

Reliability Guideline

Forced Oscillation Monitoring & Mitigation

September 2017

RELIABILITY | ACCOUNTABILITY



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The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to assure the reliability of the bulk power system (BPS) in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the electric reliability organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the BPS, which serves more than 334 million people.

The North American BPS is divided into eight Regional Entity (RE) boundaries as shown in the map and corresponding table below.



The North American BPS is divided into eight Regional Entity (RE) boundaries. The highlighted areas denote overlap as some load-serving entities participate in one Region while associated transmission owners/operators participate in another.

FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst Corporation
SERC	SERC Reliability Corporation
SPP RE	Southwest Power Pool Regional Entity
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Preamble

NERC, as the FERC-certified electric reliability organization (ERO),¹ is responsible for the reliability of the Bulk Electric System (BES) and has a suite of tools to address this responsibility, including (but not limited to) lessons learned, reliability and security guidelines, assessments and reports, the Event Analysis Program, the Compliance Monitoring and Enforcement Program, and Reliability Standards. Each entity, as registered in the NERC compliance registry, is responsible and accountable for maintaining reliability and compliance with the Reliability Standards to maintain the reliability of their portions of the BES.

It is in the public interest for NERC to develop guidelines that are useful for maintaining or enhancing the reliability of the BES. The NERC Technical Committees—the Operating Committee (OC), the Planning Committee (PC), and the Critical Infrastructure Protection Committee (CIPC)—are authorized by the NERC Board of Trustees (Board) to develop Reliability (OC and PC) and Security (CIPC) Guidelines per their charters.² These guidelines establish voluntary recommendations, considerations, and industry best practices on particular topics for use by users, owners, and operators of the BES to help assess and ensure BES reliability. These guidelines are prepared in coordination between NERC Staff and the NERC Technical Committees. As a result, these guidelines represent the collective experience, expertise, and judgment of the industry.

The objective of each reliability guideline is to distribute key practices and information on specific issues to support high levels of BES reliability. Reliability guidelines do not provide binding norms and are not subject to compliance and enforcement (unlike Reliability Standards that are monitored and subject to enforcement). Guidelines are strictly voluntary and are designed to assist in reviewing, revising, or developing individual entity practices to support reliability for the BES. Further, guidelines are not intended to take precedence over Reliability Standards, regional procedures, or regional requirements. Entities should review this guideline in conjunction with Reliability Standards and periodic review of their internal processes and procedures, and make any needed changes based on their system design, configuration, and business practices.

¹ <u>http://www.ferc.gov/whats-new/comm-meet/072006/E-5.pdf</u>

² <u>http://www.nerc.com/comm/OC/Related%20Files%20DL/OC%20Charter%2020131011%20(Clean).pdf</u> <u>http://www.nerc.com/comm/CIPC/Related%20Files%20DL/CIPC%20Charter%20(2)%20With%20BOT%20approval%20footer.pdf</u> <u>http://www.nerc.com/comm/PC/Related%20Files%202013/PC%20Charter%20-%20Board%20Approved%20November%202013.pdf</u>

Purpose

This Reliability Guideline is intended to provide guidance and awareness for identifying and mitigating forced oscillations (FOs) on the BPS. The guideline describes the fundamental behavior of forced oscillations and how they differ from system (natural) oscillations such as local, inter-area, intra-plant, or torsional oscillations. It also highlights the use of synchrophasor data from phasor measurement units (PMUs) and data from other dynamic disturbance recorders (DDRs) for oscillation monitoring and analysis. A framework for identifying and characterizing forced oscillations as well as determining the source of these oscillations is provided. Recommended practices and mitigation strategies are included to provide system operators and operations engineers with useful and actionable information for dealing with forced oscillation that could have an adverse impact on reliable operation of the BPS. The appendices provide a list of currently operational forced oscillation applications as well as a library³ of actual forced oscillation events that have occurred across the North American interconnections.

The reliability guideline applies primarily to Reliability Coordinators (RCs), Transmission Operators (TOPs), Transmission Owners (TOs), Distribution Providers (DPs), Generator Operators (GOPs), and Generator Owners (GOs). The TOPs, and/or RCs likely have wide-area coverage using PMUs which enables monitoring of oscillatory behavior on the BPS. Upon detection of forced oscillations, these entities may need to work with DPs, TOs, GOs, and GOPs to operate the system reliably, identify the source of the forced oscillations, and mitigate these oscillations if applicable.

³ This library is simply a sample of oscillation events that frequently occur across the BPS in all interconnections.

Before discussing forced oscillations in detail, it is important to characterize and differentiate forced oscillations from system modes. This section describes the different types of oscillations observed on the BPS, and the similarities and differences between these types of oscillations.

Significance of Forced Oscillations

Forced oscillations can occur in the power grid under a wide variety of circumstances, such as equipment failure, inadequate control designs, and abnormal generator operating conditions. Depending on the dynamic nature of the oscillations, the impact of such forced oscillations may be experienced locally near the source of the forced oscillation or across wide geographical regions of the system.

Forced oscillations with frequencies over 1 Hz tend to be local in nature and may be seen in a few plants near the source of the oscillations. Forced oscillations with frequencies under 1 Hz may interact with natural oscillatory modes of the power grid and can lead to wide-area oscillations across an interconnected power system. For instance, a 0.25 Hz forced oscillation in Alberta, Canada in 2005 led to 200 MW resonant oscillations on California-Oregon Intertie (COI) interties 1100 miles away from the source (Figure 1.1). More recently, oscillations at 0.27 Hz at a nuclear plant in Mississippi in 2016 interacted with an Eastern Interconnection natural oscillatory mode and led to widespread oscillations that were seen from New York to Florida for over thirty minutes.

The occurrence of large resonant oscillations far away from the source is especially a concern for system operation since they may lead to unnecessary or inadvertent tripping of generators that may be simply reacting to the forced oscillations originating from a different source. Simulation studies show that if a forced oscillation interacts with a system mode that has weak damping, it can lead to wide-area resonant oscillations of large amplitude that can contribute to potential disturbances, such as the August 10, 1996 outage in the Western Interconnection.⁴ The sustained presence of significant forced oscillations on the BPS could lead to long-term effects, such as equipment fatigue and potential damage to rotor shafts exposed to such sustained, high-magnitude oscillations. Power quality may also be a concern depending on the amplitude and frequency of the forced oscillations. These types of issues provide a basis for the significance of monitoring for these oscillations, understanding how they can interact on the BPS, and potential mitigation measures for these events.



Figure 1.1: MW Flow on California-Oregon Intertie during Forced Oscillation Event (Source: Bonneville Power Administration (BPA))

⁴ D. Kosterev, C. Taylor, W. Mittelstadt, "Model Validation for the August 10, 1996 WSCC System Outage," IEEE Trans. Power Systems, Vol. 14, No. 3, pp. 967-979, Aug 2002.

Fundamentals of Power System Oscillations

Oscillations are always present in the BPS due to the electromechanical nature of the electric grid. Under no significant external influence to the system, the grid oscillates at its natural frequencies for small perturbations such as constant changes in load. These oscillations are usually well-damped and contained; however, growing or high-energy oscillations can present system instability, potential equipment damage, safety concerns, and power quality issues. In addition to these natural oscillations, forced or "rogue" inputs to the system can also cause oscillations and should be detected and mitigated to the extent possible. It is important to clearly differentiate between the types of electromechanical oscillations that are present. From a practical standpoint, power system oscillations can be categorized as follows:

- **System (Natural):** low-frequency rotor angle oscillations caused by instantaneous power imbalances. These are often differentiated further as follows:
 - Local: oscillations where one power plant or generating unit oscillates with the rest of the system, generally caused by heavy loading and generator controls
 - Intra-plant: oscillations where generating units within a power plant oscillate with each other at the same location⁵, generally caused by poor tuning, unit control interactions, and unit operating modes
 - Inter-area: oscillations characterized by several coherent units or parts of the system oscillating
 against other groups of machines, often predominant in power systems with relatively weaker interarea connections
 - Torsional: high (subsynchronous) frequency oscillations caused by resonance conditions between highly compensated transmission lines and the mechanical modes of a steam-turbine generator (typically referred to as subsynchronous resonance⁶).
- Forced: sustained oscillations driven by external inputs to the power system that can occur at any frequency, such as unexpected equipment failures, control interactions, or abnormal operating conditions⁷

System modes are clearly visible following a system disturbance as these modes are excited in the response of the system. Poorly damped system oscillations (e.g., caused by poorly tuned controls) may be observed as background oscillatory noise on the system with fluctuating magnitude constantly excited by small changes in power system operating conditions.⁸ Figure 1.2 shows an illustration of a system event where the natural modes cause parts of the system to swing against other parts of the system. Forced oscillations are a result of an external forcing function into the natural system response (e.g., a control interaction, equipment failure, etc.). Figure 1.3 shows an example of a forced oscillation. In this example, the unnatural forced oscillation is clearly visible for over five minutes on a transmission circuit active power flows. An external source is driving this perturbation in power flows.

⁵ These types of oscillations are normally manifested within the plant site and often difficult to observe external to the power plant itself. ⁶ Past subsynchronous resonance (SSR) and subsynchronous control interaction (SSCI) oscillation events have resulted in equipment

damage. See reference: J. Adams, C Carter, S.-H. Huang, "ERCOT Experience with Sub-Synchronous Control Interaction and Proposed Remediation," IEEE PES Transmission and Distribution Conference and Exposition, May 2012.

⁷ Examples of these types of issues may include logic controller control card failure, steam valve control issues, or operating a generating unit at an abnormal output level.

⁸ Forced oscillations may develop under low short circuit ratio conditions, particularly in areas with high penetration of inverter-based resources. This may also occur with fast excitations system voltage controls as well as pulsating loads. These types of scenarios are common and can be addressed accordingly by reviewing control system tuning, etc.



