-jump event. Figures 17a and 17b (pp. 48 and 49) show the response of the 2.3 MVA inverter at NREL during phase jumps of magnitudes ranging from 5 to 50 degrees. The graphs show responses for both GFM and GFL operation modes of the inverter. The inverter was able to ride through all phase-jump tests except the 50 degree phase-jump event during the GFM operation mode. GFM inverters respond more aggressively to phase-jump events than GFL inverters, especially with regard to the duration of the response, because of inherent voltage source behavior. As a result, it is more challenging for a GFM inverter than a GFL inverter to ride through a phase-jump event. The requirement for the Great

FIGURE 16

Frequency Scan Method for Estimating the Inherent Active Power Response, Damping, and Frequency Response of Generators



(a) Simulation test on an IEEE 9-bus system for different droop settings in generators. (b) Experimental test on a 2 MW synchronous generator.

Source: National Renewable Energy Laboratory.

Britain GFM inverter (as per GC0137) is to be able to ride through a 60 degree phase jump. This may be a challenging requirement for these resources to meet. If riding through such a large phase jump indeed corresponds to a system need (and if it has been done to date by existing synchronous generators), more advanced grid-support capabilities need to be developed and become commercially available to serve this need.

Figures 17a and 17b (pp. 48 and 49) also demonstrate the inherent active power response of GFM and GFL inverters during phase jumps, discussed in the previous section.

Steady-State Performance

IBRs can be a source of harmonics and interharmonics with amplitudes and frequencies that depend on a number of inverter design factors. The International Electrotechnical Commission's IEC 61400-4-7 standard provides guidance on testing and measurement techniques for voltage and current harmonics and interharmonics for resources that supply loads, and provides requirements and classes of accuracy for test equipment for both single-phase and three-phase emission measurements (IEC, 2002). To simplify the measurement process, the standard defines harmonic and interharmonic grouping methods for both voltage and current. Discrete Fourier Transform (DFT) is applied to measured current and voltage waveforms with a certain window width (12 for 60 Hz systems) with rectangular weighting. For the assessment of harmonics and interharmonics, the components from the DFT output for both voltage and current waveforms for each 5 Hz window are subgrouped as shown in Figure 18 (p. 50). The harmonic and subharmonic subgroups are then calculated as a modulus of the subgroups consisting of individual harmonic (h) and subharmonic (g) RMS (root mean squared) values:

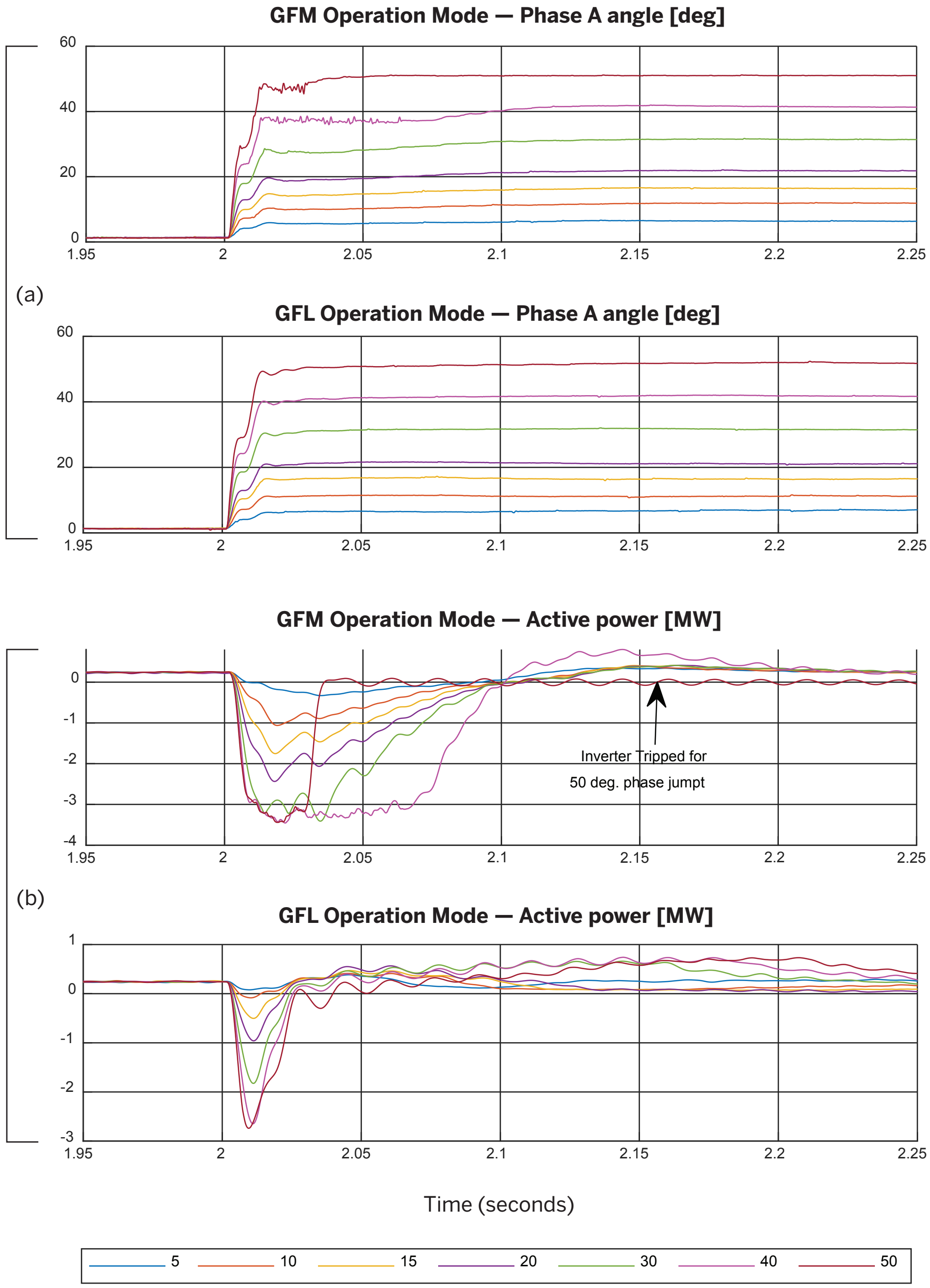
$$H_n = \sqrt{\sum_{k=-1}^{1} h_{12n+1}^2} \text{ and } G_n = \sqrt{\sum_{k=2}^{10} g_{12n+1}^2} \quad (5.1)$$

Some testing standards for IBRs (such as IEC 61400-21 for wind turbine generators) also require measurements of current distortions from 2 kHz to 9 kHz during continuous operation. These high-frequency current distortions in that range are measured and averaged over a 10 minute interval. The same harmonic and interharmonic measurement and evaluation techniques can be applied to inverters operating in the GFM mode.

Flicker in power systems is caused by low-frequency variations in the RMS voltage magnitude, which can be caused by harmonics and interharmonics, and it usually presents itself in the form of noticeable disturbances in light source illumination. The methodology provided by the IEC 61400-4-15 standard has been used in flicker meter equipment for decades. However, there is an

FIGURE 17a

Response of an Inverter to Phase Jumps in Its Terminal Voltage for GFM and GFL Operation Modes



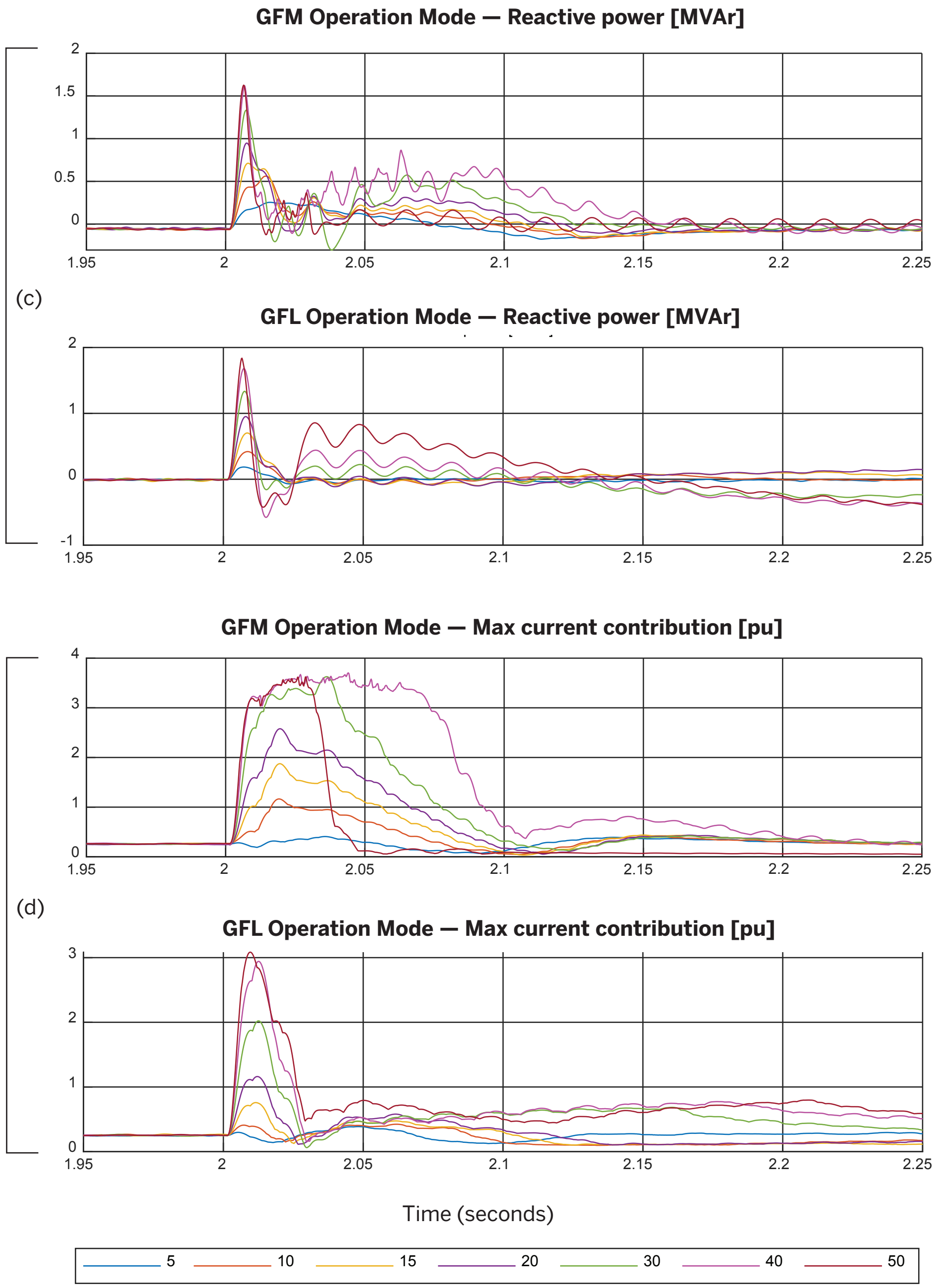
These tests show the response of the 2.3 MVA inverter to phase jumps of different magnitudes (ranging from 5 to 50 degrees) in its terminal voltage for the GFM and GFL operation modes. (a) Phase of terminal voltages in degrees; (b) active power output in MW; (c) reactive power output in MVAr (p. 49); and (d) maximum current contribution per unit on 1 MW base rating (p. 49).

