Multi-Range Signal Oscillation Detection – Concepts and Applications

Mark Adamiak Zhiying Zhang Ilia Voloh
GE Grid Solutions

Abstract

Oscillations on the power system represent an exchange of real or reactive power between entities on the grid or quantities induced onto the grid or as the result of a resonance. Due to the electromechanical make-up of the grid, oscillations have existed from the beginning power system time. In the beginning, the primary source of oscillations was machine-to-machine hunting – resulting in what is known today as Inter-Area Oscillations. As the power system has grown and expanded into new realms, the sources and frequencies of oscillations have expanded. This paper identifies a set of ranges of sub-synchronous oscillations, introduces a new measurement technique for these oscillations, and identifies possible mitigation strategies.

Oscillation Definition

Oscillations can be characterized by:

- Frequency
- Magnitude
- Synchro Angle
- Damping constant

In the example in figure 1, one can see examples of both Positively (Figure 1a) and Negatively (Figure 1b) damped oscillations. The August 10, 1996 Western US system breakup has been attributed to negatively damped electromechanical oscillations on the grid[3].

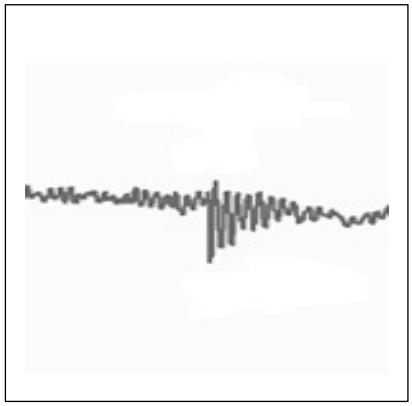

Figure 1a
Positively Damped Oscillation

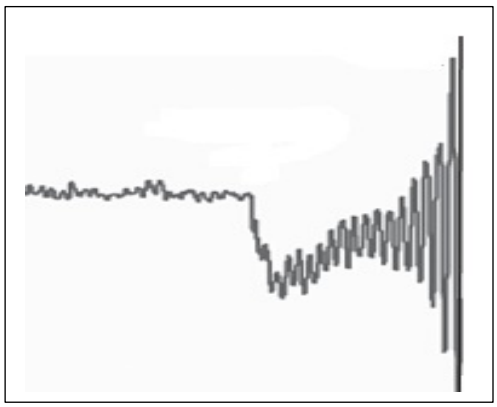

Figure 1b
Negatively Damped Oscillation

Sources and Ranges of Oscillations

Oscillations in power system are caused by the interaction of different power system components with each other, usually happening after system disturbances and system re-configuration. A new class of oscillations termed Forced Oscillations has been identified by NERC. Forced oscillations are driven by external inputs to the power system and can occur at any frequency.

Oscillations can be classified by certain types, with each type exhibiting a certain range of the oscillation frequency when this phenomenon occurs. These major types are as follows:

- Local plant mode oscillations- happen when some generators are oscillating against the rest of the power system with a characteristic frequency of 1-2Hz

- Inter-area mode oscillations happen when generators in the one part of the system are oscillating against other generators in another part of the system. Characteristic frequency of inter-area oscillations is 0.1Hz to 1Hz.

- Torsional mode oscillations- happen due to interaction of the turbine-generator mechanical system and with a system, connected through the series-compensated line. Characteristic frequency of interarea oscillations is 10Hz to 46Hz.

