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PNNL-35221

Online Monitoring Applications Enabled by Phasor Measurement Units

Technical Assistance to the Power Sectors of Southeast Asia

November 2023

Kaustav Chatterjee
Shuchismita Biswas
Jim Follum
Slaven Kincic

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Richland, Washington 99352

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1.0 Introduction

Phasor measurement units (PMUs) provide high-resolution insight into power grid dynamics through precise time-synchronized measurements [De La Ree et al., 2010, Phadke, 1993]. Simply put, PMUs are high-precision measurement devices that report synchronized phasor quantities (or *synchrophasors*) at different points of the grid at high temporal rates. Typically, in the bulk power transmission system, PMUs with reporting rates of 25/50 (for a 50 Hz grid) or 30/60 (for a 60 Hz grid) frames-per-second (fps) are used [North American Synchrophasor Initiative (NASPI), 2014]. Some applicable standards and guides overseeing PMU performance and data transfer include-

1. ***IEC/IEEE 60255-118-1: Synchrophasor for Power Systems - Measurements* [IEEE/IEC, 2019]:** This standard superseded the prior IEEE C37.118.1-2011 standard. It provides definitions for a synchronized phasor (synchrophasor), frequency, and rate of change of frequency measurements, describes time tag and synchronization requirements for measuring these three quantities, and specifies methods for evaluating these measurements and requirements for compliance with the standard under both static and dynamic conditions.

2. ***IEEE PC37.118.2: IEEE Draft Standard for Synchrophasor Data Transfer for Power Systems* [IEEE, 2017]:** This draft standard will supersede the previous C37.118.2-2011 standard. It defines a method for real-time exchange of synchronized phasor measurement data among power system equipment and specifies messaging that can be used with any suitable communication protocol for real-time communication among PMUs, phasor data concentrators (PDC), and other applications. It also defines message types, contents, and use, specifies data types and formats, and describes communication options and requirements. Other communication protocols used include IEC 61850-90-5, DNP.3, and ICCP.

3. ***IEEE C37.242-2021: IEEE Guide for Synchronization, Calibration, Testing, and Installation of Phasor Measurement Units (PMUs) for Power System Protection and Control* [IEEE, 2021]:** This guide addresses- (a) considerations for installing PMU devices based on application requirements and typical substation electrical bus configurations; (b) techniques focusing on the overall accuracy and availability of the time synchronization system; (c) test and calibration procedures for PMUs for laboratory and field applications; and (d) communications testing for connecting PMUs to other devices including PDCs.

Over the last few decades, utilities across the world have installed PMUs throughout their systems, enabling a suite of different *offline* (e.g., model validation and calibration, post-event diagnostics, natural oscillation characterizing, etc.) and *online* (e.g., small signal stability monitoring, voltage stability monitoring, inertia monitoring, etc.) applications. Utilities and system operators in North America have been deriving value from incorporating PMU measurements in their decision-making, and industry-academia consortia like the North American Synchrophasor Initiative (NASPI) have facilitated the sharing of best practices, lessons learned, and challenges faced, especially as the grid revolves rapidly to incorporate new distributed and inverter-interfaced resources [Silverstein and Dagle, 2012].

In this report, an overview of several online applications enabled by PMU measurements is provided. Besides a brief technical background for each application, the report also discusses control room displays and alarming methodologies used by North American organizations, and applicable standards set by the North American Electric Reliability Corporation (NERC). The five applications discussed herein are:

- Inertia monitoring
- Linear state estimation
- Voltage stability monitoring
- Small signal stability monitoring
- Forced oscillations monitoring

2.0 Inertia Monitoring

An inertia monitoring application is an online tool that uses system measurements to periodically update the transmission system operator (TSO) with the estimates of effective inertia for different regions and sub-regions of the connected system. This information can aid the TSO in dynamic security assessment and scheduling of fast frequency reserves for ensuring system reliability.

2.1 Technical Background

Inertia, in power systems, refers to the tendency of the system to arrest fast changes in frequency in response to disturbances such as generation trips and load changes. Typically, this property of the system is derived from the physical inertia of large rotating masses in the system like the shafts of the synchronous generators and industrial motors. The synchronously rotating masses have the natural propensity to absorb and release transient energy to maintain their rotational speed. This helps in slowing down the rate of change of system frequency in the first few seconds immediately following a disturbance. This fast-acting inertial response of the synchronous machines allows the primary frequency control from their turbine-governors necessary buffer time to detect and respond to the disturbance [Denholm et al., 2020].

As the grid modernizes, however, fossil fuel-fired synchronous generators are being gradually retired and replaced by inverter-based resources – e.g., solar photovoltaics, wind, batteries, etc. These new resources, in most cases, do not contribute to system inertia. The reduction in inertia presents serious operational challenges before the TSOs in terms of system security and reliability. Low inertia could lead to high rate-of-change-of-frequency (ROCOF) in response to disturbances. A schematic comparing the frequency response of low and high inertia cases following a generation trip is shown in Fig. 1.

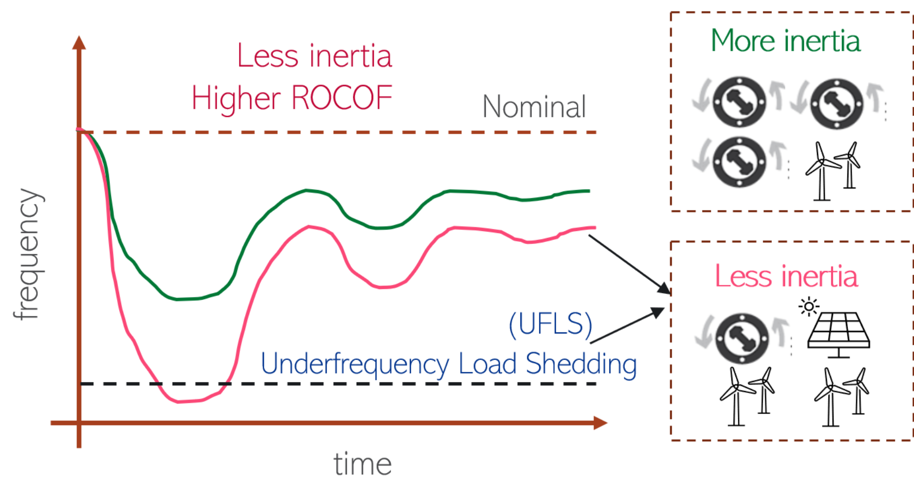

Figure 1. Schematic comparing the frequency response of low and high inertia cases following a generator trip event.

As seen from the figure, large excursions in frequency in a short time can trigger over- and under-frequency relays to undesirably shed generation and load resources. This poses operational risks. Thus concerned, the TSOs are augmenting their existing situational awareness systems with the capabilities for inertia estimation and monitoring. Inertia monitoring tool is a real-time situational awareness tool that —

1. informs the system operator of available synchronous inertia in the system,

2. checks if the available inertia is below the critical inertia required for ensuring system reliability, and

3. updates the operator if additional frequency containment reserves need to be committed to meet the desired inertia margin.

2.2 Approaches for Inertia Monitoring

The inertia estimation approaches may be broadly classified as in Fig. 2. These four categories are discussed next. The model-based approach will be discussed first to help motivate the measurement-based methods.

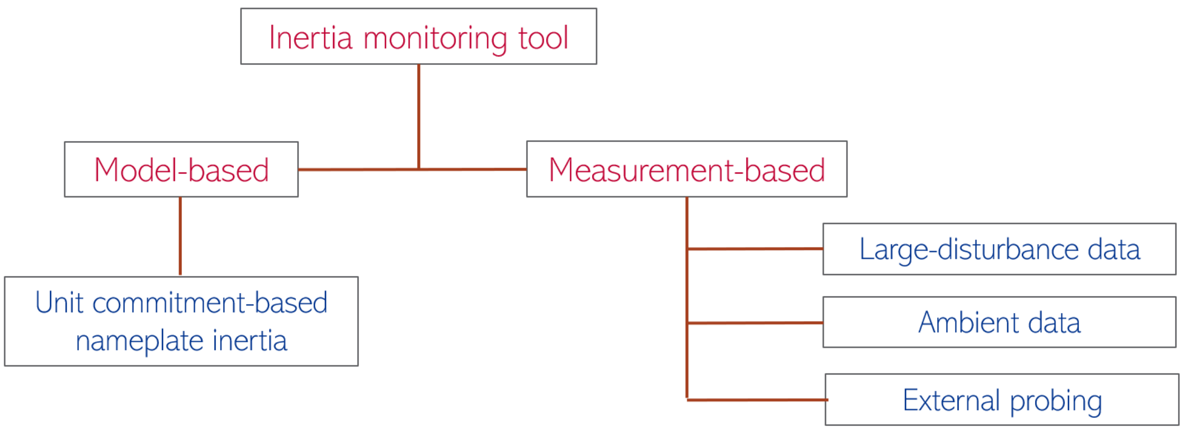

Figure 2. Classification of inertia monitoring approaches.

1. ***Calculation of an effective inertia constant by summing the nameplate inertia parameters of individual synchronous machines which are online and synchronized to the transmission system***:

   This method is in use in ERCOT [Matevosyan, 2018]. The inertia monitoring tool, in this case, utilizes the telemetry data from the energy management system (EMS) to identify the generators and synchronous condensers which are online. ERCOT's inertia monitoring tool is also capable of forecasting system inertia for the later hours, on a rolling basis, based on the dispatch plans derived from the solutions of the unit commitment program. This helps the operator forecast time periods where the expected inertia may fall below the critical level. A screenshot [Matevosyan, 2018] of ERCOT's inertia monitoring system is shown in Fig 3.

   One major limitation of this approach is that it only considers rotational inertia due to synchronous machines. It cannot measure the inertial support from the inverter-based resources (IBRs) which may be present in the system either in the form of fast-frequency reserves or may have advanced controls to emulate synthetic (or virtual) inertia.

2. ***Estimation of inertia from ROCOF during large disturbances***:

   This is a model-free, measurement-driven inertia monitoring approach. Premised on the center of inertia (COI) swing dynamics of the system, the method leverages the proportional relationship between the ROCOF and the net change in electrical power resulting from a large

Figure 3. Screenshots from inertia monitoring dashboard at ERCOT. Source: ERCOT [Matevosyan, 2018].

contingency like generation or load trip, for estimating system inertia [Ashton et al., 2015]. The inertia constant H is calculated as follows,

$$\frac{2\ H}{f_0}\frac{df}{dt} = -\Delta P_e \quad \Longrightarrow \quad H = \frac{-\Delta P_e}{ROCOF}\frac{f_0}{2} \tag{1}$$

The size of the disturbance, i.e., ΔP_e is estimated from the telemetry data. The frequency measurements f are obtained from the PMU data, either directly or as a derivative of the voltage phase angle. Research shows that the direct measurements of system frequency may suffer from errors due to quantization and resolution and therefore, it is recommended to use the derivative of voltage angle for frequency estimates. The frequency measurements/estimates are filtered and an average value of ROCOF is calculated from the initial linear region of the frequency change, as shown in Fig 4. Following which, the inertia constant is calculated using (1).

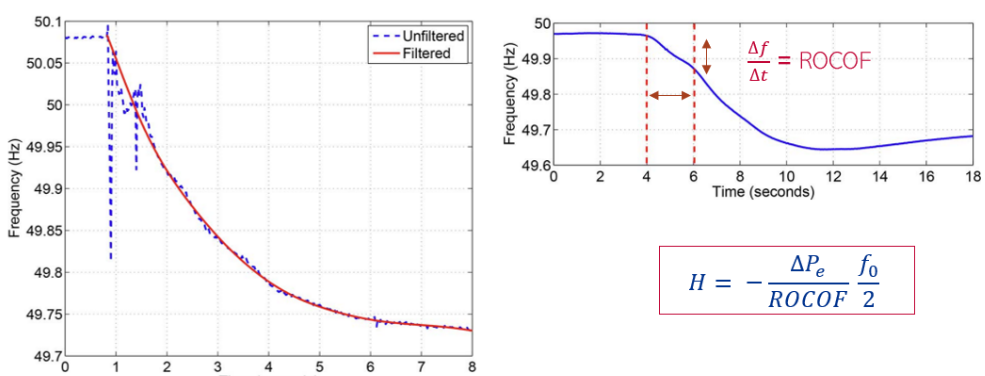

Figure 4. Filtering of frequency estimates and calculation of ROCOF. Source: [Ashton et al., 2015].

The accuracy of the method depends on the accurate determination of (1) the event start time and (2) the size of the contingency or disturbance [Ashton et al., 2015]. The method is also sensitive to the measurement locations relative to the point of contingency. For the same event, the measurements taken from an electrically weak region with low local inertia may produce higher ROCOF compared to measurements obtained from an electrically strong region. This has prompted researchers and TSOs to define and estimate *regional inertia* instead of a system wide single inertia value. In this approach, a large interconnected system with variation in generation mix across regions is divided into areas and inertia estimation is performed on each of these areas separately based on their local measurements. Regional inertia estimation is effective in identifying the pockets of low inertia in the system and alarming the TSO for the appropriate remedial actions. A laboratory-scale prototype of this estimation approach has been tested and demonstrated in the Great Britain power system [Ashton et al., 2015].

One limitation of this approach is that inertia can only be estimated following large disturbances, so it cannot support continuous monitoring. From a TSO's perspective, for situational awareness and preventive action, it may be more useful to have continuous ambient inertia monitoring. However, the ambient estimation methods, as will be discussed next, are often challenging to tune and may suffer from noise-related inaccuracies. To that end, the results of this large-disturbance method can be used to occasionally tune the parameters of the ambient estimator.

3. ***Estimation of inertia from ambient measurements***:

   This method uses the continuous streaming of ambient PMU data to fit a transfer function model between the small-signal perturbations in the frequency and the electrical power [Tuttelberg et al., 2018]. The inertia constant is calculated from the estimated parameters of the transfer function, as shown in Fig 5. Similar to the previous case for the estimation of regional inertia, a power system is divided into smaller areas. The frequency data is obtained from the PMU measurements in each area. The PMU measurements are also used to monitor the tie-line power exchanges between the area and the power generation in each area. The net load change in each area is then calculated as the sum of the total power generation in that area and the total power flowing into the area through the tie lines.

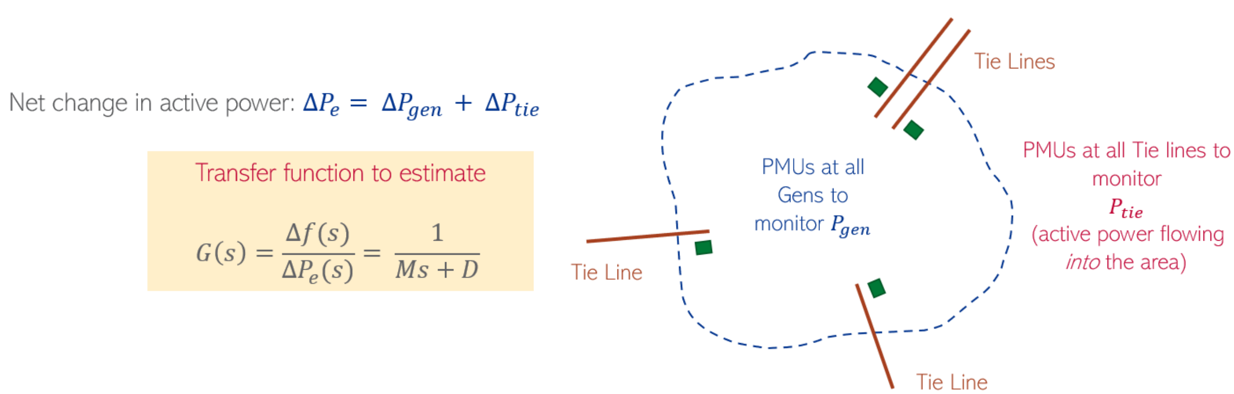

Figure 5. Inertia estimation from ambient measurements.

One important point to consider here is that for accurately identifying the ambient dynamics between the load changes and frequency deviation, the measurement time-window used in the estimation should be sufficiently long – on the order of tens of seconds to minutes. This implies that, in addition to the inertial response in the first few seconds, the data window will capture the dynamics due to primary frequency response. The order of the transfer function model should be chosen carefully to account for this.

Further, since the method assumes no change in the mechanical power of the generating units, any data window in which automatic generation control (AGC) was active or set-point changes were made by the governor should be excluded from the analysis.

The main advantage of this method is that, unlike the ROCOF-based method which can only be used during frequency disturbances, this method can enable continuous inertia monitoring. A TSO using this approach is therefore better informed of the system health and well positioned to deploy frequency containment reserves if needed, well before an actual contingency occurs. The applicability of this method has been demonstrated using PMU data from of the Icelandic power system [Tuttelberg et al., 2018] and the Japanese power system [Kerdphol et al., 2022].

