Power System Protection and Dynamic Performance Assessment

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SUMMARY

The emerging technology "Wide Area Monitoring, Protection and Control - WAMPC" can extend the application areas of System Protection Scheme (SPS) based solutions and may be applied in very large areas like the UCTE transmission system. Research activities in recent years have shown that different problems of large power systems can be identified with WAMPC based systems using Phasor Measurement Units (PMUs). On the other side, the political reality shows that the implementation of a WAMPC system in an area covered by more than one utility seems from today's point of view nearly impossible, especially if the utilities are located in different countries.

In this paper, the basic ideas for the implementation of a "Flexible System Protection Scheme" in a geographical limited area are presented, using PMUs as modern Remote Terminal Units (RTUs). The goal is to understand and solve the well known two power system problems voltage instability and small signal angle instability leading to inter area oscillations.

A prototype of a monitoring system including Phasor Measurement Units, Digital Fault Recorders with Phasor Measurement capability and a Personal Computer with a Central Software connected to the mentioned field units (DFRs and PMUs) for real time data retrieving and visualization is being prepared for the first measurements.

The in this paper proposed solutions encourages utilities to a long term investment policy to upgrade protection relays and other Intelligent Electronic Devices (IEDs) like bay controllers with new ones capable of the communication protocol IEC61850, which will lead to useful implementation of System Protection Schemes, especially in regard to fast and secure load shedding.

Although there are several promising signs that the new technology will help to operate the power system more secure and reliable, one should be aware of the fact that the installation of PMUs in various locations of the power system will not solve any problem. Long term investments into the communication infrastructure and detailed planning studies will be required before adequate system wide solutions can be implemented. Also, it must be considered that a promising Flexible System Protection Scheme will require very reliable central software; where valuable experience of power system operators and protection engineers should be incorporated during the development phase.

KEYWORDS

Phasor Measurement Unit, Digital Fault Recorder, wide area protection and monitoring, system protection scheme, power system protection, power system oscillations, voltage stability

INTRODUCTION

A *System Protection Scheme* (SPS) or *Remedial Action Scheme* (RAS) is designed to detect abnormal system conditions and take predetermined, corrective action (other than the isolation of faulted elements) to preserve system integrity and provide acceptable system performance. SPS actions include among others, changes in load (e.g. load shedding), generation, or system configuration to maintain system stability, acceptable voltages or power flows [Definition by North American Electric Reliability Council - NERC].

Detailed knowledge of the dynamic behavior of a power system is necessary prior to any implementation of a System Protection Scheme. To understand this, an appropriate modeling of the transmission system enhanced with long term measurements is necessary. As proposed in [6], the buses in a power system can be classified into one of the three categories: load bus, tie bus and source bus. Load is connected to a load bus. A tie bus is connected neither to a load nor to a generation plant directly. Source buses include generator buses whose voltages are regulated by their connected generators; boundary buses are like source buses. A generator bus becomes a load bus if the connected generator reaches its limits and loses the voltage regulation capability. The proposed modeling of a power system leads to a geographical limitation and may be used for the description of a transmission system under the responsibility of one utility. For most of the SPS applications, the model of load buses or source buses needs more than a description by a constant PQ or a constant PV node. It requires the modeling of the dynamic behavior obtained either during planning studies, either by a monitoring of the real-time response. The quality and accuracy of this modeling principle can be improved significantly with long term measurements, for example with the utilization of Digital Fault Recorders (DFRs) with Phasor Measurement capability, as described below.

Depending on the characteristics of the power system, the design engineers for the System Protection Scheme will face different problems. Weak systems covering large areas have to deal with all kinds of stability problems, while densely meshed systems with strong power generation mainly face small signal stability and thermal overload problems, as shown in the Table 1 [1].

	Densely meshed system with dispersed generation and demand	**Lightly meshed system With localized centers of Generation and/or demand**
System in large Interconnection	Small signal stability Thermal overload No large frequency variation	Transient stability Small signal stability Voltage stability
System not interconnected or by far the largest partner	Thermal overload Large frequency variation	Transient stability Voltage stability Large frequency variation

Table 1: Stability problems of power systems

POWER SYSTEM MONITORING

Phasor Measurement Units are modern Remote Terminal Units (RTUs) measuring voltage and current vector values and the power system frequency with a time stamp of high accuracy. The measured data with a typical refreshment rate of 30Hz or 25Hz (at 60Hz or 50Hz power system frequency) is usually sent to a central computer using modern communication channels. This refreshment rate is very *high* with respect to the rate of a SCADA system. The accuracy of the measured vectors is usually very high with a total vector error of 0.1% to 1%. Therefore, PMUs are suitable for dynamic performance monitoring, as for all dynamic applications in general.