- Control mode oscillations - happen due to poorly tuned exciters, governors, HVDC converters, Static Var Compensators, large wind farm connections to the system. Frequencies here range from 1 to 15 Hz

The following taxonomy of ranges of oscillations on the power grid are proposed:

a. DC to .05 Hz – this range is designed to capture the "almost" DC component of Geomagnetically Induced Currents (GIC). GIC currents result from the coupling of solar storm particles with power lines. Note that DC Coupled current and voltage sources are available as inputs to oscillation calculations

b. .05Hz to 0.1Hz – this is the expanded GIC range

c. 0.1Hz to 1.0Hz – this range captures the inter-area oscillations

d. 1.0 to 10Hz – this is the "new" range identified by NERC as the Forced Oscillation[1] range

e. 10 Hz to 55 Hz – this range is known as the Sub Synchronous Oscillation range – typically resulting from resonance of series capacitors with the power system. Forced oscillations can also occur in the lower end (10 to 15 Hz) of this range

Detection and quantification of Oscillations

Oscillations appear on the grid as a modulation of the fundamental frequency voltage and current signals – much like an AM Radio transmission. Often time, voltages and currents are integrated in a device and combined to create sequence components (phasors), and real and imaginary power values.

When fundamental frequency values are converted to power, the resulting values is typically a straight line (as shown in figures 1a and 1b).

There are several mechanisms that have been used in the industry for the extraction of oscillations[2,3] - many of which use Synchrophasors. Although Synchrophasor analysis can roughly identify oscillation modes, it does take an appropriately sized window (based on the oscillation frequency of interest) to capture the data needed for analysis – which adds latency to the calculation. Additionally, Synchrophasors cannot be used for high-frequency analysis – especially for oscillation frequencies greater than 30 Hz due to the window size of the Synchrophasor. Of note, for P-Class Synchrophasors have a 2 cycle integration window which limits them to oscillation measurements of less than 15 Hz; M-Class Synchrophasors have up to an 11 cycle window which limits them to oscillation measurements of less than 3 Hz.

A new approach for the extraction of oscillation information is proposed – one that uses RMS signals such as Voltage, Current, and Power for lower frequency signals and the signal sample data for the extraction of the higher-order frequencies from 10 to 55 Hz. On lower frequency signals, High Pass (to remove DC components) and Low Pass (for smoothing) filters are applied to the input signal. On higher frequency signals (10 Hz to 55 Hz), a digital filter bandpass filter can be applied to the ***sample data*** to remove the fundamental frequency component of the samples – leaving the raw oscillation signal (see figure 2 – red trace). The resulting oscillation signal can then be analyzed in the same manner as combined signals which is by passing the resulting oscillation waveform through digital High and Low Pass filter resulting in the BLUE trace in the middle graph in figure 2. From this signal, the frequency and magnitude of the oscillation can be computed.

This algorithm enables high-speed of identification of an oscillation. In the bottom graph in figure 2, we see the green trace which is labeled as the Validation Flag. For a 10 Hz oscillation (which has a period of 100ms), it can be seen that the Validation Flag is set in about 53ms – about half the period of the oscillation.

The computed magnitude from the Discrete Fourier Transform (DFT) of the oscillation can be checked against absolute limits or it can be compared to an Inverse Time curve such that larger magnitude oscillations can result in an output quicker and lower magnitude oscillations can take longer to respond.

A given oscillation can have 3 different decay modes, namely: Positively Damped (the oscillation is diminishing), Undamped (neither growing or diminishing), and Negatively Damped (the magnitude of the oscillation is increasing). Most oscillations on the grid are damped, meaning that as time goes on, the oscillation lessens in magnitude – as in figure 1a. An negatively-damped oscillation is just the opposite wherein the oscillation grows in magnitude over time as in figure 1b; an undamped oscillation is where the oscillation neither decreases nor increases over time.

The oscillation signal can be modeled by equation 1:

$$y(t) = \sqrt{2}A(1 + m \cdot e^{\sigma(t-t_0)} \cdot \sin(\omega_m(t - t_0)) \cdot u(t_0)) \cdot \sin(2\pi f_1 t) \qquad \text{Eq 1}$$

Where A is the magnitude of the sinusoidal signal, f_1 is the system frequency, ω_m is the angular frequency of the modulating signal (this is the oscillation frequency that will be estimated), m is the magnitude of the modulating signal (in fraction of magnitude A, note that “m” is the oscillation

magnitude to be estimated), σ is the exponential growth (or decay) rate of the modulating signal, u(t) is the step function, i.e. when $t>t_0$, the oscillation starts.