Figure 1.2: System (Natural) Oscillation of System Modes during August 4, 2000 Oscillation Event in WECC (Source: BPA)



Figure 1.3: MW Flow on Transmission Line during Forced Oscillation Event Caused by Control Failure (Source: Montana Tech)

Oscillations can also be described in terms of the operating states of the BPS, characterized by ambient, transient, and forced responses. Figure 1.4 shows how these states differ from each other based on the inputs to the power system. Ambient response is caused by unknown, small random inputs to the power system such as load variations. These inputs cause a "sizzle" in the system frequency that continuously excite the electromechanical modes in an interconnected power system. Transient response is caused by large disturbances that provide stronger excitation of some electromechanical system modes as well as the nonlinearities in the system. Forced response is the outcome of some form of cyclic or "rogue" input that acts as an unexpected forcing function to the power system.



Figure 1.4: Types of System Response – Ambient, Transient, Forced Oscillation (Source: Montana Tech)

The type of response observed can also be characterized by three types of responses: transient, forced, and ambient, described as:

- 1. **Ambient**: The response of the system to the small random changes within the system. These changes are typically characterized by small random load fluctuations and variable energy resource changes.
- 2. **Transient:** The response of the system immediately following a disturbance such as a fault, line trip, generator trip, or load rejection. Oscillations in a transient response are typically characterized by the oscillation modes.
- 3. **Forced**: The response of the system associated with an external input or a malfunctioning apparatus (e.g., malfunctioning steam valve cycling on and off, arc furnace induced dynamics). Forced oscillations may include harmonics of the fundamental frequency of the forcing function resulting from the periodicity of the external inputs. Forced oscillations are typically undamped and persist until the forcing input disappears or is removed from the system.

Oscillations are often described by the terminology below. Forced oscillations are differentiated from system oscillations using this terminology as well.

- **Oscillation Mode:**⁹ A natural property of an electromechanical system characterized by its frequency, damping, and shape.¹⁰ Inter-area modes, for example, are oscillatory modes where groups of generators move together coherently with other groups of generators. Forced oscillations are not described by modes¹¹ or eigenvalues.¹² An oscillation mode is characterized by the following three properties:
 - a. **Mode Frequency:** The frequency at which the oscillation is occurring. The following system mode oscillation ranges apply to different phenomena occurring in the BPS as described below.
 - i. 0.01 0.15 Hz: governor, plant controller, or automatic generation control (AGC)
 - ii. 0.15 1.00 Hz: electromechanical inter-area and some local plant oscillations
 - iii. 1.00 5.00 Hz: local generator control oscillations, excitation controls, dc circuit controls
 - iv. 5.00 50.00 Hz: high (subsynchronous) frequency torsional, dc controls, inverter-based generation controls, subsynchronous interactions

Forced oscillations can occur at any frequency. Forced oscillations typically have harmonics of the forced oscillation frequency since the cyclic input waveform is generally not sinusoidal. Odd harmonics are common whereas even harmonics tend to appear when the input waveform is not vertically symmetrical. The forced oscillation frequency is key to the identification of these oscillations.

- b. Mode Damping Ratio: Damping describes the rate of oscillation decay and the trend of the oscillation envelope (e.g., increasing, decreasing, or sustaining and how fast this change is occurring). Damping ratio describes the same property, only scaled (partly) by the oscillation frequency. Therefore, damping has to be used together with its associated oscillation frequency whereas damping ratio is a more independent concept. The damping ratio of inter-area oscillations is tied to the system behavior and stability. Forced oscillations often have a near-zero oscillation damping ratio since their source of oscillation perturbing the system is persistent (no decay). In the case of forced oscillations, this does not mean the system is unstable.
- c. **Mode Shape**: Relative perception of an oscillation mode in different parts of a power grid. The shape is defined by the amplitude and phase of the mode at specific measurement locations. The amplitude describes the visibility of the mode at that location, and the angles describe the relationships between different locations whether they are oscillating together or against each other. Forced oscillations are not generally described by a system mode shape; however, forced oscillations have an associated oscillatory characteristic for that forcing function that can be represented like a perceived oscillation mode shape.

⁹ Also referred to as "natural", "free", or "system" mode.

¹⁰ Mathematically, these are related to the complex system eigenvalues and associated eigenvectors.

¹¹ The frequencies of a forced oscillation are determined by the period of the rogue input driving the system. The forced oscillation's amplitude and phase at measurement locations are determined by the rogue input's characteristics and the system's transfer function from the input to the measurement location.

¹² Eigenvalue analysis determines the dynamic performance of the power system under different characteristic frequencies; modal analysis considers the eigenvalues as well as eigenvectors which provide information about the observability (right eigenvector) and controllability (left eigenvector) of an oscillation.

Key Takeaways:

- Forced oscillations are relatively common yet sporadic in nature. They can occur at any time and any place in the BPS where a "rogue" or external driving function may be applied.
- Forced oscillations are not described by modes or eigenvalues.
- Forced oscillations can occur at any frequency; the fundamental frequency of the oscillation depends on the nature of the driving cyclic force.
- Forced oscillations typically have harmonics of the forced oscillation frequency since the cyclic input waveform is generally not sinusoidal.
- Forced oscillations often have a near-zero damping ratio since their source of oscillation perturbing the system is persistent (no decay). This does not mean the system is unstable.
- Forced oscillations are not generally described by a system mode shape; however, forced oscillations have an associated oscillatory characteristic for that forcing function which can be represented like a perceived oscillation mode shape.
- The driving cyclic force is usually not accounted for in dynamic models; therefore, traditional modal analysis and transient stability analysis are not applicable to studying this phenomenon. Rather, forced oscillations are usually discovered through dynamic measurement devices such as PMUs or other DDRs.

Table 1.1: Characteristics of Oscillations						
Characteristic	System	Forced				
Oscillation Mode	Natural property of electro- mechanical system; characterized by frequency, damping ratio, and shape	Not described by oscillation modes due to external forcing function acting on system				
Mode Shape	Explains how parts of system interact with one another	Not described by system mode shapes; they have response based oscillatory characteristics				
Frequency	Frequency at which oscillation is occurring; explains type of phenomena occurring in the BPS depending on range	Can occur at any frequency; often includes harmonic content of the fundamental forced oscillation frequency				
Damping Ratio	Expresses how quickly an oscillation decays; tied to system stability	Typically very near zero since FOs caused by an external persistent input signal; does not necessarily mean the system is unstable				

Table 1.1 compares characteristics between system and forced oscillations.

This section describes various aspects that should be taken in to consideration when monitoring, analyzing, understanding, and potentially acting upon forced oscillations on the BPS. It will discuss the sources of forced oscillations, monitoring devices for forced oscillations, and the interaction between system modes and forced oscillations.

Sources of Forced Oscillations

Unfortunately, forced oscillations cannot be predicted ahead of time; therefore, typical sources of forced oscillations should be considered. While the source of a forced oscillation may be any component connected to the BPS, recent research has shown that sources of oscillations typically include the following:

- **Traditional Generating Resources:** Power plants (e.g., fossil, hydro, and nuclear power plants) have many controls with the primary electric generator functions that maintain mechanical power to the generator and generator field current at the desired level. Forced oscillations often result from malfunctioning power plant controls and/or devices and mechanical failure.¹³ Generators can also oscillate during short periods of time at specific operating conditions (e.g., during startup or shutdown, hydro generator "rough zone," etc.).
- Variable Energy Resources: Forced oscillations can also originate from resources that employ newer technologies, such as inverter-based generation. Oscillations can be induced by a number of factors, including wind turbine controls, inverter controls, plant-level controls, and other types of controls or interactions. The significantly faster and advanced controls of these types of resources, coupled with the fact that they are often placed in "weaker" areas of the BPS, make these resources common sources of forced oscillations.
- Loads: Industrial loads are highly cyclic in nature¹⁴ and can induce forced oscillations into the BPS. These can be caused by a range of processes, controls, or malfunctions within these large customers connected at either the transmission or distribution system.
- Malfunctioning Grid Controls: Elements on the BPS may fail, malfunction, or misoperate. Periodic failure
 or malfunction of these types of devices or their controls may induce oscillations into the BPS. Examples
 of these types of elements include switched capacitors, thyristor-controlled devices such as SVCs and
 HVDC circuits, voltage-source converter technology such as STATCOMs and some HVDC, and series
 compensation devices.

Potential sources of oscillations, specific components within these elements, and mitigation techniques are described in more detail later in this guideline.

Monitoring Devices for Forced Oscillations

While the effects of forced oscillations may be observed using lower resolution SCADA data, higher resolution DDR data is useful in fully characterizing oscillations on the BPS. Conversely, very high resolution data captured from devices such as fault recorders can generally capture short durations of an oscillation event; however, they typically lack the capability or configuration to capture the event in its entirety. In general, reporting rates of 30 to 60 samples per second, typical of modern DDRs is sufficient to capture the majority of forced oscillations observed on the BPS.

 ¹³ Examples of malfunctioning controls include misoperation or abnormal valve controls swinging in a limit cycle and hydroelectric generation plants operating in a "rough zone" resulting in resonance effects linked to the turbine penstock.
 ¹⁴ Such as electrolytic process in aluminum smelting.

DDRs (including PMUs) should be placed at or near generating resources (including wind and solar), large load buses, and grid control devices in order to capture the location of forced oscillations. Truly locating forced oscillation sources requires considerably wide DDR coverage across a particular interconnection. Having DDR monitoring capability at the borders between TOP and/or RC footprints can help in coordination the observation of oscillations propagating across multiple TOP and/or RC areas.

Most existing PMUs may not meet the requirement of M class¹⁵ configuration, but experience has proved that these PMUs can be effectively used for oscillation monitoring and analysis. However, if an entity is specifically installing new PMUs for oscillation monitoring, it is recommended to configure as an M class device to accurately capture oscillations in the typical frequency range. With P class filtering, phasor magnitude rolls off as oscillation frequency increases, leading to less of the oscillation captured up to the Nyquist frequency. The P class characteristic is also more susceptible to aliasing, as higher frequency (beyond the Nyquist) oscillations may not be adequately filtered. The M class characteristic displays less roll off at lower frequency, allowing for more of the oscillation to be captured. Higher frequencies are filtered out, reducing the potential effect of aliasing.

