SIMULATED AND MEASURED INTER-AREA MODE SHAPES AND FREQUENCIES IN THE ELECTRICAL POWER SYSTEM OF GREAT BRITAIN

J. Turunen[1], H. Renner[2], W.W. Hung[3], A.M. Carter[4], P.M. Ashton[4], L.C. Haarla[5]

[1]Aalto University School of Electrical Engineering, Finland, and Statnett SF, Norway (jukka.turunen@aalto.fi)
[2]Graz University of Technology, Austria (herwig.renner@tugraz.at)
[3]WH Power Systems Consultant Ltd, UK (ukwilliamhung@gmail.com)
[4]National Grid, UK (alex.carter@nationalgrid.com; phil.ashton@nationalgrid.com)
[5]Aalto University School of Electrical Engineering, Finland (liisa.haarla@aalto.fi)

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Abstract

This paper presents and compares the results of two different approaches to identify the mode shapes and frequencies of the inter-area oscillations in the electrical power system of Great Britain (GB). The approaches are simulation-based analysis, carried out using the full dynamic model of the GB network in DIgSILENT PowerFactory, and measurement-based analysis, with data provided by phasor measurement units installed in the GB transmission system, as operated by National Grid. The results show good correlations between dominant modes, but less consistency on other inter-area modes.

1 Introduction

Power system inter-area oscillations can cause a threat to system stability and may limit power transfer capacity for some operating conditions. Normally, the inter-area oscillation mode shapes and frequencies are studied with simulations. Therefore, it is extremely important that the simulation model reflects well the dynamic behavior of the real system. The accuracy of the simulation model is normally verified by comparing the simulated and measured system transient disturbances [1]-[5]. Some work has also been carried out to verify the simulation model with ambient measurements [6]-[8]. This paper aims to present and compare the dynamic behavior of the real power system under ambient conditions with simulated behavior. Focus is placed on oscillation mode frequency and mode shape, whereas mode damping is beyond the scope of this paper.

Inter-area modes are associated with the coherent swinging of several generators in one part of the system against generators in other parts. They are caused by two or more groups of closely coupled machines that are weakly interconnected [9]. Inter-area oscillations can be characterized by their oscillation frequency, damping and mode shape. Usually generator's rotor angle, speed and flux quantities are chosen as state variables in a state-space representation. Rotor angle and bus voltage angle, with the latter being measured by phasor measurement units (PMUs), are often used as output variables.

The shape of the oscillation, i.e. the number of oscillating groups and location of nodal points in a given system, depends on several parameters. The main influencing parameters are the number of generators connected and their inertias, as well as the 'electrical strength' of the inter-connection between them. Uncertainties of these parameters will affect the accuracy of mode shape calculations. Minor influence in the mode shape is given by the machine's reactance, which is usually in a limited range, and the excitation. It is recognized that there are also some uncertainties in the accuracy of the measurement data and analytical technique adopted for the assessment. The correlation between the simulated and measured results will provide indication of whether the modeling and data analysis techniques are appropriate.

2 Methodology

2.1 Mode shapes and frequencies from the measured data

Signal processing methods are applied to analyse the recorded data [10], as depicted in Fig. 1.

2.1.1 Mode shape estimation

The mode shape is estimated by calculating amplitude and relative angle of an oscillation mode at different locations around the grid. Since the grid frequency always drifts slightly around nominal frequency, it is not appropriate to operate with voltage phase angles referenced to an ideal 50Hz system synchronized on a GPS time signal. This can be resolved by processing voltage phase angle differences to a reference node with voltage angle reference ϑ_{ref}.

In order to estimate the oscillation amplitude A and angle φ, the complex wavelet transform (CWT) is applied to the voltage angle differences ϑ of the analyzed node voltages. Oscillation amplitude A corresponds to the absolute value of the wavelet coefficient and the oscillation angle φ to the angle of the wavelet coefficient. All the phasors represent the instantaneous mode shape of the investigated oscillation mode. Instead of estimating the instantaneous mode shape, average values of the phasors are calculated over a longer time interval. To allow averaging of the phasors resulting from consecutive complex wavelet coefficients, a common phase reference φ_{ref} must be chosen.

