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Bringing New Visualization Tools for the Detection and Mitigation of Dynamic Phenomena in the Transmission System

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SUMMARY

Among the latest developments in technology, Wide-Area Measurement Systems (WAMS) are being implemented in many power systems around the world. The centralization and exchange of synchronized measurements allow gathering many accurate data, but rough data must be processed to generate valuable information to the system operator, that could complement the information already available from the SCADA.

For example, the geographical representation of voltage phase angles measured by Phasor Measurement Units (PMU) allows to easily identify flow transfer directions. Update at a high rate of this picture further allows monitoring the impact of various events, like the weakening of transmission corridors. However, these rough data representations have limitations when dealing with dynamic phenomena.

This paper focuses on the critical information needed to detect dynamic phenomena in the power system, and on the way to efficiently present this information to the operator. This information can be qualitative, to help understanding the system behavior, but quantitative information will help the operator to assess the gravity of the situation. Therefore, comprehensive indices must be used, with adequately chosen threshold levels to initiate preventive or corrective actions. Graphical representation of these indices is also an important issue to facilitate the quick assessment of the system state by the operator. Specific tools have been developed for voltage stability and interarea oscillations, and examples are shown from simulations of realistic power systems.

The assessment of the *voltage stability* of the power system uses indices computed on-line. The paper describes a new method using WAMS information and related to the electrical distance from each bus to the nearest generator. The combination of the time evolution and of a geographical representation of the indices allows giving a clear understanding of the status of the system.

The crucial information to monitor *interarea oscillations* concerns the frequency, damping and mode shape of the oscillating modes. The *mode shape* indicates the involved areas and the way they swing with respect to each other, while the damping is used as index to assess the stability. A description is given of a PMU-based method developed to monitor those oscillations. Among the most interesting visualizations, the geographical view of the mode shape and the mode damping evolution with respect to time are selected. Both pictures complete each other and carry all the needed information, by showing on one hand the oscillating areas, and on the other hand the impact of small or major events on the system stability margins.

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KEYWORDS

Power system dynamics, Phasor Measurement Unit (PMU), monitoring and visualization of system conditions.

1. INTRODUCTION

Recent blackouts have emphasized the lack of information of transmission system operators about the power system *dynamic behaviour*, especially during system-wide events [1]. With today's technology, operators would be ready to understand and control the system behaviour, if only they had the right information. It is worth wondering what information is needed, and how to present it efficiently to operators so that they really have all the tools in hand.

In relation to this crucial need, this paper introduces *monitoring tools* that complement the SCADA (Supervisory Control and Data Acquisition) system. They make use of the characteristics of Phasor Measurement Units (PMU) and Wide-Area Measurement Systems (WAMS) [2, 3, 4], that is, measurements synchronization and, depending on the applications, local or global centralization of those measurements. Measurements are gathered by a central computer, called Phasor Data Concentrator (PDC), where the processing is executed. This centralization relies on the existence of a reliable telecommunication network.

Information provided by these monitoring tools can be divided into operational and historical information. *Operational information* includes all real-time information, static as well as dynamic (related to system stability). *Historical information* refers to the recording and analysis of events. It can be used for training of operators or as a comparison when similar events happen again in the future.

The efficient visualization of critical information is achieved by the following steps. First, the *critical information* must be extracted out of the huge amount of available data. For all the phenomena of interest, security margins and alarm levels have to be carefully set up. To avoid an overload of information, the operator must be provided with clear and intuitive graphical visualizations. Thanks to their high accuracy and high refreshment rate, WAMS make it possible to follow closely the temporal evolution of comprehensive parameters or indices reflecting the state and stability of the system. An efficient visualization must emphasize the weak points of the system and also suggest possible countermeasures to avoid further deterioration of the grid conditions.

2. REAL-TIME VISUALIZATION OF PHASE ANGLES IN THE POWER SYSTEM

Phasor measurements allow giving a clear representation of the voltage angles across the system, and its dual information which is the *power flows* between major areas. Geographical representation of this – updated at a high rate – would help operators understand the impact of various events, like generation rescheduling, decentralized generation start up and shut down, changes in topology.

Fig. 1 gives an example of such representation in the Nordic-32 power system [5]. This system is a simplified yet realistic Swedish network particularly sensitive to voltage collapse. It has been studied using the simulation software EUROSTAG [6]. The left hand side of the figure shows the initial situation of the power system at high load. The main information from this visualization is the direct understanding of the location of the generation and load areas and of the loading of the system. The red area, where the voltage phase angles lead, is the exporting part and the blue area, where the voltage phase angles lag, is globally the importing region. The right hand side shows the situation after a line trip in the transmission corridor between the North and the central area. This kind of visualization allows seeing the spectacular increase of the phase angles in the whole network accompanied by bigger rates of change in the corridor, synonym of an important power transfer and/or high impedances.