In the GFL mode, the tested inverter was able to ride through all emulated phase-jump events of up to 50 degrees for operation. In the GFM mode, the inverter was able to ride through the same events except for the 50 degree phase-jump event. The active power response is inherently provided by the inverter immediately after the phase jump. The inverter returns to the pre-disturbance level after riding through the phase-jump event.

Source: National Renewable Energy Laboratory.

FIGURE 17b

Response of an Inverter to Phase Jumps in Its Terminal Voltage for GFM and GFL Operation Modes



These tests show the response of the 2.3 MVA inverter to phase jumps of different magnitudes (ranging from 5 to 50 degrees)in its terminal voltage for the GFM and GFL operation modes. (a) Phase of terminal voltages in degrees (p. 48); (b) active power output in MW (p. 48); (c) reactive power output in MVAr; and (d) maximum current contribution per unit on 1 MW base rating.

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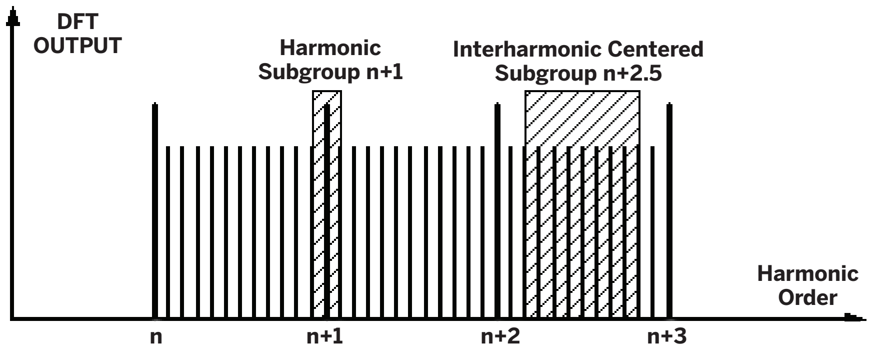
Source: National Renewable Energy Laboratory.

FIGURE 18

Harmonic and Interharmonic Centered Subgroups for 60 Hz Systems



Harmonic and interharmonic subgroupings are done on voltage and current for 60 Hz systems to calculate total harmonic and interharmonic distortion on a waveform, according to IEC 61000-4-7. This subgrouping methodology simplifies the calculation of harmonic and interharmonic content.

Source: National Renewable Energy Laboratory.

ongoing discussion in the research community about the applicability of this standard for proper measurements of flicker, especially if it is composed of multiple frequency components (Elvira-Ortiz et al., 2018). In the case of variable generation (wind and solar), change in the power output of the variable resource can also lead to increased flicker levels (Ebad and Grady, 2016).

Testing with Grids of Different Short-Circuit Strength

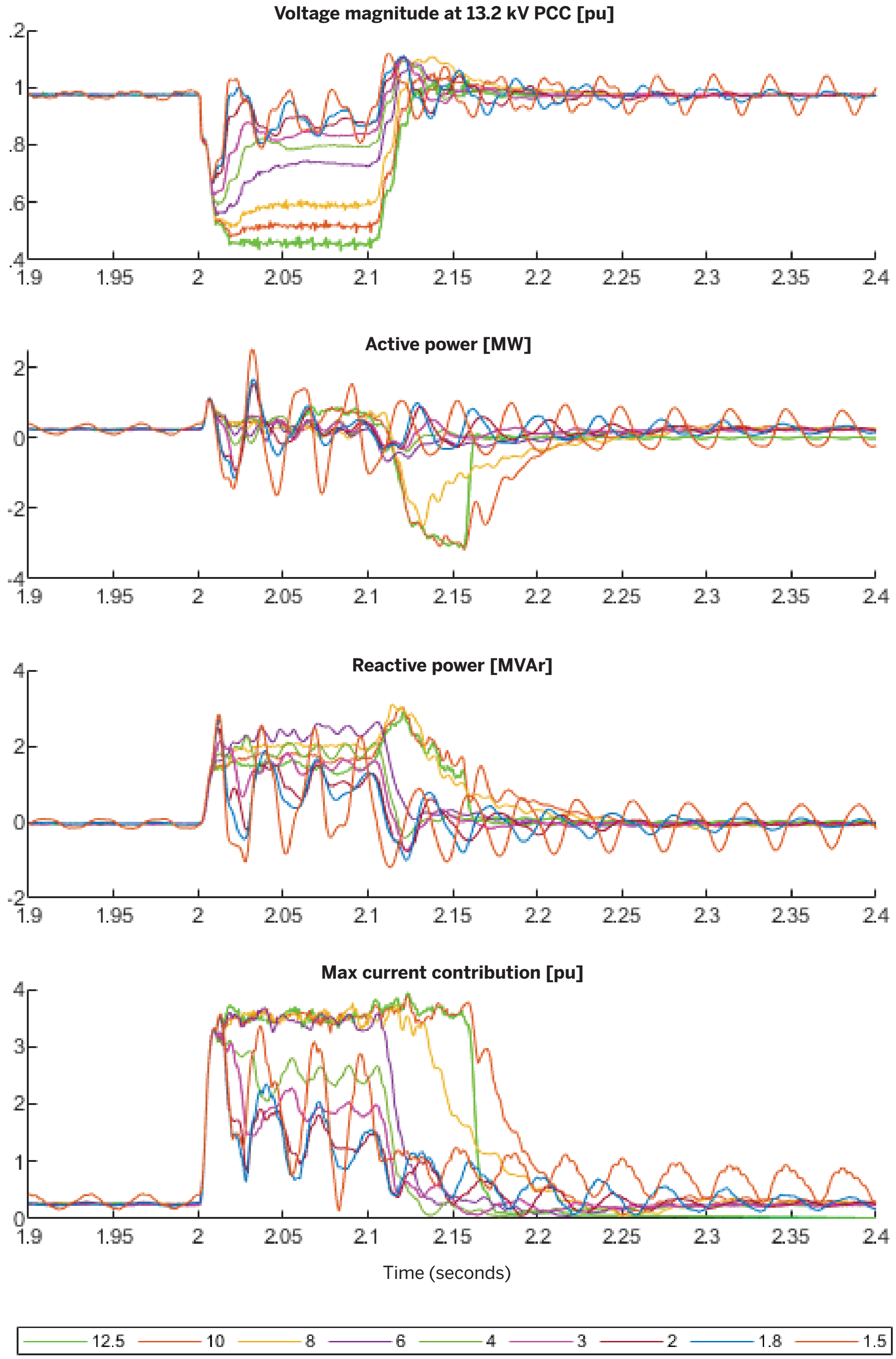
All of the tests for GFM and GFL inverters described above were performed using a grid simulator with very low internal impedance, meaning the tests were performed for an extremely strong grid condition. While the response of an inverter obtained from frequency scan tests (for example, small-signal impedance measurement) is independent of the strength of the grid at the inverter's terminals, the response of an inverter during transient tests (including low-voltage ride-through tests, frequency step and RoCoF tests, and phase-jump tests) might be strongly correlated with the strength of the grid at its terminals. An inverter might behave completely differently for the same transient event for two different grid conditions. To address this, it is recommended that while the laboratory tests for product certification can use the same grid strength as adopted in this report (i.e., almost an ideal grid established by a grid simulator), the additional EMT model–based site-specific inverter testing should consider grid strengths that the inverter is expected to encounter in the field. These additional tests for different grid strengths can be performed using EMT simulation models that are validated using the laboratory tests.

To demonstrate the impact of the grid strength on the transient response of an inverter, LVRT tests were performed on the 2.3 MVA inverter for operation in the GFL mode for different grid strengths emulated by a virtual impedance inside the 7 MVA grid simulator. Results are shown in Figure 19 (p. 51).

Each trace on Figure 19 corresponds to a different grid short-circuit ratio (SCR) emulated by the grid simulator. For each LVRT test (at each SCR), the internal voltage of the grid simulator was reduced by 60 percent. It can be seen that for the higher impedance between the internal voltage source of the grid simulator and the point of interconnection of the inverter (i.e., for lower SCRs), the inverter was able to maintain the voltage at the point of interconnection closer to the nominal level for the same dip in the magnitude of the internal voltage source. The 2.3 MVA inverter was tripping because of overvoltage for the SCR of 12.5 (bright green line) at the end of the LVRT event (t=2.17 seconds), because it was not able to resynchronize to the grid voltage at its terminal. In contrast, the inverter was able to ride through LVRT event for the SCR values from 10 to 1.5 (all other traces on

FIGURE 19

Low-Voltage Ride-Through Tests of a 2.3 MVA Grid-Following Inverter for Different Grid Strengths



These tests demonstrate how the strength of the grid at the terminal of an inverter changes the inverter's behavior during grid disturbances such as low-voltage faults. Short-circuit ratios in these tests ranges from 1.5 to 12.5. Per-unit current contribution corresponds to the base power of 1 MW.

Source: National Renewable Energy Laboratory.

Figure 19). However, the inverter response became more and more oscillatory during and after the event as grid strength was reduced by the virtual impedance in the grid simulator (traces with SCR<3). The inverter was not able to ride through the low-voltage event for the SCR value below 1.5 because of oscillations in the active and reactive power output (not shown on this figure).

In summary, higher effective impedance of the grid at the terminal of an inverter, which can be interpreted as a grid with low short-circuit strength, helps the inverter to ride through a low-voltage fault event because the higher grid impedance electrically separates the fault event from the inverter, imparting better controllability to the inverter to regulate the voltage at the point of interconnection. On the other hand, higher grid impedance at the terminal of an inverter may induce oscillations during grid events, and the inverter may fail to ride through them. This highlights the importance of understanding the behavior of inverters during grid events for different short-circuit strength of the grid.

Tests Specific to Grid-Forming Inverters

Voltage Control Response

The voltage response of GFM inverters can be characterized by time-domain and frequency-domain tests. The response of a GFM inverter to a step change in the magnitude and phase of the grid voltages can be obtained using a grid simulator or by artificially manipulating the reference commands in the control system of the inverter, if such access is provided by the manufacturer. Such responses can be used to quantify the bandwidths of the voltage magnitude and phase control loops as well as the reactive power injection capability of an inverter. It is important to note here that the response of a GFM inverter to a step change in the voltage magnitude and phase jump will depend on the magnitude of the excitation, the implementation of the current-limiting mode, and the headroom and overload capability of the inverter. Hence, several tests are necessary to quantify the voltage response for different operating conditions. The frequency-domain test for characterizing the voltage response of a GFM resource requires estimation of the transfer function from the reactive power injected to the voltage magnitude at the point of interconnection under different operating conditions.