The damping ratio of this oscillation signal is defined as (Eq 2):

$$\xi = \frac{-\sigma}{\sqrt{\sigma^2 + \omega_m{}^2}} \qquad \text{Eq 2}$$

When σ is a negative number, the damping ratio is positive which means that the oscillation is damped, i.e. the oscillation magnitude will get smaller and smaller with time; when σ is a positive number, the damping ratio is negative which means that the oscillation is negatively-damped, i.e. the oscillation magnitude will get larger with time.

Synchro Oscillation Angle

Similar to fundamental frequency signals, an oscillation signal has a Synchrophasor – which is the Magnitude and the Angle of the oscillation at the oscillation frequency. The computation of the Synchro Oscillation phasor is possible since the sample values used in the oscillation analysis are time stamped to absolute time. Of significance is the fact that the Synchro Oscillation Angle can be used to identify "groups" of generators that are oscillating with other "groups" of generators. The identification of which groups of generators are oscillating with which other groups of generators can then be used to damp inter-area oscillations. One can visualize this concept through the analogy of a see-saw. At any instant in time, when one end is up, the other end is down. The Synchro Oscillation Angle can be visualized as the angle between a measurement at each power plant and some reference point (which is the horizontal axis in figure 4).

In the implementation proposed above, in as much as the processed signals are passed through digital filters, without removal of the phase shifts resulting from these filters, the Synchro Angle will only align on devices with similar digital filters.