However, the information remains limited to these two elements: highlight of importing and exporting regions and rate of change between these areas. Some limitations can be enumerated:

- An in-depth analysis is not really possible and the snapshots can be analyzed only in comparative way. Indeed, depending on the system, large angle differences can be normal or not. The condition of the system can be understood only compared to a previous situation or to a default reference case which can be extracted from historical information.
- Some events lead to very slight changes in the phase angles of the system, even if they strongly impact the safety of the power system with respect to certain dynamic phenomena (for example: reactive limiter of generators affecting the voltage stability).
- The complete 2-D maps given in Fig. 1 are left to criticism: a phase angle is given at every point even if the information is valid only at the busses and on the lines. A more correct representation would give colors only at these valid points but that leads to a less intuitive view.

The first two points lead us to the conclusion that this new information brought by phasor measurement units is still raw and must be processed to increase its value. New indices using these PMU data must be proposed associated with clear, intuitive and understandable visualizations. The three main categories of dynamic phenomena in the system (voltage stability, angular stability and transient stability, according to [7]) are linked to various causes. It sounds logical to use a distinct tool dedicated to each phenomenon, particularized to the power system under study. This is the approach adopted in this paper and the next two sections propose efficient tools adapted to voltage stability (section 3) and to interarea oscillations (section 4).

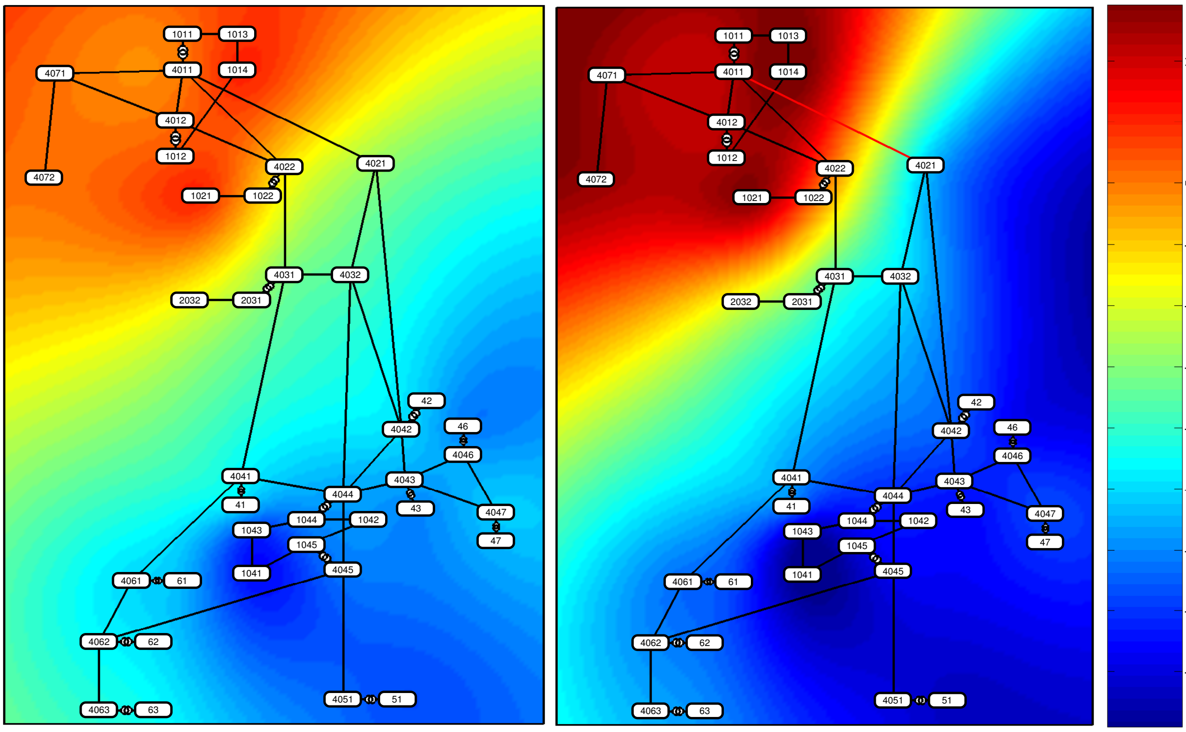

Fig. 1. Visualization of voltage phase angles (in degrees) in the Nordic-32 system before and after a line trip in a transmission corridor (line between busses 4011 and 4021).