Black Start

For some applications, a GFM BESS can be used as a black-start resource, and evaluating its black-start capability involves testing parameters such as its voltage ramp rate and the inrush currents it can supply without tripping. To demonstrate black-start capability, several experiments were conducted soft-starting a BESS. Soft start is the ability of GFM inverter to ramp its voltage from zero to nominal value with any desired ramp rate, in order to avoid high inrush currents (in excess of the inverter rating) during transformer and transmission line energization. The results of a black start of a 430 kW GFL solar photovoltaic (PV) plant using a 1 MW/1 MWh GFM BESS are shown in Figure 20 (p. 53). The BESS inverter increased its voltage with a 200 millisecond ramp to minimize the inrush currents in the PV plant transformer. After the transformer of the PV plant was energized, the initialization timers triggered the inverters in the PV plant. After the black-start process was completed and the system was restored, the GFM battery in combination with variable generation was able to provide stable operation of an isolated grid. As with synchronous generators, to achieve black start from multiple GFM inverters, black-start sequence coordination is needed.

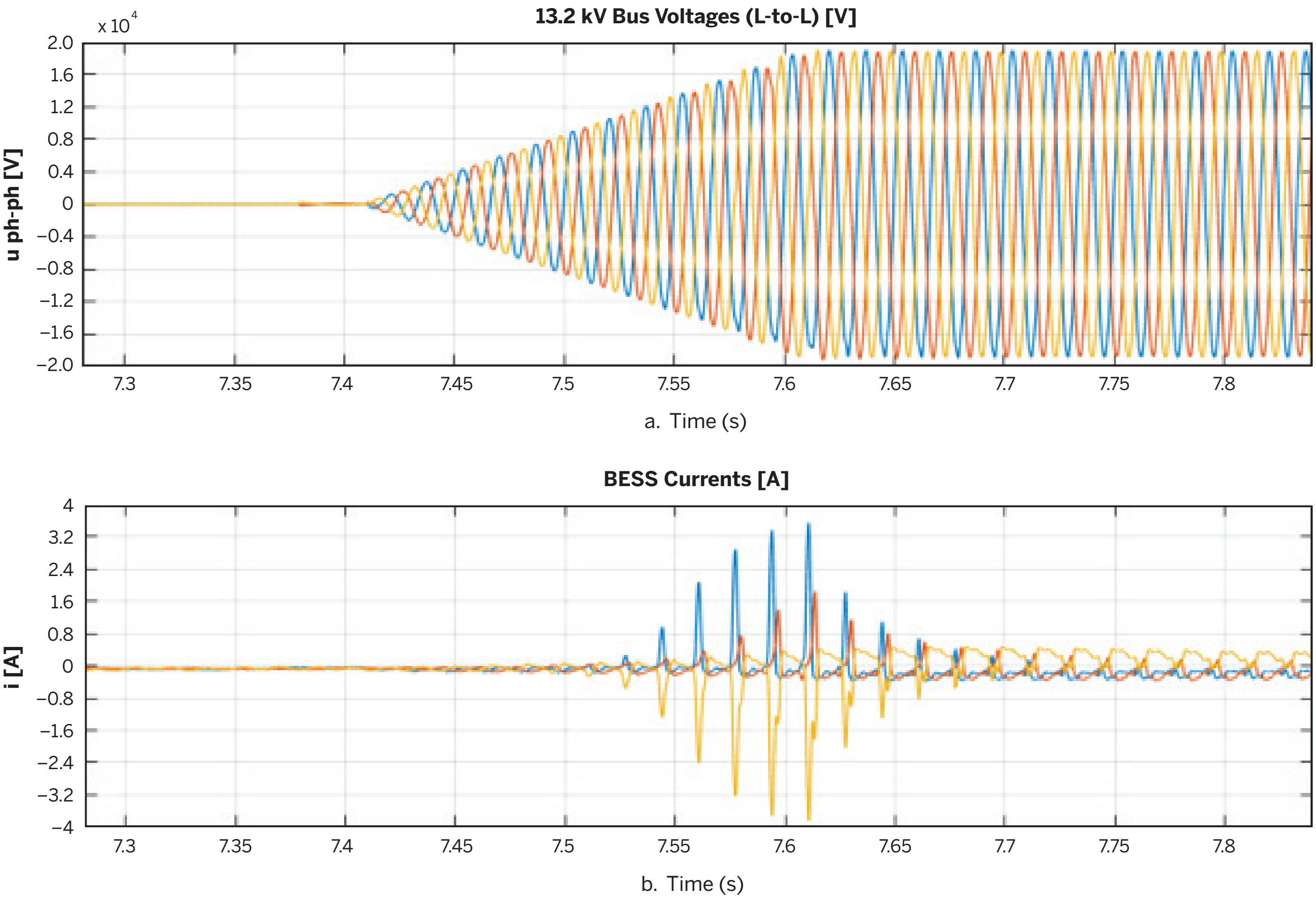
Field Tests

In addition to the laboratory tests described above, GFM inverters can be tested in the field during commissioning. Here we describe a few field tests that have been performed on GFM inverters installed recently in the Australian power system.

In recent years the Australian power system has experienced high uptake of transmission-connected BESSs. This section discusses field tests conducted on two GFM BESS projects, the Energy Storage for Commercial Renewable Integration project (also called the Dalrymple BESS) and the Hornsdale Power Reserve (also called Tesla big battery). The Dalrymple BESS is the first transmission-connected GFM BESS in the Australian National Electricity Market network. It is rated for 30 MW/8 MWh, and it started commercial operation in December 2018 (Electranet, n.d.). Among other things, the Dalrymple BESS enables islanded operation of the remote part of the grid where it is located. When in islanded mode, the BESS forms the grid, allowing for

FIGURE 20

Soft Start of a Grid-Forming Inverter Interfacing a Battery Energy Storage System



This figure shows the soft start of a GFM 2.3 MVA inverter interfacing a 1 MW/1 MWh BESS. The peak current on this figure is 3 percent of the transformer-rated current, showing that GFM resources can black start small systems using the soft-start approach without being required to supply large inrush currents (in excess of inverter rating) to the transformers. Individual GFM units can black start different parts of systems, which can be synchronized with each other.

Source: National Renewable Energy Laboratory.

continued stable operation of the nearby GFL wind plant and ensuring security of supply to local load.

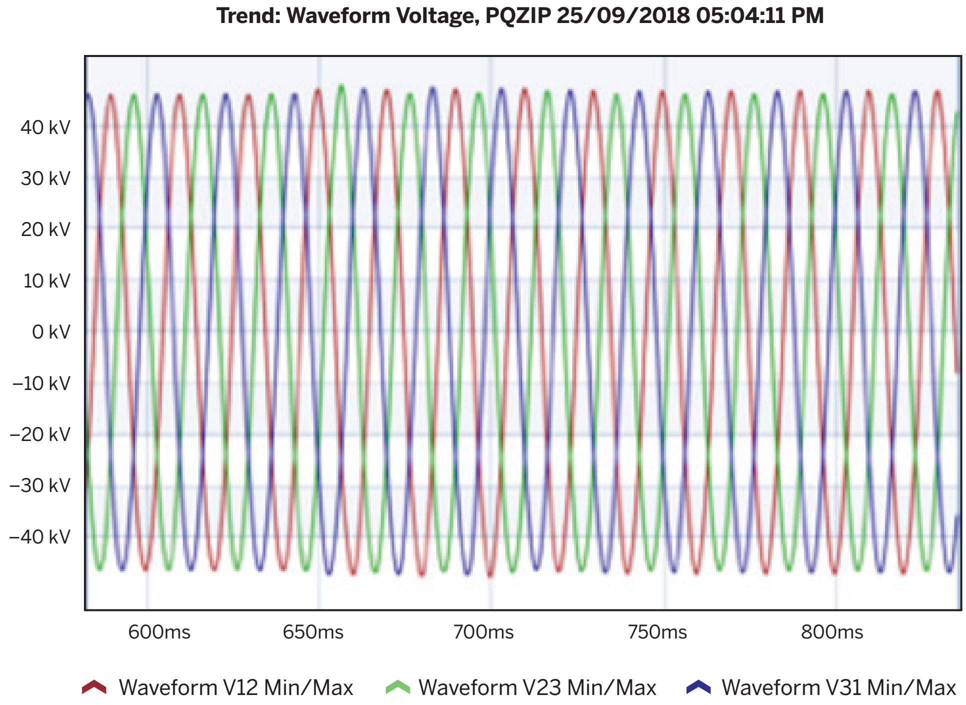
The Hornsdale Power Reserve was the largest transmission-connected GFL BESS in the National Electricity Market network when it was connected in 2017. When commissioned in 2017, it was 100 MW/128 MWh, and it was recently expanded to 150 MW/193.5 MWh. Below we describe field tests of these inverters for the GFM operation mode.

Field Test for Islanded Operation

Following a transmission disturbance, as per the design, the Dalrymple BESS supported a seamless formation of an island comprising a wind farm, local loads, and itself. Figure 21 (p. 54) shows how the Dalrymple BESS created its own voltage waveforms and avoided voltage dip and supply interruption during the process of islanding (Cherevatskiy et al., 2020). Figure 22 (p. 54) shows the frequency of this islanded power system. This practical experience demonstrates the capability of a GFM

FIGURE 21

Voltage and Current Waveform During an Islanding Event

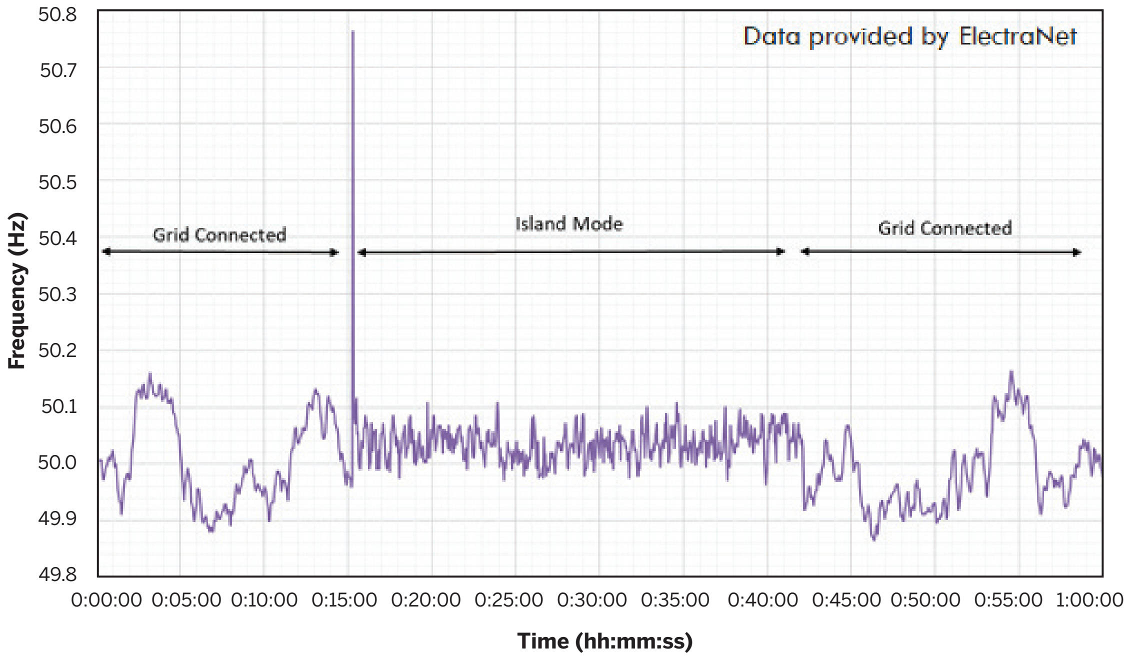


This test shows the performance of the Dalrymple BESS during an islanding event. The left plot shows three-phase voltage and the right plot shows three-phase current after islanding occurs. No appreciable voltage sag occurred during and following the event, as real and reactive current were being supplied to support grid stability and the BESS increased power output to supply islanded load.

