Issues Related to the Implementation of Synchrophasor Measurements

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Abstract

The synchrophasor technology is maturing to large scale applications. Recent large scale deployment projects emphasize the importance of standards for accuracy and interoperability. Creation of large interconnected networks of Phase Measurement Units requires testing and calibration, as well as integration of embedded monitoring and control systems in the power networks. Such integration creates challenges, but also provides unprecedented opportunities for the flexible control and protection of large scale power systems.

1. Introduction

The development of communications and the introduction and availability of a standardized time reference over wide geographic areas by Global Positioning System (GPS), laid the foundation for the synchrophasor technology. This in turn has provided the information for system-wide monitoring and control of the power system that was not previously available. The synchrophasor technology developed over two decades ago had to wait for the commercial deployment of Phasor Measurement Units (PMUs), which has started on a larger scale only relatively recently.

Electric utilities have been facing an ever increasing pressure to operate the power systems under increasingly harsh circumstances. They are represented by a combination of fast load growth, slowly increasing infrastructure, aging equipment, and more frequent exposure of the control system operators to very improbable and sometimes devastating contingencies. These and other factors have contributed to the growing availability and acceptance of the new generation of monitoring and control technologies to assist the system operators in coping with these new challenges. The need for faster monitoring systems has already been discussed [1]-[8].

Advanced detection and control strategies offer a cohesive management of disturbances through the concept of system integrity protection schemes (SIPS). The SIPS is a concept of collecting and sending appropriate local system information from selected sites to a remote processing location for detecting and counteracting the propagation of major disturbances in the power system. With the increased availability of advanced computing, communication, and measurement technologies, more intelligent equipment can be used at the local level to improve the overall system response. Traditional dependant contingency/event based systems could be enhanced to include power system response-based algorithms with proper local supervision for security [1].

Decentralized subsystems, capable of making decisions based on local measurements and remote information (system-wide data and emergency control policies) and/or of sending pre-processed information to higher hierarchical levels, are an economical approach to the voltage stability problem [9]. A major component of the SIPS is its ability to receive remote measurement information and commands via the data communication system and to send selected local information to the Supervisory Control and Data Acquisition (SCADA) centre. This information should reflect the prevailing state of the power system.

2. Current Solutions and Limitations

There are various limitations for implementation of the efficient real-time protection and control schemes.

Measurement systems: Many transducers are analog, and do not allow for direct measurements of the elements of the state vector. They usually provide measurements such as voltage and current magnitudes, active and reactive powers which have to be further processed to obtain the system state information. In conventional SCADA, typical rates of state updates of 1-5 s are slow compared to the time intervals in which transients in power systems occur.

Communication networks: Fast communication channels are needed to accommodate the data transfer rates required for state updates that would reflect transients. Although technologies exist for such networks, their implementation in power systems may be rather expensive. Modern fiber optic networks are capable of performance beyond the requirements of power systems. Other types of communications with more constrained performance such as satellite links, microwave, dedicated telephone lines, wireless, power line carrier, etc. can also be used.

Synchronized measurements: Commercially available GPS-based clock receivers with time uncertainties of less than 1 µs (or even less than 100 ns) allow for phase angle measurements with uncertainties of less than 0.02° (or even less than 0.002°).

Computing resources: Most of the present control centers were not designed to process the state information at the rates needed for real-time control of power system dynamics involving transient disturbances (in the time scales 0.01–10 s). New architectures, such as massively parallel and distributed computing environments, can provide substantial increases in processing performance.

Contemporary power systems implement protection from transient disturbances. The present means to mitigate and contain those disturbances include [9]-[18]:

- Generator Rejection,
- Load Rejection,
- Under-Frequency Load Shedding,
- Under-Voltage Load Shedding,
- Adaptive Load Mitigation,
- Out-of-Step Tripping,
- Voltage Instability Advance Warning Scheme,
- Angular Stability Advance Warning Scheme,
- Overload Mitigation,
- Congestion Mitigation,
- System Separation,
- Shunt Capacitor Switching,
- Tap-Changer Control,
- SVC/STATCOM Control,
- Turbine Valve Control,
- HVDC Controls,
- Power System Stabilizer Control,
- Discrete Excitation,
- Dynamic Breaking,
- Generator Runback.

The purpose of faster monitoring devices is to assist the existing and new protection and control schemes with faster state updates in order to meet real-time requirements.