3. VOLTAGE STABILITY ASSESSMENT AND VISUALIZATION

3.1. Existing Tools to Assess Voltage Stability

Voltage instability has been considered for a long time exclusively as a long-term phenomenon which required only static simulation tools to monitor them. The classical way is to compute the power margin of the system on which different contingencies are applied. Without questioning the interest of this analysis oriented towards security, the safety of the system could be improved by complementing it by an efficient monitoring system, working in real-time with a fast refreshment rate.

The current propositions [8, 9, 10] for the monitoring of the voltage stability can be classified in two groups:

- The methods using only local measurements: they counterbalance the lack of information in the local data by using successive measurements. Even if the concept is very attractive, the effective implementation is not easy. The assessment of the state is a compromise between speed and filtering and some parameters of the identification algorithm are difficult to tune.
- A centralized method which is very simple, giving only a regional information.

In between these two groups, we suggest in the next section a method based on WAMS. This method is centralized and uses only measurements at current time, avoiding the identification challenge. Its main advantages are the simplicity and the robustness. The method considers that all the complex voltages of the monitored grid are known.

3.2. Description of a New WAMS-Based Method

Like other monitoring methods, we use the Thevenin's equivalent model. It allows assessing the distance to the point of maximum loadability (corresponding to the nose of the PV curve) which is generally different from the limit of stability. However, this information is already useful given that the lower part of the PV curve corresponds to low voltages and it is not desirable to operate the system at those points, even if they may be stable.

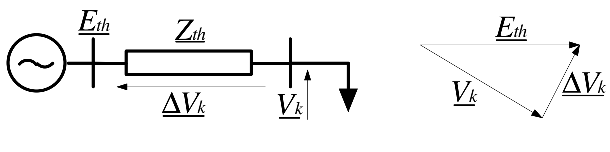

Fig. 2. Thevenin's equivalent.

The maximum loadability point is reached when the amplitude of the complex voltage drop on the Thevenin's impedance is equal to the amplitude of the voltage at the load bus $|\underline{V}_k| = |\Delta\underline{V}_k|$, see Fig. 2).

The main assumption is that the distance from a load to the nearest generator can give information comparable to the voltage drop on the Thevenin's impedance. Some definitions must be given:

- We defined the *electrical distance to a generator* as the sum of the amplitudes of the complex voltage drop on each line along the shortest path from a bus to the generator.
- The *nearest generator* is the one for which the so-defined electrical distance is minimum. All generators are not taken into account but only those controlling their voltage. The algorithm can use a possibility of forecast linked to the change in the control mode, as detailed in the next paragraph.

The normal operating mode of a generator is the *PV mode:* 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. Two types of limiters may be involved: the Over-Excitation Limiter (OEL) and the Stator Current Limiter (SCL). These limiters protect the machine thermally and usually allow an overload for a few seconds (typically 10 to 60 seconds) before decreasing the reactive power output. During this time, the generator still controls its voltage but is above its capability curves.

According to the definitions here above, different statuses can be defined for a generator:

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 control the voltage, it must not be considered. In the two other cases, the generator can be assimilated to a voltage source. However, we know that in case (b), if nothing changes, a few seconds later this generator will be in PQ mode. Therefore, we propose to account only for generators with the status (a). This gives a forecasting ability to the method without running simulations (this will be illustrated in Fig. 3). In section 3.3, the results using all generators in PV mode (status (a) and (b)) will be indicated *without prediction*, and those using only generators with status (a) as *with prediction*.

The chosen index, VSI (Voltage Stability Indicator) is defined by:

$$VSI_k = V_k / \Delta V_k \qquad (1)$$

Where V_k is the voltage at the node *k* and ΔV_k is the electrical distance to the nearest generator as it is described above. The theoretical limit is one but a margin shall be introduced considering the approximation made. In normal operation, values above 5 or 10 are expected. A global index VSI can also be defined as the index of the weakest bus:

$$VSI = \min_{\mathrm{k}} VSI_k \qquad (2)$$

3.3. Results and Visualizations

The method described in the previous section is illustrated on the Nordic-32 power system, already used in section 2. This system is particularly sensitive to voltage collapses after a major contingency because of the high reactive power transfers across transmission corridors between far away generation and load areas.

Comprehensive visualizations include the geographical representation of the VSI, and the temporal evolution of the local and global indices. The former case allows to locate the source of the problem and to anticipate further events, while the latter emphasizes the cascade of events.