In most cases, forced oscillations are captured by DDRs in the following electrical quantities: real and reactive power flows, frequency signals, and voltage magnitude signals. These quantities provide physical perspective to grid operators. For example, if the output of a monitoring device identifies that a particular generator is oscillating with an RMS magnitude of 50 MW, this provides physical perspective and alarm limits to the operator. One natural perspective is to alert/alarm operators on forced oscillations that are X MW above the normal ambient level and that persist for more than Y seconds.

Key Takeaways:

- PMUs are a form of DDR device that provide continuous, high-resolution monitoring of grid electrical quantities.
- PMUs can accurately capture oscillations of interest up to around 15-30 Hz, depending on sampling rate and filtering. PMU filtering and aliasing should be considered when selecting configuration settings, such as filtering.
- It is recommended to locate PMUs at or near generating resources, large load buses, grid control devices, and interties with neighboring TOPs or RCs. This will ensure more accurate and effectively identification of oscillations and determining the source of these oscillations.
- Time synchronized synchrophasor measurements voltage and current phasors, as well as frequency and active and reactive power, are useful for oscillation analysis.

Interaction between System and Forced Oscillations

Forced oscillations that occur on the BPS are generally locally contained and can be identified accordingly. However, if a forced oscillation occurs at an oscillation frequency near the frequency of an inter-area system mode, the forced oscillation can "excite" the mode so that the oscillations propagate through wide geographical domains where the system mode is active. Under certain circumstances, the interactions can also lead to a "resonance" effect so that the resulting system-wide oscillations are much larger than the oscillations at the source. In this case, even small oscillations can induce larger, system-wide oscillations from resonance amplification. An important property of such resonance conditions is that the larger magnitude forced oscillation can be observed in multiple locations across the grid, particularly far away from the actual source where the magnitude of the oscillation can be relatively small. That significantly complicates the identification of the source

¹⁵ IEEE Standard for Synchrophasor Measurements for Power Systems, IEEE Standard C37.118.1-2011, 2011.

of oscillations in practice when there is no prior knowledge of the location and nature of the forced signal. Using the magnitude/energy of the oscillations as an indicator of the source location could be misleading in these situations. In these situations, it is important for RCs to coordinate with one another to simultaneously identify the oscillation and attempt to determine a source and mitigating procedure if necessary.

There have been documented instances (outlined later in this guideline) where small generation plants across North America that experienced a forced oscillation have induced these larger system-wide oscillations. This drives the need to understand the electromechanical modes in each of the North American interconnections to be prepared for these types of situations where the oscillations could interact with one another. Understanding the potential interactions is critical when trying to identify the source of oscillations, particularly when they are observed throughout the BPS.

Example of Resonant Interaction between Inter-Area and Forced Oscillation

On November 29, 2005, a steam extractor valve failed at the Nova Joffre power plant in Alberta, Canada leading to 20 MW forced oscillations in the active power output of the plant that lasted from 23:37 to 23:42 Pacific time. The frequency of the oscillation was around 0.27 Hz and these oscillations interacted with the 0.26 Hz North-South inter-area mode of the Western Interconnection. Since Alberta is a key participant in the 0.26 Hz system mode, the forced oscillations were amplified by the resonance effect even though the system mode was well-damped at the time of the event.¹⁶ The California-Oregon Intertie (COI) lines 1100 miles away from the plant experienced 200 MW oscillations, much larger than the 20 MW oscillations at the Nova Joffre power plant. Figure 2.1 shows the flow on a 500 kV transmission circuit near the COI.



Figure 2.1: MW Flow on California-Oregon Intertie during Forced Oscillation Event (Source: BPA)

Example of Interaction between Inter-Area and Forced Oscillation

On June 17, 2016, a forced oscillation in the Eastern Interconnection (EI) occurred at 0312 Eastern Daylight Time around 0.27 Hz. The EI has a system mode near that frequency that resulted in an interaction between the forced oscillation and system mode at that frequency. This caused the forced oscillation to show up across the system. The source was determined to be a control valve malfunction at Grand Gulf Nuclear Station (GGNS) in Entergy footprint; however, power oscillations were seen across the entire EI system. Figure 2.2 shows the two line flows

¹⁶ Details available at "Analysis of November 29, 2005 western American oscillation event", IEEE Transactions on Power Systems, Volume 31, No.6.

(green and blue trends) capturing GGNS output. Because of the interaction with the eastern system mode, the 200 MW forced oscillation at Grand Gulf resulted in 40 MW tie line oscillations on one of the New York to New England lines about 1400 miles away (Figure 2.3) from the source in Mississippi. This event is explained in more detail in Appendix B. An animation of the event has been prepared by the FNET GridEye monitoring system at University of Tennessee Knoxville.¹⁷ The animation clearly shows inter-area oscillations across the Eastern Interconnection during this event.



Figure 2.2: Approximately 200 MW Forced Oscillation at GGNS (Source: Entergy)



Figure 2.3: Approximately 40 MW Oscillations Seen in New England Region (Source: ISO-NE)

¹⁷ FNET videos available: <u>https://www.youtube.com/watch?v=1vuxZJitEJg&feature=youtu.be</u> and <u>https://www.youtube.com/watch?v=2YKb2yj1P_M&feature=youtu.be</u>.

Chapter 3: Recommended Practices & Mitigation Measures

Understanding forced oscillations and mitigating their impact on reliable operation of the BPS can be separated into three distinct phases, as shown in Figure 3.1: detecting the forced oscillation, characterizing the mechanism of the oscillation, and identifying the source(s) of the forced oscillation. Once these phases are accomplished, appropriate and effective mitigating action can be taken. Forced oscillations on the power system should be mitigated, to the extent possible, since these forced perturbations on the system are unplanned, unstudied, and may have short- and/or long-term reliability impacts.



Figure 3.1: Steps toward Mitigating Forced Oscillations

This section provides a framework based on this approach and also includes some insights and considerations for each step in the process. Step 1 focuses on detection, Steps 2 and 3 relate to characterizing the oscillation, and Steps 4 and 5 seek to identify the source and root cause of the oscillation.

Step 1: Detect the Forced Oscillation

The first step in the process is to identify an oscillation that is occurring. This can be through advanced tools or simply by observing oscillatory behavior in electrical signals such as frequency, voltage magnitude, or power flows. With high resolution data, advanced algorithms use various techniques to detect the oscillation (e.g., energy, oscillation, coherency, matched filter detectors). This allows automated and fast detection of any abnormal oscillations occurring on the BPS. While high resolution data provides the clearest picture of the oscillation since aliasing is avoided, in some cases SCADA data can also be used to identify these oscillations.¹⁸ Figures 3.2 and 3.3 show examples of SCADA and PMU data overlaid¹⁹ on one another to show how the oscillation looks in each of the data sources.²⁰ Figure 3.4 shows another example of SCADA data where the occurrence of the oscillations can clearly be seen from the change in the nature of the plots from "steady state" to "noisy" in the shaded portion of the plots.

¹⁸ SCADA data may or may not identify a forced oscillation depending on the SCADA scan rate and the forced oscillation frequency. The SCADA data may be aliasing the actual waveforms and may not detect the oscillation. In other instances, SCADA may be able to identify some form of oscillatory behavior. Abnormal movement in SCADA values may be indicative that an oscillation is occurring (assuming good quality of SCADA measurements),

¹⁹ The data may not overlay exactly due to compression and exception processing of the SCADA data vs. the PMU data.

²⁰ NASPI Control Room Solutions Task Team (CRSTT) has a number of video examples that show SCADA versus PMU data for oscillation events. Available: <u>https://www.naspi.org/crstt</u>



Figure 3.2: Forced Oscillation Observed with SCADA and PMU Data (Source: ATC)



Figure 3.3: Forced Oscillation Observed with SCADA and PMU Data (Source: OG&E)



(Source: WSU)

It is useful to record, if possible, the times when the oscillation started and stopped. This information can be useful for correlating with events on the system or at specific generation sites, for example, to aid in detecting where and how the oscillation manifested. Also worth noting is whether this is a recurring oscillation and whether the oscillation has any cyclic nature to it (e.g., pulses every second, shows up during the day, shows up when it's windy, etc.).

Step 2: Determine Oscillation Frequency and Magnitude

Advanced tools will likely be able to detect the oscillation and provide the operator or operations engineer useful information about the oscillation, including the oscillation frequency. However, if this information is unavailable, a TOP or RC can simply get a rough estimate of the frequency by observing time series data and determining the period, *T*, of oscillation. The dominant²¹ frequency, f, of the oscillation is then determined as the reciprocal of the oscillation period, $f = \frac{1}{m}$.

The oscillation frequency is an important characteristic for identifying and mitigating its source. As described in previous sections, different oscillation frequencies can be tracked to different electromechanical aspects of the BPS. If the forced oscillation is occurring at the frequency near a system mode frequency, this can cause additional reliability risks since that forced oscillation can propagate across the BPS.

In addition, note the magnitude of the oscillation and whether it appears to pose any reliability risk to the system. This can be as simple as a qualitative point of reference to quickly understand its impact. For example, is the oscillation in real power a couple MWs or hundreds of MWs? Is the voltage oscillation one or two kV, or is it tens of kV? Key locations in the system to observe these oscillations are at major generating resources, tie lines, and critical load buses throughout the system. If the magnitude is noticeably large, this is indicative that a more severe problem has arisen and should be addressed more rapidly.

As described in previous sections, forced oscillations generally have a very low or zero damping ratio. So it is normal to have tools to alarm of an undamped oscillation when these forced oscillations occur. This is not system instability and should be treated differently than a poorly damped inter-area system oscillation. As described in the previous section, the interaction between forced oscillations and system modes can be a challenge in determining potential risks to the BPS.

²¹ This should be handled carefully in the presence of harmonic content and nonlinear characteristics in the signal.

Step 3: Determine Extent of Oscillation

TOPs and RCs who have detected a forced oscillation should identify the extent to which the oscillation is seen across their footprint. Is the oscillation more localized (observed in electrical quantities within a contained area of the system) or more widespread (observed across a significantly wider area)? If the oscillation is localized yet occurring near the border of a TOP footprint, the TOP should coordinate with its RC to identify the extent of the oscillation, the impact it may be having on reliability, and possible sources of the oscillation. If the oscillation is occurring near borders of an RC footprint, the RC should coordinate with neighboring RCs to identify its extent. If the oscillation is occurring across the TOP or RC footprint, then the TOP and RC should coordinate with neighboring RCs to understand the extent of the oscillation.