The Effective Inertia Metering and Forecasting tool (see, Fig. 6) developed by GE Digital and deployed at National Grid ESO, UK, is a real-world implementation where ambient PMU data is being used for continuous monitoring of system inertia. The tool provides regional inertia estimates for four regions in the Great Britain power system by monitoring frequency and power flow changes between the regions as discussed previously. In addition, the tool uses knowledge of historic inertia trends and machine learning to forecast inertia estimates for short- and long-term time horizons. This inertia metering platform is entirely a non-invasive technology and does not need any additional hardware components to be installed or any external probing signals to be injected. The inertia monitoring dashboard from National Grid is shown in Fig. 7.

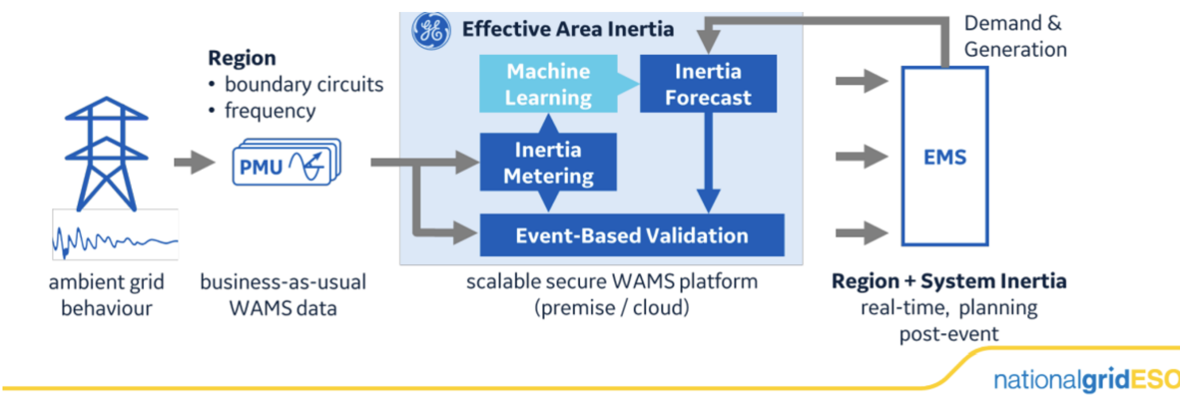

Figure 6. GE's effective inertia Metering and forecasting tool. Source: National Grid [Dytham, 2021].

4. ***Continuous inertia estimation via external probing***:

Reactive Technologies, UK has developed an inertia estimation platform called GridMetrix that uses external probing signals to measuring system inertia [Kimmett and Cassiadoro, 2022]. The GridMetrix system consists of a custom-built modulator that injects small-magnitude active power pulses into the system to perturb the grid frequency. Proprietary high-speed frequency measurement units, called the eXtensible Measurement Units (XMUs), are placed throughout the grid to measure the changes in system frequency in response to the probing. These measurements are then sent to Reactive Technologies' cloud analytics platform for further processing and inertia estimation [Enas et al., 2022]. The estimation principle (see,

Figure 7. Dashboard at National Grid, UK with results from GE's inertia monitoring tool. Source: National Grid [Dytham, 2021].

Fig. 8) is the same as the large disturbance approach with innovations mostly in signal processing to extract the slightest trends in frequency for small perturbations in power. The active power probing is typically around 0.03% of the total system load. As an example for the UK system with about 60 GW capacity, a 10 MW pulse yields reasonably good accuracy for estimation. The frequency perturbations in response to these pulses are on the order of 1 - 20 mHz. The GridMetrix system is presently in use at the National Grid ESO, UK. A schematic of the monitoring system is shown in Fig. 9. The dashboard [Enas et al., 2022] with the monitoring results is shown in Fig. 10.

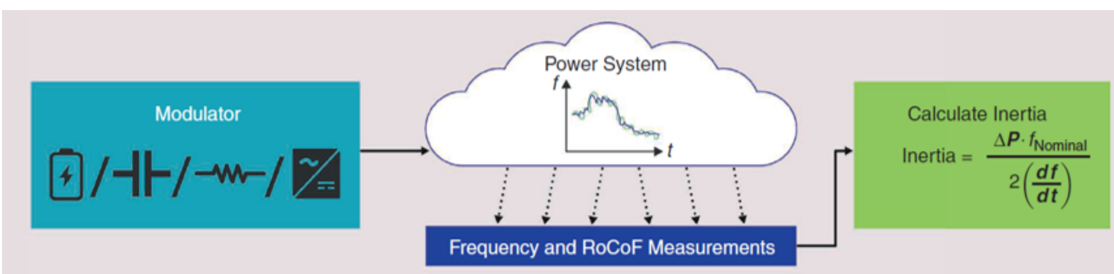

Figure 8. Overview of the probing-based GridMetrix inertia monitoring system. Source: Reactive Technologies [Enas et al., 2022].

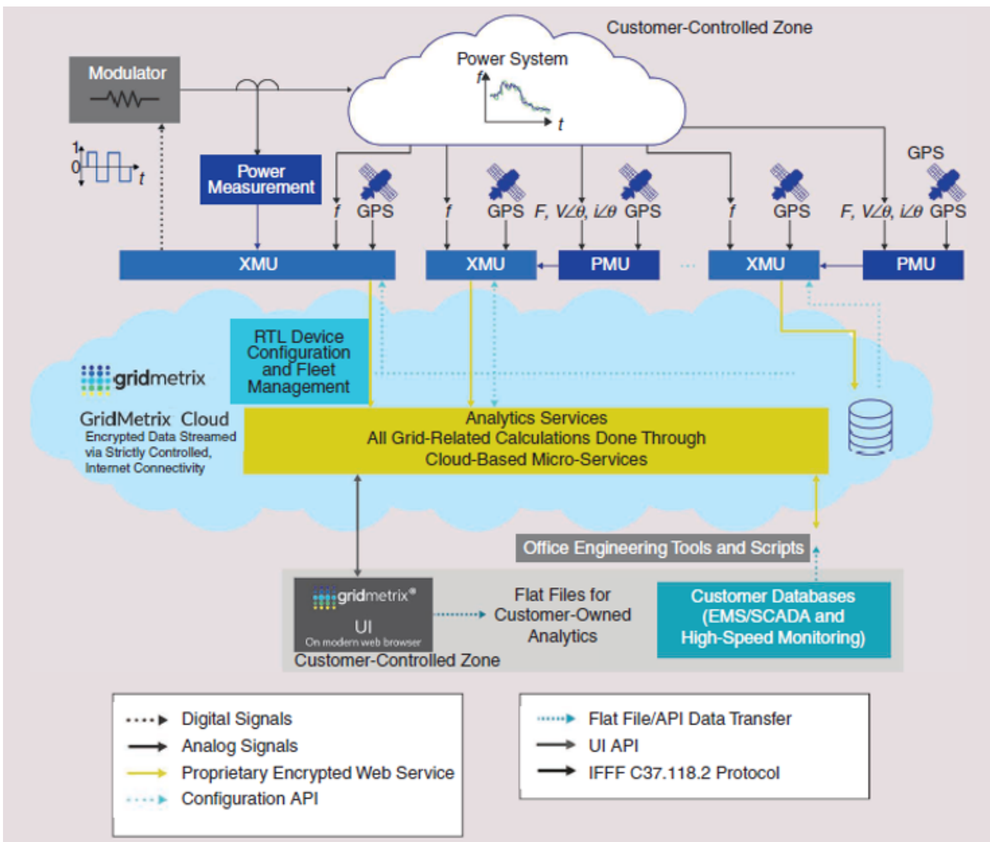

Figure 9. GridMetrix inertia monitoring system. Source: Reactive Technologies. Source: Reactive Technologies [Enas et al., 2022].

Figure 10. GridMetrix inertia monitoring dashboard. Source: Reactive Technologies [Enas et al., 2022].

3.0 Linear State Estimation

Linear state estimation (LSE) is a fast online state estimation approach that uses PMU measurements as inputs. In contrast with conventional state estimators, LSE offers a closed-form non-iterative direct solution which makes it suitable for real-time applications. LSE also offers bad data detection and correction capabilities [Yang et al., 2011].

3.1 Technical Background

The traditional power system state estimators (SEs) developed in the 1970s use real-time measurements from the supervisory control and data acquisition (SCADA) system to estimate the quasi-steady-state values of bus voltage magnitude and angle across a connected system. Typically deployed at control centers, the SEs are software functions embedded into a utility's energy management system (EMS). Besides real-time SCADA measurements, a SE application also utilizes the information of the system parameters, like line impedances, breaker status, and network connectivity from the EMS database. The fastest rate at which a traditional SE can run is limited by the reporting rate of the SCADA system, which is typically between 1-5 seconds [Yang et al., 2011].

PMUs, on the other hand, can report time-synchronized bus voltage and line current phasors from remote substations to control centers at rates much faster than SCADA. If a sufficient number of PMUs are deployed to ensure full observability of the system from PMU measurements alone, then the problem of estimating voltage magnitude and angle at unknown nodes becomes a linear state estimation (LSE) problem. In other words, the unknown voltage variables in a network can then be expressed as linear functions of the known phasor quantities, i.e., the complex-valued voltage and current measurements. The LSE problem has a direct closed-form non-iterative solution. Compared to a traditional SE, an LSE therefore has fewer computational requirements and, as a consequence, is much faster. In a control center, LSE may run in tandem with a traditional SE. In such a case, LSE solution can serve as a backup to the traditional SE solution if the later fails to solve or the SCADA data is not available. It can also be used to validate the quality and accuracy of the traditional SE solution.

3.2 Submodules in a Linear State Estimator

LSE applications typically have the following submodules which are solved sequentially –

1. ***Topology processing:*** The function of this submodule is to determine the topology of the power network for use in SE. To do so, it processes the substation connectivity information and the circuit breaker (CB) statuses to build a bus-branch model of the network from the node-breaker model (see Fig. 11). It also utilizes the information of the interrupt switch statuses and the transformer tap settings. Breaker statuses are typically obtained from SCADA via the ICCP protocol. They may also be brought in via a digital word in C37.118 PMU streams. Telemetry of this type, however, is limited.

2. ***Observability analysis:*** At this stage, the topology information obtained from the previous submodule is correlated with the available PMU measurements to identify the observable regions in the network. Observable locations are those buses/nodes for which – 1) a direct PMU-based voltage measurement is available or 2) the voltages can be calculated from the neighboring PMUs using Kirchoff's laws. The LSE can only estimate the system states for the observable nodes. There may be islands of observable nodes and the LSE can run

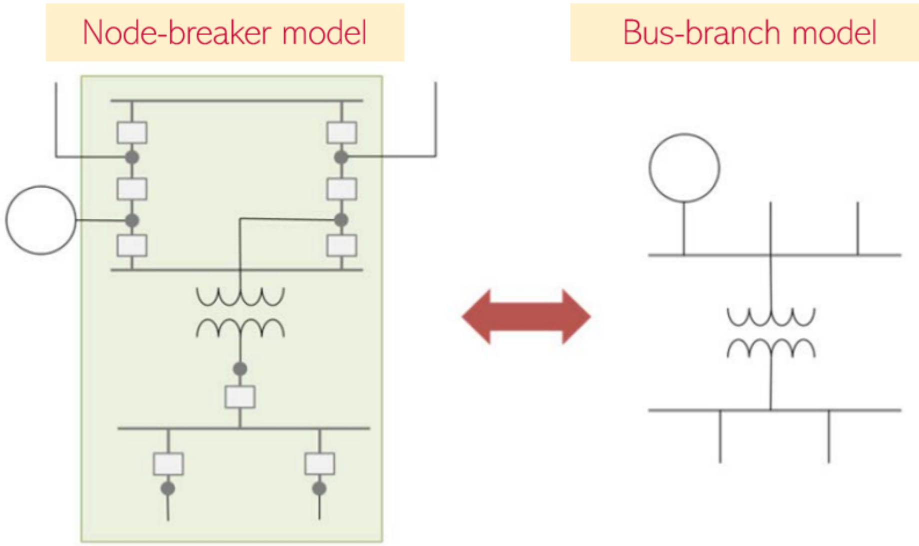

Figure 11. Representative image showing a topology conversion from node-breaker model to bus-branch model. Source: Siemens PTI/EPRI [Farantatos, 2017].

independently for each of these islands. The objective of this submodule is therefore to inform the operator of the number of discrete observable islands and the connectivity of the buses in each of these islands.

3. ***LSE solution:*** This forms the main submodule of the application where the state estimation problem is solved separately for each observable island. The estimation problem is formulated in the complex-plane where the measurement functions, expressing the PMU measurements in terms of the system states, are linear. A non-iterative closed-form solution of the linear state estimation problem is obtained via least-squares error minimization approach. Different PMU measurements are assigned different weights depending on the historic records and operator's confidence in their data quality.

   In addition to the minimum number required to ensure network observability, if redundant PMU measurements are available, the LSE can be made robust to missing data. Otherwise, for missing data scenarios leading to lack of observability, the LSE is solved only for those regions of the original network which are still observable with the available measurements.

4. ***Bad-data detection and conditioning:*** Usually, a chi-square test is performed on the measurement residuals (i.e., the difference between the actual measurement data and that calculated from the estimated states) to detect bad data. Measurement values outside the three-sigma bands of the chi-square distribution are eliminated and replaced by their estimated values.

The results obtained from the state estimation are used as input to other advanced applications such as voltage stability monitoring, contingency analysis, phase angle limit computation, analysis of cascading outages, and remedial action schemes. They are also used in the control center-level visualization of system health with respect to the safety margins and can be used to trigger alarms when needed. The schematic for this is shown in Figs. 12 and 13.

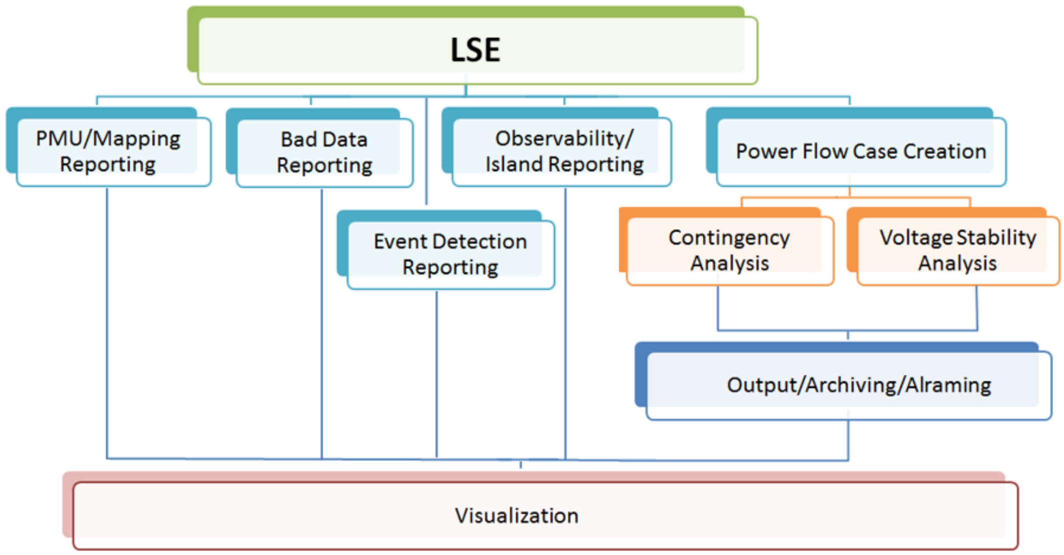

Figure 12. Outputs of LSE and their use in advanced monitoring applications. Source: V&R Energy [Ciniglio et al., 2018].

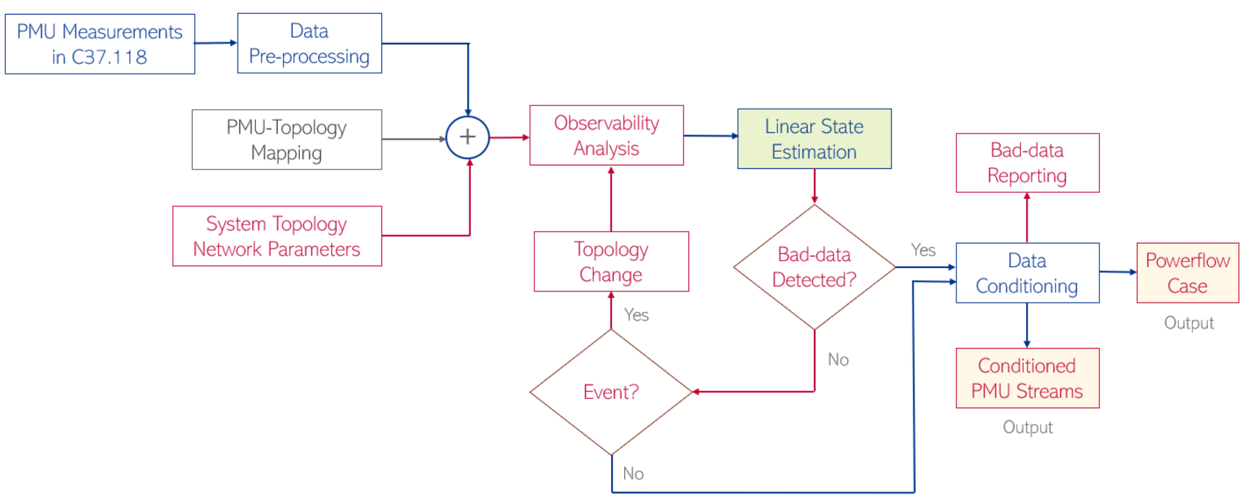

Figure 13. Schematic of the LSE process showing the inputs and the outputs.