Measurement Hardware: Phasor measurements are accomplished by a distributed microcomputer-based data acquisition system. The system consists of a network of phasor measurement units as nodes with advanced communication capabilities, which are located in various sites in the power system for simultaneous measurement of the state vector, and possibly other quantities that can be derived from it (currents, powers, frequency, etc). A typical phasor measurement unit may contain:

- interface with the power system (PTs, CTs, signal conditioners),
- microcomputer with related peripherals,
- GPS-based clock receiver for measurement synchronization,
- local man-machine interface including (optional) graphical user interface (GUI),
- interface for communication with other nodes in the network.

Monitoring of instantaneous phase angles and frequency: This is needed from all three phases at several locations in the system, in order to monitor the evolution of the transient, and as an input to control loops. Several algorithms for measurement of frequency, frequency deviation, and its rate of change in power networks have been proposed and implemented in various devices [19]. There are many unresolved issues in phase angle and frequency measurements, such as nonlinearities of transducers, sensitivity to harmonics, various types of noise, etc. Instantaneous frequency measurement algorithms are particularly sensitive to these factors. Due to the nature of measurements, extremely low synchronization uncertainties of the order of 1 μs are required system-wide. These have become available by virtue of the GPS satellite network, although a number of alternatives for synchronization exist when the accuracy requirements are not as strict.

Some of the algorithms for phasor calculation rely upon discrete Fourier transform (DFT) of the sampled voltage data. DFT acts as a filter against the low order harmonics in the signal, but offers limited protection from wideband noise, especially when it is to be used for the subsequent calculations of the instantaneous frequency. Other methods utilize phase demodulation techniques, or extended Kalman filtering, to obtain estimates of the phase angle [20]. The accurate tracking of transient phase angle and efficient and fast algorithms are crucial for the success of any real-time control. Most of the control systems for transient stabilization do not take advantage of complete real-time state measurements, primarily because the use of such equipment is still not widespread, but also because the measurement algorithms need to be tailored to specific implementations. This usually involves a trade-off between computational efficiency and steady-state and/or transient tracking accuracy. Hybrid applications have also been proposed as transient solutions.

Applications of fast measurements: Practical issues of monitoring, various aspects of phasor measurement systems related to associated hardware, measurement algorithms, and implementation, are widely discussed in the literature [1],[21],[22]: from the application of phasor measurements to the adaptive protection scheme of an intertie against transient oscillations, the use of phasor measurement units for the assessment of power system voltage stability, to the calculation of dynamic equivalents for power systems, phasor measurements offers an alternative to the use of conventional transducers. Potential applications of fast measurement systems, such as PMUs, are almost unlimited. Even though this new technology is still undergoing field testing as a monitoring system, its inherent potential for monitoring and real-time control of power system dynamics is still largely untapped.

Coordination and control techniques: The literature concerning power system transient control can roughly be divided into multivariable state space techniques, frequency domain analysis, and, more recently, a combination thereof. Among the first techniques proposed for transient stability control was modal analysis for coordination of power system stabilizers (PSS). State space analytical methods were also used to perform eigenvalue assignment for the allocation of PSS. The drawback of these techniques is the failure to perform under changing network conditions. Frequency domain techniques can be used for coordinated design of PSS, but do not produce consistent results, and, as much as state space techniques, fail to account for the nonlinear nature of the power system oscillations.

Time-frequency distribution analysis of the electromechanical energy oscillations in power systems, a relatively new concept, also possesses interesting features for control applications, provided that the analysis can be obtained in real-time. A multi-level hierarchical approach for the control of transient oscillations employs the concept of a transient coordinating controller, which provides closed-loop feedback within a decentralized control system. The uncertainty in determining the parameters of the system undergoing a fault-induced transient requires caution in applying certain optimal control techniques, since their sensitivity to parameter variations may not be sufficient. Robust control of feedback linearized excitation controls may be one of the possible answers to parameter sensitivity problems.

3. Phasors: Measurement Issues

Phasors are obtained from high-speed data acquisition devices producing time-tagged sequences of voltage and current samples, which are usually subjected to a spectral decomposition (such as DFT). The *k*-th sample of the DFT taken over M samples beginning with one at time zero can be evaluated as:

$$X^0(k) = \frac{2}{M}\sum_{n=0}^{M-1} x(n) e^{-2j\pi\frac{kn}{M}} \tag{1}$$

where $x(n)$ are the input samples, and M is the length of the calculation window. Ordinarily this computation requires $M \log(M)$ complex operations to compute for all values of k from 0 to $M-1$, but for the purpose of phasor tracking not all M DFT-coefficients are needed.