When coordinating with the RC or neighboring RCs, the following considerations may help in determining the source and extent of the oscillation:

- 1. Does the RC or neighboring RC have oscillation detection tools or the capability to quickly extract or monitor high resolution PMU data on a wide-area basis?
- 2. Is the neighboring RC seeing the oscillations in their own data?
- 3. Is the neighboring RC able to identify the oscillation near the affected border using any of their tools and capabilities?
- 4. Is it possible to mutually determine whether and where the oscillation is largest? This may be helpful²² in determining the location of the oscillation.
- 5. Are there parts of the system(s) that are not experiencing the oscillation? This is useful for larger TOPs and RCs who have a significantly large footprint.

Step 4: Determine Location or General Proximity of Oscillation

Once the general vicinity and affected entities have been identified, the source of the oscillation can be pursued. In general, if the oscillation frequency is not at a system mode frequency, the source is close to the measurement location with the largest amplitude oscillation. However, if the forced oscillation is at or near a system mode frequency, the forced oscillation shape changes to the relevant system mode shape and the amplitude may be misleading. Again, this is dependent on whether the forced oscillation is observed in a localized manner or observed across larger parts of the system. If high-resolution monitoring from PMUs is not available directly at the source of the oscillation, it can be a challenge to quickly identify the source location. For example, a PMU is monitoring the 500 kV network, but multiple generators are connected at the 230 kV system in close proximity. Regardless, identifying the source of the oscillation to the extent possible is useful.

For localized forced oscillations, TOPs and RCs can use available PMU data and possibly SCADA data (if useful) to determine where the oscillation magnitude is largest and hone in on an exact location. Using high resolution PMU data for this task is critical to have a clear understanding of the oscillation magnitude. If PMU data is available at the source of the oscillation (e.g., the point of interconnection of a power plant), this helps to identify the source. However, once the PMU data has been used to its fullest extent, lower resolution SCADA data can still be valuable to identify the true source. For example, as described above, if the PMU data points to a specific PMU on the EHV system (e.g., 500 kV) with multiple generating units in the vicinity or connected at lower voltage, the RC or TOP can extract SCADA data for the suspect generating units. Useful electrical quantities include voltage, current, frequency, active power, and reactive power. In some cases, these units may be at the same power plant, and the RC or TOP may need to coordinate with the GOP. In other cases, these may be separate power plants and coordinating with both entities may be required.

²² Again, this should be handled carefully when the frequency of the forced oscillation is near one of the known system mode frequencies.

Step 5: Determine Specific System Component Causing Oscillation

If a BPS element can be determined as the source of the oscillation, the RC and TOP should notify the owner of the element to further investigate the cause of the oscillation. For example, if a single power plant is identified, this plant may have multiple units connected to the BPS. Similarly, a large end-use load customer may have multiple processes that may be causing or contributing to the oscillation. This analysis, in many cases, will require investigation of SCADA data or data collected by the equipment owner for specific components within the plant or at the site. In addition, the cause of the oscillation can sometimes be quickly identified based on the electrical quantities experiencing the oscillation. Oscillations within a one equipment owner's facility could lead to damage of their own equipment or potentially damage of others' equipment. Hence the importance of mitigating forced oscillations and correctly identifying the source of these oscillations. Considerations that may be made based on the specific component on the system experiencing the oscillatory behavior are provided below.

Generating Resources

Generating resources are the predominant cause of significant forced oscillations on the BPS, based on the events described in Appendix B. This is expected due to the complexity of these resources and the fact that these individual resources provide significant injections of power into the system. If a generator is identified by the TOP and RC as the source of the oscillation, they should coordinate with the GOP to determine if the GOP is aware of the oscillation at its resource. These entities should coordinate, as necessary, to identify the specific source of the oscillation within the plant. Considerations include the following:

- **Changes in operating mode:** Any significant changes in operating modes (e.g., manual to automatic regulation, component statuses, etc.) can result in significantly different dynamic behavior from generating resources. This is especially true for situations where these changes are not planned ahead of time and coordinated with the TOP.
- Changes in operating condition: Certain operating conditions can cause abnormal oscillatory behavior to occur. For example, as shown in Appendix B, combined cycle resources may experience a "rough zone" during startup that may cause oscillations. Similarly, hydro generators may have a "rough zone" at low power output levels caused by the water vortex in the turbine.
- **Controller failures:** There are many components in any power plant that control mechanical processes or electrical output of the machine which could potentially fail. Examples include components within the excitation system, the power system stabilizer, and turbine-governor system. These failures may manifest themselves into oscillatory or abnormal behavior in control valves, generator output, and other quantities.
- **Control interactions:** In some unexpected situations, controls may interact with one another within a plant or between nearby plants. Unexpected or abnormal control actions should be mitigated as effectively as possible to avoid any safety issues or adverse reliability impacts to the BPS. This may require advanced studies or removing the unit from service to better understand the drivers for these interactions.

Potential short-term mitigation techniques for identified forced oscillations at generating units may include:

- Increasing or maneuvering generator active power output away from abnormal operating conditions (e.g., "rough zone")
- Changing generator excitation or voltage set point and therefore reactive power output; changing excitation from automatic to manual control (after coordination with the GOP, TOP, and RC)
- Reverting back to any control settings, if any were changed which caused the oscillation
- Curtailing generator output to levels in which the forced oscillations do not appear

- Removing one unit from service if a plant with multiple units is experiencing any interactions where other mitigations have not reduced the identified forced oscillation
- Removing the generating unit or power plant from service for severe situations where other mitigations have not reduced the identified forced oscillation

Renewable Energy Resources (e.g., Wind and Solar)

Power electronic controls in inverter-based resources such as wind and solar power plants may experience oscillations either with interactions with the grid, other control systems, or due to improper tuning. These oscillations can be manifested in active and reactive power outputs as well as plant voltages. These typically happen when the power electronic controls operate in system conditions that were different from what they were designed for. Examples include topological changes in the transmission network near a wind farm, wrong choice of control parameters and incorrect operation mode of the control system. Typically these oscillations occur at high frequencies above 3 Hz and the effects of the oscillations tend to be local. They can be mitigated in the short term by curtailing the output of the generation sources or by tripping the units from the grid in the worst case. In the long term, the TOP should work with the owner of these facilities to identify the oscillatory behavior. The owner can then identify the problem and mitigate any control-related issues.

End-Use Load

Oscillations can be caused by the consumption of electrical power by the end-use load equipment converting that electrical energy to some other form of energy. Power quality engineers monitor, study, and try to mitigate significant modifications to the relatively balanced system conditions at fundamental frequency. On occasion, end-loads may cause oscillatory behavior on the BPS due to many different reasons. This may be process-based, a resonance between the load and electrical grid, or other factors. Another benefit is that for the majority of loads, no single control failure could cause hundreds or thousands of loads to begin oscillating at a given time. The exception to this is large industrial or commercial customers that may consume large quantities of electric power. In these cases, any oscillatory behavior may be seen by the BPS rather clearly simply due to the sheer size of these loads. TOPs and RCs should coordinate with their respective Distribution Providers to ensure all entities are aware of any abnormal oscillatory behavior. The Distribution Provider should work with the end-use load customers to also ensure they are aware of the oscillation and try to identify any causes of such events. Similar to the generating resources, changes in operating conditions, operating modes, or specific processes may be driving these oscillations.

Mitigation techniques for identified forced oscillations at end-use loads could include:

- Working with the customer to identify the cause of the oscillation and minimizing or mitigating this cause to the extent possible
- Installing or tuning system components such as dynamic or static reactive resources, if applicable
- Changing terminal conditions that may be causing the oscillations (e.g., delivery voltage, if abnormal)

Transmission Elements: FACTS Device, DC Line, etc.

Transmission system elements (e.g., FACTS (Flexible AC Transmission System) devices, DC circuits, and other dynamic resources) may also cause forced oscillations on the BPS. Fortunately, these valuable resources on the BPS generally include some form of fault recording or dynamic disturbance recording so pinpointing the source of any forced oscillations from these resources is relatively easy. Similar to the preceding sections, forced oscillations from these resources may be caused by changes in control settings, unstudied operating conditions, controls interactions, or component failures. TOPs should report any abnormal oscillatory behavior from these resources to their RC immediately. RCs can coordinate with the TOP and any other potentially affected TOPs, if necessary.

These resources will generally very rapidly respond to changes in terminal quantities to support the BPS. For example, an SVC or STATCOM will quickly change reactive power output to support changes in grid voltage. While a dynamic device will begin oscillating if it perceives these changes in terminal conditions, it does not mean it is the source of the oscillation. Therefore, the TOP and RC should work towards identifying the source of the oscillation before taking any significant actions. However, if it is clear that the oscillation is originating from any device, then action should be taken to mitigate any potential damage to the equipment and adverse impacts to the BPS.

Mitigation techniques for identified forced oscillations at transmission elements may include:

- Modifying control set points or terminal conditions to move the resource away from the operating conditions causing the oscillation
- Increasing system strength by returning to service any transmission elements out of service
- Reverting back to previous control settings, if any were inadvertently changed

Appendix A: Operational Oscillation Detection Applications

This section describes oscillation detection tools that are operationally used by utilities to monitor and detect potential forced oscillations on the BPS.

Bonneville Power Administration (BPA)

BPA successfully deployed an Oscillation Detection Application²³ on their control center video wall in October 2012 that uses an "RMS Energy Filter"²⁴ shown in Figure A.1. The application scans multiple signals (power, frequency, voltages) across the grid for indication of growing or sustained high energy oscillations. The application monitors the point of interconnection (POI) of power plants, the Pacific HVDC Intertie, SVCs, and the BPA 500 kV grid internal to the Pacific Northwest. The application's primary purpose is to detect unanticipated oscillations that result from control system failures, local power plant instability, forced oscillations, excitation of inter-area modes, or a generating unit in an unstable operating region.



