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Integrating Synchrophasor Technology into Power System Protection Applications

Task Force on Synchrophasor Protection Applications

NASPI Engineering Analysis Task Team

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Acknowledgments

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Executive Summary

System protection for the bulk power system entails the use of hardware, software, planning rules and standards to prevent cascading outages, protect power grid equipment and maintain system reliability. To date, system protection has primarily relied upon protective relaying, used within substation or local area communication-assisted systems.

The goal of this report is to analyze the current potential for using synchrophasors for protection system applications. The report first reviews the current state of PMU data collection and transmission and compares that with the current data collection standards of protective relay systems. Second, the report offers a general analysis of current protection schemes and whether and how each could use synchrophasor data. The report addresses:

- Analysis of protection system data and processing timing as compared to PMU data collection timing to determine where and how protection systems can benefit from the use of synchrophasor data,
- The data quality requirements for relay or PMU data used in power system protection schemes,
- A review of protection system applications and how PMUs can be applied.
- An analysis of current research into synchrophasor data obstacles such as latency and security, and,
- Findings from an industry survey regarding how electric utilities, the research and development community, and software and hardware vendors see the use of and opportunity for synchrophasor technology to enhance protection systems.

A 2015 survey revealed that off-line monitoring, event analysis and fault analysis are the most widely used industry uses of synchrophasor technology for system protection today. Those using PMU data for real-time monitoring are focused on real-time warnings, alarms, and oscillation detection. Protection applications that are expected to grow with time and experience include system protection configuration, determining real-time transmission line impedance, and creating real-time monitoring and adjustment of system safety nets. The long-term protection goal is to create both local and regional automated control and protection schemes that are actuated by real-time PMU measurements.

The report concludes that power system protection can be enhanced with synchrophasor technology, starting with the use of PMU data for substation-level element protection schemes (where data can be delivered on local, dedicated lines, avoiding potential network latency problems). The next step is to ask whether the timing and quality of PMU data equal that of existing protection systems, and whether there is potential benefit to having PMU-based protection supplement relay-based protection measures. In-depth experimental trials of parallel PMU-based and relay-based protection systems should be conducted to determine the true benefits, if any, of synchrophasor-based protection.

The other immediate opportunity for synchrophasor use in system protection is to use PMU data to monitor and review every system protection operation, to determine whether each operation occurred as it should have, diagnose any misoperations, and identify potential problems before they cause transmission events.

1.0 Introduction

The goal of this report is to analyze the current potential for using synchrophasors for protection system applications. The report first reviews the current state of PMU data collection and transmission and compares that with the current data collection standards of protective relay systems. Second, the report offers a general analysis of current protection schemes and whether and how each could use synchrophasor data. The report addresses:

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- Findings from an industry survey regarding how electric utilities, the research and development community, and software and hardware vendors see the use of and opportunity for synchrophasor technology to enhance protection systems.

1.1 Protection systems versus synchrophasor network/data

System protection for the bulk power system entails the use of hardware, software, planning rules and standards to prevent cascading outages, protect power grid equipment and maintain system reliability. To date, system protection has primarily relied upon protective relaying, used within substation or local area communication-assisted systems. With the availability of high-quality, high-speed communications networks, protection-oriented relaying systems now span across Transmission, Distribution, and Generation. Recent power system performance standards have required expansion of protection systems to cover wider areas using Remedial Action Schemes (RAS) with multiple relay communication networks; these require highly accurate, reliable, real-time system-wide data.

System protection departments in utilities are responsible for developing and implementing protection schemes and programming power system relays to operate, trip and reclose high voltage equipment to isolate fault currents or mitigate potential system contingencies. The challenge is to balance protecting system equipment from damage while ensuring reliability by reducing outage duration.

Every protection scheme operates by examining a number of signals or devices that bound the region or device to be protected. For most protection functions (such as a distance function aligning voltages and currents, or a synchro-check function comparing voltages), all of those measurements from devices at different physical locations must be synchronized to an absolute time. Furthermore, most system protection schemes in use today are triggered based upon whether conditions at specific points on the grid reach pre-determined minimum or maximum levels – even though system topology changes constantly and those trigger levels may not be problematic for a wide range of dynamic system configurations. The benefit of using time-stamped PMU data is that it allows protection to be set based on actual grid stresses as measured by phase angles in real time, producing more appropriate protection operations,[1] and the time-stamped data can be time-aligned automatically for analysis.

There are three key questions in assessing the potential for using synchrophasor data in lieu of relay measurements for the information needed to determine whether to trigger and actuate a regular protection scheme:

1) Do PMU-collected data offer an advantage in terms of the types, measurement speed and accuracy of grid information collected, relative to current relay data used in existing protection systems?
2) Do current synchrophasor data networks move PMU data quickly enough to meet local or system protection timing requirements, or can dedicated PMU data transfer measures be established (much as there are dedicated data lines for many relay-based system protection schemes today)?
3) Where relays are connected to dedicated communications lines to execute a specific protection scheme, can those existing lines be used to deliver PMU data as well? This may be feasible particularly where the PMUs are not stand-alone devices, but relays that have been converted to exploit built-in PMU functionality. This could allow the time-stamped PMU data to supplement or replace the relay data in protection scheme assessments and execution.

The first question goes to whether PMU data measurement speeds (at 30 up to 120 samples per second) and calculations (such as phase angles) are more useful than relay measurements for particular types of protection schemes. This is clearly an application-dependent issue – some protection uses such as differential and distance protection need very fast grid condition measurements, while others can use directly calculated phase angles in the decision on whether to trigger the protective action. This question will be addressed in Section 2.

[1] O'Brien, J., A. Deronja, et al., "Use of Synchrophasor Measurements in Protective Relaying Applications," Power System Relaying committee, Report of Working Group C-14 of the System Protection Subcommittee, April 8, 2013, p. 5.

Protection PMUs

PMUs fall into two performance classes, as defined by IEEE standard C37.118-2014:

- “M” class PMUs require high precision for measurement or monitoring devices. These are better suited to capturing steady-state grid conditions.
- “P” class PMUs require fast response for protective devices, to capture dynamic system behavior. They sacrifice some measurement precision in pursuit of faster measurements; “P” class PMUs often do not have an anti-aliasing filter on the data acquisition stage.

Appendix B shows the detailed distinctions between the two types of devices, as specified under technical standard IEEE C.37.118-1a-2014.

1.2 PMU data delivery

The second question addresses whether the measured grid data can be delivered to the point of protection analysis and actuation fast enough to meet the protection system’s requirements. This question concerns both how quickly existing relay protection data reach the point of analysis and tripping, and whether PMU data can meet or exceed those speeds. To frame this issue, this report proposes that it will be worthwhile to study the speed of existing relay protection analog signal capture and logical tripping speeds, and the current speed of PMU analog signal capture and delivery. As an example of the first type of study, in 2013 Salt River Project analyzed the tripping times of two vendor relays for three types of protection systems: line protection, transformer protection and bus protection. The test set-up included:

1) Direct back-to-back fiber connections for relays requiring communication,
2) Analog signals provided in series between the two relays being tested (two tests, each with the vendor CT signals swapping spots in the series string),
3) Relay logic providing no additional delay in trip signals, and,
4) A third party measurement of timing results to prevent bias.

The results are shown in Table 1.

Table 1: Relay Trip Timing Tests

Line Relaying Distance	Test Number	Test Description	Time difference (cyc)	First to trip
	1A	Local distance test, Vendor 1 1st in CT string, Communication disabled	1.2	VENDOR 2
	1B	Local distance test, Vendor 2 1st in CT string, Communication disabled	1.34	VENDOR 2
Line Relaying Differential	2A	Differential test for Direct Transfer Trip, Vendor 1 1st in local CT string, Vendor 2 first in remote CT string	2.69	VENDOR 2
	2B	Differential test for Direct Transfer Trip, Vendor 2 1st in local CT string, Vendor 1 first in remote CT string	2.45	VENDOR 2
	3A	Differential test, Vendor 1 1st in local CT string, Vendor 2 first in remote CT string	0.144	VENDOR 1
	3B	Differential test, Vendor 2 1st in local CT string, Vendor 1 first in remote CT string	0.336	VENDOR 1
Transformer Relaying Differential	1A	Differential test, Vendor 1 1st on high side winding, Vendor 2 1st on low side winding	0.456	VENDOR 2
	1B	Differential test, Vendor 2 1st on high side winding, Vendor 1 1st on low side winding	0.456	VENDOR 2
	2A	Overcurrent test, Vendor 1 1st on high side winding, Vendor 2 1st on low side winding	0.528	VENDOR 1
	2B	Overcurrent test, Vendor 2 1st on high side winding, Vendor 1 1st on low side winding	0.528	VENDOR 1
Bus Relaying	1A	Differential test, Vendor 1 1st on first bus CT winding, Vendor 2 1st on second bus CT winding	0.096	VENDOR 1
	1B	Differential test, Vendor 2 1st on first bus CT winding, Vendor 1 1st on second bus CT winding	0.072	VENDOR 1

With the understanding of this type of timing data, PMUs can be tested for their analog input and data delivery speed to provide a comparison to understand the architecture required for a PMU-based protection network.

Current synchrophasor data networks have been designed principally to collect data from substation-based PMUs and deliver the data up to regional Phasor Data Concentrators (PDCs) for centralized wide-area monitoring and visualization and analysis. Most current PMU signal networks have three basic structures: PMU to PMU (Figure 1), PMU to PDC to PMU (Figure 2), and PMU to PDC to Central Logic Processor (Figure 3).

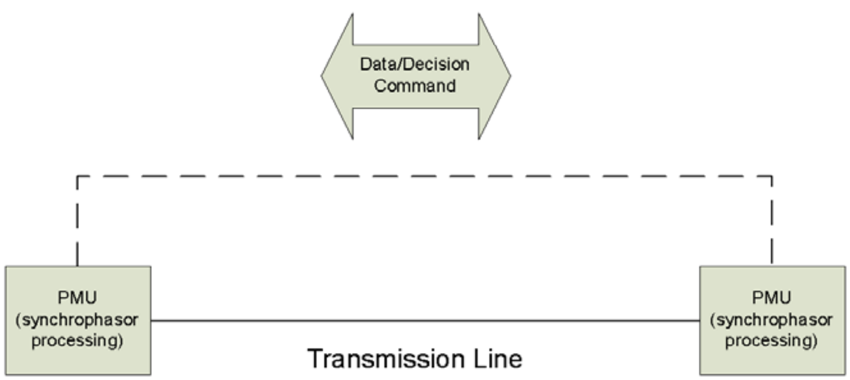


Figure 1: PMU to PMU Network Architecture

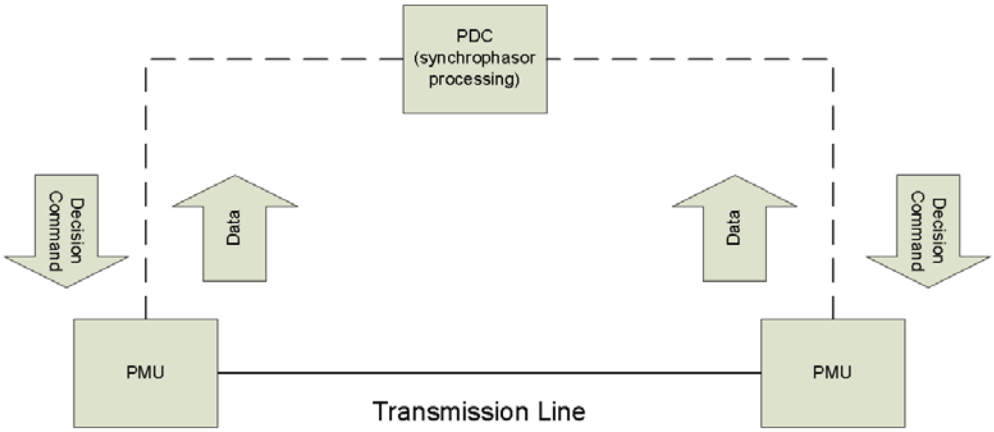


Figure 2: PMU to PDC to PMU Network Architecture

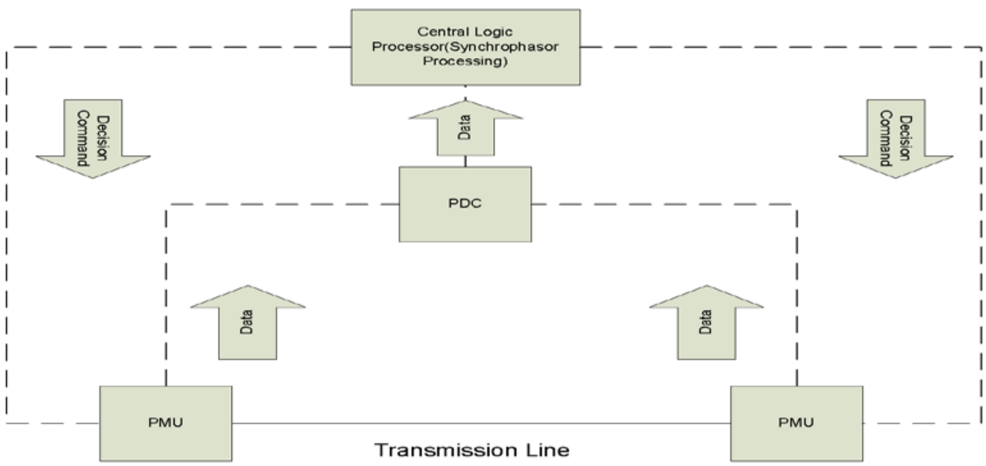


Figure 3: PMU to PDC to Central Logic Processor Network Architecture

It is within these sample synchrophasor network structures that the data capture and transmission rates of potential PMU protection systems should be analyzed. While the studies proposed above will prove the usability of synchrophasors for protection, the quality of the data as it travels through the network structure is of vital importance. For, if PMU data can be usable for protection, the effect on data quality as it passes through the mediums present in the network structure needs to be quantified and understood.