The choices of the reference signals affect the output. In theory, an arbitrary node could be chosen as voltage angle reference ϑ_{ref}. However, it is good practice to select a reference near the node of an inter-area oscillation, thus resulting in an illustrative picture of phasors in regions oscillating in opposition. Changing the voltage angle reference leads to a shift of the origin in the compass plot. For the common phase reference φ_{ref}, preferably a 'strong' and stable phasor, not affected by noise, should be chosen. Changing the phase reference leads to a rotation of the complete mode shape plot.

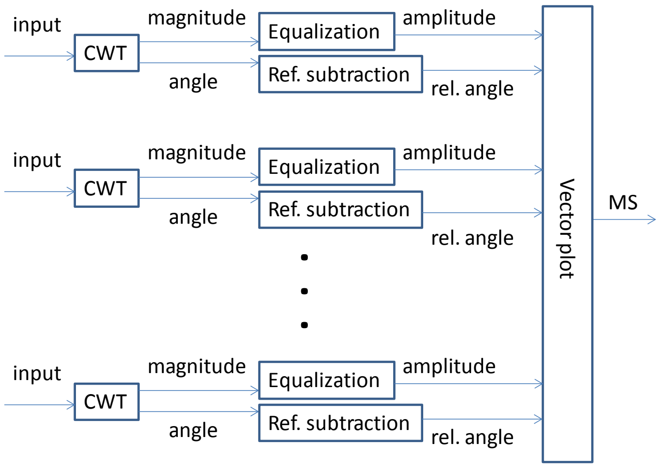


Fig. 1. Block diagram of the mode shape estimation. Input is the measured signal, e.g. voltage angle difference, CWT = continuous wavelet transform, MS = Mode Shape, rel. angle = relative angle.

2.1.1 Frequency analysis

Frequency components in the measured signals are studied with the complex wavelet analysis, which allows the identification of the frequency components at different time instances. Magnitudes of the wavelet coefficients are equalized to correspond to the amplitudes of the oscillations at different time instances and frequencies. The results are presented as three-dimensional frequency-time-amplitude – plots, as shown in Fig. 5. The results can be averaged in the direction of the time axis to provide average amplitudes at different frequencies. The dominant mode has the largest amplitude and the other modes occur as smaller peaks in the frequency spectrum.

2.2 Simulation approach

A dynamic grid model implemented in DIgSILENT PowerFactory, was used. The system model comprises the complete 400kV and 275kV transmission system, and parts of the 132kV sub-transmission system. About 500 substations, with each consisting of several buses, leads to approximately 1500 nodes. More than 2000 branch elements (overhead lines, cables, reactors, couplers, and transformers) are included. 350 generators with their main transformers, speed governors and automatic voltage regulators (AVR) with power system stabilizers (PSS) are modeled.

DIgSILENT PowerFactory provides a complete package of power system analysis functions. For dynamic analysis, synchronous machines are modeled by their stator and rotor flux linkages, voltage equations in d-axis and q-axis and the mechanical differential equations. Stator transients are neglected. Details are given in [9] and [11]. Two rotor-winding equivalents in d and q axis are utilized for round rotor machines (2.2 model), thus 4 flux variables are used. Two rotor-winding equivalents in d and one equivalent in q axis are implemented for salient pole rotor (2.1 model), resulting in 3 flux variables. In the state-space model, each synchronous generator is represented by 5 or 6 state variables:

- 4 flux variables used for round rotor
- 3 flux variables used for salient pole rotor
- rotor angle δ
- rotor speed ω

Speed governors are modeled using a simple generic model, represented by 4 state variables. Actually, the influence of the speed governors on inter-area oscillations is rather insignificant, and can be neglected. AVRs with integrated PSSs are modeled in detail according to the real controller configuration. Depending on the utilized model, up to 20 state variables are present.

To get access to bus voltage variables, dynamic dummy loads had to be inserted at PMU locations. The dynamic load model uses the bus voltage as a state variable, thus indirectly providing information about the bus voltage angle oscillation.

With the state-space description of the system, modal analysis is rather straightforward by calculating eigenvalues of the state matrix (frequency, damping), and right eigenvectors (observability). In the PowerFactory environment, a selective eigenvalue calculation based on the Arnoldi-Lanczos method [12] was performed. The latter means the computation of a user-definable number of closest eigenvalues around a complex reference point, for instance expected mode frequency.