Source: Hitachi Energy.

FIGURE 22

Frequency During Islanded Operation



This test shows the system frequency in grid-connected and islanded operation of the Dalrymple BESS. During grid-connected operation, system frequency was influenced by the operation of the entire grid. After separation of the system and the formation of an island by the Dalrymple BESS, the frequency of the island was maintained by the GFM BESS within a tighter band compared to grid-connected operation.

Source: Australian Energy Market Operator.

BESS to form an island and provide necessary frequency control.

Field Test for a Grid Separation Event

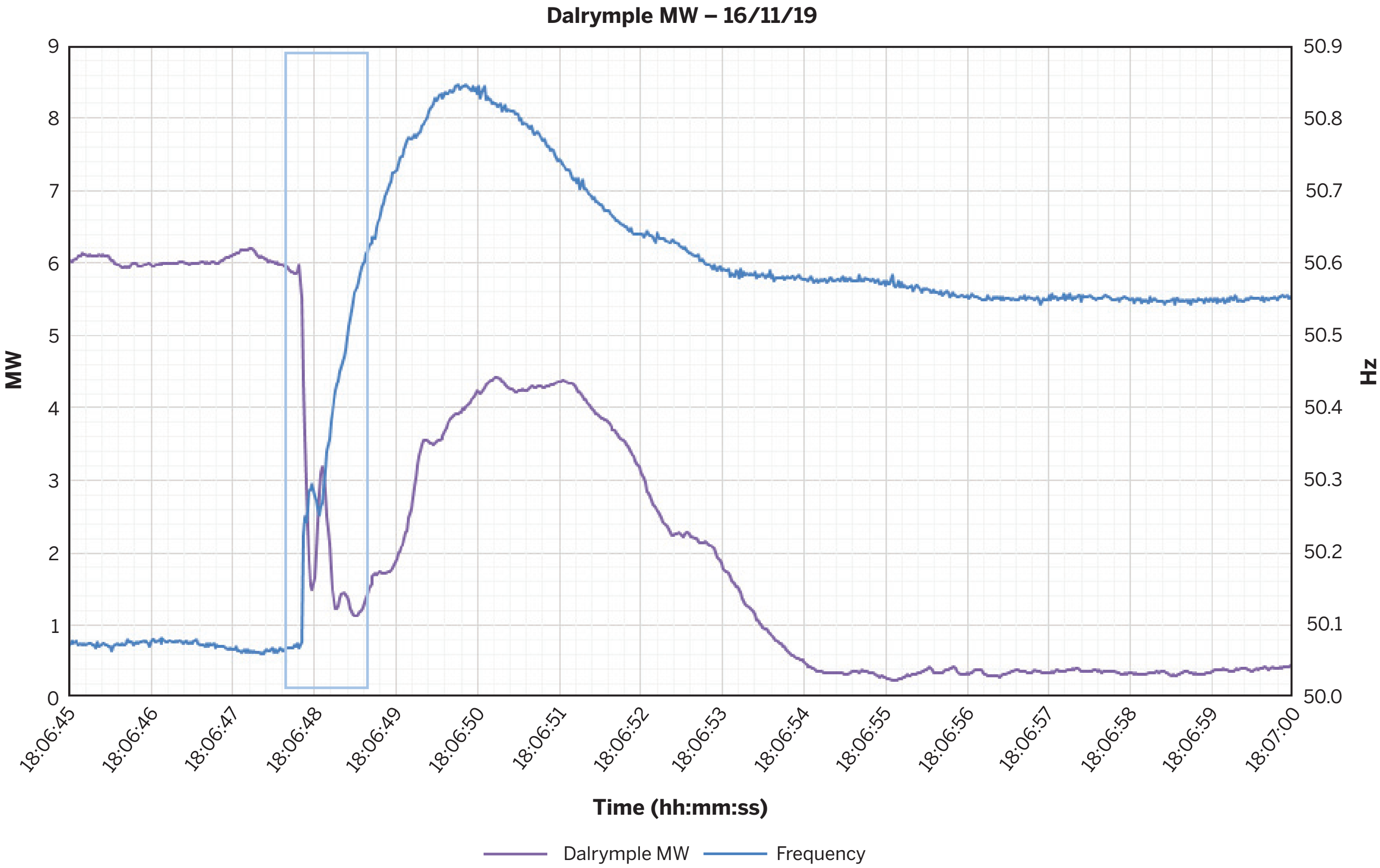
In another event, the Dalrymple BESS provided inherent active power response immediately after separation from the main grid in order to balance local loads. Figure 23 (p. 56) shows the Dalrymple BESS's response to the event. Immediately after the event, the BESS appears to have provided active power injection in a sub-second time frame before reverting to its frequency control mode (AEMO, 2019). The response looks similar to the inertial response of a synchronous machine.

Field Test for Response During a Frequency Event

While two inverters in the Hornsdale Power Reserve were trialing virtual machine mode (VMM) (one of the GFM control algorithms), a large coal power plant tripped and resulted in a large frequency change (Parkinson, 2021). Figure 24 (p. 57) shows the response of one of the inverters operating in VMM, and Figure 25 (p. 57) shows the combined response of the entire plant. During the event, the inverters responded to the RoCoF and acted to slow it down. A comparison between Figures 24 and 25 demonstrates how the inherent active power response of the inverter in VMM immediately after the coal generator trip differed from the overall frequency response of the entire plant, which was dominated by response from remaining GFL inverters on the droop control. The response of the inverter in VMM starts immediately at the inception of the event and reaches its peak prior to the frequency nadir. This is similar to the inertial response of a synchronous machine. The response of the entire plant starts slightly after the event (presumably once frequency falls outside of a pre-set deadband) and reaches its peak at the nadir and looks like fast frequency response.

FIGURE 23

Frequency Response of Grid-Forming BESS During a Grid Separation Event

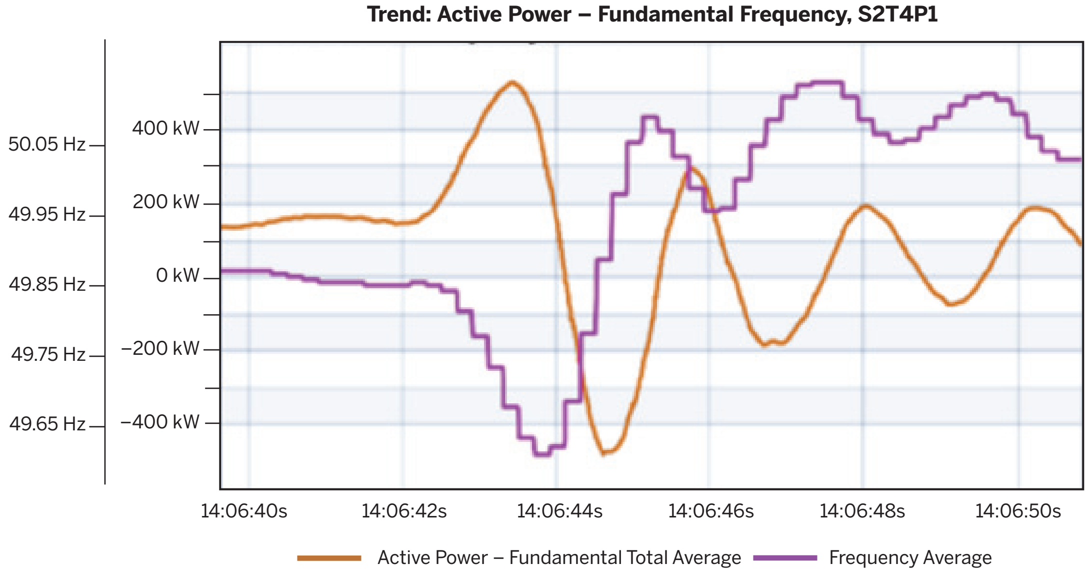


This test shows the response of the Dalrymple BESS (purple line) to a grid separation event. Immediately after the event, the BESS appears to have provided active power injection in a sub-second time frame (inside the blue rectangle) before reverting to its frequency control mode. The response looks similar to the inertial response of a synchronous machine.

Source: Australian Energy Market Operator.

FIGURE 24

GFM Inverter's Inherent Active Power Response at the Hornsdale Power Reserve Plant During a Generator Trip Event

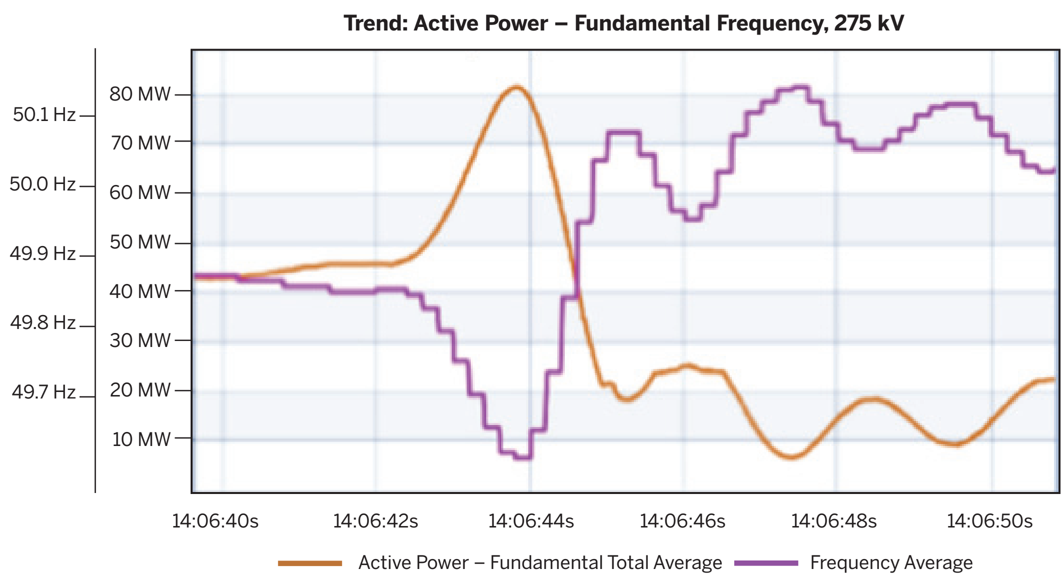


The response of one of two GFM inverters (with VMM control strategy) being tested at the Hornsdale Power Reserve during a generator trip event (orange line) was inherent active power injection immediately at the inception of the event. The response peaked prior to the frequency nadir and appears similar to inertial response from synchronous generators.