But at the same time, it is worth noting that current system protection schemes often incorporate dedicated communications lines to deliver relay data to the point of protection analysis and decision within the protection scheme's required timeline (as compared to only using the utility's SCADA or general data networks). It is therefore inappropriate to assume that PMU data cannot be used for system protection because the latency costs on the primary PMU communications path from the field PMU to the central PDC and back to the protection point are too high. It may be possible to build comparable dedicated data lines or to run PMU data across the existing protection system communications lines if there is a protection benefit to doing so.

2.0 Synchrophasors in Power System Protection

There is a growing body of research into the ways that synchrophasor technology can be used for system protection. Figure 4 provides a topical breakdown of the current research under way over the last five years, based on reports in IEEE and NASPI publications.[2]

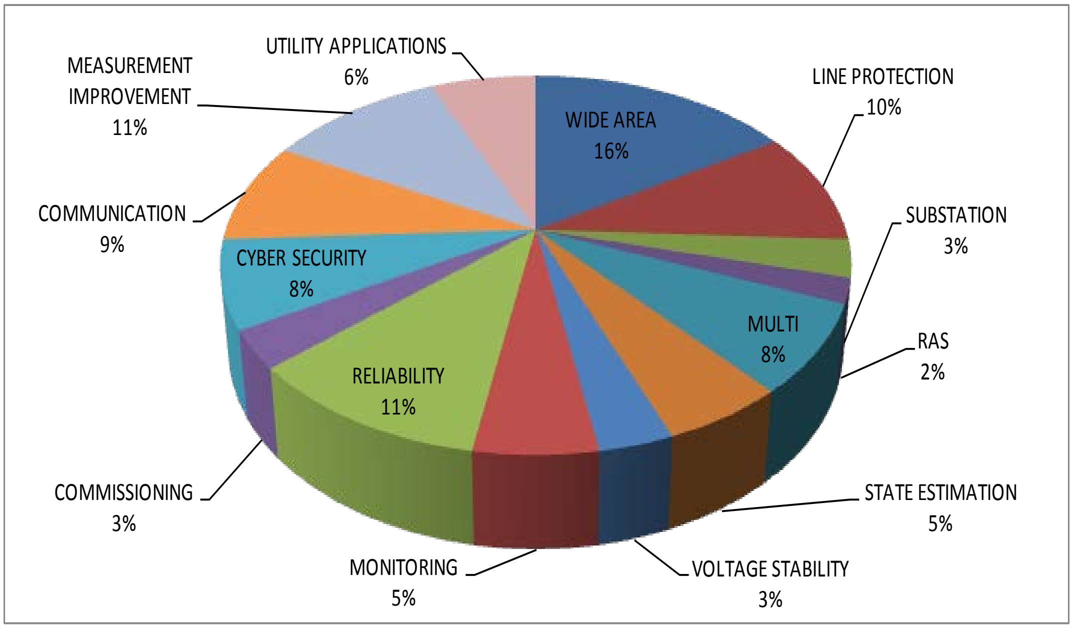


Figure 4: Synchrophasor Protection Research

The future of synchrophasors in power system protection systems starts with analyzing their potential for use in standard protection schemes. A simple explanation of these schemes and the current research and vendor solutions available offers a platform for future progress.

2.1 Asset Protection Schemes

Distance Protection

Every transmission line, as seen from one end, has a characteristic impedance that represents the line length based on Ohms law rearranged for impedance, Z=V/I. The calculated effective load impedance from a fault using fault current and pre-fault voltage is compared to the expected characteristic line impedance to determine fault location.

[2] Figure 4 data compiled by Matthew Rhodes from material posted on IEEE Explorer and www.NASPI.org from 2010 to 2015.

Distance relaying also allows for remote line backup protection by incorporating zones of protection. Zone 1 (Z1) is used for the local line protection and is usually set for 80% of the line length to allow for uncertainties in the actual line impedance. Zone 2 (Z2) is used to protect the next forward connected lines from the local relay on a time delay, usually set for 20 cycles, and is set to "see" the entire local line length and an additional percentage into the next line. By setting the impedance reach higher for this zone, overlapping protection can be accomplished between transmission lines. This same concept is applied to Zone 3 (Z3) protection to see two lines out. Figure 5 below displays this concept as the line relay at bus G protecting line XR can provide backup protection for a portion (typically 50%) of line YQ on time delay T2 in case the relay at bus H fails, and a portion (typically 10%) of line ZP on time delay T3 in case the relay at bus R fails.

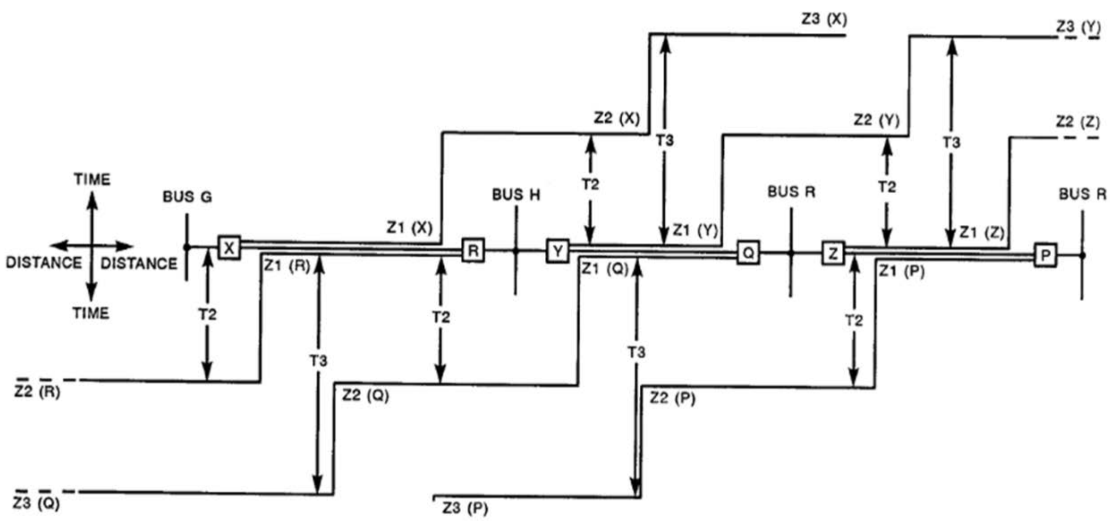


Figure 5: Step Distance Zone protection

Application of PMUs -- If multiple distance elements are implemented in various relays over a wide area, a multi-zone pilot-operated scheme could be developed incorporating PMU data from several PMUs. Implementing this type of scheme within relay logic is typically either too cumbersome or possibly unachievable without a dedicated remedial action scheme; however, the same scheme could be implemented on a synchrophasor-capable programmable logic controller (PLC) to perform the required protection computation and coordination actions. Current P-class PMU technology today does report phasor data at rates fast enough for coordinated backup line distance protection. The phasor calculation latency for protection-rated PMUs is shorter than the delayed pickup durations of typical zone 3 distance protection configurations, so this protection use is fully feasible.

Differential Protection

Differential protection basic theory is based on Kirchhoff's current law for electrical circuits: The sum of all currents entering a node must equal zero. This law can be restated as the sum of all currents entering a node must equal the sum of all currents exiting that node. In power system terms, this law translates as any current entering one electrical terminal of any protected device must exit the opposite electrical terminal of that device. The difference in current angles on each end of the device should be close to 180^{o} with small variance due to loading conditions. In a faulted condition, current will flow to the path of least resistance, to the fault on the device, and thus the current direction, specified by the angle, at both terminals will be equal to 0^{o}**.** Differential protection theory is applied to transmission lines, transformers, bus work and generators. Figure 6 graphically depicts transmission line current differential theory.

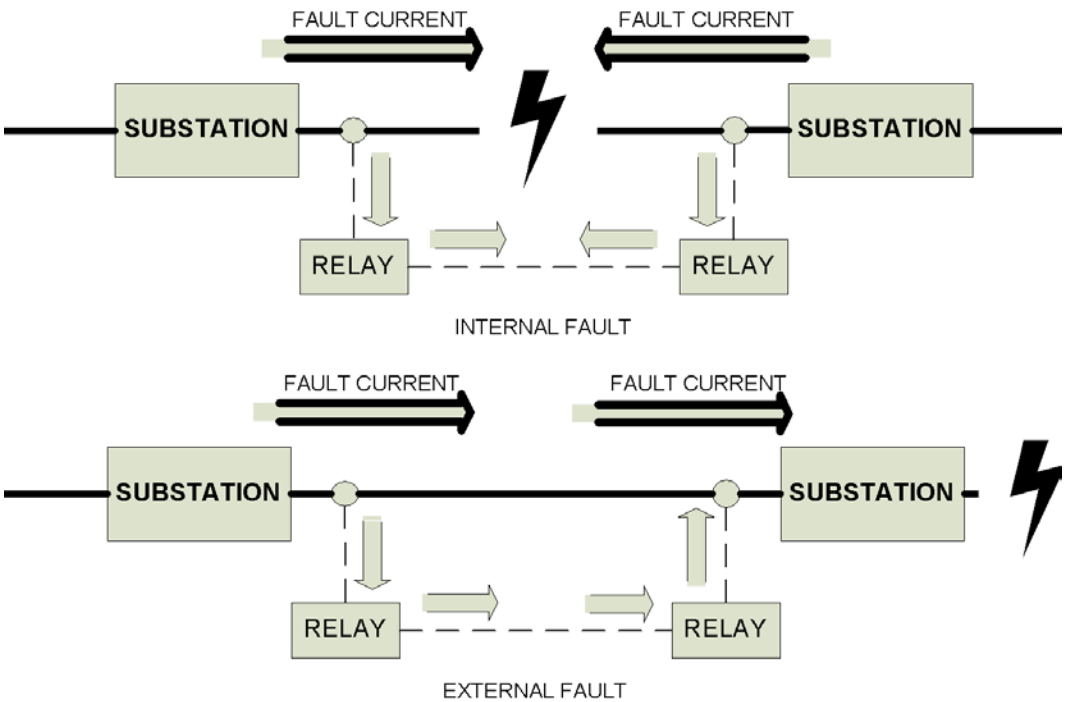


Figure 6: Transmission Line Differential Protection Theory of Operation

To account for potential current transformer saturation issues, analytics use a percent differential which calculates the ratio of the summation discussed above with a phasor magnitude average.

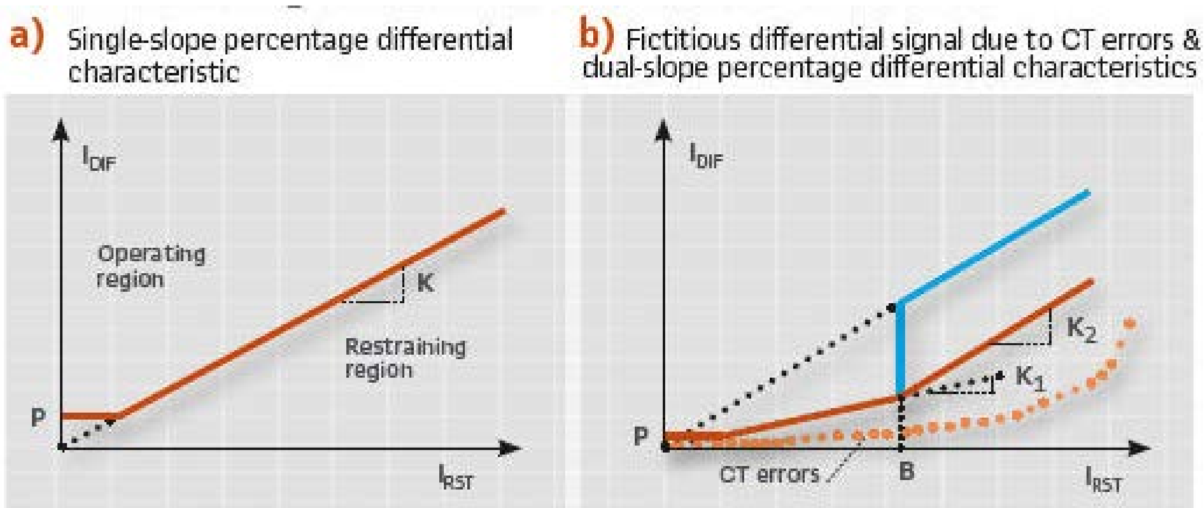


Figure 6: Percent Differential Protection[3]

As demonstrated in Figure 4b above, if a CT saturates and misrepresents the actual current on the line, the restraint current, I_{RST}, on the X axis, will increase greatly while the differential current, on the Y axis, I_{DIFF}, will increase to a lesser degree. This will place the percent differential calculation in the restraining region of the graph and block operation.

