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Webinar Questions and Answers

"Let's Talk About Synchrophasors, PMUs & Applications" with Evangelos Farantatos

What are the differences between localized and centralized data concentrators?
Answer: A phasor data concentrator (PDC) can be hardware or software. Localized vs Centralized data concentrators can be categorized based on a) physical location and b) organization collecting the data. A local data concentrator is typically a hardware PDC installed at a substation collecting measurements from that substation PMUs. Typically, utilities/transmission owners (TOs) have a centralized PDC to collect measurements from all the PMUs/PDCs of their substations. This is typically software PDC and the measurements are collected at a central location, such as a control center. Similarly, RTOs/ISOs have a centralized PDC (typically software) to collect PMU measurements from the PDCs of their TOs.

At what rate the PMU installations are growing and what is the expected growth rate for next 3-5 years?
Answer: Calculating the PMU installation growth rate would need an analysis, survey utilities and collect the number of PMUs they have installed the last few years, as well as their plans for future installations. We are seeing a growing trend, with some utilities expanding their deployments to more substations in their footprint and a few new utilities installing PMUs, but likely the rate is slower compared to a few years ago.

What are the typical distances between adjacent PMUs? Also, are they useful for distribution system state estimation?
Answer: PMUs are installed at high voltage transmission/sub-transmission substations, so their distance depends on the distance between the substations.

PMUs installed at the distribution system (also referred to as microPMUs) can be used for distribution state estimation. For example, ComEd is exploring the use of microPMUs for Distribution Linear State Estimation (DLSE)

PMU placement strategies vary among utilities. Typically, the objective is to select the location and number of PMUs to be installed, such that to ensure maximum benefit across multiple applications whilst being most economical by leveraging existing and planned infrastructure upgrades. Different PMU applications impose their own set of requirements on the number and location of PMUs, so the placement is driven by the intended end-user applications. For example, a wide area situational

awareness scheme would require as many PMUs a possible at the utility's footprint to achieve full observability. On the other hand, for a generator model validation application, one PMU at the POI of the generator of interest would be sufficient.

How LSE improves the regular State Estimator? When PMUs are incorporated into the regular State Estimation, how the timing is addressed so the SCADA data and PMU data are in synched.
Answer: LSE is a state estimator (SE) itself that uses only PMU measurements. PMU measurements can be incorporated into conventional state estimator. That leads to a Hybrid SE. For a Hybrid SE the expected improvement is due to additional measurements of voltage and current phase angles (SCADA does not include phase angle measurements). The main challenge for a Hybrid SE is the timing differences between SCADA and PMU measurements. PMU measurements are timed tagged based on GPS synchronization. SCADA are time tagged based on EMS clock. Resolution is also different. Typically a Hybrid SE executes as often as a conventional SE (e.g. 1 min), and the latest set of PMU measurements is used along with SCADA measurements. So basically, the high-resolution of PMU measurements is not leveraged.

Can the source of oscillation be detected using PMUs?
Answer: Yes. But observability is a key aspect. It is preferable to have PMUs close to the source for higher accuracy. For example, at the January 2019 event, ISO-NE's source location algorithm pointed that the source was outside ISO-NE's footprint, and that it was in the south, but ISO-NE doesn't have observability of PMUs in Florida to point to the exact location.

What is the frequency range for known and suspected solar/wind caused oscillations?
Answer: It is typically higher than 5Hz.
The following reference reports solar PV oscillations around 7Hz: "Deploying Utility-Scale PV Power Plants in Weak Grids", First Solar, 2017 PES General Meeting, Chicago, IL, July 2017

The following reference reports oscillations around 25hz due to resonance between wind farms and adjacent series capacitors: "Simulation of 2017 wind farms into series capacitor sub-synchronous oscillation events," R. O'Keefe, E. Rezaei, K. Andiv and Y. Gong, in CIGRE US National Committee - Grid of the Future, 2018,

Can you elaborate on the use cases how PMUs are used to analyze the impact from IBR based resources, e.g. wind and solar?
Answer: PMUs can be used to analyze events due to IBRs. They can be also used to perform validation/calibration of IBR models. In operations environment PMUs can capture sub-synchronous oscillations caused by IBRs. However, IBRs could create fast grid transients or dynamics that PMUs may not capture due to their filtering and relative slow resolution with respect to point-on-wave data.

Are there any free software tools available for testing/learning PMU applications?
Answer: US National Labs, especially PNNL have developed various open source PMU application tools, such as FRAT.

NASPI also started an initiative a few years ago to create a repository for open source PMU applications. Some tools have been uploaded at the following link: https://www.naspi.org/node/484

ISO-NE provides free of charge their offline version of Oscillation Source Locating application.

Also, some academic books such as “Power System Dynamics and Stability: With Synchrophasor Measurement and Power System Toolbox, 2nd Edition by Peter W. Sauer, M. A. Pai, Joe H. Chow” have examples (with the source code and actual data) on using synchrophasors.

Can you explain how PMUs are used for event analysis?
Answer: Upon an event, PMU measurements can be collected and synthesized to analyze the event, i.e. identify time of the event, location, type (e.g. line, generator trip, fault etc.), and analyze response of protection system. Time alignment based on the measurements synchronized time tags are extremely helpful in this process. For example, PMU data was instrumental for investigation of Aug. 1996, Aug 2003 blackouts, and Jan. 2019 oscillations.

OpenPMU is able to produce synchronized point-on-wave measurements. What are the format / presentation requirements needed to make this data useful on a mass scale?
Answer: Use cases and value of point-on-wave measurements compared to synchrophasors is a topic of growing interest and discussions in the industry, and in particular at NASPI. Consensus is that the expected value is in relation to inverter-based resources due to the fast dynamics/transients they may introduce to the grid, which may be not captured by synchrophasors.

Can you tell something more about instrumentation channel error? Is that concern if we know that its error is 10 times fold PMU measurement error? Should it be concern or just we can behave like this is general error in power system which is then kind of self-corrective?
Answer: Instrumentation channel errors is something that needs to be considered in PMU applications that require high measurement accuracy. If the instrumentation channel is modeled and considered in the PMU application, any errors can be compensated for. For example, Georgia Tech (Prof. Sakis Meliopoulos) has proposed substation level state estimation that includes modeling of instrumentation channels. Also, NASPI’s Performance Requirements, Standards, & Verification Task Team (PRSVTT) is addressing this topic.

Is there any PMU data available for test?
Answer: In the US, PMU measurements are considered Critical Energy Infrastructure Information (CEII), and one typically needs an NDA or another type of confidentiality agreement to obtain them.

Do the current standards for PMU accuracy requirements support Point on Wave requirements (or synchronized sampled value measurements)?
Answer: The Streaming Telemetry Transport Protocol (STTP) developed under the Department of Energy’s (DOE) Advanced Synchrophasor Protocol (ASP) Development and Demonstration Project DE-OE0000859 supports Point on Wave (or synchronized sampled value) measurements