Only one element of DFT is needed, the one which corresponds to the fundamental frequency f of the measured signal. Under the assumption that $k = M/N$, it is possible to obtain the recursive relationship:

$$X^r = X^{r-1} + \frac{2}{M}[x(M+r-1) - x(r-1)]e^{-j2\pi\frac{r-1}{N}} \tag{2}$$

Obviously, this approach has lower computational complexity since for each window, only two complex multiplications and one addition are needed. However, the method based on (2) also has some potential downsides. Sometimes it is better to window the signal before transforming it to the spectral domain in order to decrease the influence of higher harmonics or high frequency noise. However, the recursive implementation is not straightforwardly extended to this. It is further assumed that the exact frequency of the tracked sinewave is known, which, in general, is not true. However, the deviation in the frequency should be obvious from the trend of the observed phase and this kind of defect can be remedied easily.

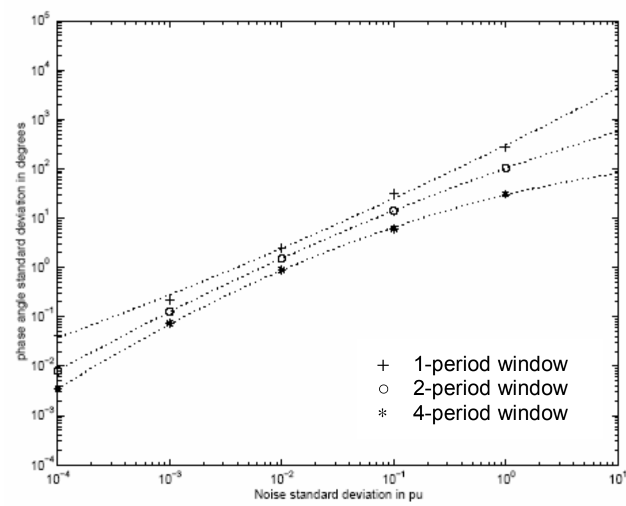

Fig. 1. Dependence of the standard deviation of the observed phase angle on the standard deviation of the additive white Gaussian noise

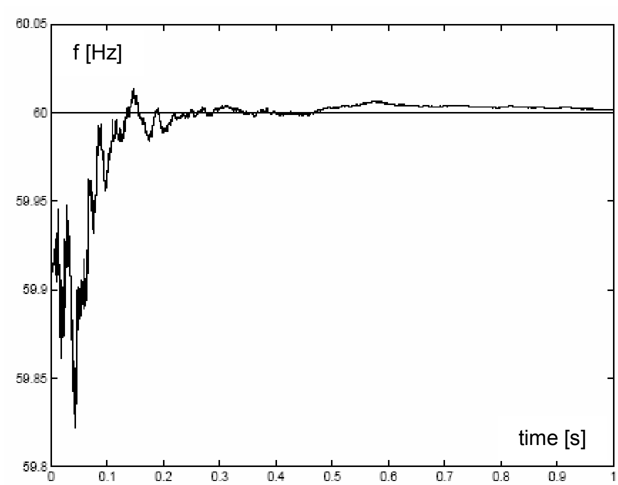

Fig. 2. RLS Frequency tracking for AWGN with 0.1 standard deviation. The tracking algorithm quickly averages out the initially predominant noise to settle to the exact value after as little as 1 s.

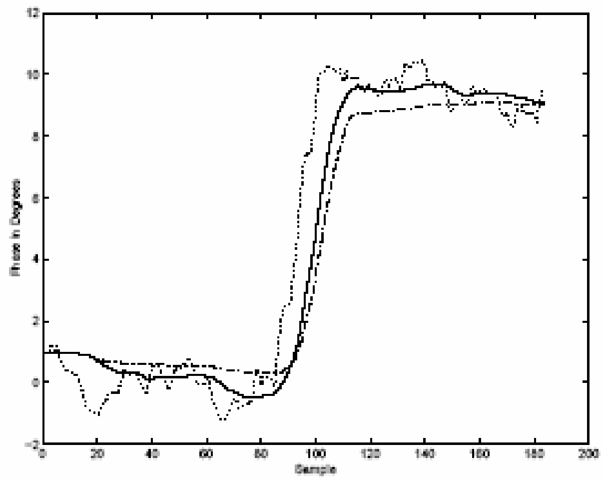

Fig. 3. Phase tracking: dashed line represents instantaneous observation by DFT, solid: tracked via variance adaptive step size gradient, dash-dot lines show tracking via error adaptive step size gradient.