Application of PMUs -- PMUs can be used for line differential protection because current phasors are measured and can be transmitted to a central or remote end(s) of the line for the differential calculation. PMU measurements are time-synchronized and therefore provide a common time reference for aligning the phasor measurements from each end of the line being protected. Each PMU serving the zone of protection can calculate the differential current as the sum of currents entering the line, in every time-stamped set of measurements.

Line differential protection calculations should be performed in a sub-cycle timeframe; therefore, PMUs would need to measure phasor data at rates of at least 2 samples per cycle (120 samples per second), or preferably 4+ samples per cycle. However, the quality of PMU data at these rates will need be qualified as reliable for protection purposes. Current state-of-the-art PMUs on the market today report phasor data at a maximum of 120 samples per second, or 2 samples per cycle; however, most PMUs deployed today are reporting at rates of 30 or 60 samples per second and would not be sufficient for line differential protection. There are additional latency costs incurred as the protection measurements are transmitted to the remote terminals; unless the EHV bus where PMUs are installed has a high-bandwidth, low latency communications channel to deliver the data from the PMU to the remote terminal, the protection calculation and action may be delayed for too long to be effective. This type of protection requires minimal latency and would generally require PMU-to-PMU communications

[3] Pacworld, "Adaptive Line Differential Protection," June 2012: https://www.pacw.org/no-cache/issue/june_2012_issue/adaptive_line_differential_protection/adaptive_line_differential_protection.html

without passage through a PDC; similar dedicated local relay-to-relay communications links are routine protection measures today.

Bad PMU data or loss of time synchronization for one of the PMUs measuring the terminal current poses a risk for this application in terms of false tripping (as does loss of timing for a protection relay). Loss of synchronization manifests into an incorrect phase angle value that affects the current phasor used in the differential protection calculation.

PMUs have been proposed in [3] as a backup transmission line negative-sequence current differential element. The performance of this system improves with faster messaging rates and filtering processes.

Transfer Trip Schemes

A transfer trip scheme essentially sends a trip signal from one end (local end) to another end (remote end) to trip the breaker at that end. Such a scheme could serve several purposes, including tripping the remote source breaker if the local breaker fails to clear a fault (breaker failure), or to trip the interconnection breaker for bus or transformer failure (or PCC- Point of common coupling) between the utility and a generation capable plant anytime the utility breaker trips.

Direct Transfer Trips are initiated from station relays when a serious event occurs in the substations. Hence, the signal has to transmit in high speed with dependable communication. This transfer trip signal is sent in the form of a digital (or Boolean) bit, where a Boolean 1 could imply TRIP and a Boolean 0 could imply NO TRIP or vice versa. The protocol used to send this digital bit signal could be a vendor proprietary protocol or could be a standard protocol e.g. IEC 61850.

Application of PMUs -- If the devices intended to send these transfer trip signals are used as PMUs as well, then it takes little extra effort to send an additional single digital bit (transfer trip signal) along with the PMU-measured voltage and current data. As above, a PMU-to-PMU communication might be necessary, given that many transfer trip applications would be latency-constrained. Testing would need to be performed between various sets of PMUs at different message rate settings to determine the corresponding latencies, yielding a table of the latency results to determine the acceptability of PMU-to-PMU communications for transfer trip applications.

2.2 System Protection Schemes

Out of Step Protection

Out of Step protection involves being able to either separate generation when slip frequency and the acceleration of slip frequency drives the system in an unstable position, or blocking tripping during a power system swing that can correct itself without separating the system. Figure 7 illustrates power swing regions with respect to slip frequencies and acceleration.

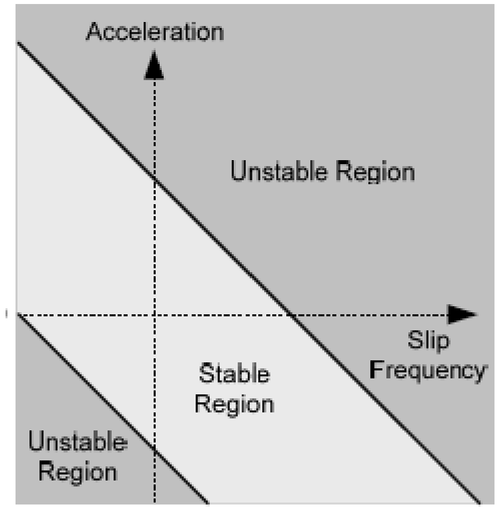
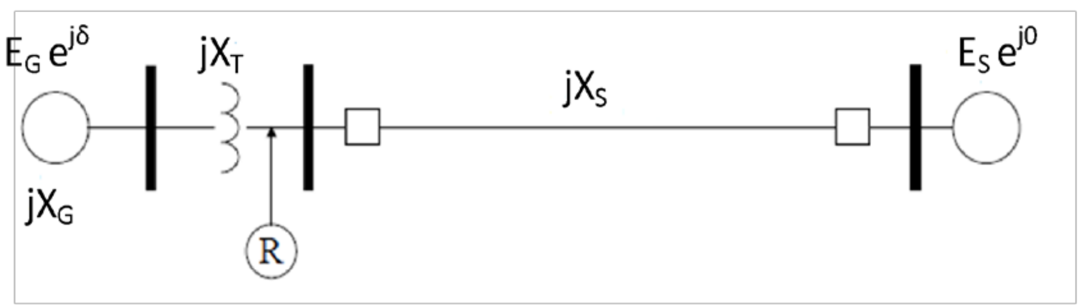


Figure 7: Out of Step stability graph

Generator out-of-step protection trips an unstable generator losing synchronism with the grid. Loss of synchronism conditions causes high stator winding currents, mechanical stress, pulsating torques, and resonance effects that can result in severe damage to the generator. The most usual form of out-of-step protection uses a distance relay function to monitor the impedance trajectory seen at the terminals of the generator. Figure 8 shows an equivalent system and the equivalent impedance seen by the relay using the voltage and current phasors.



$$Z = \frac{V}{I} = \frac{E_G\angle\delta - I\cdot j\cdot(x_G + x_T)}{\dfrac{E_G\angle\delta - E_S}{j\cdot(x_G+x_T+x_s)}} = -j\cdot(x_G+x_T) + j\cdot(x_G+x_T+x_s)\cdot\frac{E_G\angle\delta}{E_G\angle\delta - E_S}$$

$$= j\cdot\frac{(x_G+x_T+x_s)\cdot n\cdot(n-\cos\delta - j\cdot\sin\delta)}{(n-\cos\delta)^2+\sin^2\delta} - j\cdot(x_G+x_T)$$

$$n = \frac{E_G}{E_S}$$

Figure 8: Example Two-Source System

The impedance locus is illustrated in Figure 9. For n = 1, the impedance trajectory is a straight line that is perpendicular to and crosses the midpoint of the total impedance $x_G + x_T + x_S$. For n ≠ 1, the trajectory is a circle.

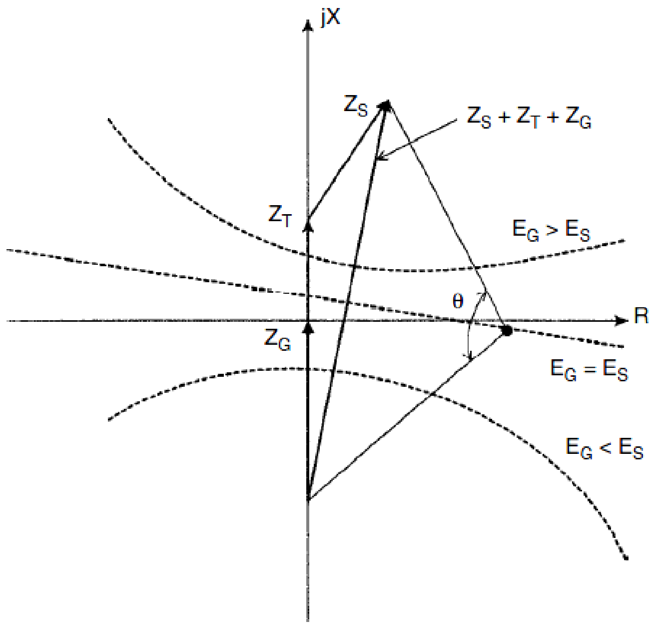


Figure 9: Impedance trajectory during a power swing [1]

Common out-of-step protection schemes use a mho relay function with single or double blinders, as shown in Figure 10. For single blinder protection, out-of-step conditions are detected if the impedance trajectory remains within the two blinders for a time greater than a specified duration, or if it crosses both the blinders. For example, scenarios "a" and "b" are considered stable scenarios while scenario "c" is an unstable scenario. Double blinder schemes use a timer between entering the outer blinder (RRO) and inner blinder (RRI) and tripping occurs if the timer expires, identifying an unstable swing condition.

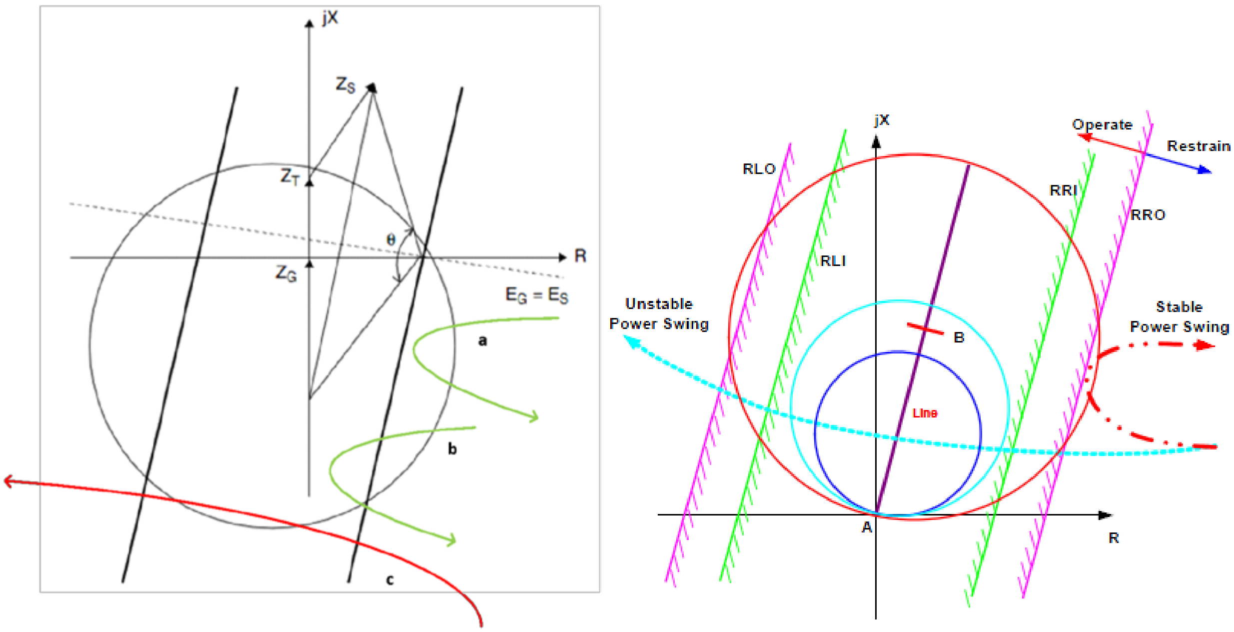


Figure 10: Single and double blinder out-of-step protection schemes [2]

Application of PMUs -- A novel predictive generator out-of-step protection scheme has been developed which utilizes synchrophasor technology. The generator out-of-step protection scheme is enabled by a synchrophasor-based dynamic state estimator, along with a measurement based dynamic equivalencing technique for deriving in real time an updated dynamic equivalent of the system. This equivalent is used for the stability characterization of the generator with respect to the system based on Lyapunov's direct method. The distributed dynamic state estimation is performed in a substation utilizing synchronized and non-synchronized local measurements and provides a highly accurate and verified dynamic model of the substation and incoming power circuits. For a substation which serves a generator, the scheme can use these data scheme to identify the center of oscillations of the system.

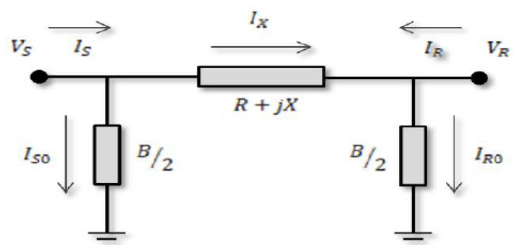
This procedure is initiated when a disturbance is detected. Given the center of oscillations, an equivalent system is derived that mimics the dynamics of the actual system. The equivalent dynamic system is updated continuously and is utilized for the characterization of the generator stability. Specifically, the total energy of the generator (potential plus kinetic energy) is continuously monitored and compared to the stability limit of the total energy function. When the total energy exceeds the stability limit then instability is asserted and a trip signal is sent to the generator breaker. The major advantage of the proposed scheme is that the out-of-step condition is predicted before its occurrence, when the angle between the generator and the system is relatively small. In this case the generator can be tripped much faster than the traditional out-of-step technology for the simple reason that breaker transient recovery voltage (TRV) phenomena will be mild. The generator out-of-step protection scheme has been demonstrated through simulations on a generating substation of New York Power Authority's

(NYPA) system and was compared with the response of a conventional impedance out-of-step relay. For a simulated unstable scenario the developed method predicted instability 0.2 seconds before the conventional relay, enabling action before the generator slipped a pole and the breaker was not overstressed with transient recovery voltage.

