Synchrophasor Data Applications for Wide-Area Systems *

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Abstract - The successful deployment of Smart Grids at the transmission level will largely depend on the development and implementation of synchronized phasor measurement data-based applications and on the continuous improvement of the information and communication infrastructures supporting them. During the last decade several phasor measurement unit (PMU) data applications, that will potentially enable Smart Transmission Grids (STGs), have been proposed. In this paper we provide an overview on several of these applications, with focus in a subset devoted to PMU-only state estimation, modal analysis and voltage stability, as well as work related to developing some supporting IT infrastructure. Rather than discussing details of applications, this paper aims to give *highlights* of the relevant features of these applications in the context of STGs, and outlines additional research efforts necessary for phasing in these tools tools into practical use.

Keywords - syncrhonized phasor measurements, wide-area measurement systems, wide-area control systems, wide-area protection, PMU-data applications

1 Introduction

THE successful transition of today's bulk power delivery system into "Smart Transmission Grids" (i.e. "Smart Grids" at the transmission level) will largely depend on the development and implementation of synchronized phasor measurement data-based applications, and on the continuous improvement of the information and communication infrastructures supporting them [6].

Over the last eight years many wide-area monitoring systems (WAMS), have been deployed across the world [19] and are being continuously upgraded to meet unprecedented performance [8], delivery [5] and storage [28] requirements. At the same time, the number of available installations of phasor measurement units (PMUs) continues to increase [19], and several PMU-data applications, that could potentially enable Smart Transmission Grids (STGs), have been proposed [9]. In this paper we provide an overview of two of these applications, and on recent proposals for phasor data concentration [3], synchronized phasor measurement-based state estimation [24], and electromechanical mode estimation [25], which are normally considered as important control center applications.

Wide-area control systems (WACS) and wide-area protections systems (WAPS) and their applications are important for the development of STGs. While we briefly discuss the elements of WAMS and WACS, this paper is devoted as a review of a few wide-area monitoring elements, applications and related infrastructure. The remainder of this paper is organized as follows, Section 2 discusses how WAMS can help achieve Smart Grids at the transmission level, the common current architecture used for WAMS, and a phasor data concentrator design that can be used within WAMS systems and as a *Phasor Gateway*. Next, in Section 3 different approaches for state estimation with PMUs are discussed, in particular, it is shown how the Phasor State Estimation (PSE) approach can be used to deal with an specific type of bad data observed from *real* PMU measurements from the US Eastern Interconnection. A second important application of synchrophasor data is discussed in Section 4, and emerging challenges for mode estimation using mode meters are outlines. Finally, a conclusion of this review paper is given in Section 5.

2 Wide-Area Systems: The Enabling Technologies for Smart Transmission Grids

2.1 Synchrophasor-Enabled STGs

A STG should be considered as more than an hybrid system of power, measurement, and communication apparatus liked via an ICT system handling a vast amount of data. At a minimum, a STG should make use of this data in order to exploit all the available "observability" and "controllability" in a power system through closed-loop feedback control, and to coordinate system control with protection. As such, an STG can behave as a "self-healing" system, or at least provide mechanisms so that the power grid can be operated more securely through increased awareness.

To accomplish this ambitions, STGs should contain the elements outlines in Fig. 1, where a conceptual diagram of a "centralized model" for a Smart Transmission Grid is shown. In such STG synchronized measurements are obtained at transmission substations through not only from PMUs, but also from other highly accurate time-synchronized measurement systems retrieving data from controllable devices and protective device "information sets" (i.e. all available information from within a protective relay).

This plethora of data is sent through communication networks, received and concentrated at a Decision and Control Support System that determines appropriate preventive, corrective and protective measures. This sup-

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port system is the cornerstone for enabling STGs using synchrophasor data, it is here where the newly developed analysis techniques will produce "smarter" operator decisions allowing the power system to operate more securely, efficiently, and reliably. The decisions determined by this support system will then support operators at control centers to take "smarter operator control actions" or even device "smart-automatic control/protective actions". These actions are translated into feedback signals that are sent through communication networks to exploit the controllability and protection resources of the power system.

The centralized model is conceptually very similar to wide-area systems currently being developed, however, automatic feedback control is limited in today's WAMS systems.