Source: Neoen Australia.

FIGURE 25

The Entire Hornsdale Power Reserve Plant Response During a Generator Trip Event



During the generator trip event, all but two inverters in the Hornsdale Power Reserve plant were operating in GFL mode with frequency response through droop control; therefore, the overall frequency response of the plant (orange line) looks like fast frequency response. The response starts at the beginning of the event and reaches its peak in a few seconds, with the peak of the response coinciding with the frequency nadir.

Source: Neoen Australia.

6 Tools

As power systems migrate to high levels of renewables, traditional analytical tools and techniques are no longer sufficient to address the phenomena associated with these higher levels of inverter-based resources (IBRs). A vast array of planning and operating tools have been developed and are now available that address variability and uncertainty, stability, interoperability, and all of the spatial and temporal issues that accompany the changing portfolio.

Stability Tools

Among time frames ranging from sub-cycle to years, the issues for which the distinction between synchronous machines, grid-following (GFL) inverters, and grid-forming (GFM) technologies is relevant tend to be in the relatively short time frames. Given how the dynamic performance of IBRs in general, and GFM IBRs in particular, substantially affects grid stability, the subset of simulation and supporting tools that is most affected by the presence of GFM resources comprises those tools centered on the determination of (and proximity to) stability limits. Stability covers a broad spectrum of challenges, with detailed definitions and language offered by IEEE. The familiar IEEE classification diagram is shown in Figure 26 (p. 59) (Hatziargyriou et al., 2021). This latest version was recently created by IEEE in response to the massive growth of IBRs.[16] Two stability categories, resonance stability and converter-driven stability, were added on the left side of the diagram, recognizing relatively new stability phenomena that have become more prominent with growing shares of IBRs.

Given that every category of stability in the figure must be satisfied for successful incorporation of any generation resource into the power system, including any IBR, it is not surprising that the simulation tool environment is complex. There exist many individual classes of tools from a variety of sources and offering a wide spectrum of maturity. Every category of stability is impacted to some extent by the shift to IBRs from predominantly synchronous resources. Consequently, the individual tools have had to evolve, and are continuing to do so.

Expanding Beyond Phasor-Domain Tools

Given the centrality of equipment performance during grid disturbances, it is useful to look at the present institutional reality in which the analysis of system dynamics in most power systems is centered around fundamental frequency positive-sequence simulations. These phasor-domain tools have historically been developed to address specific phenomena or time frames of risk. That is, they focus on the short-term behavior of equipment such as response and recovery from grid disturbances. These phasor-based tools are mature commercial products that include such products as PSS/E,[17] PSLF,[18] Power Factory,[19] DSAtools,[20] PowerWorld,[21] and others. A core element in today's system planning and operations are simulations of the power system, checking response to hundreds or thousands of design basis events (e.g., fault

16 The IEEE document refers to IBRs as CIGs—converter-interfaced generation—and provides an excellent up-to-date view of stability concerns.

17 Power System Simulator for Engineering, PSS/E, is a phasor-domain simulation software tool by Siemens.

18 Positive Sequence Load Flow is a phasor-domain simulation software tool by General Electric.

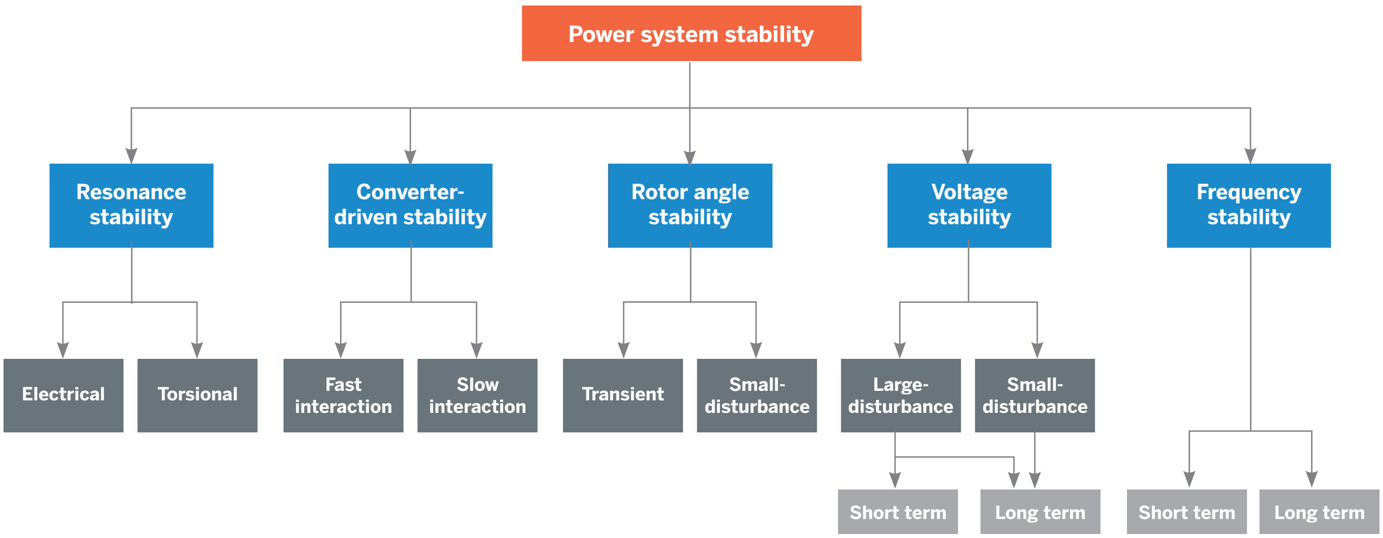
19 Power Factory is a phasor-domain simulation software tool by DigSilent.

20 DSATools is a suite of power system analysis tools by Powertech, including phasor-domain simulation tools such as TSAT.

21 PowerWorld is a suite of phasor-domain simulation and analysis tools by PowerWorld Corporation.

FIGURE 26

IEEE Stability Classification Hierarchy



On the right-hand side, the figure shows the familiar classification of power system stability. In the recent version of stability definitions, two additional categories were introduced, resonance stability and converter-driven stability, to recognize stability phenomena that are becoming more prominent with growing shares of IBRs.

Source: Hatziargyriou et al. (2021). © 2022 IEEE.

and line trip, or generator trip events) for large, grid-wide representations for a range of initial conditions.

Many stability challenges cannot be well analyzed within the structural limitations of phasor modeling, and phasor-based simulation tools have always been complemented by a variety of other programs and types of analysis. But with the evolution to systems with high levels of IBRs, and particularly with a complex mix of GFL and GFM IBRs without synchronous machines nearby, there is an increasing need for electromagnetic transient (EMT) and state-space tools to aid in the design and evaluation of power systems. The environment illustrated in Figure 27 (p. 60) is representative of the emerging practice for design and stability analysis of IBR-dominant systems.

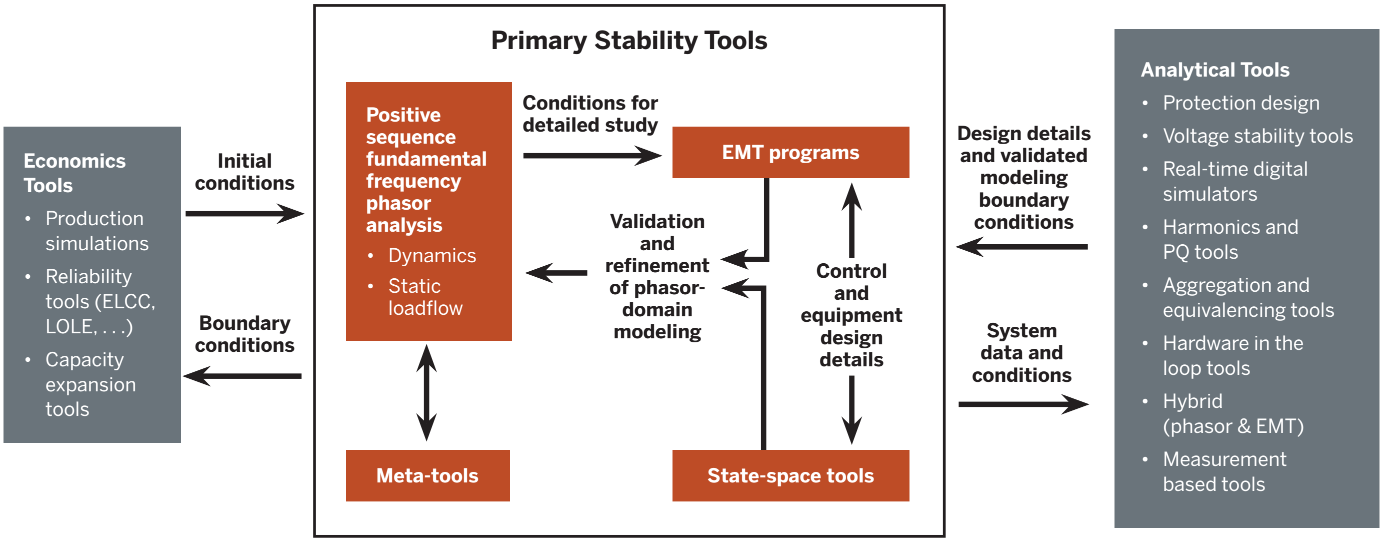
At the center of this environment, traditional phasor-based tools that have been augmented to include better representation of IBRs in the phasor domain are now growing ever more closely linked with EMT and state-space tools. The role of EMT analysis has evolved dramatically. Once largely limited to design questions associated with fast transients and highly specialized modeling of large electronics (such as HVDC equipment), EMT analysis has become an essential element in the design of stable systems with high levels of IBRs. The vastly wider frequency bandwidth of EMT simulations allows for the meaningful analysis of faster, more nonlinear, and unbalanced phenomena—all of which are essential to establishing IBR stability with confidence. Similarly, a variety of frequency-domain or state-space tools can bring clarity to stability issues that are now dominated by controls rather than just electromagnetic physics.

The addition of these tools to the "core" suite of stability analysis alongside phasor-based tools allows for more confident design and evaluation of stability for real, large, IBR-dominant systems. If used in a coordinated fashion, this suite of stability tools is also a key to ensuring successful interoperability of all resources and grid elements. The arrows within the core block of Figure 27 illustrate the need for the constituent tools to be used in concert.

Massive numbers of cases run on huge system representations in phasor-based tools allow for systematic testing over wide ranges of possible operating conditions and

FIGURE 27

Stability Simulation Environment



Source: HickoryLedge.

disturbances, and, in planning studies, for wide varieties of possible network topologies. In both applications, meta-tools are needed to screen and diagnose outputs, as well as facilitate input data. EMT and state-space tools tend to have partial representations of the grid and be vastly more computationally intensive, so effective screening of phasor-based results should be used to focus more detailed EMT and state-space simulations on critical performance concerns.