Modern Phasor Measurement Units meeting the standard IEEE C37.118 have also process signal inputs, for example to measure the value of the excitation current of a generator in a power plant, the value of the DC current of a HVDC system or the actual value of the capacitance of a Thyristor Controlled Series Capacitor – TCSC. Important topological information can be gained using binary inputs of a PMU, and breaker control is possible with contact outputs.

The typical PMU as defined in the standard IEEE C37.118 runs like a modern transducer. All measured and calculated data is immediately sent to the Central Computer via serial link or Ethernet.

If the communication channel is disturbed, all data is lost until the communication link is reestablished.

This practice may be not satisfactory for all applications if the system dynamics should be determined with long term measurements, like the dynamic behavior of various loads and Flexible Alternating Current Transmission Systems (FACTS). In this case, Digital Fault Recorders with Phasor Measurement capability with integrated mass storage bring additional measurement security. The utilization of DFRs is a more reliable and economical solution compared with a standard PMU communicating with a dedicated Personal Computer close to it, especially if the DFR meets all the electromagnetic immunity standards applied to protection relays. The long term records of the DFRs can also be used for parameter estimation of various power system components like transmission lines and complex loads.

Depending on the task, the installation of the Phasor Measurement Units in a Power System can be a challenging task. For small-signal stability, we suggest putting PMUs at HV and EHV nodes next to generators, while for voltage stability PMUs must also be placed close to loads. Reference [9] suggests optimal placement strategies for system dynamics assessment.

VOLTAGE STABILITY

Voltage stability is a well known problem which has led to some major blackouts during the last years. A short explanation of this problem can be given by the following definition [13]: *"Voltage instability stems from the attempt of **load dynamic** to restore power consumption beyond the capability of the combined **transmission and generation system"**.* By this definition, there are three major sources for voltage instabilities:

- *Load dynamic*: after a voltage decrease, dynamic loads like motors or thermostatic loads try to restore their power consumption by increasing the current. This load category is strongly linked to the reaction of On-Load Tap Changers (OLTC).

- *Transmission system:* due to the increase of the load, the maximum capacity of the lines may be reached.

- *Generation system:* with growing power transfer, the transmission system needs more reactive power and the generators can reach their reactive power limit. In this case, protection units can limit the reactive power output of a generator. In this case, the generator is no more able to control the voltage at the terminals.

As described above, the three sources are strongly linked to each other. Examples where they are decoupled are shown in [13], [14] and [15]. In a real voltage collapse case, the complete instability mechanism involves generally the three aspects.

The possible countermeasures for an evolving instability are mainly capacitor switching, OLTC blocking or decreasing of their set-points, load shedding and generation rescheduling or starting-up of gas turbines.

Voltage stability is often studied as a static problem in system security analysis. Security assessment programs liked to EMS systems run a high number of simulations for different contingencies, starting with the actual power system status. These analysis tools have two major weak points:

- The static simulation tools run with a rough system model, describing the dynamic of the power system with low accuracy

- The required type and number of the simulated contingencies is usually not complete. Only credible contingencies are simulated, but a non credible contingency may lead to a voltage collapse.

With the current trend to operate the power system closer to the stability limits, the above mentioned slow security analysis is not sufficient. The refreshment rate of the state estimator based on the SCADA (between 1 and 15 minutes) is too low to predict a voltage collapse. The addition of a powerful real time monitoring system to the current static security analysis software may lead to a significant improvement. This requires new tools for measurements at higher refreshment rates, like

the application of PMUs. The output of this monitoring can then be used to take simple actions to avoid a voltage collapse, which is the goal of the proposed SPS.

System Protection Scheme against voltage collapse

The Thevenin´s equivalent seen from the load gives useful information about the maximum transfer capacity. The maximum loadability of the node is reached when the amplitude of the complex voltage drop across the Thevenin´s impedance (Figure 1) is equal to the voltage at node [13]. Even if the maximum loadability of a node is not necessarily the point of collapse, it gives a good approximation
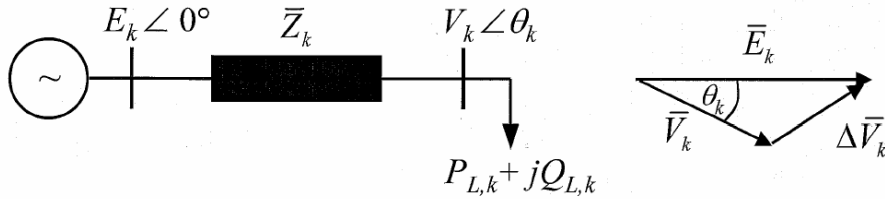

Figure 1: Thevenin´s equivalent and complex voltage drop across Thevenin´s impedance

of the stress and the weakness of the system. The problem is obviously the correct estimation of the parameters for the Thevenin´s equivalent. Milosevic and Begovic [12] propose a local algorithm based on a Recursive Least Square (RLS) method. From the experience of the authors, this method has two major drawbacks: the parameters of the RLS method are difficult to tune for an online application and the parameters of the load must be known for a precise estimation of the equivalent.