Mode identification, in the sense of detecting inter-area modes, was carried out in a heuristic way by looking at mode frequencies, participation factors and identification of groups of synchronous machines oscillating in phase. Based on experience, oscillation modes with frequencies above 1Hz are assumed to represent local oscillations, and therefore out of scope of this work. On the other hand, local low frequency controller oscillation modes, characterized by dominant participation of a single controller variable were also excluded. Furthermore, the evaluation of the remaining modes was restricted to modes with a maximum of 3 coherent groups of oscillating generators. Bus voltage phase angle oscillations were processed according to the measurement results, as described in the previous section.

The additional results regarding rotor angle oscillations are presented to demonstrate clearly the oscillation modes. The processing of rotor angle differences was done analogical to the voltage angle differences. For the reference value δ_{ref}, a virtual reference was chosen. This was calculated using a weighted, according to rated power of each machine (S_i), mean of all rotor angles (δ_i).

$$\delta_{\mathrm{ref}} = \frac{\sum S_i \cdot \delta_i}{\sum S_i}$$

3 GB power system

The national electricity transmission system operator (NETSO), National Grid (NG) operates the entire GB system and is also the transmission owner (TO) for England and Wales. The Scottish network is owned by Scottish Hydro Electric Transmission Limited (SHETL) in the north and Scottish Power Transmission Limited (SPTL) in the south. The separate networks are quite strongly intermeshed but the inter-connection between Scotland and England is weaker, consisting of two long 400kV double circuits.

There is a dominant North-South-oscillation, with generators in Scotland swinging against the generators in England and Wales [13]. To monitor the system dynamics, PMUs have been installed in different sites around the transmission system of England and Wales. The WAMS provides alarm information to the Energy Management System (EMS) to alert operators when the system is believed to be approaching instability [14]. In addition to modal characteristics, the PMU data of the GB system has been recently applied to comparisons with the state estimator [15] and inertia estimation [16].

In this paper, the data from 9 PMUs were utilized; the approximate locations and acronyms of these are shown in Fig. 2. For the purpose of comparison of simulation results with measured results, different grid conditions according to available measurements were modelled. At this time, no PMUs located in the Scottish network have been integrated into the WAMS, at NG; this work is pending as part of a recent Ofgem funded project [17].

4 Results

4.1 Identified major inter-area modes

The three main inter-area oscillation modes, derived from simulation and partly confirmed by measurement, are described in the following.

4.1.1 Mode 1: England-Scotland

Mode 1 is the well-known England-Scotland mode (north-south-mode) [13]. The mode appears in the simulation model as an oscillation mode with the lowest frequency, ranging around 0.5Hz. The frequency is mainly dependent on the amount of connected generation in Scotland. This mode is unambiguously identified by the PowerFactory model and the PMU measurement analysis.

4.1.2 Mode 2: North-South-2

Mode 2 appears in the simulation model as the oscillation with frequency ranging from 0.7 to 0.8Hz with three coherent generator groups. The northern part of Scotland oscillates in phase with the southern part of England, and these two areas oscillate against the northern part of England and Wales. The mode was identified with the PowerFactory model and vaguely by the measurement analysis.

4.1.3 Mode 3: East-West

Mode 3 is the mode with the next higher oscillation frequency. It appears in the simulation model as an oscillation mode in the frequency range from 0.75 to 0.9Hz. It describes an inter-area oscillation between the western part of England and Wales against the eastern part of England.

4.1.4 Graphical representation of the modes

A graphical representation of the modes based on the detailed PowerFactory simulation model with rotor angle signals is given for modes 1, 2, and 3 in Fig. 2, Fig. 3, and Fig. 4, respectively.

4.1.5 Identification of the modes from measurements

Inter-area frequency components in a typical case in the GB power system are shown as a function of time in Fig. 5. The analyzed signal is voltage angle difference between North and Central England. The results show that there are continuous oscillations around 0.5 Hz. In addition, there are well-damped transient oscillations with a frequency of 0.85 Hz, obviously triggered by a switching event (Fig. 5 and Fig. 6 at time instance 1008 min). Another set of measurements includes strong oscillations at about 0.85Hz in Fig. 7. Voltage angle difference signals during this time are shown in Fig. 8 (a), where strong oscillations occur in the middle of the time series. Fig 8 (b) shows the oscillations starting spontaneously without any large initiating transient events and lasting for about 6 minutes.