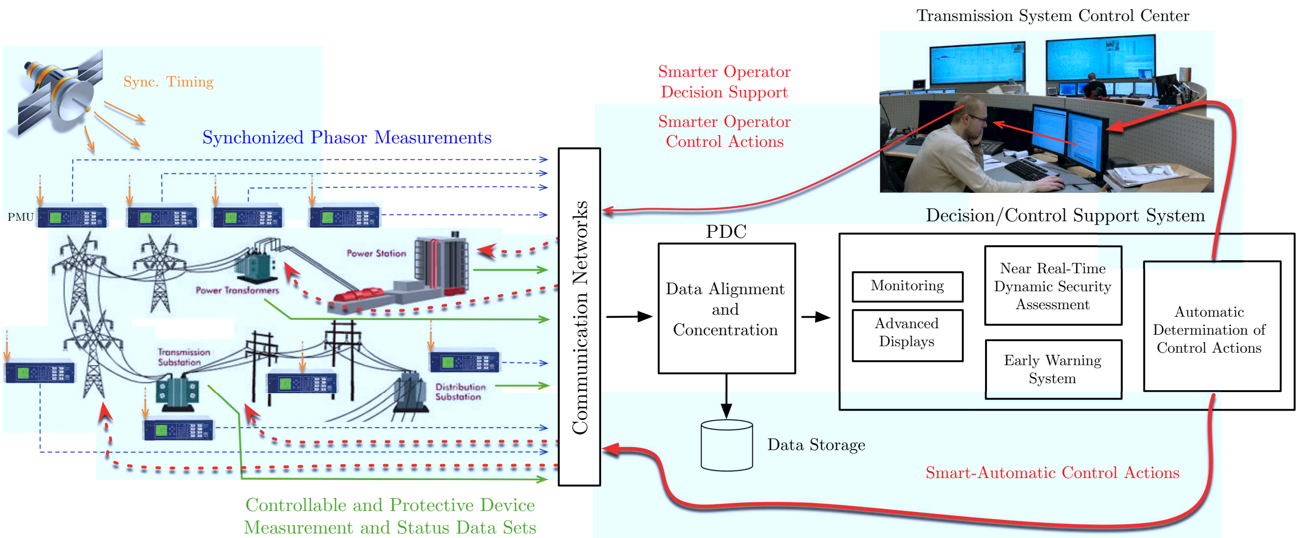

Figure 1: A centralized model of a smart transmission grid

Note that although the diagram shown in Fig. 1 is a centralized model, there can be other more decentralized models for STGs. A "decentralized model" is also possible, and most likely more appropriate to deal with the colossal amount of data involved. While this is out of the scope if this paper, it is important to realize that in such "decentralized model", data delivery can be accomplished through a publisher-subscriber model, such as GridStat [11] which uses Quality of Service (QoS) concepts for these purposes. Feasible approaches considered in [6, 11, 5] have great potential and should be further investigated.

It must be realized that regardless of the chosen paradigm (centralized or decentralized) there exists a dilemma: the ICT system will be determined by the requirements from different applications using PMU data, which in turn need the ICT infrastructure to be developed and tested.Acknowledging that both ICT aspects and specific requirements of each PMU data application need to be considered simultaneously if reliable applications are to be deployed deepens this dilemma. Hence, this dilemma also outlines the most important research challenge for wide-area systems. A possible solution to find the appropriate ICT architecture that fits the needs of future PMU applications is to develop a research, development, and testing platform where this issues can be addressed. While this is out of the scope of this paper, it should be recognized that such platform would have a tremendous value for developing PMU-based applications supporting the vision of Smart Transmission Grids explained above.

2.2 Wide-Area Monitoring, and Control Systems Elements

Wide-area systems are comprised by a set of measurement devices, communication devices and links, and computer systems. Figure 2 presents a generic architecture which is common place today: PMUs are measurement devices providing time-synchronized phasor data; phasor data concentrators (PDCs) and super-data concentrators (SPDCs) are computer systems receiving, processing, and sending out results to applications or storage, or signals for control; finally communication is typically accomplished through Multi-Protocol Label Switching (MPLS) virtual private networks [21], or Frame relay circuits [7].

As indicated in Fig. 2 PMU data can be stored and exploited at a *local*, *central*, or *external* layer. The local layer addresses sub-station level applications and data handling, a PDC may be used, but it is not strictly necessary. At the central layer, different communication mechanisms may be used, and thus the data from different locations may not arrive simultaneously. Hence, the most important functions of a PDC are to gather data from different locations, provide time-aligned data for applications, and create a useful archive of all the available measurements. In addition, it is very common to find that at this *central* layer some PDCs have been supplemented with other functions such as historian capabilities, monitoring and control applications. PDCs from different utilities or ISOs may also share data among them to support interconnection-wide applications. This is the *external* layer, that is used in large scale power systems as a further hierarchical level for wide-area applications and monitoring. To this extent a Super Phasor Data Concentrators (SPDC) can be used to perform similar functions as PDCs, however, requiring measurements over an entire network. Bidirectional communication is needed for data requests, configuration, and other interoperability functions.