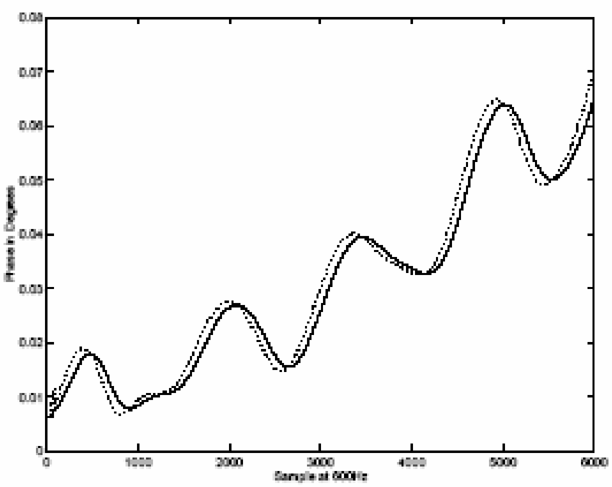

Fig. 4. Voltage phase on a bus in a 16-machine system model after the simulated fault with no noise added to the observation. Dotted line shows recursive DFT observation, solid line shows variance adapted step size gradient.

Figures 1-3 demonstrate how different computational approaches may affect the noisy steady state phase angle measurements (Fig. 1), steady state frequency tracking abilities of the PMU (Fig. 2), or phase angle dynamic tracking (Fig. 3). Figure 4 shows dynamic phase angle tracking on a bus of a power system model during the simulated fault. Since there is no noise, both adaptive algorithms perform similarly. The total simulated time is 10 s.

The multitude of possible approaches does not offer an easy choice of a preferential technique, but the potential for conflicting situations arising from concurrent use of different techniques within the same network of PMUs is posing a potential problem. A structured approach to testing may help resolve this issue.

4. PMU Technology: Testing and Calibration Issues

Electrical metrology is critical for the operation of the electrical power system from technical (monitoring, control, protection, planning, reliability) and economic (revenue metering/energy trade, investments) point of view. International trade agreements demand demonstrated equivalence of both the measurement standards and the accreditation systems of the trading parties.

The International Organization for Legal Metrology (OIML) entails the representatives of almost 100 countries working on uniform design requirements and testing instructions for all measuring instruments. The European Union, through its regional bodies, coordinates legal metrology activities of its members' national authorities. In Japan, that role is filled by Japan Electric Meters Inspection Corporation (JEMIC). In Canada, a government Special Operating Agency, Measurement Canada, has a mandate of administration and enforcement of the Weights and Measures Act and the Electricity and Gas Inspection Act. In the US, legal metrology responsibilities are distributed among local, state and federal governments. The National Institute of Standards and Technology (NIST) Office of Weights and Measures has a special role in promoting uniformity in this field.

National Measurement Institutes (NMIs) provide the link between the legal metrology and international system of units (SI) through the realizations (called national standards) of units which are primarily based on physical laws and fundamental constants. The SI units serve as the basis of traceability, which is a fundamental concept for a unified system of metrology, and is also applicable to PMUs. A traceability requirement often stated in contracts, standards, guides, etc. as "traceability to an NMI" means in fact traceability to the SI through an NMI's realizations of the SI definitions. The realizations of an NMI should agree with those of other NMIs within the quoted uncertainties of the NMIs involved. The International Organization for Standardization (ISO) defines traceability as a "property of the result of a measurement or the value of a standard whereby it can be related to stated references, usually national or international standards, through an unbroken chain of comparisons all of which have stated uncertainties."

The accurate and consistent performance of all phasor measurement units is crucial for the overall performance of the system. Conformance to existing technical standards, such as [23], is of essential value for attaining this particular requirement of the phasor measurement system. Therefore, PMU testing (all functions and message formats) and calibration (phasor magnitude, phase, total vector error and associated uncertainty over all ranges) should be regarded as an integral part of the implementation of a large scale PMU system. The goal is to ensure that all PMUs:

- have consistent performance across the system,
- are interoperable, regardless of their makes and models,
- comply with system application requirements.

In addition to novel protection, real-time monitoring (disturbance event recording, data logging) and control (e.g. stability and power flow), metering for state estimation and revenue purposes (energy measurement and power demand recording) has been common among PMU functions. PMUs have been used for power quality monitoring (harmonics, interharmonics, voltage sags, swells, flicker, etc.), synchronization of digital fault recorders, as well as revenue metering and other equipment. More recently, PMU functions have been added to a variety of intelligent electronic devices (IEDs), most notably to protective relays. In general, PMUs have developed into a variety of commercial products.