A centralized measurement method based on PMUs communicating with a Central Computer seems to be the better approach. This measurement principle requires PMUs installed at the main buses and power plants of the transmission system, but also near to major loads. The main assumption of the measurement principle is that the generator *nearest* to a load can give reliable information for the Thevenin´s equivalent. But first, it must be described what the nearest generator is and which generators can be taken into account.

The distance to a generator is defined as the sum of the absolute values of the complex voltage drop for each line along the shortest path from a node to the generator. The *nearest* generator is the one for which the so-defined electrical distance is a minimum.

Next, the different possible status of a generator must be defined to understand which generators should be considered. A generator is in *PV mode* if it controls the active power and the voltage at its output. A generator is in *PQ mode* if it controls active and reactive power but not the voltage. This happens when a limiter is activated. Here, two types of limiters may be involved: The Over-Excitation Limiter (OEL) and the Stator Current Limiter (SCL). These limiters protect the machine from thermal overload and usually allow a limited overload for a few seconds (typically 10 to 20 seconds) before limiting the output. During this time, the generator still controls its voltage.

According to the definitions above, the different status of a generator are:

   a) PV mode and power output below capability curves
   b) PV mode and power output above capability curves
   c) PQ mode

Since a generator in PQ mode can not regulate the voltage during a voltage collapse, it can not be considered for the search of the nearest generator. So, two possibilities remain to select the nearest generator, (a) and (b). In case of (b) we know indeed that, if nothing changes, a few seconds later this generator will be in PQ mode. Therefore, only generators with the status (a) are considered in the example presented in this paper,

As a next step, a voltage stability index (VSI) will be defined, which is the equivalent to the index proposed in [12]:

$$VSI_k = V_k / \Delta V_k$$

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V_k is the voltage at the node k and ΔV_k is the distance to the nearest generator as it is described above. It is assumed that this distance approximates the voltage drop across the Thevenin´s impedance. If this is exact, the value of VSI_k is one at the maximum loadability point. Since simplifying approximations have been done, a margin must also be introduced. The global index for the whole power system is then defined as the minimum of all VSI_k.

The complex voltage at each node of the network is measured by a PMU. To detect the status of the generators, there are two possibilities:

a) Monitoring the power and the voltage and comparing these with the capability curve and with the reference voltage
b) Receiving directly the status information from limiters.

The automatic actions done by a flexible SPS must be as simple and efficient as possible and need important planning studies. The results of those studies are typically optimized for a unique network; from today's point of view there is no general application principle. The actions for voltage stability include mainly switching capacitor banks, load shedding and blocking tap changers. The latter only stops the restoration of static loads and do not decrease the weakness of the system. A SPS with a good logic should initiate this type of action before load shedding and quick enough to avoid a collapse due to other instability mechanisms. Thanks to an efficient automatic SPS using a VSI response-based design, dispatchers will have more time to take more complex actions like change in the topology, starting up of gas turbines or rescheduling of generation.

Visualizations and results

Voltage collapse is mainly a local phenomenon. A global index for the network (usually the index of the worst node at every moment) has two weaknesses. Firstly, we do not see immediately at which location the problem is situated and the severity of the instability. Secondly, a node may have a bad index whereas it does not evolve anymore. If this index is taken as the global index, it could hide evolutions elsewhere in the system. Therefore, a geographical visualization with colors representing the index value at each node is proposed. This view is complementary to a global index because the history of the index is not visible in this case.

The results presented in this paper were obtained from simulations performed with Eurostag on a simplified but realistic network, the Nordic 32 [11]. This network is inspired of the Swedish network
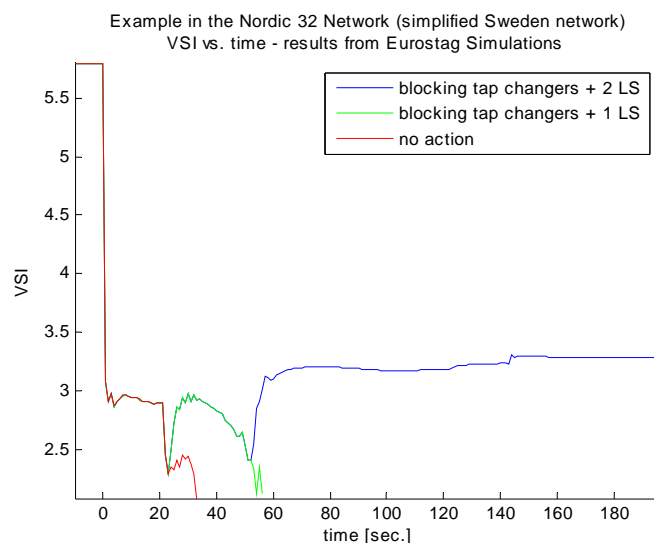

Figure 2: Remedy actions of a SPS in the Nordic 32 network

and is designed to study the voltage stability problem. It is composed of 3 areas separated by long transmission corridors. The North and the South are generation regions and the central area is mainly a load region (Figure 3).