Figure A.1: RMS Energy Filter in Oscillation Detection Application (Source: BPA)

A PMU-derived input signal (e.g., active power or voltage magnitude) is formed and passed through a bandpass (BP) filter that focuses on the desired bandwidth for oscillation detection. The application extends classic energy detector methods²⁵ to multiple frequency bands, including:

- 0.01 to 0.15 Hz band: for governor, plant controller or AGC control oscillations
- **0.15 to 1 Hz band:** for electromechanical inter-area and some local plant oscillations, and also oscillations caused by sustained operation of a hydro-power plant in rough zone
- 1 to 5 Hz band: for local generator oscillations, generator excitation controls, PDCI controls, etc.
- **5 to 15 Hz high frequency band:** for steam-generator torsional, PDCI, wind generator control oscillations, sub-synchronous interactions

After filtering, the signal is then squared, passed through an averaging filter, and then square-rooted. The goal of the averaging filter is to estimate the mean of the squared signal matched to the BP filter. The resulting output will be an estimate of the RMS of the input signal in the bandwidth of the BP filter. An oscillation must be persistent for several minutes for the application to issue an alarm. An inverse-time characteristic, often used in protective relaying, could be considered.

The current alarm system used in the BPA control center is a definite-time alarm strategy. If the RMS energy for a given band exceeds a trigger level for a fixed amount of time, an alarm is set. Future versions being considered use a combination of inverse-time and definite-time alarms, as shown in Figure A.2. The black curve is the alarm curve. The A_i are alarm levels set by the user.

²³ BPA Oscillation Detection Application developed by Montana Tech University and University of Wyoming based on original work of Dr. John Hauer.

²⁴ M. Donnelly, D. Trudnowski, J. Colwell, J. Pierre, and L. Dosiek, "RMS-Energy Filter Design for Real-Time Oscillation Detection," Proceedings of the 2015 IEEE PES General Meeting, July 2015.

²⁵ S.M. Kay, Fundamentals of Statistical Signal Processing: Volume 2, Detection Theory, Prentice Hall, 1998.



Figure A.2: Combined Inverse-Time and Definite-Time Alarm Curve (Source: BPA)

Figure A.3 shows an overview of BPA display for the Oscillation Detection application. PMUs at locations where oscillations are monitored are placed on a geographic map. Each PMU has four frequency bands as described above. Should an oscillation alarm occur, a corresponding frequency band at that PMU will turn red. The display provides very effective visual indication on whether the oscillation is local or wide-area. For local oscillation, only one or a few PMUs in the vicinity of the oscillation source will go into alarm state. For wide-area oscillations, multiple PMUs will go into alarm state over a large geographic area. The display also provides initial indication of the type of oscillation based on the frequency band alarmed.

BPA dispatchers and operations technical staff can drill down further into the oscillation by selecting the PMU, which brings up a trend display with monitored signals. The signals that triggered the alarm will be identified on the display.

The display includes signal trend, alarm status trends, and oscillation energy trend and alarm settings for all four frequency bands. BPA developed dispatcher standing orders with instructions for operators on actions to be taken when an oscillation alarm is issued. BPA technical staff conducted several training sessions for dispatchers on oscillation basics, the Oscillation Detection application and the associated operating procedures went into effect in June 2016.

BPA Oscillation Detection application has detected several oscillation events since it was implemented in 2012. Most of the events are local forced oscillations due to equipment issues. However, there were several wide-area events due to oscillatory instability of generators.



Figure A.3: Overview Display for Oscillation Detection Application (Source: BPA)



Figure A.4: Third Layer for Oscillation Detection Application with Energy Bands (Source: BPA)

Peak Reliability (Peak)

Peak Reliability currently uses a suite of applications for oscillation detection. These applications include:

- Oscillation Detection Module (ODM)
- Mode Meter Module (MMM)²⁶
- Oscillation Monitoring System (OMS)²⁷
 - Event Analysis Offline (EAO)
 - Damping Monitor Offline (DMO)
- Pattern-Mining Algorithm (PMA) Tool²⁸

The ODM and MMM applications (version 1.0) implemented at Peak Reliability were customized into GE-Alstom's PhasorPoint application. Currently, Peak is in the process of properly configuring the ODM application to detect forced oscillations in the WECC system. The MMM application is configured to monitor N-S mode A (~0.25 Hz) and N-S mode B (~0.4 Hz), and Peak is in the process of setting up other known WECC inter-area modes.²⁹

The ODM runs in real-time in the Peak control center. Further offline analysis of the identified oscillations by ODM is performed using the OMS software and in-house developed PMA tool. Offline OMS monitors low-frequency electromechanical oscillations using hundreds of wide-area PMU measurements across the Western Interconnection and detects the presence of poorly damped or growing oscillations. It combines signal-processing algorithms with heuristic rules³⁰ to automatically extract the modal information. PMU measurements that Peak receives from its operating entities can be exported to either .csv or COMTRADE format and imported into OMS software to perform the analysis. The tool uses hundreds of PMU measurements simultaneously; therefore, detected bad PMU data such as signal drop-outs will not impact the results.

Even with the existing wide-area PMU coverage reported to Peak in the Western Interconnection, finding the source of the forced oscillation detected by ODM and OMS software can be a challenge. Therefore, Peak worked closely with Washington State University to develop the PMA algorithm to process SCADA data (mainly generator MW and MVAR output data) and to find the likely source of the oscillation. The primary advantage of using SCADA data is the wide-area coverage; Peak receives data from essentially all BES generators in the Western Interconnection into the EMS/SCADA system with a typical sample rate of 10 seconds. The DataPullTool was developed using Excel VBA to export large amounts of generator data automatically from OSIsoft PI archive. Figure A.5 shows a screenshot of the tool where the user provides a time range, fuel type, and entity(ies).

²⁶ ODM and MMM developed by D. Trudnowski from Montana Tech University and J. Pierre from the University of Wyoming.

²⁷ The OMS suite including EAO and DMO developed by Dr. Mani V. Venkatasubramanian from Washington State University.

²⁸ Tools developed by Peak RC and WSU to detect and analyze forced oscillations using both PMU and SCADA data.

²⁹ The MMM is intended to monitor inter-area modes while ODM monitors for forced oscillations. The oscillation modes of the Western Interconnection have been coined over the years. The N-S Mode A and N-S Mode B modes refer to two distinct inter-area modes between coherent sets of generators in the North-South direction.

³⁰ Developed by subject matter expertise.

Appendix A: Operational Oscillation Detection Applications

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Figure A.5: Peak DataPullTool for PMA (Source: Peak)

PMA (Pattern-Mining Algorithm) tool was initially developed in MATLAB with a newer version written in C# language. A screenshot of the tool is shown in Figure A.6.





ISO New England (ISO-NE)

ISO-NE has used the PhasorPoint application by GE for detecting and characterizing oscillations online since 2012. PhasorPoint estimates magnitude, frequency, and damping of several dominant modes in the range from 0.05 Hz to 4 Hz. The entire frequency range is split into several adjustable sub-bands and each sub-band has predefined alarm/alert thresholds based on magnitude and damping of oscillations. PhasorPoint generates alarms and alerts when the detected oscillations exceed the corresponding thresholds for all types of oscillations regardless of their forced or natural classifications. Detection and characterization of oscillations at ISO-NE is considered a well-established and reliable process.

Multiple instances of sustained oscillations with significant magnitude in the frequency range from 0.05 Hz to 2 Hz, and some instances of oscillations up to 8 Hz have been observed since installing PMUs. Regardless of the forced or natural classification, sustained oscillations with significant magnitudes should be mitigated. The key step for successful mitigation is to identify the source of sustained oscillations. In order to apply the proper remedial measures, the identification process should answer the question on whether the source is located inside or outside of the control area. If the source is located inside, then the identification should provide the resolution up to the specific power plant or even to a specific unit within a power plant.

Several methods were evaluated by ISO-NE, and the energy-based method³¹ was selected as the candidate for a practical use. The method is based on the primary attribute of oscillations (i.e., energy) and is generally more robust in multiple possible situations while other methods that are based on other attributes of oscillations (e.g., magnitude, phase angles, propagation speed) and statistical signature experience deficiencies. The method has solid theoretical justification; however, the proposed original implementation does not account for actual PMU characteristics and thus is not sufficiently robust for practical use.

ISO-NE developed the dissipating energy flow (DEF) method,³² combining the original energy-based method with PMU data processing. The DEF method has demonstrated efficiency in identifying the source of forced oscillations for a variety of possible situations. It is equally efficient for natural or forced oscillations, resonance conditions of forced oscillations with local or inter-area modes, and for multiple sources of oscillation. Using PMU measurements in tie-lines between control areas, the method is able to identify whether the source is located inside or outside the control area. In testing, the method has correctly identified the source in all situations of the specifically created library of simulated cases to test the source locating methods,³³ and in more than 30 actual events from ISO-NE and in two actual events from WECC.

The use of the DEF method is expected to be a significant milestone in the application of the PMU data for creation of actionable items for the control room information. ISO-NE plans to develop the oscillation source locating (OSL) tool for online use based on the DEF method. OSL tool will be an important part of the oscillation management process (Figure A.7).

³¹ L. Chen, Y. Min, W. Hu, "An energy-based method for location of power system oscillation source," *IEEE Transaction on Power Systems*, 28(2):828-836, 2013.

³² S. Maslennikov, B. Wang, E. Litvinov, "Dissipating Energy Flow Method for Locating the Source of Sustained Oscillations", International Journal of Electrical Power and Energy Systems, issue 88, 2017, pp.55-62.

³³ See: <u>http://curent.utk.edu/research/test-cases</u>.



Figure A.7: Oscillations Management process at ISO-NE

The DEF method uses standard PMU data and calculates the flow of dissipating energy (DE) in any network element monitored by PMU. DE flow can be viewed similarly to regular MW power flow. The sign of DE indicates the direction of where the dissipating energy is coming from and the DE value indicates the amount of energy (Figure A.8). DE calculated for multiple transmission elements allows tracing the source of an oscillation in network. If the source of an oscillation is a generator monitored by PMU, the DEF methods will identify this generator as the source of the oscillation.



