Diagnosis and Mitigation of Observed Oscillations in IBR-Dominant Power Systems

A PRACTICAL GUIDE

A Publication by the Energy Systems Integration Group's Stability Task Force

August 2024

ESIG
ENERGY SYSTEMS INTEGRATION GROUP

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Prepared by

Nicholas W. Miller, HickoryLedge

Contributing Task Force Members

Andrew Isaacs, Electranix

Reigh Walling, Walling Energy Systems Consulting

Jayanth R. Ramamurthy, Australian Energy Market Operator

Babak Badrzadeh, Etik Energy

Nilesh Modi, Australian Energy Market Operator

Lingling Fan, University of South Florida

Shahil Shah, National Renewable Energy Laboratory

Andy Hoke, National Renewable Energy Laboratory

Xiaoyao Zhou, National Grid ESO

Balarko Chaudhuri, Imperial College London

Karin Matchett, Energy Systems Integration Group

Julia Matevosyan, Energy Systems Integration Group

Matthew Richwine, Telos Energy

Dan Leonard, Peregrine Engineering Consulting

Sebastian Achilles, GE Vernova

Dustin Howard, GE Vernova

George Boukarim, Peregrine Engineering Consulting

Slava Maslennikov, Independent System Operator of New England

Henry Gras, EMTP

Shuan Dong, National Renewable Energy Laboratory

Deepak Ramasubramanian, EPRI

Shruti Rao, GE Vernova

Sudipta Dutta, EPRI

Jin Tan, National Renewable Energy Laboratory

Jason MacDowell, GE Vernova

Tim Green, Imperial College London

This guide was produced by a task force made up of diverse members with diverse viewpoints and levels of participation. Specific statements may not necessarily represent a consensus among all participants.

Suggested Citation

Energy Systems Integration Group. 2024. *Diagnosis and Mitigation of Observed Oscillations in IBR-Dominant Power Systems: A Practical Guide.* Reston, VA. https://www.esig.energy/oscillations-guide/.

Contents

Table of Figures

Executive Summary

Oscillations in power systems have always been of concern. The increasing use of inverter-based resources (IBRs)—such as solar photovoltaics, wind, and battery systems and inverter-based transmission, distribution, and load technologies—has led to oscillations with a wider range of characteristics and root causes. These raise new issues and risks for power system operation and planning, since oscillations can lead to unwanted equipment disconnections, supply interruptions, equipment damage, and other violations of reliability criteria.

This practical guide is a starting point for practitioners who encounter oscillatory behavior, a sort of field guide or diagnostician's assistant. Consulting the guide is the first step that follows "I see an oscillation. What is it? What do I do about it?"

The document is primarily intended to provide help for practitioners when the oscillations observed are "real"—that is, they have been detected or measured in the field (say, by a relay or phasor-measurement unit). But, since much of the diagnostic approach applies to oscillations observed in time simulations, they are included as well. Users will find the guide an aid to understanding and mitigating simulated oscillations.

Causes of Oscillatory Behavior

While this topic is complex, some practical simplifications cover most oscillatory behaviors:

- Something is broken: some aspect of the installation is not what you thought it was.
- Controls are too aggressive for the condition: gains too high, time constants too short, delays too long.

This practical guide is a starting point for practitioners who encounter oscillatory behavior, a sort of field guide or diagnostician's assistant. Consulting the guide is the first step that follows "I see an oscillation. What is it? What do I do about it?"

- The simulation is bad: wrong or inadequate models or the wrong tool was used.

The experienced practitioner will recognize these points and immediately observe that each one has a world of detail behind it. This guide will help the user find out which applies, what to do about it, and where to go for more help. A causality screening matrix is included that introduces a compact synopsis of attributes and causality, and the detailed table of contents will help the more experienced user to zero in on the topic of their choosing.

Something is broken.

Some practitioners will be inclined to immediately reach toward simulation tools to get to the bottom of observed oscillations. However, poor behavior is often the result of physical or software problems outside of normal modeling. Practical examples include:

- Switched polarity or phase rolling on signals
- Parameters like gains or ratios improperly implemented, documented, or per-unitized
- Equipment in improper operating paradigm, such as stuck in start-up, standby, or island mode, or just shut down

- Equipment that is physically broken, such as stuck actuators, shorted wires, or failed circuitry

A key to diagnosing these types of problems is knowing where to look. Operational monitoring that is aided with identification tools can be a key to finding “bad actors.” A growing arsenal of visualization and mapping tools have often proven to be effective, with their ability to track locations of high-amplitude oscillations, detect the direction of oscillatory energy flow, and distill mode shapes or other information about the potential participation of generators in oscillatory behavior. After-the-fact forensic measurements and simulations can confirm causality and often point to simple fixes.

The control is too aggressive.

The practical reality of closed-loop controls is that the desire or even requirement for rapid response often drives unstable behavior. This has always been true, but the advent of IBRs places equipment physically capable of astonishingly fast changes into the complex power system. As conventional high-inertia synchronous units are retired, it becomes increasingly possible for fast controllers to push the system into instability.

Anecdotal experience suggests that the majority of oscillations originate with a single “bad actor.” An ensuing debate as to whether the control of that single resource is too aggressive, too slow, or too dumb, the grid is too weak, or the bad actor is just the straw-on-the-back of a systemic problem, may be more a matter of semantics than practical utility. The simple expedient of calming the control or avoiding the problematic operating condition may have other unacceptable consequences (including poor regulation, non-compliance with requirements, constrained operation of the plant, or subeconomic operation). This drives the practical reality, recognized in this guide, that such short-term fixes to avoid oscillations may need to be replaced or supplemented with more extensive (and expensive) long-term mitigation. All mitigation options may have some negative consequences, ranging from significant capital costs, to reduced economy or flexibility of operation, to degradation of other aspects of dynamic performance.

A possible synopsis of mitigations, roughly in order of speed of implementation, includes:

- Control setpoint adjustment
- Operation or dispatch adjustment (within plant)
- Operation adjustment on host network (dispatch, topology switching)
- Control parameter modification (tuning)
- Reduction of series (or shunt) compensation levels
- Control structure modification (e.g., added signal filtering, damping control, reduced latency, altered phase-locked loop, change of inverter control mode from grid-following to grid-forming)
- Addition of passive elements within plant (e.g., compensation, filtering, detuning of resonances)
- Addition of active elements within plant (e.g., static synchronous compensator (STATCOM), active filters, storage with grid-forming inverters)
- Host grid reinforcement, improvement of system strength, or addition of dynamic reactive compensation and active damping devices

Simulation is bad.

The art of simulating IBRs has been evolving and occasionally problematic for a couple decades. Practice has not reached equilibrium. Potential for misleading or meaningless simulations of a range of IBR behaviors abound—including those that cause oscillations. This guide provides some help recognizing bad simulations and avoiding some of the more common mistakes, which include:

- The use of poor input data, i.e., bad parameterization for properly structured models
- The use of IBR models with structures that are inappropriate or missing details, such as latency or phase-locked loop, that are important to the phenomenon being observed
- The use of grid models that are overly simplified, poorly coded, or missing key attributes
- Inappropriate choice of simulation platform, such as phasor analysis when electromagnetic transient study is required
- Poorly controlled or processed simulations, with pathologies like aliasing or numerical instability

And beyond.

These basics do not always cover more complex causality. Interactions can occur between many resources that may have multiple owners or cross jurisdictions. The resultant oscillations may be without identifiable individual bad actors. Experience supports the investigation of such possibilities but generally only after the single bad actor possibility has been dismissed. This guide can help the diagnostician understand when the behavior is more complex and can help with the initial steps to resolution. But some complex phenomena are beyond the scope of this guide, and oscillations are one face of a complex and overlapping problem space. Concerns about other dynamic behaviors, notably fault ride-through issues, urgently need attention as well, but are outside this scope.

Components of This Guide

This guide is organized to provide the diagnostician with background and processes to quickly address most types of oscillatory behaviors in power systems, especially those associated with high levels of IBRs. The information presented becomes progressively more detailed. The reader interested in the topic, but not charged with solving a specific problem, will find earlier sections the most illuminating. The introduction and the section "Oscillations and System Stability" provide the technical background necessary as a foundation for forensics. An overall diagnostic process is then presented with a high-level flow chart and supporting sections on measurements and analytical tools.

The steps for the actual diagnostic process begin in the "Initial Assessment" section. Here we introduce a novel causality screening matrix that distills correlation between observed behaviors and possible causes into an extremely compact diagnostic aid. The diagnostician will emerge from this initial diagnostic assessment with a candidate causality for more detailed diagnosis. The balance of the guide provides detailed guidance for assessment and countermeasures for specific phenomena. Guidance is provided on the use of simulations, including ways to avoid common simulation errors, along with extensive references aimed at helping the user find more detailed and advanced help.

Beyond consulting this guide, diagnosticians must also recognize the need for collaboration with equipment manufacturers, researchers, organizations (like ESIG), and other practitioners in understanding and mitigating the more complex problems.

The industry is on a steep learning curve, with new tools and understanding constantly emerging. Most of the material in this guide will remain foundational, even as new understanding and tools are developed. Beyond consulting this guide, diagnosticians must also recognize the need for collaboration with equipment manufacturers, researchers, organizations (like ESIG), and other practitioners in understanding and mitigating the more complex problems.

Introduction

As modern power systems experience some of the fastest transformation in the history of electric power, the behavior of the largest and most complicated dynamic systems ever created is constantly changing. While there are a host of economic, societal, environmental, and technical issues that accompany this transformation, one important truth remains: a viable power system must be dynamically stable. It must tolerate design-basis physical disturbances, satisfactorily transitioning from its pre-disturbance state to an acceptable post-disturbance equilibrium.

Oscillations in power systems are one important facet of stability. The power industry has a long history of addressing a variety of oscillatory behaviors, particularly those that are problematic. But with an array of rapid changes underway, new types of oscillatory behaviors have emerged, mixed with and complicated by changes in known oscillation causes. These rapid changes involve:

- Generation technologies, including inverter-based and distributed generation
- Load/consumer technology and behavior, including distributed storage and electrification of previously independent energy loads
- Transmission topology, technology, and stress levels
- Ownership of system assets and responsibilities for their satisfactory operation

Much concern and attention is directed at changes specifically due to the explosive growth of inverter-based resources (IBRs), including wind, solar, batteries, and many other grid, energy storage, generation, and load technologies that depend on inverters. The dynamic characteristics of these devices are substantively different from the synchronous technologies that have dominated systems for a century. Their behavior is complex, and the industry is on a steep learning curve relative to some of the newest concerns that have arisen. While oscillations primarily caused by synchronous generation are still very much of concern, the primary genesis of this guide is concern over oscillations that are associated with IBRs, interacting with each other, with synchronous generation, and with the bulk power system in general. The body of literature on these subjects is vast. Indeed, it can be overwhelming. Methods to deal with oscillations have been identified by industry stakeholders as a top priority.

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Regardless of the source—IBRs, synchronous generation, grid equipment, loads, or combinations thereof—undamped undiagnosed oscillations in the power system are not desirable. It is important to identify the oscillations and investigate whether they present a risk to equipment damage or power system security.

Purpose of This Document

The function of the guide is to help provide a starting point for practitioners who encounter oscillatory behavior. It can be viewed as a sort of field guide or diagnostician's assistant. In the vernacular, we envision this guide being the first step that follows variations on "I see an oscillation. What is it? Should I worry about it? What do I do about it?"

The industry has a growing wealth of knowledge about every facet of systems with increasing shares of IBRs. The International Council on Large Electric Systems (CIGRE) and the Institute of Electrical and Electronics Engineers (IEEE) have a multiplicity of activities underway now, and detailed publications are available with in-depth explorations of relevant topics from modeling IBRs, subsynchronous oscillations, and design of offshore wind plants to high-voltage DC control and interconnection, to name a few. Many of the best reference documents produced by these groups are referenced at appropriate places in this guide. However, concise guidance focused on the practical aspects of dealing with power system oscillations is scarce. There is a great deal of practical knowledge among industry experts immersed in the minutiae of power system dynamics that can greatly benefit the would-be diagnostician, but it is currently underdocumented. This guide aims to change that.

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The intent of this guide is to help the user sort through the jungle of phenomena, identify possible causes of observed oscillatory behavior, and plot an initial course of action. The guide is emphatically *not* a comprehensive reference with great depth on each phenomenon. Rather, it is meant to complement other resources, such as those mentioned above.

The document is intended to provide help when the oscillations observed are "real"—they have been detected or measured in the field (say, by a relay or phasor-measurement unit). But, since much of the diagnostic approach applies to oscillations observed in time simulations, we include those here as well.

This document aims to help the practitioner determine the cause of observed oscillations and get a sense of what mitigations could be considered. Many of the physical and control mechanisms that can contribute to oscillatory behavior are either not included or greatly simplified in standard equipment (e.g., IEEE) models. Throughout the document, possible causality for problems that cannot be captured with standard models are noted. These notes tend to be anecdotal, based on observations of experienced practitioners. These notes are, in a sense, the antithesis of textbook reference and will rarely be found elsewhere in the literature.

Regarding mitigation, while the industry is learning rapidly, some emerging phenomena are not fully understood, and there may be no well-established mitigation at this time. Where possible we have identified today's gaps.

Intended Audience and Options for Using This Guide

The primary user of this guide is expected to be engineering staff that have a degree of responsibility for maintaining system performance. This includes moderately experienced system planners and operations engineers, people who regularly perform dynamic analysis (e.g., phasor-domain transient stability work, electromagnetic transient stability work) for independent system operators, regional transmission organizations, transmission operators/owners, original equipment manufacturers, asset owners, and developers, but who may not have extensive experience with integration of IBRs. These people are the ones who will be in the line of fire when reports and measurements of oscillations (presumably on the grid) emerge after something untoward happens in the field. They are the people who will be charged with answering the questions of "what the heck is this, and what do we do about it?" While the primary focus is for diagnosticians charged with addressing problems off-line, the information and screening tools will have some utility for use in the control room. The guide should allow for relatively quick identification of the nature of many oscillatory phenomena with insights into possible immediate actions.

Less experienced users, or the interested student, will find this guide useful as well, as we have attempted to condense a massively complex field of study into a relatively simple and organized format. Those aiming to increase their understanding of the basics of oscillations in high-IBR systems, without being charged to solve a specific problem, should at least read through the next two sections ("Oscillations and System Stability" and "Basics of Identification Diagnostics") and then read the introductory paragraphs of each major section. Deeper reading of individual sections of particular interest can be illuminating—the document need not be read cover-to-cover sequentially. A glossary with abbreviations and definitions is provided at the end of the guide.

The steps for the actual diagnostic process begin in the "Initial Assessment" section. Here we introduce a novel causality screening matrix that distills correlation between observed behaviors and possible causes into an extremely compact diagnostic aid. The diagnostician will emerge from this initial diagnostic assessment with a candidate causality for more detailed diagnosis. The balance of the guide provides detailed guidance for assessment and countermeasures for specific phenomena. Guidance on the use of simulations, including ways to avoid common simulation errors, is provided, along with extensive references aimed at helping the user find more detailed and advanced help.

The brevity of the document entails a cost in simplification. The document is broad, but not terribly deep. At each step, we have endeavored to capture the most important aspects of the phenomena. Nuances and details that will be known to highly skilled practitioners are often absent. Other, more complete and scholarly works are recommended often. The user may find that some types of needed analysis can only be performed by or in partnership with others—especially with equipment manufacturers who will have access to details and tools that are not otherwise available. Further, the industry is learning rapidly, and practice will continue to evolve quickly.

Oscillations and System Stability

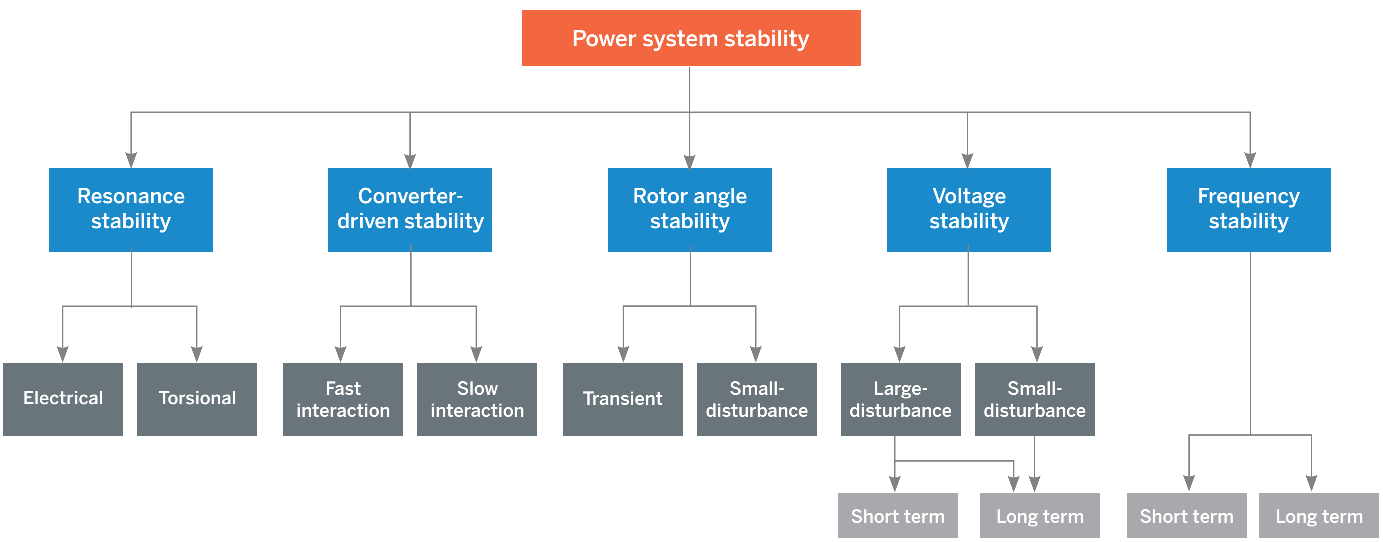
The operation of power systems can be viewed as a continuous quest for stasis in an environment that is constantly changing. The requirement that a power system be stable means that it must return along an acceptable path to an acceptable condition when stimulated and must not initiate unacceptable oscillations even when not stimulated. Stimuli can be discrete, in the form of impulses or steps, or continuous, in the form of ramps, operational noise, or other similar changes in stress or boundary conditions.

IEEE Stability Definitions

The seminal IEEE reference "Definition and Classification of Power System Stability" lays out the entire technical space for stability. It was updated in 2021, as reproduced in Figure 1, to include "converter driven stability" and "resonance stability" (Hatziargyriou et al., 2021). The structure shows groups based on the nature of the behavior and then provides finer divisions based on the size, speed, and signature of the behavior. This

FIGURE 1

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. For diagnosis of oscillatory problems, this guide has adopted a modified taxonomy.

Source: Hatziargyriou et al. (2021).

document provides a common basis for discussion across the industry. IEEE provided further clarification of these definitions as they relate systems with high levels of IBRs in *Stability Definitions and Characterization of Dynamic Behavior in Systems with High Penetration of Power Electronic Interfaced Technologies* (Hatziargyriou et al., 2020).

While the IEEE definitions present the gold standard of reference, oscillatory behaviors that are the subject of this guide do not necessarily fit neatly into single boxes of the IEEE taxonomy. This can lead to some confusion, particularly with respect to labels and nomenclature. Traditionally (more than 50 years ago), the box "small disturbance" under "rotor angle stability" would have been the main oscillation concern. The core concern there is poorly damped oscillations driven by high-response excitation systems and mitigated by power system stabilizers. In older references, these problems are referred to as "dynamic stability." That language has now been mostly abandoned, since all stability problems are arguably dynamic.

Further, aspects of instabilities that lead to oscillations for present and emerging systems can be found across several of the cells in the figure. For example, converter-driven stability issues may overlap into the categories of voltage stability, angle stability, or resonance stability. The IEEE Power & Energy Society Task Force on Modeling Subsynchronous Oscillations in Wind Energy Interconnected Systems (IBR SSO task force) reported that many converter-driven low-frequency oscillations are similar to voltage stability issues (Cheng et al., 2022 [IEEE PES IBR SSO Task Force]). It is common for these oscillations to become severe if the grid becomes weak and power transfer is high. In these cases, countermeasures include voltage control tuning. Phase-locked loop (PLL) loss of synchronism, like the 2021 Texas Odessa event (NERC, 2022), is a converter-driven instability that could be viewed as angle stability. In some events, wind farms' turbine controls lead to a poorly damped mode, and this mode interacts with a synchronous generator's torsional mode (e.g., West China 30 Hz event, 2015 (IEEE, 2020)). Again, this is an event of resonance stability. These examples point to a need to adopt a somewhat modified taxonomy, as presented next.

Causality-Based Taxonomy of Oscillatory Phenomena

In this guide, we are primarily concerned with identifying the *causes* of oscillatory behavior. To that end, we offer a hierarchical approach that is based on causality of oscillations. It is quite similar to the IEEE hierarchy but is organized with the intent of helping the practitioner quickly find the cause of their problems. In doing so, we group phenomena in progressively finer distinction/resolution in a hierarchical structure. Throughout this document we have grouped oscillation by cause into five broad categories, with detailed discussion of each provided in the appropriate sections below.

- SSO: Subsynchronous and supersynchronous oscillations
- Voltage control–induced oscillations
- Transient/synchronization stability–induced oscillations
- Frequency or active power control–induced oscillations
- Harmonic oscillations

Forced Oscillations vs. Systemic Poor Damping

For all five of the oscillation types, it is possible to separate oscillation problems into two general groups that give a different perspective on causality and mitigation. IEEE makes the following distinction: "*Natural oscillations* are the behavior of an autonomous system only, while *forced oscillations* are the behavior of an input-output system" (Chen et al., 2023 [IEEE TR110]) (italics added).

Forced Oscillations

Some practitioners identify oscillations caused by a single resource (or, more rarely, a group of resources) that is misbehaving by actively injecting energy to the system at the oscillatory frequency as "forced oscillations" (Chen et al., 2023 [IEEE TR110]). Problems that arise from physical equipment problems or acutely incorrect control settings tend to fall into this group. The forced oscillations may be due to faulty equipment (e.g., failed sensors or actuators, or lost signals) or control systems that are incompatible with the host system. They can also be caused by various cycling behaviors by loads and other power system components besides generation. These oscillations tend to be sustained, often showing zero damping, and persist as long as the forced signal exists and the system remains sensitive to the stimulus. NERC recognizes forced oscillations as a reliability concern and has issued guidelines for monitoring and mitigation (NERC, 2017a). Throughout this document, specific forced oscillation phenomena are addressed by their causality—both the source of the driving energy and the systemic conditions that are sensitive to that stimulus. A variety of approaches exist for tracking down the bad actor, as discussed below.

Systemic, "Natural" Oscillations

Oscillations in the other group are more systemic. These "natural oscillations" occur when the combination of many elements in the power system collectively produces poor damping. This is not completely separate from the idea of forced oscillations in that some elements, even a single element, may be dominant participants. Problems like inter-area oscillations tend to be of this type. It is often more difficult to pinpoint causality and mitigation for these systemic problems.

Natural oscillations occur when the interactions among multiple system elements, particularly their controls, create a system that is prone to oscillations. A common characteristic of these oscillations is sensitivity to operating conditions, normal vs. abnormal, which introduce the possibility of interaction with a variety of system resonances. Such poor behavior may be the result of inadequate or inappropriate control design or tuning of IBRs and other assets.

Natural oscillations occur at frequencies that are identifiable with linear analysis. The roots of the differential-algebraic equations are extracted in the form of complex eigenvalues. The frequency (jw or "imaginary") component dictates periodicity—the natural frequency—and the "real" component dictates the inherent damping. Negative damping is intrinsically unstable, with oscillations "spontaneously" arising when system conditions drive the eigenvalue unstable.

Distinguishing Between the Two

Distinguishing the two varieties can be important because the practical responses are different. Natural mode oscillations tend to need monitoring (for damping and concurrent operating conditions) and after-the-fact analysis (such as state-space and time simulations) to facilitate tracing and mitigation. In contrast, forced oscillation needs to be detected and alarmed in real time, with a search for the source and correction. Many drivers of forced oscillations are ignored or poorly modeled in simulations. Again, IEEE notes that:

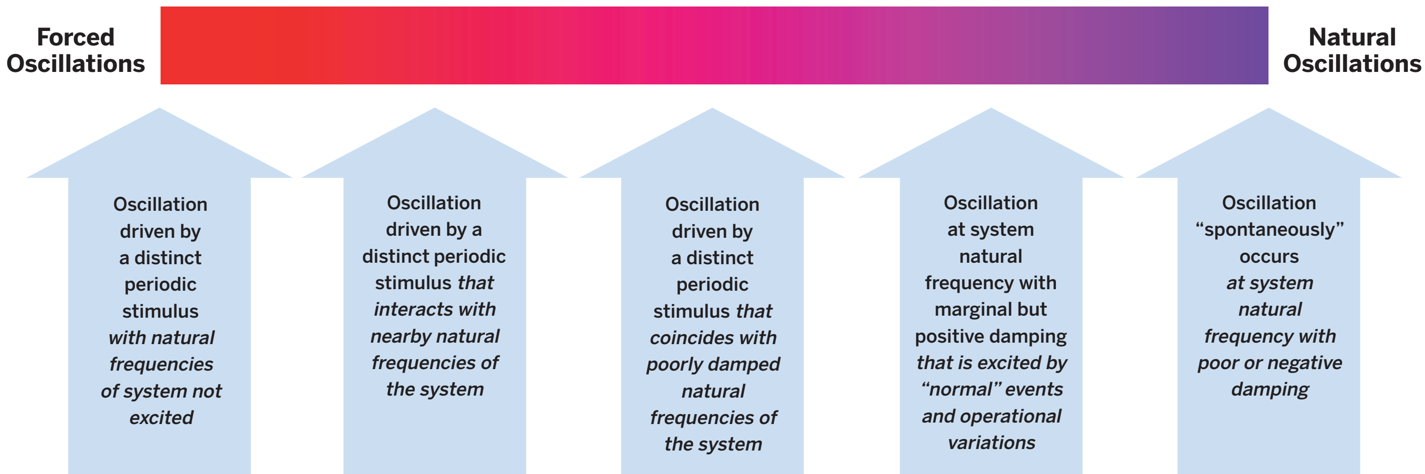
> Investigations show that these oscillations are in fact induced and [are often] driven by pathologies like oscillating steam valves, loose contact in excitation systems, and hydro/thermodynamics, which are usually not included in power system models. Notably, forced oscillations often last for a relatively long time (minutes to hours), with either near-zero or varying observed damping ratios, as long as the source is persistent (Chen et al., 2023 [IEEE TR110]).

The practical reality is that oscillations may not fit neatly into one of these two varieties; rather, they represent the bounds of a continuum of behaviors that can be confusing for the diagnostician. There is often some sort of stimulus involved when natural frequencies are excited to oscillate. Figure 2 (p. 7) suggests that there is often a mix of forced and natural oscillations.

As Chen et al. (2023) note, "when the forced oscillation is at a natural frequency . . . tracing the source can be challenging." This corresponds roughly to the middle of this continuum. Moving from the center to the right, the constant, usually low-level, stimulus that accompanies normal operation will excite poorly damped frequencies. "Normal" in this context means switching operations, normally cleared faults, and the myriad other relatively minor stimuli that occur often. These may manifest as continuous, low-grade oscillations—recently termed pink oscillations—even if the eigenvalue shows marginally positive damping. In the common case when a single resource has a badly performing controller, the behavior becomes a sort of duality: (a) the poor control introduces a new unstable mode or destabilizes an existing mode, as evidence of natural oscillations, but (b) the poor

FIGURE 2

Continuum Between Forced and Natural Oscillations



Forced and natural oscillations represent the bounds of a continuum of behaviors. On the far left, forcing drives oscillations without interaction with natural frequencies. Moving right, forcing excites nearby natural frequencies. At the center, the forcing frequency aligns with an otherwise positively damped natural frequency. Moving from the center to the right, the constant, usually low-level, stimulus that accompanies normal operation will excite poorly damped frequencies. "Normal" in this context means switching operations, normally cleared faults, and the myriad other relatively minor stimuli that occur often. At the far right, the system is naturally unstable, with an unstable eigenvalue.

Source: Energy Systems Integration Group.

performance of the device introduces the energy to force oscillations. Nonlinear behavior, not necessarily identifiable with linear eigen-analysis, may also manifest as oscillations (as discussed in the section "Transient/Synchronization Stability–Induced Oscillations"). Exact labeling of the phenomenon is less important than finding effective mitigation.

In summary, many oscillations require that the "bad actor" forcing them be found and neutralized. Curing a systemic, natural oscillation requires that the system be detuned in some fashion, such as by altering operating condition, network topology, or controls. Real systems may exhibit a combination of the two.

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Basics of Identification Diagnostics

The purpose of this guide is to help practitioners determine likely causes and potential mitigation of observed oscillatory behavior. This diagnosis process has no single, commonly agreed-upon path, and different experts approach the challenge differently. Here we introduce a diagnostic process that reflects one practical approach. The balance of this guide is based on this process, and each subsequent section provides a moderately detailed discussion and guidance on where to find more comprehensive resources. (A glossary with abbreviations and definitions is provided at the end of the guide.) The overall process is shown in the flow chart of Figure 3.

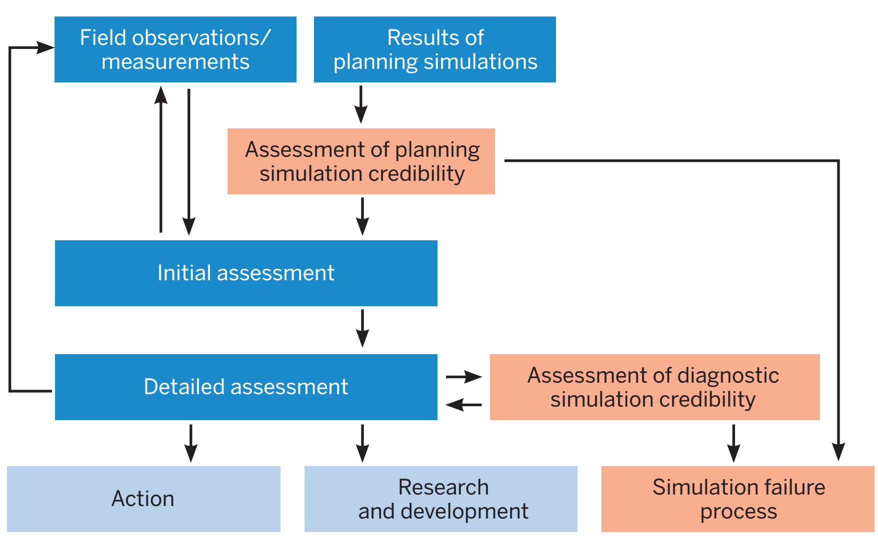
Field observations vs. simulations. The premise of this guide is that the diagnostician has been presented with evidence of oscillations that need further attention. There are two starting points for the diagnosis process, depending on whether the practitioner is starting with *either*:

- Actual physical evidence of oscillations, i.e., field measurements, oscillography, and possibly observed phenomena (noise, needles swinging, physical vibrations, etc.), or
- Results of simulation—e.g., a planning or facility study, in which oscillations show up in the results

Where there is physical evidence of oscillations, the diagnostician can proceed with a degree of confidence that the phenomenon is "real," whereas with simulation results some due diligence is required to make sure that

FIGURE 3

Overview of the Process of Causality Identification for Power System Oscillations



Source: Energy Systems Integration Group.

the simulation results are credible and that observed oscillations are not an artifact of a faulty process.

Simulation credibility. When starting with simulation results, the process includes an operation to check that the results are "credible." There are nuances to be respected here. The idea is to screen results to make certain that avoidable mistakes do not invalidate results. Credible simulations may not be perfect, in the sense that they may not exactly capture actual physical behavior, but still provide meaningful insight into the phenomenon and possible causality. Imperfections that result from modeling inadequacy have consequences ranging from inconsequential all the way to resulting in useless simulations. Engineering judgment comes into play here. However, at this screening stage, we are less concerned with that class of failure than with avoiding a spectrum of common mistakes that completely invalidate simulation results. (Simulations run later in the process for the purpose of determining causality or evaluating mitigation are also subject to these risks, as reflected in the process map.)

Initial assessment. This step narrows down the possible cause of the observed oscillations to a very small number or a single candidate for further detailed investigation. As with the overall process presented here, there is no single "right" approach, and indeed this stage of diagnosis is a combination of art and science. We present guidance, a long list of diagnostic questions, and a screening matrix tool to aid the practitioner. One possible outcome of this step is that it becomes clear that there is insufficient information to proceed, in which case the diagnostician returns to the field observations/measurements step. In some cases, an initial assessment (or downstream during the detailed assessment) may make it clear that the observed behavior is sufficiently inconsequential that no further action is required. In most cases the diagnostician proceeds from the initial assessment to the detailed assessment.

Detailed assessment. Starting with the "good guess" of an initial assessment, a sequence of analytical steps leads the diagnostician to different possible outcomes. The specific causes of oscillations will be identified through a process customized for each grouping of phenomena (subsynchronous and supersynchronous oscillations, voltage control–induced oscillations, transient/synchronization stability–induced oscillations, frequency or active power control–induced oscillations, and harmonic oscillations). An understanding of the causality will sometimes advise the decision whether to continue toward countermeasures or not. Given that the state of the art is rapidly changing, and that not all phenomena are fully understood, one distinctly possible outcome is that the problem is beyond the scope of this guide. More sophisticated approaches or research and development may be needed.

Countermeasures. These are shown separately as "action" in this high-level process map, but in practice an understanding of what is needed to address problems goes hand in hand with the process of understanding the causality. Countermeasures may include mitigation (preventing, reducing, or avoiding the phenomenon), protection (reducing or eliminating the risk associated with the phenomenon by, for example, tripping equipment when oscillations occur), monitoring (watching to see if it happens again or gets worse), or combinations thereof.

Diagnostic simulation credibility. Simulations run for the purpose of determining causality or evaluating mitigation and protection are subject to the same risks as seen for planning simulations. Further, for diagnostic simulations it is necessary to reasonably replicate specific operating conditions and device behaviors. Getting these operating details and adequate details about device models is central to successful diagnosis and can be highly challenging.

Simulation failures. Once simulations are deemed not credible (or at least suspect), the process of identifying the cause and correcting it becomes a somewhat separate diagnostic process. Deficiencies in input data, device model structure and implementation, simulation platform selection, and simulation parameterization can all contribute to failures.

The balance of the document follows the flow chart in Figure 3 (p. 8). While the document is somewhat sequential, the reader can proceed directly to sections corresponding to the operation in this figure for more details and commentary.

Field Measurements and Observations

This section discusses elements of measurements that are unique to "real" signals. The main signals of interest for any investigation may include (at a minimum) voltage, current, frequency, phase angle, active power, and reactive power, either at the terminals of the inverter-based resource (IBR) unit (i.e., single inverter) or at the connection point or at key nodes in the power system. Other measurements may be necessary depending on the scenario investigated, such as speed of nearby synchronous generators/condensers, any rotating machines, or any other equipment in the vicinity such as static VAR compensators (SVC), high-voltage DC (HVDC), static synchronous compensators (STATCOM), etc. In cases when forced oscillations are suspected, it can be invaluable to have measurements or recordings of signals internal to specific equipment, especially controls. Intermediate signals such as error codes, outputs of integrators and limit blocks, and binary status flags can all be critical to understanding but are rarely available in the first stages of diagnosis.

It is preferable to use high-resolution instantaneous measured quantities when identifying oscillations through field measurements; however, phasor measurement units (PMUs) with power frequency reporting rate can also yield useful signatures, if the oscillation frequencies are less than the Nyquist sampling rate. Wide-area measurements like these can be a particularly important element in the diagnosis of natural oscillations, especially when there is no immediately obvious bad actor. High-resolution data may be obtained from dedicated power quality monitors installed at the interconnection of the IBR or through substation digital fault recorders or even protection relay equipment, if so configured. The IBR plant owners may also have access to fault recorders that can be triggered as part of the inverter-level monitoring to aid in providing data for investigation following oscillations. Typically, SCADA (supervisory control and data acquisition)–type data are not sufficient for identifying power system oscillations. However, they may provide additional information such as changes to dispatch levels, setpoints, etc. to aid in the investigation.

Measurement Quality

Measurements are often an essential element in identification and diagnosis of system problems. However, they must correctly capture the phenomenon; poor-quality measurements can result in incorrect diagnosis and wasted time. While field measurement practice for quality and safety is a broad topic, a few steps to avoid common mistakes are noted here.

The first source of information for the diagnostician is likely to include measurements from dedicated systems—that is, monitoring that has been installed in the field as part of regular operations, which is tested and operated on a regular basis. While there is opportunity for such measurements to be compromised, it is relatively unlikely. As long as the sampling interval and signal processing (discussed below) are adequate, they can normally be taken at face value.

The same cannot be said of temporary measurements made on site for the purpose of diagnosis or other ephemeral needs. Temporary set-ups are prone to a variety of mistakes. Three of the more common errors are discussed here.

Inadequate Sampling

Sampling rate—how often the signal is recorded—must at a minimum satisfy Nyquist criteria. Sampling rates should be at least two to three times as fast, and preferably an order of magnitude faster, than the phenomenon of interest, e.g., 1 kHz to capture 100 Hz oscillations. In practice, the frequency of interest might not be known, so the diagnostician must avoid being fooled by aliased signals. Some visual warning flags on aliased signals include sawtooth signals, sawtooth signals that beat with a slower frequency, and jagged non-periodic signals.

Poor Reference

Measurements of voltage and current can be subject to error from incorrect reference (e.g., incorrect neutral), especially when these are used to calculate active and reactive power. Paired measurements such as two line-to-line voltages and two line current signals pulled from secondaries of dedicated potential transformers (PTs) and current transformers (CTs) will usually avoid these problems.

Incorrect Documentation

The correctness of temporary measurements often hinges on station documents (i.e., documentation held at or on behalf of a power station or other asset). Station one-line diagrams, three-line diagrams, and related signal maps are often incorrect. It is common to see inconsistencies like swapped polarities, phase mislabeling, and incorrect ratios on measurement transformers or shunts (especially for DC measurements). Using these signals will result in nonsensical results.

One practical step to guard against these problems is to compare steady-state results from the temporary measurement system to dedicated station measurements before conducting tests or making high-frequency examination of signals. While dedicated station measurements may lack the necessary bandwidth to diagnose oscillations, temporary measurements should reasonably match fundamental frequency information when the subject plant or other system is in approximately steady state. Results that mismatch by integer multiples are an indication of error in documented ratios. Diagnosis of swapped polarities and similar errors can be aided by the creation of a matching phasor diagram.

Signal Processing

Measurements are only as useful as the information derived from them. Good signal processing can help ensure that all of the useful information is being extracted from the available signals.

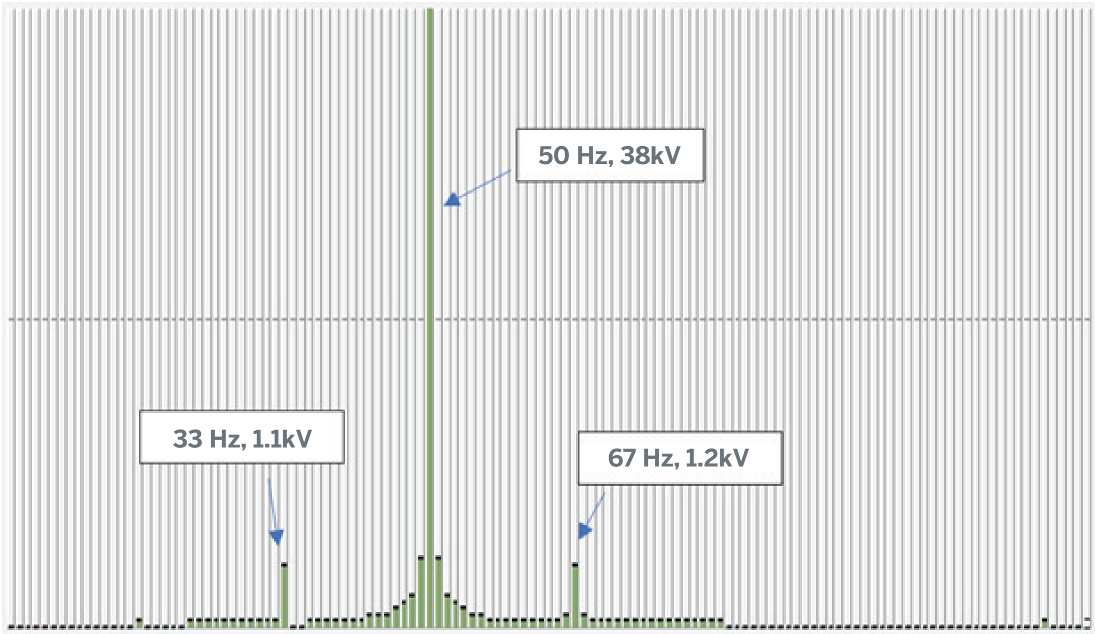
The selection and processing of measurements can be important to diagnostics. It is important to distinguish whether the measurements are based on instantaneous quantities or root-mean-square (RMS)–aliased quantities. If the latter, it must be noted that the frequencies observed in RMS plots are RMS-aliased quantities. That is, actual 50 Hz or 60 Hz signals appear as DC—a straight line when the system is in equilibrium. Fundamental-frequency phase imbalance appears as 100 Hz or 120 Hz. Further, it is important to distinguish between individual phase RMS, sequence quantities (magnitude only), and phasor quantities (magnitude and phase). Clean-up of measurements can include such elements as getting rid of noise, biases, and offsets—both y-axis and temporal shifts. Transducers must have appropriate accuracy at the frequencies of interest, or they can introduce significant error. For example, capacitor-coupled voltage transformers (CCVTs) have transient response that makes measurements at other-than-fundamental frequency questionable. There are examples of commercial measurement devices that erroneously calculate phasor quantities from their own waveform data, so validation of calculated quantities can be important.

FFTs and Related Algorithms

FFTs—fast Fourier transforms—are an analytical workhorse for extracting frequency information from time series signals, including measurements. When

FIGURE 4

Example FFT Analysis of an Instantaneous Phase Voltage Waveform at a 66 kV Connection Point



Fast Fourier transform (FFT) of a 50 Hz voltage being modulated at 17 Hz. The FFT sidebands at ± the modulation frequency around fundamental frequency are characteristic of modulated oscillations. The diagnostician is not concerned with 33 and 67 Hz phenomena per se.

Source: Australian Energy Market Operator.

performing FFTs, if the frequency of interest is known ahead of time, it is easy to decide the bin width or resolution needed such as to avoid spectral leakage effects; however, that is often not the case. Therefore, a reasonable bin resolution may need to be selected (depending on length of the sampling window) to highlight the frequencies of interest especially if the dominant frequency is not easily identified.

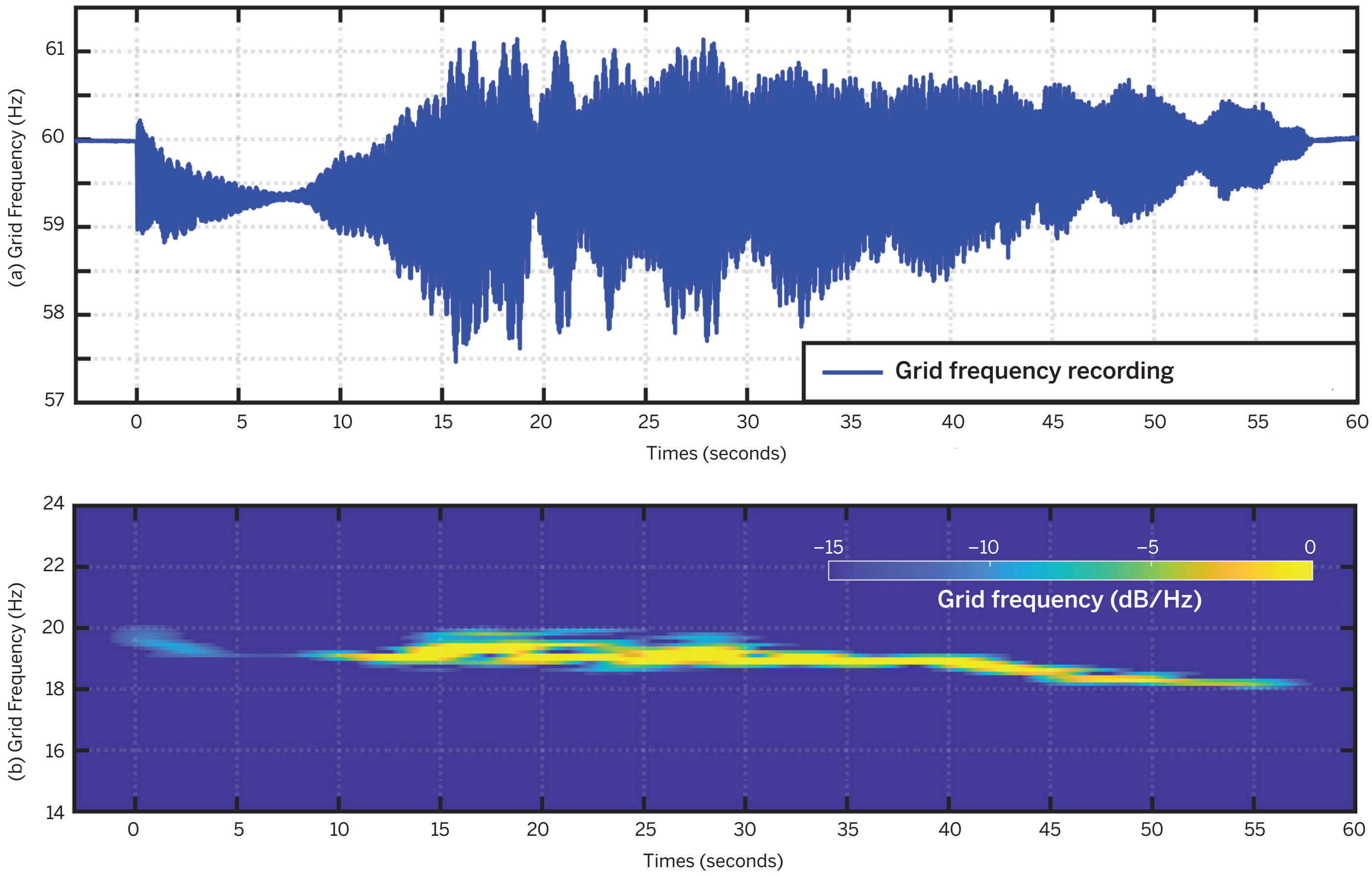
If the signal comprises individual frequency components like $A_1 \cos 2\pi F_1(t) + A_2 \cos 2\pi F_2(t)$, the FFT will clearly show F_1 and F_2 as discrete frequency components. However, if the frequency is modulated, such as $A_1 \cos 2\pi F_1(t) \times A_2 \cos 2\pi F_2(t)$, the modulated frequency will appear as side bands to the dominant frequency, say F_2+F_1 and F_2-F_1. Figure 4 shows an example FFT of an instantaneous voltage waveform where the modulated frequency is 17 Hz and the RMS-aliased measurements showed the 17 Hz.

Spectrograms can also be useful tools when trying to see the frequency, magnitude, and duration of the oscillations. Figure 5 (p. 13) shows an example of the recorded grid frequency on Kaua'i Island with fundamental frequency (upper trace) and the corresponding spectrogram of frequency (lower trace), showing 18 to 20 Hz oscillations (Dong et al., 2023).

Other tools like Prony analysis can also yield useful information to identify oscillations and damping. This is particularly useful in scenarios where the waveform appears to be visually damping out but the waveforms are highly distorted and certain frequency components may be undamped, indicating the presence of undamped oscillations. Since Prony analysis is an estimation tool, the error with the fitted model may be sensitive to the window length of the data considered. Other considerations include background noise and conditioning the signal appropriate for analysis.

FIGURE 5

Example Spectrogram of an RMS Phase Voltage Showing Oscillations near 19 Hz



Example spectrogram of a Kaua'i frequency recording showing 18 to 20 Hz oscillations. (a) Modulation of fundamental frequency. (b) Spectrogram of modulation frequency showing a drift of the modulation frequency from 20 to 18 Hz oscillations over the course of an hour.

Source: Dong et al. (2023); National Renewable Energy Laboratory.

Frequency

Measurement of power frequency can be surprisingly difficult. Various techniques used to measure frequency include:

- Measurement of instantaneous waveform voltage periods
- Phase-locked-loop (PLL) measurement, where the frequency of a local oscillator required to stay in synchronism with the measured voltage is used
- Numerical techniques (e.g., FFT) based on numerous samples per fundamental cycle
- Phasor measurement units (PMUs)
- Eyeball. The human eye with a ruler naturally incorporates sophisticated filtering and can produce highly accurate results.