3.3 Real-world Implementations of LSE

1. ***PMU ROSE LSE:***

   PMU Region of Stability Existence (ROSE) is a PMU data-driven software platform, developed and commercialized by V&R Energy that, "...provides real-time situational awareness in order to improve resilience of the grid and enhance its reliability" [Ciniglio et al., 2018]. The LSE application in PMU ROSE consists of the following functionalities: solution to the PMU-based LSE case, observability analysis, bad PMU data detection and correction, detection/identification of switching events, advanced visualization of system state, archiving, and alarming. In addition, it also supports offline planning applications like optimal PMU placement for full grid observability.

The inputs to the PMU ROSE LSE application are — 1) PMU data in C37.118 format, 2) model parameters like network topology, line impedances, generator parameters, etc., and 3) mapping between the PMUs and the network model. As shown in Fig. **??**, the incoming data streams from the phasor data concentrator (PDC) are pre-screened and processed for outliers and anomalies before it is used in SE.

The outputs of the PMU ROSE LSE are — 1) the estimated voltages, current, and real and reactive powers at locations where PMUs are installed, as well as locations where PMUs are not installed but are observable using PMU measurements, 2) information on the observability of the buses and formation of islands, 3) residuals and bad data reports, 4) event alarms, 5) violation alarms, and 6) initialized SE case in Siemens PSSE .raw format which serves as an input to a conventional SE.

An overall schematic of the ROSE architecture is shown in Fig. 14.

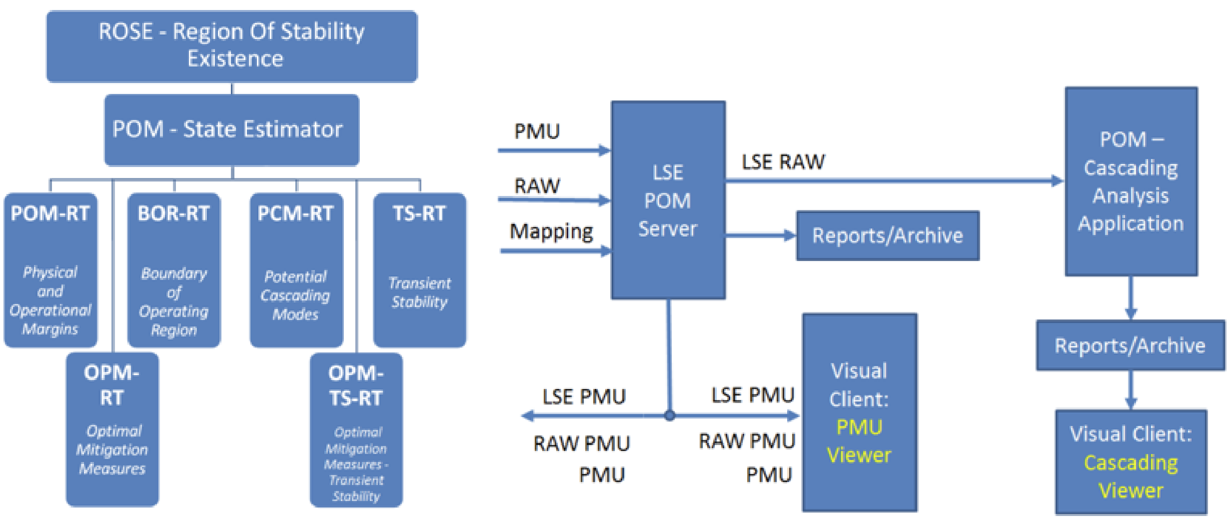

Figure 14. Conceptual overview of the PMU ROSE architecture. Source: V&R Energy [Sarmin and Vaiman, 2018].

The PMU ROSE LSE has been implemented at San Diego Gas and Electric (SDG&E) [Ciniglio et al., 2018]. The LSE is performed 30 times-per-second and includes previously described functionalities such as observability analysis and bad data detection. The solved LSE cases are used by the real-time contingency application (RTCA). The LSE can also be connected to remedial action schemes, voltage stability analysis, and cascading analysis applications. A screenshot of the LSE display at SDG&E is shown in Fig. 15. A screenshot of the estimation results is shown in Fig. 16.

2. ***eLSE*:**

Enhanced Linear State Estimation (eLSE) is a commercial software platform developed by Electric Power Group (EPG) for PMU data-based real-time situational awareness [Abu-Jardeh, 2022]. It is presently in use at Dominion Energy. eLSE is completely integrated with Dominion's common information model (CIM) network with PMU locations mapped to CIM. The architecture of eLSE and its role in Dominion's PMU-based monitoring system is shown in Figs. 17 and 18, respectively. A screenshot of the estimation results is shown in Fig. 19.

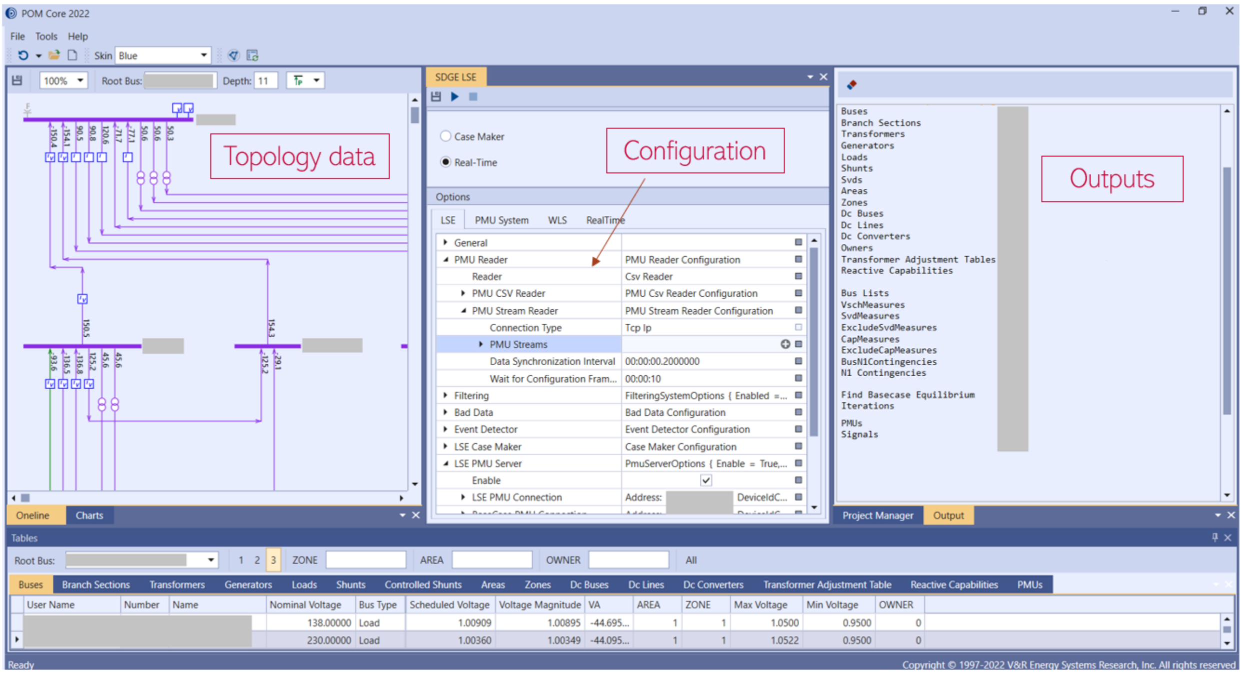

Figure 15. Screenshot showing the LSE display at SDG&E. Source: V&R Energy [Sarmin and Vaiman, 2018].

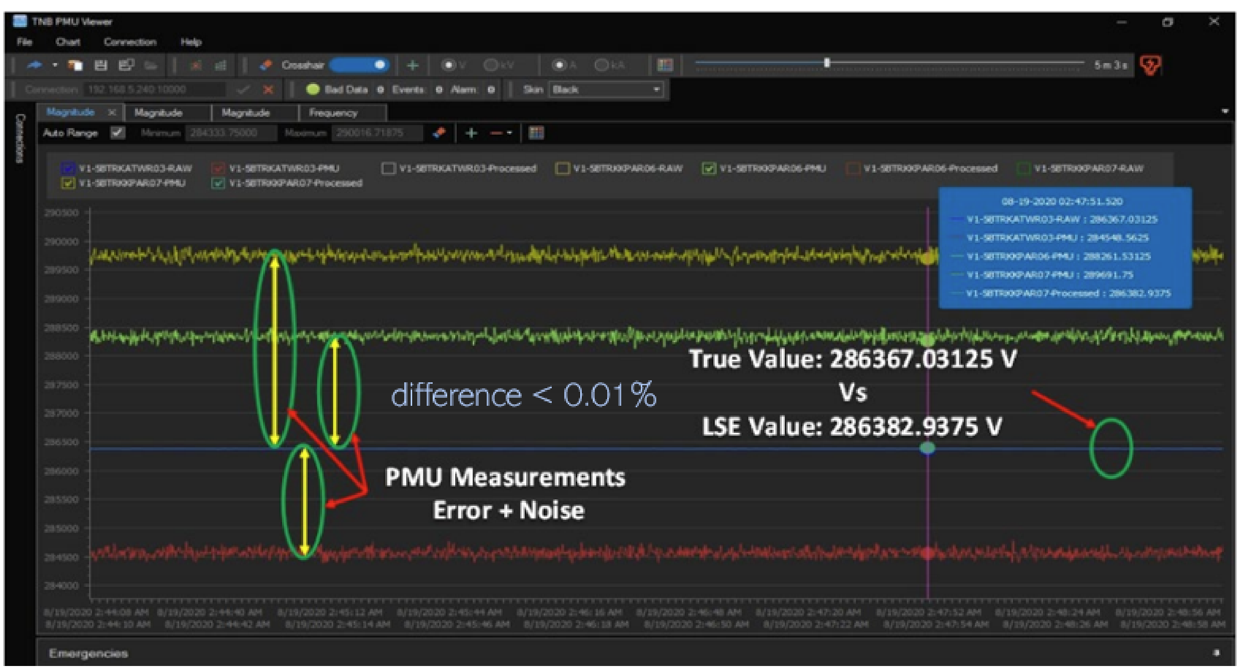

Figure 16. Screenshot showing the estimation results from ROSE LSE displayed in the PMU Viewer. Source: V&R Energy [Sarmin and Vaiman, 2018].

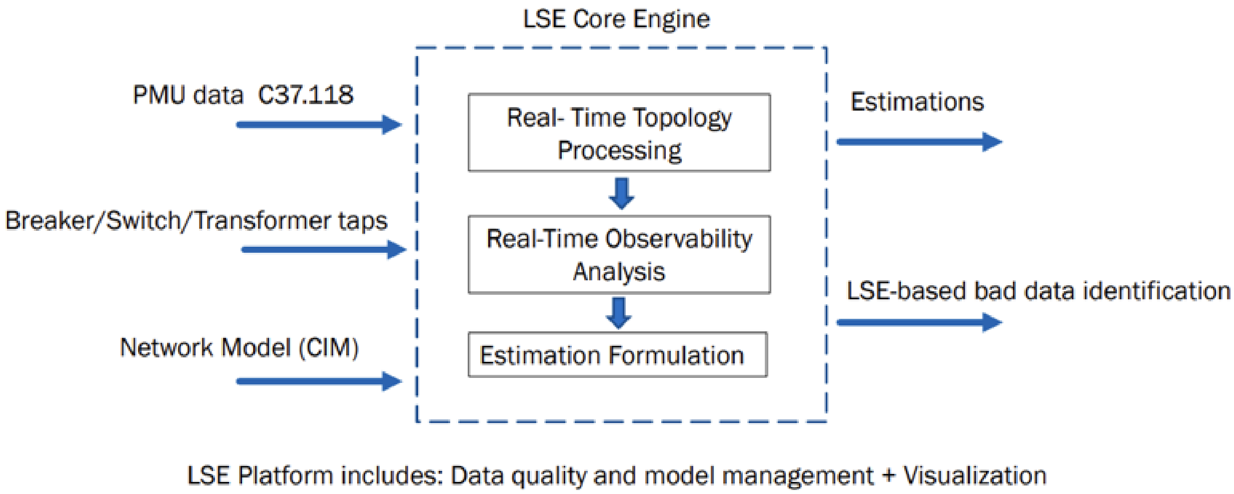

Figure 17. Architecture of eLSE as used in Dominion Energy. Source: Dominion Energy [Abu-Jardeh, 2022].

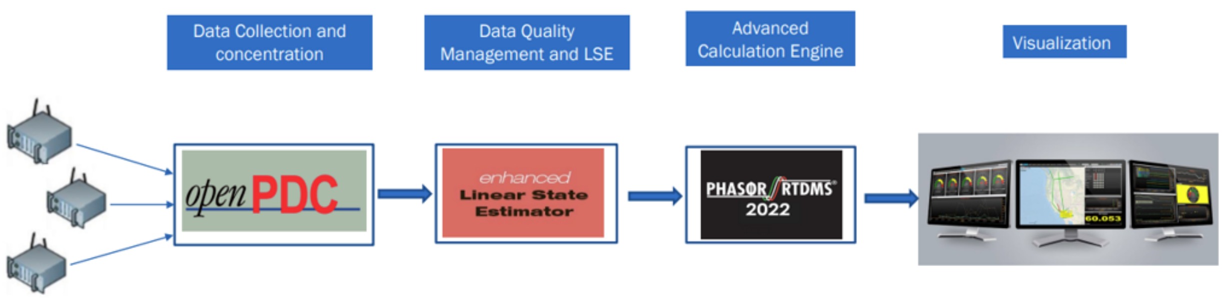

Figure 18. eLSE at Dominion Energy. Source: Dominion Energy [Abu-Jardeh, 2022].

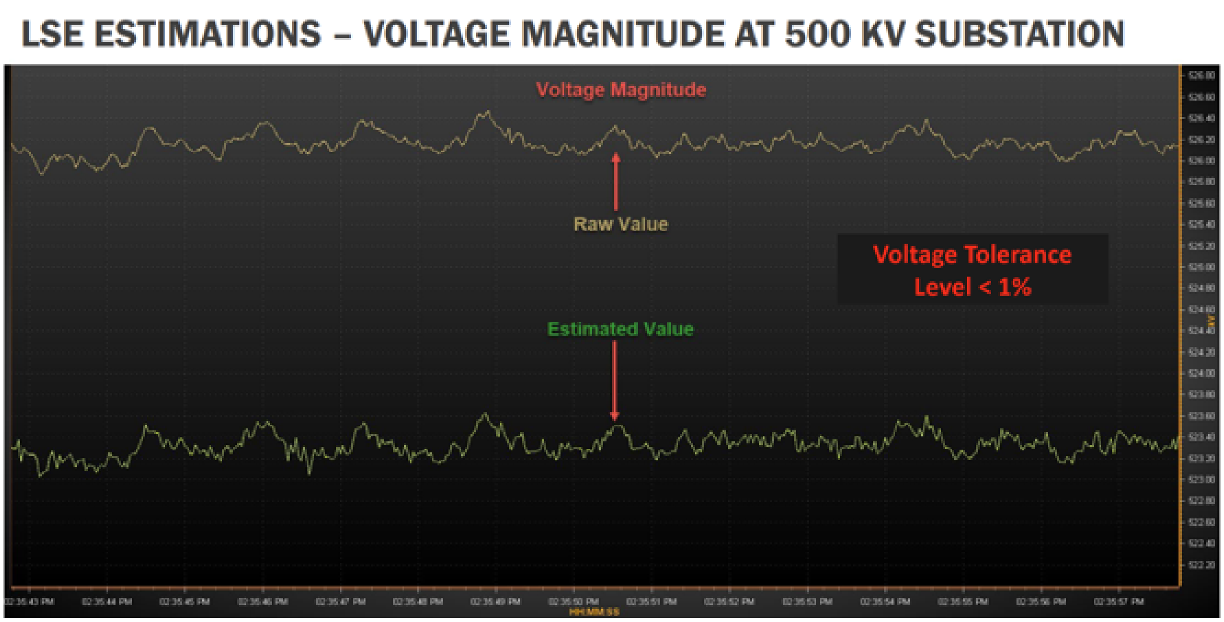

Figure 19. Screenshot showing the estimation results from eLSE at Dominion Energy. Source: Dominion Energy [Abu-Jardeh, 2022].

4.0 Voltage Stability Monitoring

Voltage stability refers to the ability of a power system to maintain steady-state voltages at all buses within safe operating limits and close to their nominal values, both under normal conditions and after disturbances [Hatziargyriou et al., 2021]. Voltage instability occurs when the combined generation-transmission system is unable to meet the demands of the loads.

4.1 Technical Background

Depending on the root causes of instability and their time-scales of manifestation, voltage instability phenomena can be classified as either long- or short-term[Hatziargyriou et al., 2021]. These are discussed next.