Figure A.8: Interpretation of DE³⁴ for locating source of oscillations

Below are some examples of using the DEF method for actual events in ISO-NE.

April 5, 2013 Event: Rapidly growing in magnitude oscillations of 0.12 Hz were observed in a significant part of the system. The magnitude of oscillations reached up to 100 MW peak to peak in some transmission lines. Oscillations gradually disappeared in 3 minutes. Figure A.9a shows MW flow in one of the lines. The DEF method has clearly identified one power plant as a source of the oscillations and Figure A.9b illustrates the dissipating energy flow in the 345 kV network around that power plant.



(a) MW flow in line B

³⁴ DE calculated by PMU measurement at bus i.



(b) DEF in 345 kV network. Arrows indicate calculated DE values. Blue color substations do not have PMU measurements.

Figure A.9: Oscillation Source Location for April 5, 2013 Event

June 17, 2016 Event: Oscillations with magnitude up to RMS = 11 MW and frequency fluctuating from 0.22 Hz to 0.28 Hz were detected in multiple locations of ISO-NE lasting 45 minutes. Figure A.10a shows the active power flow in one of the two 345 kV lines connecting ISO-NE and New York ISO (NYISO) during the initial stage of the event. The mode shape showed that the majority of ISO-NE generators were oscillating in phase, suggesting that ISO-NE PMUs allow the observation of only a part of the system wide event. The DEF method was applied for this event by using available PMU data from ISO-NE. Figure A.10b shows the DE values for the 345 kV part of network connecting ISO-NE and NYISO. DE flow clearly indicate that the source of oscillations was located outside ISO-NE.



(a) MW flow in 345 kV line B between NYISO and ISO-NE



(b) Red arrows indicate DE in the 345 kV network

Figure A.10: Locating Source of Oscillations for June 17, 2016 Event

June 30, 2016 Event: Three generators (G1, G2, and G3) at one of the power plants were operating in the same conditions, producing 237 MW each. A failure suddenly occurred at the excitation system of G3 that resulted in 1.3 Hz oscillations with RMS magnitude of 18 MW and consequential tripping of this unit. Figure A.11 shows power plant terminal voltage. Excitation failure at G3 started at t = 5s and the unit was disconnected at t = 24s. All three units were monitored by PMU and Table A.1 shows the results of the DE results. Unit G3 is reliably identified as

the source of oscillations producing energy while other two units were contributing into damping by dissipating energy. Note that the G3 has the highest DE flow in the network. This example illustrates the ability of the DEF method to identify a specific unit as the source from multiple units within a power plant.



Figure A.11: Power plant terminal voltage during June 30, 2016 event

Table A.1: DE of Generators for June 30, 2016 Event					
Generator	G1	G2	G3		
DE	-0.01	-0.01	1.0		

Oklahoma Gas & Electric (OG&E)

OG&E, along with many other utilities in the U.S. Great Plains region, has a large wind generation resource potential. Many large scale wind farm facilities, varying in size from 100 MW to 300 MW, have been brought online with total wind capacity now exceeding 5300 MW on the OG&E system. Each new wind farm facility brought on-line in OG&E's service territory is accompanied by PMU measurements at the point of interconnection. In December 2010, the utility began observing sub-synchronous oscillations on the transmission system in a concentrated portion of the grid in northwestern Oklahoma as shown in Event 19: Woodward Wind 13 Hz Oscillation.

This phenomenon could not be observed with traditional SCADA monitoring and would have taken much longer to identify and resolve without synchrophasor technology. After observing these instances of voltage oscillations, the company implemented a Fast Fourier Transform (FFT) detection program to detect the oscillations and send email notifications when it requires corrective action.



Figure A.12: FFT Emailer application (Source: OG&E)

The application was developed in VB.net and utilizes the OSS exocortex library for FFT oscillation detection (http://www.exocortex.org/dsp). To validate that the program was correctly calculating the FFT, the output was compared with MathCad's FFT algorithm (www.ptc.com/product/mathcad), which proved to be a match. To

provide some additional details on how the algorithm is used, the input parameters to the program will be discussed. The user can set the number of samples to be queried (in this case, 1024) and how often the query is repeated. The user then specifies the PMU to take measurements from and the frequency range of interest. The trigger on/off settings allows the user to specify how sensitive the detection should be. A set of email recipients are specified with some reasonable limits to be sure that the users are not flooded with nuisance emails. The user can also test the parameters against a historical data sample to tune the parameters and make sure they are detecting only events of interest.

The output of the program comes via email (see Figure A.13) to operations support engineers, and these engineers will investigate and determine if action should be taken. If it is determined that mitigation is necessary, they will contact the transmission control center and recommend a mitigation strategy to the operators.



Figure A.13: Email notification example (Source: OG&E)

This section provides illustrative examples of forced oscillation events, how they were identified, and any mitigation measures taken.

Event 1: Controller Oscillation at Pacific HVDC Intertie

An oscillation event occurred on the Pacific HVDC Intertie (PDCI) on January 26, 2008. At the time of event, the PDCI was operating in the South to North direction with the Pacific Northwest (Celilo) importing about 1,700 MW from Southern California (Sylmar). An outage of two 500/230 kV transformers near the Celilo converter station resulted in low short-circuit ratio conditions, causing the PDCI controls to develop a high-frequency power oscillation. The active power oscillation reached 150 MW, reactive power oscillation was at 200 MVAR peak to peak, and the 230 kV bus voltage oscillation was at 7 kV peak to peak. The oscillation frequency was 4 Hz, indicating a control system oscillation.

BPA did not have an oscillation detection application at the time so the event lasted for almost an hour. Reports were made about the oscillation causing erratic readings at power plants in Southern California. The oscillation persisted until the PDCI power transfer was lowered below a certain threshold. A combined-cycle plant was tripped in the Pacific Northwest close to the Celilo terminal; however, a link between the trip and the oscillation was not definitively established.




Event 2: Alberta Forced Oscillation Event

A sustained oscillation developed in the Western Interconnection at 23:37 PST on November 29, 2005. The oscillation was initiated by a malfunctioning steam extractor control valve at a cogenerating plant in Alberta, Canada. Figure B.2 shows the plant diagram and plant recordings. The steam turbine generator developed a 20 MW peak-to-peak 0.28 Hz oscillation. The plant oscillation resonated with one of North-South modes of inter-area oscillations, causing a 200 MW peak-to-peak oscillation on California – Oregon Intertie (Figure B.3). The oscillation went away after 6 minutes when the steam supply to the industrial process was reduced. BPA did not have the Oscillation Detection Application at that time.



Figure B.2: Combined Cycle Simplified Oneline (Source: BPA)





(Source: BPA)



Figure B.4: Active and Reactive Power Oscillations on California-Oregon Intertie (COI) during Nov 29, 2005 Event (Source: BPA)

Event 3: Wind Power Plant High Frequency Oscillations

As early as May 2011, BPA observed high frequency oscillations during high wind generation operating conditions. However, the older research-grade PMUs installed at that time were not adequate to locate the source of oscillation nor was the PMU bandwidth sufficient to do oscillation analysis. Deployment of newer, high bandwidth PMUs at the wind power plant enabled BPA engineers to identify a 450 MW wind plant in Northeast Oregon as the source of the oscillation. After the event, BPA was able to link the onset of oscillation events with the energization of the second and third phases of the wind plant consisting of Type 4 full converter wind turbines.

The oscillations were detected on numerous occasions using BPA's Oscillation Detection Application when it became available in summer 2013. Figure B.5 shows the application display for one of the events. The oscillation is local, confined to the wind generation site. The oscillation frequency is above 5 Hz, suggesting voltage control problems.

Oscillations developed every time the wind plant was generating above about 85 percent of its rated output, and reactive power oscillations reached 80 MVAR peak to peak (Figure B.6). The oscillation frequency was 14 Hz, similar to the oscillation frequency observed during sub-synchronous control interaction events in Texas in 2009. BPA also has series compensated transmission lines in the area, and there was a concern about the potential of similar interactions should a wind power plant become isolated on a series-compensated line.

BPA engineering staff notified the plant owner about the oscillation and associated risks and the plant owner requested that the wind generator manufacturer upgrade their voltage controls. No oscillations³⁵ have been detected since April 2014 (Figure B.7).



Figure B.5: Oscillation Detection Application Display Alarming on Wind Plant Oscillation (Source: BPA)

³⁵ The magnitude of any oscillations has been drastically reduced and is no longer considered a reliability issue.



Figure B.6: Two Examples of Controller Oscillation Events (1/20/2014 and 3/6/2014) at a Wind Power Plant³⁶ (Source: BPA)

³⁶ Measurements are taken at the BPA substation looking into the plant; negative values refer to power flow from the plant to the substation.



Figure B.7: Wind Power Plant Ramp to Full Output after Controls Fixed on 4/15/2014 (Source: BPA)

Event 4: Hydro Power Plant Surging Vortex Oscillations

Hydro turbines are designed for the most efficient operation at nominal head and flow. Hydro turbines operating at flows and heads significantly different from their design values can experience rough operation and power swings from water passing through the draft tube in a whirling and spiraling vortex. Hydrodynamic instability occurs at partial load, typically 25 to 60 percent of their rated generator output. The result of the instability is high vibration of the machine components with the possibility of premature wear or even catastrophic damage. The generators go through the "rough zone" during start-up loading and shutdown unloading; however, the transition only lasts about 30 seconds in these situations as the unit is ramping through the zone. Continuous operation in the "rough zone" is very undesirable for generator turbines.

BPA's Oscillation Detection Application issued an alarm of a sustained oscillation at one of its hydro power plants in October 2014. The oscillation alarm was local and in the second frequency band as shown in Figure B.8. Analysis of the sustained oscillation using the application pointed to powerhouse line #2 of the hydro power plant being monitored by PMUs (Figure B.9). The oscillation frequency was about 0.38 Hz (Figure B.10) and observable in both active and reactive power outputs.

Advised by BPA's operations engineering staff, BPA dispatchers contacted the plant operators and notified them about the oscillation. Plant operators were not aware of the problem and increased generator active power output above the "rough zone." Once the unit was maneuvered out of the rough zone, the oscillation went away. There have been several occasions when sustained oscillations due to surging water vortexes have been detected at hydro power plants using the tool.