The period measurement approach, typically implemented by time differences between voltage zero crossings, is particularly prone to spurious or inaccurate response due to waveform distortion. The presence of certain harmonics can cause measurements to be incorrect even in steady state. All of these techniques are prone to spurious response to transient distortion, such as due to faults or even line or capacitor bank switching, and to switching that causes abrupt changes in phase angle. Since frequency is the time derivative of the angle of the voltage sine wave, the PMU approach is particularly vulnerable to noise. Step discontinuities—for example, those associated with switching operations or other discrete changes in topology such as faults—present challenges. Frequency measurements across such discontinuities tend to lead to nearly meaningless results, which have sometimes caused problems with protection or other decisions based on frequency. Frequency measurements for periods shorter than a few cycles of fundamental need to be regarded with the utmost care. Fortunately, for diagnosis of system oscillations, the sampling window can generally be several cycles, which substantially reduces the risk of poor fidelity frequency measurements.

Some care is needed to avoid confusion about which "frequency" is being discussed. From a diagnostic perspective, it is the superimposed or modulation frequency, not the actual frequency of the sidebands, that is relevant for small signal analysis. The equations above in "FFTs and Related Algorithms" apply: oscillations superimposed on the sinusoidal fundamental-frequency phase voltages and currents appear in the controls at the superimposed frequency minus the fundamental for positive-sequence superimposed oscillations, and at the sum of the superimposed frequency plus the fundamental for negative-sequence superimposed oscillations. Likewise, an oscillation in a control quantity appears as a magnitude or phase oscillation of the phase quantities, consisting of relatively symmetric "sidebands" of superimposed oscillations at the fundamental frequency plus and minus the modulation frequency. For example, in Figure 4 (p. 12), we are concerned with 17 Hz oscillations, not 33 and 67 Hz oscillations.

Angle and Coherency

Examination of the phase relationship of system measurements at the frequency of oscillation can be a critical diagnostic indicator when looking for causality. For example, the phase angle of oscillation of active power and frequency can be illuminating. When power and frequency are in phase (or close), that is an indicator of forced oscillations being driven by that device. When power and frequency are approximately in quadrature, this is evidence of systemic resonance. Angle coherency can also help determine whether individual resources or groups of resources are participating (Chow, 2013). Identification methods such as dissipating energy flow (DEF) use coherency. The well-understood relationship between the internal angle of synchronous machines and power may be different with IBRs. Internal angles of grid-following

inverters do not have the same meaning as in synchronous machines and are not usually useful information. When reactive power and voltage swings are in quadrature, this is evidence that one or more voltage regulators may be mistuned. It can be evidence that controllers are subject to undue (unexpected) lags from signal latency. Synchrophasor measurements from PMUs can play a critical role in understanding phase relationships. They are especially useful for diagnostics of active power oscillations.

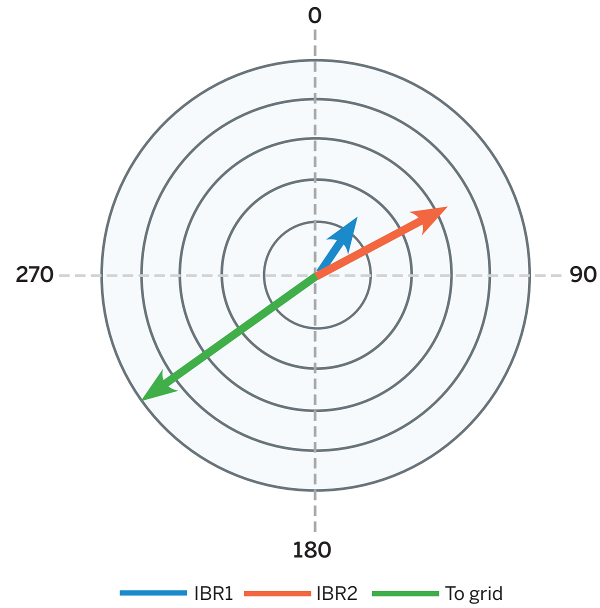
Plotting and Graphics Options

It is not always obvious how to create plots of measurements that facilitate extracting information. The diagnostician should ask some simple questions:

- Are the right variables being plotted together (e.g., V and Q together)?
- Are cross-plots needed (R vs. X, V vs. P, Q vs. P, etc.)?
- Are the plots properly scaled?

Polar plots are a useful tool. If currents drawn by the IBR are plotted against a common reference, say, with reference to the bus voltage angle, they can show oscillations against the grid. An example polar plot in Figure 6 shows two IBRs oscillating against the grid by feeding energy to the grid rather than between themselves. This helps to identify coherent groups of IBR clusters: if the phase angles are close to each other, as is the case here, the participants can be grouped. Conversely, if the two IBRs here had opposing phase angles, they would be interacting and exchanging energy with each other.

FIGURE 6
Example Polar Plot of Phase Currents Showing IBR1 and IBR2 Oscillating Against the Grid



Polar plot of the currents for one oscillatory mode involving two IBRs. In this case, the two IBRs are largely coherent and are oscillating against the host grid. IBR2 has roughly double the participation of IBR1.

Source: Energy Systems Integration Group.

Square Waves, Sawtooths, and Other Non-sinusoidal Signals

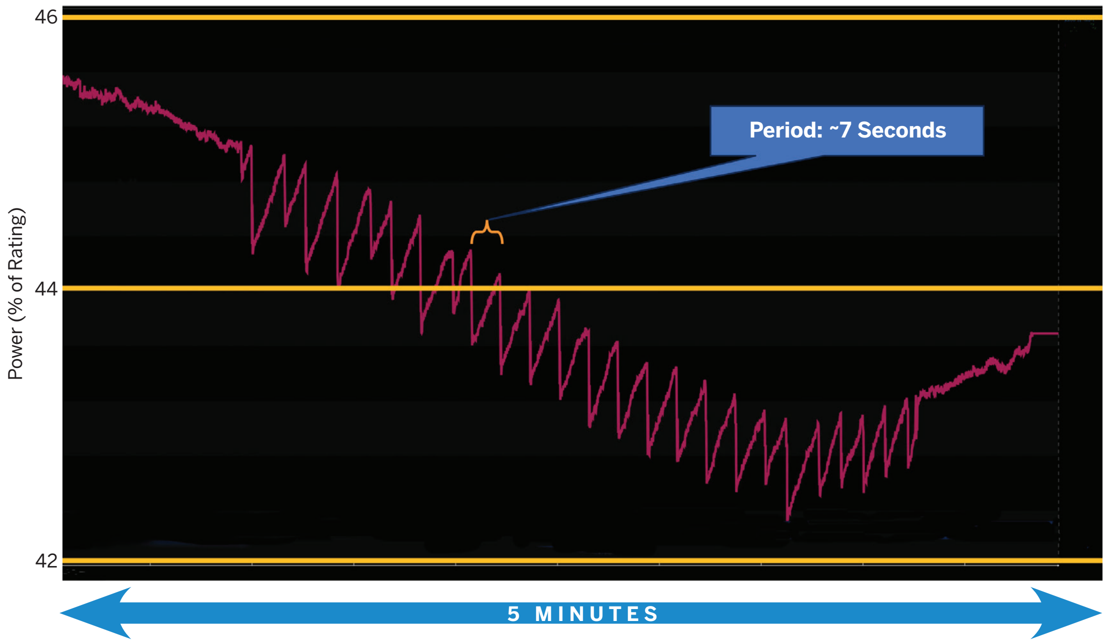
When the system is subject to forced oscillations, the oscillations often persist with relatively fixed amplitude—essentially zero damping. The steady-state waveform is significantly influenced by the shape of the forcing input. If the input is square, "scalloped" (repetitive exponential swings of alternating polarity), or sawtoothed, other measured signals will have harmonic components, which is a strong indicator of forced oscillations. For example, the sawtoothed behavior of active power in Figure 7 (p. 16) shows a limit cycle of about 7-second periodicity. This points to a control pathology in which a discrete threshold is hit repeatedly. The systemic conditions that create this tuning come and go, as can be observed at the beginning and end of the measurement sample.

The next section, "General Discussion of Analytical Tools and Approaches," continues this discussion. The IEEE Technical Report 110, *Forced Oscillations in Power Systems,* introduces supporting math and some specific analytical techniques including "cross spectrum index," which has some rigor in separating out natural and forced oscillations (Chen et al., 2023 [IEEE TR110]).

Time Window for Samples

Diagnosis of observed oscillations can sometime benefit from inspection of the suspect equipment at other times "near" the event. For example, in the UK in 2019, a large wind plant went unstable and took down a chunk of the regional grid (ESO, 2019). The actual event was violent and very nonlinear, making causality assessment

FIGURE 7
Active Power Sawtooth at a Utility-Scale PV Plant



The sawtoothed behavior of active power shows a limit cycle of about 7-second periodicity, pointing to a control pathology in which a discrete threshold is hit repeatedly. The systemic conditions that create this tuning come and go, as can be observed at the beginning and end of the measurement sample.

Source: American Transmission Company.

challenging. However, about 10 minutes prior to the event there had been a "warning" event with similar but much smaller oscillations that self-extinguished. Measurements from that more linear event showed the problem much more clearly than the big event, and were useful in identifying the causality and mitigation.

Observations

When system oscillations occur, it may be immediately obvious what equipment is the culprit. Alternatively, the "Methods for Locating the Source of Oscillations" discussed below may point to specific equipment in the power system. Regardless of how a particular equipment installation becomes the focus of the forensic investigation, inspection of the installation by manual methods (i.e., "go look") can be invaluable. For example, if a control appears to be misbehaving, a first check is to make sure that controls have actually been implemented as intended. Simple as it seems, it is not unheard of for mistakes to be made moving from simulation parameters, which tend to be in per-unit, to device settings, which are typically in physical units. Visual inspection can reveal broken equipment, switches incorrectly positioned, disconnections, and a host of other mundane failures.

General Discussion of Analytical Tools and Approaches

This section provides a brief overview of the kinds of analysis that are used for different types of oscillations. The spectrum of tools available is wide and includes several types of analyses that are outside the realm of standard grid planning. Tools for analysis of power system oscillations are themselves a subset of the rapidly evolving battery of tools used today. A recent inventory of tools by ESIG and the Global Power System Transformation Consortium (G-PST) explains the relationship and status of this broader spectrum (Miller et al., 2021). (Please refer to the glossary with abbreviations and definitions provided at the end of the guide as needed.)

Selection of the right tools is a necessary, but not sufficient, condition for successful diagnosis. It is also necessary to have good data and good models for use within the confines of the particular tool. Some of the ways in which simulations fail to produce meaningful results are addressed in the "Simulation Credibility" section.

Tools Overview

A synopsis of tools that can be used for diagnostics is presented here. They have different functions and applicability for different types of phenomena. Following these individual descriptions is an applicability matrix to help the diagnostician select the appropriate tools.

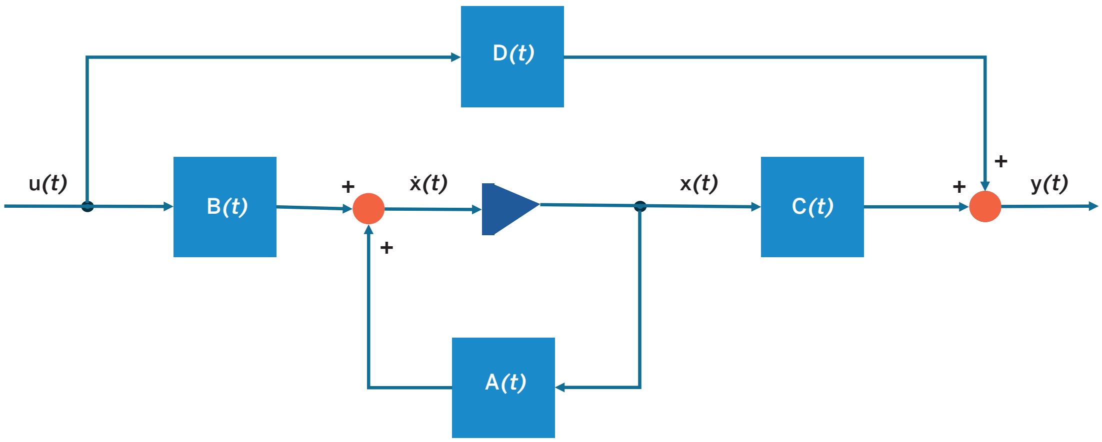
State-Space Methods

There is a well-established foundation of practice used by control engineers in every discipline that depends on linearized dynamics of a system. These state-space methods, a.k.a. eigenanalysis, take place in the frequency domain, rather than time domain. At the core are eigenvalues, which provide deep insight in the oscillatory behavior of systems, insight that may be difficult or impossible to extract from time-domain simulations alone. In order to perform all state-space analysis, a linearized model is required. Methods for linearization of power system representations have evolved over the past half century (Chow and Sanchez-Gasca, 2020, chapter 6). The familiar state-space representation is shown in Figure 8 (p. 18). The (square) state matrix, A, in a full model has dimensions equal to the count of differential equations or state variables. The matrices that map control actions to derivatives (B matrix), states to measurable outputs (C matrix), and controls to measurement (D matrix) can be limited in scale based on the problem at hand. In practical power systems the matrices can be enormous, since there might be 10 to 30 state variables associated with each power plant in a positive-sequence representation. Building A is a non-trivial computational exercise, and many dynamic component models are ill-suited for direct linearization. A variety of methods exist (and continue to be developed) to create simplified, but still meaningful, state matrices.

To arrive at a linearized system, one can either build linearized models block by block and assemble them together, or build a nonlinear analytical model with state variables projected into d-q frames. Impedance-based modeling belongs to the former type. In the latter category, model building is based on d-q frames or phasors and requires quite a few techniques: understanding of the physical systems, frame conversion, initial steady-state value assignment, Jacobian linearization, etc. In general, each inverter manufacturer has such expertise. For example, for IBR grid-connected system model building, interested readers may refer to Fan (2018). One useful technique is to model the PLL in the synchronous d-q frame, which requires analysis to

FIGURE 8

State-Space Representation of Continuous-Time Linear System



General state-space input/output block diagram from standard linear control theory. "A" represents the state matrix that defines the relationship between state variables, "B" represents the relationship between control inputs and state variables, "C" represents the relationship between state variables and measurable quantities, and "D" represents algebraic impacts of control inputs on measurements.

Source: Energy Systems Integration Group.

convert its original control format into the format suitable for d-q frame–based modeling. Knowledge of the internal workings of controls is helpful for developing good linearizations. Considering the most dominant internal states (based on participation factor) of different IBRs in a particular oscillation mode might reveal an oscillation pathway different from that obtained from IBR terminal states (or measurements) alone. However, the reality is that many detailed models are proprietary and have been black-boxed. This is an important point for practitioners. Tools that extract input/output relationships, including dynamic frequency scans (discussed next), can be used (with caution) to create state-space models of black-boxed time-domain models.

Static Frequency Scan Methods

A variety of useful information about the frequency-dependent behavior of the grid can be determined with tools that model the grid with static elements. The basic tools in this group represent (most) elements as resistance, inductance, and capacitance (Johansson, Angquist, and Nee, 2011). These tools sweep through frequencies, calculating impedances at each frequency step and building network impedance/admittance matrices. From these, one can extract useful information such as driving point impedances, transfer and coupling impedances, amplification factors, unit interaction factors, and many others. Tools may focus on subsynchronous and supersynchronous, as well as harmonic frequency, ranges. The component modeling is similar for different frequency ranges and target problems but may have application-dependent refinements. While the outputs may be similar, usage of the tools for sub- or supersynchronous oscillations (SSO) vs. harmonic analysis can be very different.

A primary output of these passive frequency scans is the identification of system resonances. When the effective reactance of the entire system including inverters sums to zero, this is a natural frequency resonance. Zero reactance is sometimes termed a series resonance. Stimulation by a voltage at this frequency will result in high currents. The system, when perturbed, will produce oscillations at this frequency superimposed on the instantaneous voltage and frequency waveforms. The sharpness of the resonance is an indicator of severity. For example, a dip in apparent impedance that actually swings to capacitive is indicative that the capacitance responsible for the resonance is in close electrical proximity. The capacitive and reactive elements of the system can also combine to produce effectively an open circuit, that is, the apparent admittance approaches zero. Stimulation by a current injection will result in high voltages, as well as high currents in some elements of the network. Passive frequency scans will identify both series and parallel resonances.

Static frequency scans ordinarily only capture the frequency dependence of passive network elements, whereas dynamic frequency scans, discussed next, capture dynamic transfer functions, usually in the form of impedances or admittances, with device differential equations active. These dynamic tools normally include appropriate mappings between sequence quantities for the network and d-q axis quantities for IBRs and synchronous machines. There are techniques that blur the demarcation between static and dynamic scanning methods. These approaches map nonlinear impedances of active devices back into static scans (EPRI, 2023). Unit interaction factors from static frequency scans check for electrical coupling at known mechanical natural frequencies of subject synchronous machines. They are widely used as the first step in screening for sub-synchronous resonance (SSR).

There are a variety of static techniques for determining metrics that establish coupling or risk between resources and the network. For example, "radiality factor" (CIGRE, 2023a), which establishes the relative topological position of a resource, which in turn advises control stability risk, is based on static topology at power frequency. Similarly, static power tools are typically used to support screening for transient torque and related mechanical oscillation risks.

Because admittances are sometimes used in place of impedances, a new portmanteau, "immittance," has been suggested and is sometimes used in methods that span static and dynamic frequency scans (Sun, 2023).

Dynamic Model Network Frequency Scans

The introduction of dynamics to static frequency scan tools provides a powerful class of analytical approaches that are increasingly central to understanding oscillations due to IBRs. Compared to a static frequency scan in which a passive component does not need to be energized, in order to perform a dynamic frequency scan the device needs to be first configured to work at a specific operating condition. The resulting immittance is based on this operating condition.

Extracting Transfer Function from EMT Time-Domain Simulation Models

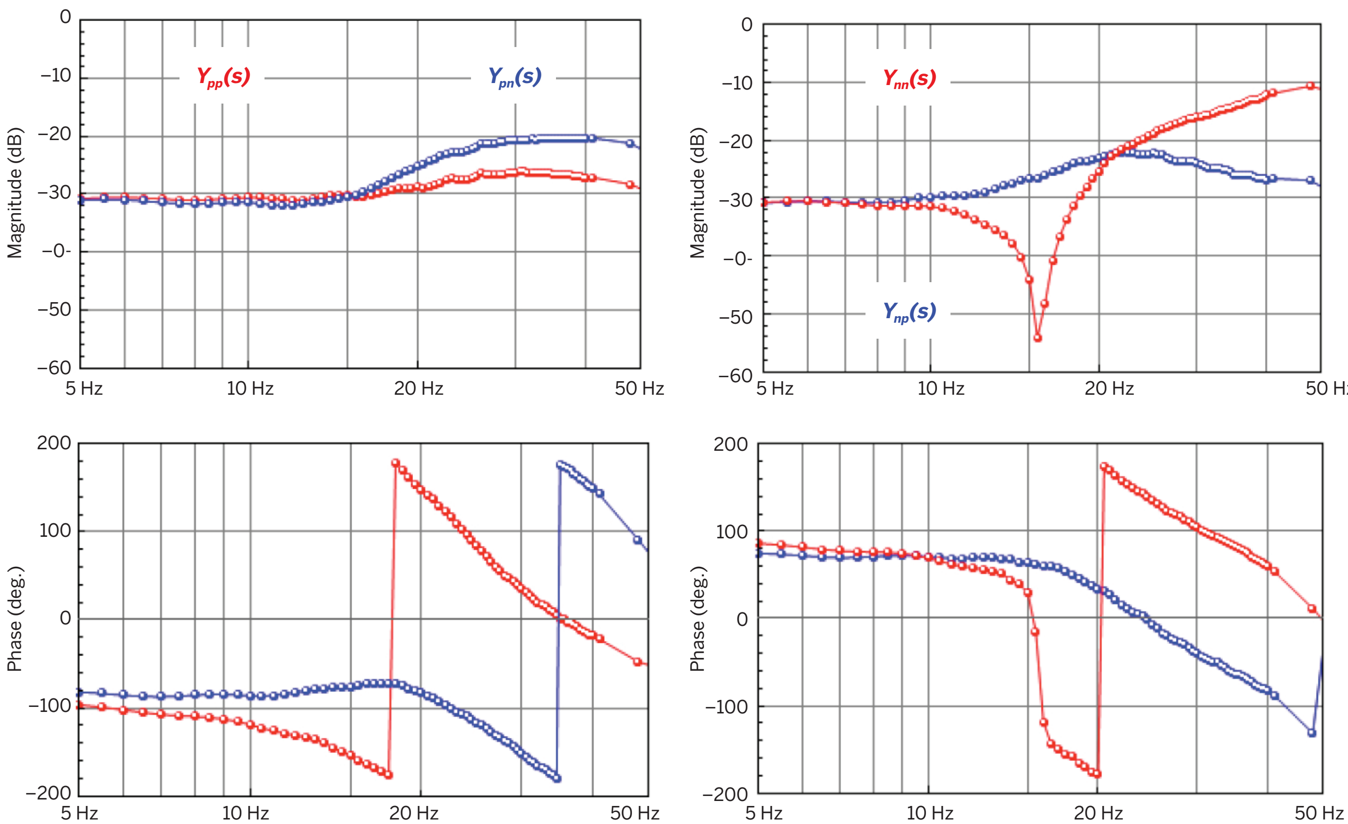
Dynamic frequency scan tools obtain transfer functions of IBRs and the grid at their terminals by extracting frequency-domain measurements directly from electromagnetic transient (EMT) simulation models. In addition to leveraging the higher accuracy of EMT models in comparison to analytical or phasor models, the dynamic frequency scan tools also accommodate real-code vendor-supplied EMT models.

This class of tool, exemplified by the National Renewable Energy Laboratory's (NREL's) Grid Impedance Scanning Tool (GIST) (NREL, 2024), can identify the participation of different IBRs in a particular oscillation mode as well as their positive or negative contribution to the damping of the mode. Dynamic frequency scan tools often measure impedance or admittance transfer functions of IBRs and the grid from EMT models for analyzing oscillation modes using so-called impedance-based stability analysis methods (Shah et al., 2021). Figure 9 (p. 20) shows an example admittance frequency scan of an IBR at a particular operating condition. This scan shows an underdamped resonance mode at 17 Hz inside the IBR, presented in the synchronous time frame. Such frequency scan of an IBR in conjunction with the frequency scan of the network at the terminal of the IBR can be used to quantify the impact of the IBR on system oscillations modes, both frequency and damping (Figure 10, p. 21). Mapping these results to a polar Nyquist plot and applying Nyquist stability criteria is one way of determining whether the system is stable. Sequence impedances Zpp, Zpn, Znp, and Znn can be obtained from sequence admittances Ypp, Ypn, Ynp, and Ynn shown in the figure. However, one needs to invert the entire sequence admittance matrix to obtain the sequence impedance matrix.

However, while dynamic frequency scans using EMT models of IBRs and the network are accurate for the operating condition used in the scan, they can be very time consuming—a scan at an IBR takes around a couple of hours, while a scan of a reasonably large power system with tens or hundreds of IBRs can take a couple of days. Hence, to reduce the number of dynamic frequency scans, some of the following methods are used: either (a) performing scans at IBRs only in weak parts of the

FIGURE 9

Example Dynamic Frequency Scan of the Sequence Admittance of an IBR Showing Severe Resonance at 17 Hz



The positive- and negative-sequence dynamic admittances (red traces, left and right, respectively) show sharp negative-sequence resonance at 17 Hz, indicating the IBR will tend to modulate negative sequence at this frequency. Diagonal terms (blue) have little participation at this frequency.

Source: Shah, Lu, and Modi (2024); National Renewable Energy Laboratory.

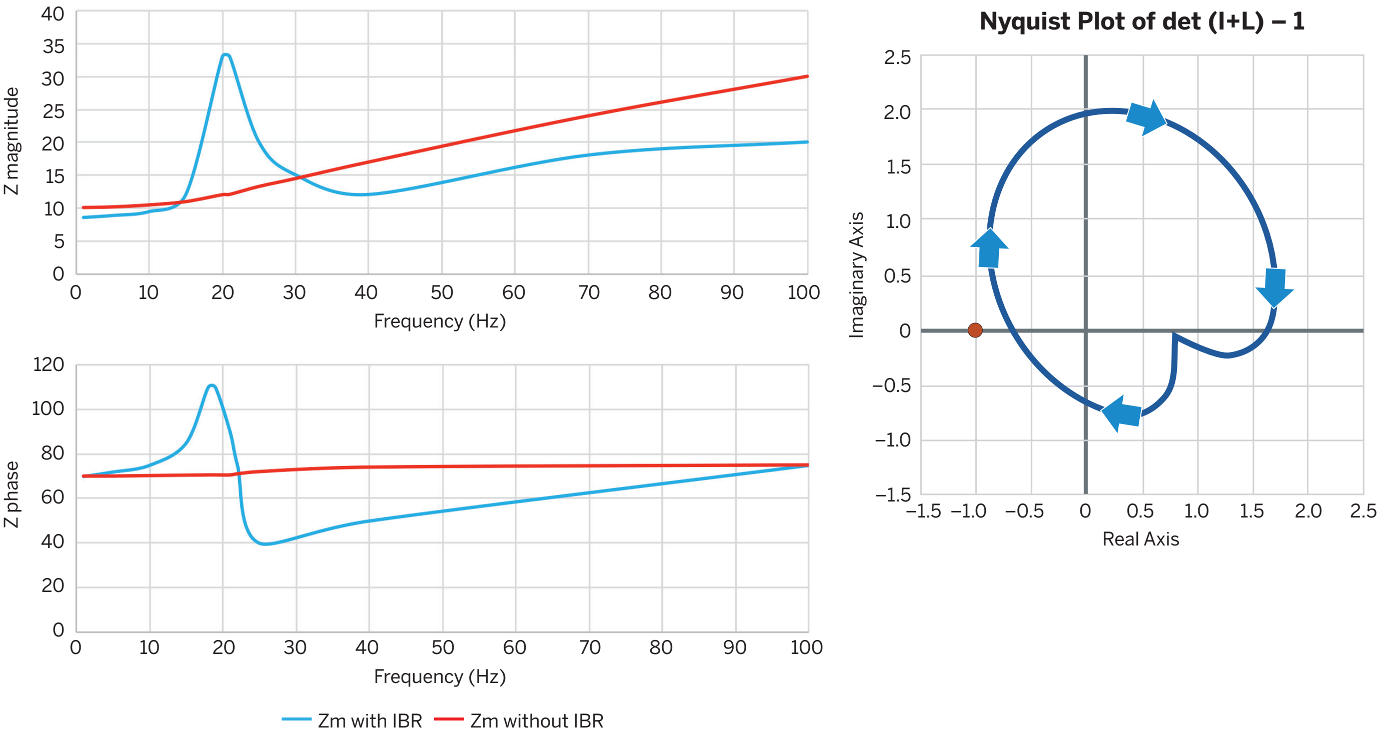
network; (b) performing scans only at IBRs where, and under the operating conditions when, oscillations have been observed in field measurements; or (c) using static frequency scans for networks in conjunction with dynamic frequency scans of IBRs. Each approach carries some risk of missing interactions or other effects. The last method can provide accurate results for scanning the network at the terminals of an IBR if other IBRs are located far enough away that they do not influence the network frequency scan. Scans can provide other types of outputs that are related to admittance, including reactive sensitivities (e.g., dV/dQ(s)) and active sensitivities (e.g., dδ/dP(s)). As noted below, unexpectedly high sensitivities can point toward control-induced oscillations.

An important part of the diagnostic process is to create comparisons. In their simplest form there are pairs of with and without (or before and after) cases. Changing a single feature at a time gives a clearer view of causality than a single case.

As Figures 9 and 10 illustrate, an important part of the diagnostic process is to create comparisons. In their simplest form, like here, there are pairs of with and without (or before and after) cases. Changing a single feature at a time gives a clearer view of causality than a single case. In more complicated situations, for example, where there are multiple IBRs or other resources involved, adding them one at a time, or even creating a

FIGURE 10

Modal Impedance Frequency Scan of Grid Showing the Impact of Adding an IBR



Combined dynamic frequency scans, with and without IBR at the point of connection, showing approximately 19 Hz natural frequency due to the IBR. The corresponding Nyquist plot (on the right) with the IBR shows that the system is marginally stable at the resonant frequency: it does not encircle (–1,0).

Source: Shah, Lu, and Modi (2024); National Renewable Energy Laboratory.

full set of combinatorial cases, can be highly illuminating. Great Britain's National Grid Electricity System Operator recommends these methods (ESO, 2024) for active frequency scans up to 2.5 kHz.

These methods use detailed time-domain simulations, in which the system is perturbed with a periodic (usually sinusoidal) input. Simulations are allowed to reach approximately steady state, and time measurements of a variety of responses are collected. These time signals are then subjected to a post-processing, e.g., a digital Fourier transform (DFT) algorithm, to extract frequency response information. "Diagonal" terms, i.e., responses at the driving frequency, give transfer functions that can then be used in diagnostic and control design. Further, these techniques can reveal off-diagonal information—responses at frequencies other than the driving frequency, that are indicative of systemic nonlinearities, such as saturation. Unexpected saturation of control systems can produce problematic responses.

Performing Dynamic Frequency Scans

The dynamic frequency scans can be performed on any size of power system simulated in an EMT platform with sufficient computing power. Generally, different parts of the network and different IBRs are simulated on different central processing units (CPUs) to speed up the simulation and consequently frequency scans. The dynamic frequency scans are obtained by injecting either series voltage or shunt current perturbations at the point of interconnection of an IBR and the network. Perturbations are injected after the system has reached steady state following initial start-up sequences and transients. To reduce the dynamic frequency scan time, it is recommended to use the snapshot feature to start the simulation from a steady-state point for each frequency point. However, the snapshot feature is not supported by many vendor-supplied real-code dll file–based EMT models of IBRs—this feature can be requested by system operators in the EMT model intake procedure. In addition to the response at the perturbation injection frequency, the response at the coupling frequency is also important for capturing the off-diagonal elements of the second-order impedance/admittance matrix of IBRs and the network. And it is important to properly select the magnitude of perturbation and length of the data capture window for FFT analysis depending on the perturbation frequency. Recent publications have discussed different aspects and a step-by-step process for performing dynamic frequency scans using either EMT simulation models or experimentally on real hardware using a grid simulator (see, for example, Shah et al. (2022)).

The use of detailed, nonlinear component models in EMT allows for evaluation and design across a multiplicity of possible operating conditions. Scans can be done for conditions such as:

- Full/partial load, or count of units in service
- Varied reactive power levels
- Varied perturbation size

Opportunities to do this type of test in the field (on the actual power system vs. a model) tend to be limited but can be very illuminating. The fact that some IBRs have extremely fine, accurate control introduces some options that were historically rare. For example, small signal modulation of reactive power input from an IBR can be done with care. Switching of shunt devices, like capacitor banks, is a common practical way to stimulate real systems for reactive response tests. Coordination with system operators is essential. Unfortunately, tests of active power controls are more difficult; for example, modulation of active power injection (or consumption) tends to be regarded as unacceptably risky for grid operation.

Static Power Frequency Tools

Static power frequency tools are typically based on load flow programs often with additional features. These platforms cover a variety of tools like PV/QV tools, continuation power flows, and even optimizing power flows. It is not immediately intuitive that these tools are relevant to oscillations; however, they have a role particularly in establishing the stress levels of the system when oscillations occur. Specifically, oscillations that occur due to high stress, such as operation in proximity to power transfer limits, tend to have different causality from oscillations that are uncorrelated to stress levels.

The duality between traditional transient stability concerns and traditional voltage stability limit of the PV curves has increased importance in high-IBR systems. The point is illustrated by the three diagrams of Figure 11 (p. 23): an equal area curve, a PV nose curve, and a phasor diagram. Each is used to map a specific operating point. Here an initial pre-disturbance condition is labeled "1." As a system's operating point changes, the point moves. Recognizing this simultaneous change can help with understanding the systemic boundary conditions that tend to enable oscillatory behavior. They are particularly important for oscillations related to synchronization failures.

Methods for Locating the Source of Oscillations

A variety of methods are particularly good for identifying the "bad actor" driving forced oscillations (per the discussion in "Forced Oscillations"). The IEEE Technical Report 110, *Forced Oscillations in Power Systems*, created by its Task Force on Oscillation Source Location, is rich in insights (Chen et al., 2023). Multiple elements of the power system may be observed to be participating in oscillations. Participation is evidenced by significant amplitude swings of quantities connected to those elements at the frequency of the oscillation. These methods help distinguish between cause and effect of participating elements (i.e., "what is the dog and what is the tail?").

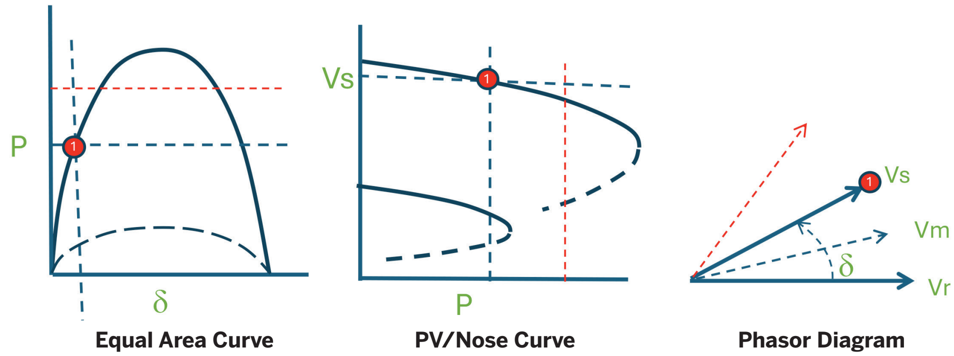
Phasor Measurement–Based Analytics

There are commercial software products available that take phasor measurement unit (PMU) data, specifically, synchrophasor measurements, and turn it into information. Examples of these analytics are increasingly found in operations centers to help with situational awareness and diagnosis of performance issues. An example from the California Independent System Operator, based on the Real Time Dynamics Monitoring System (RTDMS) programs from Electric Power Group (EPG, 2024) is shown in Figure 12 (p. 24) (Agrawal et al., 2024). The Independent System Operator of New England finds that its PMU-based system captures oscillations between about 0.05 Hz and roughly 5 Hz.

By this point it should be clear that recognizing that oscillations are occurring does not necessarily point to the source. Detection methods are relatively mature;

FIGURE 11

Static Power-Angle and Voltage-Power Curves



The duality between traditional transient stability concerns as represented by power-angle curve used for equal area criteria and traditional voltage stability limit of the PV curves has increased importance in high-IBR systems. Each of the three diagrams here is used to map a specific operating point. An initial pre-disturbance condition is labeled "1." As a system's operating point changes, the point moves, for example, toward a post-contingency equilibrium as shown in dashed red. Oscillations that accompany that transition have different characteristics with IBR systems compared to synchronous machines. Recognizing the increased importance of proximity to the end of the PV nose with IBRs can help with understanding stability limits. The behaviors can be highly nonlinear and are particularly important for oscillations related to synchronization failures.

Source: HickoryLedge.

indeed, the user of this document may be here because of them. When there are known oscillatory modes, monitoring can be created/tuned that specifically watches for stimulation of that mode. (Dedicated monitoring can reduce the institutional time delay between the oscillations arising and response actions.)

Location methods, however, are still evolving. These phasor measurement–based software programs may employ multiple algorithmic methods, including those discussed here (Wang and Maslenikov, 2023). Oscillation monitors can have alarm thresholds. While not guaranteed, locations that have high-amplitude oscillations tend to be proximate to bad actors. Experiences in several systems show that the relatively straightforward method of comparing magnitudes of oscillations (e.g., of voltage) at different locations in the system can be quite effective for zeroing in on offending resources.

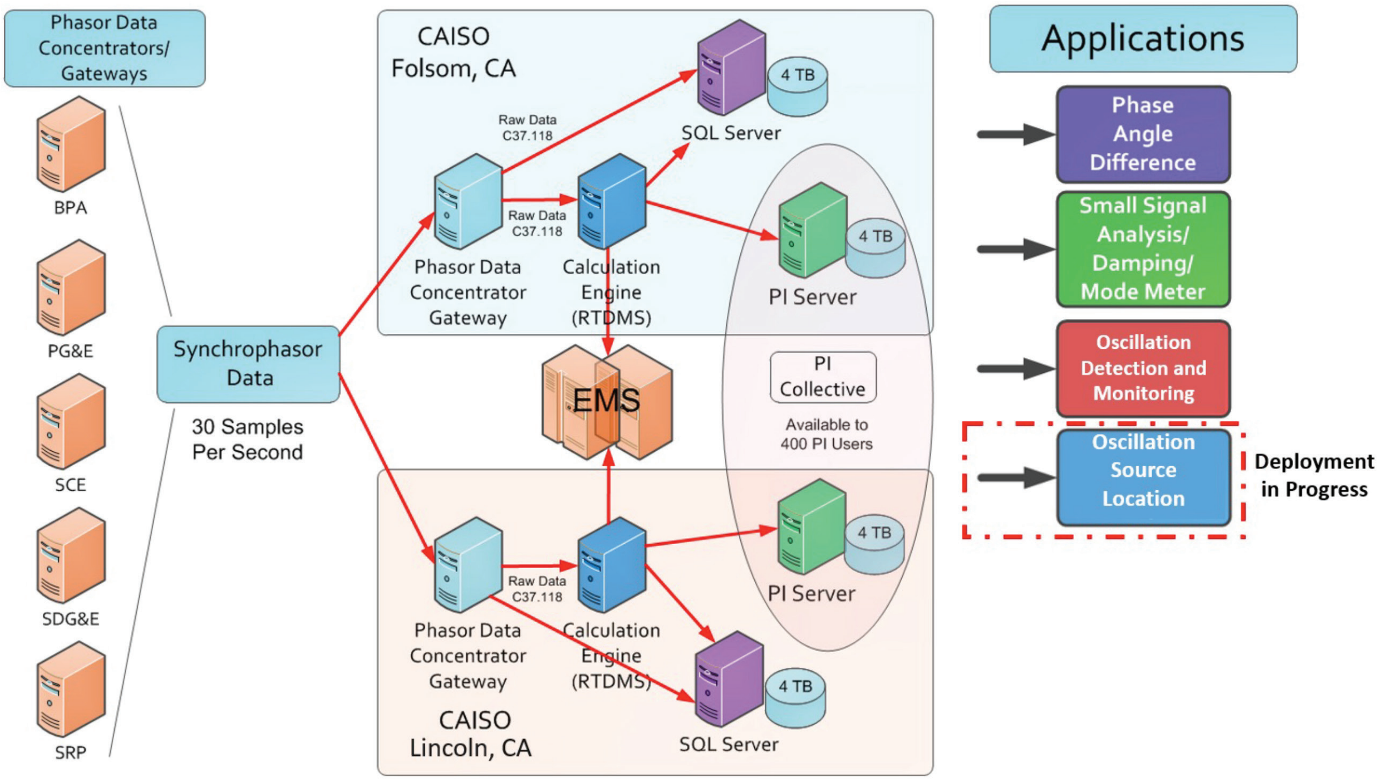
It can be highly informative to compare the behavior of suspected bad actors to that of other resources, especially in the same electrical proximity. It is indicative when some resources show acute oscillations—especially limit-to-limit swings—while nearby resources exhibit limited response. As noted above, sustained zero-damping oscillations are indicative of forced oscillations (i.e., of a single resource). This type of monitoring has notable successes in detecting these and providing actionable advice to system operators.

Checking sensitivities and phase relationships for individual resources is sometimes a straightforward and illuminating diagnostic. Monitoring of Q/V and P/F relationships can show both high sensitivities (an indicator of risk for excessive gains) and poor phase relationships. The cross-plots mentioned above in the section "Angle and Coherency" are an aid to extracting phase relationships from complex time traces. Undue lag in active and reactive response to frequency and voltage, respectively, are warning indicators.

One practical option for diagnosis when multiple installations are involved or in electrical proximity is to compare the response of different plants that are expected to have a similar response to systemic stimuli. The appearance of substantive, unexplained differences in response can sometimes lead quickly to identification of bad actors.

FIGURE 12

Example of Synchrophasor (PMU) Architecture and Applications



This conceptual schematic shows how phasor measurement units (PMUs) in CAISO's member utilities transmit phasor data from around the state to the two CAISO operations centers (Folsom and Lincoln). A variety of data handling and storage functions deliver measured data to stability applications (represented by the boxes on the right) at the Energy Management System. All four applications contribute to operational awareness of oscillations. Notice that "detection and monitoring" (red box) are distinct from "source location" (blue box).

Source: Agrawal et al. (2024); California Independent System Operator.

Mode Shape Analysis

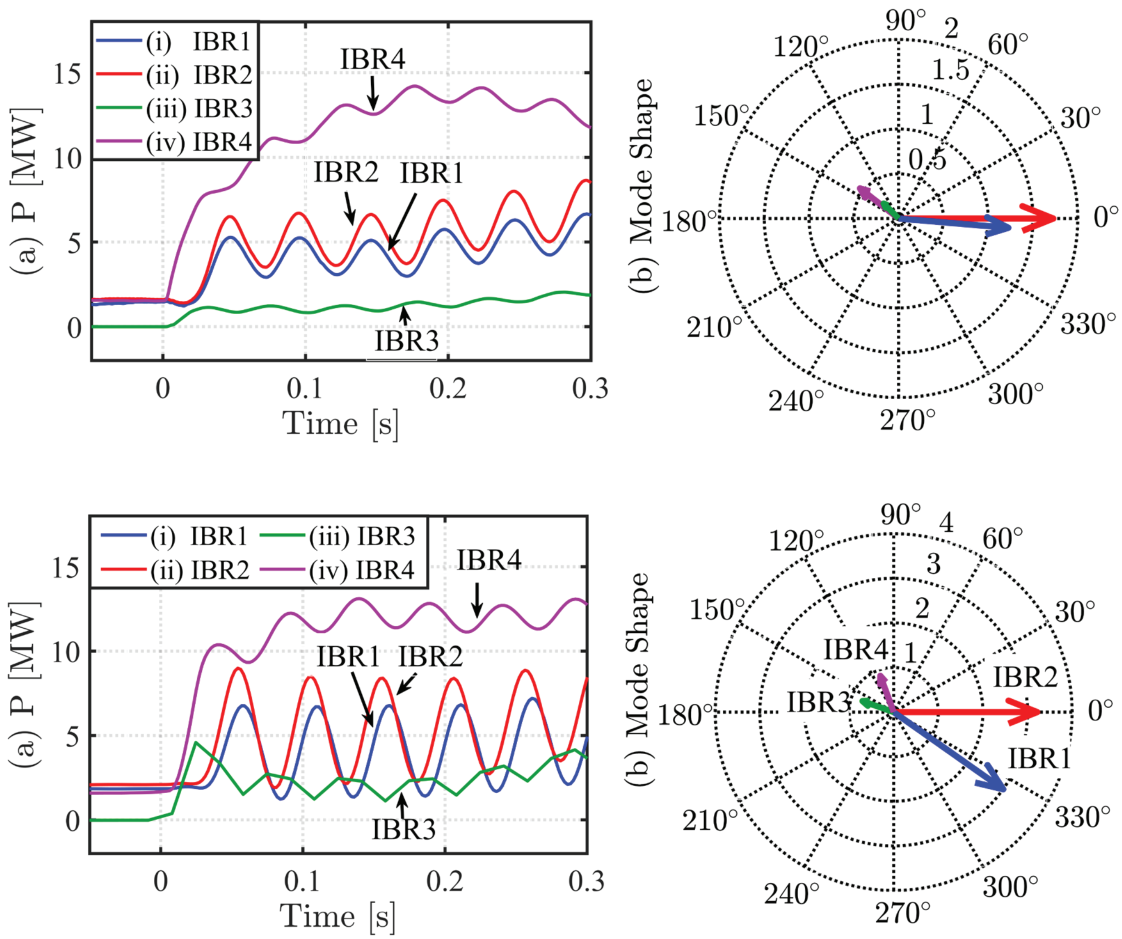
One useful step in the identification of drivers is to examine the magnitudes of oscillations at different locations. Usually those with the largest magnitudes are close to the source. Additionally, mode shape (right eigenvector elements) can be plotted for different buses. Examples of time traces and eigenvectors are shown in Figure 13 (Dong et al., 2023). The time and phase plots are color coded. If two buses far away from one another have mode shapes opposite to each other, this means the oscillation mode is caused by the interactions of the two buses and can be viewed as a differential mode or inter-area mode (Zhang et al., 2022; Fan, 2022). This is the case for IBR 2 (red) and IBR 4 (purple) in the figure. IBR 3 (green) has minimal participation, as evidenced by the small amplitude. Conversely, if two IBRs have mode shapes in similar directions, then this mode is an aggregated mode, as shown for IBR 1 and IBR 2. The upper and lower portions of Figure 13 show how the eigenvalue plots can be useful in comparing the results of simulations and field measurements.

Dissipating Energy Flow Method(s)

There are a variety of relatively new methods emerging that use grid measurements, often at multiple locations in an affected grid, to identify the source of energy driving system oscillations. These techniques, under development for a decade or more, are now in use in some grid operations centers.

FIGURE 13

Mode Shape Analysis (Measurements and Simulation)



Examples of time traces and eigenvector mode shapes. The time and phase plots are color coded. If two buses far away from one another have mode shapes opposite (~180°) to each other, this means the oscillation mode is caused by the interactions of the two buses and can be viewed as a differential mode or inter-area mode. This is the case for IBR 2 (red) and IBR 4 (purple). IBR 3 (green) has minimal participation, as evidenced by the small amplitude. Conversely, if two IBRs have mode shapes in similar directions, then this mode is an aggregated mode, as shown for IBR 1 and IBR 2, which are largely coherent. The upper and lower portions of the figure show how the eigenvalue plots can be useful in comparing the results of simulations and field measurements.

Source: Dong et al. (2023); National Renewable Energy Laboratory.

The dissipating energy flow (DEF) techniques have been shown to be quite effective at locating the source of oscillations when there are forced oscillations, particularly those originating from synchronous resources. Oscillations at frequencies roughly in the range of 0.1 to 3 Hz have had some notable locating successes in real, operational situations. Operations center grade software is available (Wang and Sun, 2017). Bad actors, such as malfunctioning governors, have been spotted by these techniques. DEF may give wrong answers for oscillations caused by automatic voltage regulators (AVRs). A few research papers show that DEF methods require a few conditions to be successful: the oscillation source must be able to be viewed as a voltage source, not a current source, and the source impedance should not be passive (Chevalier et al., 2019; Fan, Wang, et al., 2023). The techniques are good for finding some types of bad actors, which is a critical part of forensics, though other complementary techniques may be needed to determine what is happening and how to mitigate the problem.

While these techniques show promise and have been used effectively in practical situations, they are still developing. To date, some researchers report that their efficacy for use in the diagnosis of *inverter-driven* instabilities appears limited, while others report success. Recent collaboration between the University of South Florida and the Independent System Operator of New England on IBR oscillations shows that the DEF methods fail to identify any IBR oscillations created in the EMT testbeds (Fan, Wang, et al., 2023). Limitations in PMU sampling can also limit DEF methods' efficacy for higher-frequency oscillations. However, NREL reports success with using DEF methods to diagnose IBR-driven instabilities, and the Australian Energy Market Operator is moving forward with implementation in its control center based on good preliminary tests (AEMO, 2023b). Generally, it appears that these methods are better suited to zeroing in on problems for which there is truly a single malfunctioning resource driving forced oscillations. Their use for more complex phenomena, for example, interaction between multiple resources at different locations on the grid, is at the development stage.

Sub/Supersynchronous Power Flow Methods

The harmonic power flow method is a straightforward method to examine active power flow and reactive power flow at a certain oscillation frequency to detect the source. This concept is the same as in the 60 Hz fundamental component, showing active power flowing out if the voltage phasor and the current phasor (exporting direction) have a small angle separation, and reactive power flowing out if the current phasor lags the voltage phasor. Care needs to be taken to examine at which frequency to apply the method. In particular, "mirror" frequency phenomena with IBRs should be taken into account. For example, a 20 Hz oscillation mode caused by a misbehaving phase-locked loop (PLL) manifests as 40 Hz and 80 Hz modes in the phase currents (as per the discussion in "FFTs and Related Algorithms" above). It is suitable to apply a single-mode harmonic flow calculation in the d-q frame.

Time-Domain Simulation with Positive-Sequence Phasor-Based Tools

Time-domain tools that are based on positive-sequence phasor representation of the power system have historically been at the core of power system dynamic analysis, including stability issues with oscillations. There are many commercial versions in wide use. Models of IBR resources have evolved over the past 20 years and generally have good fidelity. Available models must meet several requirements. Model functional objectives include accuracy, numerical stability, ability to handle reasonable integration time steps (usually ¼ of a cycle), simplicity, transparency, and generality. These objectives are often in conflict, with resultant models necessarily being a compromise. The main issue of concern here is that there are inherent limitations with phasor analysis that preclude precise replication of very fast and/or unbalanced behaviors. Consequently, the utility of positive-sequence phasor-based tools for analysis of oscillations drops with increased frequency (i.e., fast oscillations) and when the phenomena being considered depend upon precise behavior of individual phase quantities (anecdotally) with reduced system strength. While there is no firm or agreed-upon upper bound on frequency for meaningful positive-sequence phasor simulations, any phenomena faster than about 3 to 5 Hz should be regarded with caution that increases with frequency.