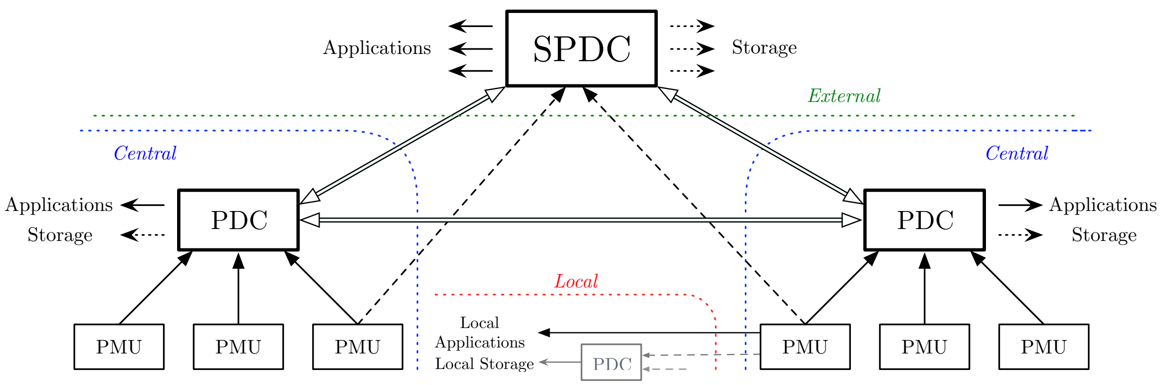

Figure 2: Generic Architecture of Wide Area Monitoring and Control Systems

This particular area of phasor measurement technology is continuously evolving and will be subject to many improvements in the near future. Of notable remark, is NASPINet, which proposes a different paradigm for data delivery [5].

2.3 Phasor Data Concentrators and Phasor Data Systems

From the previous discussion it is evident that PDCs play a crucial role in WAMS. Although phasor concentrators have been available in the Western Electricity Coordinating Council (WECC) power system [13] since the mid-90's, it's not until recently that they have become more available [19]. Earlier PDCs, such as the BPA PCD, were specialized standalone units [16]. However, in Oct. 2009, the Tennessee Valley Authority made openly available the source code of the TVA SPDC under the name *open*PDC [28], and its expected that it will accelerate the use of synchrophasors in more utilities. Nevertheless, it should be acknowledged that most transmission operators do not have the ability to process, store, and utilize the data from their own PMUs, and depended on concentrators located elsewhere including those using *open*PDC.

FIPS

A Flexible Phasor Data Concentrator (FIPS) developed to provide an accommodating and lower cost alternative for system operators and transmission owners to access their phasor data was first presented in [3]. An overview of FIPS is shown in Fig. 3. In the design stage of FIPS, several important issues came into consideration. Currently, PMU data is routed to large data concentrators in central locations. This data may then be routed back to independent system operators (ISOs) and transmission owners (TOs) via existing networks such as those based on the Inter-Control Center Communication Protocol (ICCP) [1]. Systems configured in this way have considerable communication overhead, and data storage at the central data concentrator is a difficult problem, especially as the number of PMUs increases [28].

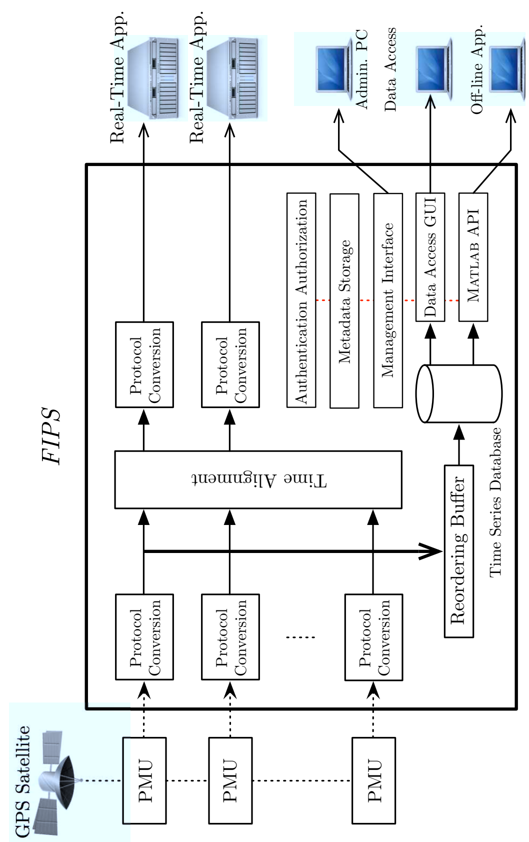

Figure 3: An overview of FIPS

Moreover, in existing synchrophasor systems, networking issues can cause data loss. Reliable transport protocols, which detect and attempt to correct transmission errors, are adopted to combat this problem. For instance, the Transmission Control Protocol (TCP) is not well suited for synchrophasor data transmission, because high latency can occur on lossy links. Other protocols for improving reliability provide a more robust solution to the problem of synchrophasor transmission over lossy links.