Transmission Line Impedance Estimation

Accurate transmission line impedances are critical because these values are used in a wide variety of tools and analyses for planning, operating, and designing the bulk power system. Inaccurate impedance values, if severe enough, can have major impacts on the validity and accuracy of the studies performed. Generally, conductor data is provided by the manufacturer in Ohms/mile; however, the actual impedance of the circuit is influenced by many factors including total length, number of towers, construction and landscape, soil resistivity, ambient temperature, and mutual impedance from other lines.

Application of PMUs -- With time-synchronized phasor measurements at each end of a transmission line, the impedance of the line can be calculated continuously over time. The line remains energized and these calculations can cover all operating conditions for the line. Figure 11 shows an example transmission line circuit and the equation for deriving the impedance of the line from the measured data.



$$\frac{V_S^2 - V_R^2}{I_S V_R - V_S I_R} = R + jX$$

Figure 11: Transmission Line Circuit and Impedance Calculation [10]

Dominion Virginia Power (DVP) has been working on PMU fault location and impedance estimation on its 500kV network. DVP has over 17 500kV lines with PMUs monitoring both terminals of the line. One of their 65-mile 500kV lines experienced an A-G fault located 17 miles from the substation. Conventional double-ended fault locations methods using DFR data produced a location 11 miles away. PMU data from the 5 minutes prior to the event was then used to estimate the positive sequence line impedance parameters; results showed an improvement in the fault location by 17% using the PMU-based impedance values calculated.

Subsynchronous Resonance (SSR)

Synchronous resonance (SSR) oscillations involve interactions and exchange of power from the turbine-generator system with the electrical network due to resonance effects; these oscillations can cause generator shaft stress and fatigue that can lead to fracture over time. SSR is generally associated with conventional steam turbine generators connected to the electrical system, particularly for highly series- compensated networks. The natural frequency of the system, f_n, can be defined as

$$f_n = f_s \frac{X_c}{X_l}$$

Where f_s is the nominal frequency, and X_c and X_l are the capacitive and inductive reactances of the system, respectively. X_c is significantly smaller than X_l in the bulk power system and therefore the natural frequency is a subsynchronous value. SSR is characterized by two types:

1. Induction Generator Effect – an interaction between the generator rotor and magnetic field produced resulting in a negative resistance effect and operation as an induction generator. This results in self-excitation and the subsynchronous currents can grow to dangerous levels.
2. Torsional Interactions – a resonance effect between the electrical network natural frequency and the natural frequency of the mechanical turbine shaft system, which can cause induced current and torque on the shaft of the machine.

Application of PMUs -- SSR can manifest itself at different frequencies based on the natural frequencies of the electrical network and mechanical system of the generator. These frequencies tend to range from 15-30 Hz. Anti-aliasing becomes an issue for frequencies of interest, particularly for commonly deployed PMUs with a 60 Hz reporting rate (30 Hz reporting rate is not sufficient for most SSR detection). PMU filtering and signal attenuation are also a concern at subsynchronous frequencies that high. Ideally, PMUs would have a sharp roll-off of the frequency response of the PMU, filtering out frequencies past the Nyquist rate while fully retaining the integrity of the measured signal up to that value. However, this is generally not the case and PMUs will either roll-off the frequency response to ensure high accuracies at intended 60 Hz nominal frequencies (M-class type of PMU) or have a relatively flat frequency response up to and past the Nyquist rate, posing a risk of non-attenuated signals past the Nyquist (P-class type of PMU). One potential solution would be to explore PMUs at higher reporting rates such as 120 samples per second and determine if the frequency response for off-nominal frequencies is sufficient.

Reference [6] describes a similar modal analysis based oscillation detection application implemented to protect from wind-farm induced oscillations in Texas.

<u>Oscillatory Stability Protection</u>

Monitoring and protecting against undamped oscillatory behavior on the power system is a valuable use of synchrophasor technology for protection and control. For example, the Guatemala power system is connected to the 50 GW grid in Mexico and the 7GW grid of the remaining Central American countries. When it observes sustained, undamped oscillatory behavior across its interconnection, Guatemala has deployed a real-time stability protection scheme using synchrophasors that monitors for undamped oscillatory conditions and separates from the smaller 7GW Central American system, remaining interconnected with the stiffer Mexico power grid. [8] Figure 12 shows the electrical topology and an example separation event detected by PMUs resulting in automated separation.

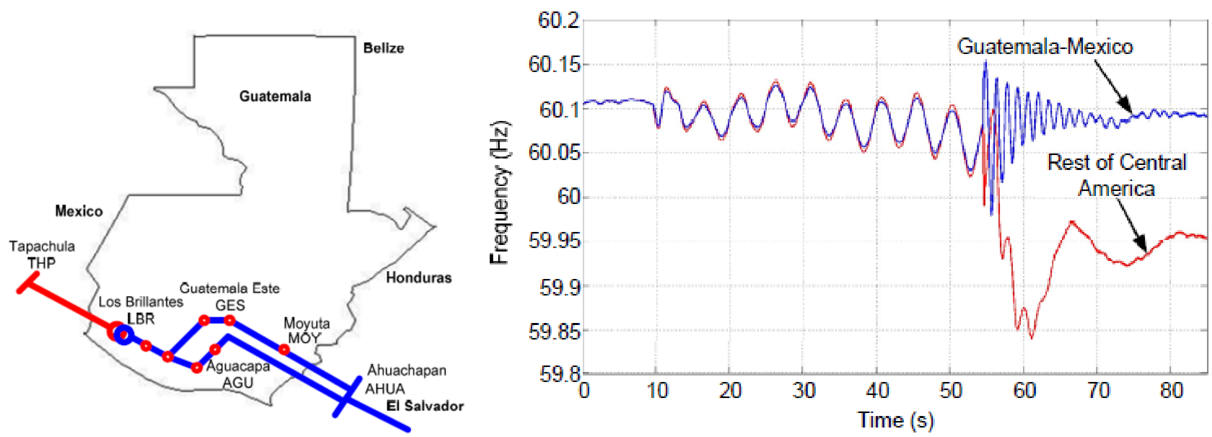


Figure 12: Guatemalan Power System and PMU-Based Stability Scheme [8]

The synchrophasor-based monitoring system detects oscillations on the real power flow measurements across the system. Modal analysis (modified Prony analysis) is implemented on the SEL-3378 Synchrophasor Vector Processor. Voltage and current phasor measurements are reported 30 times per second via C37.118 protocol. Negative damping ratio triggers the Remedial Action Scheme (RAS), separating the tie lines connecting Guatemala to the rest of Central America.

Application of PMUs -- Oscillation frequencies for local and inter-area oscillations are relatively low (< 5 Hz) and accurately measurable by PMUs reporting at 30 or 60 samples per second. It has been proven that PMUs can detect undamped growing oscillations either in a pre-contingency or post-contingency condition in actual system operations. Marginally damped or slightly negatively damped oscillations will manifest over a relatively long period of time. This allows for automated controls or even system operators to take action upon robust detection of the unstable oscillations occurring. While this solution may be system-dependent, PMUs may be a cheap and sustainable tool to inform and operate remedial actions to mitigate these.

Microgrid Protection

Microgrids are small-scale decentralized electrical power system networks consisting of various types of generation facilities (small-scale synchronous generators, induction generators, and inverter-based distributed energy resources (DER)) and loads. Microgrids can operate as grid-connected or islanded, and a RAS is usually applied to support the transition between operating states. When it detects that the microgrid is operating as an island relative to the main grid, the microgrid RAS may shed generation or load within the microgrid to balance real power mismatch as well as automatically change generation controls to droop control to enable accurate power sharing.

Application of PMUs -- PMUs can be used to detect when a microgrid becomes islanded from the larger bulk power system. The frequency, rate-of-change-of-frequency (ROCOF), and phase angle measurements can be used to detect these conditions. Islanding can result in severe changes in frequency due to the low inertia within the microgrid; separation during (expected) import conditions results in a substantial ROCOF. If phase angle measurements are made within the microgrid as well as external to the microgrid, then phase angle difference can be used as a detector. It is assumed, and has been tested, that PMU reporting rates of 60 samples per second can suffice for islanding detection and RAS on microgrids. Interoperability and effective communications are required for effective microgrid operation, as many new and existing devices – including PMUs -- must securely and effectively communicate with each other.

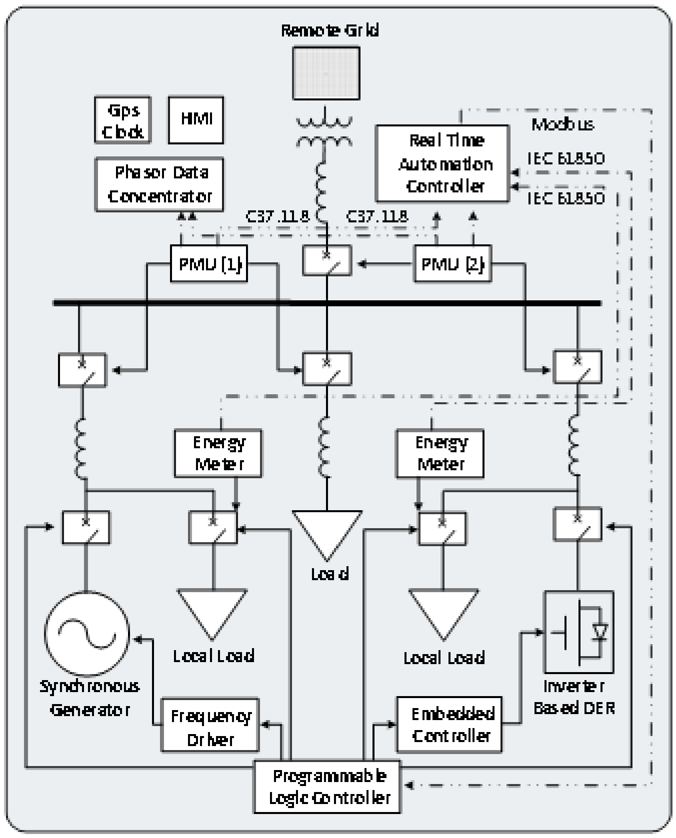


Figure 13: Microgrid Architecture [9]

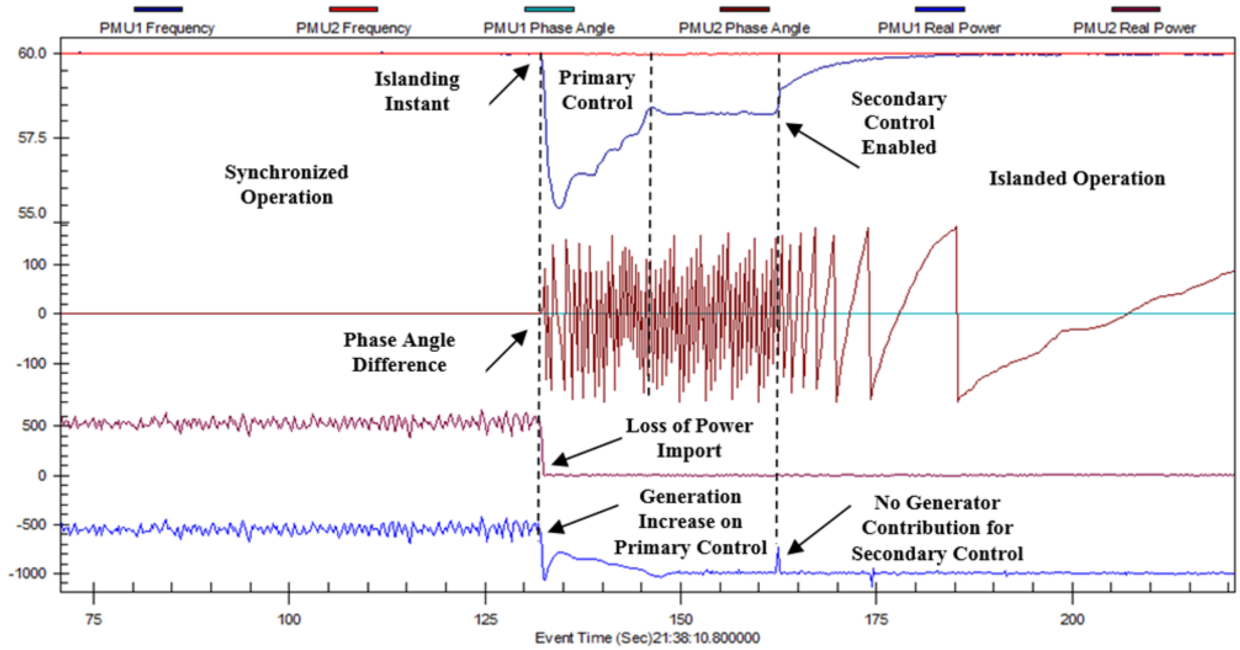


Figure 14: Simulation of Islanding and Microgrid Controls

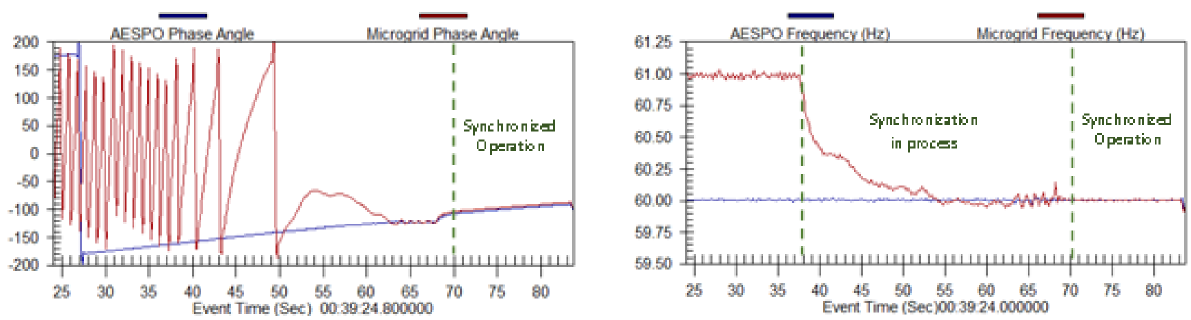


Figure 15: Resynchronization of the Microgrid

2.3 Protection-related Power System Monitoring

Delayed Voltage Recovery Monitoring

Transient voltage response is an indicator of significant reactive power demands on the grid due to motor stalling and motor reacceleration [NERC Report]. Fault Induced Delayed Voltage Recovery (FIDVR) is a form of transient voltage response in which voltage remain depressed following a system fault for a prolonged period of time (up to 20+ seconds). These events have been seen in Southern California Edison (SCE) and Southern Company, among others. While FIDVR is more prominent and common on the distribution system, it has been recorded at the sub-transmission and transmission level voltages as well; FIDVR events can begin at the distribution level and propagate to affect transmission voltages.