Fig. 3 shows the time evolution of the VSI index following the disturbance described in section 2 (loss of one transmission line in the North). Looking at the curve without prediction, one can conclude that the system remains nearly unaffected until the first OEL acts. That leads to a dramatic fall of the index in t = 20s. The curve with prediction takes this fall directly into account. The decrease of the index follows immediately the trip of the line in t=1s. All generators that will be limited in t = 20s are already considered in PQ mode because they are above their capability curves (b status refering to section 3.2). Moreover, the prediction of the index just before the real limitation is very close to the index just after. The positive effect of the prediction is thus clearly shown here and is one of the major advantages of this WAMS based method.

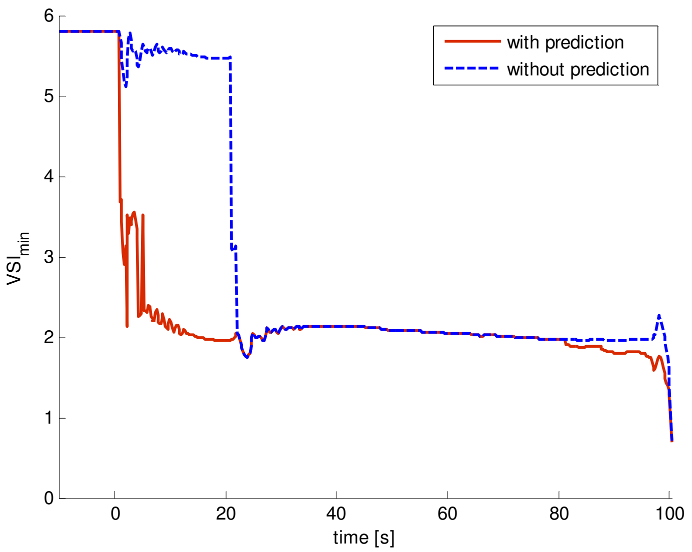

Fig. 3. Time evolution of the VSI_{min} in the Nordic-32 power system after a line trip in the Northern part of the grid. VSI computed with or without prediction on the limiters of the generators.

These time evolution curves have however some limitations. A bus 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. Two solutions can be brought:

- Represent more curves: one per bus or per sub-region. That gives a result hard to interpret with highly loaded graph or several graphs.
- Use a geographical representation where the color of the busses gives the information of the value of the VSI. The result is very intuitive. The importance and the extent of the instability is directly visible. This can be seen in the geographical representation of the Fig. 4, where two pictures of the system are presented (12s and 92s after the line trip). It shows the index for each bus in color, the darker corresponding to the weaker busses. The generators are also represented with a color giving their status defined in section 3.2 (a – blue, b – yellow or c – red). That allows an easy comprehension of the causes of the instability.

The contribution of the geographical view can be demonstrated in this example. The results of the Fig. 3 can lead to the conclusion that the system does not evolve between 20s and 80s. The truth is that the minimal index hides the decrease of the *VSI* of other indices. This is clearly visible in Fig. 4, comparing the two snapshots. The minimal index at bus 1022 remains nearly constant but the situation is considerably weaker in the central area.

Of course, this geographical representation has some drawbacks too. The major one is that the evolutions are not visible. An important part of the information is thus lost. The two kinds of view are thus complementary and must be presented together to understand clearly the condition of the power system.