EMT Tools

EMT tools, like phasor-based programs, have been developed over more than half a century of practice. Representing the individual phases and physical differential equations of the network as well as the grid resources, these tools have long been used to design system elements that include inverters. EMT tools can provide the basis for detailed equipment and control designs, which are then reflected in simpler form in stability programs. They are complex, are computationally burdensome, and require considerable specialized skill to use well.

Historically, the great amount of detail on equipment components (generators, transformers, FACTS (flexible alternating current transmission systems), etc.) in phasor-based tools was balanced with limited and relatively simple representation of the surrounding power system. In a synchronous machine–dominated grid, these equipment components were more inherently coordinated, and it did not merit extensive analysis to ensure a coordinated, reliable, and resilient energy supply. However, with rapidly rising levels of IBRs, the limitations of these tools have surfaced, driving interest in and need for greater use of EMT simulations. Today, EMT tools continue their historical role of providing the basis for detailed equipment and control designs, which are then reflected in simpler form in stability programs. But their role is also expanding in that some classes of analysis—especially in systems or parts of systems that are at or near to 100 percent shares of IBRs—are not just complementing stability analysis but replacing it. There are new modes of failure and demand for resource coordination on multiple time scales, and the tools need to capture the phenomena and capability of network and equipment needs and limits in order to mitigate risks and maximize benefits of new technology capability. Whether the evolution toward GFM IBRs will accelerate or slow this trend remains to be seen.

State-Space Tools

State-space (frequency-domain or eigenvector) tools have increasing importance as well, as they are critical for understanding performance, tuning controls, and identifying conditions and stimuli that are most important or limiting for GFM resources. System oscillatory behaviors are more complex and of wider frequency range than is typical for most synchronous machine–dominant systems. State matrices and eigenvalues that are based on phasor modeling will continue to have a key role, but they suffer from some of the same limitations as phasor-based time simulations. Building state matrices for EMT-based modeling can be challenging and today tends to be limited to representations of relatively small parts of the system. Other frequency-domain techniques, such as those based on small-signal perturbation of EMT representations, are emerging and show great promise.

IBR Models for Stability Tools

The need to represent IBRs in stability simulations has been a focus of industry efforts for decades. As discussed above, these stability simulations have long been performed with tools and models using positive-sequence phasor analysis, representing fundamental frequency dynamics no faster than one electrical cycle. The last half century of learning that brought satisfactory modeling of synchronous generation to the industry has been compressed for modeling of IBRs. Model development for IBRs, whose dynamic behavior has been rapidly changing over time, involves maintaining a balance between often-conflicting objectives that include accuracy, transparency, numerical stability, flexibility, simplicity, adaptability, and interoperability. Perfection in all respects is impossible, and the industry has long accepted compromises between these factors in the modeling of conventional synchronous resources.

Over the past decade, the emergence of generic, open structure phasor-based IBR models for GFL equipment has largely, if imperfectly, met industry needs for analyzing power systems with relatively low shares of IBRs. These models were originally developed to create a common platform for all equipment manufacturers, equipment owners, and grid companies to use and share across all stakeholders. A generic and open model structure is a way for all stakeholders to share a common representation of IBR technologies across all stakeholders without the complexity of proprietary protection of more detailed models from manufacturers and equipment owners.

The experience with phasor-based models is being repeated to some extent with EMT models, but includes some additional challenges. It is generally agreed that the best

Accuracy, numerical stability, simplicity, and interoperability of equipment models are of paramount importance for high fidelity simulation results.

fidelity EMT models of IBRs are those validated by equipment manufacturers for the specifics of their equipment. These are often "black-boxed" since they tend to contain proprietary information. Development of more transparent generic EMT model representations would help with exchange, maintenance, tuning, and debugging of specific implementations. However, this is usually at the expense of individual inverter implementation specificity; striking a balance between these elements is challenging. And as noted above, better state-space or frequency-domain models of IBRs are needed.

This evolution is continuing, with the first generation of phasor-domain models for GFM equipment nearing dissemination to the broader user community (Ramasubramanian, 2021). As with the GFL models, these new models will pass through multiple evolutionary steps, as our understanding and their functionality evolve. This evolution will also increase our understanding of the boundaries within which these models will be sufficiently accurate, and when there is a need for EMT modeling or other types of tools when considering a 100 percent or near 100 percent IBR power system.

The expanded functionality and tighter connectivity of the three classes of stability tools creates an opportunity for better decisionmaking by system planners and operators and, as a result, better grid design. However, as discussed above, each of the tools has its strengths and limitations in terms of grid representation (partial versus entire system), number of scenarios that can be studied, accuracy of the results, and the computational burden. Additionally, accuracy, numerical stability, simplicity, and interoperability of equipment models are of paramount importance for high fidelity simulation results. The use of more detailed tools, including (and perhaps especially) EMT tools, does not automatically guarantee success or good outcomes. Simulations, even ones done well and with the best available tools, are still only a mechanism to support good engineering decisions. Further work is also needed in IBR model development, including GFM IBR models, and improvements in computational efficiency of EMT tools.

Use of more detailed tools does not automatically guarantee success or good outcomes. Simulations, even if done with the best available tools, are still only a mechanism to support good engineering decisions.

The emerging stability-centric environment shown in Figure 27 on page 60 is accompanied by the many other simulation tools that we group into the general categories of analytical and economics tools. These tools help system planners and operators generate meaningful scenarios to be used as inputs into stability studies as well as process and analyze numerous simulation results. The use of these tools further contributes to the better design of power systems, specifically those with high shares of IBRs.

Analytical Tools

The spectrum of tools that give more detailed and often specialized information for the design of systems, facilities, or specific equipment are critical as levels of IBRs in power systems become high. Some of the analytical tools listed in Figure 27 on page 60 are aimed at providing relatively narrow design insights into, for example, protection settings, power quality, voltage stability, and other aspects. Elements like protective relay selection and settings are strongly affected by the differences between IBRs and synchronous resources. System protection design with very high shares of IBRs is still an area of active research, and it will likely drive new functionality in protection design software (as well as probably in the actual protection devices themselves). Similarly, power quality including harmonics analysis can be critical at the design stage, to make sure that new IBR resources behave acceptably and harmoniously with the grid (and other resources).

Other tools are necessary that extend stability analysis, such as voltage stability, are currently based on load-flow tools, but show promise to evolve toward IBR-specific applications. Some specialty tools serve to connect data and models between different types of analysis. For example, aggregation and equivalencing programs are essential for creating manageable and meaningful network representations for EMT and state-space tools, providing a mapping from phasor-based data sets that are sometimes vastly larger than can be handled by these tools.

Economics Tools

Economics tools focus on the long-term planning of power systems in terms of resources and economy of operation. From the perspective of IBRs, these tools are very much concerned with temporal and locational issues of supply (for example, when is it windy or sunny, or when should energy storage charge or discharge?). Economics tools are not explicitly concerned with the existence of inverters; however, they need to incorporate the limits of the grid—especially power transfer limits—that are set by systems dynamics, including IBRs. Thus, the prime concern is not whether a technology is GFM or GFL, but rather the operational conditions where GFM IBRs could provide additional support.

Conversely, the new realm of stability starts with a realistic depiction of unit commitment and dispatch, provided by economics tools, which ultimately determines the availability of capabilities and services that are present at any given moment to support grid needs. New tools are emerging to better reflect these couplings and make them more meaningful in IBR-dominant systems.

Compatibility of Tools and Studies

In analyses of IBR-dominant systems, stability tools, economic tools, and analytical tools are heavily interdependent, as suggested by the arrows in Figure 27 (p. 60). Realistic initial conditions for stability analysis come from economics tools, specifically, production cost simulations performed on system resource mixes that are determined by capacity expansion and reliability tools. But there is an interplay between the types of tools, as boundary conditions, such as transmission interface and generation resource constraints, result from stability analysis and analytical tools and constrain the economic operation of the system.

The new realm of planning depends on analysis and compatibility of tools to ensure that equipment physics address stability needs under all credible operating conditions moving into the future resource mix. The interoperability of EMT, stability, and economics models is needed to ensure that equipment performance is sufficient to support grid needs during the most stressful operating conditions. Appropriate analysis is critical to identify and mitigate interconnection risks in areas with high levels of IBRs. This means deploying well-tuned and appropriate controls during all grid operating conditions, including conditions involving high levels of IBRs, high ramping, low headroom, low system strength, and low inertia. Interconnection and planning analyses now have to account for the need and capability of GFM controls to support the network, making it critical to have compatibility between fundamental frequency, economic, and EMT tools, models, and data. The information exchange arrows in Figure 27 (p. 60) are indicative of linkages that must be developed to ensure seamless exchange of data and results between analytical specialties.

The interoperability of EMT, stability, and economics models is needed to ensure that equipment performance is sufficient to support grid needs during the most stressful operating conditions.

7 Conclusions and Recommendations

With growing shares of inverter-based resources (IBRs) and continued retirements of conventional synchronous generation, grid needs continue to evolve. New advanced controls for IBRs are needed to allow them to replace some of the services that are currently or were previously provided by synchronous generators (either inherently, deployed through interconnection requirements, or incentivized through market products). Grid-forming (GFM) technology is gaining traction and unlocks greater capability to integrate more IBRs into the grid, adding another tool to the toolbox for system operators and equipment owners to support stable voltage and frequency in a high-renewables grid, as well as control stability in power systems with lower system strength. It is important to note that while GFM technology is one of the necessary enablers for higher IBR penetration, it will not be sufficient to resolve all issues. Further reinforcement of transmission systems will be necessary, because of the stability constraints of high-impedance networks, to enable long-distance high-power transfer from remote areas rich with renewable resources to large load centers. But GFM technology will play a key role in high-IBR levels above 75 to 80 percent.

Various types of GFM controls are in varying stages of development, with different characteristics to enhance stability and provide services. GFM controls generally hold the magnitude and angle of the inverter's internal voltage constant and provide the necessary current within the inverter's limits in the transient time frame immediately after a grid disturbance. Advanced services, such as black start, are also achievable if GFM controls are coupled with an energy buffer and configured to provide such a service. Not all GFM controls need to have all possible characteristics or provide all services; rather, GFM resources should be designed to provide the characteristics and services needed for the application they are serving.

Although wind and solar IBRs may be equipped with GFM capabilities, there is other low-hanging fruit such as GFM battery storage and GFM inverter-based reactive power compensation devices, which are commercially available technologies and have fewer trade-offs around design and implementation.

GFM resources can take many different forms. Although wind and solar IBRs may be equipped with GFM capabilities, there is other low-hanging fruit, including GFM battery storage, GFM inverter-based reactive power compensation devices (e.g., GFM static synchronous compensators (STATCOMs)), and voltage source converter (VSC) HVDC. These devices with GFM controls are commercially available and have fewer trade-offs around design and implementation than solar- and wind-based GFM IBRs. In addition, given that large volumes of IBRs today equipped with GFL controls will be installed in the near term, system operators and equipment owners should, in addition to evaluating the benefits of incentivizing GFM controls on these devices, determine how best to maximize the capability of existing and new GFL resources.