Unlike SCADA, PMUs can capture a time-synchronized view of system voltage magnitudes, phase angles, and power consumption. PMUs are valuable in providing a time reference to other non-synchronized measurement devices such as power quality meters, fault recorders, or digital relays that may trigger to capture a FIDVR event at lower voltages. Figure 16 shows PMU recordings at the 500 kV and 115 kV level time-aligned with power quality (PQ) measurements at the distribution level recording voltage and currents for individual feeds and loads.

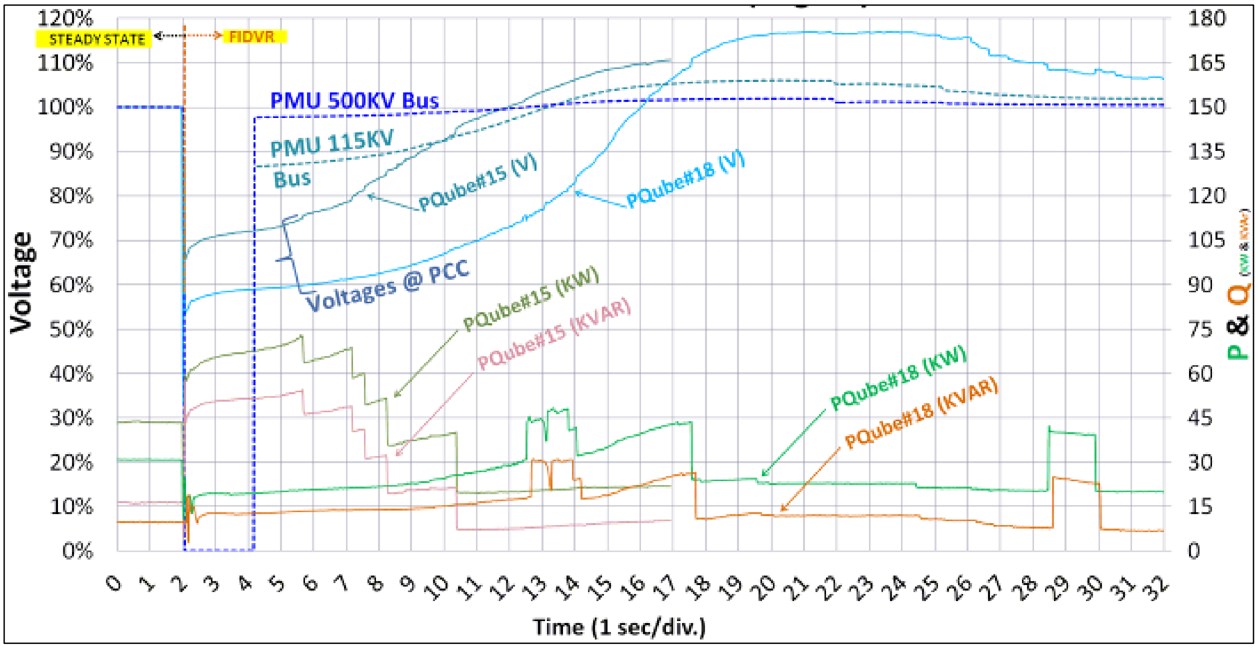


Figure 16: FIDVR Recordings in Southern California Edison (SCE) Area [11]

<u>Generator Synchronization Monitoring</u>

Figure 17 demonstrates synchrophasor data from a large generation plant as it was being synchronized to the system. This type of data provides situational awareness during every-day system operation as well as during system restoration. Besides the system state information (voltage, currents), system frequency data from various points is also essential as it is a key indicator of system health.

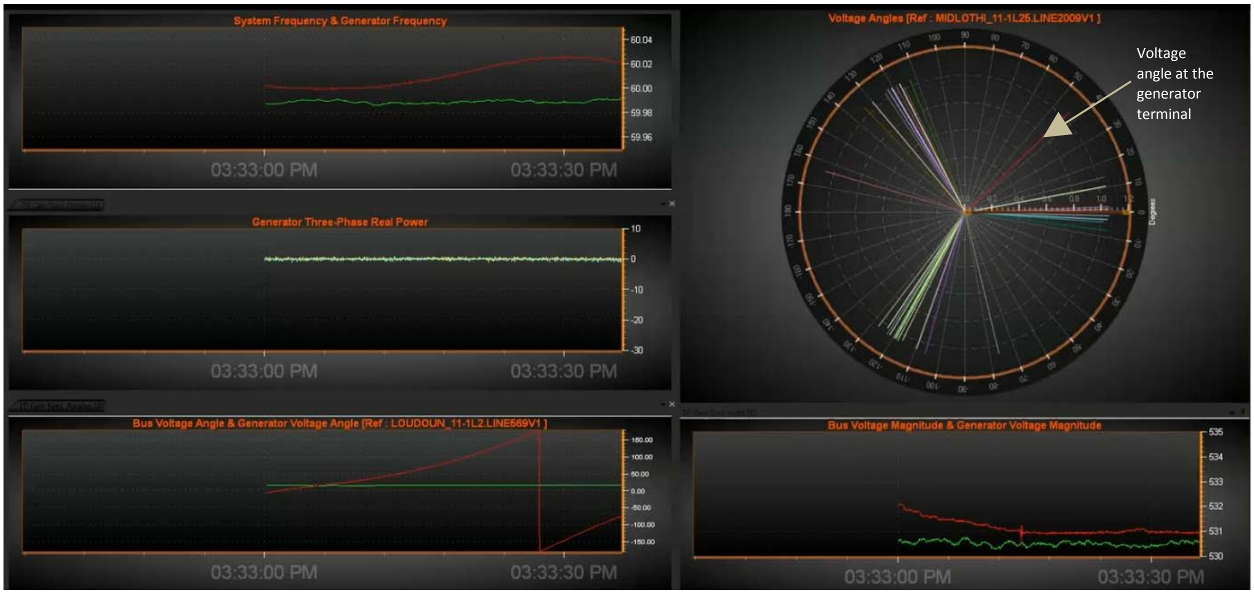


Figure 17a: Synchrophasor data pre-synchronization of large coal unit in Dominion system

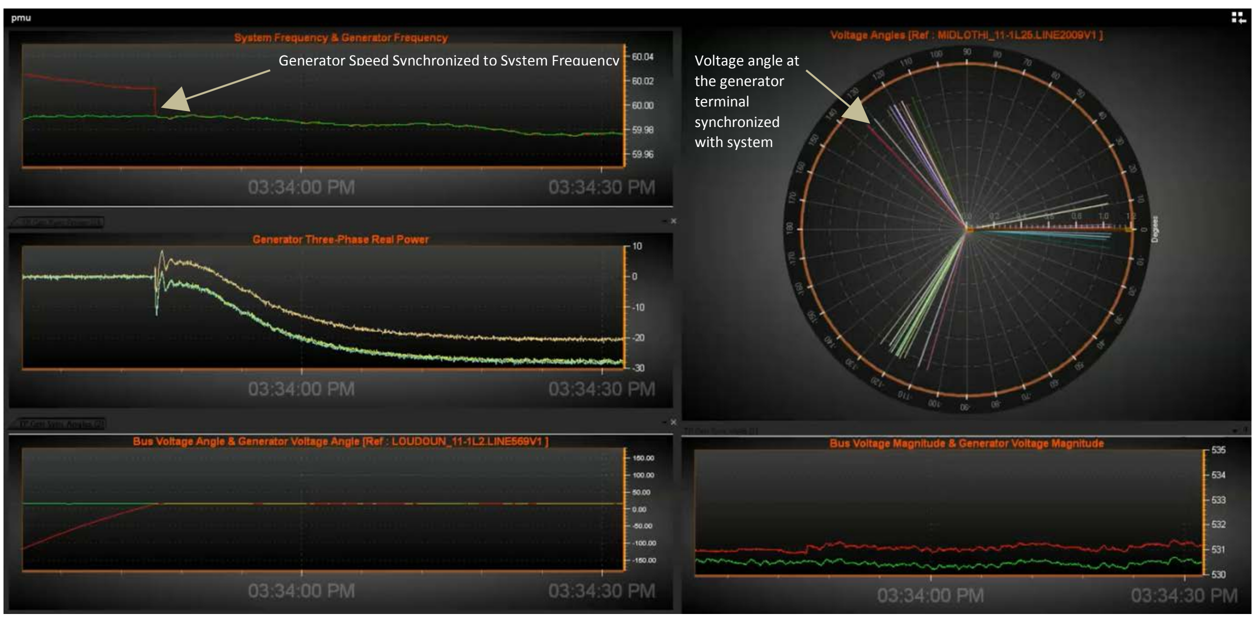


Figure 17b: Synchronization of Post-Synchronization of Large Coal Unit in Dominion System

2.4 Monitoring the Protection System

The North American Electric Reliability Corporation has found that more than 68% of recent transmission-related Qualified Events were caused by, associated with, or exacerbated by protection system misoperations.[4] NERC's President wrote to members:

[4] NERC, "State of Reliability Report 2015," May 2015, pp. 10, 46-47.

> Nearly all major system failures, excluding perhaps those caused by severe weather, have misoperations of relays or automatic controls as a factor contributing to the propagation of the failure…. Relays can misoperate, either operate when not needed or fail to operate when needed, for a number of reasons…. Most commonly, relays fail to operate correctly due to incorrect settings, improper coordination (of timing and set points) with other devices, ineffective maintenance and testing, or failure of communications channels or power supplies."[5]

Because PMU data are time-stamped, have a high measurement rate, and are widely deployed, PMU records can be used for routine review of relay and protection operations to verify that they operated correctly and identify any erroneous or odd behavior that could reveal actual or potential misoperations.[6] Data from PMUs deployed to support the disturbance data collection requirements of NERC PRC-002-2 or the modeling standards NERC MOD-026 and MOD-027 can also be used proactively to deal with the requirements of NERC PRC-004-4(i), the updated standard for Protection System Misoperation Identification and Correction.[7]

3.0 Obstacles for the Application of Synchrophasors to Protection Systems

Synchrophasor technology has developed considerably from its inception and offers great benefits for system protection. But signal quality, signal delay and security inherent in spatially remote protection systems are the main obstacles slowing the use of synchrophasor technology in live protection systems.

3.1 Synchrophasor Signal Quality

The NASPI PMU Applications Requirements Task Force is developing a report [16] to standardize data quality requirements that can be tailored to the desired application. This report defines attributes of single data points, data sets and live data streams that pin down all aspects of PMU signals that can affect the quality of synchrophasor data to end-user applications. Examples of specific attributes include PMU data source, model and manufacturer, measurement rate, etc.

The report offers a widely accepted set of terms for all aspects of PMU data as the first step to truly understand and be able to test the applicability of PMU data to specific applications. The

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[5] Cauley, G., letter to NERC members, January 7, 2011, http://www.nerc.com/pa/Stand/Project%20201005%20Protection%20System%20Misoperations%20DL/20110209130708-Cauley%20letter.pdf.

[6] American Transmission Company engineers have been using their extensive PMU network for routine review of protection operations.

[7] NERC reliability standards are posted at http://www.nerc.com/pa/stand/Pages/ReliabilityStandardsUnitedStates.aspx?jurisdiction=United%20States, including the Protection & Control standards (PRC) and Modeling, Data & Analysis (MOD) standards.

segregation of different data scopes helps to define data attributes that need to be analyzed to improve and maintain high PMU data quality, with three types of data groupings:

1) The data point which produces attributes such as data specifiers (realized quantity, precision), accuracy (inherent errors from data transformers and introduced errors from PMU estimation algorithms) and meta-data(PMU standard data settings)
2) The data set which produces attributes such as data coverage (timing and topology) and consistency (headers, standards)
3) The data stream which produces attributes such as the process path and availability.

Table 2 below is a sample of the data attributes that this report has identified as important for an analysis of data quality.