Time-Domain Simulation with Three-Phase, Point-on-Wave Tools

EMT simulation provides two fundamental advantages compared to positive-sequence phasor-based simulation:

- All three phases are represented, including mutual couplings between phases.
- Inductances and capacitances are represented by differential equations, and transmission lines and cables can be represented with distributed-parameter models, allowing the simulation of traveling waves.

Differential equation representation of network elements, even lumped equivalents of lines, cables, and transformers, greatly increases the upper limits of frequency for which simulations are meaningful. The introduction of traveling wave representations provides simulation frequency bandwidth that is theoretically limited only by the choice

of time step. This overcomes the limitations of positive-sequence phasor-domain tools, which must assume a fundamental frequency for phasor calculation and are inherently limited to relatively slow phenomena and control performance. The simulation bandwidth and three-phase representation allow network models to be electrically correct at any frequency and require much less approximation of control algorithms in IBR model development. It is common to use "real-code" EMT simulation models that employ the actual software of IBR (and other device, e.g., STATCOM) controls.

The increased capability of EMT simulation comes with a substantial increase in computational burden. It is typical to use transmission network models of limited extent to allow simulations with reasonable run times. However, it often requires significant judgment to identify the elements or characteristics of the network that should be included in order to represent the phenomena of interest adequately. For example, it is important to ensure that any reduction of model detail does not substantially detract from accurate driving point impedances within the frequency range of interest at the IBRs under investigation. Nearby system elements may also introduce important dynamics that should be included if they are important to the IBR under investigation. The use of EMT simulation requires a different expertise than for fundamental-frequency tools, including skills required to accurately estimate undocumented network component characteristics (such as transformer saturation characteristics, frequency-dependent damping, etc.).

EMT models of inverters can either use detailed switching representations of the power electronic bridges or use "average source" (a.k.a. "averaged switch") models. The latter replace the switching bridges with voltage sources having magnitude and phase as determined by the inverter's controls and use simulation tricks to mimic gate blocking. The high switching frequency of modern inverters (several kHz or more) requires very short simulation time steps and special interpolation algorithms if a switching model is used. Well-designed average source models are suitable for most dynamic performance investigations, but are not appropriate for the evaluation of harmonic generation above the inverter control bandwidth or certain special instances of interaction between network harmonic impedances and control vulnerabilities.

Simulators using massive parallel processing are available that allow EMT simulation in real time. This allows actual hardware to be connected to the real-time simulators to perform simulations. There are two general classes of hardware-in-the-loop simulations. With control-hardware-in-the-loop (CHIL), the actual controls (often including the actual control cabinetry) are interfaced to the real-time simulator, which provides all network representation as well as the electrical components of the inverters. When a real-time simulator is coupled with controlled sources (power amplifiers and loads), simulation with actual inverter units, including the power electronics and output filters, is possible. These are usually termed power-hardware-in-the-loop (PHIL) simulations and tests. IEEE provides extensive guidance on the use of PHIL and CHIL simulations in its "Recommended Practice" document (IEEE, 2024).

Analysis of oscillations is an important subset of problems for which EMT simulation can be essential. As noted above in the section "State-Space Methods," extraction of state-space models using time domain is one key piece. But further, EMT time simulations that have the ability to capture nonlinear dynamics that can contribute to oscillations are essential in many practical cases.

Hybrid Tools

Hybrid simulation tools have also been developed, combining EMT representation of the local network and positive-sequence phasor-based dynamic simulations of the remainder of the network. Compared with a static impedance representation of the external system, the positive-sequence phasor-based dynamic representation allows more accurate modeling of lower-frequency phenomena that are driven by network elements extending beyond what would be normally possible to simulate in EMT alone. Because the external positive-sequence phasor-based model only represents fundamental-frequency impedance characteristics, the extent of the detailed EMT model determines the frequency-dependent driving point impedances at the IBRs of interest, as well as the extent to which the "fast" behavior of any nearby IBR devices may be accurately represented. This concern applies to both SSO and harmonic phenomena.

Appropriate representation of non-fundamental impedance characteristics becomes increasingly necessary for accurate investigation of higher-frequency oscillations. Specific care must be exercised on where to place the boundaries between EMT and positive-sequence phasor-domain models because these boundaries introduce a dynamic when the transformation is applied to EMT waveforms to go into the phasor domain.

Tools Applicability

The correct selection of tools for analysis of observed phenomena is critical to successful diagnosis of oscillations and identification of countermeasures, and Table 1 (p. 29) provides guidance on what tools are best used for what phenomena. The rows are for the tool and are grouped to reflect the discussion above. Columns are for the phenomena and correspond to those of the screening matrix and detailed discussions below. Color coding of the cells are as follows:

- **Green:** Primary analytical tool. This is a standard tool for establishing causality of an oscillation and/or designing fixes for the phenomenon. The diagnostician is likely to need it.
- **Light green:** Supporting analytical tool. This tool can normally be used, either to refine or verify results from the primary tool. Some caution may be required in that this class of tool may not always be suitable for analysis of the phenomenon in question.
- **Grey:** Tool is inapplicable or rarely used. The use of this tool is rarely helpful in determining causality or mitigation of this phenomenon. Its use may be misleading.
- **Yellow:** Tool is not normally valid (or valid only under limited circumstances). This tool is usually invalid for analysis of this phenomenon, but may be used with considerable caution or as an adjunct to other tools.
- **Red:** Tool is not valid. This tool is contraindicated for analysis of this phenomenon. Its use is normally inappropriate and may produce misleading results.

TABLE 1

Tools Applicability Matrix

Tools		Causality/Failure Modes															
		Sub/super Synchronous Oscillations				Voltage Control–Induced Oscillations			Angle (Transient) Stability–Induced Oscillations			Frequency or Active Power Control–Induced Oscillations			Harmonic Oscillations	
Class	Subtype	Traditional SSR	Control interaction with network (SSCI)	Torsional interaction with IBRs (SSTI)	Ferro-resonance with nonlinear elements	Voltage control mistuning	Voltage control malperfor-mance	PSS and torque-related mistuning	Incipient voltage collapse	Large signal transfer limit	FIDVR or other load/DER failure	PFC/ governor mistuning	Inter-regional power oscillations	Market services miscoor-dination	Within plant	Between plants and/ or network elements
State space	Eigenvalues															
	Root locus plus															
	Eigenvector participation															
Network	Static frequency scan	a	a													
	Dynamic frequency scan	b														
	Static power frequency					c	c									
	Harmonic power flow															
Locating tools	Dissipating energy flow															
	Sub/super-synchronous power flow															
	Mode shape analysis															
Positive-sequence phasor-based time	Large-scale commercial															
	Specialized phasor based												g	g		
EMT						d			e				f			
Hybrid																

Primary analytical tool · Supporting analytical tool · Inapplicable or rarely used · Not normally valid (or valid only under limited circumstances) · Not valid for this phenomenon

This table provides guidance on what tools are best used for what phenomena. The rows are for the tool and are grouped to reflect the discussion above. Columns are for the phenomena and correspond to those of the screening matrix and detailed discussions below.

Notes: DER = distributed energy resources; EMT = electromagnetic transient; FIDVR = fault-induced delayed voltage recovery; PFC = power frequency control; PSS = power system stabilizer.

Source: Energy Systems Integration Group.

(See page 30 for extended key and footnotes.

Table 1 Extended Key

- Primary analytical tool
  This is a standard tool for establishing causality of an oscillation and/or designing fixes for the phenomenon. The diagnostician is likely to need it.
- Supporting analytical tool
  This tool can normally be used, either to refine or to verify results from the primary tool. Some caution may be required in that this class of tool may not always be suitable for analysis of the phenomenon in question.
- Inapplicable or rarely used
  The use of this tool is rarely helpful in determining causality or mitigation of this phenomenon. Its use may be misleading.
- Not normally valid (or valid only under limited circumstances)
  This tool is usually invalid for analysis of this phenomenon, but may be used with caution or as an adjunct to other tools.
- Not valid for this phenomenon
  This tool is contraindicated for analysis of this phenomenon. Its use is normally inappropriate and may produce misleading results.

Table 1 Footnotes

a Static scans include unit interaction factor (UIF), for sub- and supersynchronous oscillations.

b Linear analysis for conventional SSR tends to be the primary tool, with EMT time simulations providing verification.

c Static load flows are useful for referencing "reasonableness" of operating conditions for most issues. However, voltage-related problems are particularly condition-sensitive.

d Occasionally this is the primary analytical tool.

e In some cases, EMT is the primary analytical tool, such as for inverter-driven voltage collapse, or IBR mitigation for voltage collapse. But only after initial assessment with simpler tools.

f This one might be rarely used, as EMT requires highly equivalenced models for big systems which are challenging for accurate frequency modeling.

g Extended-term stability programs that are capable of simulating periods of multiple minutes and that include appropriate component models can be used.

Simulation Credibility

With the background information on measurements, signal processing, and tools now presented, the user may consult the overall process flow presented in Figure 3 (p. 8) for the final preparation necessary before diving into the core activity of determining causality for oscillations. Here we are specifically concerned with vetting simulation results.

Whenever oscillations (or other unacceptable or unexpected behavior) are observed in time simulation results—whether planning or diagnostic simulations—the practitioner should consider the possibility that the simulation departs substantively from reality. Inspecting simulations with a skeptical eye can avoid a great deal of wasted time spent chasing phantoms.

This section presents a sequence of steps that will help to expose simulation artifacts, or, alternatively, to clear simulations for diagnostic work on the oscillations they exhibit. The primary focus here is for planning simulations, depicted in the process box "Assessment of planning simulation credibility" in Figure 3 (p. 8). However, simulations run for diagnostic purposes—for example, to reproduce and understand oscillations observed in the field—are subject to similar problems. They need to be checked by essentially the same mechanisms that are applied in the initial planning simulations.

The processes outlined here are aimed at helping the diagnostician avoid some relatively common, simple mistakes. The spectrum of problems with simulations is broad, ranging from simple errors in mechanics to nuanced misuse or misalignment of models and tools with the phenomena being analyzed. Selection of the correct tool or simulation platform is addressed in the section "Tools Applicability." A glossary with abbreviations and definitions is provided at the end of the guide.

Model Nomenclature

Issues surrounding models are core to establishing the credibility of simulations. The seemingly simple question "what is a 'model'?" is in practice surprisingly complex. There are many opportunities for confusion and ambiguity. We are generally concerned with simulating a power system that includes representation of the grid and specific equipment connected to that grid. To that end, we create an assembly of parts that is somewhat hierarchical. At the highest level we have a *system model*, which has a *network model* with all the static network elements like lines, transformers, etc. represented, and *equipment models* of all the relevant dynamic devices like inverter-based resource (IBR) plants, synchronous generators, flexible AC transmission system (FACTS) devices, etc. that are connected to the grid. For many types of simulation, particularly the time simulations that are the primary focus of this section, the entire system model must be energized and operating at conditions relevant to the study at hand. Normally, establishing this *initial condition* for the system model is a critical step.

Equipment models normally have several key attributes, each of which needs to be correct to yield credible simulations. We will couch this in terms of a large IBR plant, but the concepts generalize. First, the equipment needs to be connected to the grid. For an IBR plant, there is usually at least a transformer, and there may be a collector system and other switchable network elements like capacitor banks. These parts normally end up as part of the *network model*, even though they are specifically part of the equipment. The *dynamic model* of the equipment includes representation of everything necessary to capture its behavior of interest, in terms of impact on and response to the network. In most situations, the main part of the dynamic model is the device model. For IBRs, the *device* *model* includes representation of the brains that gather measurements from the network, make decisions on what the inverters should do in response, and implement those actions at the network interface. For positive-sequence phasor-based simulation, the interface to the network is through a controlled current or voltage source. In more complex plants, the overall dynamic model can include interface or instructions to other network elements (e.g., operating switches) or to other dynamic models.

The device model itself normally has a structure built of *components* that are linked together—sometimes by the user and sometimes within software. For example, an IBR plant device model may have: (a) a voltage control component, (b) a primary frequency response control component, (c) a current-limiting component, (d) a fault-ride-through control component, (e) a phase-locked loop component, and so on. Communication latency, if modeled, may be a component of the device model or included in the overall dynamic model. Each device or component model has two important, distinct features. The first is a fixed *structure*. In most cases this structure is reflected in a block diagram containing paths for signal inputs and outputs, blocks for dynamics (i.e., gains and time constants), limiters, and a variety of different logic. The way the components are linked together is part of the device model structure. Normally, the structure is fixed for the diagnostician user. The exception is when the user is defining the model themselves—a "user-defined model" (UDM). The second feature is the parameterization, i.e., the input data. The user is expected to provide these parameters, and a significant part of the forensic process involves manipulating them. In this context, we make a distinction between the *parameterization* and the *initial conditions*. While there are exceptions, the normal expectation is that the model parameters are fixed for a known, specific equipment model, whereas the initial conditions define how the equipment is operating at the start of the analysis. Initial conditions typically include quantities like the active and reactive power level, terminal voltage, control mode, etc.—anything that is important to defining operation.

Initial Credibility Screening of Equipment Models

Credible equipment models are a necessary precondition for producing credible simulations. In the past, there were well-established (e.g., IEEE) model structures for synchronous generation and other equipment. Questions of model credibility then centered on whether the parameterization (i.e., input data) was correct. But with the emergence and rapid evolution of new resources, particularly IBRs, it is not only the input data, but the entire device model structure itself, that warrant scrutiny.

Diagnostic Questions for Equipment Models

The following groups of questions will help the diagnostician weed out non-credible equipment models. They are posed so that a negative answer should trigger closer inspection. In lieu of describing *why* negative answers are of concern here, guidance is provided in the section below on "Simulation Failures."

- Assessing whether the **dynamic models** (differential equations, block diagrams, device models, component models) are **defective**
  - Are all time constants at least two time steps long?
  - Is the maximum specific time step needed to run IBR models provided by the original equipment manufacturer (OEM) reasonable, e.g., at least ¼ cycle in positive-sequence phasor analysis?
  - Do simple equipment model acceptance tests (e.g., in a single-machine-infinite-bus (SMIB) test set-up) such as step change, setpoint ramp test or voltage/frequency, or MW/MVAR setpoint changes yield reasonable results?
  - Was the model developed for and is it appropriate for use in this tool or platform?
  - Is the simulation free of obvious limit cycling that can be traced back to one source?
- Are the **dynamic models appropriate**? Regardless of whether a generic/library model or an OEM-supplied, equipment-specific model is used, the user must establish whether the device model is suited to analysis under these conditions.
  - Is the strength of the (post-disturbance) system within the capability of the model? Many representations, especially generic models, will decline in accuracy as the system is weakened.

– Is the model able to accurately represent the specific phenomenon you are trying to evaluate? For example, the ability of an IBR to ride through a fault is critically dependent upon the details of synchronization controls, which are hidden in an EMT model and may be missing entirely in a phasor model.

– Does the model include the control and protection functions relevant to the phenomenon being analyzed? With the parameters that represent this installation?

– Are the models of those devices suitable for simulation of the post-disturbance condition? For example, for positive-sequence phasor-based simulation, are fundamental frequencies within the bandwidth of the model (e.g., ±3 Hz)?

– For OEM-provided models, was the model written and parameterized in a way that is meaningful and correct for this specific application or installation?

– OEM-provided IBR models may be tuned to work in a specific control mode (such as active power priority), while a different control regime (such as reactive power) may not work. Does the model have working representation of the mode of interest in the simulation?

– Is the device model sensitive to grid conditions? For example, do the observed oscillations change for variation in X/R or short-circuit ratio (SCR)? (See the section "Single-Machine Infinite-Bus Tests.")

Initial Credibility Screening of Simulation Results

Populating a simulation with credible models is necessary but not sufficient to ensure credible simulations. The previous section is intended to surface problems with specific devices or installations, for example, to check on whether a participating IBR power plant is modeled correctly. Many of those tests, as noted, can be performed on SMIB-type test set-ups. This section assumes simulation results that are systemic. There are still "model" issues to be addressed, but they may cut across multiple devices, network elements, and complex interactions. The exact question of whether the "model" or the "simulation" is bad is less clear.

Diagnostic Questions for Simulations

The following groups of questions will help the diagnostician weed out non-credible simulations. They are posed so that a negative answer should trigger closer inspection. The idea for this screening is not necessarily to find that simulations aren't accurately reflecting physical behavior, but rather to make sure there is nothing overly wrong or nonsensical. The section "Simulation Failures" presents some insights and methods for confirming and fixing simulation problems that might be surfaced by negative answers here.

- Whether the **initial condition** being simulated is reasonable
  – Are the initial, pre-disturbance voltages and power flows within credible bounds?
  – Are controls saturated before the disturbance? If so, is this realistic?
  – Does a flat (or no-disturbance) run of the simulation model yield meaningful results?
- Whether the oscillations in the simulation results are due to numerical (integration) instability. (This may involve simulation software **platform settings** or simulation control problems.)
  – Are the oscillations slower than two times periodicity of the integration time step?
  – Are the oscillations unaffected by small changes in the simulation time step?
  – Are the oscillations unaffected by reasonable changes in the convergence tolerance? (They should be unaffected by these small simulation control changes if they are real.)
  – Are the plotted signals at every time step or sampled sufficiently frequently and at odd multiples of the time step to avoid aliasing?
  – If high-frequency oscillations are initiated by opening an inductive branch, have dampers or other numerical mitigation been included? (applicable to EMT simulations using certain programs)
- Whether the oscillations are due to **missing discrete model** elements
  – If the oscillations are due to one or more synchronous machines slipping poles, is the appropriate

loss-of-synchronism protection included in the model?

  - If the oscillations are due to meaningless switching operations, is the logic complete? (For example, are cap banks banging in and out repeatedly, with no hysteresis or other preventative functions included?)
  - If oscillations are of substantial amplitude, are protections relevant to the oscillations (e.g., very high voltages) modeled?
  - Do the oscillations persist after disabling the suspect elements or the suspect portion of the network and re-running the simulation ?

- Whether simulation results have defects that make **results meaningless**
  - Are magnitudes of network measurements, especially voltage and current, within bounds that can be rationally explained?
  - If there are single-time-step voltage spikes, are they physically meaningful?
  - If there are single-time-step current spikes, are they physically meaningful?
  - For discrete tripping actions based on sensitive signals such as frequency or transient overvoltage, are input signals plausible such that the consequent protective discrete actions can be trusted?

- Whether the network (grid, algebraic elements) is **defective** (i.e., nonsense)
  - Is the network free of zero or near-zero impedance elements?
  - Is the network free of large or non-sensical negative impedance elements (e.g., due to equivalencing, rather than to a representation of series compensation)?
  - Is the network free of any fictitious equivalent voltage sources in the network that may be a by-product of network equivalencing that can substantively impact the oscillations observed?
  - Do transformers include saturation modeling with reasonable representation? (applicable to EMT)
  - Is the network free of unreasonable resistances of network elements like lines, cables, transformer windings, generator windings, etc.?
  - Does the simulation include appropriate representation of damping of elements like power transformers, lines, cables, and shunt capacitances for the frequency range of interest?

For any "no" answers, the user is directed to the section "Simulation Failures."

Overlap of Credibility Testing and Diagnostic Investigation

Many of the steps necessary to establish credible equipment models and system simulations are themselves valuable for both initial causality screening and detailed assessment and countermeasures. The battery of tests described in the sections "Equipment Model Fidelity" and "Network Model Fidelity" below provide insights toward diagnosis of oscillations. These tests, when run a priori, that is, at the planning or model acceptance testing stage, can help establish whether equipment performance is acceptable. A recent document by the National Grid Electricity System Operator provides useful guidance, describing a set of model acceptance tests (ESO, 2024).

Initial Assessment

The initial assessment stage of Figure 3 (p. 8) is intended to surface likely causes to the observed oscillations and help the diagnostician proceed in a focused fashion toward detailed assessment. Before this process is begun, simulated oscillations should have passed the simulation credibility screening in "Simulation Credibility" above. Now, with initial measurements as discussed in the section "Field Measurements and Observations" in hand, the diagnostician should consider the following questions:

- Do you have the right information/measurements?
- What needs to be measured, and how?
- What behaviors, signatures, and clues do you look for initially?
- How do you use that information to select one or two likely causes of the oscillation for further investigation?

The process of identifying the cause of an oscillation depends heavily on the answers to a set of initial diagnostic questions. This approach is similar to that for diagnostic problems in other fields that tend to defy rigid proscriptive processes—for example, it has many similarities to the medical process of disease diagnosis. There is room for intuition, recursion, and judgment on the part of the diagnostician.

First, we present a set of high-level screening questions, designed to surface and quantify symptoms that will point toward causality. Then, a causality screening matrix is offered as a tool to help with sorting through the answers. The desirable outcome of this process is the identification of one candidate (or a couple) that will be subjected to more detailed investigation. The diagnostician may be unable to identify possible causality, which could point to the need to collect more measurements and other data. (A glossary with abbreviations and definitions is provided at the end of the guide.)

High-Level Diagnostic Screening Questions

The following questions are intended to help guide the initial investigation of observed oscillations, and they correspond to the questions listed in the screening matrix in Table 2 (p. 39). They are brief, and the experienced practitioner will recognize that many carry considerable weight and nuance for some classes of phenomena. Some questions are systemic, while others are more applicable to an individual device (e.g., a single inverter-based resource (IBR) plant) that may initially appear to have a high level of participation in the observed oscillations.

The diagnostician is unlikely to be able to answer all the questions, and answers to many will be less than definitive ("well, it kind of looks like XYZ..."). Diagnosis will tend to follow threads of evidence. The diagnostician will likely need to return to earlier steps, particularly when it appears that more information or measurements are needed. The inability to answer too many questions is indicative of the need to gather more information. However, in some cases the diagnostician may be faced with an urgent situation, requiring some immediate action. Consequently, at this stage of diagnosis it may be necessary to proceed with incomplete information, making provision for recursion when more information (and time) is available.

The questions below serve two functions. First, in order to answer them, the diagnostician is directing their attention at physical characteristics and specific behaviors that will help determine causality of the observed oscillations. Second, the answers feed into the causality screening matrix that immediately follows the questions.

- **Frequency of oscillations:** At what frequency(ies) are they observed?
  - Are frequencies relatively fast for system dynamics (above roughly 3 Hz up to several hundred Hz)?
  - Are frequencies relatively low (below about 3 Hz)?
  - Are frequencies very low (below about 0.1 Hz)?
  - Are frequencies integer multiples of fundamental, or are they above about 2 kHz and not necessarily integer multiples of fundamental?
- **Participation:** What generation and other resources are oscillating?
  - Are mainly IBRs oscillating? Grid-following only?
  - Are synchronous machine speed and/or reactive power oscillating?
  - Do loads and/or distributed energy resources appear to be a significant factor? (For example, is this related to fault-induced delayed voltage recovery (FIDVR) or other load peculiarities?)
  - Are the oscillations observable in area control error (ACE) signal? Are automatic generation control (AGC) systems responding?
  - Did markets or other system-level economics react?
- **Phase relationships and coherency** (this is closely related to "participation")
  - What is the phasing across signals? (For example, are P & Q swings in phase or anti-phase? Etc.)
  - What is the phasing of similar signals (e.g., angle) across geographical or topology distances?
  - Are individual IBRs/resources oscillating against the rest of the system?
  - Are small groups of resources that are in close proximity oscillating together and against the rest of the system?
  - Are large(r) coherent groups oscillating against other large groups?
- **Signals:** What are the characteristics of the distortion from fundamental frequency?
  - In what signal is the oscillation dominant? (e.g., voltage, power, etc.)
  - Is there evidence of limit cycles? (e.g., exactly zero damping, square signals, clipping, triangle waves, etc.)
  - Are there symmetrical side bands around fundamental frequency?
- **Grid attributes:** What are the characteristics of the grid near where oscillations are of greatest amplitude or where they are known to be originating?
  - Is the topology radial and weak?
  - Is there a low first natural frequency?
  - Are there series capacitors nearby?
  - Are there shunt capacitors nearby?
  - Are there HVDC converter stations nearby?
  - What else is nearby? In particular, are there other large IBR or otherwise unique elements that can drive the oscillations present? Specifically, are there elements such as static VAR compensators (SVCs), big, highly dynamic and/or power electronic–interfaced loads, arc furnaces, etc.?
- **Operating conditions:** What are operating conditions when oscillations occur?
  - Was the generator power high or low? (E.g., sub- or supersynchronous oscillations (SSO) are more likely at low wind speed for wind turbines and traditional subsynchronous resonance (SSR) more likely at low power; some other control problems are more likely at high power.)
  - Was the power transfer level on the grid high?
  - Was the voltage healthy? If not, where was it poor? Are the reactive flows sensible?
  - What time of the day did the oscillations occur? (For example, whether it was day or night may help rule out or otherwise identify the contribution of PV plants or their control modes.)
- **Stimulus:** What stimulated the oscillations?
  - Did the behavior start spontaneously or start in response to a small perturbation?
  - Was there a topology change? In particular, did the system get weaker, or were power flows substantively altered? Did the system step to a condition of substantively higher loading stress? Did the oscillation

extinguish following a topology change? Was there a sudden change in a participating IBR plant? For example, did a number of inverters drop out suddenly, was any control mode switched, or was there any sudden change in dispatch or load?

– Did a large disturbance or fault drive the observed behavior? (This question is meant to determine when the oscillation is driven by the fault itself, as opposed to by a substantive topology change that accompanied clearing of the fault.)

– If there was a fault, trip, or other large event, was it preceded by oscillations?

– Did the oscillations go away by themselves?

Initial Causality Screening Matrix

With the answers to at least some of the questions presented above in hand, the investigator needs to align the observed behavior with behaviors that characterize oscillations of different causality. This can be regarded as a multidimensional pattern recognition problem. To aid the mapping process, a screening matrix is provided in Table 2 (p. 38).

In the matrix below, the rows correspond to the characteristics of the observed oscillation and surrounding conditions that are elicited by the screening questions presented above, while the columns represent the main categories of causes. While this single-page matrix has the benefit of compactness, it does not allow the inclusion of all the necessary information in individual boxes of the table. More detailed discussion of the types of oscillations connected with each column appear in the "Detailed Assessment and Countermeasures" section.

Some of the causes in the column headings across the top will be familiar to any given practitioner, while others may not. Before beginning to work with the matrix for a specific oscillation, diagnosticians should familiarize themselves with the elements of each column (oscillation types) and each row (the diagnostic questions). Having some familiarity with the range of possible causes will help the diagnostician answer the screening questions most effectively.

Regarding the characteristics of oscillations elicited by the screening questions—the row headings along the left—while it would be nice for answers to be a simple "yes" or "no," in practice the answers are not going to be crisp or definitive most of the time. A few clarification comments, linked to the numbers in the table, are provided immediately after the table. However, most context is to be found in the individual write-ups in the "Detailed Assessment and Countermeasures" section that follows.

The screening matrix is an aid in collecting qualitative "symptoms" for the process of diagnosis. The cells are color coded, indicating whether a positive ("yes") is associated with a particular oscillatory cause: i.e., the characteristic is present, or observed. The color-coding is of necessity subjective.

- **Green:** Strong positive indicator. The attribute is either necessary for the phenomenon to be present or is highly likely to be observed.
- **Light green:** Weak positive indicator. This attribute tends to be present or true for the subject phenomenon but is not necessary.
- **Grey:** Neutral indicator. The presence (or absence) of this attribute is largely irrelevant to causality for the oscillation.
- **Yellow:** Weak contraindicator. The presence of this attribute reduces the likelihood of the phenomenon being the cause of the oscillation.
- **Red:** Contraindicator. The presence of this attribute precludes the phenomenon from being the cause of the oscillation.

The diagnostician has latitude in the use of the matrix. Once the diagnostician has scanned the "Detailed Assessment and Countermeasures" section and has some familiarity with the various possible causes, they can work their way down the row headings and note the item(s) in each category that pertain to the observed oscillation and for which they have information. Then, they can look horizontally along each row and note which causes are relatively more likely to be implicated or precluded in their situation.

High counts of green and low counts of yellow in individual columns will point toward phenomena (column headings) that are likely cause(s) of the observed oscillation. Any red is grounds to dismiss this cause, regardless of other attributes. Hopefully, the diagnostician will find one or two possible causes that have sufficient positive indication to warrant proceeding to more detailed evaluation.

If a user finds that there is insufficient information to answer enough questions to identify a path forward for more detailed assessment, then more information or measurements may be needed—as suggested by the process diagram in Figure 3 (p. 8). Some ways to extract better information from existing measurements are discussed in the section "Signal Processing," and additional measurements and condition information, such as status, topology, etc., that may help with diagnosis are discussed in the individual detailed assessment sections below.

Assessing Need for Mitigation

Negatively damped (i.e., growing) oscillations in the power system are not acceptable. Undamped (i.e., zero damping) oscillations may also be unacceptable, as they can be precursors to instability that poses risk of customer interruptions, trip, or damaged equipment if not mitigated. Therefore, it is a good practice to investigate the causality and identify mitigation measures. The level of urgency to pursue investigation may depend on the magnitude, damping, and location of the oscillations. For example, a 7% oscillation at a key high-voltage or extra-high-voltage bus is not acceptable, whereas a 1% "dither" (effectively zero damping) at a secondary location might be of little consequence.

Another consideration is whether the oscillations are local to a few buses in the network or are widespread. It is not uncommon for low-amplitude oscillations to appear, persist for a while, and then disappear without obvious changes in boundary conditions. However, ignoring even minor oscillations when you do not know what is causing them carries some difficult-to-quantify risk. The judgment issue here has parallels to medical diagnostics, where choosing to not act on the basis of slightly abnormal tests may be appropriate but carries some risk unless causality is established. "We'll keep an eye on that" is a common response. In power system analysis, taking measurements using new higher-resolution or otherwise superior methods can reveal oscillatory behaviors that may be harmless and that went unnoticed previously when high-resolution measurements were not available. Ideally, oscillations should be investigated for causality and the risk to power system security. But practical limitations of time and human resources call for a degree of engineering judgment—for some oscillations, the appropriate countermeasure response is simply to continue monitoring.

Once causality has been established, the question of the appropriate countermeasure, especially whether mitigation is needed, becomes better informed. The need to mitigate depends on the severity of the oscillations and on the likelihood (or risk) that the system might enter those conditions again; move to conditions that analysis shows will result in more severe, unacceptable oscillations; and/or have other consequences such as generator tripping and involuntary load-shedding. If the observed condition is rare but the consequences have the potential to be acute, protection may be the appropriate countermeasure. Protection does not affect the system in the sense of mitigating the cause, but it can stop the phenomenon or remove the equipment at risk when the oscillations are detected. Turbine-generator torsional relays are a good example of a protection countermeasure. If the oscillations are positively damped, occur rarely, and don't appear to put equipment at risk, it may be reasonable to hold off on changes and continue (or add) monitoring.

Sometimes a combination of short-term and long-term countermeasures is appropriate. Short-term solutions may involve enforcing operational constraints that have some costs (e.g., curtailment, or suboptimal commitment or dispatch of involved generators) that are unacceptable in the longer term. Corresponding long-term solutions might include the addition of physical equipment, changes in grid topology, or a host of other options that require time (and money) to implement.

Specifics are addressed in the individual detailed causality discussions in the next section.

TABLE 2

Initial Causality Screening Matrix for Determining Causality and Countermeasures for Oscillations Observed in Power Systems

Characteristics		Causality/Failure Modes														
		Sub/super Synchronous Oscillations				Voltage Control–Induced Oscillations			Angle (Transient) Stability–Induced Oscillations			Frequency or Active Power Control–Induced Oscillations			Harmonic Oscillations	
		Traditional SSR	Control interaction with network (SSCI)	Torsional interaction with IBRs (SSTI)	Ferro-resonance with nonlinear elements	Voltage control mistuning	Voltage control malperfor-mance	PSS and torque-related mistuning	Incipient voltage collapse	Large signal transfer limit	FIDVR or other load/DER failure	PFC/ governor mistuning	Inter-regional power oscillations	Market services miscoor-dination	Within plant	Between plants and/ or network elements
Frequency	Very low < 0.1 Hz											0.2<w<2	0.01<w<.2	0.01>w		
	Low 0.1 < F < 3															
	Subsynch 3 < F < 60(F0)															
	Supersynch F0 < F < ~500 Hz															
	> 3rd harmonic or >2 kHz															
Participation	IBRs											n				
	Synchronous															
	Loads and DER											o				
	Automatic generation control															
	Markets															
Phase/ Coherency	Single device															
	Small group							l								
	Between large groups							m								
Signals	Voltage dominant															
	Active power dominant		c													
	Limit cycles/square or sawtooth signals															
Grid	Radial and/or weak															
	Low resonance															
	Series capacitors near			b	g											
	Shunt capacitors near				h											
	HVDC near															
	Large IBRs near															
Operating conditions	Generation power high	a	d													
	High power transfer		e			k										
	Poor pre-event voltage health															
Stimulus	Spontaneous															
	Topology change				i											
	Fault		f		j											
	Self-extinguished															

Strong positive indicator   Weak positive indicator   Neutral indicator   Weak contraindicator   Contraindicator   (See page 40 for extended key and footnotes.)

This screening matrix is an aid in collecting qualitative "symptoms" for the process of diagnosing observed oscillations. The rows correspond to the characteristics of the observed oscillation and surrounding grid conditions, while the columns represent the main categories of causes.

Source: Energy Systems Integration Group.

Notes

AGC = automatic generation control; DER = distributed energy resources; FIDVR = fault-induced delayed voltage recovery; PFC = power frequency control; PSS = power system stabilizer.

Table 2 Extended Key

■	Strong positive indicator	The attribute is either necessary for the phenomenon to be present or is highly likely to be observed.
■	Weak positive indicator	This attribute tends to be present or true for the subject phenomenon but is not necessary.
■	Neutral indicator	The presence (or absence) of this attribute is largely irrelevant to causality for the oscillation.
■	Weak contraindicator	The presence of this attribute reduces the likelihood of the phenomenon being the cause of the oscillation.
■	Contraindicator	The presence of this attribute precludes the phenomenon from being the cause of the oscillation.

Table 2 Footnotes

a Regarding high generation power as an SSR contraindicator, while it is true that high power means higher damping, one can't completely rule out SSR at high power.

b Series capacitors are not required for SSTI; rather, they are a neutral indicator. Control interaction with series capacitors is addressed in the following questions on operating conditions.

c The anecdotal sense is that these instabilities are often accompanied by acute voltage misbehavior. But, if the phase-locked loop (PLL) is slipping, both P and Q may also swing. So, while bad voltage is usually symptomatic, active power swings are likely as well.

d For low generator power, SSCI is a bit more of a problem. Some of the same reduced damping considerations of low power in SSR apply here.

e Control interactions (non-SSCI) from weak grids tend to be worse in high power transfer scenarios.

f A fault can be a strong indicator, as it precipitates topology change. However, the intent here is to understand whether the fault itself drives the participating resources unstable.

g If ferroresonance, then capacitors in series with a saturating transformer are needed, but the behavior is usually due to severe topology change.

h For ferroresonance, shunt capacitors can become in series with the saturating transformer due to severe topology change such as an open phase.

i Ferroresonance normally needs some acute topological degradation, especially unbalanced switching or placing a transformer in series with a capacitance.

j If there is potential for ferroresonance, then a fault can drive the system into ferroresonance.

k High power transfers tend to stress the voltage controllers of devices providing voltage support. Higher stress increases the likelihood of oscillations but is not necessarily a prerequisite for them.

l/m Swings of the host machine against the rest of the system are normally targeted by power system stabilizers (PSS). However, even though a PSS may not target slow inter-area power slogs that involve lots of machines, it will respond to all oscillations that are visible at its terminals. This response to inter-area swing frequencies can be a destabilizing influence.

n IBR primary frequency control function is intended as a proxy for "governor" here.

o Load and distributed energy resource behavior becomes progressively more important as systems get smaller and more isolated. Further, load could be significantly involved by way of under-frequency load shedding, and large converter-driven loads can introduce a periodic stimulus that excites oscillations.

Detailed Assessment and Countermeasures

Once a candidate causality has been identified (in the initial assessment or otherwise), the next step is to dive into details with the aim of confirming the cause, understanding the specifics of this case, and hopefully illuminating options for mitigating problematic oscillations.

In practice, the skilled diagnostician will rarely follow a rigid process. Nevertheless, it is useful to introduce a framework here by which the practitioner may proceed and under which we can introduce important advice.

The detailed assessment and countermeasures process is presented in Figure 14 (p. 42), which shows where it fits in the overall process, followed by a discussion of the character of each of the flow chart steps and of specific actions suited to the particulars of the failure mode in the individual entries.

Overview of the Main Elements of the Detailed Assessment

Begin with Signal Diagnostics

This step includes review of the available signals, and, more generally, data and information that have been fed into the initial assessment. The intent is to extract as much information as possible toward confirming the initial assessment's assignment of cause of the observed oscillations.

From a practical perspective, the diagnostician should recognize that there is more to determining causality than instantly running off and doing simulations. This is a separate important step, one that is needed before proceeding to diagnostic simulations. Indeed, a key function of this step is to help determine the need for diagnostic simulations, and to gather necessary information (not just system data) to guide them. In this stage, the processing of signals is likely to require a return to the original signals, with the aim of extracting better frequency and coherency information with some of the techniques outlined in the "Tools Overview."

Once a candidate causality has been identified, the next step is to dive into details with the aim of confirming the cause, understanding the specifics of this case, and hopefully illuminating options for mitigating problematic oscillations.

Perform Diagnostic Simulations and Field Tests

Commonly, measurements and information that brought the oscillations to light will be insufficient to establish cause or mitigation options. The diagnostician has two general sets of options: to simulate the phenomenon or take measurements on the physical system, or both.

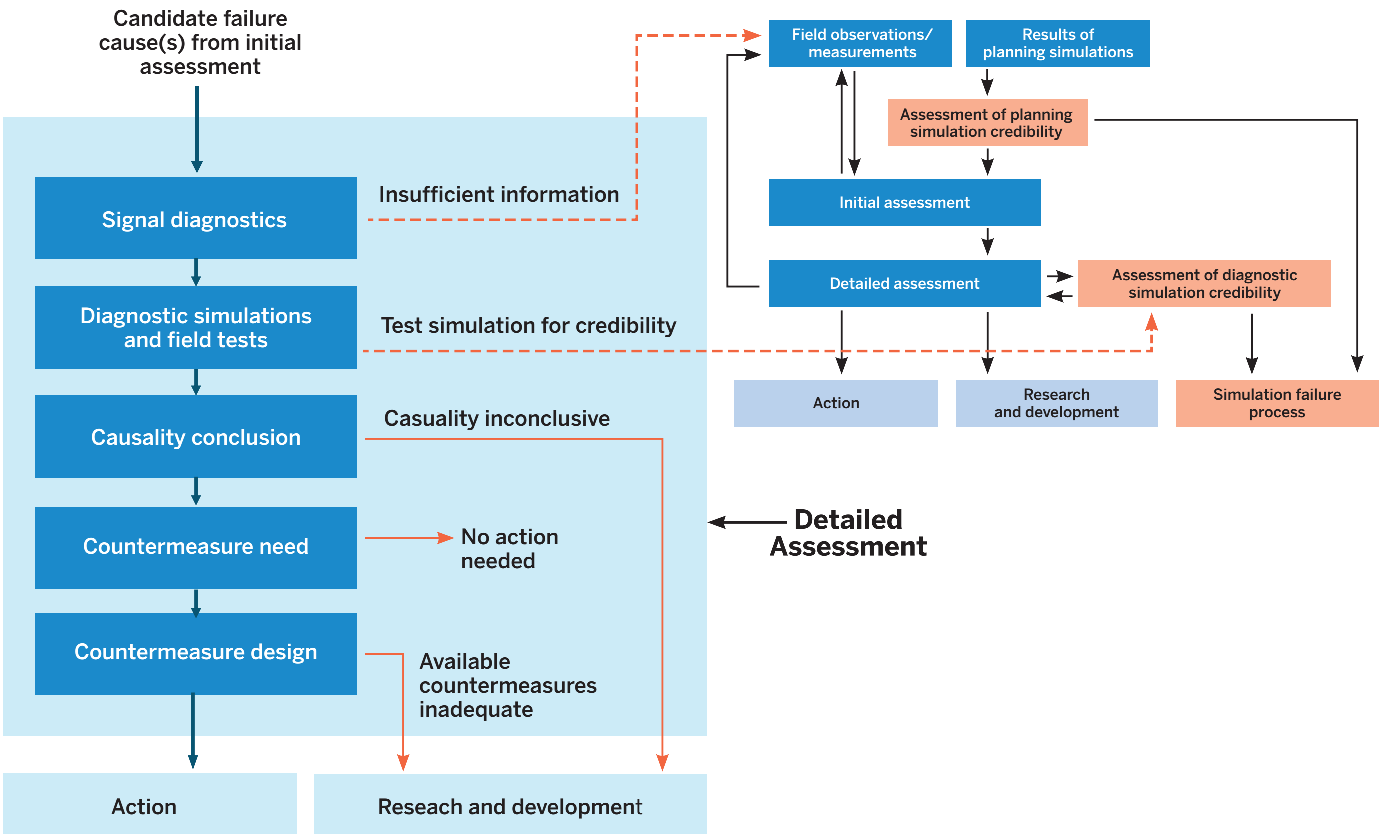
Diagnostic Simulations

Many problems will require simulations, in order to both satisfactorily identify the cause of observed oscillations and, if necessary, provide a foundation for the evaluation of countermeasures. In short, it is often necessary to reproduce the observed behavior to validate the causality and to create a foundation for identifying mitigation options.

A useful general flow of the diagnostic simulation process is shown in Figure 15 (p.43). While there is no one-size-fits-all approach, the steps tend to this pattern. The diagnostician must select the proper simulation tools, as per the section "Tools Overview." Careful

FIGURE 14

Detailed Assessment Process for Determining Causality and Countermeasures for Oscillations Observed in Power Systems



Source: Energy Systems Integration Group.

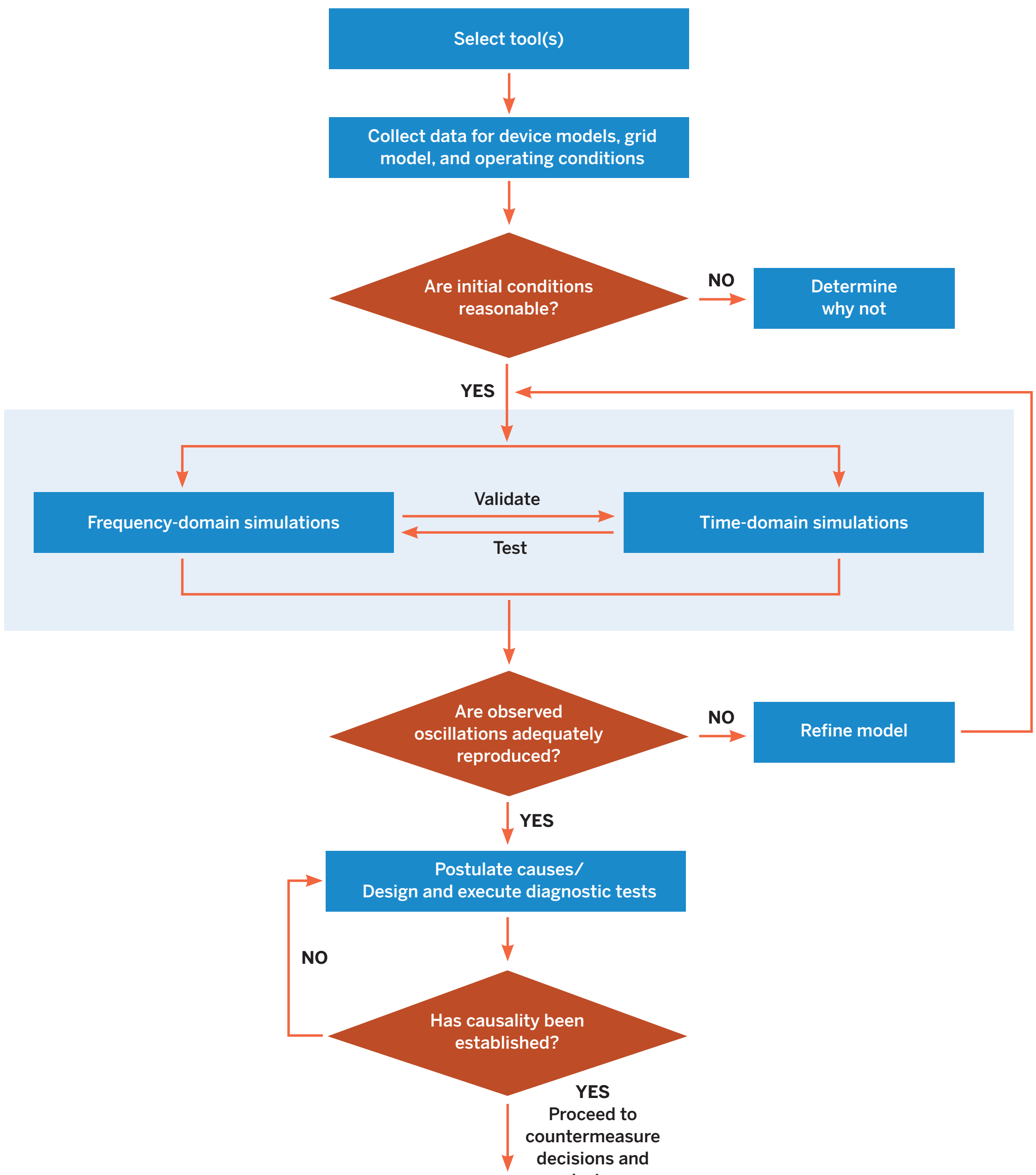
It is often necessary to reproduce the observed behavior to validate the causality and to create a foundation for identifying mitigation options.

modeling of the resources (e.g., inverter-based resources (IBRs)) participating in the oscillations is needed. The details of the device representation are likely to vary with the candidate cause. For example, analysis of sub- or super-synchronous oscillations (SSO) is likely to require a manufacturer-specific electromagnetic transient (EMT) model of each participating device. It is usually equally important to have a set-up of a grid model that captures the key operational elements of the system experiencing the oscillations. The set-up for time simulations should include the evaluation of steady-state boundary conditions such as short-circuit ratio and other impedance quantities, as well as the reasonableness of initial conditions as appropriate. For example, a system that enters oscillations when voltages are badly out of specified limits may need to have the causality of that condition evaluated before worrying about the cause of oscillations.

As noted, tools may include both time- and frequency-domain approaches, with cross-checks for validation and sensitivities (e.g., key gains impact on eigenvalues). The interaction arrows in Figure 15 (p. 43) suggest how frequency-domain and time-domain simulation may interact. For example, time-domain simulation can show oscillations and control behaviors with observable frequency and damping. These observations can help focus state-space tests. Calculation of eigenvalues, participation factors, and other metrics can validate linear behavior and point to control elements that may be critical to the oscillation cause. Once the problem can be observed in the diagnostic simulations—that is, the behavior is reproduced well enough to proceed with tests for causality—the diagnostician should be in a position to postulate on the specifics of causality. The practical reality is that the modeling improvements made in the "refine model" step often directly point to causality. However, further diagnostic tests may be needed, and they can be designed for verification. Further time and frequency simulations testing—for example, changes in such modeling elements as gain, topology, or initial conditions—will often allow for determination of causality. The specifics will vary by phenomenon, and the detailed discussions below provide some guidance for each.

FIGURE 15

Generalized Simulation Diagnostic Process



Source: Energy Systems Integration Group.

Field Tests

Some phenomena lend themselves to actual field tests, which can be the fastest route to resolving the problems. Field tests have the virtue of removing modeling unknowns, although the challenge of designing and conducting field tests that are meaningful, affordable, definitive, and safe can be substantial. But a few well-considered field tests can often greatly reduce the scope of subsequent diagnostic simulations.

Broadly, diagnostic field tests are aimed at individual plants or devices or are systemic. Plant testing to identify or validate dynamic models is well-established art, for example, with requirements set by North American Reliability Corporation (NERC) modeling standards MOD-026 and MOD-027 (NERC, 2016–2018). These tests may illuminate errors in models such as, for example, incorrect control settings or the failure to represent protective functions and time delays, or they may reveal actual malfunction of controllers. In the case of apparently forced oscillations (due to a single device), field tests designed to create similar conditions or stimuli may be effective at establishing causality.