The example for the voltage instability presented in this paper is a case where a generator trips in the central region (load area) of the network. If no action is taken, a voltage collapse occurs after 34 seconds (Figure 2) due to some limitations at the generator outputs and one tap change action at several transformers.

Following strategy is chosen to avoid the collapse: As soon as the VSI is below 3, all tap changers are blocked, and if VSI is below 2.5, 25% of the load must be shed at the weakest node, i.e. the node for which VSI is the smallest. This strategy is not optimized yet, but works for all examples which were tested with the Nordic 32 network.

The examples with one and two load shedding actions are shown in Figure 2. The case only blocking the tap changers do not save the network and is not shown. As shown in the figure, dispatchers get 23 more seconds to initiate additional actions if one group of load is shed before a collapse in 57 seconds occurs. If two groups of load is shed, the voltage collapse can be avoided.
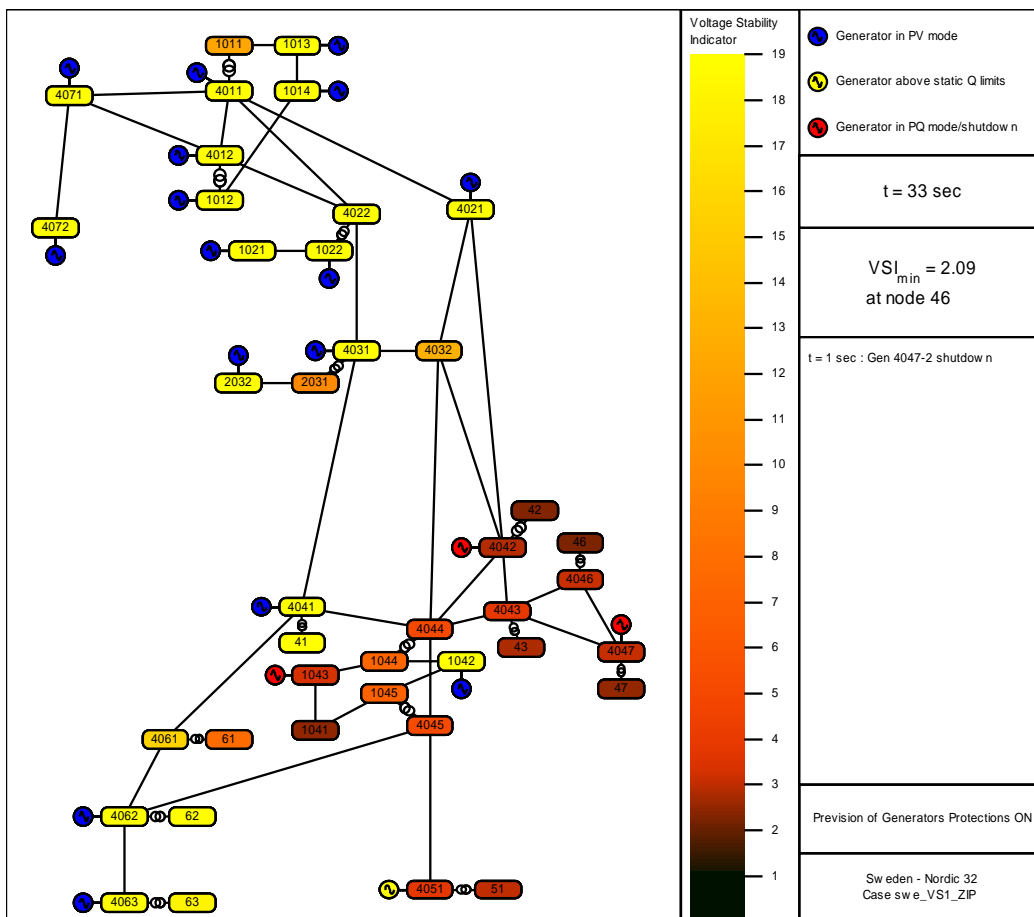

Figure 3: Geographical visualization of VSI_k in the Nordic 32 network

Figure 3 shows a geographical view of the network where the color of the node indicates the value of VSI at each node. The actual status of the generators is shown in color. The snapshot is taken just before the collapse, i.e. where no actions were initiated.