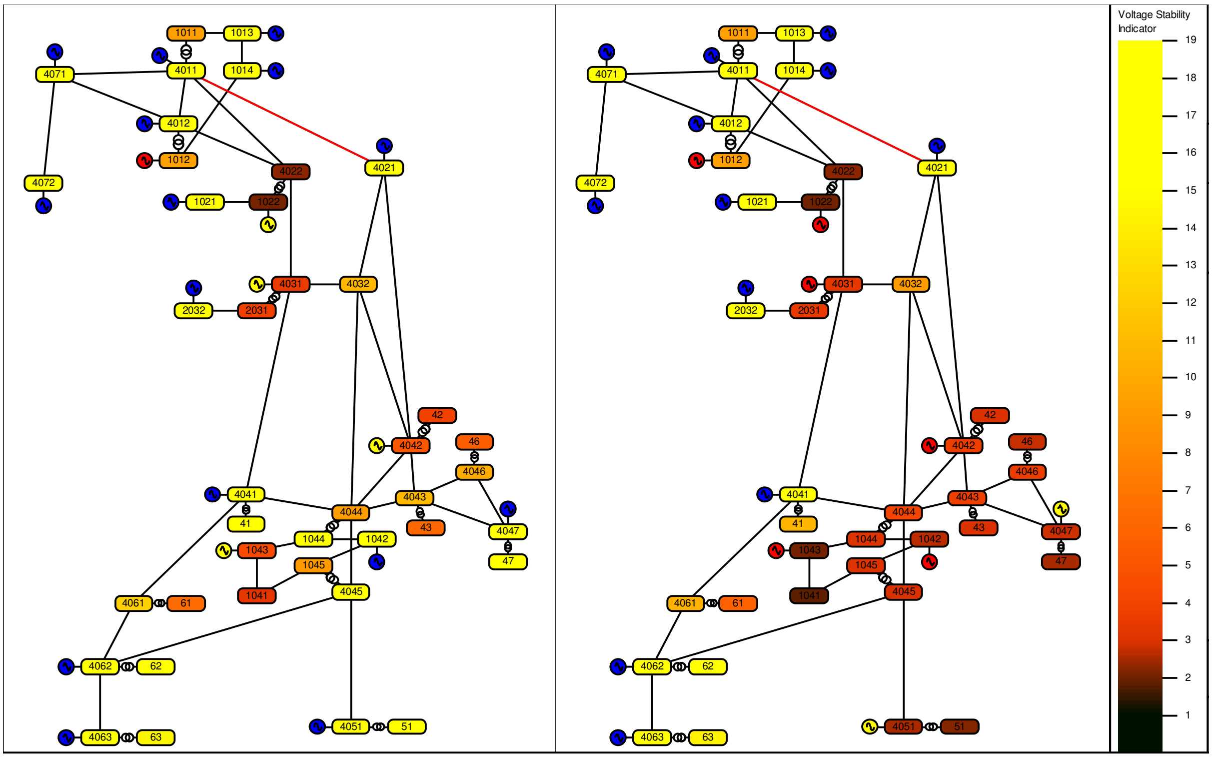

Fig. 4. Geographic representation of the VSI in the Nordic 32 power system 12s (left hand side) and 92s after a line trip in the Northern part of the grid. The VSI is computed with the prediction on the limiters of generators.

This monitoring method can be extended to a protective scheme by fixing some thresholds on the VSI to trigger corrective actions (blocking tap changers of transformers or shedding loads). These thresholds must be chosen through planning studies using historical information of the concerned power system. The effectiveness of this type of actions is shown in [11].

4. INTERAREA OSCILLATIONS

Electromechanical oscillations appear in power systems because of a lack of damping torque at the generator rotors. Those oscillations are an inherent characteristic of the system and may be excited by any small disturbance, such as load changes or switching actions. While being experimented by most power systems, some network configurations are more prone to these phenomena than others, especially highly loaded large interconnected systems.

When generator angles start oscillating against each other, voltage excursions and alternating power flow components arise. Those *electromechanical oscillations* may cause serious damage to generators. Furthermore, poorly designed protection systems can trip because of variables reaching tripping thresholds and lead to widespread cascading events. To avoid such consequences, the system must be small-signal stable. It means that all natural oscillating modes of the system must be sufficiently damped to guarantee safe operation. If no measures are taken to respect this operating constraint, larger disturbances may happen, e.g., frequency stability problems. Some oscillatory events recording are shown in references [1, 12, 13].

A broad classification identifies electromechanical oscillation modes as either *local* or *interarea*. In the first case, two neighbor generators oscillate against each other or one generator oscillates against the rest of the system. On the other hand, when two groups of generators located across the whole system oscillate against each other at one particular frequency, we designate it under the name of *interarea oscillation*. Since the oscillating inertias are huge and the involved frequencies are low – usually between 0.1 and 1Hz - poorly damped modes are sustained for a long time, increasing the risk of cascading outages.

The 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), involving slow dynamics, what makes it prone to electromechanical oscillations.

4.1. METHOD TO MONITOR INTER-AREA OSCILLATIONS

The method proposed here for the detection and analysis of oscillations is based on the frequency processing of the variations of the *angles of the machines rotor*. Inputs to the designed scheme are PMU measurements of the system response to small-disturbances in the power system. These measurements are available at a rate between 10 and 30 Hz according to the IEEE Standard for Synchrophasors [14]. For our purpose, the input signals have been generated using the simulation software EUROSTAG [6] and the results were validated through modal analysis [7].

4.1.1. Identification of the critical information

In the case of electromechanical oscillations, *critical information* needed for monitoring is frequency, damping and mode shape of the dominant oscillating modes.