In staging field tests, the distinction between diagnosis and mitigation may become blurred. Staged tests with altered equipment parameters can be illuminating for determining causality. It is often the case that the same parameters that may inform the cause of the oscillations may also be the ones that can mitigate the problem. In short, if a test shows that the problem is improved with a changed parameter, then retaining the change may be an acceptable countermeasure Systemic field tests may be useful when existing evidence does not point to a specific source. They are usually more difficult in that the operating power system may need to be perturbed, requiring permissions and coordination. Distributed, time-synchronized measurements may be needed as inputs location tools (as discussed in "Methods for Locating the Source of Oscillations"). Nevertheless, simple tests such as nearby capacitor switching to create a voltage step stimulus may be simple, quick, and illuminating. This type of test may be faster, cheaper, and more revealing than extensive off-line simulation. Field tests can also complement diagnostic simulation by providing validation and/or correction of simulation model parameters by staged tests such as, for example, those required by NERC MOD-026 and MOD-027 standards.

Draw Conclusions About Cause of Oscillations

Before proceeding to consider the need and options for implementing countermeasures, the practitioner must conclude that they have correctly identified the problem. Advice on practical aspects of this determination, or level of confidence, vary by phenomenon. In the case where diagnostic simulations have been the primary tool for establishing causality, the process outlined in Figure 15 (p. 43) should be designed to provide reasonable assurance of causality. When field measurements are the main source of diagnostic information, sometimes they will find a "smoking gun."

Assess Need for Countermeasures

As noted above, the need for mitigation will be strongly dependent on the causality of the oscillation. While some oscillations can be largely ignored, as they have little practical impact and present little risk to operational reliability or to equipment life, other seemingly inconsequential oscillations may be indicative of a substantive risk that demands serious attention—the canary in a coal mine. For oscillations that are shown to occur only under rare or abnormal operating conditions, protection may be the appropriate countermeasure. Adding protection, such as torsional relays, does not prevent the oscillations from occurring but removes the equipment at risk when they do occur.

In some circumstances, an action plan to "watch and wait" may be appropriate. Or additional measurements and monitoring might be appropriate. New features in control centers, such as the oscillation monitoring and identification tools discussed above, may be justified. It can be helpful to add dedicated field equipment from smart relays, phasor measurement units (PMUs), and equipment to monitor IBR plant controllers to digital fault recorders. Institutional processes need to be part of such strategies—in particular, there is a need for processes for installing required measuring and recording equipment; setting appropriate measuring equipment triggers; and recording, retention, collection, and analysis of available signals. It is not uncommon for measurements to languish in digital storage with no accompanying actions being triggered by them, or for useful measurement data to be overwritten in the absence of clear retention and collection guidelines.

Design Countermeasures

Countermeasures can take many forms, but there is a natural hierarchy of mitigation, particularly when a single resource such as an individual power plant has been identified as the primary cause of the oscillations. The decision tree of Figure 16 (p. 46) is representative. The process can be iterative, with a progression of steps being proposed and tested. Testing will tend to follow the diagnostic simulation and field testing processes just outlined, with the difference being the objective of establishing stable and acceptable performance under all required operating conditions. Steps in providing mitigation become progressively more difficult as suggested by the process, with each step generally having more cost and complexity.

Mitigation that takes advantage of available features of participating resources, such as control or setpoint adjustments, is often the fastest and simplest to implement. This is the first step in the flow chart, and it requires that the causality investigation point toward these as potential solutions. Changing control settings without a requirement to alter or limit plant output is a desirable, usually low-cost, outcome.

> **Mitigation that takes advantage of available features of participating resources, such as control or setpoint adjustments, is often the fastest and simplest to implement.**

Next, mitigation actions that alter the behavior of the offending plant(s), particularly actions that reduce the grid stress that may be exacerbating the oscillations, can often originate from grid operations and be implemented rapidly. Changing plant voltage or power setpoint is this kind of mitigation. In many cases, this will be sufficient. Another option may be physical plant modification, such as the addition or replacement of controls (as opposed to modifying settings of existing controls) or new equipment (such as reactive compensation).

Systemic changes may be needed when key components of causality are physical characteristics of the network or system-level stress due to particular operating conditions. It is often effective to reduce stress by reducing power transfer levels, and this can be quickly implemented. However, such mitigation may have unacceptably high collateral costs (e.g., curtailed power production, lost revenues, higher energy costs for consumers, lost carbon reduction). Under those circumstances, further mitigation that takes longer to implement may replace this kind of short-term workaround. This can take the form of grid topology changes, such as adding shunt reactive compensation, reducing series reactive compensation, new breaker positions, new lines, devices with power oscillation damping (PODs), etc.

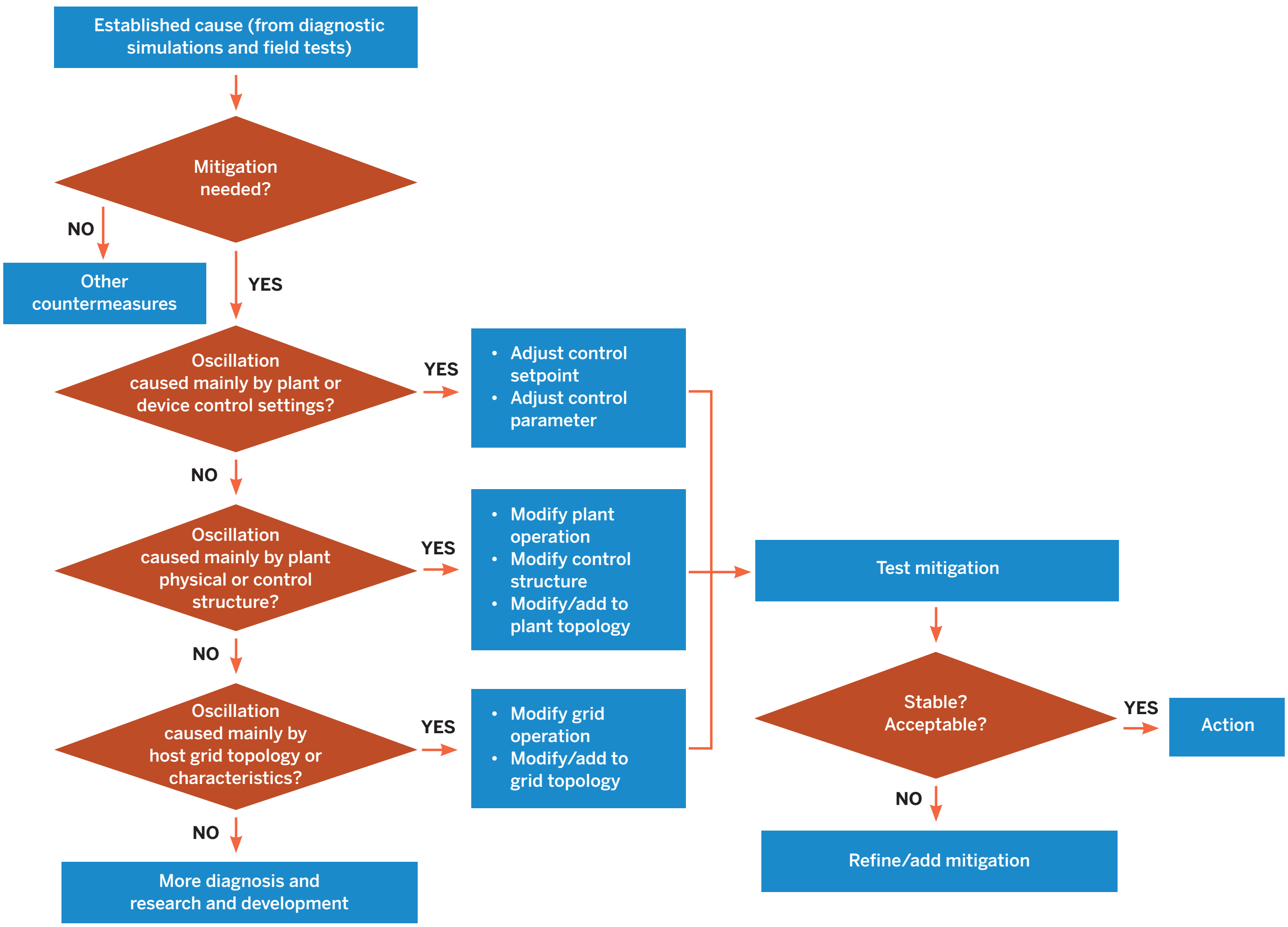
The structure of the chart in Figure 16 (p. 46) is indicative, not prescriptive. The figure shows that recursion is necessary if the mitigation design does not pass the "stable? acceptable?" test. Typically, the designer would return to the same type of mitigation initially identified for additional refinement. For example, they might try different control gains. However, the designer may determine that other mitigation measures are needed and move on to trying other options, including those in other groups (in the figure).

Some examples from each group of mitigations shown in the figure are:

- Operating point and control settings
  - Constraining IBRs (e.g., active power curtailment)
  - Altering plant voltage setpoint
  - Reducing the number of inverters on line within the offending plant
  - Making changes in control parameters (for example, (especially) transient voltage gain)
- Plant physical structure
  - Making changes in control structure (including firmware, added signals, POD, etc.)
  - Making changes in physical hardware with the affected facility (e.g., reducing communication latency, adding filters or capacitor banks, adding synchronous condensers at the plant, adding supplemental excitation damping controls (SEDC),

FIGURE 16

General Process for Identifying Mitigations for Observed Oscillations



Source: Energy Systems Integration Group.

or adding passive damping filters for at-risk synchronous generators)

– Adding grid-forming inverters

– Making changes in operations, including strategies for avoiding operation conditions that trigger or present oscillation risks

• Changes in the grid

– Making topological changes and new or modified transmission and distribution infrastructure, including grid stiffening with more lines and transformers, reducing series compensation levels, instituting operating condition–based selective bypass of series compensation, adding passive damping filters at series capacitors, or adding active damping devices such a thyristor-controlled series compensation

– Adding protection, including relays or other monitoring on the grid (e.g., at series capacitor banks) that responds to (nascent) oscillations

– Adding synchronous condensers to strengthen the grid

Communication Latency

In the case of IBR resources, the greater multiplicity of devices adds communication complexity and introduces new mechanisms for delay. Latencies can cause oscillatory problems in a variety of ways that span several common root causes.

Latency can be a pernicious contributor to oscillations, because it is commonly ignored or underrepresented in planning and application work. The latency is not always well modeled, or even well understood. Unless specific accommodation is made within simulation model structures, it is assumed that information passes instantaneously between internal model elements and between entire models. Simulation time steps, depending on structure, may introduce a time step or two delay, which is usually, but not always, inconsequential to analysis. In the real world, operations such as measuring, digitizing, packeting, etc. take time. Seemingly small delays that may be serial can ultimately add up to the point where they impact performance. Analysis and identification of causality for problems to which excessive delay contributes is largely the same as discussed above for correcting tuning, with the added imperative to correctly account for communication latency.

The discussion below separates latency that is within the bounds of a single resource and that which can accumulate between systemic elements that may have different ownership and may involve significant distances. More details, specific to individual phenomena, are provided in the corresponding sections below.

Internal Latency

One significant risk for wind and solar PV plants, and possibly battery energy storage systems, comes from the hierarchical structure of the plant controls. These plants have many individual inverters that are physically distributed, sometimes over substantial distances. There are many variations on control structure, but most plants of significant size have a central master controller, usually located at the point of interconnection. The master controller receives and sends information to utility supervisory control and data acquisition (SCADA), and normally hosts high-level control hardware that issues commands and monitors the behavior of the individual inverters. The processing and communication latency for these signals has been the cause of poor performance, introducing phase lag without attenuation—a destabilizing factor.

Communication Structures in a Typical IBR Plant That Can Contribute to Latency Problems

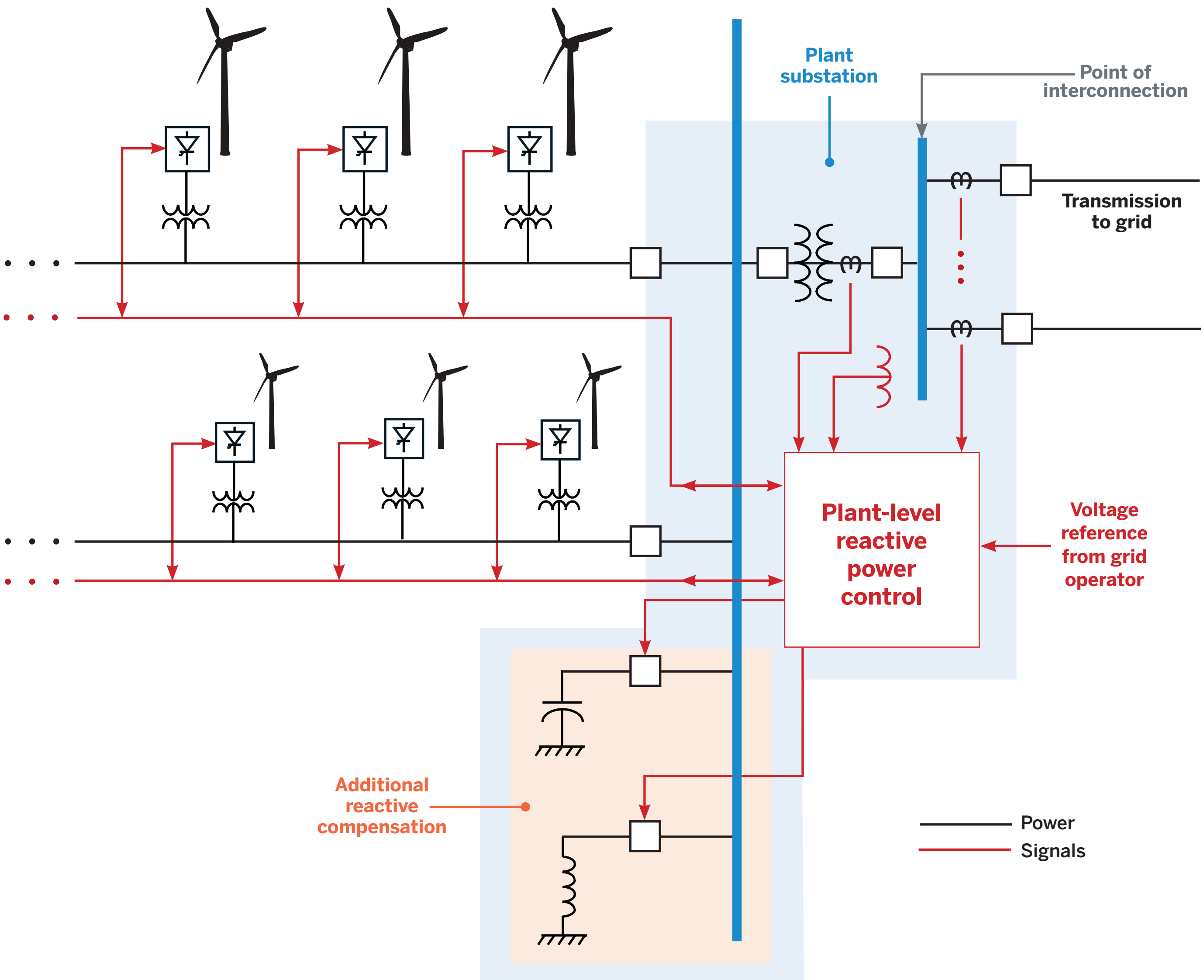
There are several communication structures in a typical IBR plant that result in latency problems. Figure 17 (p. 48) is illustrative, showing the voltage/reactive power controls of a modern wind plant (WTG). Communication is represented by the dotted red lines, which may include voltage or reactive setpoints delivered to individual inverters, status or local measurements (e.g., of reactive output) sent from individual inverters, commands to supplemental devices, and other communications. External signals might be received from grid operations, such as voltage or reactive power setpoints for the entire plant, which have their own latency and which, under some circumstances, can contribute to oscillatory behavior. Similar path arrangements may apply to active power controls for frequency or active power dispatch.

The simple schematic of Figure 18 (p. 49) shows representative components of a generic IBR plant reactive power control, with a master supervisory control and physically distributed individual inverter-based devices with local control. Actions within or between each of these components contribute to delays between physical changes (e.g., voltage change) in the power system, delivery of control instructions to the inverters, and provision of response:

- **Transducers.** It takes time to make measurements in an AC system, and there are trade-offs between the speed and the accuracy of measurement. A longer sample time will usually result in a higher fidelity measurement but create more delay. Voltage measurement is shown as an example in the figure.
- **Plant control processing.** The plant-level control will often contain familiar control functions that take in setpoints received from the grid operator (a reference voltage is shown in the figure), measured signals, and signals back from the individual devices being controlled in the plant. The plant control uses various dynamic controllers and limiter operations to produce an instruction, such as a P or Q command. These digital signal processors have discrete cycle times, buffers, and processor functions that impose delays. Similarly, the calculation of frequency for use in IBR controls entails some delay. The figure shows a reactive power command, $Q_{command}$, as an exemplary output.

FIGURE 17

Communication for IBR Plants, Example of a Wind Plant

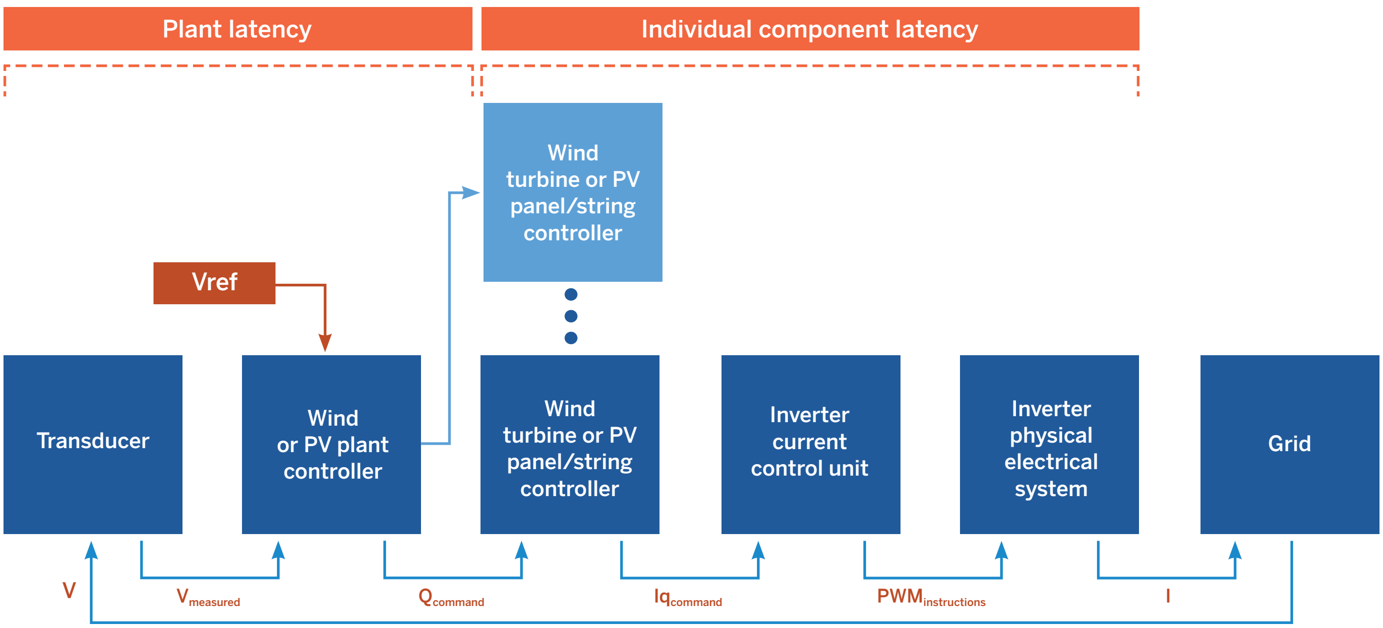


Shown are communication structures in a wind plant that can result in latency problems. Communication is represented by the red lines, which may include voltage or reactive setpoints delivered to individual inverters, status or local measurements sent from individual inverters, commands to supplemental devices, and other communications. External signals might be received from grid operations, such as voltage or reactive power setpoints for the entire plant, which have their own latency and which, under some circumstances, can contribute to oscillatory behavior.

Source: Energy Systems Integration Group.

FIGURE 18

Latency Components, Example of Wind or PV Plant Reactive Power Control



Information flow in a representative wind or solar PV plant, showing the various data transfer and processing steps that can add latency in controls. Plant-level controls, on the left, are physically separate from individual IBR elements, on the right. Processing (within the boxes) and transmittal (arrows between) may each contribute to delays.

Source: Energy Systems Integration Group.

- **Plant signal distribution.** Typically, an instruction created by the plant controller ($Q_{command}$ for this example) needs to be broken down and distributed to the individual device controls, as suggested by the arrows. For example, a wind plant of dozens or hundreds of turbines needs to send scaled or otherwise appropriately processed signals to each wind turbine (as suggested by the presence of two device controllers and ellipsis in the figure). There are many ways this distribution is accomplished. Older plants in particular may introduce significant delays in this step.
- **Individual inverter signal receipt.** Delivery of a signal to the individual device controller requires that signal to be incorporated and synchronized with the other processes of the individual inverter. Buffers at this step can introduce delays.
- **Individual control.** The local controller uses the input signal, usually compared to local information from the inverter or measured at the terminals of the inverter, to create an instruction for the inverter, such as an active or reactive current order ($Iq_{command}$ is shown in the figure). Parts of this control, especially PID and limits, are normally represented in models, but internal delays may not be.
- **Actual controller (firing control).** This final step is at the most basic functional level of the inverter, in which the current control unit (CCU) translates functional instructions (such as a reactive current command here) into firing signals for the inverter's physical valves ($PWM_{instructions}$). Latencies at this stage, for example with the phase-locked loop (PLL), can contribute to overall delays.

There are many variations on the details for each plant (and OEM), but the main point here is that the algorithmic process of distributing the signal and physical process of delivering it to each individual inverter takes time. The first three bullets in the list above are physically and process-wise upstream of the individual IBR units (the wind turbines or PV units here). Figure 18 labels this as *plant* latency to emphasize that these delay elements are often ignored, even if a plant controller is modeled. They tend to be difficult to include in bench tests and can be highly variable between plants with otherwise-identical individual IBRs. The reality that the individual recipients of the signal are physically and electrically distributed means that this delay is not necessarily uniform. Most dynamic models of IBRs aggregate all the individual inverters of a plant into a single large aggregate representation. That means that a single delay in the aggregate IBR plant model cannot precisely capture the latency impact on each inverter. (In extreme cases, individual inverters with longer latencies than their plant-mates have experienced performance problems. Fortunately, this appears to be uncommon.)

The Challenge of Measuring the Delay Between Input and Delivery of the Signal to the Individual Inverter Controls

In Figure 18 (p. 49) it looks like it should be simple to measure the delay between input and delivery of the signal to the individual inverter controls. However, in practice this is highly challenging. Wind and solar plants are not normally designed to provide this measurement, and creating meaningful external measurements is surprisingly difficult. This challenge is exacerbated by the fact that the latency may change with the location of individual inverters and with operating conditions or other externalities. Field experience suggests that trying to build up a representative overall delay by adding the estimated delay associated with each of these control hierarchy steps results in acutely over-estimating the overall delay. One practical approach is to assume delay exists, assume other model elements are correct, and tune the simulated response by adjusting delay time until it reasonably matches observed/field-tested response.

Anecdotal evidence indicates that OEMs and plant designers have made substantial improvements in reducing latency in new plants. Reports have been made (but not confirmed here) of overall delays on the order of 450 ms for plants older than 2015 vintage, 200 ms before 2020, and 100 ms now. Reducing latency in existing plants may not be easy. The first line of action is to tune available controls. In the event that cannot be made to work satisfactorily, physical improvements to the plant communications may be necessary.

Systemic Latency

A related but more complex class of problems may result from latency beyond individual IBR plants. For example, if the host independent system operator (ISO) is delivering instructions to individual plants that create closed-loop controls between the ISO and the plants, then the delays in that process can affect stability. These will tend to be more complex, in that it may not be a matter of simple communication delays but can reflect other process delays, such as gathering information, running algorithms, or synchronizing with other parallel processes. Observed oscillations that occur with the exact periodicity of the ISO communication cycle can be indicative of this problem.

Forms of Latency

Latency is not always a pure transport delay, that is, a defined time between when a certain instantaneous value goes into the delay and when it comes out. Delays can also be in the form of sampled systems that do not respond continuously, rather, only at discrete times. An example of this is with thyristor-controlled equipment such as line-commutated converter (LCC) HVDC, where control outputs have no effect until the next thyristor firing time. While modern voltage-source inverters do not have significant delay of this type, digital control processing is likely to be accomplished with processors cycling through their code and only "looking" for feedback quantities at discrete times. The cycle time effectively becomes a delay. An extreme example of this is a certain PV inverter in which the inner current controls accept inputs from the outer terminal voltage-regulating algorithms only twice per second. Delays of this type are stochastic in nature, depending on when a certain event coincides with the sampling process. Even delays that are primarily of the transport type may have variability due to factors such as processor loading.

Representation of Latency

Dynamic simulation tools structured around state variables have difficulty accurately modeling all types of transport delays, including those due to latency. All options involve compromises, as follows:

- Representation of transport delays as a first-order lag, although commonly done, is of limited accuracy. Unrealistic high-frequency attenuation with this approach can distort time simulations and eigenvalues.
- Padé approximations give better approximation to transport delay. Higher order Padé (2nd or even 3rd order) usually perform better, at a cost in computational burden and artifacts at high frequencies.
- Actual transport delays in time domain are constrained to integer multiples of the integration time step. Code structure is more complex, and state-space linearizations require special handling, so this approach is unusual.

Subsynchronous and Supersynchronous Oscillations (SSO)

This family of phenomena includes a range of subsynchronous and supersynchronous behaviors. SSO manifests as oscillations that are superimposed on power frequency instantaneous voltages and currents (in the phase reference frame). These oscillations appear in the synchronous reference frame at a frequency equal to the difference between the fundamental frequency and the superimposed oscillation frequency of the phase currents and voltage. Controls that inherently operate in a synchronous reference frame include those that regulate phasor quantities like voltage or current magnitude or phase angle, active or reactive power, and inverter DC-side current or voltage. Similarly, oscillations of these control quantities at frequency f_c create amplitude, frequency, or phase modulation of the phase voltage and currents that appear in the phasor domain at two sideband frequencies that are above and below the fundamental frequency f_0 at $f_0 \pm f_c$. Identical translations in frequency exist between torsional oscillations of generator rotors, relative to the synchronously rotating reference frame of the generator, and the currents and voltages of the machine's stator.

While there is a broad range of causality, SSO tends to be characterized by oscillatory phenomena that are fast enough to defy analysis with phasor-based, fundamental-frequency tools. There is no firm definition, but this grouping generally includes phenomena exceeding several Hz (say 5 Hz) up to roughly a few multiples of the bandwidth of the fastest inverter control, in the synchronous (control or rotor) reference frame. The fastest control loop in grid-following inverters is current regulation, and a typical current regulator bandwidth is on the order of 1000 rad/sec or in the range of 100-300 Hz for typical pulse-width modulated (PWM) inverters and even greater for inverters using multi-modular converter (MMC) technology. This is equivalent to superimposed oscillations greater than 65 Hz or less than 55 Hz (inclusive of "negative frequencies") in the phase voltages and currents of a 60 Hz (f_0) system (and greater than 55 Hz or less than 45 Hz for a 50 Hz system). Negative frequencies in these frequency translation relationships are indicative of a negative phase-sequence quantity.

Thus, SSO phenomena can take place at frequencies approaching 500 Hz or more. The phenomena are fast enough, in the synchronous reference frame where phasor-based simulation tools operate, that algebraic modeling of network element resistance, inductance, and capacitance as resistances, reactances, and susceptances (i.e., R, X, B) based on the fundamental frequency is likely to be inadequate or misleading. Differential equations, i.e., resistance inductance capacitance (RLC) representation, is necessary. This is absolutely a requirement to diagnose resonances associated with series capacitors or interaction with transmission system resonances. However, phasor-based (as opposed to EMT) representation can be adequate for some of the behaviors near the lower portion of the ranges given in the previous paragraph. Lower-frequency oscillations, for which the average of the transmission system impedances in the phasor domain at the upper and lower sideband frequencies are reasonably approximated by the fundamental-frequency impedance, and that are primarily control-driven, can sometimes, with great care, be analyzed with phasor-based tools. Variations of SSO are all "resonance" instabilities in the IEEE taxonomy (see Figure 1, p. 4). They are relatively, but not completely, separate from small signal rotor angle and voltage instabilities, as addressed later.

Historical Perspective on Language and Notation for Subsynchronous Instabilities

In 1971, torsional interaction between the Mohave steam turbine-generator in southern California and nearby series capacitors resulted in catastrophic mechanical failure of turbine-generator shafts at the plant. It was a seminal event for the industry. While some aspects of interaction between series capacitors and turbine-generators had been predicted years earlier, to say this event got the industry's attention would be an understatement. Vigorous industry activity followed that event, producing greatly increased understanding of the phenomena (note the plural) related to these interactions. At the time, the industry largely settled on the use of "subsynchronous resonance"—SSR—as the overall descriptor for these problems.

In subsequent years, variations on the phenomena have been identified. Starting in the 1980s, torsional interaction between turbine-generators and HVDC were recognized. Since then, understanding has grown, *and continues to grow,* around related phenomena. In this guide, an attempt has been made to group and discuss these newer phenomena, with the grouping guided by common physical genesis and mitigation options. Unfortunately, the language necessary to uniquely describe all these variations is inconsistent, evolving, and non-uniform. In some publications, "SSR" is used to cover behaviors that are quite removed from the interactions that doomed the Mojave power plant. Researchers and practitioners have introduced other monikers and acronyms. CIGRE has published a "classification of subsynchronous oscillations in power systems" with a four-level hierarchy with a dozen cells and several acronyms which, while detailed and useful, is more complex than this guide aims to delve into (CIGRE, 2023b). In this guide, we consider SSO to be the overall moniker for all of these phenomena. Here we try to use descriptive labels and minimize the use of acronyms in an attempt to provide clarity for the various subsets of SSO. We provide some simple diagrams to illustrate *what* is interacting for each subgroup of SSO behavior discussed in the following sections.

"Traditional" SSR (Specific to Series Compensation and Synchronous Machines)

Resonance between series capacitors and synchronous turbine-generators has been an understood risk since (at least) the 1970s. The interaction is specific to these two components, as suggested by Figure 19 (p. 53). This specific set of behavior was the only SSR recognized for many years. Given the arrival of many new variations (discussed later in this guide) we offer "traditional SSR" as a useful retronym here.

The systemic cartoon in this figure includes one each of the systemic elements that may interact for the different SSO phenomena discussed in this section. The thumbnail plot of impedance vs. frequency is meant to emphasize the frequency-dependent nature of the network as viewed from different nodes or points of interconnection. The red arrows indicate which elements are interacting in the next several illustrative figures. Here, for "traditional" SSR the arrows point to interaction between the series capacitors and the turbine-generator—both electrical and torsional mechanical systems of the turbine-generator interact.

The IEEE definition of SSR (from 40 years ago (IEEE, 1985)) includes three phenomena:

- **Torsional interaction.** Torsional interaction includes effects on both sub- and supersynchronous electrical frequencies.
- **Induction generator effect.** This confusingly named phenomenon is a purely electrical phenomenon, the frequency of which is not related to the machine torsional modes. It is stimulation of the subsynchronous electrical natural frequencies introduced by the series capacitor on the generator. It may *impact* the machine torsionally.
- **Transient torque.** This phenomenon is the intersection of transient (impact) stimulus with natural oscillations of turbine torsional modes.

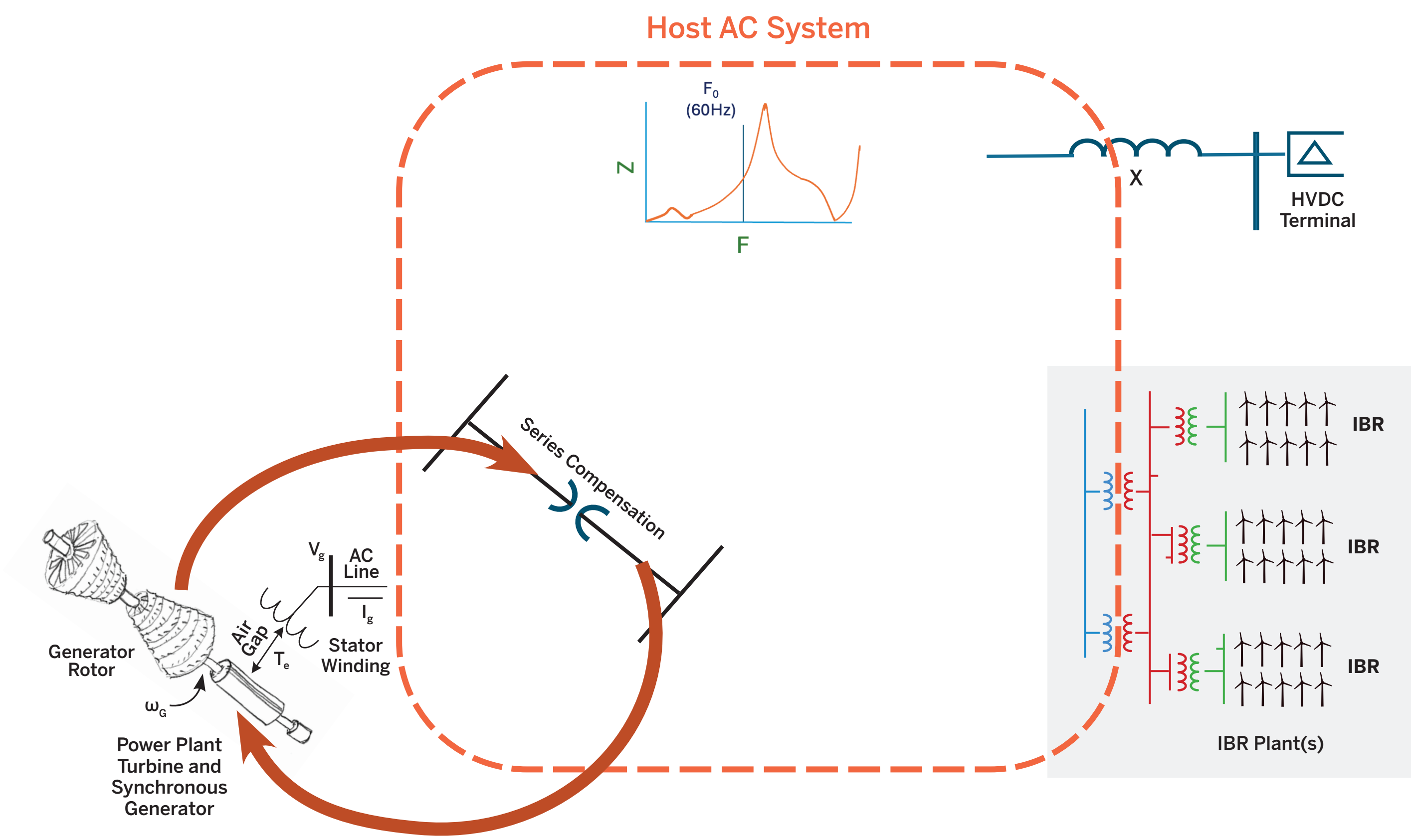
Main Characteristics and Primary Diagnostic Indicators

Torsional Interaction

The torsional interaction aspect of SSR is an electromechanical resonance phenomenon that can occur between series capacitors on the transmission system and the torsional frequencies of synchronous turbine-generators. SSR can result in growing torsional oscillations, with dire consequences. This phenomenon has been long recognized by the power industry, with the first documented turbine-generator failure due to SSR occurring in 1971. In order for SSR to occur, some relatively specific physical conditions must be met. A turbine

FIGURE 19

Interaction Associated with "Traditional" Subsynchronous Resonance (SSR)



This diagram showing the main components of a power system highlights interactions between series compensation and synchronous turbine-generators (as shown by the red arrows), that are essential elements in traditional SSR.

Source: Energy Systems Integration Group.

generator with natural torsional frequencies in the range of roughly 10 to 55 Hz must be present, which mostly restricts SSR to steam turbine-generators and large gas turbines. Series capacitors must also be present, and in relatively close electrical proximity to the affected turbine-generator. The absence of series capacitors is a contraindication for SSR.

As the name indicates, SSR is a resonance phenomenon. For it to occur, the natural electrical frequency of effective inductive impedance of the grid and the series capacitor (i.e., root of the LC circuit) must coincide almost *exactly* with the complement of the affected torsional frequency of the turbine-generator. While the torsional frequencies of a synchronous machine do not change, the apparent impedance of the system is continuously varying with operating conditions and with line contingencies. This is a key attribute, as a machine at risk may avoid operation under the conditions that result in resonance for the vast majority of the time. Normally, the electrical coupling must be tight. The highest risk exists where there is a radial connection of a turbine-generator to the grid through transmission that includes a series capacitor. But other effectively similar topologies producing tight coupling must also be considered.

The destabilizing electrical torque that occurs with SSR is countered to some extent by damping from the mechanical physics of the turbine drivetrain. Overall negative damping, i.e., instability, occurs when the negative damping of the electrical resonance exceeds the positive damping from the balance of the system.

Of particular importance is the damping introduced by steam or gas flow in thermal turbines. The greater the flow (i.e., the higher the power), the greater the positive mechanical damping. Consequently, SSR is of most concern at low or minimum load levels. While in extreme cases, machines can be unstable even at high or full load, observed oscillations at high power tend to be somewhat counter-indicative of conventional SSR.

The consequences of SSR can be extremely severe—including, in the most extreme cases, catastrophic failure of turbine-generator shafts. Consequently, simulation techniques have evolved that aggressively search for SSR conditions that have even a very remote possibility of occurring. This is explicitly different from normal (N-1) NERC-type contingency planning, in that SSR scanning is normally performed for many (e.g., N-6) contingencies—far deeper degradation of the grid than most planning studies consider.

Induction Generator Effect

Unlike SSR that involves interaction with the natural torsional modes of the turbine-generator, the induction generator effect is interaction with the generator as a monolithic rotational mass. The induction generator effect was the first mechanism of SSR postulated long before the phenomenon was observed in the field. The basic explanation of this behavior is that a generator can be viewed as an induction generator at a certain stimulating frequency below synchronous frequency. With the network tuned by the presence of series capacitors and the equivalent rotor resistance becoming negative due to a negative slip at that frequency, the net electromechanical system becomes unstable. In practice, the induction generator effect is rarely observed with synchronous generation. Torsional interaction is a much greater risk.

Transient Torque

Transient torque oscillations are related to SSR, but do not require negative or near-negative damping to be of concern. The torsional modes of turbine-generators are all stimulated by grid disturbances. Faults, line switching, and especially failed reclosures (closing back into a persistent fault) stimulate torsional vibrations, which are observable in the electrical outputs of the generator. Generation equipment is designed to tolerate such oscillations, and designs ensure positive damping. Nevertheless, the shock and subsequent swings stress the metallurgy of the equipment. Normally, the most violent single event (e.g., a close-in fault) will result in small or negligible loss of equipment life through fatigue. The concern with transient torque is when multiple events occur in rapid succession—such as might be the case with failed reclosures. If the oscillations from a previous hit have not subsided, another hit has the risk of reinforcing the swings. Torque amplification occurs, and loss of shaft life may occur.

Signal Diagnostics and Information Processing

Since the consequences of entering SSR conditions are severe, great efforts have been made to avoid it; it is relatively unusual (and very bad) to detect SSR from field measurements. Nevertheless, it is possible. SSR is observable in several signals. The signal with the highest-fidelity information for the machine participation in SSR is the shaft speed of the turbine-generator—or, more precisely, the differential speed between the two masses of the turbine-generator that are oscillating. Unfortunately, this signal isn't normally possible to obtain. Most commonly, rotor speed is derived from a magnetic pickup on the toothed wheel of the generator standard. This speed signal is used in the machine controls, and it will often, but not always, carry information about the torsional vibration of the shaft masses. This signal is critical for countermeasures (described below). In the event that this speed signal does not carry useful information about the torsional vibration of interest, there may be a need for measurements from transducers purpose-installed on another location on the turbine-generator shaft.

Unexpected incidence of SSR can show up in grid measurements including voltage, current, and power. They will often present as amplitude modulation of power frequency (e.g., 60 Hz) at the rotor (synchronous) reference-frame resonant frequency. The individual phase signals tend to be balanced; that is, the oscillations are typically positive sequence. However, care must be exercised when using filtered signals that are already converted to sequence quantities. The frequencies of SSR are high enough (i.e., 10-55 Hz) to be poorly captured by some types of filtering. Examination of actual waveforms is better. The presence of subsynchronous oscillations in grid variables alone is insufficient to establish SSR, as other SSO phenomena will also be visible. Electromechanical oscillations visible in turbine-generator variables are a necessary component.

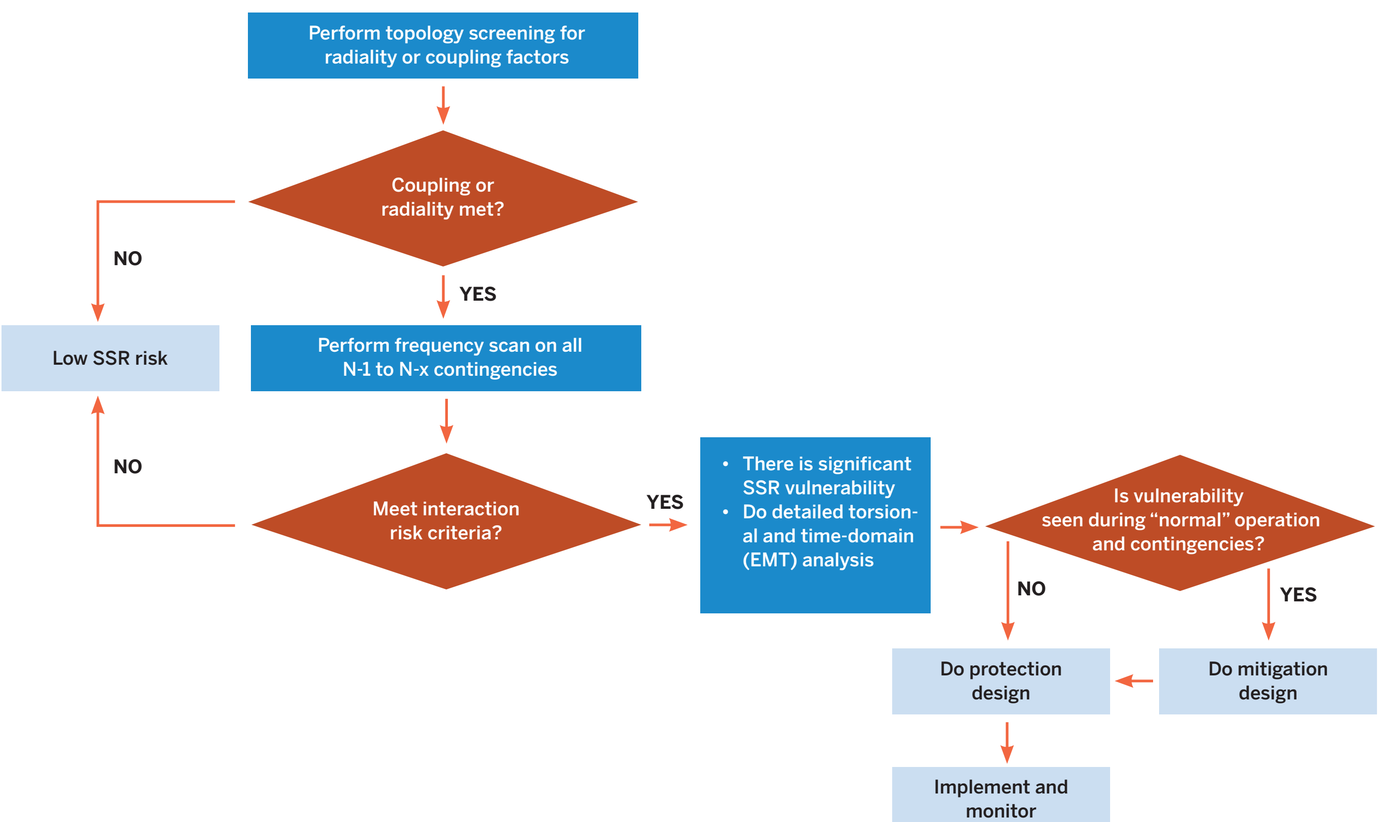
Diagnostic Simulations and Field Tests

In practice, most SSR is "discovered" by off-line analysis specifically intended to expose vulnerability. Because the phenomenon is, by definition, dependent on the electrical natural frequency of the grid, it cannot be meaningfully detected or analyzed with phasor-based tools. Static network analysis tools—ones that capture the frequency dependence of RLC networks with frequency scans—are the workhorse of SSR analysis. These tools normally will test for contingencies that result in grid natural frequencies that coincide with the fundamental-frequency complement of mechanical (torsional) natural frequencies of turbine-generators in electrical proximity to series capacitors. Conventional SSR analysis can be augmented with dynamic perturbation scans, which can reduce or eliminate the need for extensive EMT simulations. Good knowledge of the torsional mode frequencies is essential, and design data from manufacturers are the best source. However, field tests of machines are possible. The natural mechanical damping of torsional frequencies (for example, that due to steam flow) tends to drop with machine power level; consequently, the highest risk of SSR tends to be at low or minimum dispatch. Subsynchronous torsional oscillations will be stimulated by grid events like faults. These do not necessarily represent a problem —with SSR the concern is with sustained or growing oscillations that cause unacceptable fatigue risk to the turbine-generator.

An SSR study process flow chart, derived from practice of several experts, is shown in Figure 20. There are variations, but in general the steps are as follows:

- Screen for coupling or electrical proximity of generators with torsional vulnerability to series compensation. This is done with simple network impedance tools, with simple and conservative criteria. For HVDC

FIGURE 20
Subsynchronous Resonance (SSR) Study Process



Source: Energy Systems Integration Group.

screening, IEEE (1987) gives a unit interaction factor (UIF) of greater than 0.1 as a threshold for more detailed analysis. A variety of screening approaches are presented and compared in Cheah-Mane et al. (2023).

- For units that meet the threshold for concern, one runs detailed network impedance scans checking for vulnerability specific to the torsional frequencies of the subject turbine-generator under contingency conditions. A highly important point is that these scans check for vulnerability including extremely degraded conditions. Scans are often run to N-7 or higher—far beyond other types of reliability analysis.
- Units that met these criteria are subject to even closer analysis, using detailed torsional, eigenvalue, and time-domain tools. Since analysis of SSR risk can be made mostly with linear analysis, dynamic scans used to provide eigenvalue information can constitute the bulk of analysis. Time-domain simulations, which are much more computationally burdensome, tend to be used for verification of linear analysis.
- Units showing vulnerability are subject to mitigation and protection design, as discussed below.

Causality Conclusions

The presence of SSR can be unambiguously established by the coincidence of electrical natural frequencies of the grid including series capacitors and the mechanical natural frequencies of the affected turbine-generator. Observed oscillations in turbine speed are particularly conclusive.

Countermeasure Need

The consequences of unchecked SSR can be dire. Oscillations that are negatively damped are cause for acute alarm. Oscillations that exhibit poor but positive damping are indicative of high risk. For practical purposes, there are no circumstances under which diagnosed SSR risk can be ignored.

Countermeasure Design

While SSR *must* be addressed, there is a spectrum of options available. Design of countermeasures normally must take into account the degree of topological risk. For that purpose, we introduce here two groupings of SSR exposure, which dictate the types of countermeasures needed. Countermeasures fall into two categories: mitigation and protection. Mitigation options reduce the destabilization of operation at or near resonant conditions, allowing operation to continue. Protection options detect resonant conditions and prevent operation there (for example, by tripping affected turbine-generators).

SSR with Synchronous Machines Under Normal Conditions

When normal operation of the power system can result in a resonant topology, mitigation is required. The threshold for adding mitigation is often economic. Specifically, is avoiding operation under conditions that result in SSR economically acceptable? From a practical perspective, that often means that systems that are resonant when they are fully intact, or subject to occasional credible contingencies, need mitigation. Systems that are resonant up to contingencies of order (very roughly) N-2 or N-3 usually need mitigation.

SSR with Synchronous Machines Under Abnormal Conditions

Systems with mitigation in place normally also must have protection, as back-up to the mitigation. But systems that expose machines to SSR only under extremely unusual (e.g., highly degraded) conditions may tolerate protection-only strategies. Protection systems will generally detect that SSR is occurring and initiate some sort of topology change that eliminates the risk. Because the consequences of SSR can be so acute, protection schemes are often applied for contingency levels far beyond those considered for other types of risks. For example, SSR risks that accompany contingencies well beyond N-3 are still candidates for protection.

Mitigation Options

Mitigation of SSR takes two general forms: moving the frequency of the resonance or adding damping to the oscillations. Both approaches require changes or additions to the physical infrastructure of the system. Table 3 (p. 57) provides a synopsis of options.

These mitigation options are all of the "physical structure" and "changes in the grid" variety from Figure 16 (p. 46).