The implementation of the SPS requires the installation of PMUs at every power plant and HV substation, also at some boundary nodes. These boundary nodes are all the nodes inside a belt of the first generators in contact with the monitored area. At the boundaries, the VSI is not calculated, but the

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value of voltage Phasors and the status of generators at these nodes are required to calculate the VSI in the region of interest.

Figure 4 depicts the status of the same area like in Figure 3 at the same moment, before the voltage collapse, but a smaller area is under observation. The gray nodes are the extern nodes, the black and white nodes are the boundary nodes and the colored nodes are in the monitored area (here the central region). Simulations have shown that the results for the monitored area are identical to those for the complete network.

The goal of this SPS proposal is to add an additional defense layer between local protection (voltage and frequency relays) and the SCADA system. The proposed implementation method not specific to a particular network and can be applied to any network prone to voltage stability problem. The implementation of this SPS should be done in two steps. The first phase will be the implementation of a monitoring system which can already give a dynamic view of the system and important system parameters can be identified. Then, results of the monitoring system may be used to take safety actions on the network to avoid a voltage collapse.
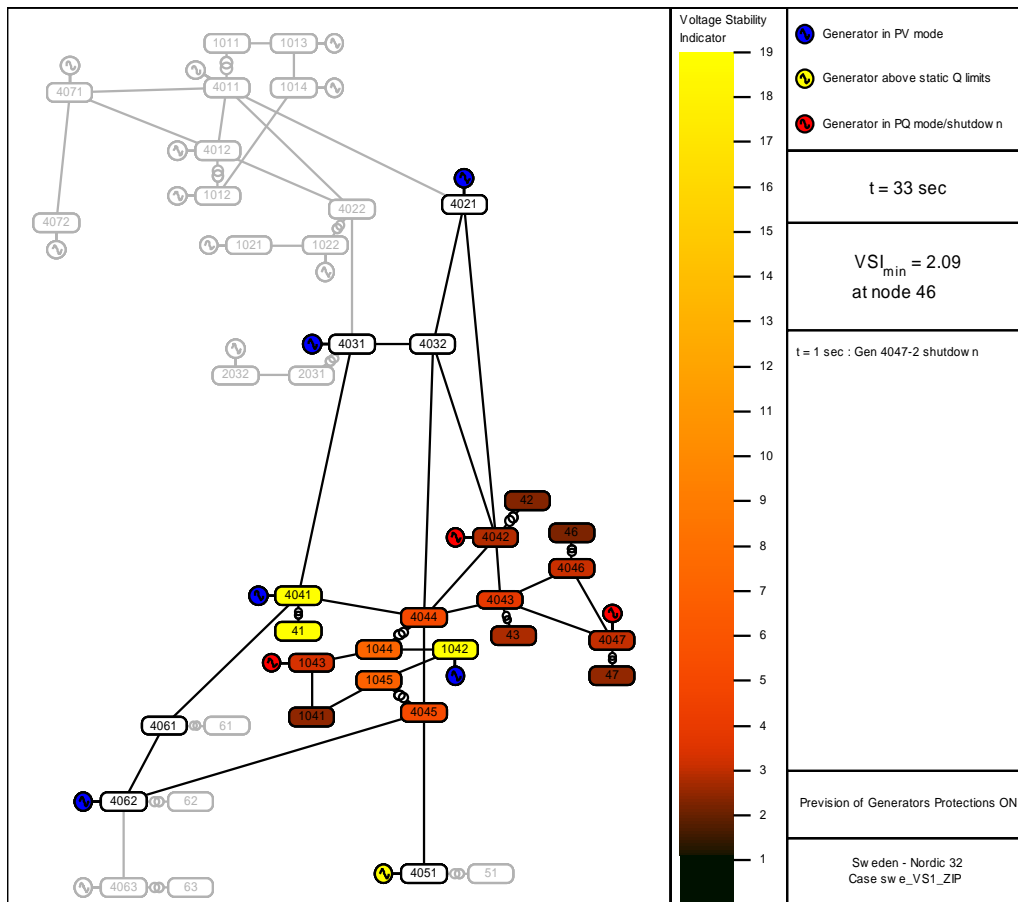

Figure 4: Geographical visualization of VSI_k in the Nordic 32 network, for a limited part

SMALL-SIGNAL ANGLE STABILITY

As a consequence of small perturbations, such as incremental load changes or switching actions, oscillations may appear in the power system. While being experimented by most power systems, some network configurations are more prone to these phenomena than others, especially large interconnected systems with high transfers through tie-lines, or with a high amount of hydro generation.