Making the Leap

Power systems around the world are at the point of now needing to make the technological leap to a system in which many services that support grid reliability are provided by GFM IBRs. However, system operators and planners, equipment owners, and manufacturers face a circular problem regarding the deployment of advanced IBR controls. Which comes first, the requirement for a capability or the capability itself? How do grid operators know what performance or capability is possible from new GFM equipment, and therefore what they could conceivably require? How can grid operators evaluate costs and benefits of having such equipment on the grid? What drives manufacturers to invest in new technology without its being mandated for interconnection to the grid or otherwise incentivized by the market?

The chicken-and-egg problem regarding GFM capability and requirements in which we are currently locked needs to be approached instead from the perspective of evolving system needs, through the following steps:

- Define the main attributes of the target system in terms of peak load, annual and seasonal energy consumption, expected load characteristics, expected shares and types of renewable resources, etc.
- Define the level of reliability desired for that system, determine system needs, and determine what services are required to meet those needs in order to operate the target system with the desired level of reliability.
- Develop clear technical requirements for the provision of these services, including the system conditions under which the activation of service is expected and the conditions under which the provision of service should be sustained. This will inform design, dimensioning, and, consequently, costs of the equipment providing the services. This will provide clear technical specifications to equipment manufacturers, including those of GFM inverters.
- Implement the services in a way that attracts and enables as many providers as possible, thus optimizing costs for the entire system. Market mechanisms are recommended where possible. This will provide incentives to implement GFM controls on future IBRs, along with incentivizing other capable technologies.
- Define clear, quantifiable benchmarking criteria to test and qualify resources for provision of the services, and develop procedures for performance evaluation at the commissioning of resources and during their operation. This will provide clear performance metrics to developers and owners of GFM resources and other capable technologies.

New phenomena and controls are prompting a need for advanced study tools, high fidelity models, and new study techniques, hardware and software, and operational capabilities. Planners need guidance on where conventional simulation techniques are still adequate and where advanced tools and models are necessary to plan the future system. Interoperability of equipment and models is a key need and enabler to allow higher levels of IBRs in the global energy transformation.

Learning from Early Adopters

Early adopters are beginning to break the chicken-and-egg cycle. In power systems including those of Great Britain, Germany, and Hawaii, grid services and requirements are being defined to specify and incentivize GFM resources. As these early adopters gain experience with GFM deployment, this will serve as a testbed for grids in other countries as they consider defining new system services, in which GFM resources could play a key role, and mechanisms to deploy these resources. This process will also be guided by successful pilots of GFM controls with rigorous testing and modeling programs, such as those demonstrated in Great Britain and Australia.

Based on analysis of the early adopters' requirements, we recommend that future adopters use high-level functional requirements as a starting point, with more details on capability verification and performance testing provided in the form of technical guides. This approach, currently being adopted in Great Britain and Hawaii, will help to avoid unnecessary focus on any particular GFM control implementation and will lead to further technology development, for example, the development of new GFM control strategies. Close cooperation between system operators, equipment manufacturers, and equipment owners is critical to defining system needs, equipment capabilities and requirements, and mechanisms to deploy GFM technology and coordinate it with existing systems.

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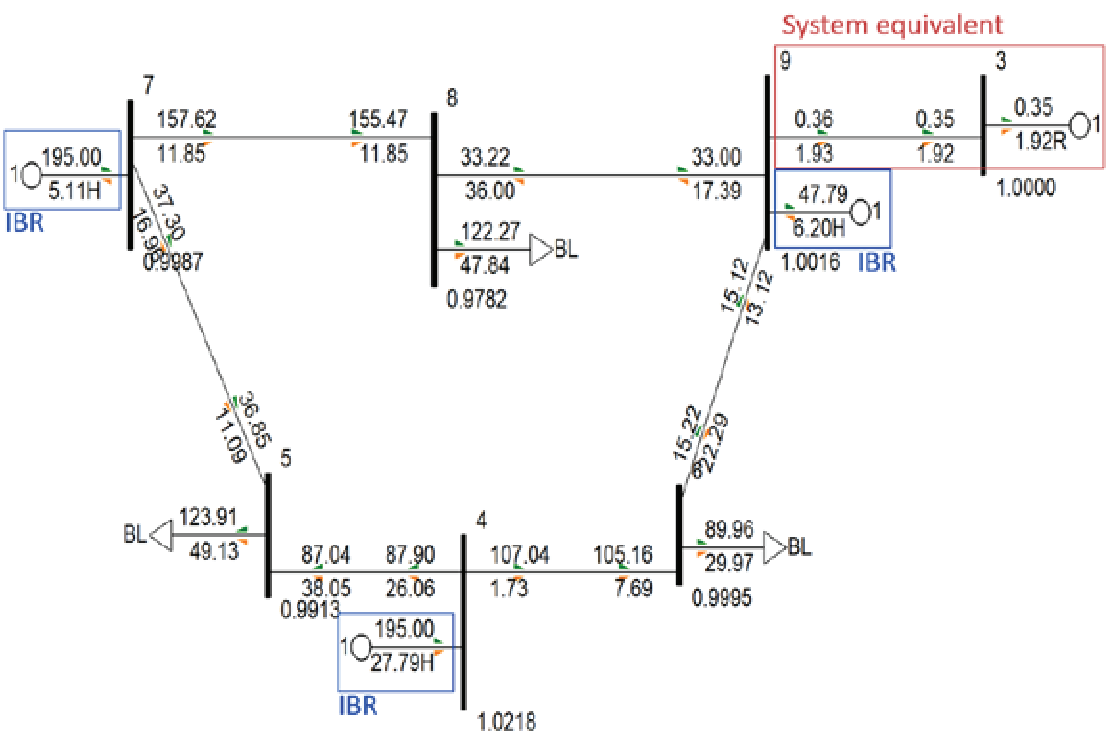
Appendix

The cost of inaction with regard to the deployment of GFM inverters can be seen in the following example that tested the stability of an electrical island that becomes an all-IBR network when disconnected from a system equivalent.

The Electric Power Research Institute performed tests using a simple test network, shown in Figure A-1 (EPRI, 2021). The IBRs at bus 4 and bus 7 are each rated at 200 MVA and operated with inverter-level active and reactive power control. The IBR at bus 9 is rated at 50 MVA and operated with constant current reference control. All inverters were initially operated using conventional grid-following (GFL) control (not grid forming (GFM)). The power exchange with the system equivalent was intentionally kept at a low value so that the disconnection of the system equivalent would be a small-signal disturbance on the network.

FIGURE A-1

A Test Network Used for Illustrating the Importance of Defining GFM Interconnection Requirements as Soon as Possible



The test network consists of IBRs at bus 4 and bus 7 rated at 200 MVA and operated with inverter-level active and reactive power control. The IBR at bus 9 is rated at 50 MVA operated with constant current reference control. All IBR devices are operated initially using conventional GFL control.

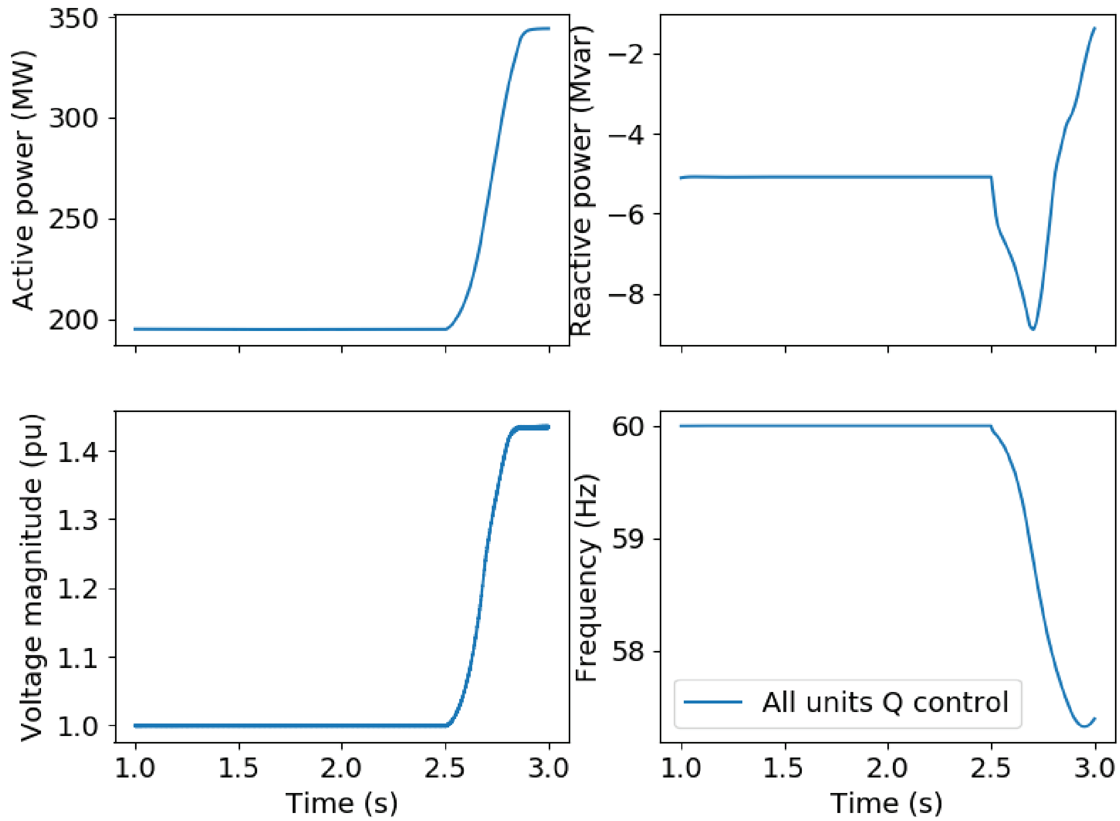
Source: Electric Power Research Institute (2021).

The first test demonstrates the behavior of the network composed of all GFL IBRs when disconnected from the system equivalent. At t=2.5s, the system equivalent was disconnected, resulting in the isolation of the all-IBR network. The time-domain response of the network is shown in Figure A-2 as seen at bus 7. Although the power exchange with the system equivalent was low prior to the disturbance, upon the disconnection of the system equivalent the network was unable to remain stable; the frequency collapsed, and the inverter modulation saturated at its upper limit. The rigid operation brought about by all GFL inverters did not allow for the re-distribution of reactive power around the network when the system equivalent disconnected. As a result, voltage became uncontrolled in the network, which also resulted in load variation (due to the load's voltage-dependent constant impedance characteristic).

The second test demonstrated behavior of the network when one IBR was switched from GFL to GFM control. With the IBR at bus 7 switched from GFL to GFM control, and the IBRs at bus 4 and bus 9 retaining the same GFL control structure, a stabilizing effect is observed. Figure A-3 (p. 72) shows the time-domain response for the disconnection of the system equivalent at t=2.5s and a subsequent 10 percent load step increase at t=5.0s. The stabilizing influence brought about by changing to fast inverter-level voltage control is readily apparent.