Efficient storage of synchrophasor data is also important. Existing databases may require large indexes or considerable time to extract a subset of the data. A new data storage scheme based on simple, flat files eliminates these problems.

Hence, FIPS is design as phasor system capable receiving, sharing, and storing data efficiently, and serve as a solid foundation upon which synchrophasor applications can be built. FIPS contains communication components, a database, and a data alignment engine, permitting it to function as a phasor data concentrator. Also, FIPS contains interfaces to enable the development of applications using the stored and real-time data.

Synchrophasors and their applications represent a crucial part of a future STG, and FIPS was also built keeping in mind the objective of facilitating research on PMU-data applications. Hence the availability of systems such as FIPS will enable to enable these applications to be rapidly developed upon a stable base. Further details on the features of FIPS can be found in [3].

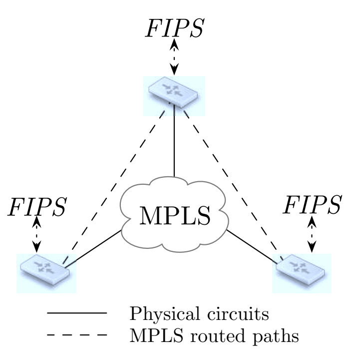

Figure 4: MPLS network topology for simple peer-to-peer data sharing

Phasor Gateways

NASPInet [14] represents a peer-to-peer architecture for the distribution of phasor data and consists of an entity called a data bus to which phasor gateways are connected. These phasor gateways communicate with each other to exchange data on an as-needed basis.

FIPS can provide the functionality of a phasor gateway with the addition of a few network services. First, a service must be provided to allow access to metadata, such as channel identifiers. Remote access must be available to data stored in the database, and a means to stream real-time data as it is received is also necessary. A system for authentication of remote systems is necessary. But these functionalities are straightforward to implement given a robust foundation.

An example network topology for peer-to-peer data sharing is shown in Figure 4. The FIPS server at the top of the diagram might be located at a large regional control center such as an ISO. The servers at the bottom might be located at transmission owners. All data is routed through the MPLS links to the central location, and the router at that point must transfer data between the two TOs, if that is desired.

When operating as a phasor gateway, the possibility of multicast for data transport should be considered. These, and other aspects, are studied in [3].

3 State Estimation using Phasor Measurements

3.1 *Conventional State Estimation including PMU data*

There has been much discussion about using phasor measurement data for state estimation. Most of the efforts have been directed into incorporating PMU measurements into conventional state estimators by merging it with conventional ICCP data [27, 12, 15]. While combining these different data types augments the measurement set of the estimator [4], it has the drawback of loosing most of the inherent characteristics of the power system dynamic nature captured by PMUs.

Although some improvements of including PMU data into conventional SEs have been identified [10], the approach to implement PMU data into conventional state estimators needs to be revised to harmonize ICCP (static data) with PMU data (dynamic data): it is necessary to address how to select the correct time window from PMU data that encompasses time-skewed data from ICCP, and how to filter the PMU data to better match the static behavior of conventional measurements.

There have been several proposals for exploiting phasor data such as hierarchical state estimation [12, 26], and distributed state estimation [15], these approaches take into account detailed level of granularity of the the power system and combine both traditional RTU data with PMU data. While improving the performance of conventional state estimators is important, a wide-area state estimator capable of capturing the power system dynamics embedded in PMU data would be an attractive solution for monitoring of large interconnected networks. In the next section, methods for PMU-only state estimation which focus on *wide-area* visibility are outlined.

3.2 *Approaches for PMU-only State Estimation*

There are basically two approaches for state estimation using only PMUs, the commonly known as *linear* state estimation approach introduced [20], and the phasor state estimation approach presented in [24]. Differently from conventional state estimators, these approaches don't use power flow models in their algorithms, instead Kirchoff laws are used.