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When generator angles start oscillating against each other, voltage excursions and alternating power flow components arise. Those *electromechanical oscillations* may cause damage to generators. To avoid such consequences, the transfer capacity of the system must be restricted. If no measures are taken to satisfy the balance and stability criteria, larger perturbations may happen, e.g., frequency stability problems. Some oscillatory events recording are shown in references [17], [18]. It is therefore necessary to make sure that these oscillations are sufficiently damped in order to guarantee safe operation. Since those oscillations appear most of the time around a steady-state operating point and are of relatively small amplitude – unless the amplitude is growing (we talk then about a negative damping) –, this phenomenon is known under the name of small-signal (angle) stability [19].

A broad classification identifies electromechanical oscillation modes as either *local* or *interarea*. In the first case, the oscillations are restricted to a small part of the system. It is the case when two neighbor generators oscillate against each other or when one generator oscillates against the rest of the system. On the other hand, when many generators located far from each other oscillate at the same frequency, we designate it under the name of *interarea oscillation*, which is most critical one. Since the oscillating inertias are huge and the frequencies are low – between 0.1 and 1Hz - poorly damped modes are then sustained for a long time, increasing the risk of cascading outages.

System Protection Scheme against interarea oscillations

Small-signal stability is a necessary condition for normal network operation. Therefore, control systems designed to damp oscillations are of the *closed-loop* type and their tuning belongs to the planning phase. Most common controls are PSS (Power System Stabilizers) [19], [20], and FACTS (Flexible AC Transmission Systems) controllers [21], [22]. Next to these local controllers, wide-area control systems [23], [24] are proposed or in planning, but are faced with political and telecommunication difficulties.

Due to particular events or market transactions, the system operating point or even its topology may be far from what was expected. As a consequence, the controller tuning may be inefficient and poorly damped oscillations may perturb the system. In such a case, it is important to detect them rapidly, and a defense plan integrating a System Protection Scheme against interarea oscillations may be necessary to avoid further propagation of the disturbances and, in some cases, a system collapse.

In case of small-signal stability problem, open-loop corrective actions must aim to reduce the load on the tie-lines. This can be done through generation rescheduling or, in case of necessity, remote load shedding. Indeed, it has been shown that small amounts of controlled load variations may significantly improve the system dynamic performances [25], [26]. To investigate where such actions have the most efficient impact on the system stability, knowledge of the oscillating areas is an important first step. Such a scheme based on generator coherency is proposed in reference [27].

Since interarea oscillations may be excited by a large number of events at various locations, an SPS designed against interarea oscillations should be of the *response-based SPS* type. While being more flexible with respect to the initiating events than the event-based SPS, response-based SPS have slower reaction times [1]. It is therefore crucial to detect oscillating modes early in order to act before propagation of disturbances occurs.

SPS are designed for more efficient and for more secure use of the transmission system. However, the two topics must be investigated for every SPS: the SPS reliability and the way operators may understand its impact on the power system behavior [28]. The acceptance of a SPS is then subjected to a clear understanding of the dynamic phenomena it is designed for and to a clear view of their impact. Those objectives can be met with the implementation of a wide-area monitoring system based on PMUs.

Signal processing for the detection of oscillations

The system proposed here for the detection of oscillations is based on PMU measurements and basic signal processing techniques. The input signals are the angles of the positive sequence voltage Phasors measured at the generator terminals. According to the *Wide-Area Monitoring, Protection and Control System* (WAMPC) definition, the measured values are gathered by a Central Computer, where the
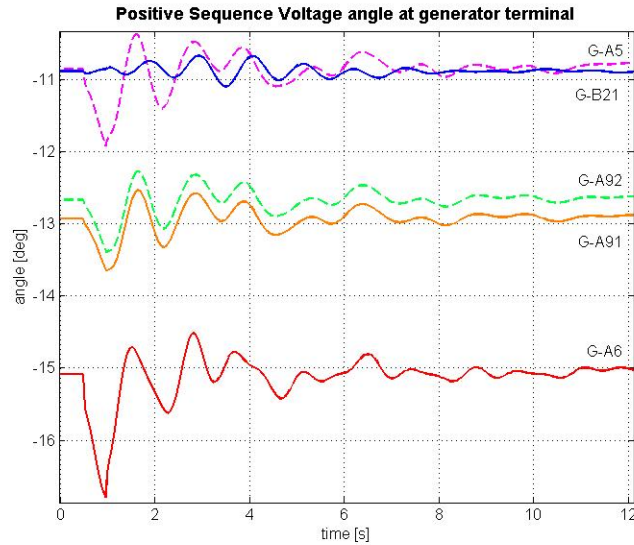
Figure 5: Oscillations of the angle of the positive sequence voltage angle after load variation.

processing is executed and corrective actions can be initiated. This centralization relies on the existence of a reliable telecommunication network.