Table 2: Sample Data Quality Attributes [16]

Attributes of data sets		
Data lineage (aka meta-data) *	Data transformation methods	Transformations applied to the data at an aggregator
		Transformations applied to the data during archiving
	Data coverage	Aggregator geographic coverage
		Aggregator topological coverage
		PMU temporal coverage (time in operation)
		Aggregator temporal coverage (time in operation)
	Data content	Number of PMUs
		Channels provided by the PMU
		Channels provided by the aggregator
		PMU reporting rate
		Aggregator reporting rate
Logical consistency *	Metrology persistence and consistency	PMU metrology persistence
		Aggegator metrology persistence
		Aggregator metrology consistency
	Header persistence and consistency	PMU header persistence
		Aggregator header persistence
		Aggregator header consistency
	Data frame persistence and consistency	PMU data frame peristence
		Aggregator data frame peristence
		Aggregator data frame consistency
	Standards compliance persistence and consistency	PMU standards compliance persistence
		Aggregator standards compliance persistence
		Aggregator standards compliance consistency
	Reporting rate persistence and consistency	PMU reporting rate persistence
		Aggregator reporting rate persistence
		Aggregator reporting rate consistency
Data completeness * †	Gap rate	Gap rate in data from PMU
		Gap rate in data from aggregator
	Gap size	Mean length of gaps in data from PMU
		Mean length of gaps from aggregator(s)
	Largest known gap	Largest known gap from PMU
		Largest known gap from aggregator
Characteristics of the data process path *	Data set manageability	
	Data set recoverability	
	Data set reliability	
	Data set serviceability	

This report also advocates the importance of creating a PMU registry to establish standards from PMU data sources, signal reporting settings, PDC settings, archiving requirements as well as PMU data reliability. In addition, PMU data testing of proposed applications with historical data will identify the data quality required from the synchrophasor data network.

3.2 Signal Delay - Synchrophasor Signal Latency

Signal latency is a prime concern for the application of synchrophasors in protection systems. From section 5.3.4 of the IEEE C37.118-1 standard:

> …PMU reporting latency is defined as the maximum time interval between the data report time as indicated by the data time stamp, and the time when the data becomes available at the PMU output (denoted by the first transition of the first bit of the output message at the communication interface point) [12].

In addition to this internal device latency, "reporting over network delay" is an even bigger factor including communication over varying distances. The standard reports in section 5.5.9 that the output latency should be 2/Fs (sampling/reporting frequency) for Protection class data and 7/Fs for Metering class data. Therefore, P-class synchrophasor data has lower latency in order to achieve high speed reporting, whereas M-class PMUs use more filtering to produce more accurate measurements, but have a higher latency. This is the scope of the IEEE standard's current recommendations for synchrophasor latency.

Most synchrophasor data networks have been designed to flow data up from field PMUs to Transmission Owner and Reliability Coordinator control rooms for centralized monitoring and analysis and action. However, there is no reason why specialized, local, low-latency communications structures cannot be designed and built to exploit the benefit of PMU-based measurements for system protection, particularly at edge applications. Since there already are dedicated communications supporting particular SPS and RAS operations, similar communications could be deployed to support PMU-based SPS and RAS schemes.

If current synchrophasor communications networks are used for system protection, the synchrophasor signal needs to pass through the PMU, communication networks, and possibly one or multiple levels of Phasor Data Concentrators (PDCs), each of which introduces some additional signal latency. Here is one calculation of the latency impacts of multiple levels of PDCs [13]:

- The substation PDC is installed at high voltage substations, and can also be connected to other, surrounding substation PMUs…[with] low internal latency (around 3 to 10 ms).
- The regional PDC is installed at regional control and operating centers (if a utility has this level in their power delivery hierarchy) … [with] moderate internal latency (approx. 10 to 100ms).
- Super PDCs are normally installed at the main grid control center, where the EMS of the grid is deployed…. [and] possess[es] moderate internal latency (approx. 100 ms to 1 sec).

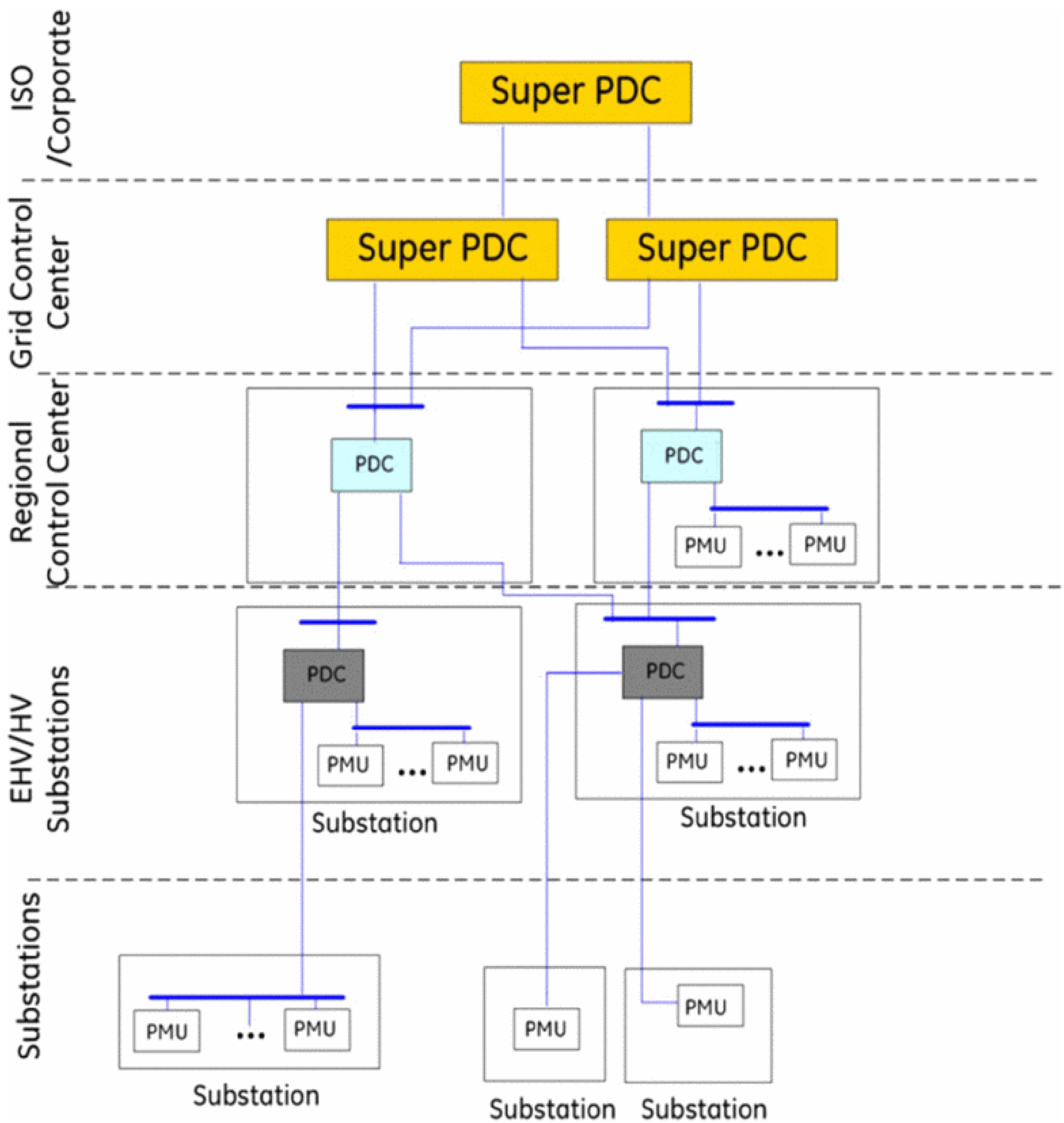

Figure 18: Wide Area Measurement System (WAMS) hierarchy [13]

Different PDC architectures have different latency costs. [13]:

> The centralized WAMS [Wide Area Measurement System] architecture eliminates intermediate levels between control centers and the substation… [with PMUs] connected to a substation PDC and then to Super PDC or directly to Super PDCs.

This creates low latency due to the reduced number of intermediate nodes, but drastically increases the number of PMU signals to the Super PDC. More intermediate PDCs create higher signal latency, but more data-concentrating power. There are also differing impacts from hardware and software PDCs -- while embedded hardware PDC latency is well determined, the latency of software PDCs across different physical hardware and operating systems is less established. A hybrid of these methods should be determined based on the individual PMU application requirements. One conclusion is “a hard-real time platform with dedicated embedded system hardware can reduce internal PDC latencies, and increases the throughput for the time-critical applications.” [13]

Latency of the signal can be improved by sectionalizing the protection region in a wide-area protection system. As [14] demonstrates, a wide-area backup protection system (WABP) can be regionalized to minimize the number of busses requiring PMUs and then optimizing the number of protection rooms that these PMUs communicate with, one per region, and finally optimizing the number of communication links the PMUs communicate with the protection rooms.[8] “For each region, the WABP scheme is individually implemented using the information collected from the respective regions.” The delays incorporated in this paper include, “…data acquisition, wide-area network (WAN) associated with data transmission, phasor data concentrators (PDCs), application algorithm, WAN associated with command transmission and circuit breakers.” The result of the research in [4] reveals that, using the IEEE-14, 30, 39, 57, and 118 bus systems, a maximum of half the busses would require PMUs; the IEEE 118-bus system would only require three protection rooms, and two protection rooms in the 57-bus system, to reduce the latency of the measurement signal from PMU to circuit breaker operation time. Figure 19 below shows the MD (measurement device) and protection room locations that optimize latency.

[8] [14] defines a protection room is defined as a centralized location for regional system protection decisions to be made, as opposed to a “master room” for the entire system.

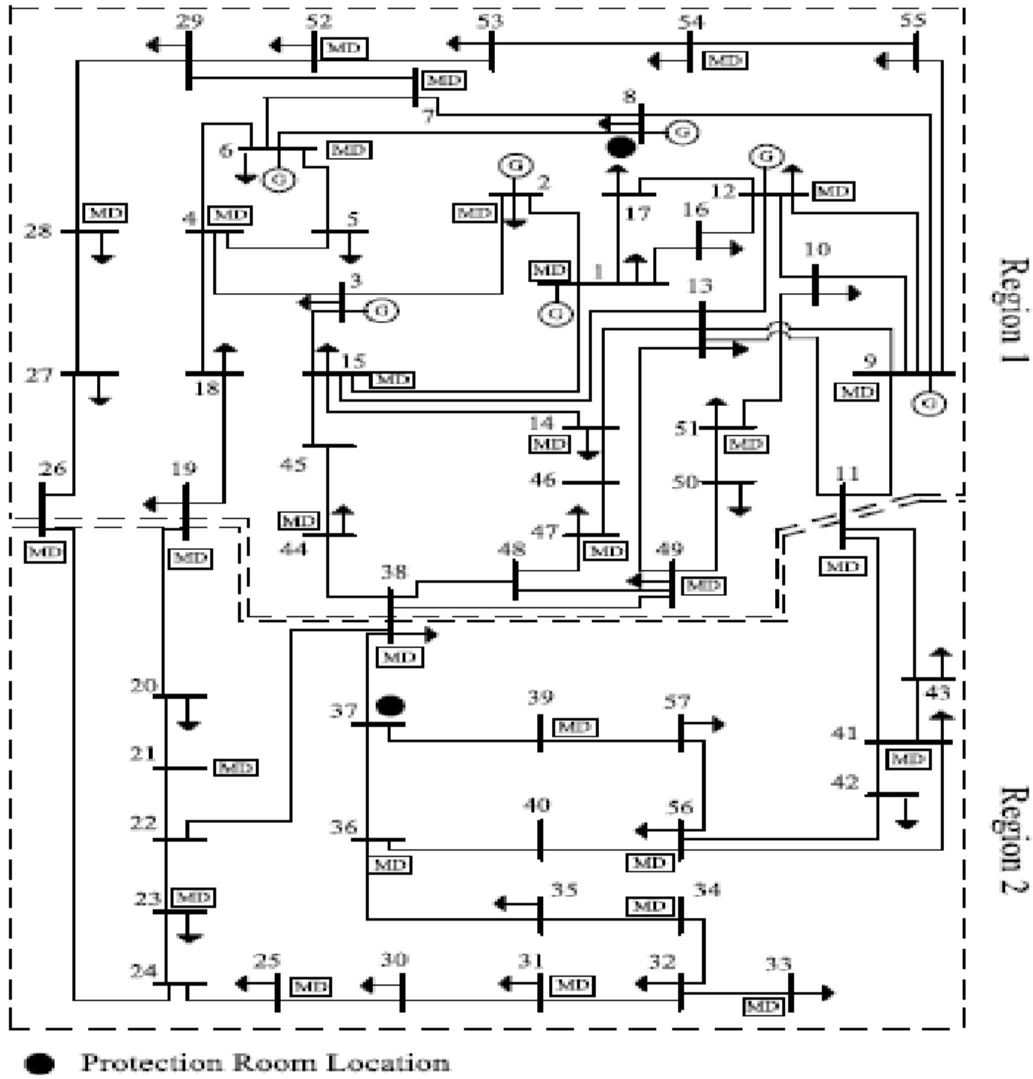

Figure 19: IEEE 57-bus test system. MDs and protection room location and specified protection regions [14]

As an example, the author demonstrates using a three phase fault in the IEEE-57 bus system, initiated at *t* = 2s on lines 9–12 at a distance of 10% away from bus 12 in the IEEE 57-bus test system. Without the regional protection rooms, the central WABP algorithm trips the faulted line at 2.6s. With the regional WABP protection scheme, the line is tripped in 2.35s.