Moreover, the aim of these state estimators is to perform state estimation for each snapshot of the system, i.e. 30-60 times every second, and to provide an independent state estimator instead of replacing conventional ones already in use. Nevertheless, the solution approaches differ in that the linear state estimator uses a weighted linear least squares estimation solution, while the phasor state estimator uses a non-linear WLS estimator to deal with inherent PMU data errors in the phasor angles. Both methods are briefly explained and contrasted below.

3.3 *Linear State Estimation*

It was first realized in ([22] - see Conclusions) that it is feasible to construct a linear state estimator by directly measuring voltage and line current phasors using PMUs, and by reformulating the WLS problem in terms of complex voltage and currents. In later publication [20], it is described how to develop this purely PMU- based estimator.

While we don't present this method in detail, it should be noted that in extremis direct state measurement can be accomplished by deploying PMUs at all system nodes, in this case the measured current phasors would provide redundancy in the measurement vector. Regardless if this kind of redundancy is available or not, this approach does not take into account the deterministic behavior of certain PMU-data errors [24]. One of such possible errors is shown in Fig. 5, which presents PMU data from the US Eastern Interconnection† from 2008. Here PMU 1 presents angle shifts or "jumps" that are not present in PMU 2 or PMU 3. Regardless of the source of this error, these angle jumps will have an important impact on the solution from the *linear* state estimator.

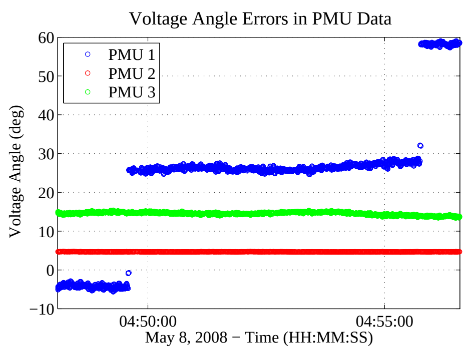

Figure 5: Typical Angle Error in the Measurement Voltage Phasor from PMUs (PMU 1 shows angle errors, while PMU 2 and PMU 3 do not show angle errors)

We illustrate this drawback with the example power system in Fig. 6 in which all voltage and current phasors are monitored by PMUs. Firstly PMU data is emulated as follows: a dynamic response is computed from the power system model, errors and noise are considered by adding white Gaussian noise to the dynamic response, and finally, a snapshot off all phasors is taken and an angle jump of 7.5° is added to the voltage phasor angle. The linear state estimation solution is obtained computed using the procedure and measurement weights design as described in [20].

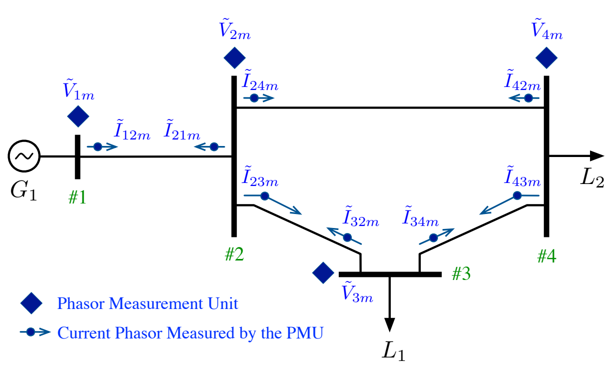

Figure 6: Example power system with all voltage and current phasors monitored by PMUs

#	θ^{true}	θ^{meas}	θ^{se}	True Residual	Meas. Residual
1	20	19.99	19.97	0.03	0.024
2	17.51	17.51	17.49	0.02	0.021
3	-1.46	-1.46	-1.46	0.00	0.001
4	-1.46	6.03	6.02	7.49	0.009

Table 1: Effect of phasor angle "jumps" in the voltage phasor estimates from *linear* state estimation

Table 1 shows the results from this simple experiment. The superscript *"true"* correspond to the uncorrupted simulation, the *"meas"* (measured) corresponds to emulated PMU data, and *"se"* corresponds to the linear state estimation solution. Perhaps the most relevant issue to point out is the difference between the true (forth column) and measurement residuals (fifth column). Observe that while the true residual detects the presence of the angle jump as highlighted by the 4th row of Table 1, the measurement residual does not. Therefore, in this example the linear state estimator approach has given an invalid solution. Moreover, this issue makes traditional bad-data detection techniques that depend on the measurement residual [17] inadequate to deal with this type of bad data. More importantly, this kind of bad data has a deterministic behavior (although it occurs randomly), and knowledge of this characteristic can be exploited as explained below.