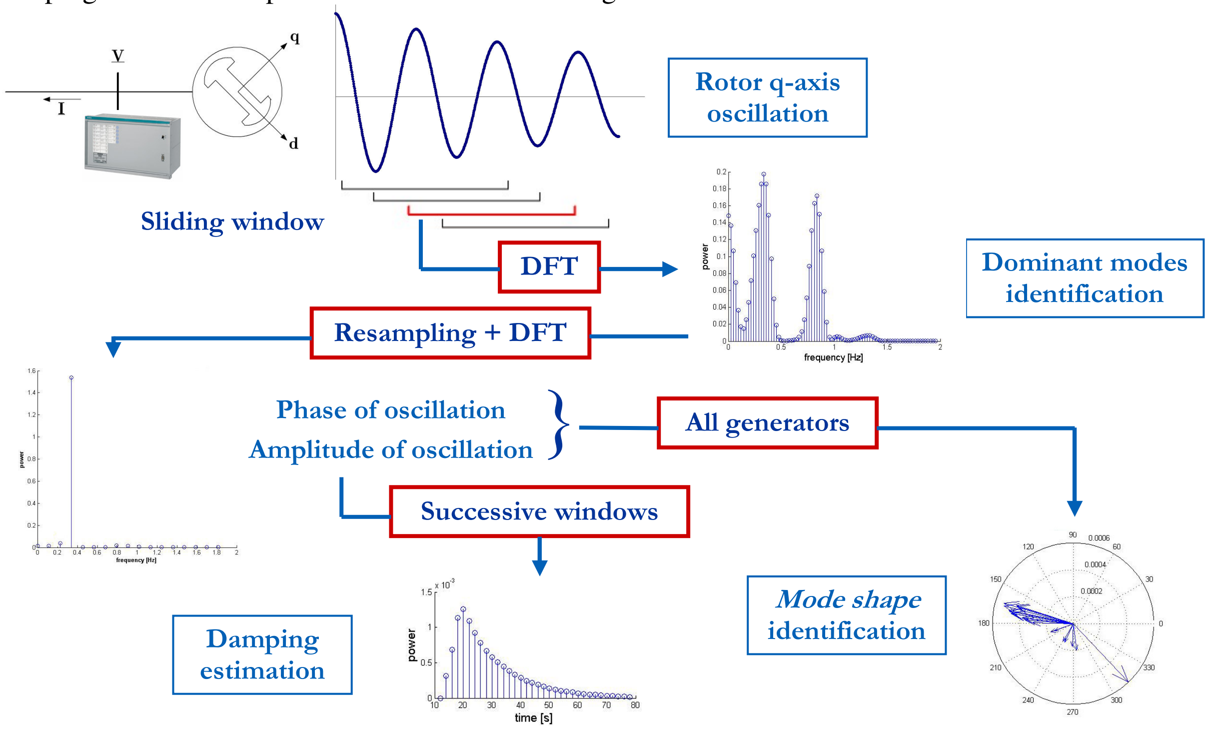

Fig. 5. Mode shape and damping identification of dominant oscillatory modes.

The processing technique relies on a *sliding window* of about ten seconds, which is long enough to cover one cycle of oscillation at the lowest monitored frequency, and short enough to limit the delay in the detection of critical modes. The Discrete Fourier Transform (DFT) is applied to extract the spectrum of the rotor angles variations at selected locations. By inspection of the power spectrum, the *dominant modes* are identified. The dominant modes are defined as the frequencies showing the largest angle excursions. Historical data can also be used to monitor known modes. For the selected dominant modes, the input signals are then resampled at a multiple of the oscillating frequency before computing again the DFT. We then obtain an accurate measure of the amplitude and phase of the rotor angle deviations at those particular frequencies. For a particular mode, we can then associate one oriented vector to each oscillating generator.

By putting together the computed vectors, we are able to construct the *mode shape* of the dominant modes for every time window. The mode shape represents the respective amplitude and phase of oscillation of the participating generators. Once the mode shape is known, *coherent group*s of generators are easily identified in order to determine which areas oscillate against each other. When a series of consecutive windows is available, the mode relative *damping* factor (that is, the decay in amplitude between two consecutive peaks) can be roughly evaluated by following the evolution of the rotor angle oscillations amplitude. The method is illustrated in Fig. 5.

4.1.2. Computation of the rotor angular position

In the given description, it is supposed that the rotor angles, usually referred to as θ, are known. θ represents the angular position of the axis in quadrature with the direction of the field flux, or *q-axis*, with respect to a rotating reference. However, the direct measurement of θ leads to two problems: the measurement accuracy and the need to access the inner machine.