All of these various functions of PMUs, or PMU-like functions in IEDs, require functional verifications and performance evaluations. The early tests and calibrations were started first by manufacturers, and, about two decades ago, by electric utilities [24] that showed initiative in adopting new technology for addressing technical challenges that they were facing. The initial testing and calibrations consisted of comparisons with the existing analog transducers. An IEEE Standard for PMUs [25] was adopted in 1995. The universities which were involved in the development of PMU technology have also been involved in the testing and calibration of PMUs, mostly from a research point of view [18]. Most of these tests and calibrations gave the performance results relative to some other lab equipment, as absolute calibrations were not developed and available. Involvement of a National Measurement Institute (NMI) in this area is very recent. The NIST Synchro Laboratory was formed in 2005 [26] as an initiative by manufacturers and the US Department of Energy (DOE), partly as a result of recent blackouts such as that in Aug. 2003, and the related US legislators' reports. The new IEEE Standard for PMUs was adopted in 2005 [23].

Since [23] did not address the dynamic performance requirements and did not specify the methods for conformance tests, the North American Synchro Phasor Initiative (NASPI) Performance and Standards Requirement Task Team (PSTT) started developing a guide for PMU Testing and Calibration [27]. The guide outlines laboratory and field testing and calibration procedures, and is focused on:

1. frequency, amplitude, and phase performance tests for PMUs and IEDs with integrated PMU function,
2. compatibility with Phasor Data Concentrators (PDCs) and system requirements,
3. interoperability requirements,
4. minimizing the possibility of misinterpretation of performance and test results,
5. tests such as:
    - harmonic sensitivity,
    - inter-harmonic sensitivity,
    - frequency ramps,
    - additional dynamic tests.

The IEEE Standard [23] requires traceability to SI units - NIST as an NMI clearly has an important role and is currently developing tests and procedures for evaluation of dynamic performance of PMUs [28].

The IEEE Standard [23] defines the total vector error (TVE), and specifies the TVE limits under various operating conditions to basically 1%. The NIST calibration system has an estimated TVE uncertainty of 0.015% under steady state conditions. Due to various operating conditions, there are numerous tests, in the order of hundreds, to perform. This points to a need for automation both in carrying them out and in result analysis.

In general, a calibration system should have at least four times, or, preferably, ten times smaller uncertainties than those of a system under calibration. The latter requirement implies that, for example, the uncertainties of the system for calibration of instrument transformers of the accuracy class 0.1 [29]-[30] should be less than $100 \cdot 10^{-6}$ for magnitude, and less than 145.4 μrad for phase. These are demanding but achievable requirements. As per [23], a calibration system for PMU performance verification should have at least four times better accuracy compared with the TVE test requirements from the Standard. These requirements to have TVE within 1% under most conditions and for both compliance levels 0 and 1, are not overly demanding from the revenue metering point of view. Although [23] specifies 1% TVE limit, some of the PMU manufacturers specify that their PMUs measure power/energy at an accuracy level of 0.25% or better. The NIST calibration system TVE estimated uncertainty goes far beyond the requirements for calibrating these PMUs.

For revenue metering, the meter uncertainties are important but not the only factor to take into account. Other important elements of the measurement chain are the instrument transformers that are used for scaling the voltages and currents to the levels that can be processed by the meters.

Until 2005, the most stringent accuracy class for instrument transformers defined by IEEE was 0.3 and currently is 0.15 [31]. The most stringent accuracy class defined by IEC is 0.1 for both Electronic Current Transformers (ECTs) [29] and Electronic Voltage Transformers (EVTs) [30]. Their error limits are given in the Table I.

Table I IEC Error Limits for ECTs [29] and EVTs [30]

I [%In]	ECT Error Limits		V [%Vn]	EVT Error Limits	
	Mag.	Phase		Mag.	Phase
120	0.10%	5 min	80-120	0.10%	5 min
5	0.40%	15 min			

Accuracy requirements for protection current and voltage transformers are significantly less stringent.