Figure B.8: Oscillation Detection Overview Display with Hydro Plant in Rough Zone (Source: BPA)

Appendix B: Forced Oscillation Event Examples



Figure B.9: Oscillation Trend Display (Source: BPA)





Event 5: Control Interactions between UEL and PSS

The BPA Oscillation Detection Application detected several occurrences of sustained oscillations at one of its hydro-power plants in fall 2015. The oscillation triggered local alarms in frequency bands 3 and 4 (see Figures B.11–B.14). The oscillation waveform had a unique beat characteristic (see Figure B.14). Further analysis indicated that the oscillation was due to interactions between the plant's power system stabilizers (PSS) and under-excitation limiters (UEL).

BPA technical staff notified the plant operators about the problem. The plant operator re-tuned UEL gains and retested for the interactions in January 2016. The problem has since been resolved.



Figure B.11: Oscillation Detection Overview Display with Control Interaction Oscillation (Source: BPA)

Appendix B: Forced Oscillation Event Examples



Figure B.12: Oscillation Trend Display (Source: BPA)









Event 6: Plant Controller Issues

In December 2011, BPA engineering staff observed via SCADA sustained active power oscillations at a wind power plant in Oregon. The oscillation lasted for nearly seven hours with a 15 MW peak-to-peak magnitude. The oscillation period was about 25 seconds, indicating a possible active power controller issue. Operating wind turbine blades in this condition can cause excessive wear. The plant operators and wind turbine manufacturers were notified about the issue. BPA did not have the Oscillation Detection Application implemented at that time.





Figure B.15: Active Power Controller Oscillation at a Wind Power Plant (Source: BPA)

Event 7: Hydro Generator Issue

On April 19 and 20 2015, oscillation analysis using the DMO tool identified a forced oscillation at around 2.05 Hz with less than a one percent damping ratio, as shown in Figure B.16. BPA's ODM alarmed on one of their substations as well. From Figure B.17, the source of the forced oscillation is not clear due to minimal PMU coverage near that substation. SCADA data of the surrounding generators supplemented the synchrophasor-based applications and showed that a hydro generator nearby may be the source of the oscillation (Figure B.18). This analysis was initially performed manually, taking about 3 weeks).

Using the PMA tool developed by Peak, the data was extracted within seconds, shown in Figure B.19, and the generator described was identified as the likely source of the oscillation. This event was not verified with the GO to identify the cause of the oscillation.



Figure B.16: DMO Analysis for April 2015 Event (Source: Peak)



Figure B.17: Mode Shape for April 2015 Event (Source: Peak)



Figure B.18: Hydro Generator Output (SCADA Data) for April 2015 Event (Source: Peak)



Figure B.19: PMA Tool Results for April 2015 Event (Source: Peak)

Event 8: Hydro Plant Controller Issue

BPA ODM alarmed on several local substations; however, there was not full PMU coverage in that area to directly identify the source of the oscillation in real-time. Oscillation analysis, using the DMO tool, clearly identified a forced oscillation at 1.47 Hz with less than a one percent damping ratio (Figures B.20 and B.21). The PMA tool identified one hydro generator as the likely source of the oscillation (Figure B.22). Later, BPA confirmed with the GO that there was a plant controller issue during the time of the forced oscillation.



Figure B.20: DMO Analysis (Source: Peak)









Figure B.22: PMA Tool Results (Source: Peak)

Event 9: Interaction with Inter-Area Oscillation Tools

When analyzing the real-time Mode Meter results for N-S Mode B, a low damping ratio of about 2 percent for a period of ~30 minutes was identified as shown in Figure B.23. There were no significant changes to the system such as topology, generation, load, or tie line flows during that time. Results were verified using WSU DMO tool shown in Figure B.24. The mode shape plot (Figure B.26) clearly shows the source of the oscillation as the signal in red with highest magnitude. Using the PMA tool, it showed that a generator in Nevada as the likely source of the oscillation (Figure B.25). The cause of the oscillation was verified with the GO, identified as a faulty combustion turbine MW transducer. There are two MW transducers for this unit and the control logic uses a select logic of the two values to control the output to a MW set point. If the measured output is incorrect or oscillating, then the control system attempts to correct to the set point, resulting in active power output swings.

















Figure B.26: September 5, 2015 Event – Mode Shape (Source: Peak)

The significance of this event is that the forced oscillation of about 6 MW had a "resonance"³⁷ effect with the system mode at 0.4 Hz (N-S mode B) that showed up on a major intertie as ~40 MW oscillations (Figure B.27).



Figure B.27: September 5, 2015 Event – Intertie MW Flow (Source: Peak)

³⁷ The system has an electromechanical mode near the forced oscillation frequency. Often referred to as "resonance"; however, it is not true resonance in the academic sense because the system mode is stable. The system has high gain near the mode so the forced oscillation shows up at many locations.

Event 10: June 17 Forced Oscillation due to Control Failure

On June 17, 2016 at 02:57, the Grand Gulf Nuclear Station (GGNS) automatically scrammed³⁸ while performing the main turbine stop and control valve surveillance. The unit had reduced load to approximately 65 percent power for a control rod pattern adjustment. At approximately 02:15, prior to the scram and while performing the Main turbine stop and control valve surveillance, one turbine stop valve would not reopen after testing due to a malfunction of a hydraulic control test valve. After the first stop valve would not reopen, a second stop valve closed. This resulted in power oscillations for about 45 minutes while the main generator was connected to the transmission system and then a subsequent reactor shutdown. The specific cause of the malfunction was not known. Figure B.28 shows the power oscillations prior to the unit tripping off-line (the blue and green lines are line flows capturing GGNS output).



Figure B.28: Approximately 200 MW Forced Oscillation at GGNS (Source: Entergy)

The forced oscillation frequency occurred around 0.28 Hz, which is near the frequency of a system mode in the EI. This resulted in the oscillation being observed throughout the EI, as shown in Figures B.29-B.31. Oscillations in ISO-NE area were around 40 MW, 70 MW near the Florida border, and around 50 MW in the SPP region.

³⁸ A scram is an emergency shutdown of a nuclear reactor.



Figure B.29: Approximately 40 MW Oscillations Seen in New England Region (Source: ISO-NE)



Figure B.30: Approximately 70 MW Oscillations Seen Near the Florida Border (Source: FPL)



Figure B.31: Approximately 50 MW Oscillations in the SPP Region (Source: OG&E)

This oscillation persisted for about 45 minutes, causing large magnitude oscillations across the EI for a prolonged period of time. Eventually the reactor was shut down and the unit removed from service. No automated oscillation detection tools identified the event to aid in detecting and mitigating the "rogue" input.

Event 11: Combined Cycle 1 Hz Oscillation

This forced oscillation originated at a combined cycle plant with 2 gas turbines and 1 steam turbine. ISO-NE receives voltage and current PMU signals for the combined output of the plant at the point of interconnection (POI) in the transmission substation. PMU data is streamed at 30 points per second. SCADA data is available for each machine at a rate one point every five seconds.

PMU data showed a sustained oscillation from this plant almost continuously, usually at low amplitude of about 5 MW peak to peak and at a frequency of around 0.9~1 Hz. The oscillation amplitude would occasionally rise to much higher levels. Below is an example of the plant oscillating for 20 minutes with amplitude reaching a maximum 100 MW peak to peak. SCADA data showed oscillations from each machine.







Figure B.33: SCADA Data from Event (Source: ISO-NE)

Diagnosis

Soon after the PMU at the generator POI was installed in 2013, the real-time oscillation detection feature of the PhasorPoint software identified oscillations at this generating station. ISO engineers subsequently analyzed a number of other times when oscillations at this station grew to relatively high levels. There are several other participating generators in the local 1 Hz mode. However, the subject generator has the most consistent oscillation and especially when other generators were off-line. The oscillation was later confirmed to originate at the subject generating station using the dissipating energy flow (DEF) method, an analytic method for locating the source of oscillations adopted and further developed at ISO-NE.

Event 12: Coal Unit 0.03 and 0.05 Hz Oscillation

A single coal-fired generator experienced a 100 MW peak-to-peak oscillation at 0.03 Hz for eight minutes before the unit was tripped. Three months later, a very similar 70 MW peak-to-peak oscillation at 0.05 Hz was observed for 44 minutes before unit tripping. These are the known oscillation events at this plant.



Figure B.34: Coal Unit 0.03 Hz Oscillation (Source: ISO-NE)



(Source: ISO-NE)

Event 13: Combined Cycle Oscillation Events

This combined cycle generator consists of two gas turbines and one steam turbine. ISO-NE has PMU data at the POI of the plant and SCADA data from each individual generating unit. Relatively large oscillations have been observed from this unit from time to time with different oscillation frequencies.



Sustained 0.08 Hz Oscillation Event

Figure B.36: PMU Data at POI (full event and zoomed in) (Source: ISO-NE)





Diagnosis

Several scenarios were analyzed, and the in-house-developed DEF tool clearly indicated that this unit was the oscillation source. Further, SCADA data showed that the steam turbine was the source inside this plant. This oscillation usually happens when one gas turbine is off-line.

Two Temporary 1.7 Hz Oscillation Events

The same generator also experienced a 1.7 Hz oscillation during its start-up and shut-down processes. PMU Data at POI:



Figure B.38: PMU Data at POI for Startup Event (full event and zoomed in) (Source: ISO-NE)



Figure B.39: PMU Data at POI for Shutdown Event (full event and zoomed in) (Source: ISO-NE)

Diagnosis

The in-house-developed DEF tool clearly indicated that the plant was the oscillation source. Since there was only one gas turbine operating at the time, it was identified as the sole source inside the plant.

Event 14: Combined Cycle Unit with Harmonics

This combined cycle generator has two gas turbines and one steam turbine. ISO-NE has PMU data at POI and SCADA data for each unit. PMU data showed a growing oscillation in real-time with mixed modes for nine minutes before it disappeared as the plant was shut down.