1. Long-term voltage instability is typically triggered by the actions of load tap changers (LTCs), overexcitation limiters (OELs) in generators, thermostatically controlled loads, or by a slow-acting remedial action scheme [Hatziargyriou et al., 2021]. Instability in this case can be a slow progressive phenomenon in which the loads drawing large amounts of power from the sources cause substantial voltage drops in the transmission paths. The resulting low voltages in the load buses causes these loads to draw more reactive power from the sources, leading to further voltage drop and eventually voltage collapse.

2. Short-term voltage instability involves fast-acting components like power-electronics-controlled loads, induction motors, HVDC systems, and inverter-based resources. One common example is that of instability driven by stalling of a large number of induction motors following a large disturbance [Hatziargyriou et al., 2021]. During a fault, if the induction motors decelerate below a speed threshold, then upon clearing of the fault they cannot re-accelerate and therefore stall. The stalled motors, if not disconnected by the protection schemes, draw large reactive currents depressing the voltage in that local area. The low-voltage condition can trigger induction motors at the neighboring buses to stall as well, thereby pushing the system towards instability. The onset of instability in this case is very fast compared to the progressive loss of stability margin in the first case, which makes its early detection challenging.

This report focuses primarily on system monitoring for early detection of long-term instability, which can help the transmission operator engage necessary corrective actions early to prevent an impending voltage collapse. This involves use of phasor measurement data for assessing the stability margin of the present operating point and anticipating its future trajectory based on the sensitivities of system voltages with respect to the changes in the real and reactive power demands.

4.2 Detection of Voltage Instability

Any voltage stability monitoring tool should ideally have the following attributes [V&R Energy, 2023]:

1. It should be able to determine voltage values for critical buses either directly from measurements or from estimation and powerflow simulations using the system model.

2. It should alert and alarm the system operator if voltage is outside the reliability limits.

3. It should identify the critical contingencies which could lead to voltage violations.

4. It should be able to determine the P and Q margins accurately across a wide-area and locally.

5. Using the results of $P-V$, $Q-V$, dV/dP, and dV/dQ sensitivity studies, it should alert the operator if voltages are approaching violation limits.

6. It should provide an easy-to-interpret visualization of the results.

7. It should suggest remedial actions for mitigating the risks of possible instabilities.

Voltage stability monitoring tools can be classified into the two broad categories summarized in Fig. 20 – 1) tools based on model-based simulations and 2) tools based on measurement-based indicators. Model-based methods include eigenvalue and Jacobian analysis, voltage stability assessment from state estimation, and continuation power flow. Measurement-based methods include data-driven indices like the voltage instability predictor, reactive power margin, and PMU data-driven sensitivity analysis and singular value decomposition. Two of the PMU data-driven tools used by US utilities for voltage stability monitoring are discussed next.

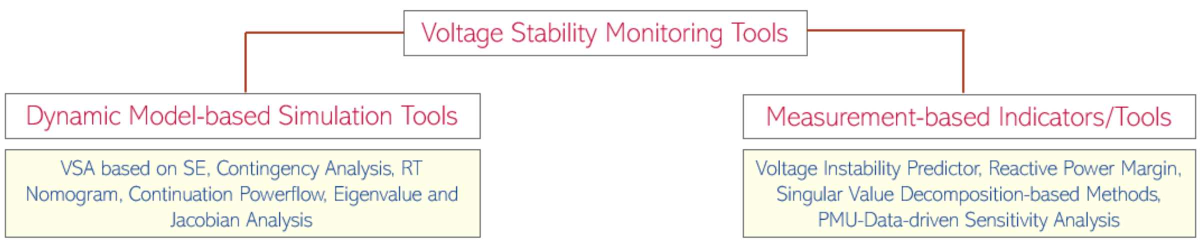

Figure 20. Classification of voltage stability monitoring tools.

1. ***Impedance-based Voltage Instability Predictor (VIP)***:

   This measurement-based real-time instability margin monitoring method, commercialized by Quanta Technology, is based on the principle of maximum power transfer [Novosel, 2012], [Vu and Novosel, 2001]. From circuit theory, we know that at the point of maximum power transfer, the apparent impedance of the load at the bus is numerically equal to the Thevenin impedance looking back into the network. It also corresponds to the nose point on the $P-V$ curve beyond which the system is unstable. Based on this principle, this method uses terminal voltage and current phasor measurements to compute the values of load impedance Z_l and the Thevenin impedance Z_{eq}. The difference between Z_l and Z_{eq} is the margin of voltage stability (see, Fig. 21). The VIP metric is shown on the right side of the voltage stability monitoring dashboard in use by Southern California Edison (SCE) in Fig. 22.

2. ***Reactive Power Margin (RPM) Method***:

   This is another voltage instability detection approach commercialized by Quanta Technology and adopted by several utilities in the US [Lelic, 2013]. The method calculates the Q-margin for each operating point using phasor measurements. While computing the margins and stability boundaries, the method considers changes in system topology and breaker statuses from switching events. This method can also process data from different reporting systems, namely PMUs, SCADA, and synthetic simulation data. One important attribute is that the method can make a distinction between instability and fault-induced delayed voltage recovery (FIDVR). In the dashboard depicted in Fig. 22, the RPM is plotted.

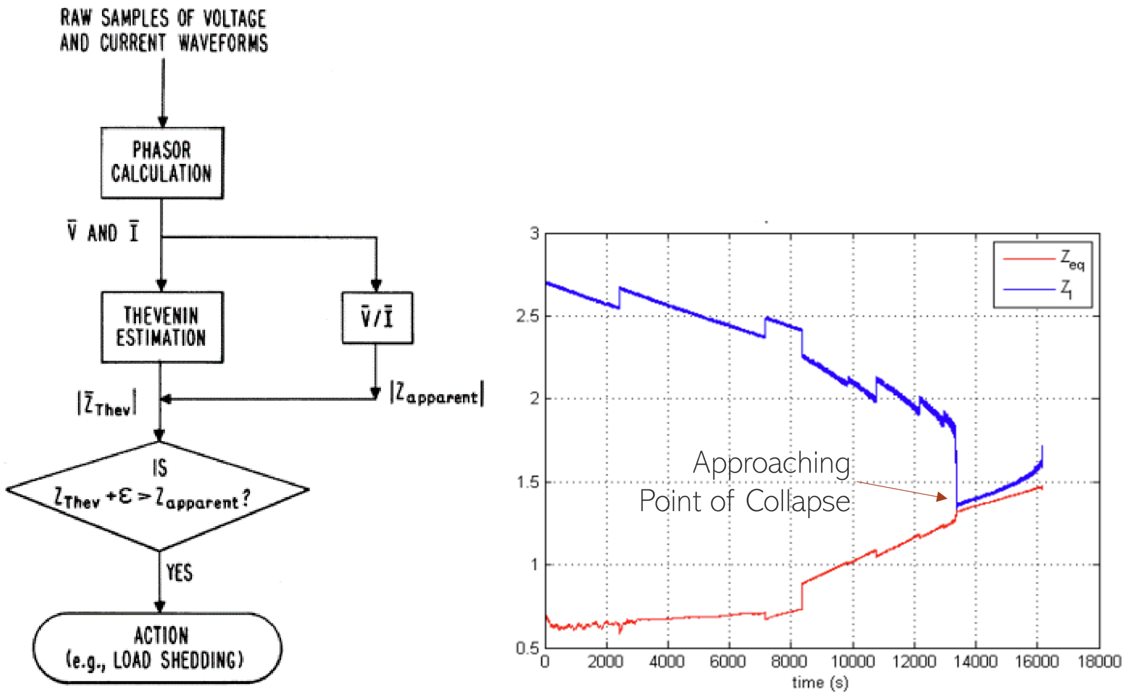

Figure 21. On the left is the flowchart describing the working of the impedance-based voltage instability predictor [Vu and Novosel, 2001], on the right is a representative plot showing the values of imepdances and the progressive loss of stability margin. Source: Quanta Technology [Novosel, 2012].

In its implementation at the Bonneville Power Administration (BPA), the RPM method monitored field measurements of real and reactive power flow between Malin and Round Mountain substations, as shown in Fig. 23. A switching event is captured, after which four operating points A, B, C, and D are shown. The stability boundaries for each of these operating points, computed using the RPM method, are shown in Fig. 24. As the system moves from A to D, the bus at Malin progressively loses stability margin, ultimately becoming marginally stable at point D [Lelic, 2013].

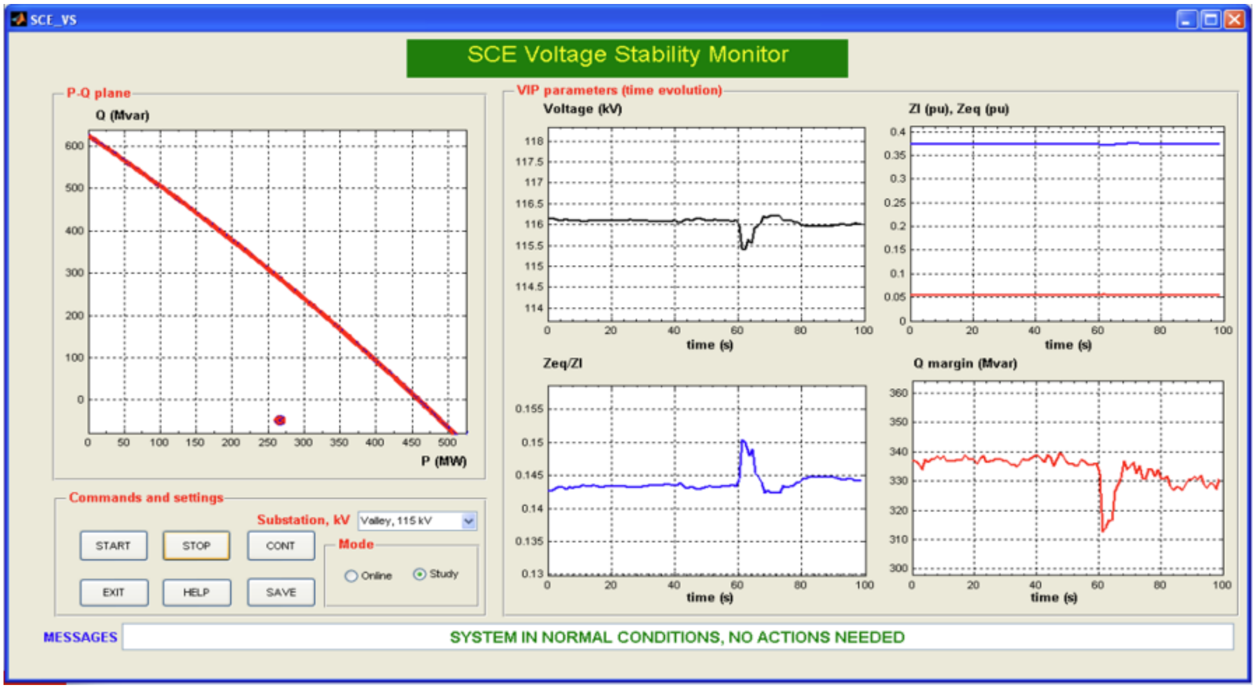

Figure 22. SCE voltage stability monitoring dashboard with VIP and RPM metrics. Source: Quanta Technology [Lelic, 2013].

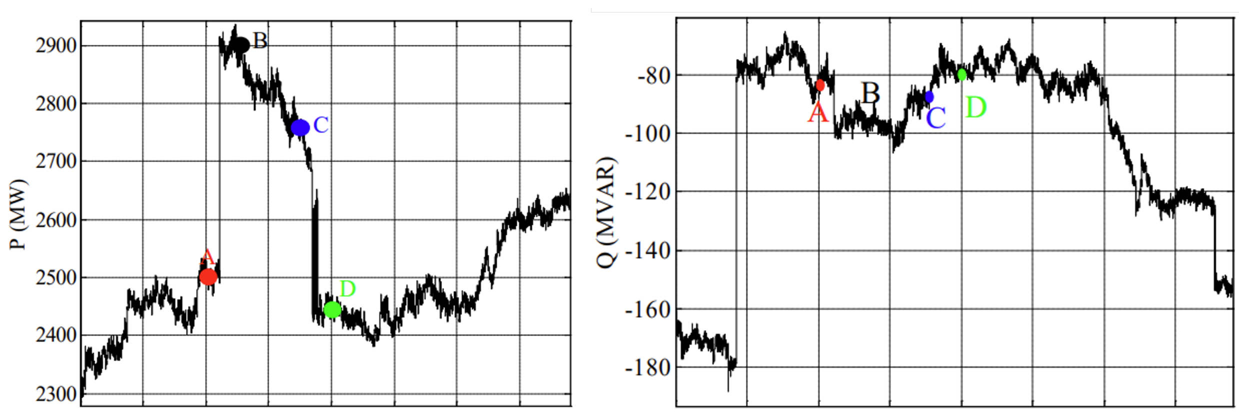

Figure 23. Active and reactive power flows between the Malin and Round Mountain substations in BPA. Four operating points designated by A, B, C, and D are shown. Source: Quanta Technology [Lelic, 2013].

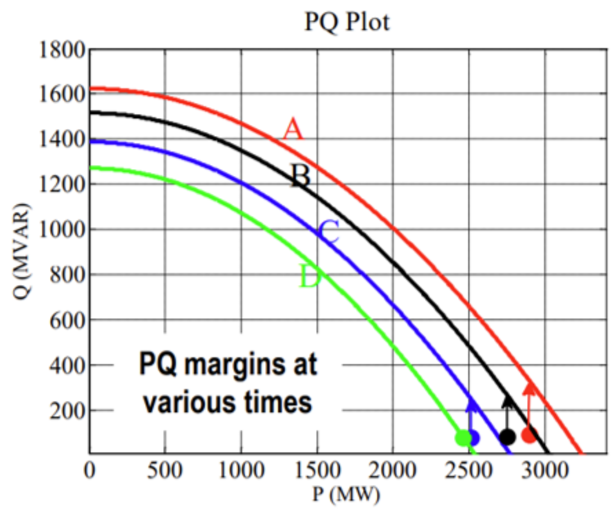

Figure 24. Stability boundaries and the PQ-margins for the four operating points A, B, C, and D shown in Fig. 23. Source: Quanta Technology [Lelic, 2013].

5.0 Small Signal Stability Monitoring

The small-signal stability of a power system refers to its ability to maintain synchronism when disturbances (e.g., load fluctuations, switching actions, etc.) occur. It is important to monitor the properties of the oscillation modes to ensure that they are appropriately damped. When a power system is stressed (e.g., heavy power transfer over long lines, component outages, etc.), modes may become poorly damped and grid disturbances can lead to growing oscillations resulting in cascading outages. Such an event was documented in the US Western Interconnection (WI) in August 1996, when a poorly damped mode directly contributed to a blackout affecting 7.5 million people in North America [Venkatasubramanian and Li, 2004].

5.1 Technical Background

Power system oscillations may broadly be categorized into – natural oscillations (the focus of this chapter) and forced oscillations (discussed in detail in Section 6.0) [NERC SMWG, 2021, NASPI, 2017a]. In large interconnections, generators electrically close to each other tend to self-organize into groups that operate synchronously in nearly exact harmony. Such coherent groups in different areas of the interconnection, generally separated by long distances, operate slightly out of synchronism with each other. These slight differences between two such groups create low-frequency inter-area oscillations, typically in the 0.1-1 Hz frequency range. Due to the constant perturbation of the system's modes of oscillation by random load changes, these natural oscillations are always present in the form of low-level ambient noise.

5.1.1 Inter-area Modes

An interconnection may have multiple natural oscillatory modes, but only a few of these become dominant and observable across the interconnection, thereby requiring close monitoring. A natural oscillation mode is characterized by its – (a) frequency: a narrow range of frequency where it is observable, (b) damping ratio (DR): a measure of how fast oscillations will dissipate following a large grid disturbance, and (c) shape: a representation of generator groups participating in an oscillation mode. A mode is considered well-damped if its DR is higher than 10%, and if the DR falls below 3-5%, the poorly damped mode is considered of concern. The mode shape is a complex number whose magnitude depicts the extent to which an individual generator participates in the given mode, and angle indicates which generators swing together. The properties of a mode may drift based on changing system conditions such as system load, topology, and power transfer patterns. For example, the DR of a mode may decrease in light-load conditions when fewer synchronous generators are online to contribute to damping and inter-area power transfer is high [Western Interconnection Modes Review Group, 2021, Follum et al., 2023]. Understanding mode shape is critical, as disturbances occurring near one end of a mode shape can interact with system dynamics and be observable at locations away from the source.

An example of a mode shape plot from the U.S. Eastern Interconnection (EI) is shown in Fig. 25 [Follum et al., 2023]. The diameters of the circles indicate mode shape magnitude, and white arrows indicate mode shape angle. Generator locations are clustered by mode shape angles into two groups (shown in red and blue) that are about 180 degrees apart. Locations indicated in gray dots do not significantly participate in the mode being examined. Note that generators at the extreme ends of the interconnection tend to exhibit higher participation in inter-area modes.