The simulated test system used for illustration is inspired by the interconnected network of West Africa, where 5 countries share the same grid. This system is weakly interconnected and has an important amount of hydro generation (about 55% of the total installed capacity which is 2500MW), what makes it prone to electromechanical oscillations. Simulation results shown here are based on a load variation of 10MW at time $t = 0.5$s, in the South of the system, causing poorly damped interarea oscillations. Simulations have been done with EUROSTAG [30] and the results were validated through modal analysis. A sample of these oscillations is shown in Figure 5.

The processing technique is as follows. The Discrete Fourier Transform is applied to a *sliding window* of about ten seconds in order to extract the spectrum of the positive sequence voltage at every selected bus. The length of the window has been chosen long enough to contain at least one signal period at all expected frequencies (0.1Hz being the lowest observed frequency), but short enough not to delay too much the detection of critical modes. Since measurements come from PMUs, the sampling frequency has been taken equal to 25Hz (for a 50Hz system). By inspection of the power spectrum, the *dominant modes* are identified. The dominant modes are defined as the frequencies showing the largest angle excursions. For every selected dominant mode, the input signals are then resampled at a multiple of the oscillating frequency in order to obtain an accurate measure of the amplitude and phase of all recorded signals at that frequency. For one mode, we can then associate a vector to each oscillating generator.

By putting together the computed vectors, we are able for every time window to construct the *mode shape* of the dominant modes. The mode shape represents the respective amplitude and phase of oscillation for every generator. Once the mode shape is known, *coherent group*s of generators are easily identified in order to determine which areas oscillate against each other. The analysis results lead to a wide range of visualizations, as shown in Figures 6, 7 and 8. When a series of consecutive windows is available, the mode relative *damping* factor (that is, the decay in amplitude between to consecutive peaks) can be roughly evaluated by following the evolution of the oscillations amplitude.

Power system oscillations monitoring

Classical mode shape representations include compass plot and bar plot, as shown respectively in figures 6 and 7. In particular, the mode shown is a poorly damped interarea mode between generators in the East and those in the West. Its frequency is 0.35Hz and its relative damping is about 2.6%. The