TABLE 3
Mitigation Options for Subsynchronous Resonance (SSR)

Mitigation options to move the resonance
Reduce the level of series compensation. SSR problems for systems below about 35% compensation are relatively rare.
Add or change transmission. New lines, new substations or taps, and altered substation breaker arrangements can all move or reduce the risk of resonance.
Mitigation options that add damping
Add passive damping filters at the turbine-generator (Bowler et al., 1977).
Add passive damping filters at the series capacitor (Miller et al., 2001).
Add active damping at the series capacitor, e.g., by thyristor control (Clark et al., 1995).
Add active damping at the turbine-generator, e.g., by SEDC (supplemental excitation damping control) (Wang and Hsu, 1988).
Add separate active damping devices, e.g., by IBR equipment specifically installed to provide damping or with controls added to IBR equipment that serve other functions as well. For example, static VAR compensators (SVCs) have had damping controls added. Active power devices like a battery energy storage system might have a damping function added.

Source: Energy Systems Integration Group.

Protection Options

Protection options are generally discrete relay actions that remove some element from the system when SSR is detected. The most common option is for relays that reside at the turbine-generator(s) at risk. These "torsional stress relays" usually directly measure the speed of the machine, subject it to sophisticated filtering, and cause the machine to trip offline if SSR sufficient to cause torsional loss-of-life is detected. These devices are customized for each machine by the protection supplier. Other, even less common protection schemes reside at the series capacitor. These schemes detect SSR in the electrical quantities at the series bank (Miller et al., 2001). Differentiation and detection of risk is considerably more difficult at the bank, so these schemes are rare.

Monitoring Options

SSR is of sufficient risk that monitoring alone is normally insufficient. However, monitoring as a additional level of countermeasure can be appropriate. One monitoring technology is a torsional stress analyzer (TSA). A TSA uses the same inputs as a torsional relay, but does not actuate any breakers or other devices. Rather, it contains a customized electromechanical model of the protected turbine-generator that calculated the metal fatigue loss-of-life on the shaft for each torsional event. The cumulative loss-of-life measure is useful in making mitigation, protection, and retirement decisions.

Subsynchronous and Supersynchronous Control Interaction (SSCI)

Subsynchronous and supersynchronous control interaction is the class of events when the dominant contributor to the oscillation is inverter controls. The ability of inverter controls to properly observe and respond to changes in terminal conditions can be compromised by unexpected or unusual response of the host system in frequency ranges significantly faster than "traditional" power system dynamic swings. Many problems of this type arise from interaction with a resonance or natural frequency for which one or more converter controls are unprepared. When viewed from an impedance perspective, all SSCI phenomena include manifestation of negative resistance at the unstable frequency. Controls are a key element in that only active elements such as IBRs, flexible AC transmission system (FACTS) devices (including active dampers), HVDC, generator excitation systems, and others can provide the effective negative resistance needed for instability.

Main Characteristics and Primary Diagnostic Indicators

The participation of IBRs can range from individual devices—especially large installations like HVDC—to homogeneous groups, like individual or tight groups of wind or solar plants, all the way to large heterogenous groups of IBRs such as entire subsystems or regions. Diagnosis and mitigation become progressively more difficult with increased complexity. Sensitivity to power operating point is less clearly dependent than with torsional stability of thermal generation. In marginal stable situations, it has been observed that for given total power delivery (from, say, a plant or region), having more inverters loaded at a lower fraction of their rating tends to be less stable. This is directionally consistent with observations that a lower effective short-circuit ratio (SCR), using SCR methods based on rating, tends to be less stable. Power transfers nearing the end of PV "noses" result in high sensitivity of voltage to changes in active and reactive power flows. This type of instability can be driven by step changes in topology, especially those that result in reduced system strength or substantively altered power flow patterns. Grid faults that result in altered topology are part of the topological examination. Loss of a synchronous generator or grid-forming IBR can also induce SSCI by reducing system strength.

The diagnostician must recognize that all of these observations are indicative, not definitive. Generalizations about sensitivity to operating point must be regarded with caution. In some instances, the response of inverters *during the fault* can be an important factor. This is particularly the case when fault response drives some type of mode switching, in which the controller enforces different control priorities, gains, or limits. Diagnosis of these mode-switching instabilities can be challenging and may rely on especially detailed control documentation and dynamic models. While causality of SSCI is more complex than "simple" misbehavior of voltage regulators (next chapter), field observation of SSCI often, but not always, includes marked voltage and reactive power swings. Active power and angular swings are likely as well and have been observed to dominate in smaller, high-IBR systems (IEEE, 2020).

For oscillations in phasor quantities (magnitude or angle), power (active or reactive), or other control variables at frequencies greater than 5-10 Hz, it is particularly insightful to consider how the effective impedances of the active system components (inverters, entire IBR plants, or even groups of IBR plants) interact with the transmission network impedances at the sideband frequencies around the fundamental frequency. Controls within the active components substantially influence the effective impedances, as seen in the phasor domain, at frequencies above and below the fundamental frequency by a few multiples of the control bandwidth frequency. For example, an inverter current regulator with a typical 1000 rad/sec (159 Hz) bandwidth can influence the inverter's effective impedance out to several hundred Hz. In comparison, an IBR plant voltage control with a time constant of 10 seconds (0.1 rad/sec or 16 mHz) only influences the effective impedance over a very narrow frequency range of less than a fraction of 1 Hz around the fundamental frequency.

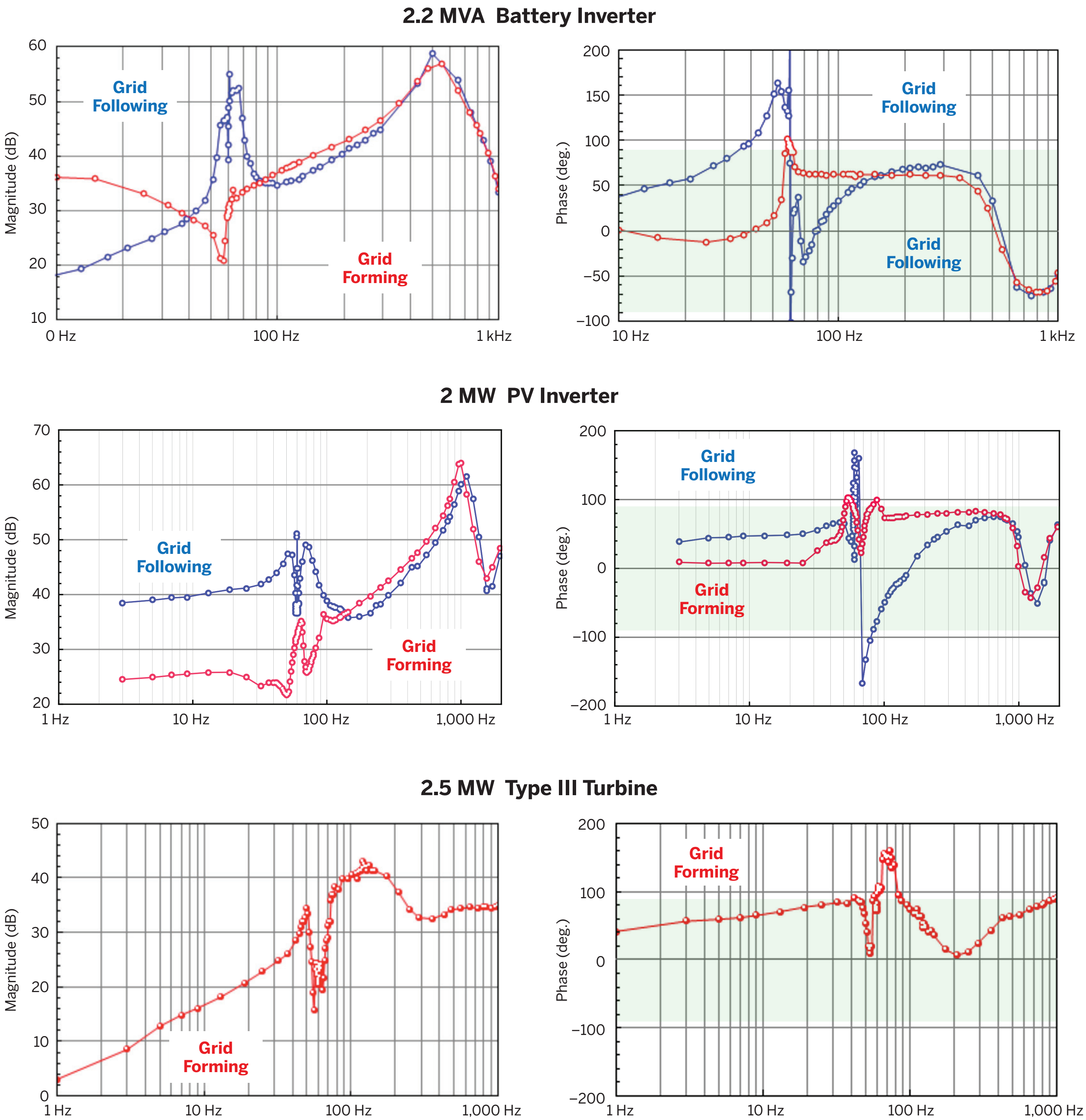
The effective active system component (e.g., IBR plant) impedances have both imaginary (reactive) and real (resistive) components that vary with frequency. Control characteristics can make the effective reactance positive (inductive) or negative (capacitive) over various portions of this frequency range. Unlike a passive system, which always has a positive resistance at any frequency, the resistance of an actively controlled system can be negative over a certain frequency range.

Figure 21 (p. 59) illustrates the impact of control on the effective impedance of several types of IBR inverters. In the figure, impedance magnitude (upper plots) and phase (lower plots) are created using dynamic frequency scans. For the battery system and PV (top and middle, respectively), representative grid-following control is plotted in blue, and a representative grid-forming control is plotted in red. Further, a grid-forming controlled type-3 wind turbine is shown on the bottom. These are all "active" impedance that includes the impact of controls. Inverter current controls substantially influence the effective impedance of an inverter within these controls' bandwidth. For some of the controls, phase lag in this control causes the impedance angle to be outside of a stable range of ±90 degrees, as shown by the green area. For example, the grid-following control on the battery system exceeds 90 degrees at subsynchronous (less than 60 Hz) frequency. This means the inverter exhibits a negative resistance effect at these frequencies. This particular lower-frequency destabilizing effect increases the risk of overall unstable interaction due to less inherent network damping at lower frequencies. This method is an effective screening for risk of instability. Caution is required in use of the ±90 degrees criteria if the sequence frequency coupling effect is not negligible in the impedance of an IBR plant. The frequency coupling effect can be generally ignored at high frequencies above twice the fundamental frequency.

When the effective reactances of the IBR plant and the transmission system (including the influence of other IBR plants) sum to zero at a certain frequency, a natural

FIGURE 21

Comparison of Active Impedances of Various Inverter Controls



An illustration of the impact of control on the effective impedance of various inverters. This is an effective screening method for stability. When the phase impedance angle is outside ± 90°, and the frequency coupling is negligible, the control exhibits negative resistance, which tends to be destabilizing.

Source: Shahil Shah; National Renewable Energy Laboratory.

frequency resonance is created. The system, when perturbed, will produce oscillations at this frequency superimposed on the instantaneous voltage and frequency waveforms. The net-zero reactance sum requires one reactance to be negative (capacitive) and the other positive (inductive) with equal magnitude. If the sum of the resistances is positive, oscillations will be damped. However, if the summed resistance is negative, an instability results, characterized by oscillations that grow until something trips or a control limit is reached.

Considerable insight can be gained using static network representations that calculate driving point frequency-dependent impedances of the transmission network alone, using RLC representations of grid elements. These tools are relatively simple and lend themselves to quick analysis of many grid topologies. Analysis of IBR plant effective impedances can be used in conjunction with transmission system analysis to yield more thorough analysis of resonant-interaction issues. However, calculation of IBR plant effective impedance vs. frequency, including the influence of inverter controls, is not simple and usually requires the use of EMT simulations (as discussed in "Dynamic Model Network Frequency Scans"). Further, in higher frequency ranges (roughly > ~3-4x fundamental frequency), EMT models for passive components may need to be specially adapted to properly represent the high-frequency characteristics of passive components (particularly transformers) to realistically account for system resistance at high frequencies (as discussed in "Network Model Fidelity"). These high-frequency characteristics may not be included within standard library components of commercial EMT software. Identification of conditions that correspond to observed oscillation frequencies can then advise the use of more sophisticated state-space tools and selective EMT time-domain analysis.

Within this class of interactions, this guide separates interactions that are dependent on the presence of series capacitors from those that are not, since mitigation options tend to be rather different. In the IEEE taxonomy (Figure 1, p. 4), these are resonance and converter-driven instabilities.

Four specific variations on SSCI are explored here, followed by a discussion of mitigation for these phenomena.

Series Capacitor Interaction: SSO Specific to Series Compensation and IBRs

One specific variety of SSCI is predicated on IBR control interaction with series capacitors. This is primarily an electrical phenomenon in which interaction with series capacitors is the dominant feature, as indicated in Figure 22 (p. 61). Further, this is distinct in that mechanical torsional aspects, while possibly present, are not a significant factor in the causality of the oscillations.

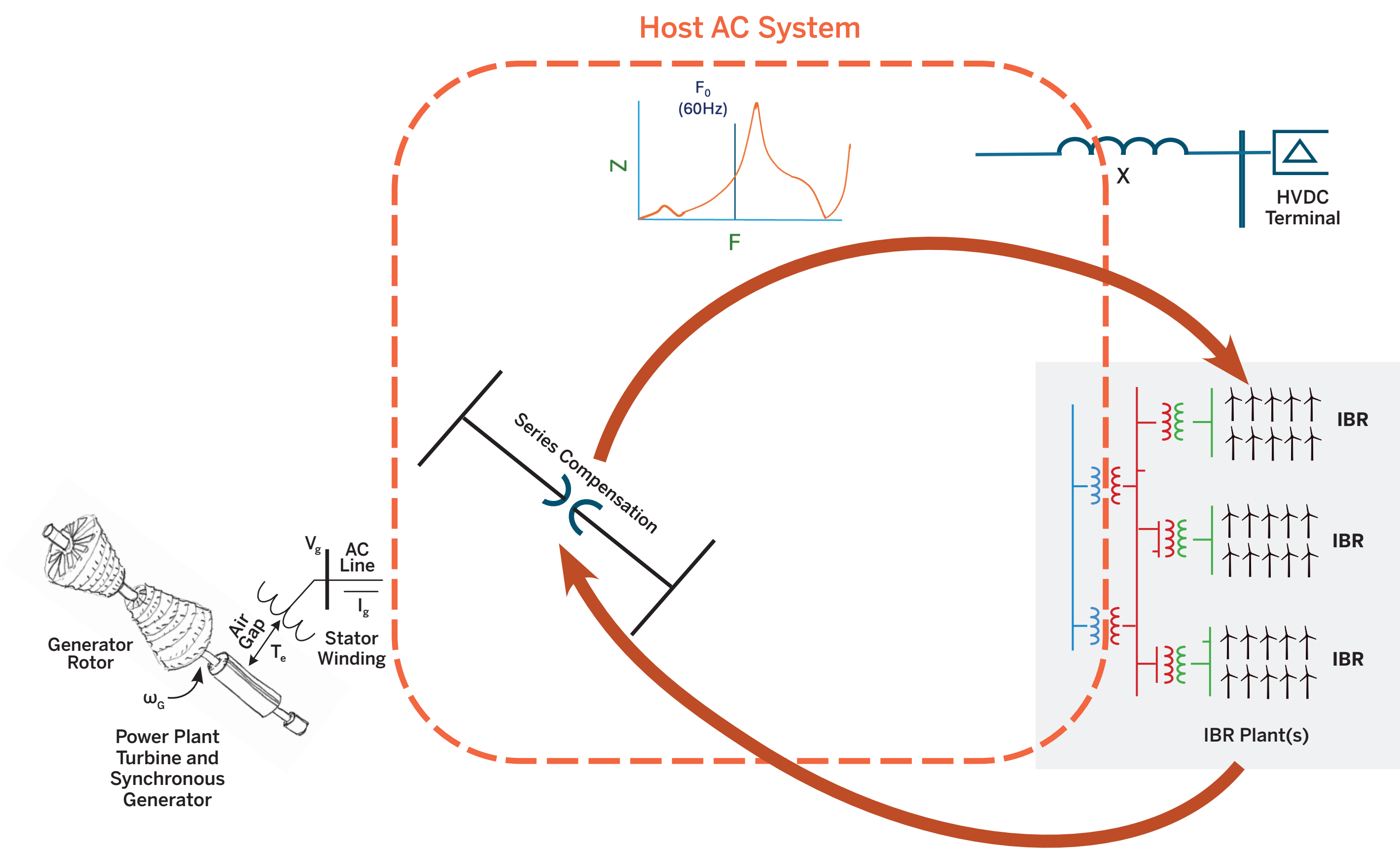
This is the type of oscillation that was observed in a well-publicized event in Texas in 2009 (IEEE, 2020). The SSO event resulted from the fault and clear of an uncompensated line, which left the subject wind plant radially connected through a series-compensated 345 kV transmission line. Rapid subsynchronous current oscillations of about 25 Hz appeared almost immediately, causing high voltages and resulting in damage to both the series capacitors and to the wind turbine crowbar circuits. Some details of the oscillations from that event are shown in Figure 23 (p. 62), with field measurements of phase currents and voltages. Mitigation had two stages. Initially, an SSR relay was installed to disconnect the transmission feeding the wind plant. In the longer term, subsynchronous damping controllers were installed at the wind plant. That improvement coupled with other transmission changes that allowed the level of compensation to be lowered, allowed the relay to be retired.

This is one of the phenomena for which industry language is not uniform: multiple sources have termed this specific interaction as "subsynchronous resonance" or SSR. But even though there were induction generator effects, this event did not include any synchronous machines. Consequently, we have avoided that notation to make certain the user recognizes the distinction between this behavior and "traditional" SSR.

In a transmission system without series capacitors, the system reactance is inductive up to at least the first parallel resonant frequency (i.e., the frequency at which the total system admittance approaches zero), which in typical systems is at several hundred Hz. Even if the effective impedance of the IBR is capacitive at some portion of this range, the capacitive reactance is typically far greater in magnitude than the transmission system's inductive reactance, and resonance between the IBR and

FIGURE 22

Series Capacitor Interaction with IBRs



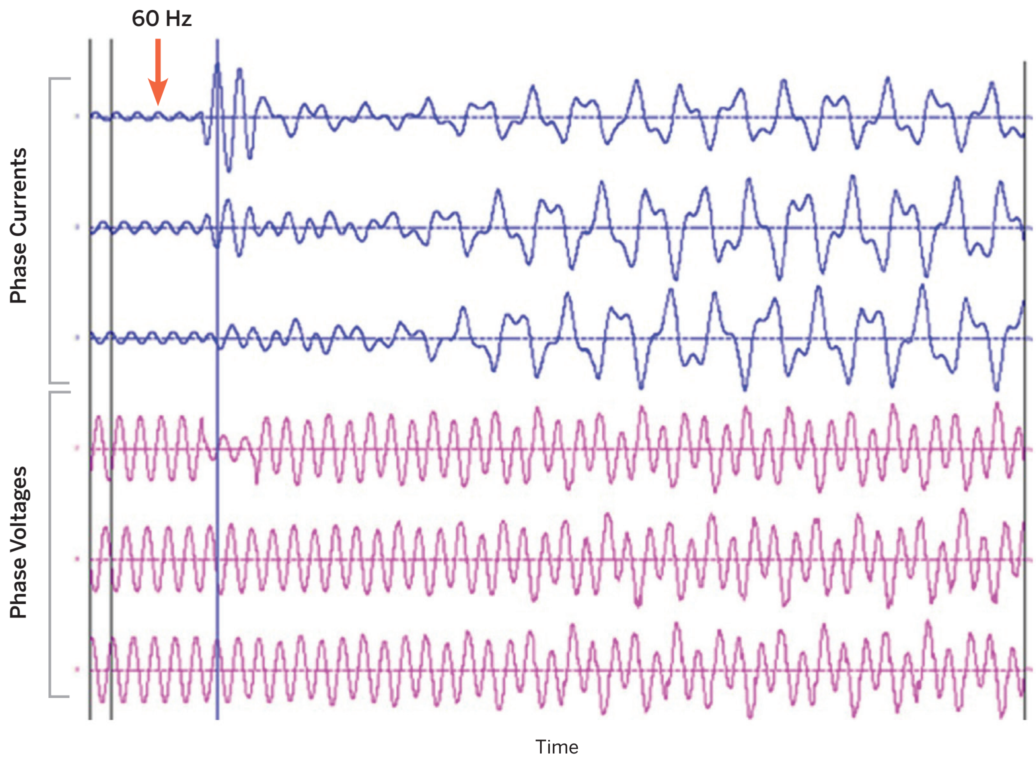
This diagram showing the main components of a power system highlights interactions between series compensation and IBR plants (as shown by the red arrows), which can be a source of oscillatory behavior.

Source: Energy Systems Integration Group.

transmission system will not occur. The presence of a series capacitor in the transmission system can make the transmission system reactance negative (capacitive) at frequencies up to the series capacitor's resonant point and with small magnitude near this resonance point. This low transmission system reactance can add to an IBR effective reactance of opposite sign at a frequency in the vicinity of the resonant point of the transmission system alone. In theory, if the IBR controls are tuned such that the effective resistance is negative and of greater absolute value than the transmission system's resistance at this frequency, an unstable interaction between the IBR and the series-compensated transmission system will result. This will create growing oscillations in the instantaneous phase voltages and currents at a frequency near the transmission system's resonant frequency. Control quantities, like current commands, will oscillate at a frequency equal to the difference between this phasor-domain resonant frequency and the fundamental frequency. In practice, SSO interaction with series capacitors and IBRs has been limited to type-3 wind turbine-generators, where the induction motor slip term results in negative resistance in a fashion that is essentially the same as that found in synchronous machines. This is distinguished from "traditional" SSR in two ways. First, the type-3 wind turbines are not synchronous machines, and second, the inductive interaction of the machine field with the network must involve the controls of the actively controlled AC field. Control interaction is an integral part of the phenomenon.

FIGURE 23

Field Measurement of Wind Plant Subsynchronous Interaction with Series Capacitors



Field measurements of a wind plant entering into subsynchronous oscillations after being tripped on fault clearing to a radial connection through a transmission series capacitor. Oscillations are at about 25 Hz and were of sufficient magnitude to damage equipment. Mitigation included relays, reduced compensation, and addition of damping controls.

Source: Cheng et al. (2022); Electric Reliability Council of Texas.

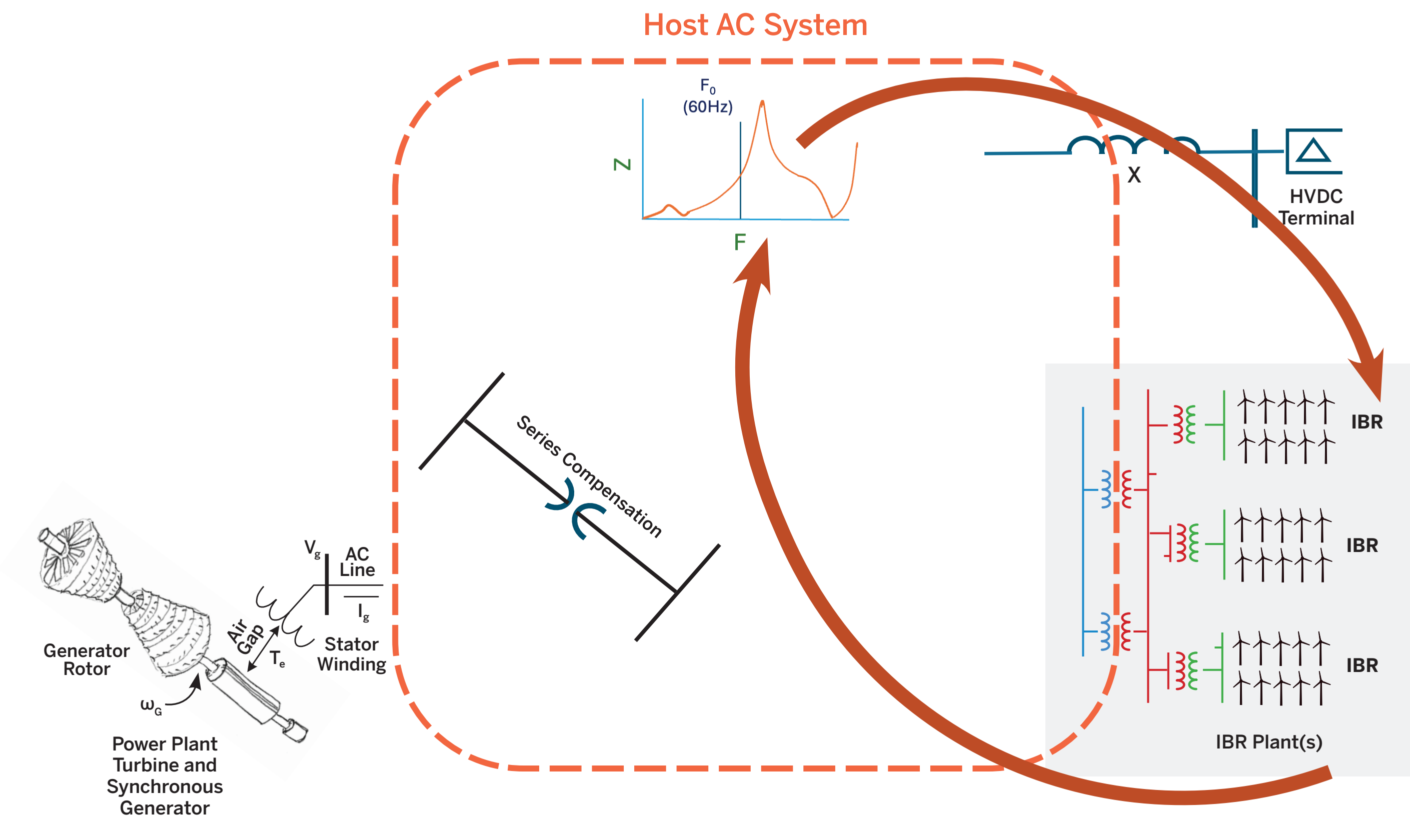
Subsynchronous Interaction Triggered by Metal Oxide Varistor (MOV) Protection

Small signal instabilities involving series capacitors are normally predicated on normal, linear operation of the capacitor banks. Under the high current conditions that accompany faults and some other disturbances, the metal oxide varistor (MOV) protection of series capacitor systems introduces acute nonlinearities as the capacitors are bypassed during high instantaneous current portions of the waveform. The energy discharge of the capacitors may cause high voltage and currents at the IBR, driving more nonlinear behavior. Faults on heavily loaded systems with series compensation can drive the system toward transient instabilities, as discussed in "Transient/Synchronization Stability–Induced Oscillations," which are made even more complex by the nonlinear behavior of the series compensation interacting with IBR controls that may themselves be driven into acutely nonlinear behaviors. Consequently, instabilities that are specifically associated with network conditions *during* the fault may have radically different causality and mitigation. Accurate modeling in EMT time simulations is required.

Supersynchronous Control Interaction Between IBRs and the Network

Another type of SSCI occurs when IBR controls interact with the network. This phenomenon is similar to interaction with series capacitors, in that impedance of the host network is rarely monotonically increasing with frequency. But it is important to note that it is *specifically absent interaction with series capacitors.* Rather, there are resonances and otherwise unexpected maxima and

FIGURE 24
Control Interaction Between IBRs and Network



This diagram showing the main components of a power system highlights interactions between IBR plants and the host network (as shown by the red arrows). The thumbnail plot of impedance vs. frequency depicts the frequency-dependent nature of the network as viewed from different nodes or points of interconnection, which is a key factor in establishing the frequency and damping of oscillatory interactions with IBRs.

Source: Energy Systems Integration Group.

minima of network impedance that will interact with IBR controls. These interactions are purely electrical, and the torsional modes of IBRs (like wind turbine-generators) and synchronous machines are not involved, as suggested by Figure 24. Further, the presumption here is that the transmission network is passive, that is, the resonances are due to the interaction of inductive and capacitive elements and not to controls of elements in the network. The primary concern here is with fast, low-level controls (e.g., PLL and current controls). Unlike series capacitor subsynchronous resonance, causality may not be linked tightly to specific elements (such as a specific capacitor bank) of the host grid. Rather, it becomes the aggregate, and ever-changing, composite as viewed from the IBR controls.

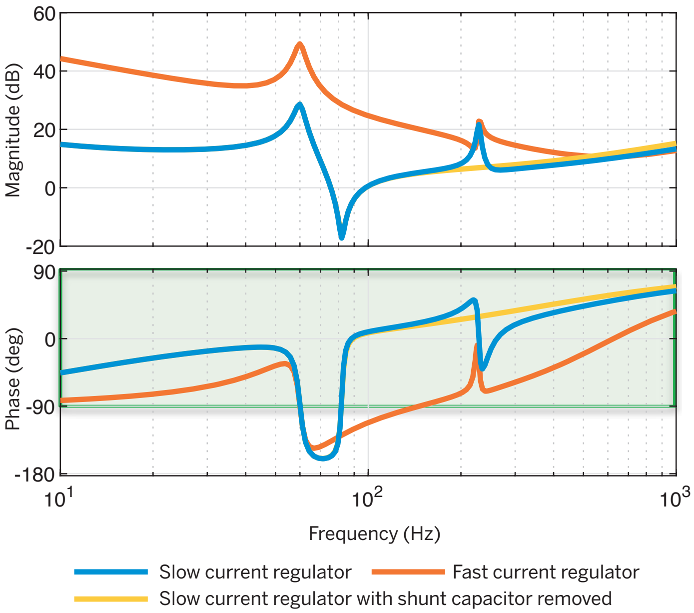
First Natural Frequency

As discussed in the context of subsynchronous control interaction with series capacitors, instability will result when the sum of the driving-point reactances of an IBR plant and the transmission system (including the influence of other IBR plants) sum to zero at a certain frequency, and the sum of the resistances is negative. A capacitive IBR response coupled with an inductive grid resulted in an 80 Hz resonance observed in the field (Fan et al., 2022), as shown in Figure 25 (p. 64).

Bulk power systems typically have a "first" supersynchronous parallel resonance at which the interaction of the inductive and capacitive elements of the system results in a high impedance. In robust grids, this first resonance

FIGURE 25

Supersynchronous Interaction Between an IBR and Network



The magnitude and phase of the combination of a PV inverter and the host grid show a supersynchronous resonance at about 80 Hz. Two variations (fast and slow) in the current regulator shift the phase somewhat, but both remain outside of the green positive damping band of ±90°. A higher frequency positively damped resonance at about 220 Hz is due to a nearby shunt capacitor, which disappears when it is removed (yellow line).

Source: Fan et al. (2022); © IEEE 2022.

might be in the range of 200 to 300 Hz. In weak grids, particularly those with long distances and with significant amounts of shunt reactive compensation or long extra-high-voltage or high-voltage transmission cables, this natural frequency might be quite low, with values only a few tens of Hz above power frequency in extreme, perhaps degraded, cases. Also, the transmission system reactance can be negative (capacitive) at frequencies above this resonance. This unusual circumstance can lead to situations where the transmission system reactance is large enough, and with the necessary sign, for the series-resonant condition between the IBR plant and system to occur within the frequency range where the IBR controls are active. Oscillations at the differential frequency between fundamental power frequency and the resonant frequency are a strong indicator of this variety of instability. A more typical oscillation mechanism can be observed if the natural frequency is relatively low. Step or other sharp stimuli from IBRs will manifest as oscillations between network elements, observable especially in voltages, that may ring down quite slowly.

The Australian interconnected system (the National Electricity Market), operated by Australian Energy Market Operator (AEMO), has multiple examples of this type of IBR-driven instability. The West Murray Zone is an area within the Australian power system that encompasses interconnected networks in southwest New South Wales and northwest Victoria. While this area has been historically low in system strength owing to its remoteness from major synchronous generators in Victoria and New South Wales, it now has high levels of IBRs. These two factors have contributed to oscillations in the area.

The example shown in Figure 26 (p. 65) is from 2019, when a 220 kV transmission line along a key corridor connecting the IBR plants and nearest source of system strength was opened. This test showed poorly damped voltage oscillations at various transmission nodes while the line was opened. The oscillations disappeared as soon as the line was restored. The result of the field test and simulations showed that the frequency of oscillations was approximately 7 Hz with magnitude of oscillations ranging from 0.1% to 0.5% at the 220 kV transmission level.

Diagnosis of Control Interaction with Dynamic Frequency Scans

A strong indicator of SSCI is coincidence or near-coincidence of the frequencies seen in the phase quantities, or the fundamental-frequency complement of those seen in control or phasor quantities, with network resonant frequencies. Interactions of this type appear as oscillations superimposed on the instantaneous phase voltages and currents at frequencies offset from the frequency seen in the inverter control variables by the fundamental frequency. Frequencies seen in the IBR control will be the same as observed as the amplitude or phase/frequency modulation of the phase quantities.

Dynamic frequency scan methods can be especially useful in determining the roles of different actors in a complex system interaction scenario. The example shown above in Figure 9 (p. 20) is illustrative, with a 17 Hz

FIGURE 26

Replication of 7 Hz RMS Voltage Oscillations due to Reduced System Strength

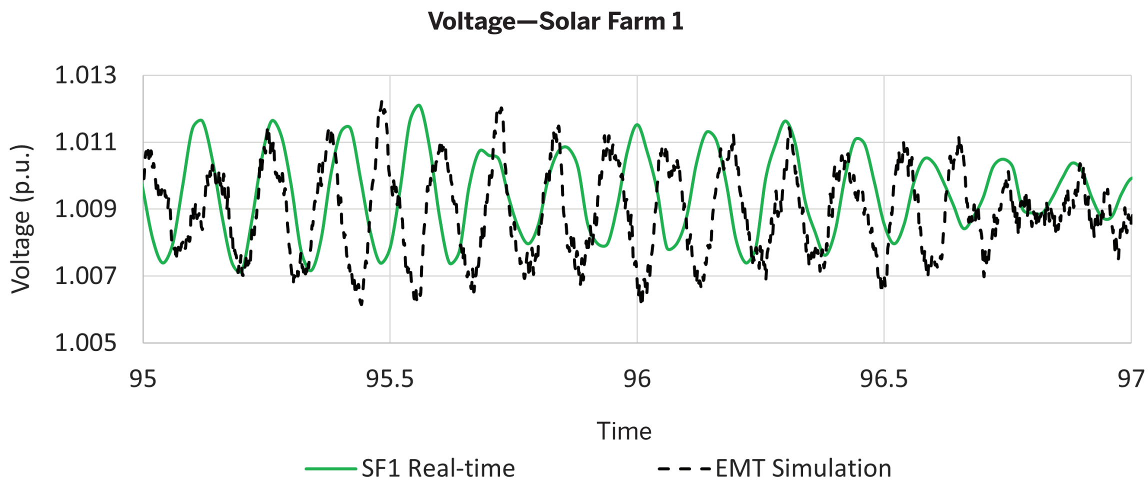


Figure shows voltage oscillations caused by IBR plant interaction with a grid weakened by a switching operation. Diagnostic EMT simulations (green trace) successfully replicate important aspects of the instability shown in the field measurements (black trace).

Source: Australian Energy Market Operator.

oscillation around power frequency being clearly linked to the addition of an IBR.

The dynamic frequency scan construct allows for variation in the network to check on the impact of the resonance. These computationally intensive scans can be augmented with passive frequency scans that allow for testing of many network topologies and conditions, letting the dynamic scans focus on the most relevant or destabilized ones.

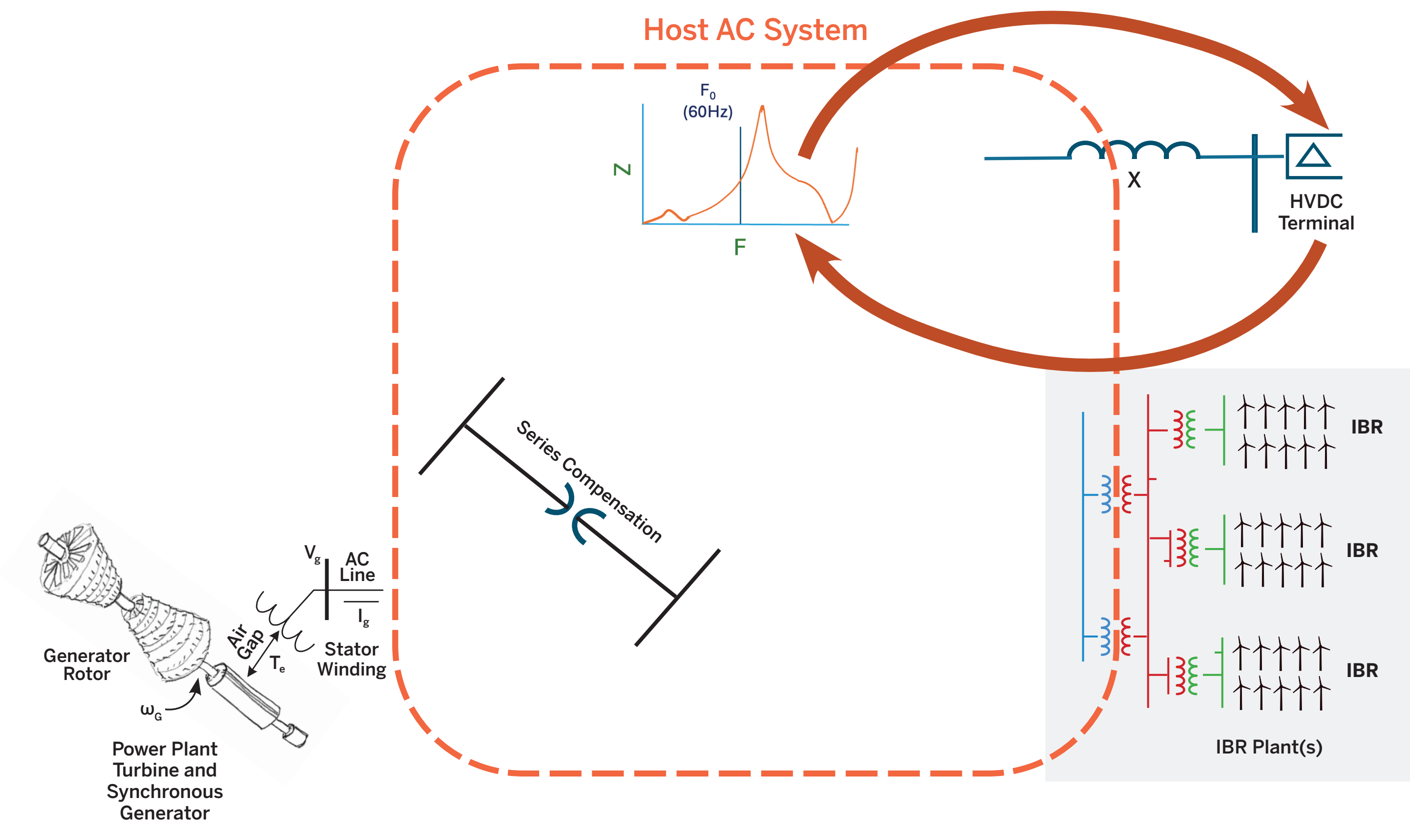
System strength plays an important role in the stability of IBRs. Experience and research with stability of IBRs with grid-following controls—currently the vast majority of commercial installations worldwide—tend to show increased risk of instability as system strength drops. NERC recognizes this and has issued “Reliability Guideline: Integrating Inverter-Based Resources into Low Short Circuit Strength Systems” (NERC, 2017b). A wide range of metrics are available for quantifying system strength, but the practical implication for the diagnostician is to be sure to investigate the weakest condition for which satisfactory performance is required. This observation is currently well established—to the point where there is a risk of focusing *only* on weak grid conditions. However, recent investigations, especially with grid-forming IBRs, also show risks with very strong systems. Specifically, grid-forming controls designed and tuned for successful operation for weak or very weak systems have been shown to be ill-mannered and prone to unacceptable interaction with other resources under very strong grid conditions. As grid-forming technology evolves and becomes more commonplace, this consideration seems likely to increase in importance.

Grid-forming controls designed and tuned for successful operation for weak or very weak systems have been shown to be ill-mannered and prone to unacceptable interaction with other resources under very strong grid conditions. As grid-forming technology evolves and becomes more commonplace, this consideration seems likely to increase in importance.

Some caution is required with establishing causality. Even if one observes that oscillations in the field are eliminated by tripping a particular IBR plant, or removing it from a simulation, this does not necessarily indicate

FIGURE 27

Control Interaction Between Network and HVDC



This diagram showing the main components of a power system highlights interactions between the host network and HVDC (as shown by the red arrows). The thumbnail plot of impedance vs. frequency depicts the frequency-dependent nature of the network, which is a key element in creating conditions susceptible to oscillations due to this type of interaction.

Source: Energy Systems Integration Group.

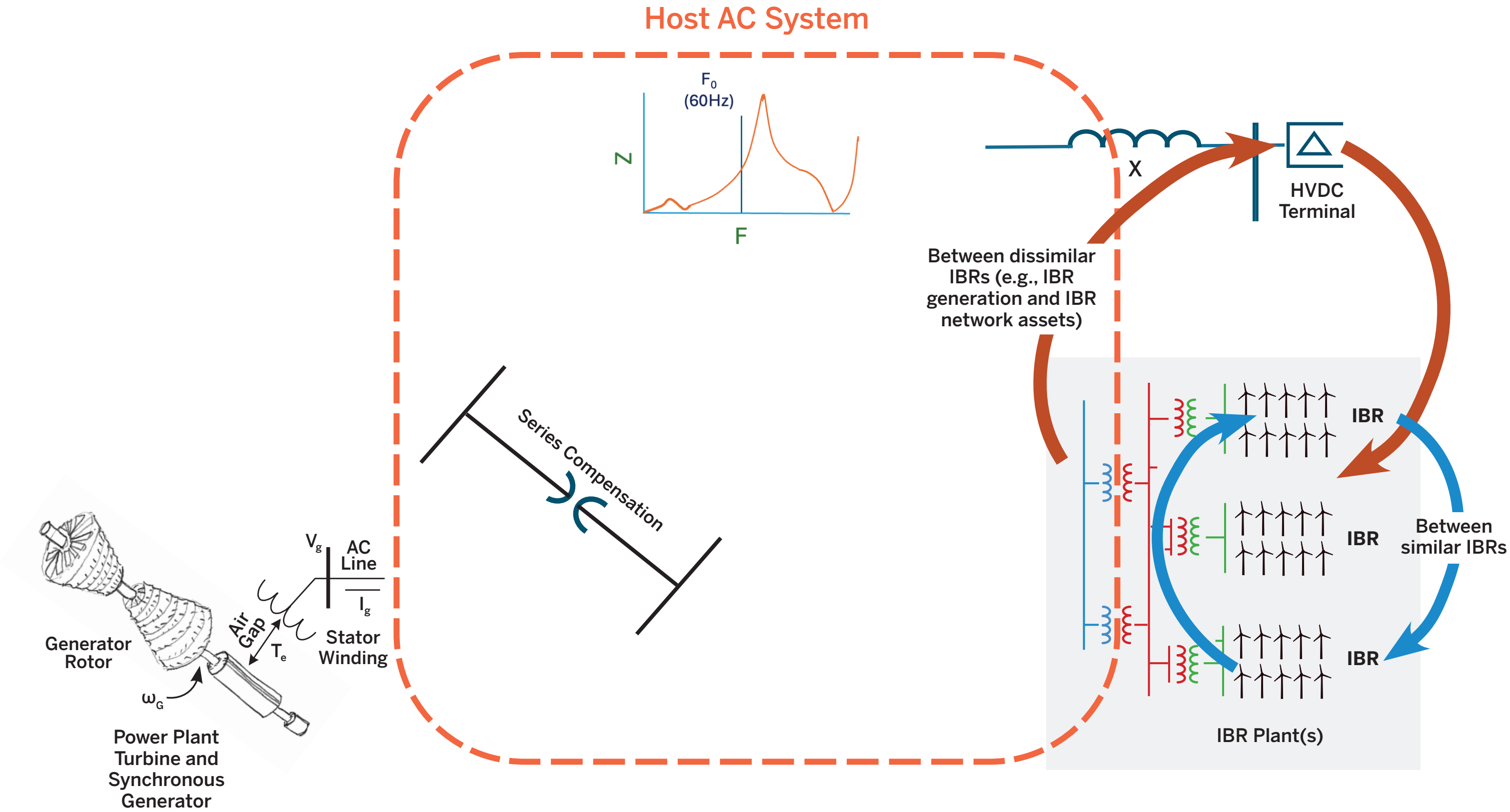
that the particular plant is the source of negative damping. The reactances presented by the plant could merely retune the system natural frequencies such that the natural frequency coincides with a range where another plant or system provides the requisite negative damping. In the example shown in Figure 9 (p. 20), there is no evidence of resonance at any frequency nearby without the IBR plant added, so assigning causality to the subject plant is reasonable.

Control Interaction Between Network and HVDC

This SSCI phenomenon is distinct in that HVDC is a required element (Figure 27). The high power at a point source of HVDC (as opposed to the more distributed nature of aggregated smaller IBRs) has long been recognized as a risk element. There is a well-established body of practice that covers interaction with traditional large LCC HVDC (EPRI, 2022), but that experience has somewhat limited value for voltage source converter (VSC) HVDC due to the inherently higher bandwidth of the fastest VSC HVDC and of VSC inverter controls in general. Newer self-commutating VSC HVDC converters have characteristics that are generally the same, with regard to oscillatory interactions, as IBRs. The body of practice for managing oscillations for VSC is less well established. While both VSC HVDC systems and IBR plants were previously relatively small, compared to historical LCC HVDC systems, both IBR plants and VSC HVDC are now implemented at the GW level. Thus, from a forensic perspective, it is unnecessary to distinguish VSC HVDC transmission systems from IBR plants with similar ratings.

FIGURE 28

Sub- and Supersynchronous Control Interaction Between IBRs



This diagram showing the main components of a power system highlights interactions between IBRs (e.g., IBR plants and HVDC) (as shown by the red arrows) or between different IBR plants which might be in close electrical proximity (as shown by the blue arrows). The interaction of different high-bandwidth controllers typical of these devices creates a variety of mechanisms for creating oscillations.

Source: Energy Systems Integration Group.

Sub- and Supersynchronous Control Interaction Between Different IBRs

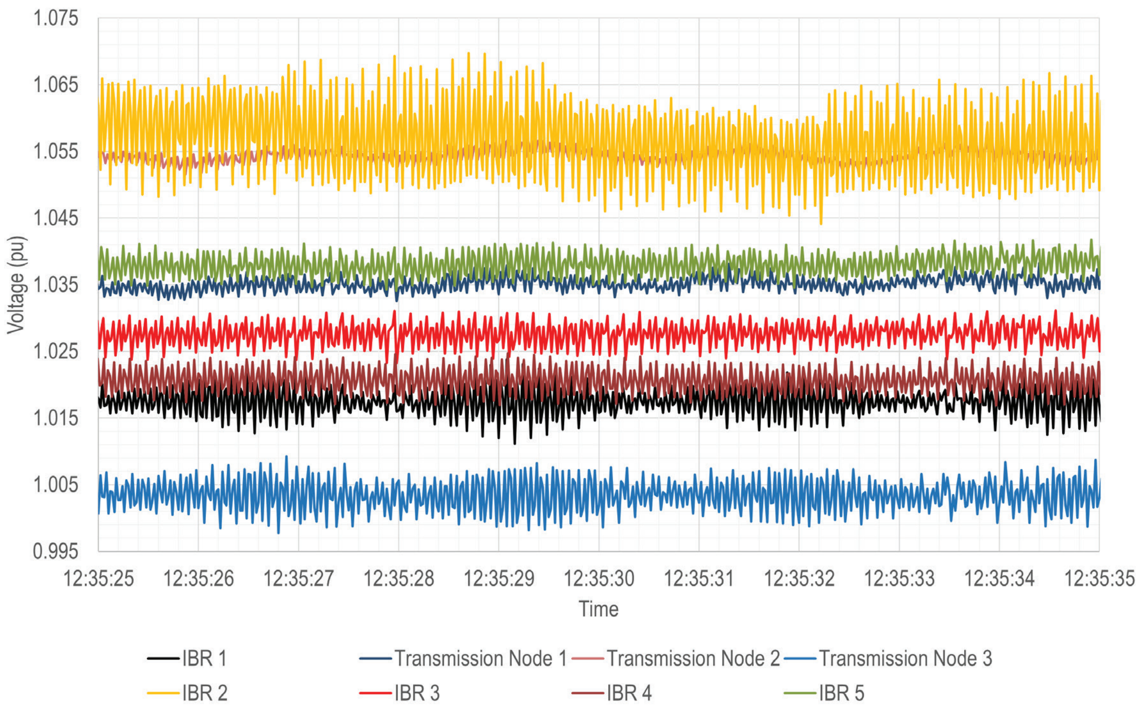
Another SSCI variant occurs when IBRs interact with each other. As seen from the point of interconnection of one IBR plant, other IBR plants in the transmission system will affect the frequency-dependent impedance of the transmission network. If, at any point, the reactances in either direction are equal in magnitude and opposite in sign, a natural frequency resonance occurs. If the sum of the resistive components at this natural frequency is negative, an oscillatory instability results. This instability need not be related to only one IBR, as natural frequencies and stability are defined by all circuit elements. An IBR plant can be a passive participant in an unstable situation by affecting the system tuning, or it can be an active participant by providing negative damping. Two variations are suggested by Figure 28.