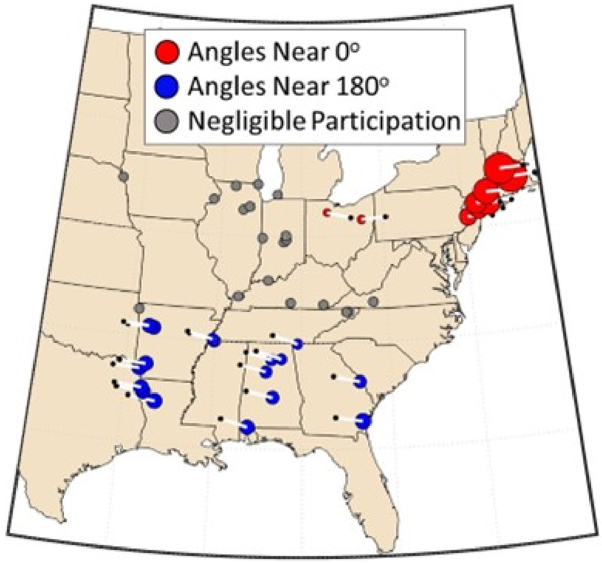

Figure 25. Example of a mode shape plot from the U.S. Eastern Interconnection [Follum et al., 2023].

Table 1. Modal analysis method and associated model/data requirements

Data Type	Ringdown	Ambient	Eigenvalue
Power-flow base cases with associated dynamic data	X		X
PMU data (ambient)		X	
PMU data (Post-disturbance)	X		

5.1.2 Analysis Techniques

A system operator may be interested in monitoring modes that show significant participation from generators across their footprint and have low damping. Analysis techniques for modal identification can be broadly grouped into- (a) eigenvalue analysis, (b) ambient, and (c) ringdown analysis methods. Data/model requirements for employing the analysis methods are summarized in Table 1. This report does not delve into the different algorithms in detail, but the interested reader can refer [NASPI, 2017a] for a more detailed review.

Eigenvalue analysis methods seek to compute the eigenvalues ($\lambda_i = \sigma_i + j\omega_i$) of the linearized power system from power-flow base cases using offline planning models, snapshots from state estimators, etc. [Powertech Labs, 2023, Wang and Semlyen, 1990]. Once the eigenvalues are computed, the frequency and damping ratio of the i-th mode may be expressed as $f_i = \frac{\omega_i}{2\pi}$ Hz and $\zeta_i = \frac{-\sigma_i}{\sqrt{\sigma_i^2+\omega_i^2}} \times 100\%$, respectively. This class of methods can be computationally intensive, especially for large interconnections, and it can be computationally prohibitive to run eigenvalue analysis on multiple power-flow cases representing different power system conditions to understand how a given mode may behave under different conditions. However, such model-based analyses can help form initial understanding about which modes are significant in a system, and where they are the most observable.

Estimates obtained from model-based eigenvalue analyses can be validated by analyzing PMU

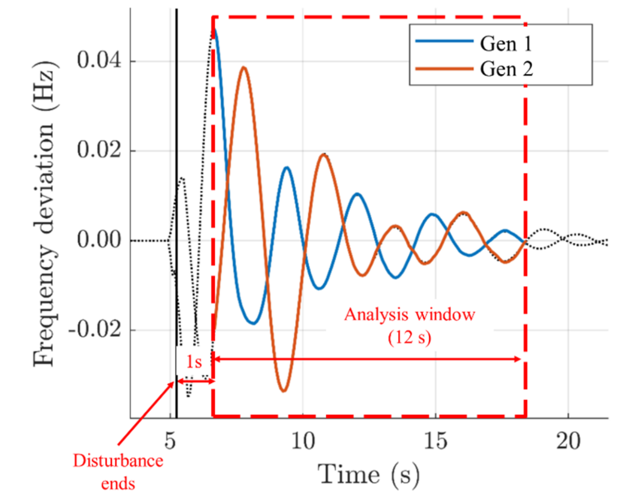

Figure 26. Example analysis window selection for ringdown analysis. The red dotted rectangle shows the data window selected for curve fitting.

measurements. Large disturbances excite system modes, and by analyzing post-disturbance oscillations (ringdowns), modal properties can be estimated. Ringdown analysis methods (e.g., Prony, Matrix Pencil, Dynamic Mode Decomposition, etc.) are essentially curve-fitting techniques that express the system free-response (i.e., the period in which the input or forcing function has been removed from the system) as a linear combination of damped sinusoids, thereby yielding mode estimates [Trudnowski et al., 1999, Liu et al., 2007]. The observability of modes depends on the location of the disturbance. The disturbance may be a naturally occurring system event like a fault or planned tests. For example, the US Western Interconnection periodically evaluates modal properties by conducting tests using the 1400 MW dynamic brake at the Chief Joseph substation [Shelton et al., 1975].

The accuracy of ringdown methods depends on the data window selected for analysis. To avoid nonlinear system behavior immediately following a disturbance, a prudent rule-of-thumb is to place the left end of the analysis window after 0.5-1s has elapsed from the disturbance. Ideally, the window should consist of 3-4 cycles of the lowest-frequency mode of interest. Ringdown analysis methods require a good signal-to-noise ratio, so care must be taken to ensure that the analysis window ends before the oscillation decays back to the level of ambient noise. An analysis window selection example is shown in Fig. 2. The disturbance is created by simulating a brake insertion from 5-5.5 s. After the removal of the brake, 1 s is allowed to elapse before the analysis window starts. The analysis window is 12 s long, containing about 4 cycles of the ∼0.25 Hz mode of interest, and does not have any flat signal content.

Since ringdown oscillations yield mode estimates from post-disturbance measurements, they are not suitable for continuous monitoring of modes. Continuous monitoring can be achieved using signal-processing methods termed *mode meters* that analyze PMU measurements under ambient conditions [Dosiek et al., 2013, Trudnowski et al., 2008]. Mode meter algorithms analyze the system's dynamic response to constant perturbation by random load changes to estimate the frequency, damping ratio, and shape of the system's modes of oscillation. An example of continuous mode estimates obtained from mode meters alongside event-driven snapshots obtained from ringdown methods is shown in Fig. 27 [Western Interconnection Modes Review Group, 2021].

Ambient analysis can be challenging, as the oscillation amplitudes in a system's ambient response are very small compared to its transient response. Therefore, ambient analysis methods

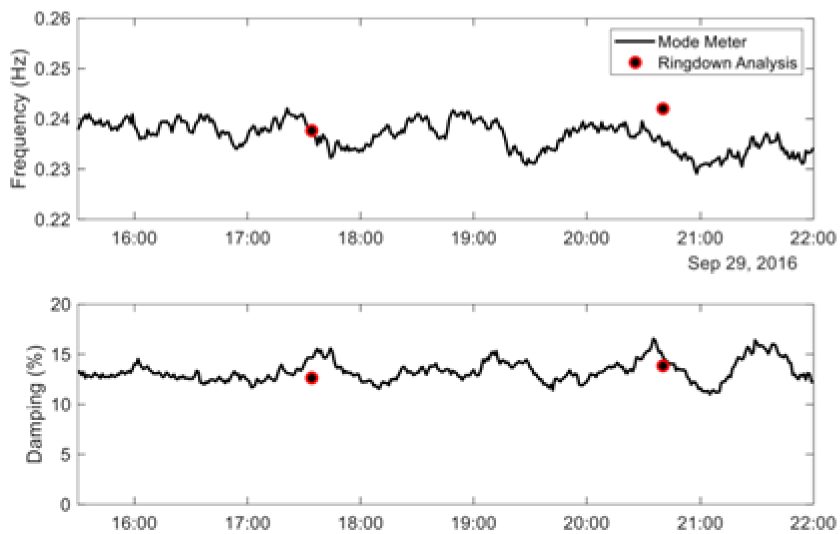

Figure 27. Example of continuous and event-driven mode estimates obtained from analyzing ambient and ringdown data respectively. The ringdown estimates validate the mode meter results [Western Interconnection Modes Review Group, 2021].

typically need to analyze longer data windows (in the range of 10-20 minutes) than ringdown methods (in the range of tens of seconds) to obtain reliable estimates. To use these techniques to obtain mode estimates successfully, choosing which signal to monitor is critical. Ideally, the chosen signal should exhibit high observability of the mode of interest. To choose which signals have high observability of a mode of interest, analyzing historic PMU data may be useful. Prior model-based and ringdown analyses can also help identify which generators show high participation in a mode. A signal commonly chosen for analysis is the difference between frequency measurements at two generator buses located at different ends of a mode's shape. Further recommendations on signal selection and preparation are provided in [NASPI, 2017a].

Despite careful signal selection, mode meter algorithms can still spuriously yield low DR estimates. As oscillations are generally observed to have poor damping when a system is stressed, low DR estimates can be validated by monitoring system conditions. If low DR estimates correspond to system stress conditions (line outages, heavy load, heavy power transfer, etc.) or continue to be low for a long period, then operators must take mitigation actions. However, if the system conditions appear normal, then low estimates may be due to algorithm performance issues.

An example workflow for leveraging eigenvalue and ringdown analysis to obtain an initial understanding of system modes, and subsequently employing ambient analysis for continuous mode monitoring, is shown in Fig. 28. Continuous mode monitoring ensures that notifications/alarms can be issued if damping reduces significantly. Mode properties may change significantly if a system undergoes changes, e.g., generation dispatch patterns change drastically, major generators are retired, inverter-based renewable energy (RE) resource penetration increases, etc. Correlating mode estimates with system conditions such as power transfer over major interfaces, RE penetration, system load, etc. can provide early signs of changing system modes, prompting system operators to take timely remediation measures.

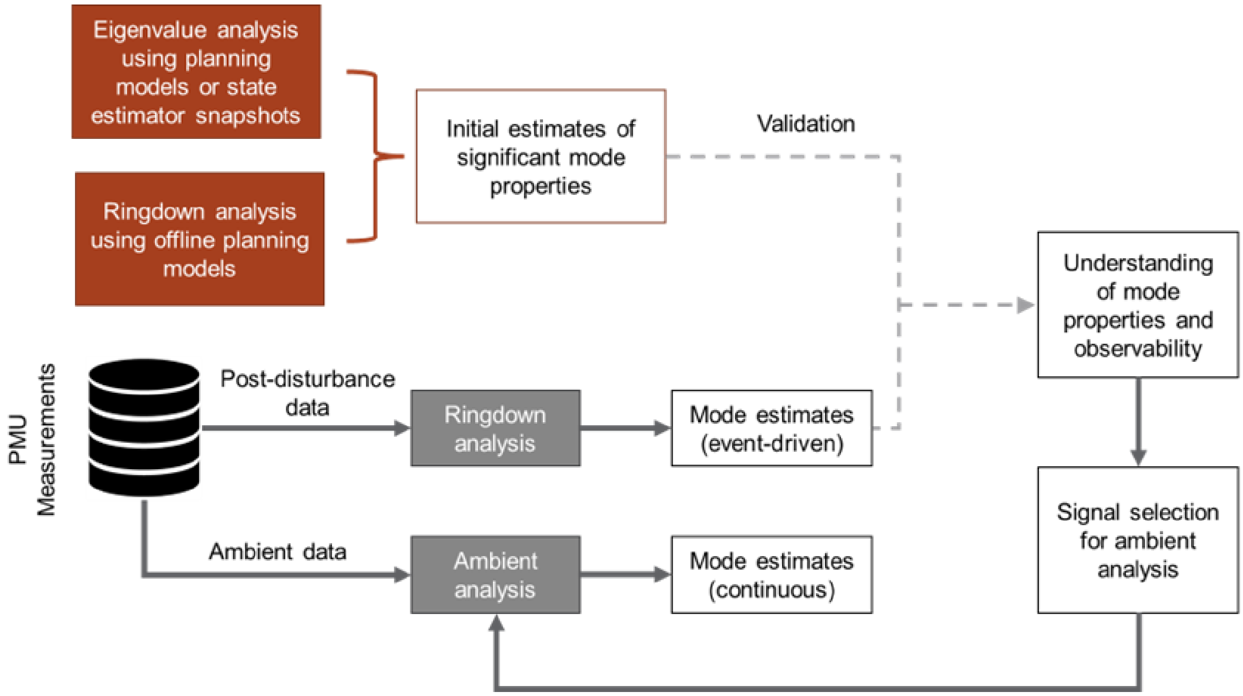

Figure 28. Example workflow for enabling continuous monitoring of system modes using PMU data.

5.2 NERC Standards

The NERC TPL-001-4 Transmission System Planning Performance Requirements R4.1.3 states that [NERC, 2018]:

> "For Planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner."

Utilities use both model- and PMU-based analysis to illustrate compliance with this requirement [Wu et al., 2017]. Two main approaches are adopted by reliability coordinators (RCs) to define oscillation-damping criteria based on their operational experience:

- *Damping Ratio*: Various RCs use different minimum DR requirements. For example, a 3% minimum criterion is used by PJM Interconnection, Independent System Operator- New England (ISO-NE), Midcontinent Independent System Operator (MISO), and Electric Reliability Council of Texas (ERCOT). A 5% minimum requirement is specified by NYISO. A 3% DR corresponds to a 1% settling time of one minute or less for all oscillations with a frequency of 0.4 Hz or higher. Utilities are allowed to demonstrate conformance with the criterion by using small signal eigenvalue analysis to explicitly identify the DR of all questionable oscillations. RCs may have other additional requirements. For example, ISO-NE requires "A sufficient number of system state quantities including rotor angle, voltage, and interface transfers should be analyzed to ensure that adequate system damping is observed." [ISO New England System Planning, 2013]

- *Time domain analysis*: One common metric in use (for example by Southwest Power Pool (SPP), Great River Energy, Xcel Energy, etc.) is the Successive Peak Positive Ratio (SPPR). The SPPR is defined as the ratio of two successive swing peak amplitudes [SPP, 2016]. A

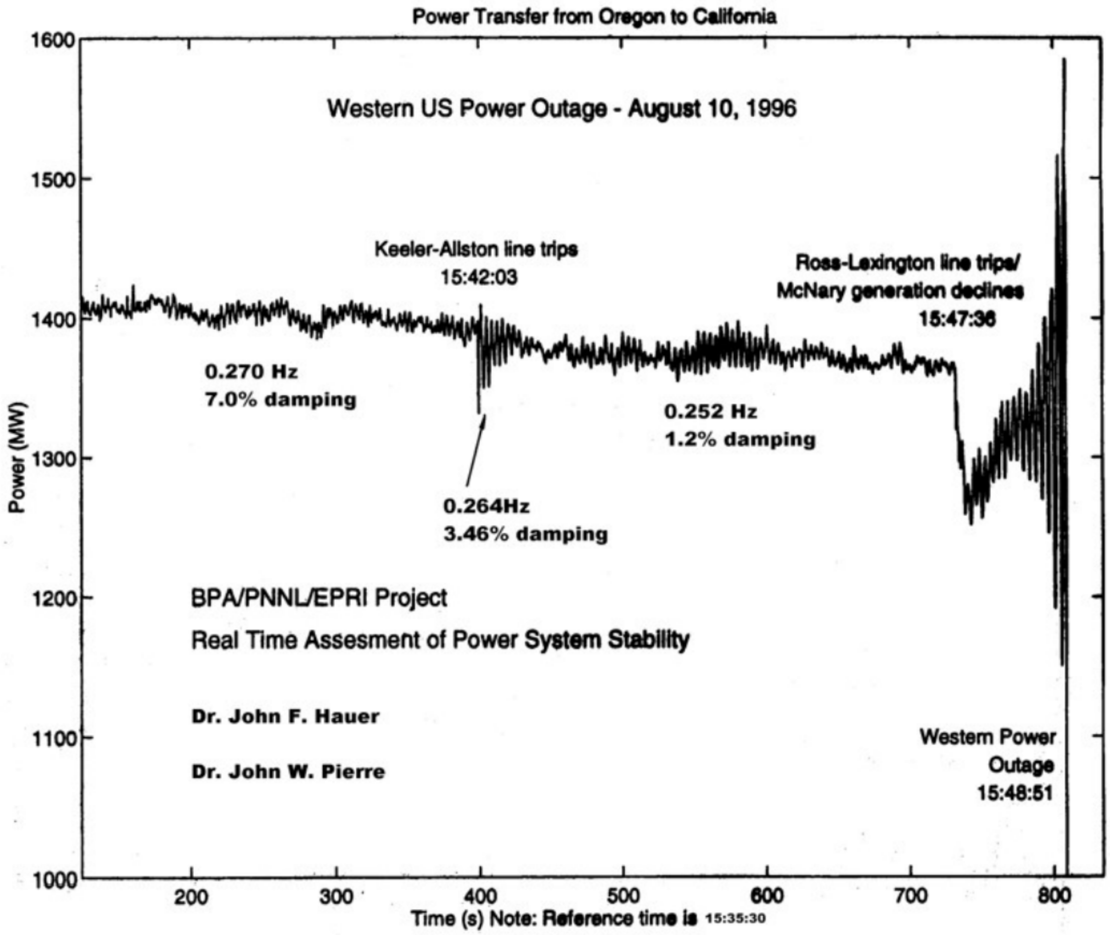

Figure 29. Sequence of events leading to the WECC outage of August 1996.

typical criterion is that the SPPR needs to be 95% or lower for disturbances with faults and 90% or lower for disturbances involving line trips without a fault. ISO-NE has the following alternate guidance for oscillation damping criterion in the time-domain. "Acceptable damping with time domain analysis requires running a transient stability simulation for sufficient time (up to 30 seconds) such that only a single mode of oscillation remains. A 53% reduction in the magnitude of the oscillation must then be observed over four periods of the oscillation, measuring from the point where only a single mode of oscillation remains in the simulation." [ISO New England System Planning, 2013]

Sometimes, the term *damping factor* = $(1-SPPR)\times 100$% is also used to describe oscillation decay in the time-domain. This term is different from the *damping ratio* discussed earlier and should not be confused.