Therefore, we opt for the computation of the machine angular position θ from easily available measurements of high accuracy. The implementation of our method then requires a PMU at the terminals of each monitored generating unit. Among other data, the synchrophasors corresponding to the positive sequence of both voltage at the machine terminals $\underline{v}$ and current flowing to the power network $\underline{i}$ are computed and centralized for processing.

If we neglect the voltage drop across the internal resistance r_a, relation (3) gives the terminal voltage $\underline{v}$ in function of the current $\underline{i}$ and the transient electromotive force $\underline{e'_q}$ [15]. This relation, which is valid during transient state, is represented on Fig. 6.

$$\begin{aligned} \underline{v} &= \underline{e}'_q + jX'_d\,\underline{i}_d + jX_q\,\underline{i}_q \\ &= jX_q\underbrace{\left(\underline{i}_d + \underline{i}_q\right)}_{\underline{i}} + j(X'_d - X_q)\underline{i}_d + \underline{e}'_q \end{aligned} \quad (3)$$

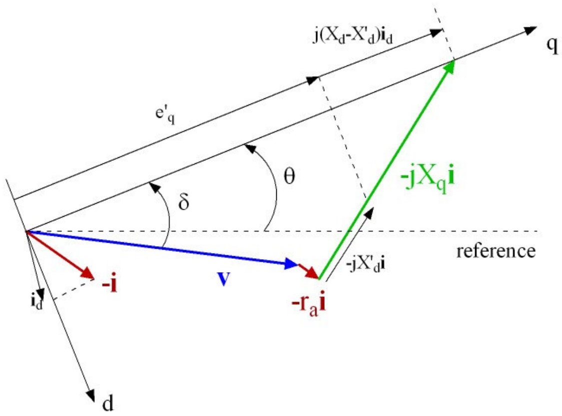

Fig. 6. Angular position θ of the machine rotor: phasor diagram.

In this relation, X_q is the generator quadrature reactance and X'_d is the generator direct transient reactance. By rearranging the terms in (3), we find that vector $\underline{e'_q}$ is parallel to the vector $(\underline{v} - jX_q\underline{i})$ that we are able to compute. We are actually only interested in its direction, that of the q-axis.

$$\underline{e}'_q \,//\, \left(\underline{v} - jX_q\underline{i}\right) \quad (4)$$

Since X_q has a stable value in the frequency range of interest, a fixed value can be used for each machine.

This construction has been validated by comparing the position of the rotor as computed by (4) with a direct measurement of θ. Simulations with EUROSTAG showed that the measured and computed values of θ are very close and that the results are therefore very accurate.

4.2. Results and Visualizations

The most interesting visualizations of modes related to interarea oscillations are the geographical view of the mode shape and the mode damping evolution with respect to time, where the impact of small or major events on the small-signal stability may be perceived.