A joint Working Group of the Power Systems Instrumentation and Measurement Committee and Transformers Committee of the IEEE Power Engineering Society has been developing the Standard for Optical Current and Voltage Sensing Systems, which is intended to address the digital interface to measurement and protection equipment [32]. For metering applications, the draft reflects the limits of errors given in [31], while for protection applications it reflects those given in [33], [29]-[31]. It states that the errors of transformers with 0.3 or 0.6 accuracy ratings shall be determined using calibration techniques and methods giving results within 0.1% of the ratio and 3 minutes of phase angle. The errors of transformers with 0.15 accuracy ratings shall be determined using calibration techniques and methods giving results within 0.05% of the ratio and 1.5 minutes of phase angle, thus three times better accuracy than that of the device being calibrated. Traceability to national standards is required.

The deregulation of the electrical power industry in various parts of the world is having an important impact on revenue measurements. Before deregulation there was usually one major point of measurement, that between a distributor and a consumer of electrical energy. After deregulation of the electrical power industry, another two measurement points appeared, one between energy generation and energy transmission entities which became independent, and the other between energy transmission and energy distribution entities, which are also separate [34]. Although now driven by financial interests and not technical factors, these two new points of measurement are nevertheless very important, even more so because they are located at the high and medium voltage levels with large energy exchanges. Large financial transactions are now drawing a lot of attention to the uncertainty of power/energy measurement as these reflect on revenue. This means the necessity of taking into account not only the accuracy of revenue meters but the remaining components of the measurement chain, including instrumentation transformers, their accuracy classes, burdens, and other operating conditions. Instrument transformers, especially current transformers, are often overrated because of anticipated needs in the future. This means that they operate significantly below their nominal values (and in some periods of exploitation even below 10%) which increases their error. In addition, their actual burdens may be very different from those for which the transformers were designed and calibrated, which can further increase the overall measurement error. In these situations, an on-site calibration of the overall system may be warranted and useful, with a short pay-off period. In some countries it is required to increase the accuracy of the measurements with the increase in level of power/energy being transferred, e.g. for power transmission above 10 MW, an accuracy of 0.5% or better is required for revenue metering at high voltage [34]. This implies that a combined uncertainly of a meter, a voltage transformer, and a current transformer has to be better than 0.5%. Using a PMU with the TVE of 1% for revenue metering in such a case would be inadequate.

PMUs following the accuracy requirements [23] would not have sufficient accuracy for revenue metering, especially for metering at high voltage levels where the energy transfer is large and has a corresponding high financial value. This may lead to a change in the requirements in the not-so-distant future if the focus on high accuracy PMU revenue measurements is driven by market forces and major participants in the electricity market.

The presence of loads producing harmonics has been increasing over the last decade, and their detrimental impact on power system equipment and operation has been documented and addressed by standards [35]. Their impact on metering has also been studied [36]. Although there have been considerations of penalties for harmonic polluters as an economic incentive to take corrective actions [37], such a practice has not been introduced in North America. The basic metering quantities used for billing have been energy, delivered to the largest extent at 60 Hz, active or apparent power demand, and power factor. PMUs with their operation based on sampling and digital signal processing allow for implementation of the provisions from [38] for separating the fundamental from harmonic quantities.

NIST has under development PMU special tests designed according to [23], for performance levels 0 and 1, i.e. 1% and 10%, respectively, of any harmonic up to the 50^{th}. International standards, such as [39] related to harmonics and interharmonics measurements and instrumentation, and [40] related to harmonic limits, point to a significant impact of harmonics, interharmonics, and flicker on power quality. That impact has prompted the introduction of concepts such as interharmonic grouping, and requires new calibration techniques, in particular those for dynamic testing of devices under fluctuating harmonics conditions, and ensuring their traceability [41].

As the number of PMUs deployed in North American power systems is growing at an unprecedented rate, in addition to NIST's work as an NMI in the field of developing and providing PMU tests and calibrations, more calibration laboratories are going to be needed to share the workload.

A highly structured system of national and international accreditation of testing and calibration laboratories is already in place. The International

Laboratory Accreditation Cooperation (ILAC) is an international cooperation of laboratory and inspection accreditation bodies. Its main objective is to remove technical barriers to trade by developing and harmonizing accreditation practices, facilitating global recognition of laboratories and acceptance of their test and calibration data [42]. To facilitate its activities, ILAC recognizes several Regional Cooperation Bodies whose Mutual Recognition Arrangements (MRAs) have been successfully peer evaluated by ILAC: the European cooperation for Accreditation (EA), the Asia Pacific Laboratory Accreditation Cooperation (APLAC), and the Inter American Accreditation Cooperation (IAAC). Individual accreditation bodies can also be members of ILAC and signatories to the ILAC arrangement.