4.2 Mode shapes of the main inter-area modes

Mode shapes of the two main inter-area modes (0.5Hz and 0.85Hz) identified in the frequency component analysis, are studied in this section based on voltage angle differences. The mode shape of the dominant 0.5Hz mode is shown for the measurement-based analysis and for the detailed PowerFactory model in Fig. 9 a) and b), respectively. The relative angles of the mode shape correspond rather well between the simulation and the measurement-based approach. The correspondence is especially good in the northern part of the system (NE1, NE2, NE3, CE1, and NW, see Fig. 2), which means that the oscillations are exactly or nearly in phase there. According to the measurement-based analysis, the oscillations at the northern part of the system are nearly in opposite phase compared to the oscillations at the southern part (SW and SE, see Fig. 2). The simulation-based approach partially verifies the result, but in the simulation the amplitudes of the oscillations are very small in the southern part. One reason is the selection of the voltage angle reference, which should be located near the oscillation node.

If, for whatever reason, the oscillation node of the real system and the oscillation node of the simulation model differ, the use of identical voltage angle references for measurement and simulation results in different visualizations of the mode shape. Although the principal representation of the mode shape in the model would be close to but not identical with reality, the mode shape plot might differ significantly and thus complicate the dynamic model verification.

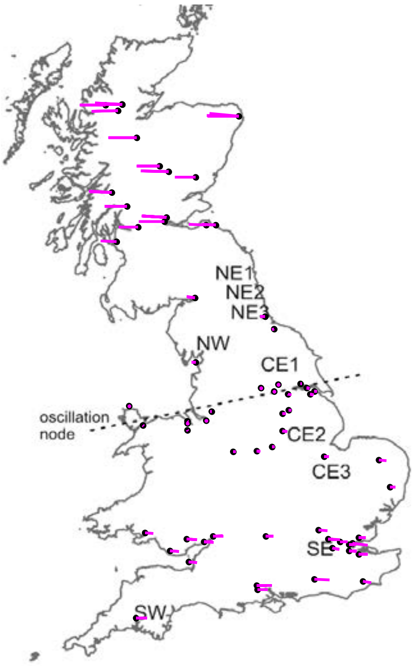


Fig. 2. Simulation-based England-Scotland mode shape with rotor angle signals.

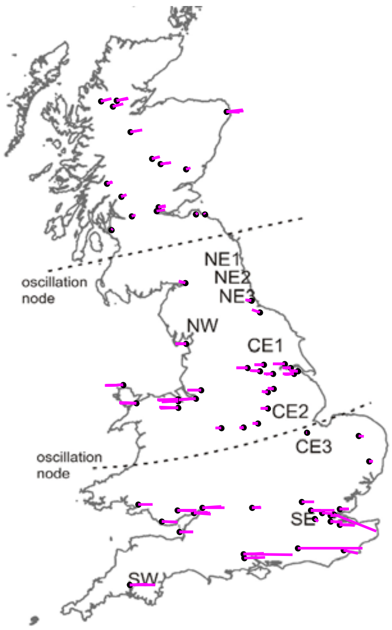


Fig. 3. Simulation-based North-South-2 mode shape with rotor angle signals.

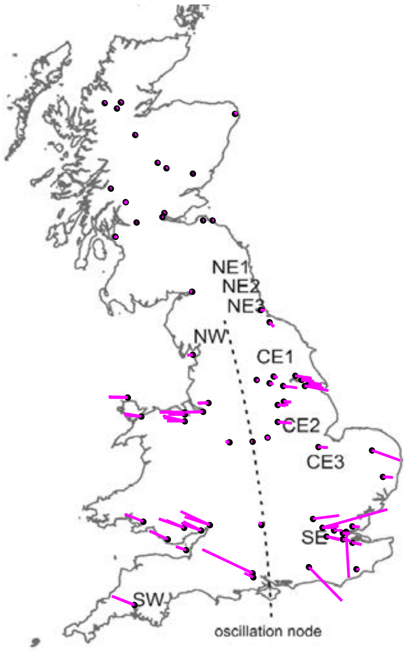


Fig. 4. Simulation-based East-West mode shape with rotor angle signals.