It must be mentioned here that although some RCs set minimum damping criteria at the 3-5% range, it is unwise to operate a power system at any marginal condition where a component outage may reduce the mode damping below 0%, which would result in growing oscillations. Such a sequence of steps resulted in the August 1996 outage in the WI (see Fig. 29). Model-based studies can help understand the impact of different contingencies on system damping, and this can inform system operators how much stability margin they should adopt during operations.

The US electrical interconnections are operated by multiple regional RCs. As inter-area oscillations are wide-area phenomena and their impact may be visible across multiple areas, utilities participate in working groups like the NERC Synchronized Measurement Working Group (SMWG) and WECC Oscillation Analysis Working Group (OAWG) to share knowledge and best practices.

5.3 Control Room Displays

System operators in the US have been using both vendor-supplied and in-house solutions for monitoring system modes in their control rooms [NASPI, 2017b]. In this section, a brief overview of three popular commercial platforms is provided- a) Electric Power Group's (EPG) Real Time Dynamics Monitoring System (RTDMS)[1], b) Schweitzer Engineering Laboratories' (SEL) Synchrowave Operations[2], and c) General Electric's (GE) PhasorPoint[3].

RTDMS is a platform for real-time wide-area analysis and monitoring using PMU data for use in control centers. It includes an oscillation detection and monitoring module that can be configured (which signals to monitor, frequency range, damping ratio range etc.) to set up monitoring of modes of interest. A real-time visualization dashboard helps visualize the frequency, damping, and energy of oscillation modes. In the US, the RTDMS platform is used by several organizations such as SPP, Electric Reliability Council of Texas (ERCOT), and RC-West. Example dashboard displays are shown in Fig. 30-31.

SEL Synchrowave Operations is another wide-area situational awareness tool that allows setting up an oscillation monitoring dashboard. Fig. 32 shows an example dashboard illustrating how notifications are displayed if ringdown oscillations are detected, time-domain measurements can be inspected, and the mode frequency, damping, and shape estimates are displayed [Cassiadoro, 2021].

GE's PhasorPoint platform is used by organizations such as ISO-NE, American Transmission Company (ATC), and the erstwhile Peak Reliability. The oscillatory stability module of the platform (example shown in Fig. 33) allows configuring mode-meters to continuously track modes of interest. Frequency and damping estimates are displayed on the left panel, and by clicking on a mode of interest, the mode shape estimates can be visualized overlaid on a geographic map.

5.4 Alarming Methodologies

Different entities in the U.S. have established different rules and procedures for generating notifications/alarms when mode damping estimates become low. Generally, any oscillation that has persistently low damping estimates for a prolonged period (>15-20 minutes) is considered concerning. It is possible that due to mode-meter algorithm limitations, damping estimates may become biased and appear low if forced oscillations are present in the system. Some organizations like ISO-NE are of the opinion that determining if an oscillation is natural or forced is not critical for practical operations, rather any high-energy oscillation with low damping estimates must be flagged.

ISO-NE has developed an alarm notification service that delivers results from GE PhasorPoint as well as an in-house Oscillation Source Localization (OSL) module (mainly aimed at identifying the source of a forced oscillation) to control room staff and operation support engineers via text and email. An example email notification is shown in Fig. 34 [NERC SMWG, 2021].

Because low mode damping conditions usually coincide with system stress conditions (usually manifesting as component outages, heavy power transfer over major corridors etc.), comparing

[1] https://www.electricpowergroup.com/rtdms.html

[2] https://selinc.com/products/5702/

[3] https://www.think-grid.org/sites/default/files/Grid-SWS-L3-e-terraphasorpoint%203.0%201007-2015_10-EN.pdf

Figure 30. Mode monitoring display setup using EPG RTDMS, courtesy: EPG and ERCOT [EPG, 2014].

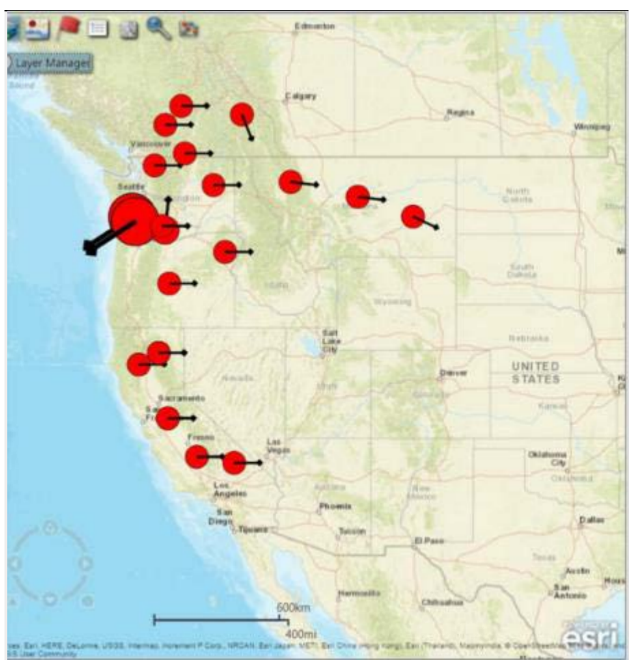

Figure 31. Geospatial visualization of mode shapes using RTDMS, courtesy: RC-West [NASPI, 2017b].

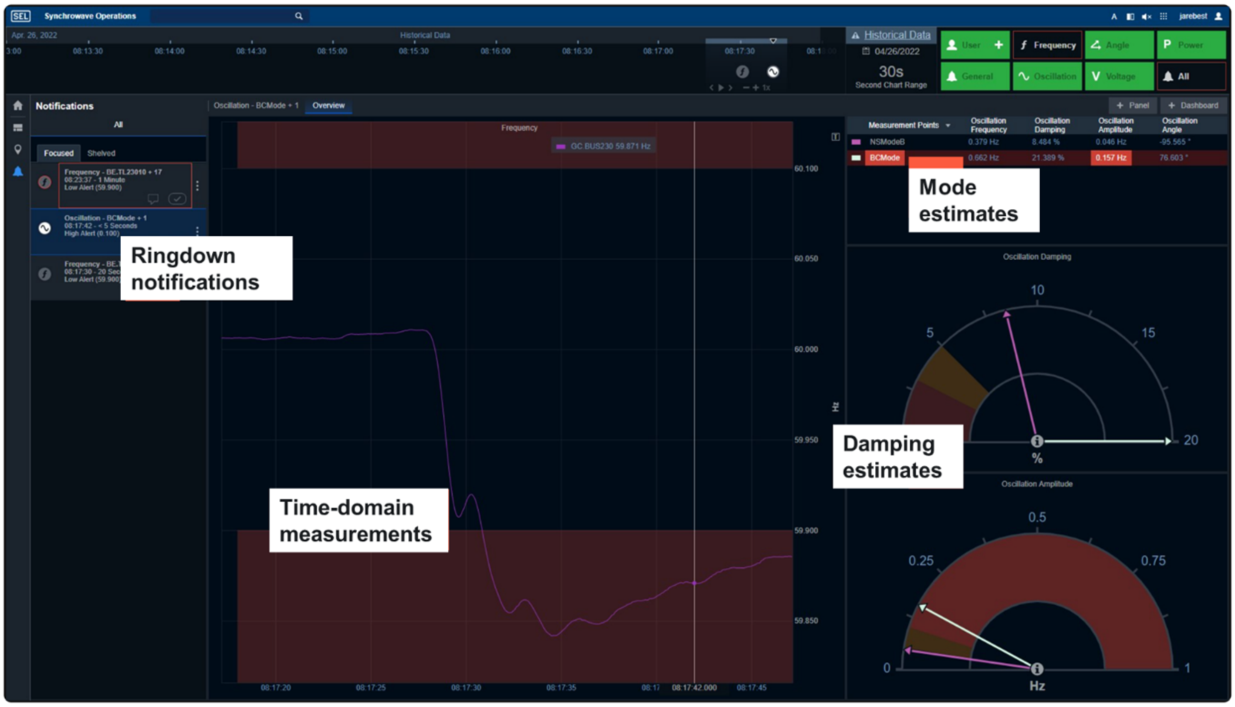

Figure 32. Oscillation monitoring dashboard example using SEL Synchrowave Operations. [Cassiadoro, 2021]

damping estimates with stress indicators like phase angle differences between major buses at different points in a network, power transfer across major interfaces, etc. can help avoid false alarms when damping estimates may be inaccurate due to data artifacts, presence of forced oscillations, inaccurate configuration, etc. A conceptual illustration of such a composite methodology developed by Bonneville Power Administration (BPA) is shown in Fig.35 [NERC SMWG, 2021].

Mitigation actions taken once poor damping conditions are detected include generator dispatch, reducing long-distance power transfer, and topology reconfiguration. Many system operators have developed standard operating procedures that are not public knowledge due to the sensitive nature of the critical infrastructure information. Some entities like RC-West validate their mitigation actions by performing SSAT (Small Signal Analysis Tool, by Powertech Labs) analysis with real-time state estimation cases that are used along with the dynamic data applicable for the season. SSAT is a commercial tool that can perform linearized eigenvalue analysis to identify modal properties of a system (example analysis shown in Fig. 36). RC-West has a running real-time transient stability analysis setup that provides the framework to perform small-signal stability analysis with the same input data from state estimation and dynamic data that is used for the transient stability analysis. The SSAT analysis allows operators to determine and validate relevant path flows or the status of equipment and generators that can be adjusted to mitigate observed sustained low damping on any of the monitored modes.

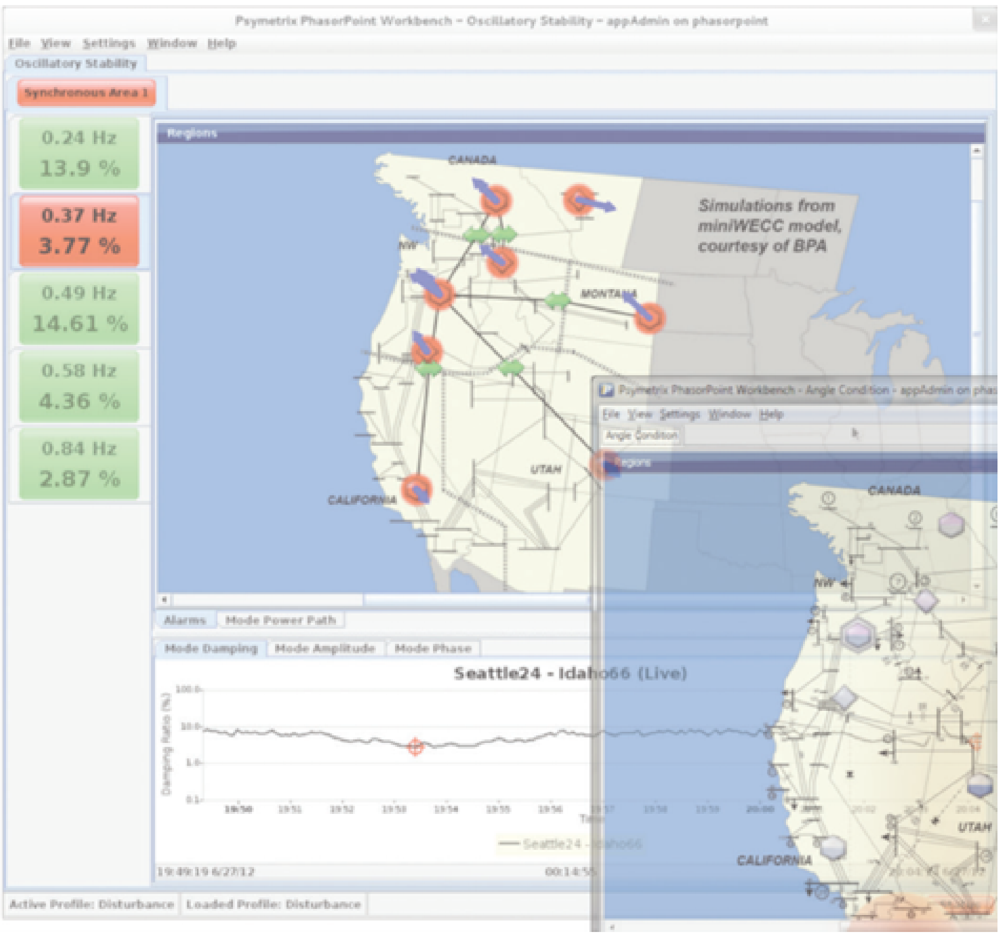

Figure 33. Example oscillatory stability dashboard in the GE PhasorPoint Platform.

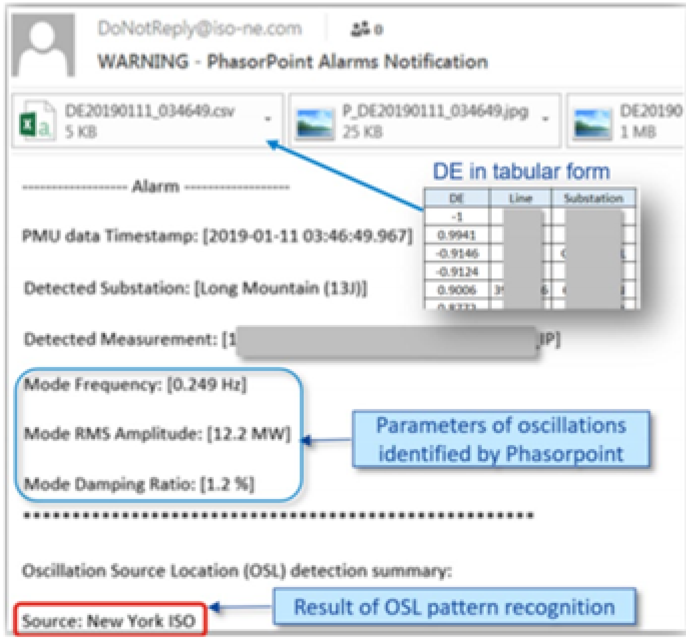

Figure 34. Example oscillation notification email used in ISO-NE [NERC SMWG, 2021].

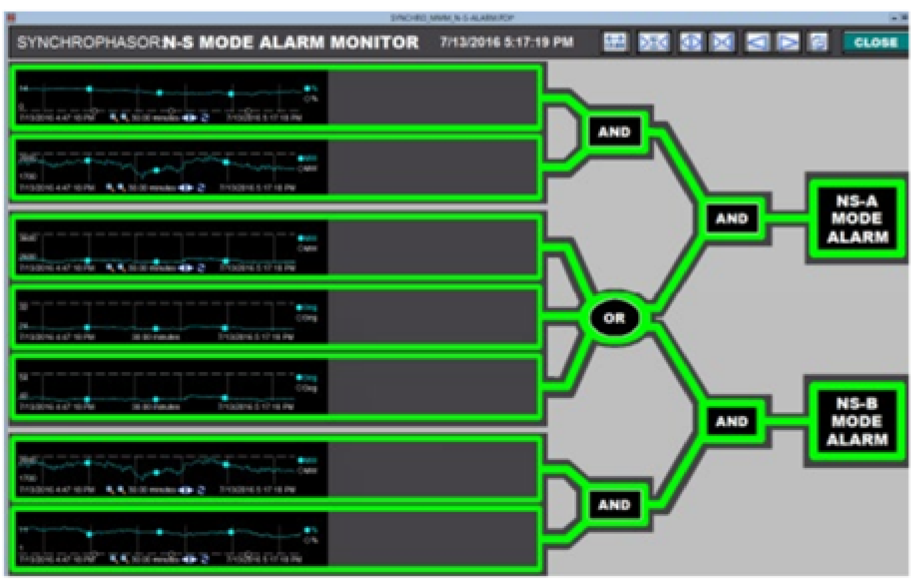

Figure 35. Conceptual illustration of composite alarming methodology designed by Bonneville Power Administration (BPA) [NERC SMWG, 2021].