Interactions Among Multiple IBRs

Oscillations caused by interactions among multiple IBRs are purely electrical, and the torsional modes of all generation (including IBRs like wind turbine-generators) are not involved. This covers a lot of ground, much of which is relatively new to the industry. Historically, large IBRs were unusual and garnered attention relative to their interaction with the balance of a relatively conventional power system. Now, multiple large IBR plants can be in electrical proximity such that one plant affects the

FIGURE 29

IBR Interaction with Network and Other IBRs, Example from the West Murray Zone in the Australian Energy Market Operator Territory



Field measurements showing the voltage at five solar PV installations in relatively close electrical proximity oscillating in the 15-20 Hz range. There is some phase coherency between them, but it is imperfect, suggesting that they are interacting with each other as well as the host system. Inspection revealed a close correlation between oscillations and low irradiance conditions.

Source: Australian Energy Market Operator.

transmission system impedances seen by other IBR plants, thus creating the opportunity for complex interaction scenarios.

This interaction makes it difficult for the designer of an IBR plant to ensure that the addition of their plant to the system will not result in oscillatory issues, particularly if only fundamental-frequency system data and phasor-based models are available. The present situation in which detailed EMT models are protected by non-disclosure agreements and other legal restrictions, and thus not available to third parties beyond the owner and the interconnecting utility or grid operator, leaves great opportunities for these complex interactions issues to be undiscovered until the plant is actually placed in service. AEMO is one system operator that has addressed this risk by providing a tool that allows interconnecting plants to investigate the impact for their plant on the grid in EMT prior to putting in an interconnection application (AEMO, 2024).

Another example from AEMO, shown in Figure 29, is from 2020 when oscillations were observed again in the West Murray Zone area but in the 15-20 Hz range on various instances with and without any power system disturbances. In this case, multiple IBR plants are in close electrical proximity, and there is a general absence of synchronous machines nearby. The magnitude of oscillations observed was around 2% at the 220 kV transmission level. Based on a process of elimination, a few likely participating IBR plants were identified in the oscillations (AEMO, 2023a). The five IBR plants shown in the figure have phase relationships at the oscillatory frequency that are not completely coherent. This is evidence that at least part of the observed behavior is interaction between them. Further investigation of the source of oscillations revealed a close correlation with low irradiance conditions that resulted in a temporary mismatch between the energy available in the DC link of the solar plant inverters and the reference active power that the IBR is asked to generate. This exacerbated the subsynchronous oscillations. It was observed that strong SCR conditions in the grid could camouflage these control system deficiencies, whereas low SCR conditions tend to reveal these instabilities (Modi et al., 2024b).

Interactions Between HVDC and Other IBRs

Another concern involves interaction between HVDC, especially off-shore DC interconnections of very large-scale wind plants, and IBRs within receiving AC systems (as suggested by the red arrows in Figure 28, p. 67). The high power rating point source, often multiple GW, provides the potential to substantively disrupt the receiving systems. The methods described in this section on SSO are suitable for investigation of these phenomena. The complexity of off-shore HVDC means analysis must include active participation by, at least, the HVDC OEMs. Generic modeling of DC in these circumstances is not appropriate. Various CIGRE technical brochures (CIGRE, 2015) and active working groups (CIGRE, 2023a; 2024) examine details of off-shore HVDC design, control, and interaction with receiving AC systems in general, and IBRs specifically.

Subsynchronous Torsional Interaction with IBRs

This type of oscillation is specific to torsional interaction with inverters that neither is dominated by, nor requires the existence of, series compensation. This is "old school" HVDC SSTI, and many authors simply use "SSTI" without the qualifier to describe this phenomenon. The red arrows of Figure 30 (p. 70) are suggestive of this interaction. The primary mechanism of instability is the loop formed by IBR regulators and the torsional frequencies of the turbine-generator as reflected in the terminal electrical quantities of the generator (Piwko and Larsen, 1982). This phenomenon is distinct from the SSCI phenomena discussed above in that mechanical torsional aspects *are* a significant factor in the causality of the oscillations and represent a substantive risk.

Most problems of this type will involve synchronous generation. While this group of behaviors may be related to the previous SSO topic, including torsional interaction with wind generation, the presence of series capacitors is not a prerequisite for these types of oscillations to manifest themselves. Specifically for this phenomenon, the presence of series capacitors is a largely neutral indicator: they may impact the coupling between the inverters and the affected rotors but are not the primary source of instability. In the IEEE taxonomy (Figure 1, p. 4), this is torsional resonance and converter-driven instability.

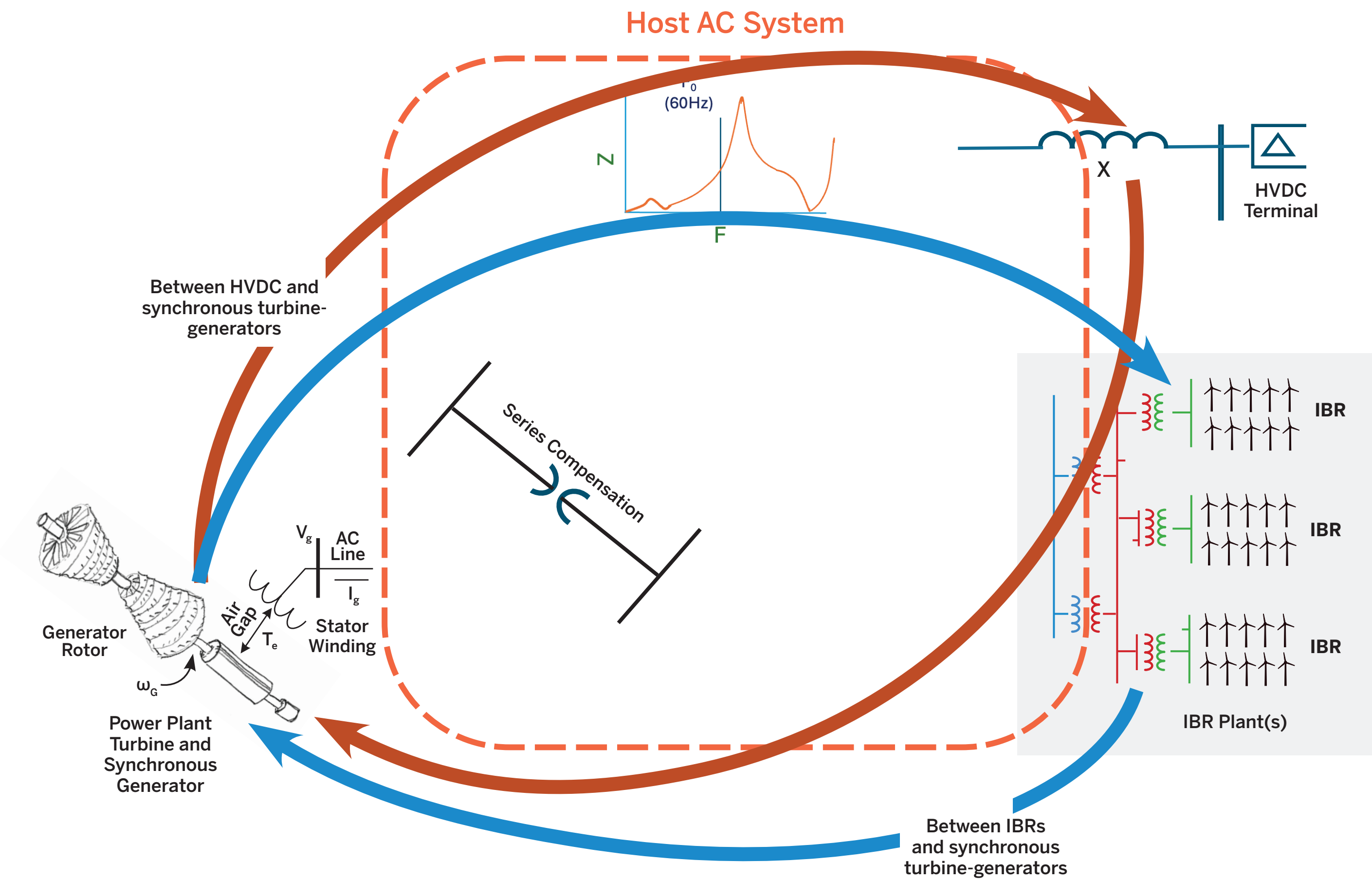
Actual SSTI events observed in practice have been associated with thyristor-based (line-commutated, or "classic") HVDC. This does not mean that SSTI is not also a possibility with VSC HVDC, or even IBRs involving voltage-source inverters and non-mechanical energy sources (e.g., PV, battery). In general, there are few situations today where large turbine-generators are closely coupled with IBR facilities of sufficient rating to engage in SSTI. The propensity for an IBR to engage in SSTI depends greatly on the IBR's control characteristics. Controls can have a band of frequencies where the converter introduces negative damping. If the region of negative damping overlaps a resonance point (either system series resonance or generator shaft mode in the case of SSTI), and the net system damping is negative at that frequency, instability may result. Consequently, a converter may oscillate at different series resonance conditions or with multiple shaft modes. However, there are also converter-driven "fixed" modes that can exist in the absence of external resonances. These interactions can sometimes be avoided with appropriate control tuning, but each unique converter design has limitations on how much (or how) the controls can be modified. Fundamental changes, such as adopting grid-forming technologies may be required.

Countermeasure Need for SSCI and SSTI

As with traditional SSR, any SSCI or SSTI phenomena that involve torsional impacts on turbine-generators must be taken seriously. The same approach for mitigation and protection outlined above in SSR "Countermeasure Design" applies here. If there are no torsional or other identified equipment stress risks, low levels of oscillation (as noted above) may be tolerable.

FIGURE 30

Subsynchronous Torsional Interaction



This diagram showing the main components of a power system highlights interactions between HVDC and synchronous turbine-generators (as shown by the red arrows) and between IBRs and synchronous turbine-generators (as shown by the blue arrows). This type of oscillation is specific to torsional interaction with inverters that neither is dominated by, nor requires the existence of, series compensation. This is "old school" HVDC SSTI, often referred to as simply "SSTI."

Source: Energy Systems Integration Group.

Countermeasure Design

Mitigation Options

The mitigation of most SSCI problems derives from modification of the controls that contribute to negative resistance at the resonant frequencies. The diagnostic process that leads to the identification of causality tends to illuminate the offending elements of the controls. Solutions often involve modifications such as reducing closed-loop gains or improving phase margins at the resonant frequencies.

Physical changes, including the options listed in Table 1 (p. 29), all have applicability for mitigation of SSCI and SSTI. Anticipation of SSTI risks is standard design practice for HVDC and other network equipment; mitigation is normally built into the original equipment.

For the oscillations shown in Figure 26 (p. 65), tuning the control system of the IBR plants involved provided mitigation (Jalali et al., 2021). In that case, other mitigation measures investigated included the reduction in the number of inverters on line when oscillations were observed and the proposed addition of synchronous condensers in the region to enhance system strength. Properly tuned grid-forming inverters were also explored as a mitigation to damp the observed oscillations.

Protection Options

Torsional relays, similar to those discussed above for traditional SSR, are used for turbine-generators subject to SSTI. Protective relays at-the-bank on series capacitors that are sensitive to specific sub- or supersynchronous frequencies (in the current) can trigger bypass of part or all of the bank.

Monitoring Options

The high bandwidth monitoring of network elements can help determine whether oscillatory conditions are of concern, produce trending reports ("are things getting worse over time?"), and provide operation indicators ("under what conditions are the oscillations occurring?").

Torsional stress analyzers, as discussed in the SSR section, can also be used for turbine-generators that are subject to torsional loss-of-life from SSCI or SSTI.

Resonance Between Series Capacitors and Nonlinear or Saturated Network Elements (Ferroresonance)

Passive, but nonlinear, elements in the power system, most notably saturation of transformers and other ferromagnetic elements, present a risk of ferroresonant oscillations that can appear at subsynchronous or supersynchronous frequencies, or even have chaotic non-periodic characteristics. This is quite distinct from most of the resonant phenomena in this group in that controls are almost never a direct driver of the oscillations (although controls may be contributory to creating the operating condition or configuration that resonates, and in very narrow circumstances, may modify the ferroresonant behavior).

Ferroresonance requires capacitance to become topologically in series with a nonlinear inductance, a topology that can occur with series capacitor compensation or for switching situations having one or two phases open in combination with certain transformer topologies. It is a common issue in distribution (Brandt, 2022), where phase-by-phase switching and single-phase protective devices (e.g., fuses) are widely used. For ferroresonance to occur, there must be very little damping in the circuit relative to the unsaturated impedance of the nonlinear element. Unlike load-serving transformers, for which there is almost always sufficient load connected, which avoids ferroresonance, IBR plant transformers may be left connected to the grid for substantial periods of time with no appreciable load or inverters connected. This introduces greater potential exposure to ferroresonance in IBR facilities provided the requisite topological conditions are present. These conditions are infrequent in transmission-connected facilities where individual phase-switching is not intentionally performed.

Ferroresonance in transmission systems tends to be limited to the following scenarios with relatively unusual topological situations, largely unrelated to added IBRs (Valverde et al., 2012):

- Inductive voltage transformer energized via the grading capacitors of circuit breakers having multiple series interrupters
- Inductive voltage transformers configured in grounded-wye on the high-voltage side, connected to an ungrounded system having phase-ground capacitance, and combined with an open phase condition (Pollet, Dennetier, and Vernay, 2022)
- Capacitor-coupled voltage transformers (CCVTs). (These typically have ferroresonance-suppression circuits.)
- Inductively grounded (via Petersen coil) transmission system where the grounding (earthing) inductance becomes saturated due to a system disturbance
- Transformer (including power transformers) having an ungrounded configuration (delta or floating wye) that is energized on only one or two phases such as by a circuit breaker failure or open single-phase disconnect, and there is sufficient phase-to-ground capacitance left connected to the open phase(s) (a cable, transmission line, shunt capacitor bank, CCVT, etc.)
- Unloaded transformer left connected to an otherwise disconnected transmission line that is in physical parallel to an energized transmission line
- Power transformer connected radially via a series-compensated transmission line (Rogersten and Eriksson, 2019)

When IBRs are involved, the problems still tend to be topological and not actually driven by the inverters. This is the case for both the example of Rogersten and Eriksson

(2019) (series capacitors) and Pollet, Dennetier, and Vernay (2022) (static VAR compensator (SVC) ferroresonance). Of the causes/conditions in the list above, only the last scenario—series-compensated transmission line—is potentially relevant to inverter control performance, as distinguished from protective or switching functions which might conceivably lead to a configuration instigating one of the other scenarios. For the last scenario, the large amount of stored energy in a series capacitor bank might allow ferroresonance to be sustained even if inverters are connected to the transformer, and the performance of the inverter may modify this ferroresonant behavior. In this case, the ferroresonance phenomenon starts to overlap with SSCI discussed above. The participation of IBRs is noted as a weak counter-indicator in the screening matrix, not so much because it can't happen but rather because the diagnostic and mitigation measures for ferroresonance are not very well suited here, and SSCI methods are more applicable.

Main Characteristics and Primary Diagnostic Indicators

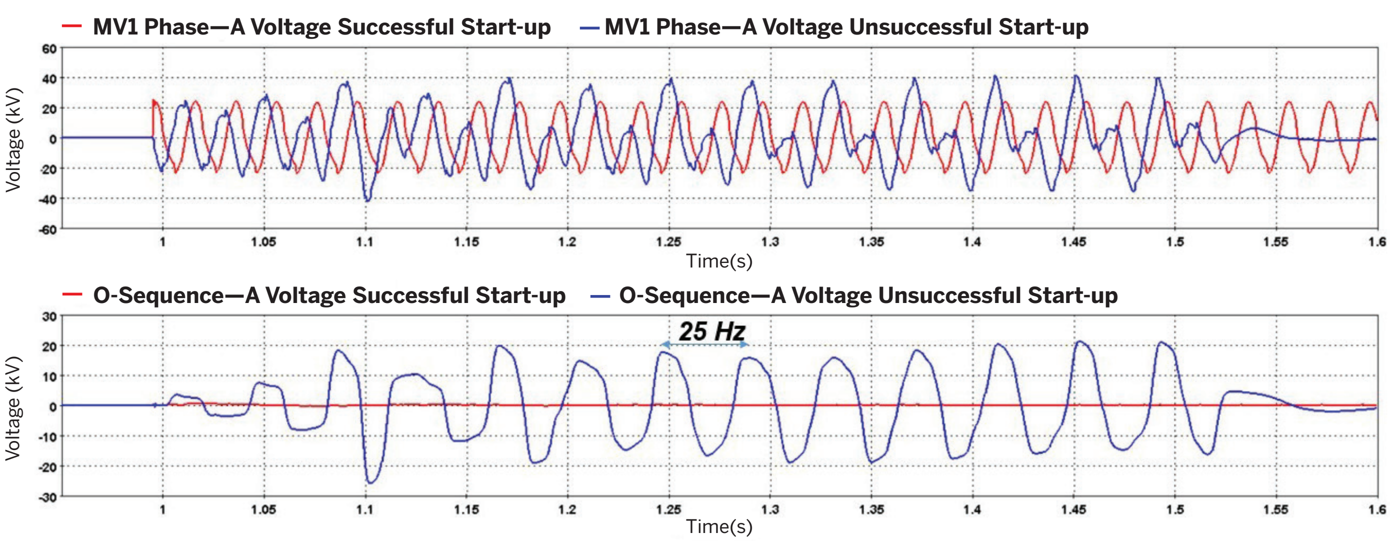
As with most resonance problems, ferroresonance will tend to manifest under a narrow, specific set of grid conditions and topology.

Ferroresonance is typically characterized by extreme voltage waveform distortion at supersynchronous frequencies. There may also be a strong subsynchronous component at a rational fraction (e.g., one-third) of the fundamental frequency; that is, the waveform pattern may repeat at integer multiples of the fundamental-frequency period. (This one-third behavior is shown dramatically in Rogersten and Eriksson (2019).) The waveform may spontaneously shift from one waveform pattern to another. In very severe ferroresonance, the voltage waveform pattern can be completely chaotic. The unbalanced nature of the phenomenon can result in confusing sequence information. For example, the ferroresonance within an SVC system of Pollet, Dennetier, and Vernay (2022) manifested as 25 Hz oscillations visible in the zero sequence of Figure 31. This problem was mitigated by increasing the size of a surge capacitor.

Ferroresonance is also characterized by audible noise of the affected nonlinear inductance which may have markedly increased magnitude and unusual tonal quality. This noise is caused by magnetostriction of the core material as it goes into saturation on each cycle.

FIGURE 31

Ferroresonance in an SVC System



On-site measurement of an SVC being driven into 25 Hz ferroresonance during start-up (blue traces). Note that the instability manifests in the zero sequence voltage. Increasing the size of the surge capacitor mitigated the problem and allows for successful start (red traces).

Source: Pollet, Dennetier, and Vernay (2022).

Causality Conclusions

Ferroresonance is usually the result of an unintended system configuration (e.g., switching that leaves a transformer radial to a series-compensated line) or component failure (e.g., CCVT ferroresonance suppression circuit, circuit breaker failure).

Countermeasure Need

Whether countermeasures beyond avoidance are required depends on the willingness and practicality of doing so. Risks to equipment, such as insulation failures and loss of life, need to be balanced with the cost of avoidance—in terms of capital cost of the physical plant, operational costs, and institutional overhead.

Countermeasure Design

The most effective countermeasures for ferroresonance are (1) avoidance of the configuration that places capacitance in series with a lightly loaded saturable inductance such as a transformer, and (2) providing sufficient system damping. Where such a configuration is unavoidable, it might be possible in some circumstances for IBR control characteristics to be adjusted to sufficiently dampen ferroresonant behavior.

Voltage Control–Induced Oscillations

Voltage control–induced oscillations are oscillations that are driven primarily by problems with controls that are relatively slow acting, i.e., low-bandwidth voltage or reactive power controls. This allows evaluation based on the fundamental-frequency characteristics of the transmission network using phasors. For these, the more complex techniques involving interactions at sideband frequencies, as discussed previously for SSCI, are not necessary or particularly helpful. Here we are mostly concerned with plant-level or individual-device voltage controls on IBRs, synchronous generation, or network devices. Other IBR controls, including current regulation, PLL synchronization, and DC-side voltage regulation, tend to be higher bandwidth and not in this low-frequency category. Analysis of these faster phenomena is given in the section "Subsynchronous and Supersynchronous Oscillations (SSO)" and requires different tools.

Oscillations will tend to present themselves as swings in voltage magnitude and reactive power. Secondary swings in voltage angle and active power will often be present but tend to be of lower amplitude. The voltage control for synchronous generation, IBR generation, synchronous condensers, and most IBR network devices (such as STATCOMs, SVCs, etc.) has some structural similarities, but differences in the detailed structure and speed of response creates different types of poor performance.

Voltage Control Mistuning (for System Strength; Primarily IBRs)

This group relates to problems caused primarily by poor control settings. These tend to be problems that can be remedied with adjustments in control parameters, as distinct from more substantial deficiencies that require physical or structural changes, as addressed in the next category.

At the core of these problems tend to be combinations of gains that are too high for grid strength combined with inappropriately assigned time constants. A significant contributor to voltage control instability can be communication latencies within the IBR plant control structure (as discussed in "Communication Latency"). There are several specific varieties, as follows.

Closed-Loop Instability (Based on Power Frequency Impedance)

In simplest terms, voltage regulators detect departure from a desired voltage and instruct the controlled element, such as a generating facility, to increase or decrease the reactive power output to reduce the error. The regulator has an expectation that a change in reactive power injection will result in a proportional change in voltage. The proportionality is the apparent reactance of the system as viewed from the device.

When the grid is weaker than expected, the closed-loop gain of the system at power frequency increases. Higher gains tend to be destabilizing, with oscillation being visible in the voltage and reactive power output. There is an increasingly common pathology emerging as systems evolve to accommodate more IBRs and owners of IBR assets respond to tightening grid code requirements: voltage controls set too aggressive for system strengths encountered in actual operation. Recent anecdotes report situations in which new IBR plants have voltage regulators set with parameters that provide very fast step (or similar) response. These settings are often field tuned during commissioning, giving "compliant" response *for the grid strength at the time of the commissioning test.* Indeed, sometimes plants are tuned with the objective of achieving the fastest response possible. But when system conditions change—for example, grid topology changes or fewer synchronous resources are committed, leading to weaker grid conditions—the closed-loop response becomes oscillatory or unstable. Permanent changes in system topology, such as the addition of another IBR plant in the nearby electrical vicinity, also present a risk to existing plants with a history of satisfactory voltage performance.

Internal Latency

Communication and process latency between plant-level voltage control and individual devices (i.e., individual IBRs in the plant) has been shown to contribute to poor voltage/reactive power performance in the field. The internal latency is not always well modeled in available voltage control model structures (see "Internal Latency"). The algorithmic structure of fundamental-frequency stability programs is not well suited to the representation of time delays; the often-used expedient of modeling delays as simple time constants (a.k.a. low pass filters) can substantially underrepresent the phase lag that these delays produce within the control structure. High latency combined with high transient gain controls can potentially pose an oscillatory risk.

Analysis and identification of causality for this type of problem uses the tools described in "Tools Overview," especially the sections "State-Space Methods" and "Time-Domain Simulation with Positive-Sequence Phasor-Based Tools," with the added imperative to correctly account for communication latency. In the event that the tuning of available controls cannot be made to work satisfactorily, it may be necessary to make physical improvements to the plant communications.

Voltage controls typically have a rather limited frequency bandwidth due to the time constants applied; therefore, voltage controls tend to affect the phasor-domain equivalent impedances of the IBR plant only in a relatively narrow range around the fundamental frequency. Within this narrow range, the differences in network impedance with frequency are not particularly significant, and thus phasor-based simulation tools and algebraic network impedance representation are fully adequate for analysis.

Fundamental Frequency Control Interaction with Other Voltage Controls

This type of instability can be exacerbated by system latency (see "Systemic Latency"). When there is some type of closed-loop supervisory function with the grid operator—or, less commonly, another layer of hierarchical controls outside the plant(s)—that sends signals to multiple plants or a mix of resources (e.g., plants plus SVCs or other grid-reactive devices), limit cycling can occur. This problem will tend to manifest as forced oscillations (e.g., "hunting") between discrete controllers. For example, one system operator reports that oscillations related to an offshore wind project seemed to be mostly related to the coordination between STATCOM/Power Park Control/wind turbine control (see ESO (2024)).

Signal Diagnostics and Information Processing

Observations of these various modes of instability can be made from positive-sequence phasor quantities. Frequencies might range from a few tenths of Hz to a few Hz. Extracting frequency information via fast Fourier transform (FFT) or other methods is normally necessary. The analytical tools vary by root cause. Power frequency instabilities can normally be analyzed using fundamental-frequency, phasor-based tools. Algebraic representation of the network and conventional state-space eigenanalysis are usually well suited for determination of causality and evaluation of mitigation.

Location of the "bad actor" can sometimes be simple, with high-amplitude oscillations in reactive power and voltage having an epicenter at the equipment with the poorly tuned controller. However, it is often unclear what controller is driving oscillatory behavior, in which case phasor measurement–based analytics can be effective for localizing the problematic equipment (see "Phasor Measurement–Based Analytics"). Once the location is narrowed, measurements of machine field voltage (for synchronous machines) and reactive power commands (for IBRs) can usually pinpoint the bad actor.

Causality Conclusions

The practical reality is that many performance issues arise when the implementation of control settings is not as intended. The first step involves checks of gains, especially regulator feedforward and feedback gains, to make sure they are correct—for example, that they have been properly mapped from per unit to physical quantities. If the implementation of control settings is as expected, e.g., from initial facilities studies or as verified by (NERC or equivalent) field tests, then further investigation with state-space tools is required. If the oscillatory frequency and damping can be approximated with those tools for a reasonable approximation of the system conditions, especially system strength, then causality can be considered as established. Testing for similar instabilities under other credible (usually weaker) operating conditions is a *critical* step in determining the need for countermeasures.

Countermeasure Need

As noted above, the need to mitigate depends on the severity and risk of worse oscillations occurring under credible conditions. Minor voltage variations are often tolerable, as long as customers are not affected. Customer impacts can possibly take the form of flicker. IEEE Standard 519-2022 sets limits on allowable voltage flicker.

Countermeasure Design

The state-space tools used to determine causality are the first stop for countermeasure design, which is often adjustment of gains and time-constants to produce better damping of the poorly damped mode (or modes). Prudent practice dictates that countermeasures, starting with control tuning, specifically target minimum system strength. It is important that parameters that can actually be adjusted in the field are the ones tuned. For example, some time-constants, limits, and other parameters relate to physical features that cannot be adjusted. It is prudent to do simulation tests of time-domain performance with proposed adjusted parameters. For example, reduced voltage regulator transient gains can sometimes degrade transient stability performance. Slower response or poorer transient stability may be at odds with an operations requirement, creating a compliance problem. It may be necessary to improve IBR plant communication latency (discussed in "Communication Latency") to enable sufficiently fast response without unacceptable oscillations.

Voltage Control Malperformance

Voltage control malperformance failures tend to be of a variety that cannot be fixed without changing the plant. In this context, "malperformance" refers to behaviors with more nefarious causes than poor tuning. Problems may be due to poor implementation of good design. Failures such as signal wires in reversed polarity, poor maintenance of moving parts, miscalibrations, or failures due to wear-and-tear can all affect equipment performance, and these types of implementation failures can manifest themselves as forced oscillations. Sometimes repairs are straightforward once the problem is identified. But poor performance because the supplied equipment, as a system, is incapable of being tuned to give satisfactory performance is more pernicious.

Mode-Switching and Limit-Cycling Pathologies

A class of performance pathologies arises from control discontinuities. These can be associated with control limits or with a variety of switching behaviors. For example, poor coordination of integral control elements with limiters can result in control wind-up. Another pathology comes from poor coordination with physically switched elements. One failure mode is for switched reactive elements such as capacitors to impose a substantial step input to high closed-loop gains on continuously acting elements, i.e., a nonlinear inverter control, such that the control enters limit cycles. These may only be associated with a narrow range of operating conditions or system stiffness, and so their occurrence may spontaneously appear and disappear.

One characteristic of these problems that is commonly observed, and is a strong indicator for this type of instability, is continuous oscillations with exactly zero damping and with at least some signals being square or sawtooths rather than sinusoids.

Signal Diagnostics and Information Processing

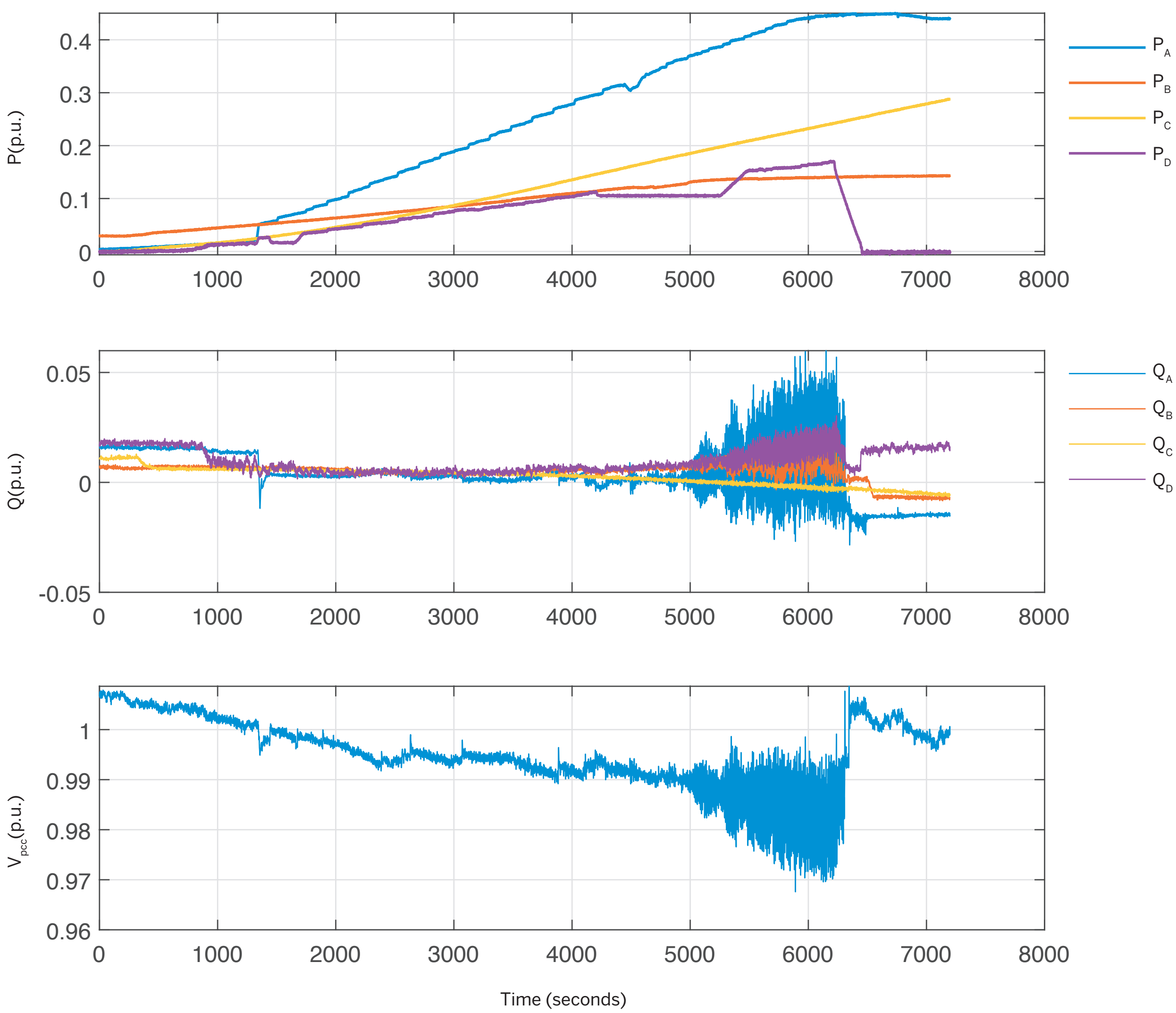
The signal processing and causality investigation for these instabilities initially follows the same process as for control mistuning. But additional signal measurements may be needed to reach conclusions. Measurements of latency may be needed to properly diagnose problems occurring from communication-induced phase lag.

For limit-cycling problems in particular, well-synchronized records of discrete switching actions (e.g., of shunt devices) may be needed in addition to input/output signals from closed-loop controllers. Standard plant models available in dynamic simulation packages may not include or accurately represent the details of control systems that coordinate IBR closed-loop controls with other switched equipment within a plant.

An example of a plant control creating roughly 1 second periodicity oscillations is shown in Figure 32 (Fan, Miao, et al., 2023). In this ramping event, the voltage sensitivity of the system increased as the loading increased. The increased stress accompanying the increased loading

FIGURE 32

Plant Voltage Control Malperformance Primarily Due to Latency



Active power of a large solar PV plant with four separate measurements is shown increasing over about 2 hours. Voltage oscillations driven by swings in reactive power stemming from excessive delays start at the power level reached at about 5000 seconds, and continue to grow as the system is stressed by approaching the nose of the PV curve for this point in the host system. Elements of the plant begin to trip at around 6300 seconds.

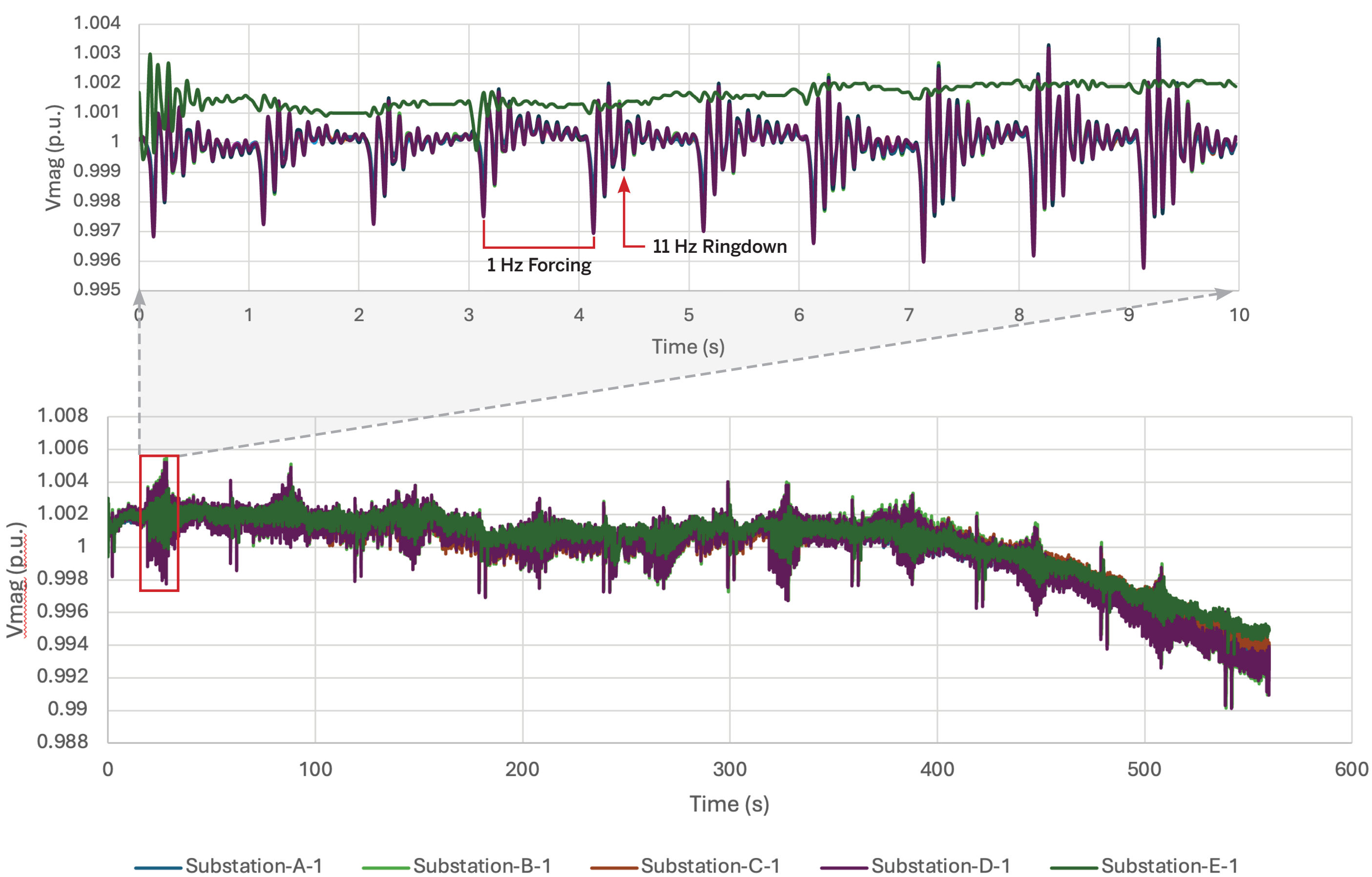
Source: Fan, Miao, et al. (2023); © IEEE 2023.

(of the type that accompanies approaching the end of the nose curve in Figure 11, p. 23) is progressively destabilizing. The plant, an approximately 1 GW solar installation, can be seen in the SCADA traces becoming unstable. Excess delays in the reactive power/voltage plant control drives slowly growing oscillations as the system crosses into an unstable zone.

An unacceptable 1 Hz forced oscillation is shown in Figure 33 (Zhu, Farantatos, and Chen, 2023). This example is illustrative of a situation in which a natural frequency is stimulated by periodic forcing of substantively different (i.e., slower) frequency. The system here is being perturbed at 1 second intervals by a malperforming load that is inadvertently pulsing. Each perturbation results in a relatively well-damped ringdown at 11 Hz. In this situation, the higher natural frequency swing is not problematic. The traces shown are from PMUs at various substations in the system. The source of the disturbance was determined using the EPRI forced oscillation localization tool (FOLT)—one of the tools discussed in "Methods for Locating the Source of Oscillations."

The malperformance in this example was driven from a single large load. Other types of forced instabilities can originate in distribution systems and be driven by poor coordination of distributed energy resources (DERs) (such as rooftop solar PV) with other distribution system

FIGURE 33
Load-Driven Forced Oscillations Example



Field measurements of forced oscillations occurring at 1 Hz that are driven by a misbehaving load. A positively damped system resonance at 11 Hz is stimulated by each discrete forcing event. The bad actor was found using an oscillation localization tool. Some substation plots are behind others and thus not visible.

Source: Zhu, Farantatos, and Chen (2023), with annotation.

equipment. The distinction between voltage malperformance and other instabilities, such as transient or synchronizing instability, is less clear. Fortunately, some of the localization methods presented here will work to at least identify the offending distribution subsystem for further investigation.

Causality Conclusions

There is often a "smoking gun" for problems of this variety, with clear indication of miscoordination. For more subtle close-loop instabilities due to structural deficiencies, the causality process is essentially the same as for control mistuning, but with the added feature of analysis showing that adjustment of available controls will not result in acceptable performance.

Countermeasure Need

In the case where unacceptable physical switching of devices is observed, the need for countermeasures is clear. Otherwise, the criteria discussed in "Assess Need for Countermeasures" above largely apply here.

Countermeasure Design

Mitigation will strongly depend on the topology of existing hardware. Changes in communication equipment are appropriate for latency-induced problems. Alternative switching logic—for example, the introduction of reactive power droop to switching logic—can be very effective. An example of added droop eliminating observed reactive miscoordination of autonomous voltage regulators in multiple, heterogenous plants is given in Miller et al. (2012b).

Voltage Control/Electromechanical Torque Mistuning

Oscillations due to voltage control combined with electromechanical torque mistuning are instabilities in which there is substantive interaction between the voltage/reactive power control and the torque/active power behavior of resources. In the IEEE taxonomy these are small signal rotor angle and voltage instabilities (Figure 1, p. 4). Traditionally, the interaction between synchronous machine excitation and torque's two components—synchronizing and damping—leads to the need for power system stabilizers (PSS). With the introduction of IBRs, there are new variations. Here we are specifically concerned with oscillations that are driven by voltage controls that adversely impact damping torque on the remaining synchronous resources.

Mistuning of Power System Stabilizers (for Synchronous Machines)

The advent of high-response excitation systems on synchronous generators about half a century ago led to poor electromechanical damping of synchronous machine swings. The development of PSS followed, becoming the preferred technology for adding damping to these oscillations. In many systems, PSSs are now mandatory equipment on synchronous generation, and normal initial interconnection processes include tuning the PSS to provide good damping under expected grid conditions. But with substantive changes in grid topology, generation mix, and loadings, PSS performance can degrade, requiring retuning (IEEE, 2009).

PSS can be the culprit in local intra-plant oscillations, i.e., oscillations between synchronous generating units within a single plant. This is a common issue, especially with the older speed-input type PSS. With this type of PSS, the gain has to be kept very low to mitigate the interaction, which limits the PSS effectiveness and its ability to damp oscillations. Modern PSS may have a variety of inputs beyond speed, including frequency, power, accelerating power, voltage, and branch current (WECC, n.d.). The intra-unit interaction issue with speed inputs, in addition to others like torsional interaction, led to the development of the new generation of dual-input PSS, which is less suspectable to those types of interactions. However, many of the old systems are still in operation today. While keeping plants with older PSS properly tuned is important, the more pressing concern is that the substantial topology and generation mix changes that accompany the growth of IBRs can cause all types of PSS to be improperly tuned. Typically, it is necessary for poor behavior to be observed in the field before retuning is undertaken; however, some systems are taking a more proactive approach and regularly retuning PSS as their systems change. Reluctance to retune PSS may be exacerbated by the fact that PSS can participate in inter-area oscillations as well as making retuning more complex (discussed more in "Interregional Power Oscillations").

Mistuning of Synchronous Condenser Excitation Controls

The renaissance of synchronous condensers for mitigation of short-circuit strength and voltage control issues presents a somewhat specialized set of issues, a portion of which can be addressed with properly tuned PSS. Synchronous condensers have a tendency toward oscillations of the type and at the frequencies traditionally addressed with PSS. The reactive-power-only function of synchronous condensers means that the relationship between excitation and torque is less conducive to adding damping using signals and controls common to conventional PSS. Industry experience with adding PSS to synchronous condensers is limited (Grondin et al., 2006). Generally, PSSs for condensers seem to require multiple input signals, not just machine speed, to be effective. In addition, there is a current trend of adding synchronous condensers in remote parts of systems with a preponderance of IBRs for voltage and short-circuit support. This combination of electrical remoteness and proximity to multiple IBRs presents risks for a variety of oscillatory problems, some of which can be ameliorated with relatively conventional PSS. But other types of mitigation —currently at the research stage—may also be possible through options applied to the synchronous condensers. For example, equipment similar to SEDC (supplemental excitation damping control) that is used for torsional damping of SSR on synchronous turbine-generators could be applied to synchronous condensers. There is also the possibility that other resources in electrical proximity (e.g., a wind or solar plant) might add control functionality to add damping to condenser swings. From a practical perspective, it is good to recognize that oscillations of synchronous condensers are usually due to overly aggressive voltage regulators. So, the first line of mitigation to consider is reduction in their transient gain, recognizing that doing so could result in degradation of other dynamic performance.

Mistuning of Power Oscillation Damping Controls (POD) for Network Elements and IBRs

Power oscillation damping controls for large conventional IBRs like HVDC and SVCs, while relatively rare, have been in use for decades. In most cases, these controls are custom designed with careful system analysis when they are first deployed (Smed and Andersson, 1993). They often target specific inter-area oscillations with known frequencies and mode shapes (as discussed in "Inter-regional Power Oscillations" below). Changes in network topology and generation mix (i.e., the addition of multiple IBRs) and the loss of institutional memory can result in poor performance. Poor phase relationship between the actuating response (e.g., Q modulation) and the observed system oscillations is evidence of tuning problems. The first line of action is retuning, and possibly reconfiguration of control structures, using the techniques described in the "State-Space Methods" section.

Main Characteristics and Primary Diagnostic Indicators

PSS mistuning may manifest as sustained speed oscillations of synchronous machines. Oscillatory frequencies from around 0.1 Hz to about 2 Hz will show up in speed, active power, and other signals. Accompanying oscillations of field voltage, sometimes in exact quadrature, can usually be seen. Faster frequencies of this range are often indicative of relatively localized problems. Interaction can occur between individual units in a single plant, especially when PSS (and/or excitation) settings are significantly dissimilar, or with nearby plants. Tuning of PSS for damping of individual machine oscillations or small groups of machines is well-established art. The efficacy of PSS for damping low-frequency inter-area oscillations affecting many machines in large grouping is limited. Controllability of these types of oscillations tends to vary with mode shape, and it is difficult to realize robust controls—ones that successfully damp one or more inter-area modes across a range of credible operating conditions.

A properly functioning PSS will normally cause machine field quantities and reactive power output to "dither." Apocryphal anecdotes of PSS being shut off because plant operators did not like to see the meters unsteady have circulated for decades. So, even though disabling PSS is normally counter to reliability rules, the diagnostician should consider the possibility when unexplained oscillations are observed.

Signal Diagnostics and Information Processing

The relatively slow (about 0.2 to 2.0 Hz) positive-sequence oscillations that can be mitigated with PSS can normally be analyzed with phasor-based time- and frequency-domain tools. Most PSSs include intrinsic filtration of input signals to allow the damping control to target the right frequencies. Signal processing of field measurements can sometimes help with identification and tuning, although it is common for PSS tuning to be done with just desktop analytics.

Causality Conclusions

As noted elsewhere, the cause of oscillations can often be narrowed to a single bad actor. Investigation needs to include representation of a large enough portion of the system to allow for distinguishing between a single poorly performing plant and large multi-machine or multi-source participation. The modal participation tools discussed above can help. The ability to improve systemic oscillations with retuning of a single resource may be limited. Nevertheless, practical considerations (of schedule and resources) may make a one-plant-at-a-time approach the preferred choice over a broader systemic overhaul of controls.

Countermeasure Need

As always, negatively damped oscillations require action. Oscillations with low positive damping may be tolerable if analysis shows they represent a low risk of becoming negatively damped under credible conditions. There are reliability performance requirements that target low-frequency electromechanical oscillations in many jurisdictions by specifying minimum damping ratios. Individual resources that violate these criteria need attention. There is greater urgency when detailed causality analysis shows that the observed oscillations may become unstable for moderately more stressful operating conditions or for larger stimuli. In this case, the diagnostician can regard observed behavior as a warning to act.

Countermeasure Design

As noted earlier, PSS tuning is well established art. The IEEE tutorial is an excellent starting point (IEEE, 2009).

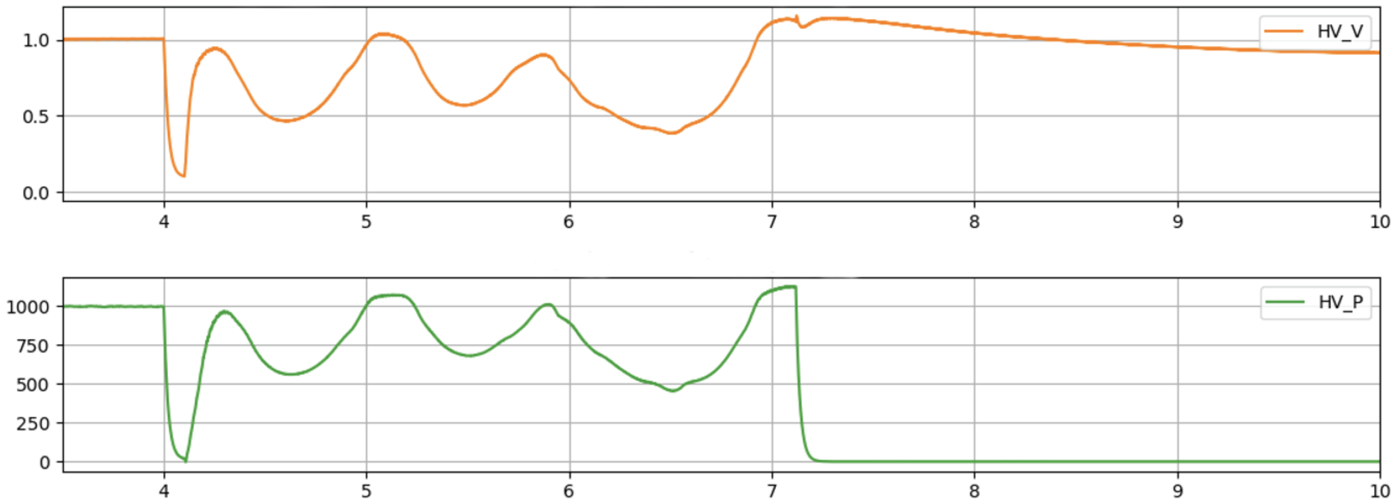
Transient/Synchronization Stability–Induced Oscillations

Transient stability failures often result in abrupt, even monotonic, failures. However, transient stability problems in which the instability is less severe can often present as oscillations. While the industry has tended to make a strong distinction between large-signal and small-signal instabilities, in practice the distinctions are sometimes less clear. The oscillations addressed here are focused mainly, but not exclusively, on power transfer limits and oscillations that are more closely aligned with "traditional" transient stability (and voltage stability) limits. An example of such a failure is shown in Figure 34 (p. 81) (Richwine et al., 2023). In this case, violent post-fault-clearing swings in active power and voltage are negatively damped. The system loses synchronism on the 4th swing, though the first post-fault voltage dip is in violation of stability criteria. This particular system is dominated by IBRs, and mitigation of this synchronizing failure is achieved through improvements to the transient voltage control of the IBRs. While there is clearly a periodicity of about 1 Hz in these swings, the behavior is actually quite nonlinear. State-space analysis alone would be insufficient to identify causality and mitigation.