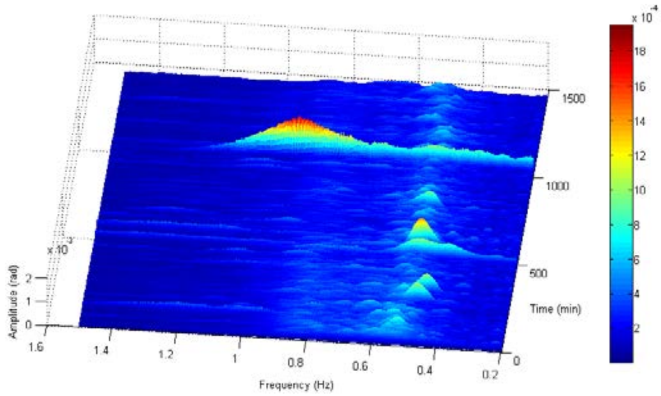


Fig. 5. Amplitude as a function of oscillation frequency and time. Voltage angle difference between North and Central England analyzed.

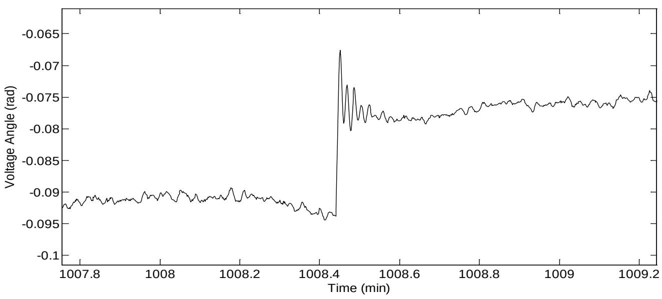


Fig. 6. Voltage angle difference between North and Central England (mean value removed). Zoomed in to show the transient in the data.

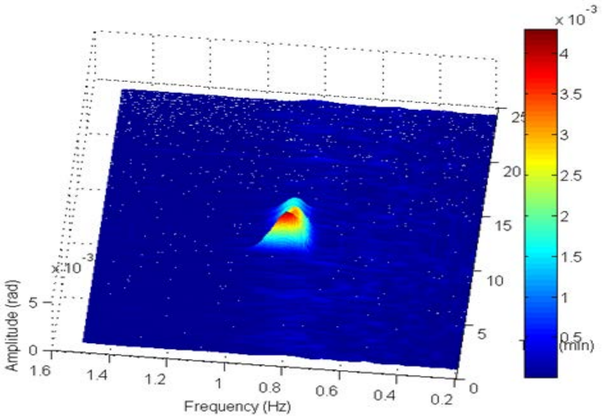
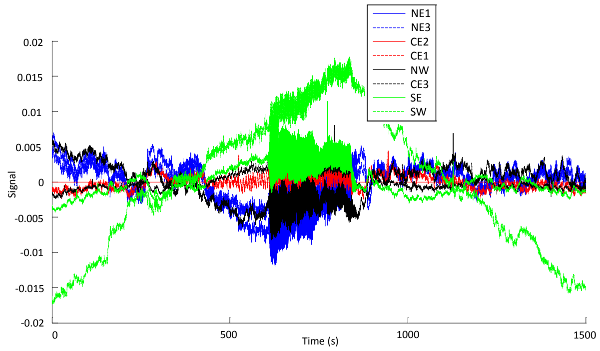
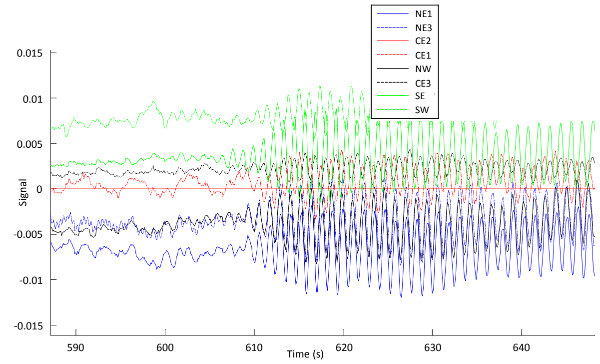


Fig. 7. Amplitude as a function of oscillation frequency and time. Voltage angle difference between North and Central England analyzed.



a) Overview



b) Expanded view showing the beginning of the oscillation

Fig. 8. Voltage angle differences with the CE2 measurement as a reference.