In Canada, the Standards Council of Canada (SCC), through its Program for the Accreditation of Laboratories-Canada (PALCAN), accredits testing and calibration laboratories to ISO/IEC 17025 [43]. Calibration laboratories are accredited in conjunction with the National Research Council of Canada (NRC) Institute for National Measurement Standards (INMS) which, through the Calibration Laboratory Assessment Service (CLAS) [44], provides quality system and technical assessments of specific measurement capabilities. In Mexico, the entidad mexicana de acreditación (ema) accredits testing and calibration laboratories. In the US, the system is more open market; there are a number of accreditation bodies providing various services to the divers markets. Some seek international recognition through ILAC. These accreditation bodies include the National Voluntary Laboratory Accreditation Program (NVLAP) which is part of the NIST Technology Services [45], and the American Association for Laboratory Accreditation (A2LA) [46].

Laboratories interested in providing PMU testing and calibration services are encouraged to go through the accreditation process. This includes an assessment of their capability and competence to provide scientifically sound and valid calibration or testing services as documented on their scope of accreditation and provided on the calibration certificates and/or test reports that they will be issuing. The process of accreditation requires time, financial and technical resources, trained and dedicated personnel, and a continuous commitment from both management and employees. Once the calibration laboratory is set up, the scope of its services determined, its quality system put in place, application for accreditation submitted with necessary supporting information, and appropriate fees paid, a usually iterative process of assessments, audits, corrective actions, and proficiency testing starts. This may take up to a few years to complete. Although the process of getting accreditation is involved and demanding, it results in national and international recognition and acceptance of calibration reports, and a number of other direct and indirect benefits such as greater client confidence and increased visibility in the industry. Many laboratories are accepting accreditation as a sound business practice.

5. PMUs as Embedded System

The emerging vision of the power system of the future is a multi-scale network, both in terms of time and topology. It is the complexity of one of the largest man-made engineering systems that is driving the need for the separation of analysis and control structures but without jeopardizing the coherency of the network.

The conventional approach is to simplify a multi-scale problem, eliminating other scales of no interest (be they temporal or spatial). Such a model is usually the basis for computer simulations. There are a number of approaches applied to that end in various scientific disciplines. Among them, singular perturbation and integral manifold theory have successfully been applied to time-scale separation of transmission networks.

The emerging power networks require that empirical approaches to modeling be considered in conjunction with analytical techniques. Similar analysis can be found in other enormously complex systems, such as biological systems. The link between microscopic and macroscopic models of the system can be achieved through the application of heterogeneous multiscale methods in order to best exploit the scale separation in the problem of improving the efficiency. Features of the approach are the reduction of complexity of the micro scale models, judicious use of macro scale models whenever possible and the use of computational and measurement data whenever available.

The research dimension in the area of embedded networks for power system monitoring and control is very tightly coupled with highly distributed infrastructure of hardware / software / communication system with heavy reliance on digital signal processing and information technology.

Enabling technologies applicable here are sensor networks applied as embedded subsystems. The application in power systems involves large differences in scales of integration and functionality, thus opening a number of problems and challenges related to computational power of sensors at various locations, bandwidth restrictions in communications, performance requirements for non-networked applications and operation in a variety of environments.

In sensor design, problems relate to the choice of architecture, benchmarks for testing and operation, calibration and development of standards. When sensors operate in a network configuration, the choice of the network topology, its self-organization, routing, latency and congestion performance are critical for certain applications (such as protection) and flexible for others (longer time scale optimizations). Network information theory needs to be applied to investigate the performance of various alternatives.

Data management is also an important aspect of the design of sensor networks – data flow in networks, structure of the database of measurements, security of communications and higher-level reasoning embedded in individual sensors of groups of sensors are essential parts of the application-specific integration process. The architecture of the computing platforms, node design principles, data compression and the aggregation rules as well as source authentication methodologies are aspects of the sensor design. The integration of true real-time operating systems for various multi-functional uses will also play an important role in embedded system integration.

6. Applications of Synchronized Measurements

Synchronized measurement technology offers major improvements in preventing and minimizing the impact of major disturbances in the following areas:

- detection of unstable system conditions that may result in system separation. These conditions are: angular stability; low frequency, inter-area oscillations; voltage stability; and line thermal overload.
- intelligent load shedding,
- improved restoration.

Synchronized measurement information, such as phase angle difference across interconnection, enables assessment of the stress on the grids and early identification of potential problems both locally and regionally. Real time information of angular separation allows the operator to anticipate, detect and correct problems during abnormal system conditions.