As systems approach transfer limits, either by continuous means such as system redispatch or from discrete topology changes such as the loss of a transmission element, they will become ill-mannered. Large events, like fault-and-clear, that involve substantial amounts of energy exhibit well-understood loss of synchronism behavior. Analysis rooted in concepts like equal-area criteria (e.g., Figure 11, p. 23) is appropriate for systems dominated by synchronous generation. During faults, synchronous machines accumulate energy from their prime mover turbines that is not delivered to the grid. Following the clearing of the fault, that same energy must be dissipated, before the two ends of the system separate. The nastier and longer the disturbance, the more energy is accumulated. The more degraded the post-fault grid, the harder it is to get rid of the energy. The stability problem is a race, as the grid must be able to carry the pre-disturbance power and enough power to dissipate the excess energy fast enough to win the race against separation. With systems dominated by IBRs, export stability changes, with the energy associated with the particular disturbance being less important, and physical limits on power transfer—including voltage stability limits—becoming dominant. Synchronization challenges are driven by transient voltage collapse consideration, as discussed next, and less by energy.

FIGURE 34

Synchronization Failure in an IBR-Dominant Exporting System



This is an example EMT simulation in which a grid-following resource is exporting power at a point near the nose of the post-fault PV curve. The system voltage (orange trace) and active power (green trace) exhibit unstable 1 Hz oscillation, ending in loss of synchronism as the voltage control fails to reestablish control. The behavior is highly nonlinear and would resist successful diagnosis using only state-space methods.

Source: Richwine et al. (2023); Telos/HickoryLedge.

Another class of transient stability failure is that associated with fault-ride-through failures (NERC, 2023). Much attention has been given to this problem recently, with specific focus on IBRs tripping or going into momentary cessation in response to system disturbances. While these stimulating events tend to be discrete and not oscillatory, the resultant change in power flow and energy balance can move the system into an unstable operating condition that is oscillatory.

Incipient Voltage Collapse

Oscillations can manifest when the system is driven close to voltage collapse. The distinction between synchronization failure and voltage collapse is much less clear in IBR-dominant systems. A useful parallel to the angle-power curve is the power-voltage curve, both shown with a representative phasor diagram in Figure 11 (p. 23). The P-V "nose curve" shows how voltage declines as power transfer increases and indicates that there is maximum at the tip of the nose. Attempts to push power in excess of the maximum will result in lower voltage and less power being transmitted. This is voltage collapse, and if it happens rapidly, it is transient voltage collapse. The reader familiar with "equal area criteria" (McCalley, n.d.) will recognize that moving right along the y (angle δ) axis in a system with synchronous machines involves energy accumulated by the machines which must be dissipated. With IBRs, there is no energy equivalent on the PV portion of Figure 11, consequently, maintaining healthy voltage at the points of power injection is critical. But beyond that, there is practically nothing that can be done on either end of the network to alter this maximum. Transfer capability is all in the network. Changes there can increase the maximum, but there is little that the generating resource can do besides reduce power injection. This can be termed "the entitlement" of the network. This simple observation plays a critical role in the calculation of stability limits with systems dominated by inverter-based generation in the future.

Static PV and VQ analysis has been used as a tool for reactive power planning and reactive compensation studies. With IBR-dominant systems, these techniques are showing promise for identification of transfer limits. In essence, the region of dynamic attraction near the end of power transfer nose begins to degrade—showing increasing voltage sensitivity to variations in active and reactive power. As a disturbed system migrates toward a new equilibrium on or near the end of PV nose curve, it will often exhibit oscillatory behavior. Plotting time-domain measurements or simulation results in the PV plane will show trajectories that "circle" around an equilibrium. These show up as oscillations in time traces.

Approaching voltage collapse is also indicative of proximity to large-signal synchronous transfer limits. The duality of Figure 11 (p. 23) applies here. The distinction in causality and mitigation becomes more important for large-signal events. The energy involved in, for example, severe or prolonged faults makes the acceleration of all resources, but especially synchronous machines, a critical consideration. Sufficiently violent events will exhibit monotonic failure, but it is common for unstable systems to have multiple swings before separation occurs.

Signal Diagnostics and Information Processing

The analysis for this type of instability starts with time-domain signals. The diagnostician needs measurements of voltage and power flows that are time synchronized and cover the geographical area involved. Measurements solely from generation terminals are unlikely to be sufficient to produce confident diagnoses. Synchronized PMU measurements of nodal angles can be very helpful here (see "Phasor Measurement–Based Analytics"). These problems will have a tendency to spread across systems, with weak points in the middle showing the most acute voltage swings during oscillations. Finding these points—the "belly" of the swings—helps with understanding and with identification of network-based mitigation. Time-domain simulations can be augmented with static analysis—PV and VQ curves are helpful. Frequency-domain tools can point to controls (and specific state variables) that have the strongest participation in the oscillations. Some extra care is needed using linearizations and resulting eigenvalues, as these types of oscillations tend to occur in quite nonlinear regimes. So, while eigenanalysis can be highly useful in identification, quantitative performance (and mitigation proof) needs to be done with at least some time-domain simulations that are specific to the limiting conditions. These types of problems are highly dependent on the specifics of pre- and post-disturbance power flow conditions.

The sequence of analysis and tools for diagnosis of this phenomenon is open to debate. The jury is still out as to whether the diagnostician can solely trust available phasor-domain modeling to capture this phenomenon well. Nevertheless, proceeding with caution in a sequential approach can produce good outcomes. Start with static phasor tools (load flow, then PV/QV), followed by time simulations, linearizations, and perturbations, and, in the case of IBR-dominated behaviors, go to EMT. Ultimately, EMT may prove to be the main tool, but jumping directly to EMT tools without preamble to help understand systemic constraints can lead the diagnostician astray.

Causality Conclusions

The static tools alone, i.e., PV nose curves, can provide a good initial indication of causality. Specifically, if static curves show that the system is well past the maximum (i.e., past the end of the nose) under conditions where the oscillations are observed, that may be diagnostically sufficient. However, these tools alone do not give very fine resolution, and so may indicate that the conditions observed are marginally stable. In this case, the ultimate arbiter is high-fidelity time-domain simulations.

Countermeasure Need

For instabilities that arise as power transfer approaches limits, the first question is, "is this level of power transfer necessary?" If the unstable condition can be economically and environmentally avoided (e.g., by redispatch), then the solution is process-related or institutional. However, if the cost of operating around the instability is unacceptable, then countermeasures are warranted.

Countermeasure Design

Countermeasures here fall into two major categories: modification of control and equipment at the IBR, and grid modifications. One of the most effective options, and therefore one of the first avenues of investigation, is to improve voltage control at the exporting plants. In general, voltage controls that "reach" farther into the grid, for example, that regulate the extra-high-voltage point of interconnection or even reach farther, can increase transfer limits *if they are fast enough.* If IBR plants hit reactive (or internal voltage) limits during these events, effective options are to augment reactive range (e.g., by adding shunt reactive devices) and manage swing voltages within the IBR plant (e.g., by adjustment of transformer taps). Since substantial distances are involved, improvements to the network may be needed. The locations identified as weak points tend to be good candidates for dynamic shunt compensation. Fast inverter-based compensation, like SVCs, STATCOMs, and thyristor-controlled series compensation (TCSC) can be highly effective in extending stability limits. Established practice for design of compensation, both shunt and series, apply here, with the added proviso that fast control interaction between these added network elements and the exporting IBRs must be avoided (per section "Subsynchronous and Supersynchronous Control Interaction (SSCI)").

Fault-Induced Delayed Voltage Recovery (FIDVR) and Other Load- or DER-Induced Oscillations

Oscillations that originate between the distribution system and the bulk power system have taken on greater importance with the advance of DERs. To date, a few power systems have experienced fault-induced delayed voltage recovery (FIDVR). However, the amounts of inverter-based loads and inverter-based DERs are increasing. These sometimes exhibit complex and unexpected responses to faults, which raises concerns that FIDVR problems may increase. While these responses are usually single transient events (i.e., not oscillatory), it is possible for them to manifest as multiple cycles of extreme behavior which will appear as oscillations on the grid.

Air Conditioner– and Other Load-Induced FIDVR

The interaction of air conditioner and other compressor loads with bulk power system faults has been well documented (NERC, 2015). The main characteristic of FIDVR is acutely elevated reactive power consumption by loads following a deep fault-induced voltage depression. This is driven by compressor motor stall and results in poor recovery of voltage. Substation voltages may "hang" well below acceptable levels until the loads, in aggregate, move to a new operation point—either recovered or tripped. Complex systems may experience a multiplicity of events that look like system oscillations. This problem is diagnosed through a combination of measurements of substation voltage and active and reactive power flow.

A new concern that has not, as of this writing, manifested itself in the field is common-mode misbehavior of large amounts of homogeneous loads. This concern has surfaced with particular attention to electric vehicle charging. Projections of massive electric vehicle adoption mean that unprecedented amounts of similar inverter-based loads will be added to grids in the near future. A variety of pathologies related to fault-ride-through behavior for electric vehicles have been postulated, including momentary cessation, which could possibly drive oscillations. Similar concerns have been raised recently about huge cryptomining and data center loads exhibiting pathological behavior during disturbances.

The proliferation of large inverter-based loads introduces a new and potentially important (even dominant) element. In particular, the fault-ride-through behavior of newly electrified loads, such as electric vehicle chargers and electric heating and cooling systems, have been flagged as systemic risks. Of particular concern is cyclic cessation and recovery of loads in response to system upsets. Such acutely nonlinear behavior of even a relatively small fraction of total system load can drive forced oscillations. Closed-loop control instabilities of individual loads, especially large loads (for example, industrial processes) have been known to disrupt systems. While not exactly FIDVR, this is closely related.

DER-Induced Oscillations

With high levels of DERs, the collective dynamic response of distribution systems is largely new ground for the industry. The concerns about fault ride-through and momentary cessation raised above apply here as well. The grid events of this sort documented by NERC have been caused by poor performance of multiple, large transmission-connected IBR plants. However, the aggregate behavior of many DERs has been postulated to present similar risks. There is typically little difference between inverters used for transmission-connected IBR applications and those used in DERs. The impedances between DERs and the bulk transmission systems, on a per-unit of inverter rating basis, are not much different from transmission-connected IBR solar and wind plants. The salient differences relate to the adjacency to local load and applicability of different standards and interconnection requirements, which result in variances in the level of sophistication in IBR controls.

One impact of standards is that DER inverters are required to have active anti-islanding functionality in order to obtain UL-1741 certification, which is in turn required by electrical codes. There are various forms of DER anti-islanding functionality, which are not required to be disclosed. However, testing by Sandia National Laboratory and EPRI has identified a number of common anti-islanding algorithms. Several of these can be roughly considered to be power system "de-stabilizers," as their intended role is to drive inadvertently islanded distribution circuits into voltage or frequency instability, thus initiating DER tripping when voltage or frequency limits are reached. The impact of high levels of DERs with such algorithms on bulk transmission systems is largely unknown and is a prime topic for investigation.

Beyond the discrete or step-wise performance issues associated with DER fault-ride-through behavior are aggregate closed-loop response concerns. As inverter-based DERs start to implement new closed-loop controls, e.g., for IEEE 1547 compliance, new mechanisms for oscillations will surface. Pin-pointing causes may prove tricky. As discussed in the section above, dissipating energy flow methods can be useful for finding the bad actor. But these will tend to be limited to pointing toward the interface (i.e., the substation) between the offending distribution system and the bulk power system. Further investigation, reaching into the distribution system by taking measurements and creating distribution system models for diagnosis, are likely to be needed to pinpoint causality.

Frequency or Active Power Control–Induced Oscillations

All of the oscillations in this category are active power–dominant phenomena, and they can involve all types of generation resources. This group of instabilities is distinguished from the previous group (transient stability, voltage stability, etc.) by the time frame and dominance of active power in the observed signals. Broadly, there are two classes of problems:

- Localized problems, in which the oscillations tend to be most observable in power flow on individual lines or across interfaces
- System-wide problems, in which oscillations tend to be observable in frequency, especially in the common (or zero) mode frequency of the system

The control of frequency and area interchange shifts over time from the response of autonomous local speed and/or frequency control (e.g., governor response) to centralized area generation control. The diagram widely used by NERC is shown in Figure 35 (Eto et al., 2010) (p. 85). The NERC figure is augmented to include representation of inertial response and new fast frequency response (FFR) services. The inertial response, by definition, drops to zero at the frequency nadir marking the end of the arresting period. The inclusion of inertia as a service is subject to industry discussion, but each of these five services has the potential to cause oscillations. Temporal overlap of the services, which have substantively different characteristics, presents opportunities for miscoordination that could lead to oscillations.

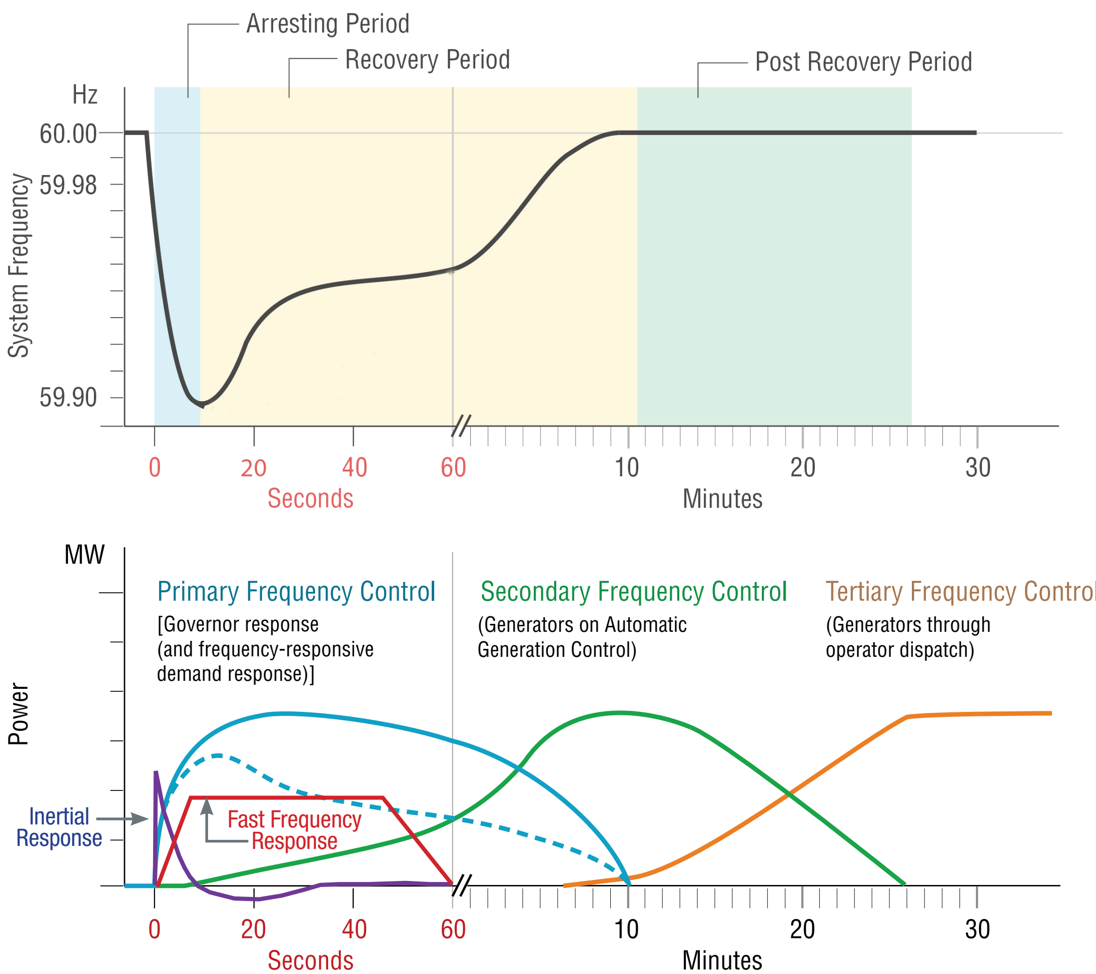
Primary Frequency Control/Governor Function Mistuning

Primary frequency control of synchronous generation is well-established art. Active power output is the sole actuator in a control system with multiple objectives, mainly: maintaining unit speed (as a proxy for grid frequency), maintaining scheduled dispatch, maintaining acceptable emissions or environmental performance, and respecting unit limits. The portion of the control typically associated with power system dynamics and stability, the speed and power setpoint, is "upstream" of the turbine controls. The speed regulator portion typically has a few parameters that can be set, most notably, gain (droop), speed deadband, and some transient gain reduction control blocks. The physical response of turbines is largely built-in, and there is little opportunity for adjustment of properly performing equipment.

Many of the physical and control mechanisms that can contribute to oscillatory behavior are either not included or greatly simplified in standard turbine-governor (e.g., IEEE) models. While some types of misbehavior can be captured with these models, many can't.

FIGURE 35

Frequency Recovery and Frequency Control Regimes



This is the figure widely used by NERC showing three distinct periods following a loss-of-generation event, and frequency control services that align with those periods. Inertial response and fast frequency response have been added to the figure. The five services all have characteristics that can lead to oscillations. The temporal overlap between services also creates the potential for oscillatory interaction between them.

Source: Eto et al. (2010), with annotation; Lawrence Berkeley National Laboratory.

Excessive deadbands or "slop" (inaccuracies) in the turbine control (such as valve actuation, fuel delivery, and particularly fuel/gas pressure regulators) can result in a unit (or possibly an entire plant) "hunting" or otherwise oscillating. Constant magnitude swings with zero damping are evidence of such hunting behavior. Another potential cause of oscillations is excessive time delay in communication of signals to the unit governor.

The requirement that IBRs have primary frequency response functionality increases the scope of unintended consequences. Unlike thermal and hydro turbines, which have intrinsic physical limitations on the speed of response, IBR resources are likely to be capable of extremely fast response. This can be systemically beneficial, but it also introduces opportunities for problems. Higher gains—i.e., smaller droops—are already becoming standard practice for some IBRs in some systems (MacDowell et al., 2023). OEMs have offered features such as asymmetric frequency response (e.g., more aggressive response to over-frequency than under-frequency) (Miller et al., 2012a) and zero deadbands. The IEEE

2800 requirement for IBRs to have fast frequency response capability with response times of less than one second and default droop of 1% introduces particular concerns with regard to this type of stability issue (IEEE, 2022b).

Further, IBR wind and solar plants have hierarchical controls, as discussed in the "Communication Latency" section. Because frequency is invariant (with the exception of small and very fast transient variations) within the plant, frequency response may be implemented on an individual unit basis. However, some IBR plants use a hierarchical control structure for frequency response with primary frequency response originating at the higher-level plant control and being communicated (e.g., as power setpoints) to many individual devices in the plant (wind turbines, solar panels, battery strings). The individual devices then respond, subject to their physical and control characteristics.

The introduction of new faster frequency services, notably fast frequency response (FFR), introduces an additional or extended consideration for frequency service–induced oscillations. Some FFR services are discrete, triggered services—acting once in a given event (as opposed to proportional response) (Du, 2023). These services have the possibility of creating transient stability or voltage problems but have little ability to induce oscillations. However, other FFR services that have prescribed response profiles with the potential to be triggered multiple times have the potential to cycle, driving forced oscillations. Yet other implementations are continuously acting (i.e., frequency droop–based), with effectively very high transient gains. Miscoordination with other services and across systems presents mechanisms for oscillations—including interregional oscillations, as discussed next.

Individual Resource

When a malfunction occurs in an individual governor on a synchronous turbine-generator or the primary frequency response (PFR) function on an IBR resource providing a similar frequency-control service, the misbehaving device can often be found by inspection or by using the techniques outlined in "Methods for Locating the Source of Oscillations."

Synchronous turbine-generators often have control systems that maintain and protect units when they are spinning but not synchronized to the grid. These systems may have substantively different speed, power, voltage, and fuel-delivery objectives. One failure mechanism is for these systems to stay active after the plant is synchronized to the grid, resulting in interference or malperformance of the unit.

An initial check by straightforward simulation and eigenanalysis using standard (or available) models can screen for excessive gains or delays in the main control—as represented in the models. Plant controls should show good performance in very simple simulations (see discussion in "Equipment Model Fidelity") and in simulations with realistic representation of host system inertia and PFR.

Once checks are made to ensure that these problems are absent, the communication and process latency is a prime suspect (as discussed above in "Communication Latency"). Primary frequency control in IBRs is commonly implemented at the plant-level controls. Measurement of frequency error is processed through droop controls to create a plant-level power (or delta power) instruction. Distribution of power instructions to individual units (e.g., wind turbine-generators) based on the plant-level instruction is necessary. All of these steps introduce delays and potential for miscoordination.

When there are complex interactions between multiple resources, the diagnostics are a lot harder. Character and forensics are similar to those required for interregional power oscillations, as discussed next.

Interregional Power Oscillations

Main Characteristics and Primary Diagnostic Indicators

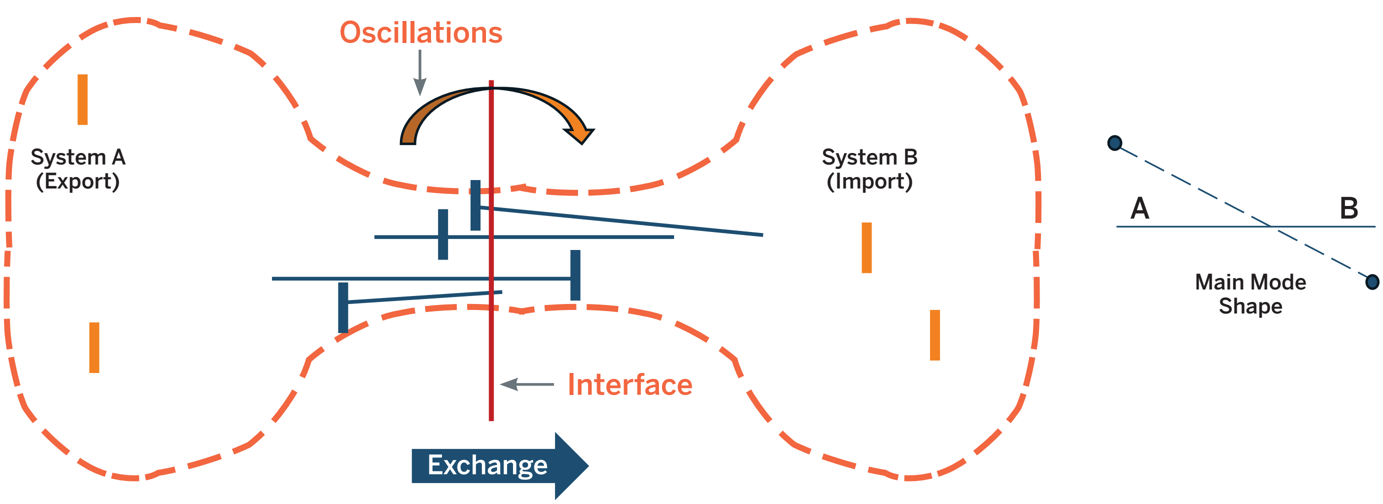
Interregional power oscillations are characterized by active power swings involving entire interfaces between adjacent major regions of interconnected systems. These power swings can have periodicity of longer than 1 second, and sometimes reaching tens of seconds. They often involve multiple systems or jurisdictions and may cross borders. The poor damping of inter-area oscillatory modes tends to have complex genesis. Diagnosis and mitigation can be both technically and institutionally difficult (NERC, 2019).

The conceptual sketches below illustrate types of topologies that can be subject to these kinds of oscillations. When there are only two systems, as suggested by the "dog bone" topology of Figure 36, the oscillatory mode shape tends to be simpler, as sketched on the right. Power swings between the two systems will tend to have a single dominant frequency, which changes somewhat with generation commitment. There is often a well-defined interface (as suggested by the red dotted line) that consists of the power lines between the two ends. These are sometimes referred to as paths. In more complex topologies, such as the ring illustrated in Figure 37 (p. 88), there can be a multiplicity of modes interacting. In this illustrative topology, four regions of an interconnected system create the potential for several different modes, of which two are shown. The mode shape on the right shows regions A and D mostly coherent and oscillating against regions B and C, which are also mostly coherent, at the first modal frequency. This would be an east-west mode here. The second modal groups the regions differently, resulting in a north-south mode.

Net flow variations across interfaces are often easy to spot, and systems with known inter-area modes can have dedicated measurement and detection operations functions that monitor and alarm when flow swings arise. One such system monitors the California-Oregon Interface, which has a long history of oscillations. The system in Figure 12 (p. 24) includes monitoring of this interface. The identification of causality of poor damping in these geographically dispersed oscillations can be difficult. The tendency to oscillate is rarely only the result of a single misbehaving resource; rather, oscillations may result from the interaction of groups of resources in one of the regions or from other systemic influences. However, sometimes a single bad actor can push an otherwise marginally stable system into unacceptable oscillations. This behavior of the type suggested by the second arrow from the left in Figure 2 (p. 7). From a practical perspective, the immediate need of the diagnostician is to find the driver (a.k.a. "the last straw"). The search for individual or small groups of bad actors starts with measurements and use of the causality location tools discussed in "Methods for Locating the Source of Oscillations."

FIGURE 36

Dogbone Inter-area Topology

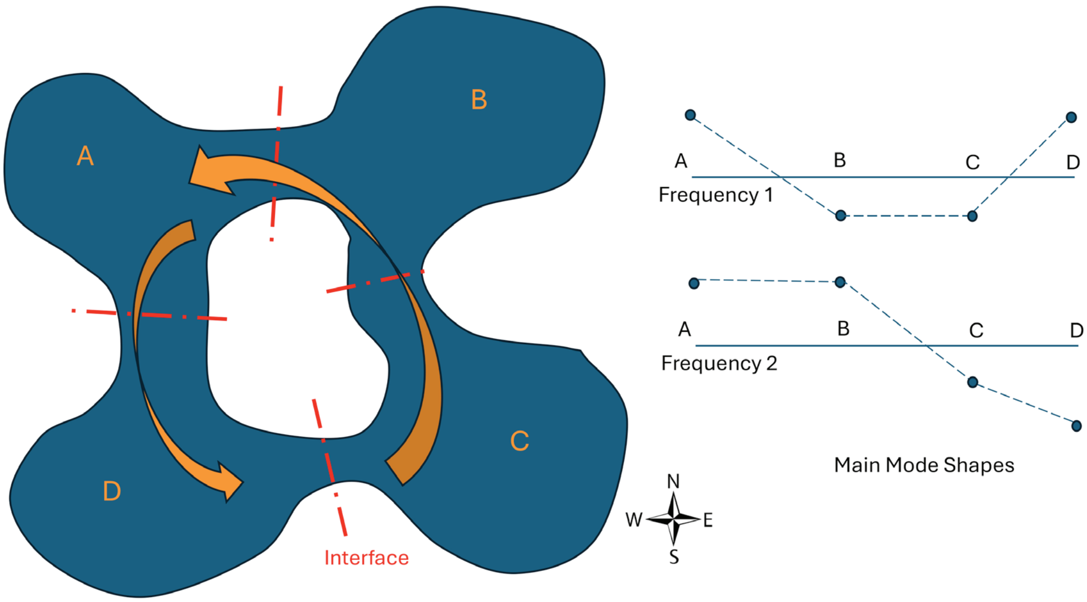


This conceptual sketch illustrates one type of topology that can be subject to interregional power oscillations. When there are only two systems, the oscillatory mode shape tends to be simpler, as sketched on the right. Power swings between the two systems will tend to have a single dominant frequency, which changes somewhat with generation commitment. There is often a well-defined interface (as suggested by the solid red line) that consists of the power lines between the two ends, which are sometimes referred to as paths.

Source: Energy Systems Integration Group.

FIGURE 37

Complex Multiple Interregional Oscillatory Topology



This conceptual sketch illustrates a more complex topology that can be subject to interregional power oscillations. In topologies such as the ring shown here, there can be a multiplicity of modes interacting. In this sketch, four regions of an interconnected system create the potential for several different modes, of which two are shown. The mode shape on the upper right shows regions A and D mostly coherent and oscillating against regions B and C, which are also mostly coherent, at the first modal frequency. This would be an east-west mode here. The second mode groups the regions differently, resulting in a north-south mode.

Source: Energy Systems Integration Group.

Figure 38 (p. 89) shows a useful practical example of a malperforming IBR resource driving inter-area oscillations at a natural frequency (~0.25 Hz) that is normally positively damped (Agrawal et al., 2024). The offending equipment, in two IBR plants that were near one another and of the same vintage, had something wrong with it. The active power output of the devices was swinging between maximum and minimum limits at this frequency. The output was close to a square-wave. The unacceptable behavior would never have been caught with a priori studies because the model would not have represented this equipment behavior, but monitoring and on-line diagnostic tools allowed for rapid identification of the offending resources.

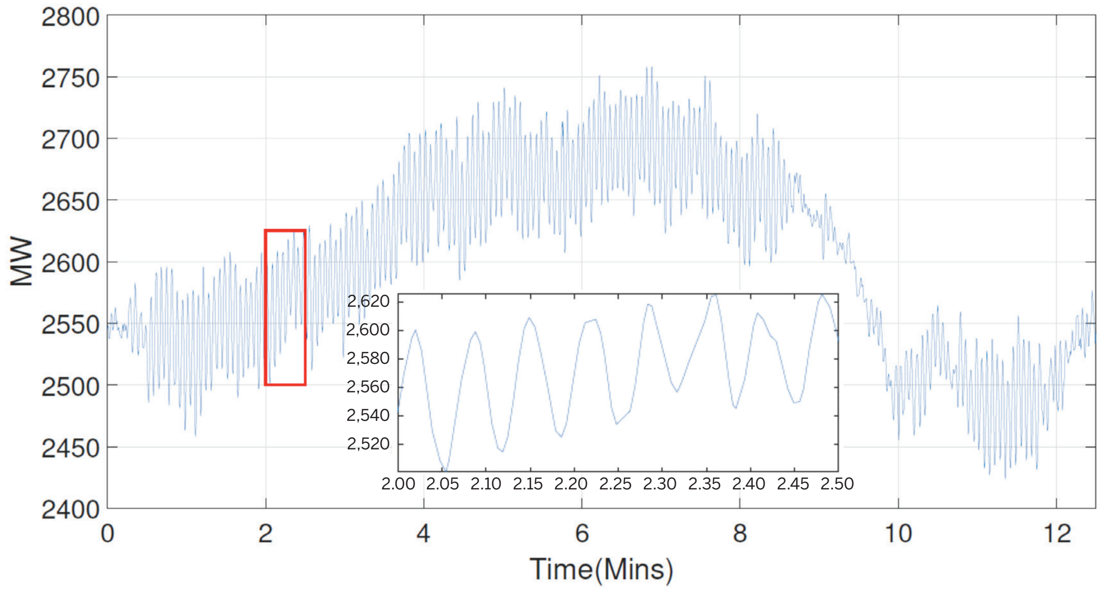
This example presents some useful positive evidence of the efficacy of active power modulation by IBRs, especially battery and other agile energy storage devices like flywheels and ultracaps, to introduce positive damping with POD controls. The fact (in this case) that poor control of the device outputs was able to destabilize an interregional power flow is *prima facie* evidence that a proper power oscillation damping control that modulates the device active power would be effective for adding damping.

PSS and Inter-area Power Oscillations

PSS can be a factor as well. For a generator to participate in an inter-area mode, it must not be located at a node of that mode's mode shape. The PSS of the participating generator will see that modal frequency through its input signal(s)—speed, power, or both—and will respond to it. Additionally, a generator may participate in more than one inter-area mode with different frequencies—simultaneously or individually at different times depending on the type/location of the initiating disturbance—and the PSS will see and respond to all of those modes. Therefore, the PSS needs to be tuned to respond to and

FIGURE 38

Example Sustained Inter-area Oscillation Due to Individual Resource Malperformance



An example of a malperforming IBR resource driving inter-area oscillations at a natural frequency (~0.25 Hz) that is normally positively damped. The two offending IBR plants, which were near to each other and of similar vintage, had something wrong with control implementation. The active power output of the devices was found to be swinging between maximum and minimum limits at this frequency. The output was close to a square-wave. The unacceptable behavior would never have been caught with a priori studies because the model would not have represented this equipment behavior, but monitoring and on-line diagnostic tools allowed for rapid identification of the offending resources.

Source: Agrawal et al. (2024); California Independent System Operator.

enhance the damping of any/all modes at any frequencies in the frequency range where inter-area modes appear. Tuning can be difficult since the generator may participate in more than one of those modes, each with a different frequency that may change depending on the system's generation/load profile and outages in the transmission grid.

If the PSS is not properly tuned for a given inter-area mode (frequency), it could potentially contribute negative damping to that mode. A single machine may not be large enough to cause a stable inter-area mode to become unstable, but many poorly tuned PSSs could.

Tool Choice for Analysis of Inter-area Oscillations

The choice of analytical tools for simulation to find causality for poor damping is not simple. The workhorse for large-system, interregional oscillations is phasor analysis. But even with these tools, getting the modeling right is not trivial. There are sometimes low-frequency (slow) phenomena at play for which the response of individual resources is poorly represented in standard stability models. For example, potentially important boiler or reservoir dynamics are usually ignored. The periodicity of fuel/pressure regulator problems and some types of fuel delivery instabilities tends to be in the range of 10 to 20 seconds. In one system, frequency oscillations with periods in excess of 10 seconds were found to have damping improved by enabling wind plant active power controls (Modi, 2024a, figure 6).

In the case where IBRs (possibly large groups of IBRs) are responsible, EMT representation may be needed. This is new ground, and EMT representations of very large models are problematic. Equivalences that capture the essence of the large system can shed light on problems but tend to be quantitatively questionable. One solution is the use of hybrid simulations: using EMT for the suspect IBRs and phasor equivalents for large sections of the system. This is labor-intensive for engineering and requires considerable simulation firepower.

Primary and Secondary Frequency Control Miscoordination

The control of frequency and area interchange shifts over time from the response of autonomous local speed and/or frequency control (e.g., governor response) to centralized area generation control as shown above in Figure 35 (p. 85). Primary and secondary frequency control overlap in about the 15 second to 5 minute time frame. Oscillations can result when the control settings of the automatic generation control (AGC) (or possibly multiple AGCs) are incompatible with the primary frequency response of resources in the subject systems. The risk of this type of miscoordination increases with the rise of IBRs and the more dramatic diurnal and weather-driven swings in dispatches, flows, and resource mixes. Staged tests of the efficacy of wind and solar PV in providing regulation service have been very positive (Loutan et al., 2017), with these IBRs showing faster and more accurate response to AGC signals than all other resources. However, the greater speed of response for IBRs compared to the thermal and hydro generation that has traditionally provided the lion's share of secondary frequency services (a.k.a. REG) leads to the possibility of spatial and temporal unbalances in response across many secondary frequency service providers. These may result in oscillations between resources and between regions. The diagnostician should inspect the amplitude and phase relationships of the area control error, the observed power swings, and, if possible, the response of individual resources responding. There are also communications latencies associated with the AGC. Information exchange between the system operator and plants under AGC may have unexpected delays. Scrutiny of these latencies may be prudent, although the discrete cycle time of AGC (typically about 5 seconds) is relatively long compared to most communication latencies. Participation by IBR resources in providing REG is still not widespread, so overall industry experience is minimal. To date, we are unaware of any systems experiencing negative damping from this cause.

Tuning of AGC parameters may be the first line of mitigation. Time-domain modeling, as noted in "Tool Choice for Analysis of Inter-area Oscillations," is difficult due to lack of available models. Cautious testing and tuning of AGC parameters in the field, i.e., at the participating control centers, may be a more practical option.

Approaching Transient Voltage Collapse

One possible cause of oscillations is excessive power transfer on a particular tie line or interface that drives the system into a condition of marginal stability. Behaviors of equipment and the network can become highly nonlinear in these cases, which creates the potential for oscillations. One mechanism for oscillation is the interaction of active power controls and voltage controls along the interface. This can be illustrated with the power-angle and nose curves of Figure 11 (p. 23). When a system is approaching the end of the nose, as pushed by exporting power, voltage along the corridor may drop and the system angle pulls out. This either reduces power flow or, in the case of the ring topology exemplified in Figure 37 (p. 88), forces power to an alternative route. Actions by voltage control mechanisms along the route may act to restore voltage, but the relatively high sensitivity of voltage to power can drive big swings. If the active power control (e.g., primary frequency control on IBRs or even AGC) has dynamics that are incompatible with the reactive control, oscillations can result. For example, nonlinear oscillations of similar nature to those shown in Figure 34 (p. 81) could occur. In that case, the poorly behaving active and reactive controls were in the same equipment, but it is possible to have similar interaction between devices and across substantial distances. The diagnostician should look for nodes that are experiencing large voltage swings that are coincident with the active flow and out of phase with reactive actuation for local voltage controllers. Use of eigenanalysis may be helpful, but for this particular problem, behavior is likely to be quite nonlinear, so linearization must be done near to the end of the nose curve. The dynamics of the offending devices need to be in the model. Latency issues, both at the plant level and at system level, should be considered.

Signal Diagnostics and Information Processing

The relatively slow frequency of inter-area oscillations reduces some of the challenges associated with making good-fidelity frequency measurements. But since large distances are typically involved, it is necessary to have perfect time synchronization. This is a problem for which PMUs are ideally suited.

When oscillations are associated with large disturbances, especially those involving loss of generation, it is important to segregate the common-mode (or zero-mode) frequency excursion from other modes with a spatial term. With high levels of IBRs, traditional measures of the common-mode such as center-of-inertia speed are less meaningful. The industry has not settled on new definitions, but variations on MVA or power-weighted center-of-bus frequency is likely to be an acceptable proxy (You et al., 2021).

Since modeling of phenomena involving AGC and covering the possibly quite slow dynamics is so difficult, ultimately, diagnostics may depend on measurements and even staged tests on the power system. Changing AGC bias or time constants may be the first line of experiment when the AGC is indicated as a participant. As noted in "Field Tests," staged diagnostic tests have the potential to directly illuminate mitigation. Changing parameters in the governors of conventional generation resources is not done lightly. However, some IBRs—especially energy storage—may lend themselves to staged experiments. Also, field tests of latency may be helpful in determining causality.

Causality Conclusions

Definitive conclusions on inter-area oscillations can be elusive. Anecdotes of low-frequency oscillations "spontaneously" appearing and disappearing without causality being determined are common. In the case where inter-area oscillations are shown to be forced (due to the behavior of a single device), concluding causality may be clearer—there is indeed a smoking gun.

Countermeasure Need

If the oscillations occur rarely, if they are not negatively damped, if they do not disrupt markets, and if they are of small magnitude, it may be possible to ignore them. Unlike (say) SSR, they do not normally presage damaging events. Grid operator response to low-amplitude ephemeral oscillations is often to wait and see if they return or get worse. Swings that result in violations of operating guidelines, such as excessive voltage swings or violations of interchange criteria, need to be remedied. On rare occasion, violent inter-area swings have caused massive and expensive system outages. These black swan events often result in the adoption of a host of countermeasures (ENTSO-E, 2018).

Countermeasure Design

Often, the first line of defense is to reduce the stress on the system that drives substantial angular separation (ENTSO-E, 2018). Reduction in inter-area power exchange that is otherwise economic in order to mitigate oscillations has economic and institutional costs. However, altering power exchange schedules can be implemented by system operators quickly. Longer-term options for mitigation of inter-area oscillations that are due to poorly performing thermal or hydro generation are somewhat limited, since changing speed of response normally requires physical changes to equipment, and reducing gains (i.e., increasing frequency droop) may violate operational rules. When IBRs are contributing to the oscillations, there is a wider spectrum of options. Primary frequency response controls from IBRs will generally have latitude for adjustment of gains, time constants, and deadbands. If the diagnostician has been successful in recreating the oscillations in simulations, then tuning experiments in time- or frequency-domain tools can be effective. The implementation of added POD controls to IBRs—both generation and network assets—can be highly effective for mitigating inter-area oscillations that otherwise resist correction. As noted in "Voltage Control/Electromechanical Torque Mistuning," PODs on devices like SVCs, HVDC, TCSC, and some other IBR network devices is reasonably well-established practice, although still relatively uncommon. Various designs for battery energy storage system (BESS)–based PODs have been proposed. The location of the devices is highly important for adding damping, and methods have been proposed for identifying effective sites for additions (Chow et al., 2000; Neely et al., 2013). Controls on distributed energy storage devices also offer promise (Copp et al., 2017). PODs on IBR generation is mostly a research topic today. IBR generation, especially solar PV, may also be a candidate for POD functions. Coordination of POD functionality with other objectives, especially power generation, is essential and can have operational cost implications. Concepts for asymmetrical modulation of power order on PV have been suggested (Gevorgian et al., 2024); these have the economic benefit of not requiring pre-curtailment to provide this service.

Market Services Miscoordination

There is an emerging class of oscillatory phenomena that is enabled by the relatively fast response of IBRs and other new resources. These system oscillations are due to unanticipated interaction between physical assets on the grid and various market-based signals. To date, the number of incidents appears to be small, and each case has substantively different details. However, there are common factors in these examples, mainly that the speed and amplitude of response (usually active power delivery or consumption) from these new market participants is great enough that the change in power substantively overshoots the expected or desired adjustment.

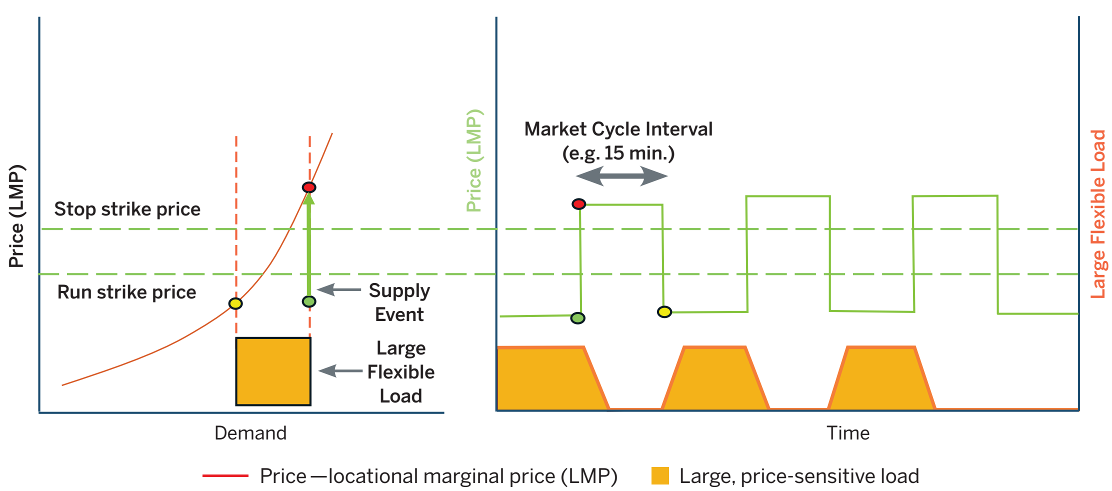
Real-Time Price Sensitivity Leading to Abrupt Changes in IBR Output

The speed and range of response possible with IBR generation allows a rapid response to market price signals. Wind, solar PV, BESS, and some other energy storage technologies can go from full available power output to idle in seconds. BESS can often reverse, going from full power charging to full power discharging rapidly. Under market conditions in which real-time locational marginal prices (LMPs) drop below the marginal value for production, generators are disincentivized to continue production. (In the case of renewable generation subject to the production tax credit (PTC), this may be at the point when the price drops below the negative of the PTC.) There have been instances in the U.S. in which an unexpectedly large amount of generation has dropped out abruptly, causing both balance and price excursions. If the collective response is of sufficient magnitude, the price may rebound above the strike price, causing the resources to restart and creating a mechanism for problematic cycling.

Recently, a similar risk has been identified with new highly price-sensitive loads, most notably cryptomining loads able and even anxious to respond to real-time prices (Springer, 2023). Recent work in the Electric Reliability Council of Texas (ERCOT) postulates that these loads, which may have limited participation or visibility in day-ahead or real-time markets, could have the potential to drive sustained price swings. A hypothetical example

FIGURE 39

Hypothetical Example of Zonal Price Oscillation



Example of a very large, highly price-sensitive load disrupting power markets. Here a hypothetical, highly flexible load interacts with market clearing price. An external event, such as a generator trip, drives the price from the green dot to the red dot, above the load's strike price. The load self-curtails, but when the load is off, the price drops below its strike price at the yellow dot. When the load goes back on, the price rises above its strike price. The resulting oscillations are at the frequency of the market clearing cycle of 15 minutes.

Source: Energy Systems Integration Group.

based on that work is shown in Figure 39 (p. 92). It shows the sensitivity of LMP to system demand along with the load's on and off strike prices shown. The price curve jumps up due to a loss of infeed (e.g., a generator trip), suggested by the movement from the green dot to the red dot. This brings the price above the load's off strike price. In this unstable case, when the load is connected, the price rises and crosses above its price threshold (for discontinuing operation). When the load disconnects, the price drops below its price threshold to start operations. The result is price swings at the 15-minute periodicity of the security-constrained economic dispatch.

These two examples show price swings across an entire system. That particular behavior is not dependent on locational variation in pricing (i.e., congestion-influenced LMPs), but mechanisms for such interaction appear to be possible. For example, suppose the power fluctuation of the hypothetical cryptomining case resulted in alternating flows on an interface subject to congestion. This could be a mechanism that drives inter-area or inter-regional power and price swings (as opposed to the system-wide variations of the examples).

Miscoordination between secondary (e.g., 5-minute) balancing functions and tertiary (e.g., 15-minute economic redispatch) functions also has the potential to cause extremely slow-periodicity swings in power and prices. Swings corresponding to market cycles are an indicator.

Ancillary Services Miscoordination

Another related class of periodic instability can occur when centralized controls such as AGC are miscoordinated with distributed controls, such as autonomous primary frequency response. At least one incident was reported in which aggressive centralized balancing, with signals delivered at discrete intervals with relatively long periodicity, caused slow oscillations. In the reported case, balancing signals were delivered at 15-minute intervals and drove primary frequency controls with substantial (by U.S. standards) deadband into sustained oscillations lasting many hours.

Although not a form of instability, observed variations in BESS power output can be the result of those plants participating in frequency regulation ancillary service markets. Unlike conventional generation resources, for which the inherent power response is sufficiently slow to substantially filter the fast "dithering" of AGC response, the practically unlimited power ramping capability of energy storage allows these plants to exactly track the AGC. This successful tracking of AGC could be misinterpreted as an instability, when in fact it is a largely desirable behavior.

Signal Diagnostics and Information Processing

The behaviors observed or postulated (to date) tend to manifest themselves as variations on limit-cycling. Participating resources tend to "bang" back and forth between nonlinear limits (e.g., maximum and minimum dispatch). As such, measured signals will tend to be square-wave, sawtooths, or other similar oscillations with essentially zero damping. Like many such behaviors, they may require that some exact combination of factors apply—in a sense the system must be "tuned." Consequently, the oscillations will seem to appear and disappear spontaneously.

Tracking down causality is likely to be primarily a heuristic inspection and comparison of market signals and power responses by the offending resources. When the period of oscillations exactly corresponds to the interval of discrete market signals, whether they are prices, setpoints, or other controls, this is highly indicative of causality. Phenomena of this sort are, so far, rare and of much slower periodicity than any other oscillatory problems described in this guide. The market signals involved may not be on the radar of engineering teams more typically focused on purely physical phenomena.

Causality Conclusions

The causality of these oscillations has some fundamental commonality with purely physical control system–induced oscillations: high gains, long latency, big deadbands, substantial phase lags. That market processes are the culprit makes the phenomenon novel. However, identification is likely to be straightforward, as swings in the market signals are largely unique to this class of behaviors.

Countermeasure Need

Whether these oscillations need to be mitigated depends on how disruptive the behavior is. Rare, low-amplitude oscillations can probably be ignored. But swings that cause saturation, such as periodically exhausting balancing resources, must be addressed.