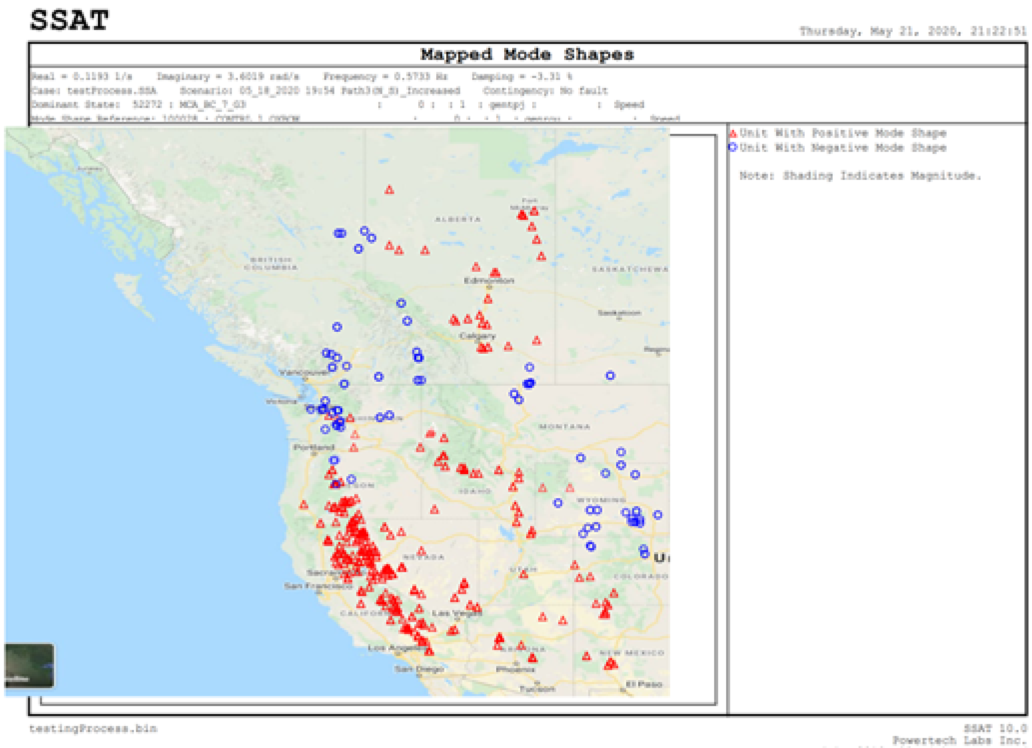

Figure 36. Example of mode estimates obtained using eigenanalysis performed by SSAT. [NERC SMWG, 2021]

6.0 Forced Oscillations Monitoring

As stated in Section 5.0, oscillations in a power system may be categorized into natural and forced responses (see Fig. 37). Unlike natural oscillations that arise due to a system's characteristic modal properties, forced oscillations (FOs) are introduced by external periodic inputs (e.g., malfunctioning equipment, improper controller design, cyclic loads, etc.) [NERC, 2017]. It is important to distinguish between natural and forced oscillations because- (a) operators may need to take different actions to mitigate persistant FOs compared to poorly damped natural oscillations, and (b) applying techniques meant for analyzing one oscillation type to another may lead to misleading results.

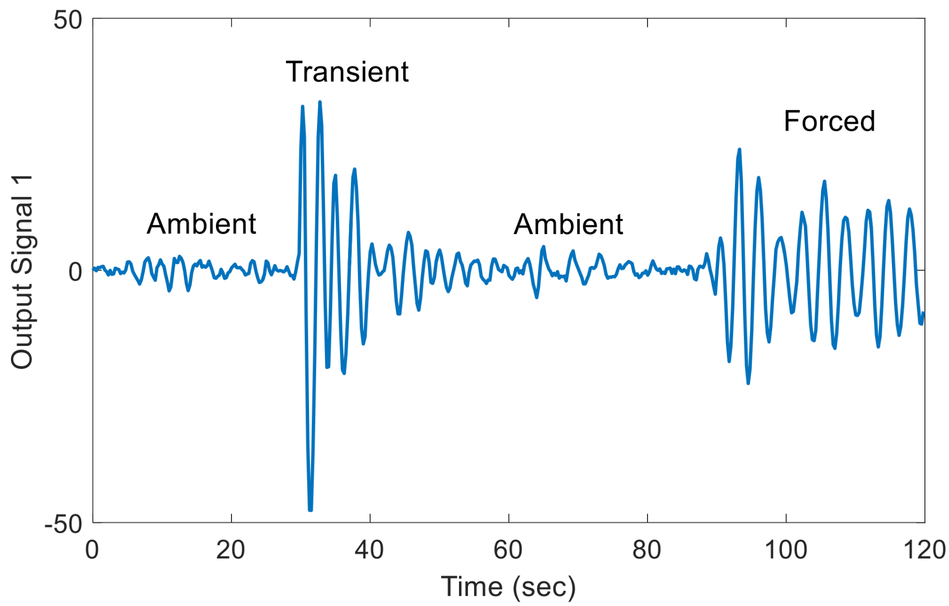

Figure 37. Typical examples of how natural (ambient and transient) and forced oscillations appear in time-domain measurements [NASPI, 2017a].

6.1 Technical Background

Depending on the source of the external driving input, a FO may persist or appear intermittently in a power system with varying levels of energy. The oscillations may be local (i.e. observable only in the vicinity of the driving input) or observable across an electrical interconnection. The sustained presence of these oscillations may cause undesirable operations, including equipment tripping, that can place the power system under further stress. Hence, it is important to detect the presence of FOs, identify their source, and take mitigation actions in a timely manner. Some common challenges encountered while addressing FOs include- a) source localization algorithms may be able to identify the broad geographical region the source belongs to correctly but fail to pinpoint the plant causing oscillations due to inadequate measurement coverage/configuration, b) the source of a FO and the location where the oscillation amplitudes are highest may be far away from each other, often operated by different entities. These issues make coordination among plant and system operators crucial for maintaining reliable operations in the presence of FOs.

Detecting the presence of sustained oscillations that would otherwise not be visible from SCADA readings is enabled by the high resolution of PMU measurements. However, SCADA

Table 2. Frequency bands and likely causes of oscillation [NERC SMWG, 2021]

Frequency band	Likely cause of oscillation
0.01-0.15 Hz	Governor, plant controller, automatic generation control (AGC)
0.15-1 Hz	Local plant controls
1-5 Hz	Local plant controls, intra-plant interactions, local generator/exciter controls
>5 Hz	Torsional oscillations, sub-synchronous oscillations (SSO), fast acting controller misoperations

can supplement the information available for deciding mitigation actions. For example, anomalous power output readings from a plant's SCADA system can help pinpoint which generator in a broad area identified by other source location algorithms is driving a FO.

In the last few years, many FO occurrences have been reported by North American system operators. With the growing penetration of inverter-based resources (IBRs), reported instances of FOs are increasing as well. Root causes of FOs may be diverse, including malfunctioning equipment, improperly tuned/designed controller settings, incorrect power system stabilizer settings, hydropower generators operating in the rough zone, cyclic loads, etc. Field experience indicates that similar devices lead to oscillations close in frequency. Looking at the FO frequency, an initial idea regarding a FO's source can be formed. Table 2 shows the frequency spectrum divided into four bands and the corresponding oscillation sources in those bands.

Oscillations in the 0.15-1 Hz band are critical from a wide-area reliability perspective, as FOs close to inter-area mode frequencies (electromechanical inter-area modes tend to appear in the 0.15-1 Hz range) may lead to resonance and amplify oscillations throughout an interconnection, making source localization extremely challenging. Research indicates that the following conditions must be met for resonance to be likely [Sarmadi and Venkatasubramanian, 2016]:

- FO frequency is at or near an inter-area mode frequency.
- The system mode is poorly damped leading up to the forced oscillation.
- The oscillation source is located in an area that exhibits strong participation in the corresponding system mode (e.g., either end of a system mode).

Some recent examples of FOs interacting with system modes in North America include- (a) in January 2019, a loose connection in the control system of a thermal generator in Florida introduced an oscillation that resonated with a system mode and caused 50 MW power swings as far away as the northeastern US [NERC, 2019]; (b) in early 2022, loss of communication in a California battery energy storage plant led to controller misoperations that resulted in 0.25 Hz oscillations amplified throughout the US Western Interconnection after interacting with a system mode [Alam and Agrawal, 2022].

6.1.1 Detection

Unlike natural oscillations that are always present, FOs appear only when an external periodic input is present in the power system, and hence the first step in addressing any FO is detecting its presence. Multiple commercial tools exist for FO detection. However, this report only discusses algorithms implemented by two commercial tools in use by multiple North American utilities and discussed in the NERC oscillation monitoring and mitigation reference document [NERC SMWG, 2021], namely the Real-Time Dynamics Monitoring System (RTDMS) by Electric Power Group (EPG) and PhasorPoint by General Electric (GE).

Energy-based Oscillation Detection: Under ambient conditions, the energy content in different frequency bands of power system measurements remains relatively constant. Hence, if there is a sudden increase of signal energy in a certain frequency band, it could indicate the presence of a FO. Energy-based oscillation detection methods use this general principle. A popular method (illustrated in Fig. 38) involves computing the root-mean-square (RMS) energy in different frequency bands and comparing it to a predetermined threshold. If the oscillation energy in a band is higher than the threshold for more than a specified amount of time, then oscillation alarms are activated. Of course, careful threshold selection is critical for obtaining good performance and minimizing nuisance alarms [Donnelly et al., 2015]. Approaches for setting these thresholds will be discussed in Section 6.4. An energy-based detection method is used in the RTDMS platform.

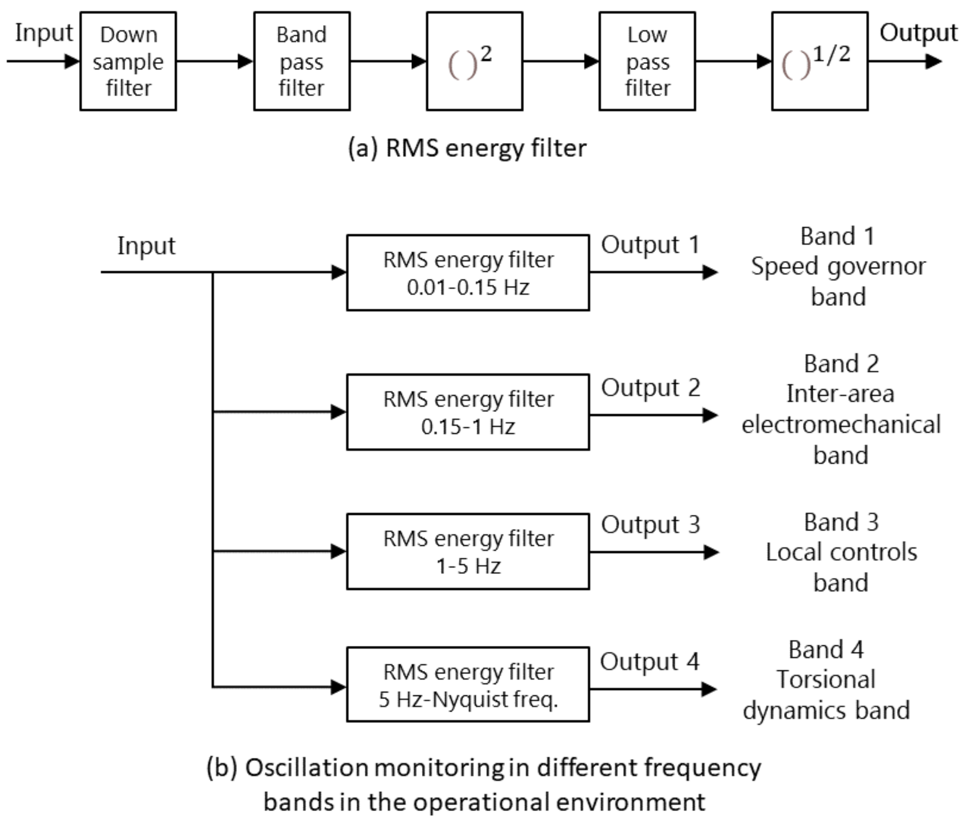

Figure 38. FO detection using RMS energy monitoring in different frequency bands, adapted from [Donnelly et al., 2015]

Power Dynamics Extraction (PDX): The PDX method implemented by GE PhasorPoint fits PMU measurements into autoregressive models to extract oscillatory components. For each oscillatory component, key characteristics- frequency, damping ratio, shape, and amplitude are determined. Sliding windows are used to obtain oscillation estimates- short windows are used to detect fast changes in damping ratio or amplitudes for alarming purposes; and longer windows are used to obtain reliable mode estimates. The oscillatory components may manifest due to either natural or forced oscillations, but the PDX method employs the same detection mechanism for any sustained oscillation.

Neither of the two detection methods discussed above directly distinguishes between forced and sustained (i.e. zero-damped) natural oscillations. Some organizations like Independent System Operator- New England (ISO-NE) are of the opinion that determining if an oscillation is natural or forced is not critical for practical operations, rather any sustained high-energy oscillation must be flagged. Field experience with ISO-NE's oscillation source localization tool (discussed in greater detail later in this chapter) indicates that an overwhelming majority of oscillations detected by the PhasorPoint tool within their footprint have been forced [Maslennikov and Litvinov, 2021]. Once a sustained oscillation is detected, its nature may be ascertained by inspecting features distinguishing natural and forced oscillations. For instance, FOs are usually accompanied by harmonics. Hence, low damping ratio estimates at one frequency and its odd harmonics are strong indicators of the presence of a FO. Similarly, as discussed in Chapter 5.0, under-damped natural oscillations tend to appear in a power system when it is stressed. Hence, correlating the appearance of oscillations with the presence of stress indicators like diverging phase angles at different network points, high power transfer across corridors, and component outages, can also help determine if the oscillation is likely to be natural.

6.1.2 Source Localization

After the detection of a FO, locating its source in a timely manner is important for maintaining reliable operations. However, this may be challenging as PMU coverage may not extend throughout a system. Hence, supplementing information from SCADA systems and coordinating with plant operators and neighboring system operators is required once the general location of an oscillation's source is determined from PMU data.

Determining the source of a wide-area FO can be more difficult than that of a local one. For instance, consider the example in Fig. 39. The trapezoids with the four bands indicate the presence (orange) or absence (green) of oscillations in the corresponding frequency band. In the example shown, one location shows the presence of an oscillation in band 3. Hence, the source is likely to be connected to the measurement location, or in its immediate vicinity. The visual display thereby provides a starting point for system operators' investigations, helping identify the equipment introducing oscillations.

In FOs that are detected at multiple locations, investigations need to be more involved, as highest oscillation amplitudes are not necessarily recorded at the source location. For example, in the January 2019 oscillation in the US Eastern Interconnection, system operators could not determine the FO source until well after the oscillation had stopped [NERC, 2019]. A popular source localization algorithm utilizes the flow of dissipating energy in the grid [Maslennikov and Litvinov, 2021].

In the dissipating energy flow (DEF) method, the transient energy is calculated using measurements of frequency, voltage magnitude, active power, and reactive power provided by PMUs. The energy is traced through the power network back to the equipment injecting the oscillation. The source equipment will have the dissipating energy flowing out of it. An illustration of the methodology is shown in Fig. 40. Of course, adequate PMU coverage and good data quality are essential for good performance of this method. The oscillation detection module implemented at ISO-NE uses the DEF method.

6.1.3 Mitigation

Once the source of an oscillation is determined, mitigation actions can be taken. Although any oscillation can be symptomatic of equipment failures, reliability coordinators in the US generally

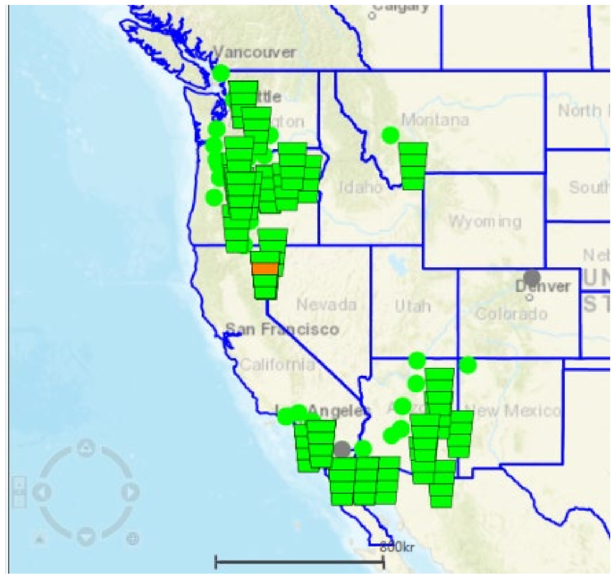

Figure 39. Example of a local forced oscillation [NERC SMWG, 2021]

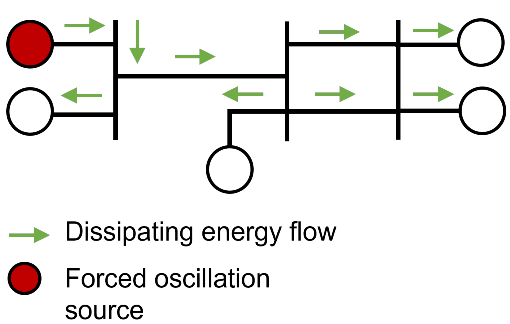

Figure 40. Schematic illustration of the DEF method for oscillation source localization. Image adapted from [Biswas et al., 2023].

use oscillation amplitudes as indicators of threat to system reliability. Similarly, FOs that are visible in the footprints of multiple organizations are considered concerning. If the source has been identified, disconnecting it or changing operating points can be effective in eliminating the oscillations. If the FO frequency is close to that of a system node, then system operators may choose to reduce system stress and increase the damping of the mode (by reducing power transfer over interfaces, redispatching, using damping controllers etc.). Although a majority of FOs are caused by equipment not functioning as desired, oscillations can also be introduced by cyclic loads for operating as designed. There is evidence of organizations operating their systems with such loads causing low amplitude oscillations without having major reliability issues [Eto et al., 2022]. Organizational knowledge about system characteristics is critical to understand how to appropriately respond to such instances.