3.4 Phasor State Estimation

This state estimator approach relies solely on PMU data [24], and has been designed to serve as an estimator of unmonitored buse which can perform phasor angle bias correction given measurement redundancy. From analysis of *real* field PMU data [24], we have observed several PMU data errors such as those in Fig. 5, which may be due to a variety of reasons

Phasor angles are typically computed using some signal processing techniques over one cycle or portions of a cycle to minimize the impact of quantization. The phase is also affected by the length of potential and current transformer cables. External synchronization issues with respect to GPS receivers and internal synchronization issues due to computational burden may also induce time delays, which translate into a phase lag in the measured data. We have observed random phase jumps of multiples of 7.5°‡ and random saw-tooth behavior. *Equally important, we have also observed that if such a phase bias occurs in a particular channel of a PMU, then the same bias will appear in all the phase channels.*§ Thus the polar coordinates provide a preferred setting for using weighted least-squares (WLS) techniques to correct the biases in the measured phasor data. The phase bias is a form of bad data, which is not part of conventional SCADA data. Here the magnitude is assumed to be correct, although it is still subject to normal calibration accuracy.

†The names of the locations are not shown for confidentiality.
‡A 60 Hz signal measured at 48 points per cycle will result in an error of $360°/48 = 7.5°$ if a data point is skipped.
§All phase channels use the same GPS clock signal and identical digital signal processing code.

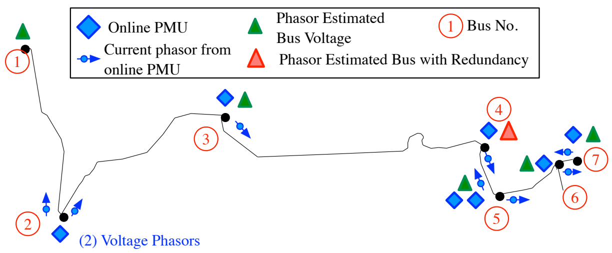

Figure 7: A portion of American Electric Power's (AEP) Transmission System with PMU Observability and Redundancy for Phasor Angle Correction

The details on this phasor state estimator approach are given in [24], however, it is useful to illustrate the capability of this estimator to detect and correct PMU data errors as the ones described above. We have used a data set that illustrates the capability for angle correction. The resulting estimates provided by the PSE are shown in Fig. 8 for Bus 4, and the measurement residuals for the voltage angles, $e_{\theta_i} = \theta_{im} - \theta_i$, are shown in Fig. 9. Angle biases are significant in some channels, possibly due to firmware and software issues in obtaining the phase of a measured quantity as shown in the voltage angle residuals in Fig. 9, the angle jumps are effectively detected by the angle shift variable of the method as shown in Fig. 8. This is relevant, as these measurement residuals can be effectively used for bad data detection [17].

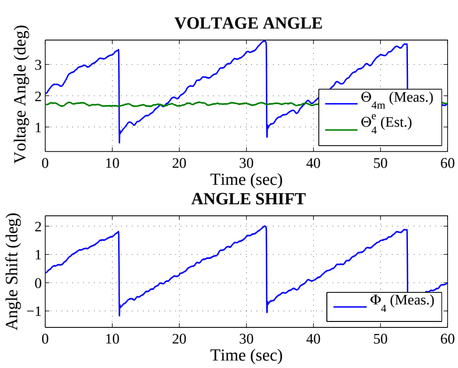

Figure 8: Bus 4 measured and estimated voltage angle using the phasor state estimator approach

Observe from Fig. 8 that the voltage and current phasors measured at Bus 4 present an angle error. The voltage angle measurement shows an undesirable *saw-tooth* behavior – a slew with a periodic reset, which was product of internal clock synchronization with the GPS signal. The PSE approach is able to remove this undesirable error and to correct the data. We should stress that without the angle bias correction capabilities of the PSE method the estimation process will converge to invalid solutions. In addition, necessary redundancy conditions must be met as described in [24].