Countermeasure Design

Mitigation options need to address aspects that contribute to poor performance. Here we list four aspects that can exacerbate market-induced oscillations and suggest the types of countermeasures that should be considered.

- **Large discrete steps.** Controlled large discrete steps (e.g., of dispatch), as distinct from unplanned events like generation tripping, can exacerbate swings. Solutions that limit the maximum step response, or force smooth, rate-limited response, over each "cycle" of the destabilizing market signal can effectively reduce or eliminate over-shoots. At least one U.S. independent system operator imposes a MW ramp rate limit on response to change in dispatch.
- **Failure to anticipate signals, especially LMPs.** When a resource fails to anticipate market price swings, it can produce oscillations like those discussed above. Conversely, solutions that anticipate signals—such as short-term LMPs—will trigger responses that effectively add "lead" to the control system. Resources can anticipate crossing price thresholds and act more slowly in response.
- **Delays or latency related to market operation.** The cycle time and information processing delays inherent to market operation contribute to destabilization. It can be effective to issue more frequent market signals and/or reduce the internal time delay between receipt of system conditions and the creation of new market signals.
- **Insufficient market participation.** The hypothetical ERCOT example in Figure 39 above is predicated on the large resource *not* participating in the real-time market. In the case of large loads, active participation in power markets such as bidding in strike prices or similar engagement should substantively reduce the drivers for unstable response.

Harmonic Oscillations

Power electronics and passive power system components that are saturable or otherwise nonlinear create waveform distortion. This distortion is relatively steady, persisting across sustained waveform measurements. The frequency components of that distortion often, but not always, resolve into integer multiples of the fundamental power frequency as harmonics. In particular, VSCs operating with a relatively high-frequency carrier can produce distortion content at non-integer multiples of the fundamental, depending on their design and carrier frequency selection. We are concerned here with frequencies in the range of hundreds of Hz to several kHz.

Oscillations of voltage and current at frequencies in the hundreds of Hz up to several kHz, and associated with IBRs, can have one of several causes:

- Harmonic distortion sourced or "injected" by the IBR due to the inherent switching process of the inverters
- Harmonic distortion sourced externally to the IBR and amplified by the IBR
- Oscillations caused by IBR control instability (supersynchronous oscillations) mischaracterized as "harmonics"

Harmonic Injection by IBR

Virtually all modern IBRs use PWM VSC technology switching in the kHz range. Modern VSC HVDC uses MMC technology that has effective switching frequencies far higher than those achieved by PWM converters. The characteristic harmonics produced by these converters are clustered at frequency bands centered around the switching frequency and integer multiples of the switching frequency. In the case of MMC, the generated fundamental-frequency voltage waveform is sufficiently undistorted that filtering is typically not even necessary.

Typically, the switching frequency of PWM converters is not an integer multiple of fundamental frequency, and switching is not synchronized to the fundamental voltage. The switching-related characteristic harmonics are usually not at integer multiples of fundamental frequency and are correctly characterized as "interharmonics." Because of the random phase angles of the generated harmonics, switching harmonics created by multiple inverters tend to partially self-cancel. A general rule is that the expected magnitude of the aggregate contribution of switching harmonics in an IBR plant is the square root of the sum of the squares of the individual units. Thus, an IBR plant with 100 inverters can be expected to have an aggregate injection that is 10 times the injection of an individual inverter. While the frequencies of injection due to switching may overlap with those of concern for super-synchronous oscillations, the underlying causality for instability is quite different. In the case of harmonic instability, the injection of distorted current stimulates natural circuit frequencies in the host network. It is the act of switching to form fundamental-frequency waveforms that is to blame. This is *not* generally a result of control misbehavior, and it does not lend itself well to mitigation by control tuning.

PWM converter non-idealities and fundamental-frequency voltage imbalance also create a small amount of distortion at the lower-order harmonics (e.g., 3rd, 5th, 7th orders) that are integer multiples of fundamental frequency and are reasonably in-phase between different inverters at the same operating point.

From the standpoint of the transmission system, the relevant metric of harmonic impact is voltage distortion, as this affects loads and utility equipment such as capacitor banks and filters. In some cases, there are also concerns with harmonic currents causing inductive interference with telephone circuits in parallel with transmission lines. However, for historical reasons, the harmonic performance requirements applied to IBRs in North America are generally based on harmonic current emission.

VSCs (as used in IBRs, VSC HVDC, STATCOMs, etc.) can be represented as a Thevenin voltage source in series with the effective impedance of the IBR, even though they typically operate in current-controlled regimes at and near fundamental frequency. (Other equipment such as thyristor-switched equipment or certain nonlinear loads are best characterized as current sources.) Harmonic currents produced by an IBR are dependent on the harmonic-frequency impedance of the transmission network to which it is connected. When the effective reactance of the IBR is equal in magnitude and opposite in sign from the network reactance, a series resonance is created that can result in substantially amplified harmonic current flow. The series resonance can be combined with a parallel (impedance) resonance in the transmission network that also greatly amplifies voltage distortion.

Harmonics produced by a properly operating IBR plant are rarely of significant magnitude unless they are amplified by resonances. Because of the substantial system damping at the higher frequencies and the self-cancellation effect due to phase diversity, harmonic resonance issues very rarely involve characteristic inverter-switching harmonics. When resonance issues related to IBR harmonic injection do present, these tend to be at the lower-order harmonics that are due to inverter non-idealities.

Amplification of Ambient Distortion

A wide variety of loads and other devices create an ambient level of voltage distortion in any transmission network. The impacts of these distributed sources can be amplified by system resonances to the degree that they create unacceptable levels of voltage distortion. The addition of an IBR plant to a transmission network can modify the resonant characteristics such that distortion is amplified due to the effective harmonic-frequency impedance of the IBR plant.

IBR plants, particularly wind plants, often have extensive medium-voltage underground cable collection systems. In addition, IBR plants frequently have shunt capacitor banks connected to the collection system to meet reactive power requirements. The shunt capacitances of the cables and banks, in series with the main plant substation transformer inductance, create a resonant circuit. The inverters add their own complex impedance characteristics, which can include a negative resistance effect over some frequency ranges. This negative resistance can partially cancel the natural damping of the network and greatly magnify the severity of resonances.

Offshore wind plants using AC transmission tie lines provide a very large amount of shunt capacitance due to the charging characteristics of the high- or extra-high-voltage underwater cables. Although shunt reactors are used to compensate this charging at fundamental frequency, the shunt reactors are largely ineffective in cancelling the capacitive effect at harmonic frequencies. The large amount of capacitance can cause severe resonances at relatively low frequencies, particularly if the short-circuit strength of the onshore transmission network is low.

All these IBR characteristics can aggravate harmonic distortion for which the IBR is not the "injector" of the distortion. The amplification of background distortion is recognized as the primary harmonic issue, to the extent that such an issue exists, for VSC HVDC and presumably for IBRs as well.

Control Instability

It is common for diagnosticians to consider all oscillations at frequencies in the hundreds of Hz to kHz range as "harmonics" when, in some cases, the actual situation is a high-frequency control instability. Control instabilities in this frequency range almost invariably involve inverter current regulators, as this is the control function having sufficient bandwidth to result in control interaction oscillations in this frequency range. These are not truly "harmonics," and this issue was discussed above in "Subsynchronous and Supersynchronous Control Interaction (SSCI)."

Main Characteristics and Primary Diagnostic Indicators

Harmonic problems are often readily apparent in waveform oscillography, indicated by persistent distortion on individual sinusoidal cycles that are observable across sustained samples. Relatively simple frequency decomposition will often show a single dominant frequency (in addition to the fundamental). The source of the distortion can be the inverters of an IBR plant or external sources including other IBR plants, HVDC, and flexible AC transmission system (FACTS) devices in the transmission network; saturation of transformers and other magnetic devices; or consumer loads. While it is straightforward to determine the presence of distortion, it is more difficult to distinguish whether an IBR plant is responsible for "injecting" the distortion or just amplifying background distortion.

The harmonic generation of IBRs depends on the type of device. Devices with bridges that switch once per half cycle of fundamental have well-understood characteristic harmonics that are often paired (e.g., 5th and 7th, 11th and 13th, and so on, declining in amplitude for higher order pairs, for the simplest of three-phase converters). Devices that switch often at a determined PWM frequency will tend to have much less distortion and can create harmonic distortion with spectral amplitudes that vary with operating point. Switching-related PWM spectra appear as clusters of frequencies around multiples of the switching frequency, in the several kHz range and above.

VSCs also create a small level of distortion at the lower integer harmonic orders due to non-idealities of the converter such as pulse blanking and interaction with negative-sequence fundamental-frequency voltage imbalance. But unless greatly magnified by a severe resonance, these harmonics are usually well below any reasonable criteria.

High levels of IBR harmonic current are not necessarily indicative that the IBR is "injecting" the distortion. The IBR plant or individual inverters can potentially be a "sink" for harmonics injected elsewhere. In many cases it can be difficult to distinguish whether an IBR plant is sourcing the harmonic distortion. An increase in voltage distortion when an IBR plant is connected, but without the inverters operating, is a clear indication that the impedances of the plant's collection system are passively amplifying background distortion. However, an increase of distortion when inverters are turned on is not clear evidence that the inverters are sourcing the distortion, as their impedance characteristics may simply re-tune the system such that resonant amplification occurs. Theoretically, harmonic power flow might indicate the distortion source, but great accuracy in phase angle measurements is required. The frequency response characteristics of high-voltage current and voltage transducers can make such techniques unreliable and impractical.

Acute harmonic problems may reveal themselves through blown fuses or actuation of overcurrent or overvoltage protective devices. Devices may overheat. Sometimes distortion creates audible noise that is higher frequency than the familiar 120 Hz hum of power equipment.

As with other resonance problems (see "Traditional' SSR (Specific to Series Compensation and Synchronous Machines)"), the host system is "tuned"—that is, it is in a quite specific topology, with combinations of elements switched on and off, that results in the network resonance.

Consequently, sometimes field identification of problems can be elusive, as the exact resonant conditions need to be present to observe the problem. Indeed, in the case of problems being caused by an unfortunate combination of shunt capacitors, blown fuses have been known to self-correct the problem by changing the capacitance and detuning the resonance. Also, for particularly elusive cases, the temperature of shunt capacitors in the field may impact the capacitance enough to change when the resonance appears and disappears, particularly for resonances with high Q-factors.

Signal Diagnostics and Information Processing

The main initial tool for detecting harmonic problems is FFT analysis of voltage and/or current waveforms. However, detecting the problem is often simple compared to identifying causality. Most serious harmonic problems result from the interaction of a stimulus (harmonic generation by equipment) and network resonance. Solutions are variations on (a) reduce the stimulus, and (b) detune the resonance.

However, identification of harmonic problem causality can be difficult. For example, traditional methods of harmonic analysis assume that harmonic sources are ideal current sources. Shunt impedance paths that present low impedance at a generated frequency will tend to provide an attractive path that results in high currents. These are an effect and not a cause of distortion. At low harmonic frequencies, harmonic power flow techniques can help identify the source of the harmonic energy stimulating the system. Mitigation may involve modification of the source, but practically, detuning or desensitizing the receiving network is easier.
One example was a wind farm that had unacceptable harmonics levels. The initial guess was that the wind turbine-generator inverters were causing the high levels of voltage distortion. However, closer inspection showed that the high distortion occurred *only when the wind turbine-generators were de-energized.* In that case, the problem was a 9th harmonic resonance with collector cables and substation capacitors interacting with distortion due to magnetic saturation of transformers and system unbalance. The solution, as is often the case, was to detune the network—in this case by changing the capacitors.

In the modeling and simulation environment, the representation of high-frequency damping—particularly of power transformers, overhead lines, and underground cables—can be the difference between a real problem and one that is only manifested in the simulation environment. At frequencies in the harmonic range, the skin effect in passive elements like lines, cables, and transformers tends to increase the resistance of those elements at those frequencies, helping to damp the resonance. If the damping effect is neglected in the EMT simulation environment, then the simulations can result in unrealistically pessimistic results with excessive distortion. The CIGRE Technical Brochure 766, "Network Modeling for Harmonic Studies," provides useful guidance (CIGRE, 2019).

Some harmonics issues are technically minor but have significant commercial or regulatory implications. For example, cases in which distortion may slightly exceed limits may present minimal practical risks but are compliance issues. IEEE Standard 519-2022 sets individual and total harmonic distortion limits (IEEE, 2022a).

The basic workhorse tool for harmonics problems are static frequency analyses. Driving point impedances from these are used for passive filter design. Other useful information includes current and voltage gains, amplification factors, and transfer impedances, all of which can be used to pinpoint offending system elements as well as point to options for mitigation.

These static tools usually assume that the harmonic source is well known and can be defined simply. For modern VSC, it can be inadequate to assume that these inverters are an ideal current or voltage source, particularly in moderate to weak system-strength applications. Wind generator OEMs are now providing Thevenin- or Norton-equivalent representation of their equipment. Other OEMs, particularly serving the solar PV and energy storage markets, have not yet followed. However, forthcoming standards may require this harmonic source information (e.g., IEEE 2800.2 (IEEE, 2021b)). In the absence of an OEM's harmonic source model, it may be necessary to perform EMT time-domain analysis of a detailed model of the inverter in order to define harmonic source characteristics to use in static (frequency-domain) analysis. Such a model needs to be a full switching representation, with all higher bandwidth control functions (typically, current regulation) included. For very strong systems, the impedance of the inverter output inductors and the IBR balance of plant is sufficient relative to the network impedance such that a simple current source representation may be adequate for very approximate analysis.

Harmonic analysis tools need to be used with some caution. For example, modeling of loads in these tools is difficult. The modeler must not make the common mistake of converting active and reactive power (P and Q) from a load flow into equivalent $R + j\omega L$ series or $G - j\omega B$ parallel representation. A substantial portion of load demand is composed of induction motors that are more appropriately characterized at harmonic frequencies by their locked-rotor inductance and resistance than by their fundamental-frequency power demand. There is also substantial inductance between the transmission bus and the ultimate loads due to several stages of transformation and feeders. Distribution systems also typically have significant amounts of shunt capacitance. Ignoring load altogether can work, although it tends to give pessimistic results, anticipating sharper resonances and higher distortion than is realistic.

Harmonic generation from inverters can be highly complex, with cross-frequency terms emerging due to system unbalance or other nonlinearities. One common mistake is to assume that all triplen harmonics (multiples of 3) are zero sequence. This is the textbook reality but valid only when a balanced voltage is applied to a balanced nonlinearity. But unbalances and other imperfections introduce other triplens. Most notably, negative-sequence voltages will cause inverters to produce positive-sequence triplen currents. Diagnosis of problems observed at these frequencies should account for this real effect. Specifically, the diagnostician should recognize that the root cause of high harmonics may be fundamental-frequency unbalance. Inverter harmonic source models should reflect realistic levels of voltage imbalance. Time simulations, including detailed EMT models with individual phase representation of inverter legs, can capture complexities that static tools may miss. Getting the details right for these models can be difficult.

General guidelines for troubleshooting observed oscillations in the harmonic range (hundreds of Hz to several kHz) are:

- Oscillations at frequencies above the 20th harmonic that are at frequencies not at integer multiples of the fundamental (interharmonics), and that are not significantly present when the inverter or inverters are not operating, are likely to be caused by inverter switching and amplified by a very high-quality-factor (Q) resonant circuit. Modifications of the system parameters or configuration will usually shift tuning to mitigate this issue.
- Oscillations at integer harmonic frequencies in the lower-order range that are significantly present when the inverters are not operating, but are of much greater magnitude when the inverters are put on line, are most likely related to resonant amplification of ambient harmonics. This amplification can be mitigated by changes to the inverter control or physical parameters. Harmonics of this type, however, might also be due to resonant amplification of the relatively small levels of inverter harmonic generation at these frequencies. Modification of the system to detune such resonances can be effective, either as physical changes of electrical parameters or tuning of high-bandwidth inverter controls.
- Oscillations at frequencies in the lower-order range with the inverters in operation, not at integer multiples of fundamental, are likely related to a supersynchronous inverter control stability issue as discussed in "Sub-synchronous and Supersynchronous Oscillations (SSO)." This can be addressed by modifying the inverters' control parameters, particularly the current-regulation function and other methods outlined in that section. These control instability oscillations could also appear at integer harmonic orders by coincidence. When this happens, discriminating this phenomenon from ambient distortion amplification can be difficult.

Causality Conclusions

In more extreme cases, those with truly problematic levels of harmonic distortion, it is not unusual for the causality to be relatively clear. An observed (or calculated) network topology that results in high amplification of a frequency characteristic of nearby IBRs will tend to be obvious. Problems that manifest only when a specific resource is energized are common, pointing to that resource as the culprit. Determining causality as to *why* that resource is causing problems may require more than static frequency scans.

Countermeasure Need

The reality is that standard performance indexes like holding total harmonic distortion to less than 1.5%, or individual voltage distortion to less than 1% (IEEE, 2022a), are pretty conservative. It may be a matter of contractual or standards compliance that drives the need for countermeasures. In such cases, the causality demonstration can be economically important: "Whose fault is it?" and, more importantly, "who pays?"

In practice, it is big ringing resonances that cause urgent problems—blown fuses, confused relays, control malfunctions, and failed equipment. There's no doubt when these occur that they need to be fixed.

Countermeasure Design

Reducing the harmonic generation sourced by the correct operation of existing IBRs is a relatively difficult task, and one that can rarely be accomplished without adding or modifying physical components. Control changes within normal device parameters usually have quite limited scope for adjustment insofar as altering harmonic production is concerned, unless the root cause is a high-frequency supersynchronous control interaction issue. Control changes, however, can benefit situations in which the IBRs amplify ambient distortion or where SSCI is involved (see the prior section, "Subsynchronous and Supersynchronous Control Interaction (SSCI)").

Therefore, countermeasures tend to necessarily be ones that detune the offending resonance or modify system damping. The first option to consider is detuning by altering topology or individual components. Change the impedance of the involved components: use a smaller capacitor, add a transformer, etc. This is especially attractive if the change produces other benefits (e.g., better volt/VAR control), but one can consider it a "win" if there are no unacceptably bad side effects.

Designing harmonic filters is a practical solution, but not one to be taken lightly. It looks easier than it is, and there can be unintended consequences. Simple filters, such as notch (series RLC-to-ground filters) add capacitance. This may be okay if there is systemic benefit to added reactive power production. But changes in VAR supply have a tendency to cascade into complications in overall reactive power and voltage management. Further, for each frequency filtered, a new resonance is added at adjacent, lower frequency. Care is needed to make sure these do not cause problems, including under conditions when the filter is detuned (by, for example, actuated fuses on individual capacitor elements blowing or temperature coefficient impacts on capacitance). IEEE provides help with filters in "IEEE Guide for the Application and Specification of Harmonic Filters" (IEEE, 2021a).

From a practical perspective, options for solutions are likely to depend on both the source of the resonance and the ownership of the elements that contribute.

If discrete network elements are at the root of the resonance, especially capacitor banks, the most effective solution is often to change their size or change where they're connected. However, if some of the resonant elements are outside the IBR plant and under the control and ownership of the host transmission operator, then the business and jurisdictional reality may be that such changes are not easily effected.

If distributed elements, most notably long cable runs with significant capacitance, are a dominant factor, then changing the capacitance is not easily accomplished. Resonances are a particularly significant issue for off-shore wind plants using high-voltage or extra-high-voltage transmission tie lines. Changes in IBR plant topology, such as changing the segmentation of individual feeders within a plant, may be cost effective.

In most cases, when discrete changes or control modifications are ineffective or impossible, filters may be needed. Filters focused on the high-frequency inverter switching–related distortion are typically included within inverter units. Separate harmonic filters, addressing lower-order harmonics, are sometimes used. Where IBR plants have included capacitor banks to meet reactive range requirements, inductances in series with these capacitors are sometimes added to avoid resonances at problematic harmonic orders. Filters and detuning inductors need to be applied with care to avoid unintended consequences.

Simulation Failures

This section provides a deeper dive on diagnosis and correction of problems that are due not to "real" system oscillations or instabilities, but rather to poor simulations. Here we address both (1) planning simulations that have failed the "Initial Credibility Screening of Equipment Models" above, and (2) diagnostic simulations carried out during the detailed assessment that have failed simulation credibility checks in "Diagnostic Questions for Simulations." Questions and examples here are intended to help answer the question, "is the oscillatory (or other) behavior observed in the simulation the result of a 'legitimate' physical phenomenon, or is it an artifact of an improperly staged simulation?" There are many modeling problems that will make for poor results. Some modeling problems are complex and start to commingle with actual problems. For example, the distinction between an incorrect device model banging between limits and a correct device model doing the same and driving forced oscillations in the system can be nuanced. However, performing several simple data checks for common mistakes can save a lot of time.

Unless otherwise noted, this section applies to both types of simulations: (a) simulations that triggered the causality investigation, and (b) simulations created during the process of investigation. (A glossary with abbreviations and definitions is provided at the end of the guide.)

Equipment Model Fidelity

Simulations' usefulness depends in large part on whether the individual elements of the power system are modeled in such a fashion as to create meaningful results. Simulations need not necessarily replicate physical phenomena exactly to be meaningful or useful. That is, "accuracy" can be subjective. A simulation that captures the essential character of a behavior of interest need not necessarily be quantitatively accurate, but it must point the user toward proper diagnosis.

As noted earlier, in the past there were well-established (e.g., IEEE) model structures for generation and other equipment. Questions of device model credibility centered on whether the input data (a.k.a. the parameterization) were correct. With the emergence and rapid evolution of new generation resources, particularly IBRs, not only the input data but the entire device model structure itself warrant scrutiny. Further, independent system operators have found that correct modeling of existing synchronous resources—sometimes the few that remain in service after the addition of many IBR resources—is increasingly important. Developing good device models and good power system models is a combination of technical rigor and art. This is especially the case with EMT modeling. Several resources are listed in the references to aid the modeler in creating good fidelity models.

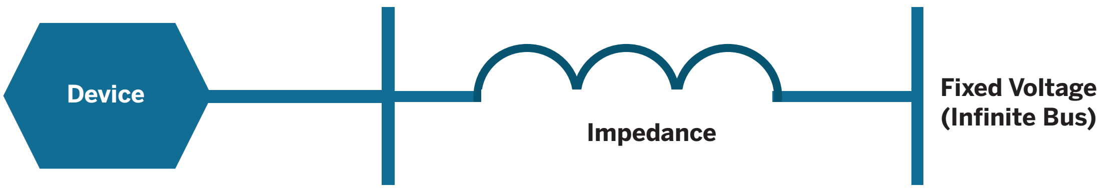
An equipment model's failure to pass the screening questions above ("Diagnostic Questions for Equipment Models") indicates a deficiency. This is a broad topic, but this guide's focus is on problems that occur with the relatively new and rapidly evolving field of modeling IBRs.

Single-Machine Infinite-Bus Tests

In the case of analysis looking at the behavior of a particular IBR resource (or perhaps a group of them), it can be very useful to do a close inspection of that resource model with a simple grid representation. Many experienced practitioners will test an important model with a single-machine infinite-bus (SMIB) set-up, as shown in Figure 40. This favorite analytical device of

FIGURE 40

Single-Machine Infinite-Bus (SMIB) System



Source: Energy Systems Integration Group.

researchers and developers might be better termed "single-device infinite-bus," because the traditional use in which the "device" in the figure was usually a synchronous machine has given way to a broader usage where it applies to the IBR or other devices in question. It is a necessary (but not sufficient) condition of good systemic simulations that good performance for well-considered SMIB tests be possible. Further good practice with the SMIB test set-up involves manipulating the "fixed" voltage to test the device behavior. Tests in which the system strength and X/R are varied can help with component testing, diagnosis, and mitigation design. This overlaps with the processes for "Dynamic Model Network Frequency Scans."

The set of test questions intended to avoid set-up problems is partly self-explanatory. Those points include:

- Most time simulations used in power systems cannot tolerate differential equations with time constants shorter than two integration time steps. In positive-sequence phasor tools, the industry standard is ¼ of a cycle of fundamental frequency, i.e., 4 to 5 ms. This well-known limitation has challenged model-makers attempting to simulate some of the faster control behaviors of IBRs. Custom device models that require very short time steps (e.g., 1 ms or shorter) have been proposed. The use of these models is tricky, at best, and the simulation set-ups that ignore this constraint are doomed to failure. Furthermore, algebraic representation of the transmission network, inherent to phasor-domain simulation tools, is inappropriate and inaccurate to represent phenomena for which such small time step resolution is required.
- Many IBR systems have multiple modes of operation, which may sometimes be set by the user as an initial condition input, or which are automatically invoked by the model depending on initial terminal conditions of the device. Simulations for which the initial conditions violate the expected mode of operation can result in unexpected and possibly meaningless behavior.

Testing whether the device model has "good" parameterization represents a continuum of outcomes from "the parameters are flat out wrong" to "these parameters (or the model structure) are okay but not for this application or condition." Here we are most concerned with "flat out wrong"–type problems. For these, simple tests can avoid many common problems. Diagnosis that the parameters or the model structure isn't right for the problem being investigated becomes part of the causality investigations outlined in "Detailed Assessment and Countermeasures."

Testing for Successful Initialization

The first test of a component model is successful initialization. A good SMIB set-up will present the device model with meaningful, representative boundary conditions to which it should initialize its algebraic and differential equations. Failure to get "straight lines" is indicative of data problems. ("Straight lines" is shorthand for steady phasor quantities, within expected bounds, and steady control signals.) If a model won't initialize, there are several common mistakes to check for, including:

- Per-unitization. The "mapping" from physical control parameters in actual equipment to simulation models often requires that physical units (e.g., gains and limits in volts, amps, cycles, etc.) be per-unitized. There are myriad opportunities for mistakes here including, for example, lost sqrt 3, lost sqrt 2, or conversion from kW or MW to per-unit device rating or to per-unit simulation base.

- Initialization against limits. If the initial condition is hard against or past a limiter in the model, initialization may fail. IBRs are notoriously nonlinear and may depend on some signals normally being against limits. This makes diagnosis of initialization problems tricky. The diagnostician will need to trace internal variables both upstream and downstream of limiters to make sure the limit is being applied properly and is not the result of poor parameterization.

Step Tests

The next tests of component models are step (and sometimes ramp) tests. SMIB tests should be made on system equivalents that reasonably approximate the short-circuit strength at the point of interconnection of the equipment on the actual power system being evaluated. The first line of step tests is normally made on control inputs, such as voltage and power references. The second line of step tests is systemic and can include a variety of network switching tests, such as capacitor and line switching. Response to step tests should show:

- Reasonable dynamic response, including overshoot and damping
- Correct (expected) final response (a test of steady-state gains)

Passing these tests is intended to indicate that the implementation of the device and controls is reasonable. But it cannot, alone, provide assurance that the model is "right" in the sense that it necessarily reflects the behavior of the (as built) equipment.

It is difficult to know whether equipment dynamic models are appropriate to a given application or investigation. Answers to many of the screening questions depend on the documentation for the specific model. Some documentation may address the specific concern and condition being evaluated by indicating that the model is (or is not) suitable. In the common case that the documentation does not give clear guidance, the diagnostician must make a choice as to which model to use. The main bifurcation in model choice is generic vs. OEM-specific. Generic models include compromises in structure in favor of simplicity, generality, and numerical behavior. Generic models are often better tested and documented than OEM-supplied models. But while these traits are all desirable, functionality limitations may result that make generic models' use inappropriate for some oscillatory problems, in which case it is necessary to use OEM-supplied models. Hopefully, documentation for models from the OEM and/or developers sets limits, such as the minimum short-circuit strength for which the model is valid. These limitations should be followed in the (unlikely) event that they are provided. IEEE P2800 provides some useful content on creating good-fidelity EMT models for IBR analysis (IEEE, 2022b). This information can be used to further vet an OEM-supplied model, or, in more extreme cases, help the diagnostician to create new or structurally modified models.

Network Model Fidelity

For all system simulation platforms, there are two major concerns to be considered with the network (a.k.a. the grid) modeling:

- How much of the network is included in the model?
- Are the elements included in the model each being properly modeled for the phenomena of interest?

Network Model Equivalencing

The extent of the transmission network model used needs to be based on sound and informed judgment. Regardless of simulation tool, care should be taken to ensure that the retained detailed model is consistent with the phenomena to be investigated.

Phasor-domain positive-sequence simulations typically employ large system models. It is not unusual for system planning studies to include an entire interconnection—modeling all of the bulk power system to its synchronous boundaries. However, for detailed dynamic studies, including those focused on oscillations, it is common to reduce more distant parts of the system by equivalencing. The label "reduction" is reflective of the mathematics behind equivalencing a network with many nodes (i.e., buses) to a simpler one with fewer nodes. Reduction creates fictitious equivalent network elements (between nodes that are retained). These elements give correct boundary conditions for static, fundamental-frequency operation, but sometimes can introduce meaningless effects on time simulations. Negative equivalent reactances should be avoided. Negative equivalent resistances are unacceptable in any time simulations.

Due to the high computational burden of EMT simulations, it is common to use a transmission network model of limited extent. Driving point impedances (represented only by their fundamental-frequency resistance and inductance) are placed at the boundaries of the detailed model to represent the external network looking out from that node. It is essential that the model provide accurate impedances over the frequency range of the phenomena of interest. Tools like those described in "Static Frequency Scan Methods" and "Dynamic Model Network Frequency Scans" can be used to calculate driving point impedances and to check on validity of the equivalent for higher frequencies. A very limited model, such as one with detailed representation limited to one bus away from the IBR point of interconnection, can be of questionable accuracy for all but very low-frequency oscillations. If the equivalenced external system is to be modeled only based on fundamental-frequency impedance, it may be necessary to increase the extent of the detailed model to several tiers of buses away from the focus IBR. Alternatively, synthetic circuits composed of resistances, inductances, and capacitances can be created that provide a frequency-dependent network equivalent.

There is no simple, foolproof way of proving that "enough" of the system has been retained. However, the cautious user will test for excessive sensitivity to the parameters of the equivalent, by varying them and testing for substantive changes in simulation results. High sensitivity is an indicator that more of the network should be explicitly modeled, or, at the least, caution applied to interpreting results.

Network Component Modeling

Within the detailed network model, components such as other IBR plants, FACTS devices, HVDC systems, and other complex devices might be modeled either by generic library models or more detailed user-defined models. Where there is any reasonable probability that another component may be a significant participant in an interaction issue, every effort should be made to secure and use the most accurate model available. Failure to represent key details of device performance may lead to false indications of stability or instability and invalidate the study.

With regard specifically to EMT modeling, there are critical characteristics of even ordinary components like lines, cables, transformers, etc. that are not revealed by the component parameters available in a positive-sequence phasor-domain system database. Some characteristics are not even defined by nameplate or other manufacturer data and must necessarily be estimated. Frequency-dependent representation of component parameters, particularly resistive losses, can be critical to simulation accuracy. This is particularly true for higher-frequency oscillations and harmonics but may also bear on subsynchronous damping evaluation. Inadequate representation of frequency-dependent losses in EMT models can exaggerate system oscillations or indicate instabilities that in reality do not occur. In the case of subsynchronous effects, the failure to consider frequency dependence can result in an overly optimistic understanding of system damping.

Another type of characteristic that almost always needs to be estimated for EMT modeling is transformer saturation. Switching events such as transformer energization or fault clearing can initiate temporary transformer saturation without any overvoltage. The resulting injection of high-magnitude harmonic currents can distort voltage waveforms, potentially resulting in control malperformance, and can produce overvoltages. Transformer saturation parameters are very rarely revealed in product information provided to the purchasing utility or developer by the transformer manufacturers and therefore need to be estimated (IEEE, 2022b).

Entire System Simulation Failures

There are many ways in which systemic simulations can fail even when the individual components being modeled are reasonable. The screening questions are grouped according to common classes of simulation failures of full, often highly complex, power systems. Discussion of each is provided here.

Initial Conditions

The SMIB model tests discussed above are intended to make sure that the input data for the specific equipment will allow for good initialization. But when the equipment model is "plugged into" a complete grid model, reasonable conditions must be imposed on the individual component models. Positive-sequence phasor analysis normally starts from a solved load flow. Solution of the load flow to acceptable initial conditions is a necessary step. "Acceptable" includes voltages within bounds and current and power flows within bounds of both network equipment and the individual devices delivering (or consuming) active and reactive power. The condition imposed on specific equipment (e.g., an IBR plant) must not only be within ratings but must be for "normal" operation—i.e., without the equipment being forced at initialization into a defensive or other transient mode of operation.

As with the SMIB tests, it is essential to have good initialization of the entire simulation model of the system, with the ability to produce sustained "straight lines." This seemingly obvious prerequisite to good analysis is ignored surprisingly often. Some simulations, notably of the EMT type, require time to allow all dynamic models of the components to move into their appropriate initial conditions, and may require additional simulation steps like artificially holding voltages or dynamics constant while devices are initializing. It requires some finesse to ensure electrical and numerical stability in the period of initialization. Some common mistakes include not waiting long enough, or neglecting to coordinate the initialization of devices in cases where special measures are needed to ease initialization.

The diagnostics to determine the *cause* of poor initialization can be complex. But simple checks against device ratings and internal control limits will often reveal bad, or at least incompatible, input data.

Numerical Instability

Most times, simulation tools that solve large systems of differential-algebraic equations (DAEs) use relatively simple Euler or trapezoid integration schemes. It is a fundamental characteristic of this class of integration scheme that the time step must be shorter than the time constant(s) of the fastest differential equations. For positive-sequence phasor-domain stability simulations, industry standard practice is to use time steps equal to ¼ of a cycle—about 5 ms. Reliable convergence of the DAE solver requires that time constants be at least twice this time step, and preferably more. It is a relatively common, if elementary, error to violate this rule; if this occurs, resultant time simulations will tend to show oscillations (sawtooth signals) with periodicity of two time steps. This is a clear red flag on the solution and has little physical meaning. Under the best of circumstances, such numerical instability is a *qualitative* warning of real instability. One diagnostic test for numerical problems is to shorten the integration time step and check for significant changes in simulation results, which would be an indication of poor input data or model structures, not actual system oscillations. Care should be taken to make sure that oscillations are not an artifact of inappropriately chosen plot step or sample.

Some EMT simulation programs are highly prone to numerical oscillations when inductive branches are opened and there is insufficient representation of stray capacitances that actually exist. This is due to a "current chopping" effect where current zero does not coincide with a simulation time step. Depending on the simulation time step used and the magnitude of the inductance, modeling realistic stray capacitances may be insufficient to avoid the oscillations. Exaggerated, artificial values of stray capacitance, sometimes in series with a damping resistance, can sometimes be used to avoid these oscillations without making a material impact on the accuracy of the simulation for the phenomena under study, but care is required to avoid adverse impacts on the results. Some EMT platforms use different integration techniques that are less susceptible to numerical problems.

Convergence Problems

Numerical problems can arise from the inclusion of series network elements that are too small. Sometimes very small elements, e.g., a reactance of 0.0001, are added to allow for two electrically identical nodes with different ownership or for other bookkeeping reasons (e.g., current or power meter). Numerical equivalencing of portions of a system, in order to reduce overall model size, can also introduce small and/or highly negative, but fictitious, impedances. In positive-sequence phasor-domain analysis, these small elements or large negative-series impedances cause the system admittance matrix to be poorly conditioned. In the EMT domain, they can cause problems related to round-off error. In either case, convergence problems can result. Positive-sequence phasor-domain simulations with these problems will often exhibit significant sensitivity to network solution tolerances.

Numerical Artifacts

There are a variety of outputs from simulation models that can present themselves as oscillations or other alarming behavior that are actually meaningless.

Power Frequency Numerical Artifacts (e.g., 60, 120 Hz Artifacts in EMT Signals)

Many signals produced by EMT simulations are phasor quantities. These include basics like active and reactive power, sequence voltages and currents, d-q (direct and quadrature axis quantities for IBRs and machines), angles, etc. The transformations that produce these signals from individual phase waveforms can produce artifacts at power frequency and 2x power frequency. One factor is DC offsets, which introduce AC distortion to signals that are expected to be steady. In short, any "oscillations" in output signals filtered from EMT waveforms that are at power frequency or 2x power frequency (e.g., 60 or 120, or 50 or 100 Hz) are probably meaningless.

Spikes and Outliers

Discrete time step simulation across discontinuities in the phasor domain introduces some simulation anomalies that are physically meaningless but can be alarming in review of results. The first network solution after a switching operation (but before time has advanced for the differential equations) needs to be regarded with some caution. It is not unusual for network solutions to show meaningless spikes in voltage or current that resolve after the next time step. These can usually be ignored. They can cause problems when models of the devices or functions such as protection act "instantaneously." Such modeling is almost invariably poor practice and should be avoided.

Pole Slipping

One common artifact of stability simulations, especially those with synchronous machines involved in marginally stable dynamics, is pole slipping. Over (and under) speed protection on machines is rarely modeled. Some simulation platforms will detect pole slipping and stop or trip the offending machine. But it is not uncommon for a remote machine, with little relevance to the system disturbance, to slip poles, driving meaningless voltage perturbations that can be mistaken for oscillations throughout the simulated network. These are characterized by the oscillations smoothly increasing in frequency, and if these are observed, the offending machine should be "tripped," and the simulation should be rerun.

Discrete Response to Meaningless Signals

Discrete actions (such as tripping or switching) may be based on logic that uses measured signals such as frequency or voltage. In simulations, these signals are vulnerable to numerical artifacts as discussed above. The risk of numerical artifacts of sufficient magnitude to trigger model logic tends to be highest under severe network conditions such as faulted or low-voltage conditions. Triggering due to an artifact (rather than a correctly calculated sign) will usually result in an incorrect simulation. Positive-sequence phasor-based analysis necessarily has fundamental algorithmic structure that can result in artifacts. In positive-sequence phasor-based simulations it is standard practice to stop time during discrete switching events (like faults or line openings), calculating the solution to the algebraic network equations once before the event and once after the event (while the differential equations are held fixed). This is a generally acceptable approximation to reality, but it carries the risk of introducing artifacts. Spikes of voltage and calculated frequency at the post-switching solutions step are usually meaningless artifacts. A variety of modeling features and algorithm tricks are embedded in simulation platforms to reduce these artifacts. This applies both to positive-sequence phasor-domain tools and to EMT tools. Nevertheless, sometimes the magnitude of signals "seen" may be unreasonable. Location in the network model and load modeling can also be important. For example, the signal at the lower-kV buses in a system representation may not be reasonable, and there may be tripping actions based on these signals. Meaningless artifacts, like frequency on the order of 30 Hz in a 60 Hz system near a severe fault, can occur, resulting in trips or other responses like mode switching within individual equipment models.

It can be tricky, but sensible screening can avoid headaches. The diagnostician should ask, "Do the signals appear to be in a plausible magnitude range such that the consequent protective discrete actions can be trusted?", with the recognition that inappropriate tripping based on poorly considered signals is a real risk.

Limit-Cycling and Hunting

Having IBR controllers swing between hard limits is an example of forced oscillations. Such phenomena can be "real," as discussed above. However, poor modeling is also a frequent cause of these simulation artifacts. It can be helpful for the diagnostician to inspect the input signals and control gains upstream of participating limiters and compare them to the input limit levels to determine whether there is a mismatch in per-unitization or other data errors. It is good practice to examine all of the intermediate signals within a model that is exhibiting limit-cycling before concluding that the behavior is real.

Nonviable Islands

Time simulations of disturbances may result in system separations. That is, the study system may have switching operations that cause two or more electrically decoupled subsystems to be created. Such events can be real and the intended subject of study, or they can be unintended results of simulations. Regardless, simulation of a system that has "broken apart" presents several opportunities for error. For a subsystem to successfully reach equilibrium, that subsystem must contain equipment that is capable of maintaining voltage and frequency—"capable" in the sense of having the necessary functionality, speed, rating, and opportunity to bring the system to a new equilibrium. Oscillations are often observed in these subsystems, sometimes as the island fails to reach equilibrium. Oscillatory failures of all the types discussed in this document may be possible. Wild swings in voltage, frequency, and other parameters may be observed. This can be real and may indeed be the point of the simulation. However, as has been pointed out several times, it is essential that the modeling be complete and appropriate for the condition being simulated. The diagnostician is well served to scrutinize every aspect, checking to make sure that system parameters (including voltage, frequency, rate of change of frequency (RoCoF), and short-circuit strength) are within the bounds of model validity, that the simulation has run properly, e.g., reaching convergence on each time step, and that no important elements that would affect the behavior of the island have been omitted.

Closure

Oscillatory stability of power systems has always been a challenge, with oscillations occasionally having complex genesis. With the growing dominance of IBRs in power systems, the characteristics of problematic phenomena have changed and will continue to do so. Practitioners are therefore faced with a growing array of oscillation types—both real and not real—whose causality can be difficult to establish.

This guide draws from both the relevant literature and the wealth of experience of the members of ESIG's Stability Task Force and is intended to help diagnosticians —those charged with determining causality and countermeasures—identify the causes and determine the mitigation of oscillations they observe in either field measurements or simulations. The guide presents new flow charts, application and decision matrices, and guiding questions to help streamline and bring order to a complex and occasionally ad hoc process.

The reference list below is subdivided into the major topics treated in this guide, and we hope that users of the guide will take advantage of these valuable resources. The industry is on a steep learning curve, with new tools and understanding constantly emerging. Most of the material in this guide will remain foundational, even as new understanding and tools are developed. Beyond consulting this guide, diagnosticians must also recognize the need for collaboration with equipment manufacturers, researchers, organizations (like ESIG), and other practitioners in understanding and mitigating the more complex problems.

Feedback

The creators of this guide see it as a work in progress; the subject is a moving target. ESIG welcomes constructive feedback for consideration in the next version of the guide. Comments can be directed to info@esig.energy. Please use a descriptive subject line—"Feedback on Oscillations Guide" or similar.

We particularly encourage comments on the following (brevity is encouraged).

Questions Specific to Oscillation Types, Methods, and Tools

- Are there important oscillatory phenomena that the guide does not address?
- Are there places where the guide's narrative could be clarified or improved?
- Do you know of better or additional methods or tools available for determining causality of oscillations?
- Are there additional practical options available for mitigating oscillations that this guide should include?
- Are there other, simple tests or questions that can help identify (or avoid) specific problems?
- Are present (simulation) tools being used properly—at the right time and for the right problem? Do they link together well? Is the guidance on tool selection provided here adequate?
- How can the inputs to the simulation tools be improved? I.e., what is needed to create higher-fidelity model data or more meaningful cases?

More General Questions About the State of the Field

- Are present analytical tools giving answers that can be trusted?
- Are the current processes for avoiding oscillations adequate for the future?
- Is there confidence that new mechanisms causing oscillations are fully understood?
- What major needs or changes are needed to do things better as levels of IBRs go up?
- In your experience, what remains to be addressed?

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Abbreviations and Glossary

Abbreviation	Full term	Notes
AEMO	Australian Energy Market Operator	Runs and plans the Australian National Electricity Market (NEM)
AGC	Automatic generation control	Fastest of centralized frequency control services; a.k.a. "aFRR" or "automatic frequency restoration reserve"
AVR	Automatic voltage regulator	Voltage control function of a generator. Traditionally in reference to a synchronous generator's excitation system.
CAISO	California Independent System Operator	California's grid operator
CCU	Current control unit	Fast low-level control for inverter
CCVT	Capacitively coupled voltage transducer	Device for measuring voltage; often in bushings
CHIL	Control hardware in the loop	An experimental and design set-up for IBR controls
CIGRE	International Council on Large Electric Systems	A pan-national professional society of power system engineers
CPU	Central processing unit	The brains of a processor
CT	Current transformer	A device for measuring AC current
DEF	Dissipating energy flow	A method for identifying disruptive power system elements
DER	Distributed energy resource	Usually generation such as photovoltaics, small reciprocating engines, batteries, etc. connected at distribution voltages or behind customer meters
DFT	Digital Fourier transform	An algorithm to perform Fourier transform on time signals. Functionally, digital Fourier transform and discrete Fourier transform are interchangeable, the key aspect being that the math applies to discrete samples, not a true continuum.
EHV	Extra-high voltage	Transmission voltages usually defined above 100 kV
EMT	Electromagnetic transient	Most EMT programs share DNA with a common ancestor, the program codes that originated at Bonneville Power Administration more than half a century ago.
ERCOT	Electric Reliability Council of Texas	Grid operator for most of the state of Texas
ESO	National Grid Electricity System Operator	Grid operator for Great Britain

Abbreviation	Full term	Notes
FACTS	Flexible AC Transmission System	A large class of inverter-enabled technologies for grid control and performance enhancement
FFT	Fast Fourier transform	A mathematical device for extracting frequency information from periodic signals
FFR	Fast frequency response	A relatively new essential reliability service for frequency
FIDVR	Fault-induced delayed voltage recovery	A pathology in which voltage comes back slowly after fault clearing
FO	Forced oscillation	An oscillation driven by one or more misoperating devices
GFL	Grid-following (inverter)	Basic inverter control paradigm common to most commercial IBRs as of this writing
GFM	Grid-forming (inverter)	An increasingly used inverter control paradigm for IBRs
HVDC	High-voltage direct current	A mature technology for point-to-point transfer of large amounts of power
IBR	Inverter-based resource	A.k.a. converter-interfaced resource; includes wind, solar PV, batteries, FACTS, and others
IEEE	Institute of Electrical and Electronics Engineers	Professional organization which includes the Power & Energy Society
ISO	Independent system operator	Grid operator in systems with full markets
LCC	Line-commutated converter	An older control paradigm for inverters and rectifiers; it is always grid-following
LCC HVDC	Line-commutated HVDC	Typical of older, very high-power HVDC
LMP	Locational marginal price	Wholesale price of electricity at a specific time and location
MMC	Multi-modular converter	An inverter configuration typical of high-power IBRs
MOV	Metal oxide varistor	A passive overvoltage protection technology, often used with capacitors and other substation equipment
NERC	North American Reliability Corporation	Sets reliability rules and standards for North America
NREL	National Renewable Energy Laboratory	One of the U.S. national laboratories
OEM	Original equipment manufacturer	Commercial manufacturers of power hardware, e.g., wind turbine-generators and inverters
PFR	Primary frequency response	Also known as frequency containment response
PHIL	Power hardware in the loop	An experimental and design set-up for IBR controls and power equipment
PID	Proportional/integral/derivative [function]	Standard linear control structure
PLL	Phase-locked loop	Mechanism by which inverter-based resources track terminal voltage angle and frequency

Abbreviation	Full term	Notes
PMU	Phasor measurement unit	A grid measurement device, physically located on the grid, with time synchronization of sufficient resolution to allow measurement of power phasor quantities
POD	Power oscillation damping	Supplemental control that usually modulates the output of grid-connected devices to add damping to oscillations
PSS	Power system stabilizer	Supplemental control for introducing damping of speed swings in synchronous generators; mandatory in NERC jurisdictions
PT	Potential transformer	For measuring voltage
PTC	Production tax credit	Tax benefit connected to energy delivery; can be important in curtailment decisions
PV	Solar photovoltaic	Solar panels and accompanying power equipment
PWM	Pulse-width modulated	A switching scheme to create AC waveforms from a DC source
RLC	Resistance inductance capacitance	As opposed to resistances, reactances, and susceptances (e.g., RXB) for fundamental-frequency phasor modeling
RMS	Root-mean-squared	A mathematical device for mapping of time-varying periodic signals to simple scalar quantities
RTDMS	Real-time distribution management system	A system for advanced control of normally passive distribution systems
RTO	Regional transmission organization	Grid operator in systems without full markets
SCADA	Supervisory control and data acquisition	Distributed central nervous system of the grid; relatively slow cycle times
SCR	Short-circuit ratio	Measure of relative system strength to device (IBR) rating. Complex. Controversial.
SEDC	Supplemental excitation damping controller	Supplemental control for introducing damping of torsional vibrations in synchronous generators
SMIB	Single-machine infinite-bus	A modeling device used widely for testing of device models
SSCI	Subsynchronous and supersynchronous control interaction	See guide section
SSO	Sub- and supersynchronous oscillations	A catch-all label for a large variety of relatively fast oscillatory behavior; includes supersynchronous phenomena
SSR	Subsynchronous resonance	See guide section
SSTI	Subsynchronous torsional interaction	See guide section
STATCOM	Static synchronous compensator	A shunt-connected reactive power control device that uses self-commutated converters
SVC	Static VAR compensator	A widely used FACTS technology for dynamic voltage support that uses LCC converters

Abbreviation	Full term	Notes
TCSC	Thyristor-controlled series compensation	A FACTS technology that allows for rapid, continuous adjustment of series compensation
UFLS	Under-frequency load shedding	The backstop for frequency control; results in involuntary disconnection of customer load
UIF	Unit interaction factor	A screening index for SSR
VSC	Voltage source converter	An inverter structure and control paradigm

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Diagnosis and Mitigation of Observed Oscillations in IBR-Dominant Power Systems: A Practical Guide

A Report by the Energy Systems Integration Group's Stability Task Force

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The report is available at https://www.esig.energy/oscillations-guide/.

To learn more about ESIG's work on this topic, 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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