6.2 NERC Standards

At present, although NERC and the industry recognize the reliability threats posed by FOs, no unified standards exist to dictate how to respond to these oscillations. Reliability coordinators formulate their operating procedures based on institutional knowledge and shared best practices. Coordinated efforts are made by NERC to conduct post-event investigations after major wide-area oscillations and publish findings for the benefit of the industry [NERC, 2019]. Moreover, reference documents and reliability guidelines for oscillation analysis and mitigation practices have been published [NERC SMWG, 2021, NERC, 2017]. The NERC Synchronized Measurement Working Group (SMWG) maintains an oscillation reporting template[4] to encourage the industry to report major oscillations observed in their footprints with the objective of sharing lessons learned.

6.3 Control Room Displays

Commercial wide-area monitoring solutions like EPG's RTDMS, GE's Phasorpoint, and SEL's Synchrowave Operations offer oscillation detection modules with visualization dashboards. A prevalent display strategy overlays visual indicators on the map of an entity's footprint. The indicators are divided into the four frequency bands listed in Table 2, which are green when no oscillations are detected at the corresponding location. The indicators issue visual alarms by turning orange or red (depending on severity) to indicate elevated oscillation energy. An example of the visualization dashboard used by RC-West, the reliability coordinator in California in the US Western Interconnection (WI), is shown in Fig. 39. RC-West uses EPG's RTDMS software, and the figure shows a local oscillation in band 3 as the indicator at only one location is observed to be orange. The RTDMS software has also been used in the FO display implemented by PJM Interconnection in the US Eastern Interconnection (EI), as shown in Fig. 41. Fig. 43 shows an example of the disturbance detector dashboard in SEL's Synchrowave Operations that has been designed for monitoring a wide range of oscillations and disturbances, including forced oscillations, using statistic-based methods.

Another example from the display used by BPA's in-house oscillation detection module, which uses the RMS-energy method discussed previously, is shown in Fig. 42. The layout is similar to RC-West's visualization, and the case shows a severe FO that was detected at multiple measurement locations.

[4] https://www.nerc.com/comm/RSTC/SMWG/SMWG%20Oscillation%20Reporting%20Document.pdf

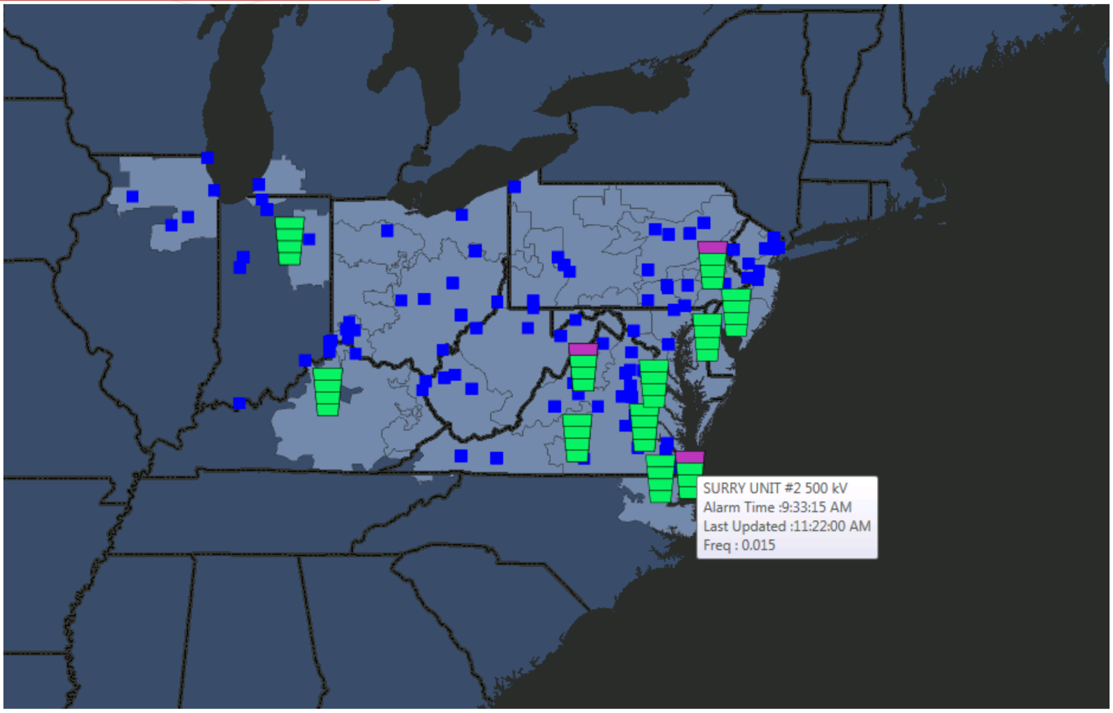

Figure 41. Forced oscillation display in PJM Interconnection showing a band 1 oscillation detected at multiple locations. Blue squares show PMU locations. Image courtesy: PJM.

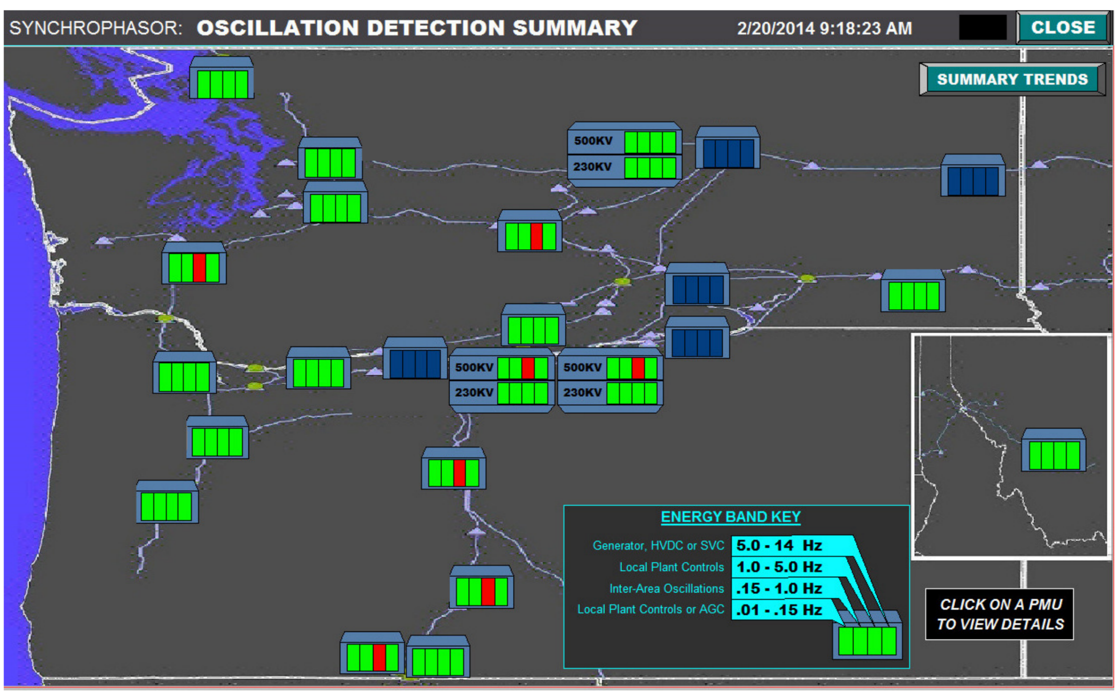

Figure 42. Forced oscillation detection application visualization platform implemented by Bonneville Power Administration (BPA) [Kosterev et al., 2016].

Figure 43. Disturbance detector dashboard in SEL's Synchrowave showing a forced oscillation [Cassiadoro, 2021]

6.4 Alarming Methodologies

To avoid nuisance alarms while ensuring the accuracy of detection, a two-tier alarming scheme has been proposed for the RMS-energy-based detection approach discussed in Section 6.1.1 [NERC SMWG, 2021]. The alarming scheme is illustrated in Table 3. More severe oscillations (i.e. oscillations with high amplitudes) are expected to result in a higher increase in energy in the corresponding frequency band. Alarming thresholds for each band must be set individually by analyzing historical data. These thresholds must also be validated periodically.

Table 3. Example criteria for setting alarm thresholds [NERC SMWG, 2021]

Alarm level	**Alarm threshold**
Level-1 (less severe)	Mean energy of ambient dataset + (3 × standard deviation of ambient dataset)
Level-2 (severe)	Mean energy of ambient dataset + (4 × standard deviation of ambient dataset)

In the PDX method, alarm thresholds are set looking at mode amplitudes and damping ratios. Alarms are issued when the damping ratio and amplitude estimates for a particular oscillation are respectively lower and higher than predetermined thresholds. A simulation example is shown in Fig. 44. Here, a 0.5 Hz FO has been injected from the Douglas substation. As visible from the mode estimates on the left panel of the figure, low damping estimates are observed near 0.5, 1, and 1.5 Hz. An alarm is issued for the 0.5 Hz component as both its damping and amplitude violate set thresholds. Amplitudes at the harmonic frequencies do not cross amplitude thresholds

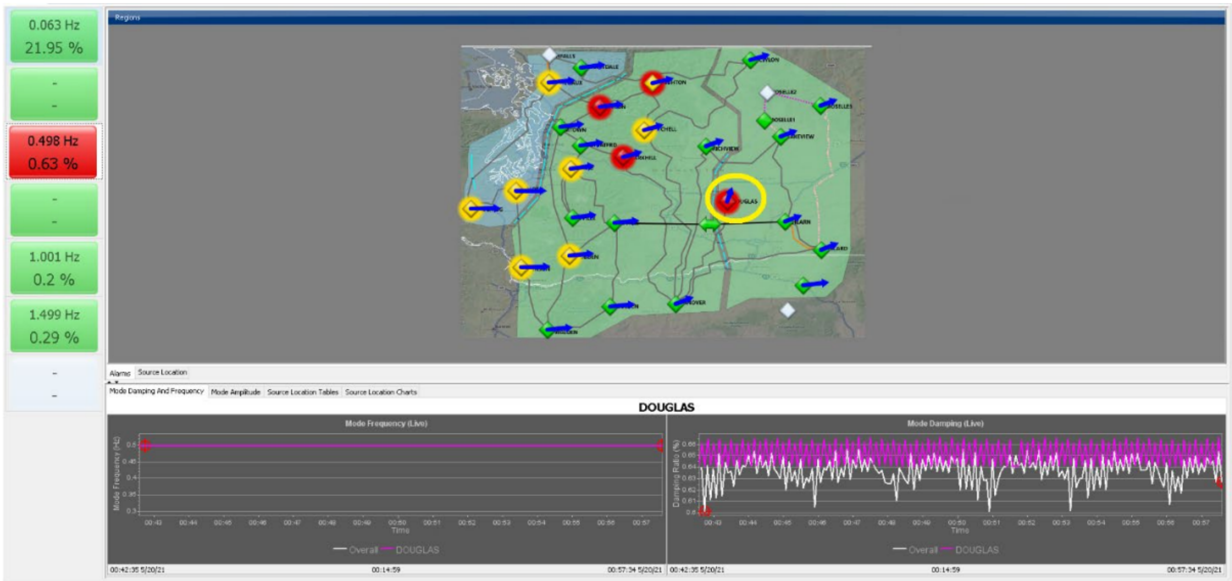

Figure 44. Detection an oscillation and alarm triggering using the PDX method [NERC SMWG, 2021]

and hence do not trigger alarms even at near-zero damping estimates. However, the presence of the harmonics helps ascertain that the detected oscillation is forced.

The display platforms discussed in Section 6.3 provide visual alarms to inform operator actions. If an alarm is received from a PMU in only one location, then the oscillation is expected to be local and operators can contact local plant operators to coordinate the investigation to identify the equipment causing the disturbance. If, on the other hand, alarms are noticed from multiple locations, then it is likely to be a wide-area oscillation needing coordination with neighboring transmission operators and reliability coordinators. In these cases, as the investigation for the source is going on, operators may also choose to take proactive actions to bolster system strength by inserting series capacitors, energizing out-of-service lines, redispatching generation, curtailing power transfers, etc. Adequate operator training is needed for control room operators to be able to correctly address oscillation alarms. Organizations like BPA, SPP, and RC West have invested in rigorous training modules for their control room operators. The legends for oscillation in different frequency bands (as visible in Fig. 42) also provides operators a starting point for their investigations.

Automated oscillation source localization (OSL) modules have also been implemented in organizations like ISO-NE (Fig. 45). ISO-NE's OSL module has been implemented in the field for several years and has processed thousands of oscillation events, an overwhelming majority of which have been forced. The ISO-NE OSL module does not attempt to distinguish forced oscillations from natural ones, and used the DEF method to identify the source. The OSL module identifies the plant causing oscillations if it is located within ISO-NE's footprint. Otherwise, the module indicates that the oscillation originated outside ISO-NE's territory. Automated emails are generated (an instance is shown in Fig. 34 in Section 5.0) by the OSL module.

Another example of an email notification generated once oscillations are detected by Oklahoma Gas & Electric's (OGE) oscillation detection module is shown in Fig. 46 .

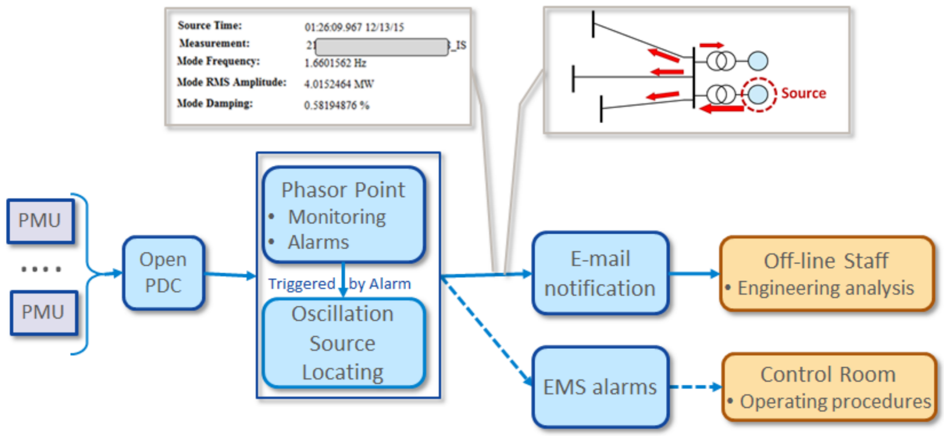

Figure 45. Oscillation management process in ISO-New England [NERC, 2017].

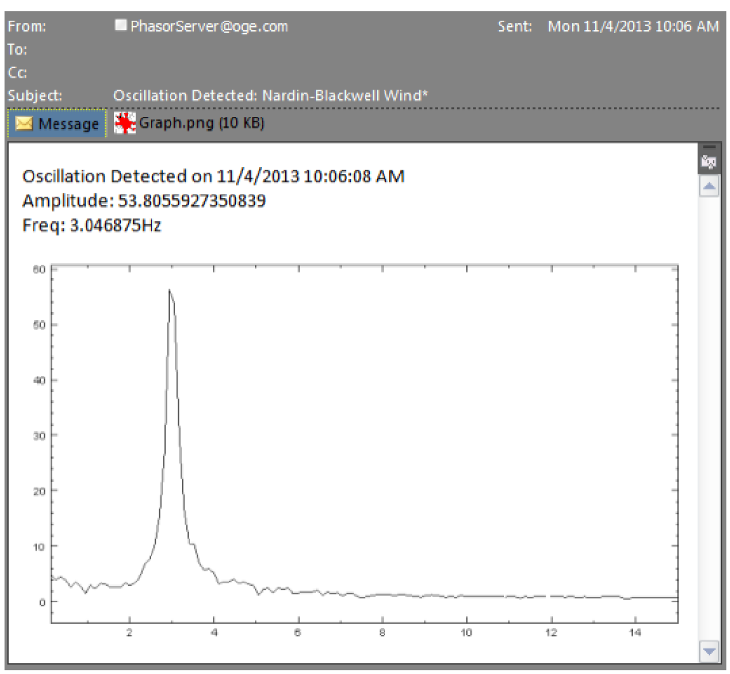

Figure 46. Email notification generated by Oklahoma Gas & Electric's (OGE) oscillation detection module [NERC, 2017]

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Pacific Northwest National Laboratory

902 Battelle Boulevard
P.O. Box 999
Richland, WA 99352
1-888-375-PNNL (7675)

www.pnnl.gov