FIGURE A-2

Time-Domain Response of the Test Network after Disconnection of the System Equivalent (All IBRs with GFL Control)

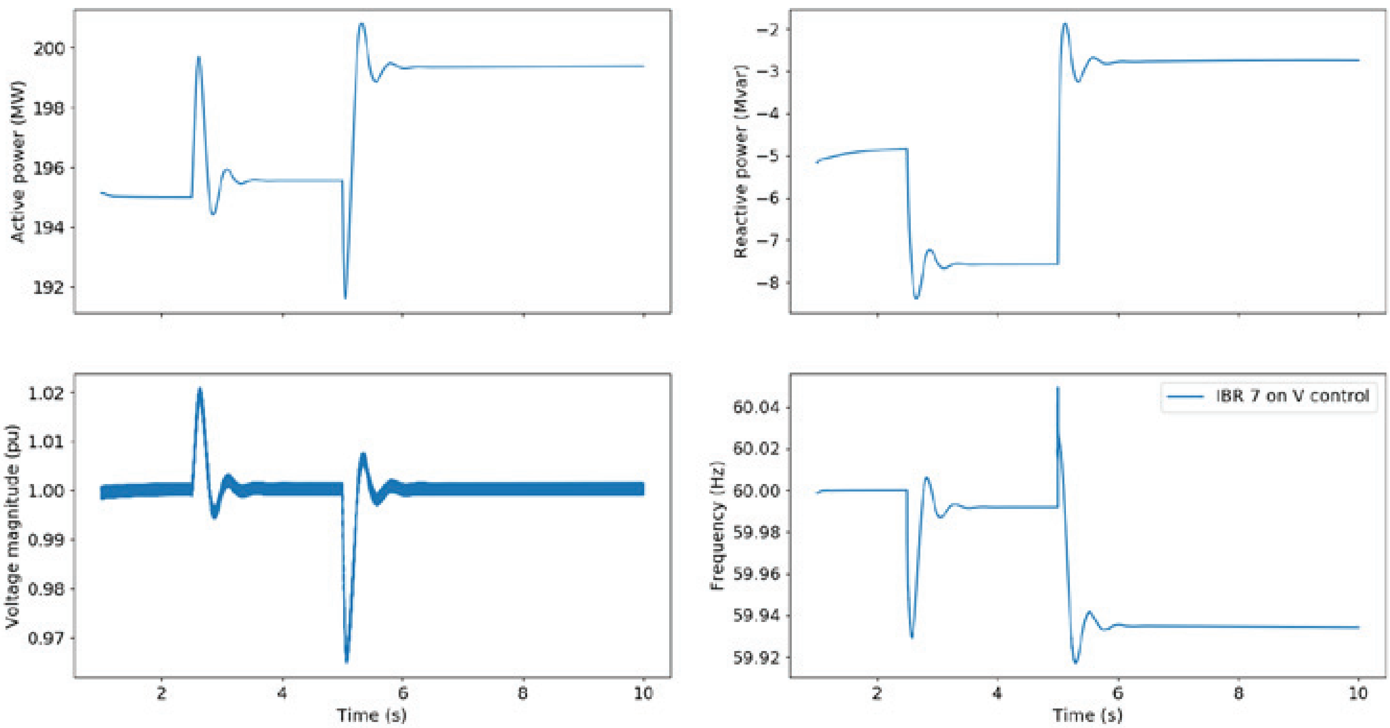


Unstable time-domain response of the test network as seen at bus 7 after disconnection of the system equivalent at t=2.5s, with all IBRs operated in GFL control. The rigid operation brought about by all GFL inverters does not allow for the re-distribution of reactive power around the network when the system equivalent disconnects, and leads to a lack of voltage control and instability.

Source: Electric Power Research Institute (2021).

FIGURE A-3

Time-Domain Response of the Test Network after Disconnection of the System Equivalent (with GFM IBR at Bus 7)



Stable time-domain response of the test network as seen from bus 7 after disconnection of the system equivalent at t=2.5s and subsequent 10 percent load increase at t=5.0s. In this test, bus 7 is on GFM control, while IBRs at bus 4 and bus 9 retain the same GFL control structure. The stabilizing effect is brought about by fast inverter-level voltage control of the GFM IBR.

Source: Electric Power Research Institute (2021).

But what are the prospects for network stability if it is not possible to change control modes for existing IBRs? Suppose interconnection requirements do not start specifying GFM requirements, but instead new IBR plants continue to interconnect as per today's interconnection requirements (i.e., new IBR plants are likely to be GFL). As the percentage of GFL IBRs increases in the network, system stability will eventually deteriorate. If the legacy IBR plants are not able to switch control modes from GFL to GFM, it will be necessary to deploy additional GFM IBRs or other devices such as synchronous condensers or GFM static synchronous compensators (STATCOMs) to maintain stability. It is not clear, however, how much burden will be placed on these new GFM devices and how these should be sized to enable a stable system response. These are central questions as transmission planners address the influx of GFM resources in their networks (see, for example, the section in the report on European efforts (pp. 35–36).

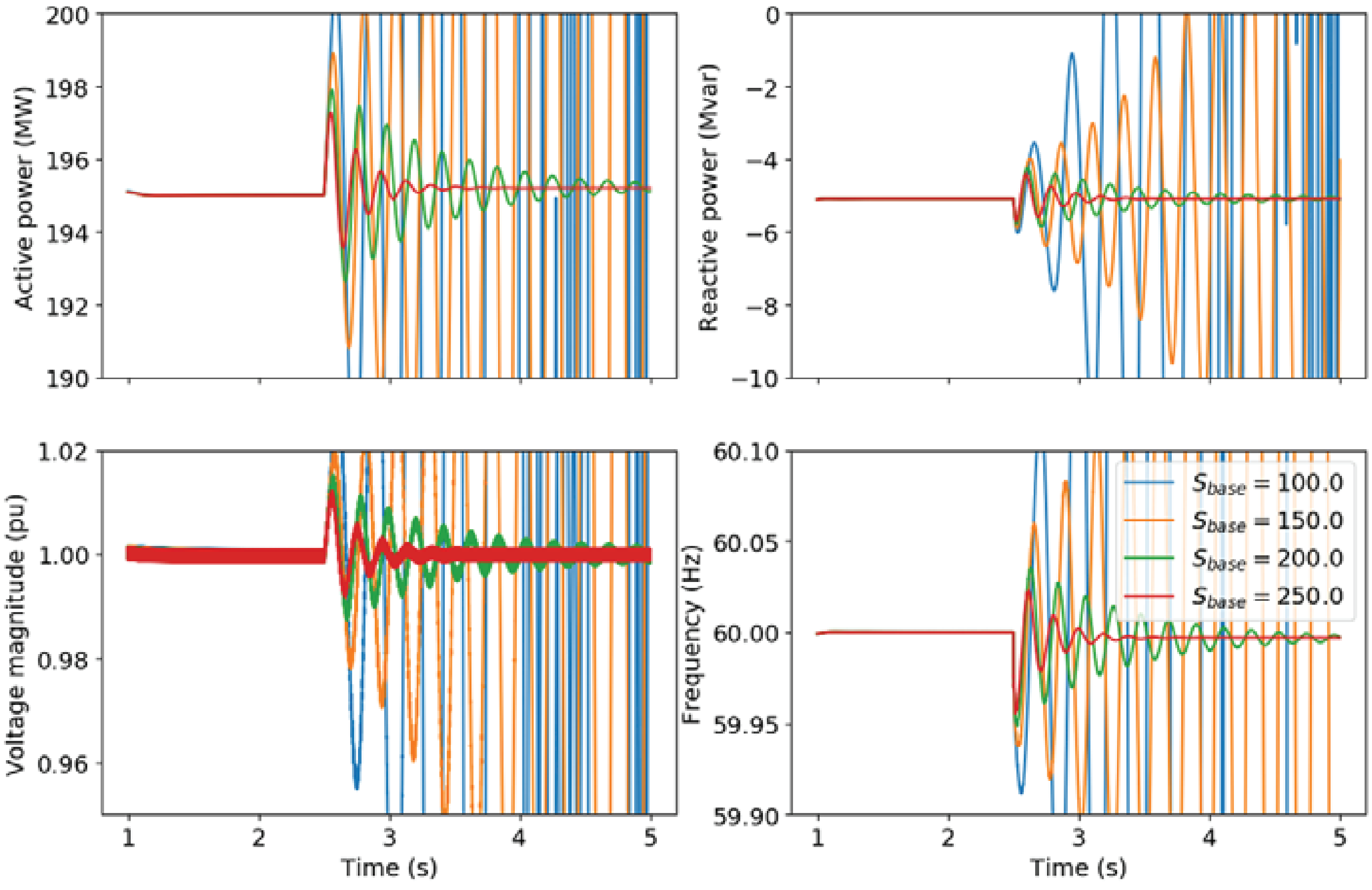
To explore these questions on the test network, suppose the IBR at bus 7 cannot be changed from GFL to GFM control. Now, upon disconnection of the system equivalent, the network would be unstable (as seen in Figure A-2) unless a new IBR with GFM control capability is connected to the network. The objective of this test is to determine the minimum capacity of a new IBR plant that is required to bring about a stable operation of the network. If the new GFM IBR is not added, the transmission system operator may have to invest in some form of stabilization device such as a STATCOM with GFM capability, which comes at an additional cost.

Since the power exchange between the all-IBR network and the system equivalent is minimal, it might initially be assumed that a GFM IBR of smaller rating would be sufficient to bring about stability. Going with this assumption, let the initial conditions of the new IBR be defined in such a way that does not alter the power flow solution of the network. In order to achieve a stable response in this scenario, the rating of the new IBR at bus 8 should be greater than 150 MVA as shown by the time-domain response in Figure A-4. Note that this need for a new GFM IBR (or GFM STATCOM) of at least 150 MVA could have been avoided if the IBR at bus 7 had been GFM.

The analysis and results shown highlight the importance of starting to specify grid interconnection requirements today so that the burden of ensuring stability in the future does not require IBRs of larger rating.

FIGURE A-4

Time-Domain Response of the Test Network after Disconnection of the System Equivalent (New IBR at Bus 8 Is the Only IBR with GFM Control)



Time-domain response of the test system as seen from bus 7 after disconnection of the system equivalent at t=2.5s, with the new IBR at bus 8 being the only IBR with GFM control. The rating of the new GFM IBR is varied between 100 MVA and 250 MVA. Stable response is achieved only when a new GFM IBR or GFM STATCOM is added at bus 8 with a rating greater than 150 MVA. (S_{base} on the figure refers to MVA base of the GFM IBR used in each simulation.) The addition of such a device could have been avoided if the IBR at bus 7 had been GFM.

Source: Electric Power Research Institute (2021).

Grid-Forming Technology in Energy Systems Integration

The report is available at https://www.esig.energy/reports-briefs.

To learn more about the recommendations in this report, please send an email to info@esig.energy.

The Energy Systems Integration Group is a nonprofit organization that marshals the expertise of the electricity industry's technical community to support grid transformation and energy systems integration and operation. More information is available at https://www.esig.energy.

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