Appendix B: Forced Oscillation Event Examples



(Source: ISO-NE)

Diagnosis

The in-house developed DEF tool clearly indicated that this power plant was the oscillation source. However, the SCADA data couldn't tell which unit is contributing inside the plant. This is a typical scenario where combined cycle units exhibit oscillatory behaviors when one gas turbine is off-line. This also shows the limitation of the SCADA data and the need for synchrophasor measurements from each unit. This is also a typical forced oscillation when the input signal is not sinusoidal; the response is a combination of the base frequency and several harmonics.

Event 15: Excitation Control System Failure

This single gas generator had two identical incidents of similar excitation failures, experienced two weeks apart from one another.



Figure B.42: Active and Reactive Power Output during Oscillation #1 (Source: ISO-NE)



Figure B.43: Active and Reactive Power Output during Oscillation #2 (Source: ISO-NE)

Diagnosis

Operations support engineers received the oscillation alarm and analyzed the event immediately. The reactive power plot showed that it was an excitation system issue. Initial investigation by plant staff found loose connections to the excitation control system and plant staff repaired them. This repair didn't prevent a second identical incident two weeks later. Further investigation identified a faulty component in the excitation control system.

Event 16: Gas Turbine Oscillation

An oscillation event in the ATC footprint was captured with PMU data. New controls were being implemented for a gas turbine, and the unit began oscillating against the grid, eventually tripping off-line. Figure B.44 shows the event with high-resolution data. The diagnosis and solution to mitigate any controls issues are not known.



Figure B.44: Gas Turbine Generator Oscillation (Source: ATC)

Event 17: Southern Wisconsin Oscillations

ATC also identified a 0.75 Hz oscillation using their online monitoring tools. These oscillations persist for extended periods of time on the system with period "notches" where the oscillation will disappear for short durations and then reappear. A new 0.6 Hz oscillation has also developed with the same type of response. ATC reports that both oscillations appear to have disappeared recently on their system, and they monitor for the reappearance of these oscillations for further forensic analysis.



Figure B.45: 0.6 Hz Oscillation in Southern Wisconsin (Source: ATC)

Event 18: Redbud 0.2 Hz Oscillation

OG&E discovered a voltage oscillation on the EHV system around 0.2 Hz. PMU data quickly identified oscillations in the reactive power plots. OG&E sent snapshots of the event along with the dates and times that it occurred to nearby power plant managers, asking if the oscillations corresponded with any events, testing, or operations at the plant(s). The plant manager at the Redbud plant indicated that they found it was being caused by the Unit 4 VAR control scheme. The units start up in VAR control mode and once the unit is synchronized to the grid, it is switched by an operator to voltage control mode. The oscillations stopped when the operator switched to voltage control mode. The plant then worked with the manufacturer to resolve the issue.





Event 19: Woodward Wind 13 Hz Oscillation

In December 2010, OG&E started noticing oscillations on the PMUs in northwestern Oklahoma. The oscillations were occurring only when wind farm output was greater than 80 percent. They performed an FFT analysis to discover sub-harmonic frequencies between 13 and 14 Hz with other components of lesser magnitude. Voltage fluctuations had been as high as five percent at the 138 kV point of interconnection.

OG&E needed to find out if the oscillations were interactions between wind farms or only at one facility. They performed switching to electrically isolate the wind farms. From this exercise, it was determined to be a problem at two different wind farms that share the same turbine model. The only solution that worked consistently was to curtail the plant's output until the manufacturer made modifications to the power conversion system.



Figure B.47: Voltages [pu] during 13 Hz Oscillation at Wind Plant (Source: OG&E)
Event 20: 3 Hz Wind Oscillation

In December of 2012, a line outage instigated a major forced oscillation at a new 60 MW wind farm interconnected at 69 kV. Voltage variations were as high as 18 percent at a frequency of 3 Hz. It took about half an hour to curtail the plant and restore the system to normal operation. The event adversely affected the operations at a nearby large industrial customer. OG&E was able to work with the manufacturer to test new power conversion parameters that successfully resolved the issue.



Figure B.48: Voltage [pu] during 3 Hz Oscillation at Wind Plant (Source: OG&E)

Event 21: Wind Plant and Impedance

On December 14, 2011, a transmission line was out of service for maintenance when a permanent fault occurred on another line in the area. The loss of the second line caused wind farms to begin oscillating, and this persisted for about half an hour until the plant's output was curtailed. Wind plant events are often triggered by something external, such as line faults or changes in topology. In this case, the change in electrical impedance of the system and reduction of system strength caused the oscillation, demonstrating the power conversion controls sensitivity to changes in grid topology and strength. Weaker POIs are more prone to issues with forced oscillations caused by electronically coupled resources.



Figure B.49: Voltage [pu] during Forced Oscillation Instigated by Topology Change (Source: OG&E)





Event 22: Solar Power Plant Oscillation

In November 2016, a forced oscillation was detected in the AEP footprint from PMU data monitoring a solar power plant. Figure B.51 shows the frequency (top) and voltage (bottom) data over multiple days. It is clear that this oscillation is occurring during the middle of the day during periods of irradiance (and likely solar output). AEP has identified this oscillatory behavior and is working to address this.



Figure B.51: Measured System Frequency [Hz] Oscillation at Solar Power Plant (Source: AEP)



Figure B.52: Measured System Voltage [kV] Oscillation at Solar Power Plant (Source: AEP)

Event 23: HVDC Oscillation

In April 2016, a high-energy forced oscillation originated at the Pacific HVDC Celilo terminal in Oregon and propagated across the Pacific Northwest system. The oscillation triggered multiple alarms, mainly in oscillation bands 3 and 4 (Figure B.53). Further investigation showed that both DC poles were involved in the oscillation (Figure B.54). The oscillation was due to equipment failure at Sylmar converter station at the southern end of the DC line near Los Angeles.



Figure B.53: Overview Display for PDCI Event in April 2016 (Source: BPA)

Appendix B: Forced Oscillation Event Examples



Figure B.54: Analysis of PDCI Event in April 2016 (Source: BPA)

Event 24: Type 2 Wind Plant Oscillations

BPA has a Type 2 wind power plant connected in its Central Washington region on the 115 kV system. The project is divided into two plants of 74 and 83 MW. The project uses variable speed (Type 2) induction generators and has been in operation since November 2005.

The wind plant substation short-circuit ratio (SCR) is about for with all lines in service. Several events of voltage instability were observed over the years, mostly with all lines in service. Figure B.55 shows recordings of a voltage instability event on July 12, 2012. For no apparent reason, voltages and active and reactive power started oscillating with an 80 second period. Voltage fluctuations reached 10 percent peak to peak, and reactive power swings were 45 MVARs. The oscillations went away when the wind power plant output was reduced.

Following the event, the wind plant project was curtailed to operate at reduced power output.

BPA and neighboring utility engineers performed model validation studies for the event. The powerflow model included the collector system equivalent and WTG step-up transformers. Powerflow model parameters, collector system equivalent, and active and reactive power flow in each of the transformers were tuned using SCADA recordings of voltages at 115 kV and 34.5 kV substations. However, powerflow studies were unable to recreate the event, and dynamic simulations were required to gain an understanding of what occurred during the event. Dynamic simulations did not have validated generic dynamic models for Type 2 generators. While generic Type 2 WTG models reproduced the observed phenomenon in principle, the details of active power were not well matched. Nevertheless, the model was adequate to determine the causes of the voltage instability and to identify the corrective measures.

Rotor resistance controls are used in Type 2 turbines to optimize active power production. However, should turbine voltages decline, the controls slowly adjust the resistance and increase reactive power consumption by the turbine. The increased reactive power consumption would cause further voltage decline, followed by additional adjustments of rotor resistance, thereby creating a positive feedback for voltage collapse. Substation transformer LTCs began tap adjustments when the collector bus voltages became low. LTC action restored collector bus voltages, and then the rotor resistance control started operating in the opposite direction, thereby reducing the reactive power demand and causing the overvoltages. It was concluded that the voltage instability was due to the actions of the rotor resistance controls. LTC interactions prevented a voltage collapse, and limited the event to an oscillatory voltage instability.





Joint studies concluded that a STATCOM was required to provide continuous voltage control. After the STATCOM was added, the voltage stability issues at the plant were mitigated.

Appendix C: References

North American Synchrophasor Initiative (NASPI):

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 IEEE, "2016 IEEE PES General Meeting Tutorial: Use of Synchrophasors in Grid Operations – From Oscillation Source Detection to Other Use Cases," Boston, MA, July 2016, accessed Jan 2017. [Online]. Available: <u>http://web.eecs.utk.edu/~kaisun/TF/publications.html</u>. Table D.1 provides a list of acronyms that are used throughout this guideline.

Table D.1: List of Acronyms		
Acronym	Description	
AGC	Automatic Generation Control	
COI	California-Oregon Intertie	
COMTRADE	Common Format for Transient Data Exchange	
DDR	Dynamic Disturbance Recorder	
DE	Dissipating Energy	
DEF	Dissipating Energy Function	
DMO	Damping Monitor Offline	
EAO	Event Analysis Offline	
EI	Eastern Interconnection	
EHV	Extra High Voltage	
FACTS	Fast AC Transmission System	
FFT	Fast Fourier Transform	
FO	Forced Oscillation	
GGNS	Grand Gulf Nuclear Station	
HVDC	High Voltage Direct Current	
IEEE	Institute of Electrical and Electronics Engineers	
ISO	Independent System Operator	
LTC	Load Tap Changer	
МММ	Mode Meter Module	
NASPI	North American Synchrophasor Initiative	
ODM	Oscillation Detection Module	
OMS	Oscillation Monitoring System	
OSL	Oscillation Source Location	
PDCI	Pacific DC Intertie	

Appendix D: List of Acronyms

Table D.1: List of Acronyms	
Acronym	Description
PMA	Pattern-Mining Algorithm
PMU	Phasor Measurement Unit
POI	Point of Interconnection
PSS	Power System Stabilizer
SCADA	Supervisory Control and Data Acquisition
SCR	Short Circuit Ratio
STATCOM	Static Synchronous Compensator
SVC	Static Var Compensator
UEL	Under-Excitation Limiter
WTG	Wind Turbine Generator