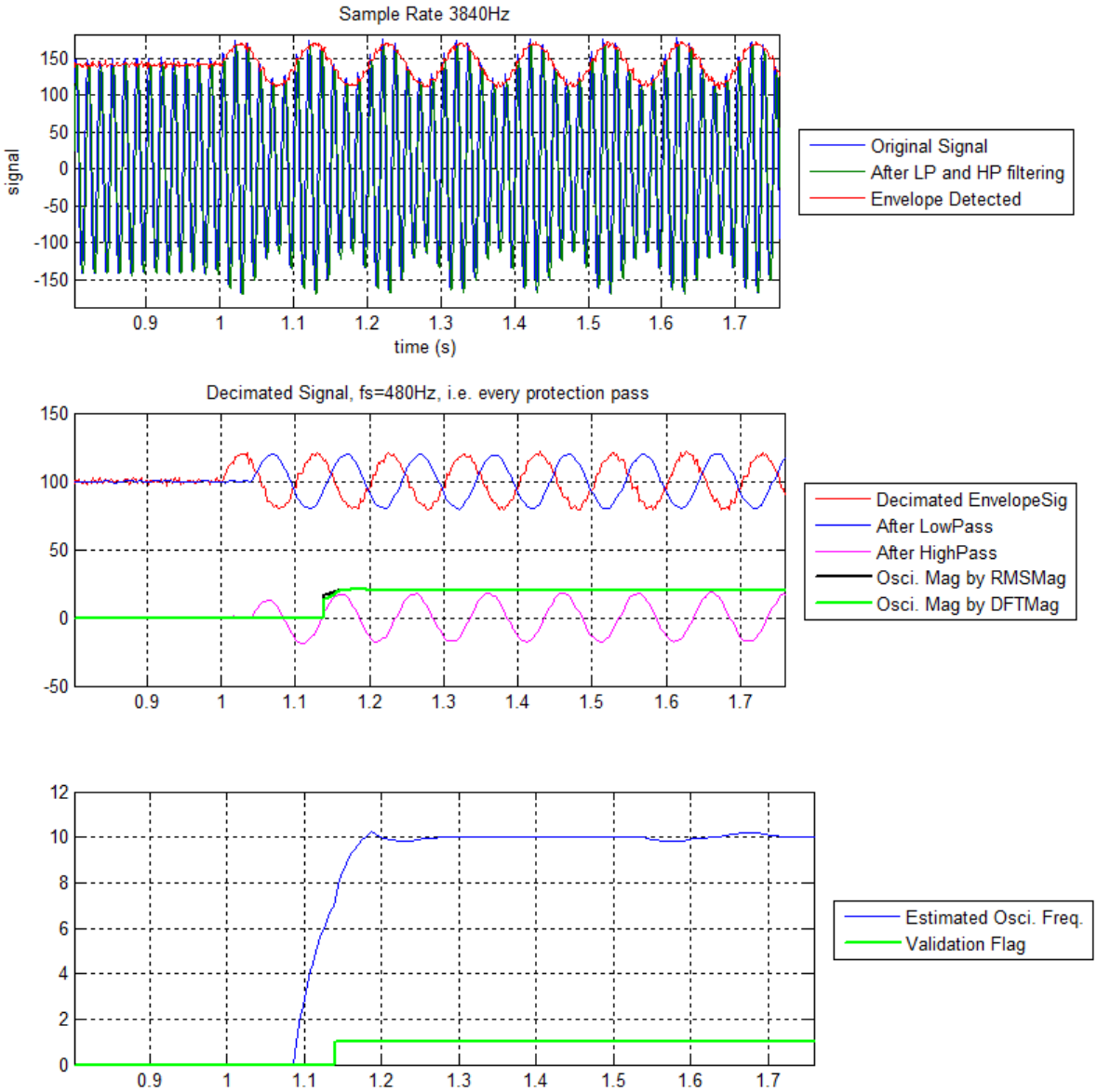

Figure 2
Demodulation Process, Frequency Detection, and Oscillation Validation of a 10 Hz Oscillation