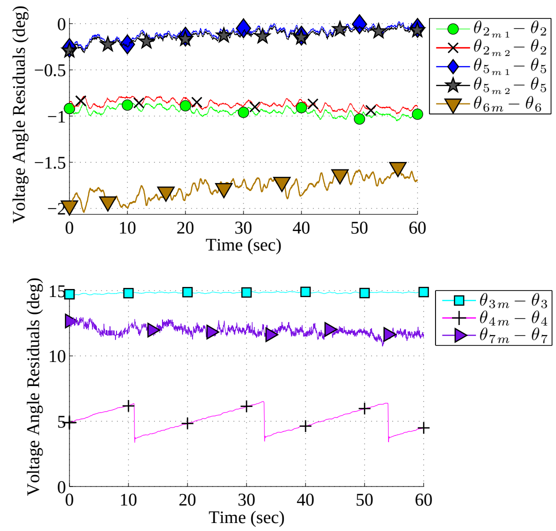

Figure 9: Voltage phasor angle measurement residuals

4 Electromechanical Mode Estimation from Ambient Data

The application of advanced signal processing techniques to power system measurement data for the estimation of dynamic power system properties has been a research subject for over two decade [13, 2]. These techniques have been proven successful for the estimation of mode properties, i.e. mode frequency, damping, and more recently mode shape. Estimates of mode frequencies and damping are indicators of a power systems stress, a declining value of these indicators point to a detriment on the capacity of a power system to operate reliably, and such condition may lead to a system brake up [13]. Mode shape estimates can give a direct indication of the major areas of a power system contributing to the oscillations in a specific mode frequency, and therefore may be used in the future for determining control actions [2]. There are several types of signal processing techniques available to provide these estimates, some are appropriate for transient signals, others are adequate for *ambient* signals, and others are used when a known probing source is used to excite the power network [13]. Some of these techniques have been implemented in off-line analysis software, and are now being incorporated to software tools used in control rooms for monitoring the near real-time behavior of power system dynamics [18].

Non-parametric and parametric power spectrum estimation techniques can be used to estimate the power spectrum from synchrophasor measurements (PMU data). The automated and continuous application of this identification process is known as a "mode meter" algorithm. As a result of applying these techniques and by focusing the analysis in the range of 0.1 to 1 Hz, the electromechanical modes are manifested as visible peaks in power spectrum density estimate (PSD). Narrow peaks in the estimated spectrum indicate light damping, and broader peaks indicate a well damped mode. With any algorithm, there will be estimated modes that are *numerical artifacts*, and not true system modes. To discriminate between these two results, a "modal energy" method can be used to determine which mode in the intearea mode range has the largest energy in the signal [23].

In [25] spectral processing techniques have have been successfully applied to characterize the small signal oscillatory modes in the US WECC interconnection, the US Eastern Interconnection, the Nordic Power System, and FDR data from the Nigerian power system. Analysis of data from the US WECC and the Nordic Power System revealed an interesting feature present in the data [25], Fig. 10 shows a Welch Spectrogram bearing a very narrow band signals appearing in the data about 0.28 Hz, which may be interpreted as a forced oscillation. We refer the readers to [25] for these analyses, here we further describe possible issues for mode meter algorithms issues due to the presence of these oscillations.

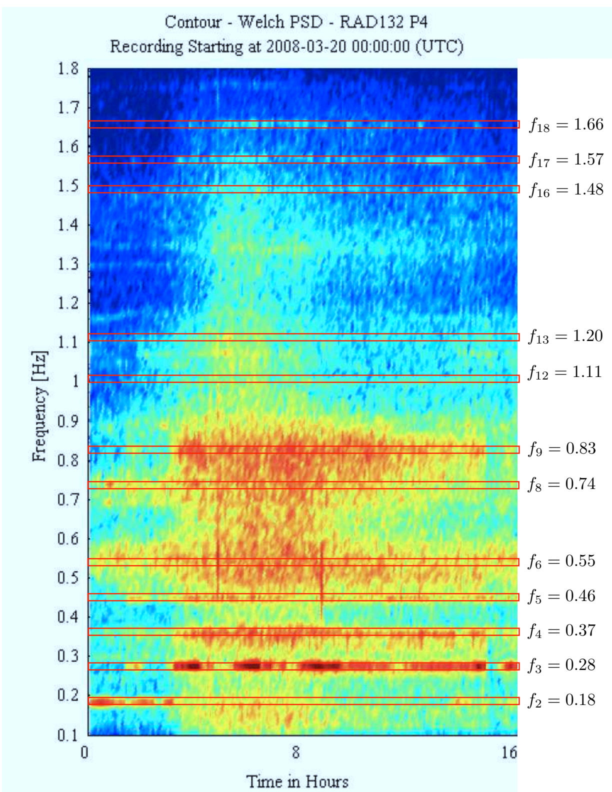

Figure 10: Welch Spectrogram for the P_1 signal from Radsted in Denmark. The red colors represent maximum values and the blue colors represent minimum values of the power spectrum density [dB]. The time is given in hours in (UTC) starting from 00:00:00 hrs, local time is given in UTC+1 hr. on 03-20-2008.