compass plot is a polar representation of the vectors indicating the phase and amplitude of the oscillations at the various measurement locations; while the bar plot emphasizes the oscillations amplitudes. Both representations are useful, but it is important for the operator to gain insight in the dynamic phenomena quickly. This can be done by representing the mode shapes geographically, as shown in Figure 8. Colors emphasize generator coherency while arrows allow the visualization of the amplitude and phase angle.
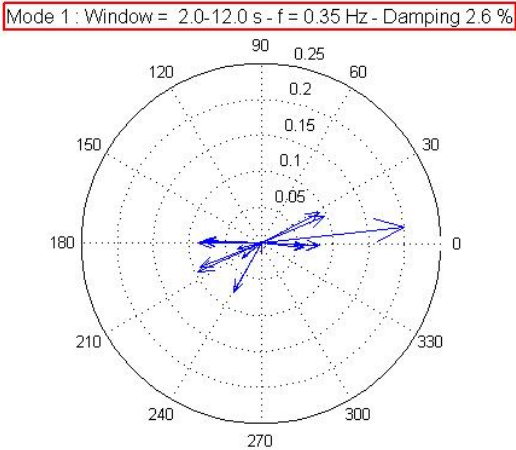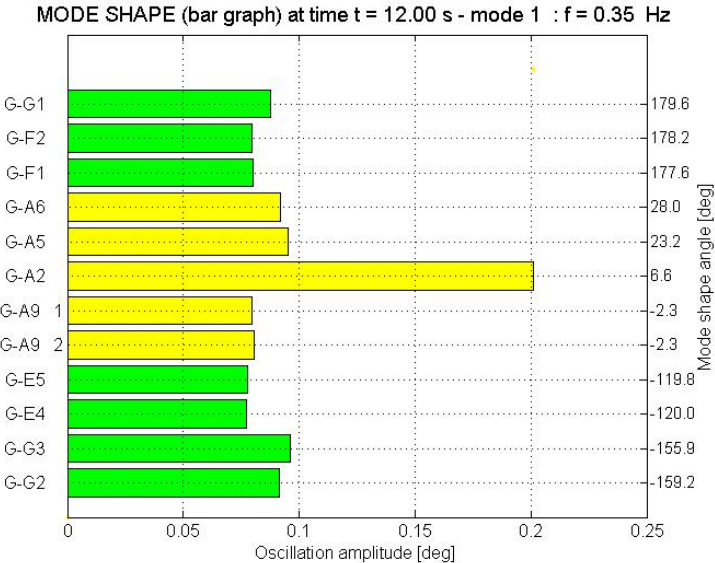
Figure 6: Mode shape compass plot
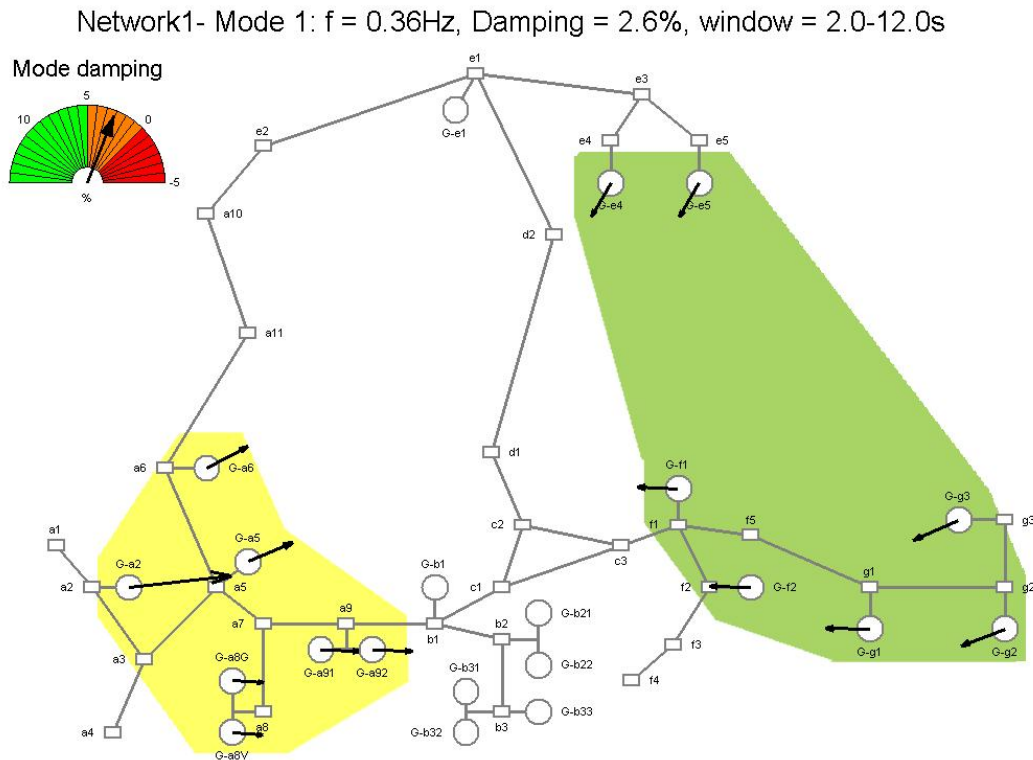
Figure 7: Mode shape bar plot

Figure 8: Geographical mode shape

CONCLUSION

Due to today's communication infrastructure limitations in nearly all countries with large power systems, the implementation of a "Wide Area Protection System" based on Phasor Measurement Units connected to a central computer will take a long time. In addition, just the installation of the PMUs in a power system will not solve any problem. Long measurements and planning studies will be necessary before a System Protection System as described above can be reality.

In this paper, two application examples for the implementation of System Protection Schemes using Phasor Measurement Units are shown. These examples are the first results of a research work, which will continue in the next years. After the first field experiences, the prototype of the Central Software for the PMUs will be enhanced for further applications like out of step problems, system islanding etc. The proposed applications show the necessity of a two steps approach: a monitoring step to understand the power system dynamics better, followed by an implementation of the SPS. After that, the monitoring remains a must to explain to the operators how the SPS has reacted in case of an emergency situation, which is very important for the acceptance of any new method. The emerging technology offers also the possibility to develop more response-based SPS, which leads to a "Flexible System Protection Scheme", whose reaction depends on the actual status of the power system, compared with the event based SPS. After the first installation of such a monitoring system, it will be also possible to implement large-scale applications like PMU-based state estimator or, better, dynamic state estimator with integrated dynamic security assessment. This topic will be an important research item for the next future.

As shown in the examples, fast load shedding is one major requirement for the application of system protection schemes. With the installation of protection relays communicating via IEC61850 protocol it will be possible to shed exactly the amount of load which is required, if wide area Ethernet communication is available. For this purpose, the load amount – real and reactive power – at every feeder may be measured by the feeder relay and transferred to a substation computer. After a request of the central software for PMU applications for a specific amount of load, the substation computers can then send "IP broadcast signals" and start shedding loads, beginning with the lowest load priority. The priority of a load may be included in the IP address of the relay with IEC 61850 protocol.

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