3.3 Signal Security – Loss of GPS Time Synchronization

Accurate timing is vitally important for PMUs because correct operation of a PMU requires a common and accurate timing reference available to all PMUs across a power system. The timing reference is described in IEEE Std. C37.118.1-2011. The common, accurate timing signals (i.e., synchronizing source) may be internal or external to the PMU. Most PMUs today are using GPS signals as the source of universal time, but it is also possible to use network-distributed time, on-board clocks, and other timing sources. PMUs used for system protection purposes should have redundant timing sources and solid, tested logic for detecting and switching between those time sources for maximum accuracy and resilience.

Within a PMU, a phase-locked oscillator is used to generate the time tags within the second. The time tag is sent out with the phasors in a data packet. Thus if a phasor information packet arrives out of order to a phasor data concentrator (PDC), the phasor time response can still be assembled correctly. If the time signal (e.g., GPS pulse) is delayed, then it could cause a time-tagging error and lead to the calculation of a significant phase error.

The time system of a PMU-based GPS system is depicted in Figure 20. The standard temporal reference of this system is generated with a signal of one pulse per second (one PPS) from a GPS. This pulse as received by any receiver on earth is coincident with all other received pulses to within 1 microsecond. The PPS signal is used for sampling the analog data. The GPS time does not take into account the earth's rotation. Corrections to the GPS time are made in the GPS receivers so that they provide UTC clock time. Loss of the time source may cause a bad time-stamp, angle drift, and frequency deviation (unless there is no back-up timing source occasional).

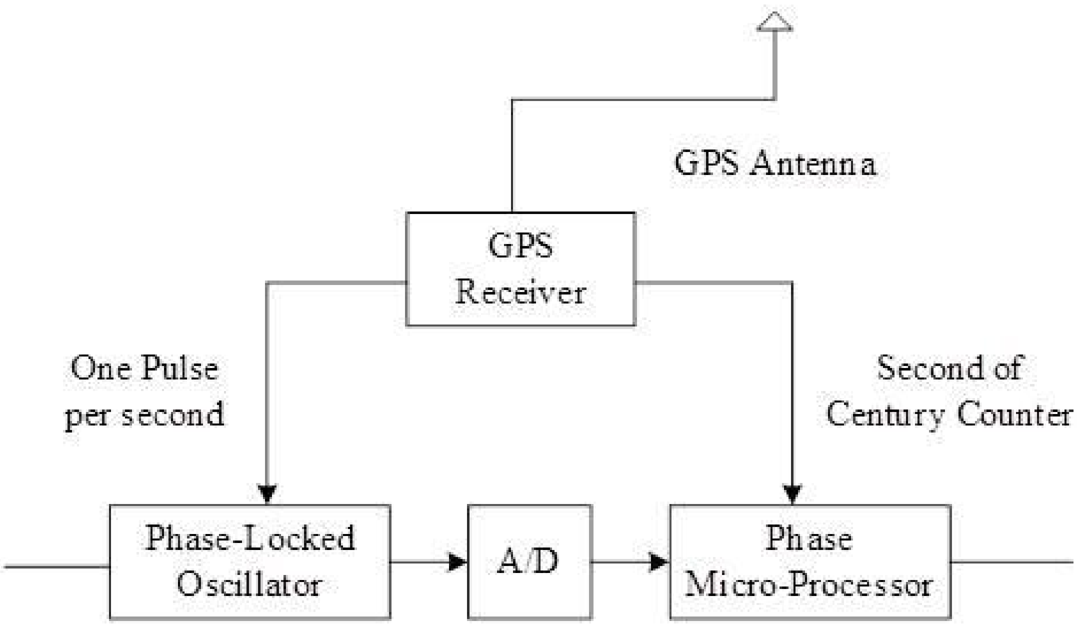

Figure 20: Indicator of the GPS loss and recovery flag

4.0 Industry Survey Results

The System Protection Task Force within the NASPI Engineering Applications Task Team developed a survey focused on Utility Applications, Research and Development Efforts, and Vendor Product Development, to assess the proliferation of PMU technology for protection system applications. The survey was sent to the NASPI community. The survey was tailored to allow multiple areas of development to be reported under one of the three categories, and sent to the entire NASPI email list (which includes about 1,000 members from utilities, hardware and software vendors, academics, consultants, and other stakeholders). For example, if a utility is performing research on synchrophasor applications but has not applied that research to live systems, then the utility had the choice of completing the research and development survey in addition to the utility survey. For these reasons, survey results should be read as indicative of use and progress, but the totals or percentages reported may omit some respondents and double-count others depending on what parts of the survey they chose to respond to. Additionally, the questions were somewhat open-ended, so many users supplied their own terms for different system protection functions; those terms are not consistent between users so there is likely overlap between reported protection functions.

4.1 Utility Survey Results

The survey was sent out in July 2015 to capture the pulse of where the industry currently is with respect to applying synchrophasor technology to protection systems as well as the vision for future application. The utility survey asked two questions:

1. Please identify how your organization currently uses synchrophasors for any of the following purposes:
    a. Offline analysis (e.g., fault analysis)
    b. Real-time monitoring (e.g., operator alarming)
    c. Safety net protection (e.g., UV/UF load shedding schemes)
    d. Specialized protection (e.g., generator, motor, or cap bank)
    e. Substation protection (e.g., transformer protection)
    f. Synchrophasor signal issues (e.g., latency or security)
    g. System configuration protection (e.g., microgrids)
    h. Transmission line protection (e.g., differential protection)
    i. Wide-area protection (e.g., RAS)
2. What system protection functions would your organization like to see being performed with synchrophasors? Please identify any obstacles impeding implementation of these functions (e.g., latency, organizational structure, technology, etc.).

Twenty-seven entities responded to the survey, with a relatively equal split of Reliability Coordinators (RCs) and Transmission Owners (TOs), with a range of national and international responses.

The first question asked for a breakdown of where synchrophasors were used currently in their organization. Categories ranged from off-line analysis to synchrophasor signal analysis to actual protection applications. The results were categorized based on common applications, as shown in Figure 21.

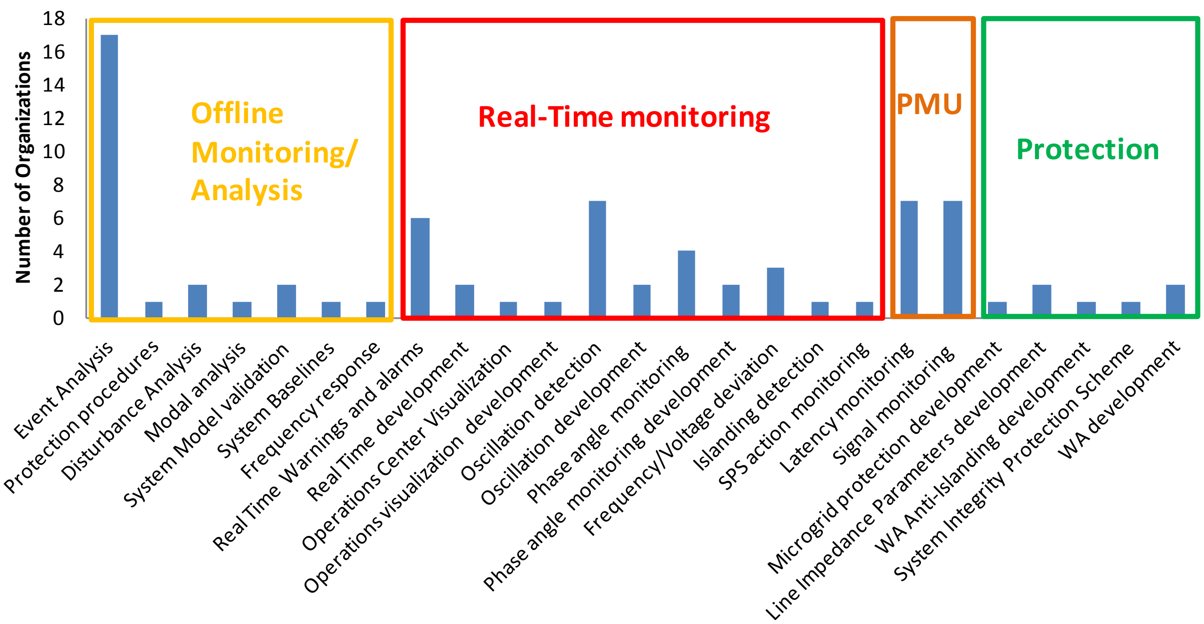

Figure 21: Industry Survey Results – Synchrophasor Protection Applications

Off-line monitoring and analysis is presently the most widely used application of synchrophasor technology by industry members. Eight organizations use PMU data for direct fault analysis while two organizations use synchrophasor data to supplement fault data or as a substitute when standard source data is unavailable. The remainder of the offline monitoring applications range from model validation to system disturbance analysis. One company specified that they use PMU data in their daily reviews and for specific level triggered frequency deviations, EHV transmission trips and large generation trips.

Most of the respondents using PMU data for real-time monitoring are focused on Real Time Warnings and alarms and oscillation detection applications. Specific examples include intelligent alarming for inter-area and oscillations using tools such as Mode Meter and forced oscillation detection.

Analyzing PMU signal quality and latency was a prominent response in the survey. Data quality such as signal latency, signal quality and PDC synchronization issues cover the range of responses. One company surveyed stated they "monitor/track/optimize synchrophasor latency data and data problems such as time synchronization loss or PMU configuration change." This large interest in PMU signal quality is an indication that utilities are becoming more interested in the use of synchrophasors.

Ten percent of utility responses say they are developing protection applications using synchrophasors or already have such applications in use. These uses are for System Configuration Protection, Transmission Line Impedance Evaluation, and Safety Net Protection.

- **System Configuration Protection** uses PMU data to identify system conditions to determine control room actions such as islanding detection, microgrid control and generator anti-islanding schemes, that could prevent system problems before they become too severe.
- **Transmission Line Impedance Evaluation** is the effort to determine more accurate live line transmission line impedances using synchrophasor data. One utility stated that they are "[e]valuating [the] use of synchrophasors to calculate/measure transmission line impedances for improved line impedance values."
- **Safety Net Protection** with synchrophasors is the live monitoring/adjustment of protection schemes. One utility is currently using PMUs to monitor RAS action for correct operation, appropriate speed of operation and the need for delayed action due to system dynamics. Southern California Edison (SCE) has developed a method to perform static var compensation using synchrophasors [16]. San Diego Gas & Electric is planning to use synchrophasor-based protection with faulted phase identification logic and current elements to drive local line tripping.

The examples above represent current synchrophasor protection practices for those entities who responded to the survey. The respondents were also asked for their expectations for future applications to power system protection, as shown in Figure 22.

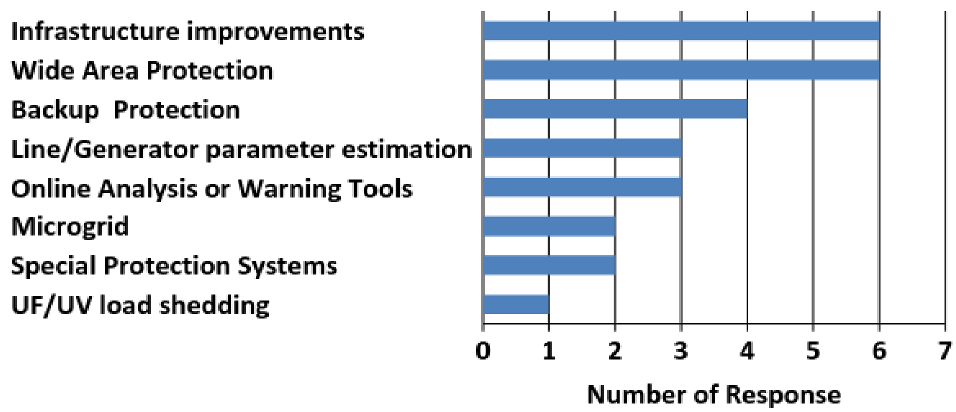

Figure 22: Utility survey responses to synchrophasor protection expectations

Five utilities want to see synchrophasor technology used for Wide Area Protection and Reliability Action Scheme activation, and three want to see synchrophasors used for transmission line differential protection.

4.2 Research and Development Survey Results

All recipients were invited to use the R&D survey to describe current and future synchrophasor-based protection projects, with the following questions:

1. Please describe synchrophasor research projects your organization has been involved in and their associated TRL level.
2. What synchrophasor protection research does your organization have planned in the future?

Examples of existing research being performed today include:

- Wide area protection
- Adaptive auto-reclosing
- Transmission line impedance evaluation
- Microgrid
- RAS
- Setting-less protection
- Signal security
- Time synchronization vulnerability

Respondents report that they are planning research on:

- Protection system communication protocols
- Safety net schemes
- Backup protection schemes
- Adaptive microgrid and distribution system protection

Technology Readiness Levels are an accepted way to describe where an emerging technology lies in the cycle from concept to full commercial readiness[8]. Table 3 lists the TRLs as used in the survey (and elsewhere). For existing projects, respondents were asked to rate the Technology Readiness Level (TRL) of each project.