A more careful inspection of the Welch spectrogram reveals that presumably another sinusoid is present at about 0.18 Hz for the time frame of 0-3 hrs. A this point, it should be realized that it is very likely that both of these components are harmonics of a fundamental sinusoid of 0.09 Hz. In fact, in Fig. 10, it is possible to observe traces of other harmonics at = 2-6, 8-13, 15-19 and 21, where is the number of the harmonic, with corresponding harmonic frequencies of f_n=0.18, 0.28, 0.37, 0.46, 0.55, 0.74, 0.83, 0.92, 1.02, 1.11, 1.20, 1.39, 1.48, 1.57, 1.66, 1.76 and 1.94 Hz (the last two are not shown in Fig. 10). The origin of the sinusoid and its harmonics is unknown; it could be possibly due to a process in the system (as a control system going into a limit cycle), aliasing from higher-frequencies, or communication or measurements issues. It is important to note that some of the sinusoid harmonics are superimposed over the "true" system modes.

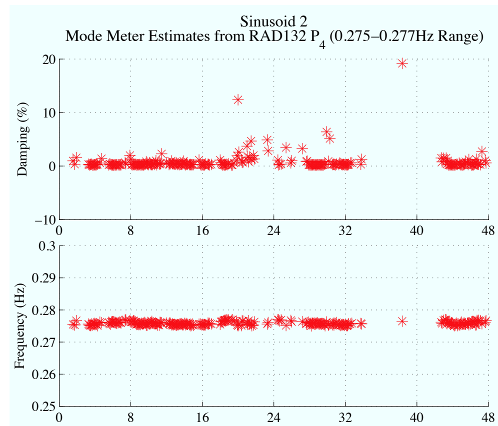

Figure 11: Damping and frequency estimation of the 0.18 and 0.27 Hz components.The time is given in hours in (UTC) starting from 00:00:00 hrs, local time is given in UTC+1 hr on 03-20-2008 and 03-21-2008

For the component 0.28 Hz in Fig. 11 the average frequency computer over 48 hrs. is of 0.276 Hz (with std. deviation of 0 Hz), and an average damping of 0.59% (with std. deviation of 1.08%). For this component the estimation results (a much lower std. deviation) give confidence that a forced sinusoid does exist, and furthermore, that the estimated damping of these components is zero.

The main concern is not necessarily that these forced sinusoids exist, but more importantly is to realize that some of the sinusoid harmonics are superimposed over the "true" system modes. Hence, it should be expected that the damping estimates for "true" system modes will be affected by the presence of forced oscillations. Similarly to the results shown in Fig. 11, the average frequency and damping for each of the modes discussed in the last section were computed. Table 2 shows the computed averages along with their respective standard deviation. While it is possible to have confidence on the estimates for the frequency, it is not possible to do so for the damping estimates for the "true" system modes (Mode 1 through Mode 3). Thus, it is possible to conclude that the presence of the superimposed harmonic components of the forced oscillation deteriorate the damping estimates for each of these frequencies. As mentioned above, the mode meter algorithm is not capable of resolving the portion of the frequency spectrum that is due to ambient load variation from the portion due to the forced oscillations, and as a consequence the analyst should be skeptical of the resulting damping estimates. The difficulties exposed above poses a new research challenge to improve the accuracy of mode damping estimates in mode meters and further research is needed to address these issues for the deployment of mode meter tools in control centers.

Mode	Signal	f (Hz)	$\bar{\sigma}_f$	d(%)	$\bar{\sigma}_d$
1	P_1	0.3615	0.0044985	4.384	7.3948
	P_3	0.36038	0.0063084	8.0646	9.1122
	P_4	0.36064	0.0048168	5.6049	7.7743
2	P_1	0.55561	0.0066281	4.9269	9.1952
	P_3	0.55556	0.0071702	6.4337	8.7984
	P_4	0.55532	0.0062926	5.1723	6.4484
3	P_1	0.82916	0.0049452	2.5384	5.4367
	P_3	0.83052	0.0051476	3.8604	6.8673
	P_4	0.82996	0.0049805	3.2916	5.5067

Table 2: Statistic of Mode Meter Estimates for 48 hrs.

5 Conclusions

In this paper we have have presented synchronized phasor measurement applications and phasor data concentrator approaches. We have highlighted phasor measurement data issues and how application can be designed to take to deal with them, these results can serve to derive requirements needed for the actual implementation of the applications in a control center. In addition, we have also outlined a phasor data concentrator approach that can manage and exploit phasor measurement data and serve as a phasor gateway. Thus, our overall aim with this paper has been to highlight that the successful transition of today's bulk power delivery system into "Smart Transmission Grids" will largely depend on the development and implementation of synchronized phasor measurement data-based applications, and on the continuous improvement of the information and communication infrastructures supporting them.

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