However, as operators may be overwhelmed with the amount of data during fast developing disturbances, automated wide area protection and control actions, such as System Integrity Protection Systems (SIPS) may be required. Improvements to event and/or parameter based SIPS could be envisioned with PMUs. With the support of off-line studies, some real-time parameters, such as phase angle difference, may be linked to line transfer limits based on system conditions and severity of the system contingencies. By establishing a certain angle or a rate of change of angle threshold criteria in combination with other events or parameters, actions (such as intelligent system separation) could be initiated with better understanding of the prevailing system conditions than conventional SIPS.

Intelligent load and generation shedding: Power system load shedding by under-frequency relays is a quick, simple, and reliable strategy, but has several disadvantages such as shedding loads when frequency is already low and shedding suboptimal amount of load [4]. Implementation of the rate-of-change of frequency is an immediate indicator of the power imbalance; however, an oscillatory nature of the rate-of-change of frequency can make the measurement unreliable.

Synchronized measurements could enable shedding a minimal amount of load and generation by accurate calculation of stability margins and cut-planes, the actual load distribution and other system parameters, such as the available spinning reserve, the total system inertia, dynamic performances and limits of the operating wide area frequency control system, and the load characteristics.

Furthermore, if the composite system inertia constant is known, the actual power imbalance may be calculated directly from the frequency derivative. This detection should be fast (to avoid a large frequency drop) and done at the location close to the center of inertia. This would require taking into account changes of load and generation with frequency and voltage as well as influence of dynamic system changes on power imbalance. Wide area synchronized measurements are very promising in implementing this approach.

Also, automated load shedding or generation shedding that will reduce line overloads or prevent system instability before the system is isolated could provide the following advantages:

- stress of system separation (resulting in unbalanced islands) would be avoided, and
- restoration efforts would be limited to the disconnected loads only.

Synchronized measurements could help in implementing this strategy.

Improved Restoration: Synchronized measurements allow us to improve processes and schemes to aid in quick restoration. Standard operating procedures, based on pre-defined system conditions and operating parameters, identify system restoration steps. Synchronized measurements give operators real-time information on the system status that could significantly improve the decision process.

For example, during power restoration, system operators often encounter an excessive phase angle difference across a breaker, which connects adjacent substations. By measuring this angle directly, the operators can make a better decision on timing, sequences, and feasibility of restoration thus minimizing risks of unsuccessful restoration and reducing the blackout time.

7. Application Requirements

The deployment of a large number of synchronized measurement devices for various applications is fundamentally different from many monitoring, protection and control systems in operation today [47]. The existing systems typically have well defined requirements and are installed, operated and maintained by a single entity. The synchronized measurement system will be built up over a period of time, and more and more applications will gradually be added to the system as it grows.

This requires designing a measurement system not only for the initial application requirements, but one that will be able to serve future applications, or have the ability to grow and change as requirements change. Various applications may have quite different requirements. For example, applications for steady-state phase angle monitoring and for SIPS improvement, even though they may be tracking the same phenomena, have different requirements, as shown in Table II. Data rate and latency requirements in Table II are much more demanding for adaptive protection and SIPS than for steady-state phase angle monitoring. Regarding PMU placement, phase angle monitoring may require measurements across a wide area to achieve topological observability.

Table II Phase Angle Monitoring and SIPS requirements

PMU	Phase Angle Monitoring	Adaptive Protection and SIPS
Placement	Selected wide area buses	Adjacent and/or wide area buses/lines
Data	V1 (and f) phasors	V and I measurements
Data Rate	≥ 1 sample/s	30 - 60 samples/s
Data Latency	1 – 5 s	< a few hundred ms

8. Conclusions

Even though the synchrophasor technology has been known for over twenty years, it is only now maturing to large scale applications. The utility industry has only recently undertaken large scale deployment projects, such as the North American Synchro Phasor Initiative (NASPI). The use of different computational techniques for phasor measurements within the same network of PMUs has a potential for creating conflicting situations. The success of large scale deployment will depend on ensuring interoperability and consistent performance of the PMUs installed across the system. Testing and calibration of PMUs and associated equipment is essential for achieving that goal and should be regarded as an integral part of the implementation of a large scale PMU system. The issues related to the testing and calibration of PMUs and associated equipment are identified in the paper and discussed in view of the relevant standards and guides. The accreditation process for testing and calibration laboratories is outlined. Careful integration of the embedded monitoring and control systems into the large networks of PMUs is necessary. Such integration creates challenges, but also provides unprecedented opportunities for the flexible control and protection of large scale power systems.

9. References

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