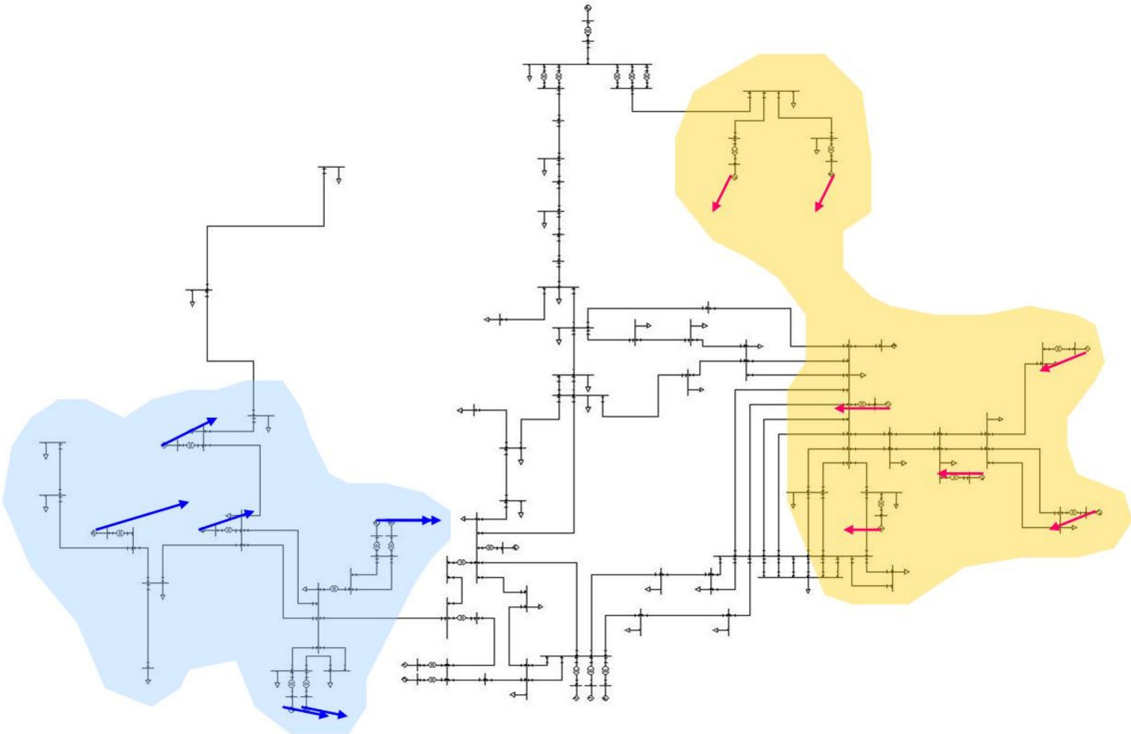

Fig. 7. Geographical representation of the mode shape of the dominant mode at 0.36Hz.

Fig. 7 and 8 show results related to simulations on the test system. The mode shown is one of the most critical interarea modes. It has a frequency of 0.36Hz and a damping of 4.7% in the base case (normal level of load and tie-line flows). The simulated scenario involves an increase of load in the Southern and Central regions, compensated mainly by hydro generation in the West. While the frequency and mode shape of the mode vary barely during this scenario, the damping factor decreases clearly, as shown on Fig. 8. The mode shape shown on Fig. 7 corresponds to the recording at time t = 600s, when the damping is equal to 1%. It appears clearly that the Western region oscillates against the Eastern region. This mode is not the mode with the lowest damping in the base case, but it is strongly impacted by the load transfers increase.

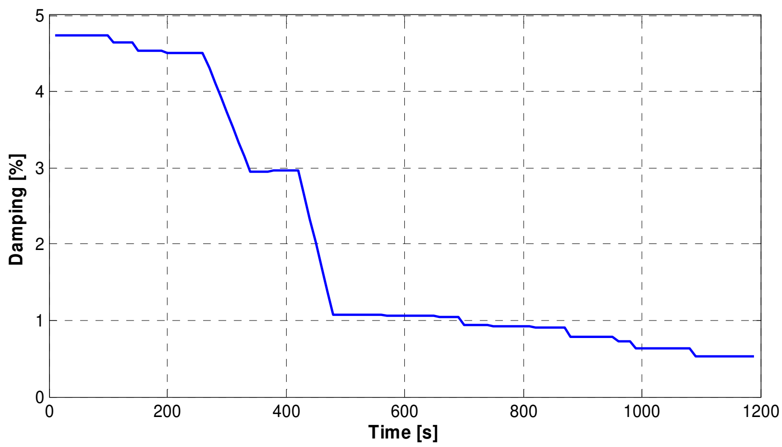

Fig. 8. Time evolution of the relative damping of the dominant mode at 0.36Hz during a sequence of events including a global load increase and two line cuts.

Alarm levels for operators or trigger levels for automatic actions are based either on the amplitude of oscillations (in MW on tie-lines or in degrees of rotor angle oscillations) or on the mode relative damping factor. The latter is preferred because of its preventive aspect. Those levels must be set according to the operational practice of the interconnected system. Rules of thumb say that an alarm must be raised at a damping between 3% and 5%. For this system with the considered topology, the value of 4% is adequate.

Possible countermeasures lie in the alteration of interarea transfers, for example through generation rescheduling, FACTS (Flexible AC Transmission Systems) controls [16] or load shedding in extreme cases. However, impact of the interarea transfers on the modes is complex. Depending on the mode shape and on the location of the tie-lines, a damping increase can be reached by either decreasing or increasing the power transfers [17]. More in-depth investigation is thus needed and information must be given to the operator to help him mitigate these events.

5. CONCLUSION

WAMS provide many accurate data that can be used to complement today's available information. However, rough synchrophasor data have many limitations, especially when dealing with dynamic phenomena. Specific tools must then be designed to provide useful information to the system operator.

Generation of useful information is done through computation of comprehensive indices dedicated to the considered dynamic phenomena: for voltage stability assessment, the Voltage Stability Index, and for interarea oscillations, the modes damping. However, without adapted visualizations, this information would not be useful. Those graphical representations must be clear enough to quickly assess the system stability and the remaining margins. It should also indicate what preventive or corrective actions will help improving the situation.

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