Table 3: Technology Readiness Level Descriptions[9]

Innovation Phase
TRL 1: Basic Research
TRL 2: Applied Research
TRL 3: Critical Function or Proof of Concept Established
Emerging Technologies
TRL 4: Laboratory Testing / Validation of Component(s) and Process(es)
TRL 5: Laboratory Testing of Integrated / Semi-Integrated System
TRL 6: Prototype System Verified
Systems Integration
TRL 7: Integrated Pilot System Demonstrated
TRL 8: System Incorporated in Commercial Design Market Penetration
TRL 9: System Proven and Ready for Full Commercial Deployment

The TRL level for R&D projects underway provided by the respondents are listed in Figure 23. Over 50% of these projects are in the Innovation Phase with the largest percentage, 26%, classified under TRL 3, Critical Function or Proof of Concept Established.

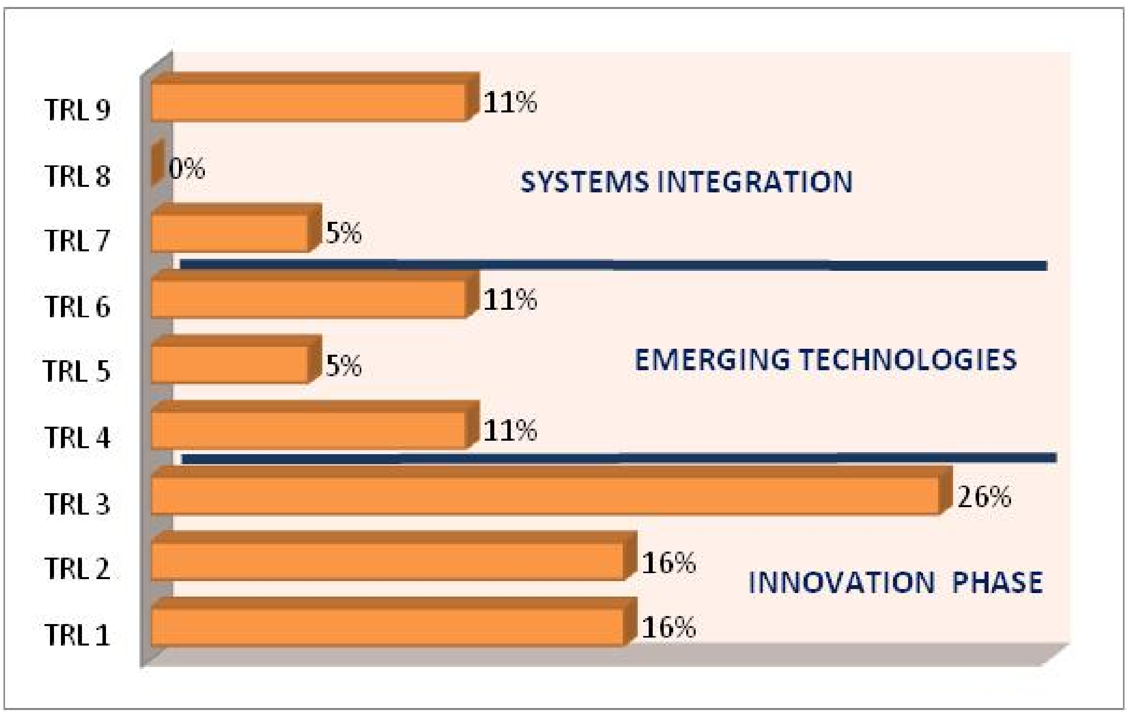

Figure 23: TRL Results from R&D Survey

[9] Bonneville Power Administration, "Technology Readiness Levels", http://www.bpa.gov/Doing%20Business/TechnologyInnovation/Documents/2014/Collaborative-Transmission-Technology-Roadmap-March-2014.pdf

4.3 Vendor Survey Results

Power system device equipment vendors were asked to describe commercially available software/hardware that incorporates synchrophasor processing, as well as their views on the future of synchrophasor-based protection. The vendor survey included the following questions:

1. What protection equipment or software that incorporates synchrophasor processing capability does your organization offer?
2. How has your organization addressed signal latency and cyber-security issues?
3. In which areas of system protection does your organization believe synchrophasors can be applied today?
4. In which areas of system protection does your organization believe synchrophasors can be applied in the future? Please identify any barriers.

Industry vendors responded that devices for PMU measurement, PDCs and stand-alone platforms are currently on the market that can perform synchrophasor data processing inclusive of calculations and data stream analytics and control algorithms. Specialized synchrophasor products are also available. One vendor has a phasor controller in development while another offers user specified customizable software for synchrophasor algorithm processing.

Vendors believe synchrophasors can be applied today in applications ranging from wide area protection to backup line protection. Also, system models can be improved using synchrophasors, which will allow engineers to improve protection system design.

Vendors see the future of synchrophasor protection lying with the development of new RAS and safety net schemes, out-of-step protection, distributed microgrids, backup to existing classical protection schemes, and proactive rather than reactive RAS. The barriers to these advancements include the acceptance of new and unproven system designs, guaranteed communication latency and cyber-security requirements, and overcoming cultural stagnation with the need for development and live testing of such new protection systems.

Signal latency and cyber-security across the vendor arena has been addressed many different ways. One vendor has focused on reducing PDC latency time to less than 5ms with no data loss and plans on using VLAN to address cyber-security concerns. Multiple vendors stress proper system architecture and testing identifies and addresses the reduction of latency and the cyber protection of PMU data. Two vendors use encrypted programming and settings along with equipment password protection to ensure information security.

5.0 Summary and Conclusions

Power system protection can be enhanced with the use of synchrophasor technology, starting with the use of PMU data for substation-level element protection schemes (since these avoid potential network latency problems). The next step is to ask whether the timing and quality of PMU data equal that of existing protection systems, and whether there is potential benefit to having PMU-based protection supplement relay-based protection measures. In-depth experimental trials of parallel PMU-based and relay-based protection systems should be studied to determine the true benefits, if any, synchrophasor-based protection.

Now that PMU data networks are more prominent and robust, it is vital that the quality of data be quantified prior to its use in applications. Data quality needs to be categorized and PMU data standards/registries need to be established and adhered to for reliable application. Current utility uses of PMU data are mostly limited to monitoring and analysis due to end user concerns over PMU data latency, reliability and questionable data quality. Therefore, the focus in today's research should focus on local substation protection schemes, and the first step is to compare/contrast existing relaying systems with PMU substation based protection systems.

The other immediate opportunity for synchrophasor use in system protection is to use PMU data to monitor and review every system protection operation, to determine whether each operation occurred as it should have, diagnose any misoperations, and identify potential equipment, settings or logic problems before they cause transmission events.

APPENDIX A -- REFERENCES

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APPENDIX B – “P” CLASS AND “M” CLASS PMU SPECIFICATIONS

All material from IEEE technical standard C37.118.1a-2014

P class PMUs are for protection applications
M class PMUs are for measurement applications

Table 4—Steady-state frequency and ROCOF measurement requirements

Influence quantity	Reference condition	Error requirements for compliance			
		P class		M class	
Signal frequency	Frequency = f_0 ($f_{nominal}$) Phase angle constant	Range: $f_0 \pm 2.0$		Range: $f_0 \pm 2.0$ Hz for $F_s \leq 10$ $\pm F_s/5$ for $10 \leq F_s < 25$ ± 5.0 Hz for $F_s \geq 25$	
		Max FE	Max RFE	Max FE	Max RFE
		0.005 Hz	0.4Hz/s	0.005 Hz	0.1 Hz/s
Harmonic distortion (same as Table 3 - single harmonic)	<0.2% THD	1% each harmonic up to 50th		10% each harmonic up to 50th	
		Max FE	Max RFE	Max FE	Max RFE
	$F_s > 20$	0.005 Hz	0.4 Hz/s	0.025 Hz	Limit suspended
	$F_s \leq 20$	0.005 Hz	0.4 Hz/s	0.005 Hz	Limit suspended
Out-of-band interference (same as Table 3)	<0.2% of input signal magnitude	No requirements		Interfering signal 10% of signal magnitude	
				Max FE	Max RFE
		None	None	0.01 Hz	Limit suspended

Table 5 —Synchrophasor measurement bandwidth requirements using modulated test signals

Modulation Level	Reference condition	Minimum range of influence quantity over which PMU must be within given TVE limit			
		Class P		Class M	
		Range	Max TVE	Range	Max TVE
$k_x = 0.1$, $k_a = 0$ radian	100% rated signal magnitude, $f_{nominal}$	Modulation frequency 0.1 to lesser of $F_s/10$ Hz or 2 Hz	3%	Modulation frequency 0.1 to lesser of $F_s/5$ Hz or 5 Hz	3%
$k_x = 0$, $k_a = 0.1$ radian	100% rated signal magnitude, $f_{nominal}$		3%		3%

Table 6 —Frequency and ROCOF performance requirements under modulation tests

F and ROCOF performance limits	Error requirements for compliance					
	P Class			M Class		
Reporting rate F_s (Hz)	F_r (Hz)	Max FE	Max RFE	F_r (Hz)	Max FE	Max RFE
10	1	0.03	0.6	2	0.12	2.3
12	1.2	0.04	0.8	2.4	0.14	3.3
15	1.5	0.05	1.3	3	0.18	5.1
20	2	0.06	2.3	4	0.24	9.0
25	2	0.06	2.3	5	0.30	14
30	2	0.06	2.3	5	0.30	14
50	2	0.06	2.3	5	0.30	14
60	2	0.06	2.3	5	0.30	14
Formulas	$\min(F_s/10,2)$	$0.03 \times F_r$	$0.18 \times \pi \times F_r^{\,2}$	$\min(F_s/5,5)$	$0.06 \times F_r$	$0.18 \times \pi \times F_r^{\,2}$

NOTE 1—Maximum frequency (F_r) in the modulation test range is determined by the reporting rate (F_s) and capped to 2 Hz or 5 Hz for the P and M class respectively as shown under Ranges in Table 5.

NOTE 2—The formulas for the maximum allowable error are based on the peak value that the frequency or ROCOF measurement will achieve over the modulation frequency range. This value is $0.1 \times F_r$ for frequency and $0.1 \times 2\pi \times F_r^2$ for ROCOF, where 0.1 is the index of modulation.

NOTE 3—The error limits are a percent of these maximum values: the FE limit is 30% for P class and 60% for M class; the RFE limits are both 90%.

For test compliance, use the rounded values as shown in the table.

Table 7—Synchrophasor performance requirements under frequency ramp tests

Test signal	Reference condition	Minimum range of influence quantity over which PMU shall be within given TVE limit does not include the exclusion interval multiplied by the ramp rate				
		Ramp rate (R_f) (positive and negative ramp)	Performance class	Exclusion interval	Ramp range	Max TVE
Linear frequency ramp	100% rated signal magnitude, and $f_{nominal}$ at a non-excluded point during the test	± 1.0 Hz/s	Class P	2/Fs	± 2 Hz	1%
			Class M	7/Fs	Lesser of ± (F_s /5) Hz or ± 5 Hz[a]	1%

[a]For F_S = 12 fps, ramp range shall be ±2 1/3 (two and one-third) Hz to allow for an integer number of samples in the result.

Table 8 —Frequency and ROCOF performance requirements under frequency ramp tests

Signal specification	Reference condition	Exclusion interval	Error requirements for compliance			
			P class		M class	
			Max FE	Max RFE	Max FE	Max RFE
Ramp tests—same as specified in Table 7	100% rated signal magnitude and 0 radian base angle	Same as specified in Table 7	0.01 Hz	0.4 Hz/s	0.01 Hz	0.2 Hz

Table 9—Phasor performance requirements for input step change

Step change specification	Reference condition	Maximum response time, delay time, aı d overshoot					
		Class P			Class M		
		Response time (s)	|Delay time (s)|	Max Overshoot /undershoot	Response time (s)	|Delay time (s)|	Max Overshoot /undershoot
Magnitude = ± 10%, k_x = ± 0.1, $k_a = 0$	All test conditions nominal at start or end of step	2 /f_0	1/(4•F_s)	5% of step magnitude	7/F_s	1/(4•F_s)	10% of step magnitude
Angle ± 10°, $k_x = 0$, $k_a = \pm \pi/18$	All test conditions nominal at start or end of step	2 /f_0	1/(4•F_s)	5% of step magnitude	7/F_s	1/(4•F_s)	10% of step magnitude

Table 10—Frequency and ROCOF performance requirements for input step change

Signal specification	Reference condition	Maximum response time			
		Class P		Class M	
		Frequency Response time (s)	ROCOF Response time (s)	Frequency Response time (s)	ROCOF Response time (s)
Magnitude test as in Table 9	Same as in Table 9	4.5/f_0	6/f_0	Greater of 14/F_s or 14/F_0	Greater of 14/F_s or 14/F_0
Phase test as in Table 9	Same as in Table 9	4.5/f_0	6/f_0	Greater of 14/F_s or 14/F_0	Greater of 14/F_s or 14/F_0

Table 11—PMU reporting latency

Performance class	Maximum PMU reporting latency (s)
P class	2/ F_S
M class	7/F_S
NOTE—For optional reporting rates F_S which are higher than nominal power system frequency $F_{nominal}$; maximum PMU reporting latency is equal to Table 11 entry for $F_S = F_{nominal}$.	