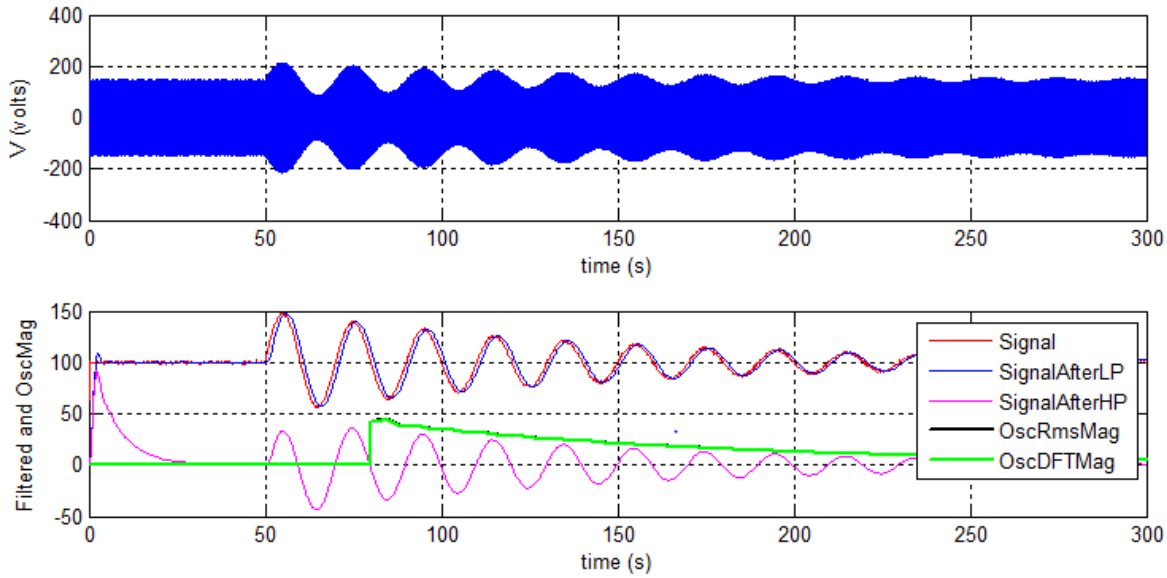

Figure 3
Positively Damped .05Hz Oscillation

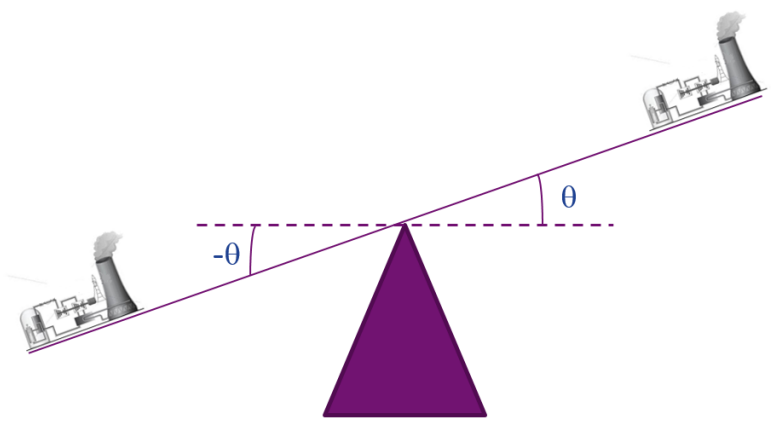

Figure 4
Synchro Oscillation Angle Visualization

Application of Oscillation Detection

The application of oscillation information can take two paths in the power system, namely, situational awareness and Remedial Action. For situational awareness, the information from the various oscillation bands (frequency, magnitude, damping constant, synchro oscillation angle) at all locations on the grid can be mapped into a SCADA system via protocols such as Modbus, DNP, IEC 60870, and IEC 61850 and

then mapped into Energy Management System displays as appropriate. One example would be showing a moving "power" bar between nodes or regions in a display to indicate power flows during inter-area oscillations. Operators viewing this information could act – via changes in power dispatch – to damp the power exchange. Additionally, identification of Geomagnetically Induced Current in a transformer could allow an operator to unload a transformer. One note – the IEC 61850 models for single frequency oscillations need to be defined and incorporated in the standard. An array of oscillations frequencies as one might get from an Fast Fourier Transform can be accommodated today but the semantics would not include features such as damping.

For faster reporting / response times, oscillation data can be included in a Synchrophasor stream – which can then be communicated at rates up to 120 messages per second. Mapping the data into a GOOSE/Routable-GOOSE message is another possibility and any changes detected by the oscillation detection process would initiate a launch of a GOOSE message.

Many times, such as during an unstable oscillation, there is little time for the operator to act. During these time, the result of an oscillation in a system can be configured to result in automatic action. An example of this is forced oscillations which occur in areas where there are high concentrations of inverter-based interfaces (i.e. – wind farms) which are interfaced to transmission lines. Resonance conditions have been observed between the inverter-based generation and series capacitors on the transmission line. An oscillation monitoring system could, upon detection of a specific frequency range and oscillation magnitude, dynamically implement controls such as bypassing of the series capacitor.

Conclusions

Oscillations exist on the grid due to the electromechanical nature of the electric power grid as well as forced from external controls. In general, these oscillations are well damped and not an issue. High-energy oscillations can be unstable and do need to be mitigated before they can result ins system instabilities. Today's digital sampling technologies are capable of detecting such oscillations and instabilities, reporting them for situational awareness, and are able to take immediate remedial actions to mitigate effects from the oscillations.

References

1. NERC Reliability Guideline – Forced Oscillation Monitoring and Mitigation – 2017 Draft

2. Oscillation Detection; NASPI.ORG; https://www.naspi.org/sites/default/files/reference_documents/crstt_oscillation_detection_20180129_final.pdf

3. Oscillation Detection Algorithm Development Summary Report and Test Plan; PNNL-18945; https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-18945.pdf

4. The Electric Power Engineering Handbook; Edited by L.L. Grigsby; IEEE Press