The 0.85Hz mode shape is shown for the measurement-based analysis and for the detailed PowerFactory model in Fig. 10 a) and b), respectively. Upon first inspection the measurement-based and simulation-based mode shapes are somewhat different. However, more careful analysis reveals that the South East part of the system (SE and CE3, see Fig. 2) oscillates nearly in the same phase according to both the simulation and measurement. According to the simulation, the oscillations at other areas are nearly in opposite phase to the oscillations at South East part of the system. According to the measurement, as a whole, the oscillations at other parts of the system are also in opposite phase to the oscillations at South East part of the system. However, the spread in the oscillation angles at other areas is much larger in the measurement-based mode shape than in the simulation-based mode shape. As well as with the 0.5Hz mode shape, the oscillation amplitudes of the 0.85Hz mode differ somewhat between the simulation and measurement. However, the amplitudes are affected by various factors in the power system, and therefore it is rather unrealistic to assume close consistence in the amplitudes. Especially in case of well-damped oscillation modes, amplitudes are small, leading to a poor signal-to-noise ratio and difficulties in a reliable analysis of measured PMU signals.

5 Discussion

Some differences were noted between the results of simulation-based and measurement-based approaches of identifying the inter-area mode characteristics. There are several reasons for these differences. In the simulations, even in the case of the detailed model, uncertainties cannot be avoided due to the lack of data regarding the distribution level, including load models and embedded generation. Also on transmission level, the modeled operating points of power plants do not exactly match reality. This leads to slight differences in the power flow situation when comparing measurement and simulation results. In the measurement-based analysis, uncertainty of the results is caused to a large extent by the very small amplitude of oscillations during ambient conditions. When the amplitude is small, the oscillations are more likely to be affected by the underlying noise and other random excursions, leading to less accurate results.

6 Conclusions and future work

This paper presents and compares the measurement and simulation derived mode shapes and frequencies of the GB power system. The measurement-based identification of the modal characteristics is carried out under ambient conditions of the power system and the results can therefore be used to validate small-signal analysis results derived from dynamic simulation studies.

There are always differences between the dynamic behavior of the real and the simulated power system. Normally, the simulation model is validated by comparing the transient behavior of the simulated and measured results. However, the opportunity of capturing significant system transients or conducting transient tests on the system is small. This paper focused especially on the frequency components and mode shapes estimated from the ambient measurements and from the detailed simulation model. The results indicate that more consistent mode characteristics between the simulation and measurement are achieved when the dominant mode is studied. For the other studied modes, there is less correlation between them mainly because of poor signal-to-noise ratio in the measurement of very small oscillation signals.

An important future work area is to study how the measurement data can be used in tuning the dynamic grid model of the power system. A robust method with well-defined quality criteria for evaluating dynamic models by

PMU measurements could be developed in addition to the subjective method of visual comparison of mode shapes.

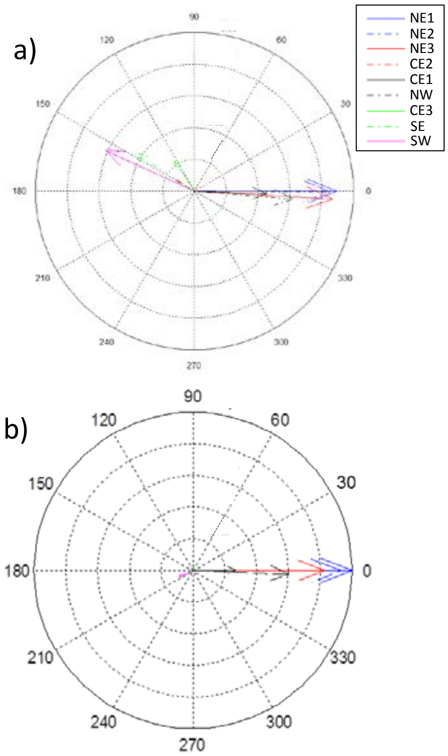


Fig. 9. Estimates of the 0.5Hz (North-South) mode shape, voltage reference angle in location CE2. a) measurement-based estimate, b) estimate based on a detailed simulation model.

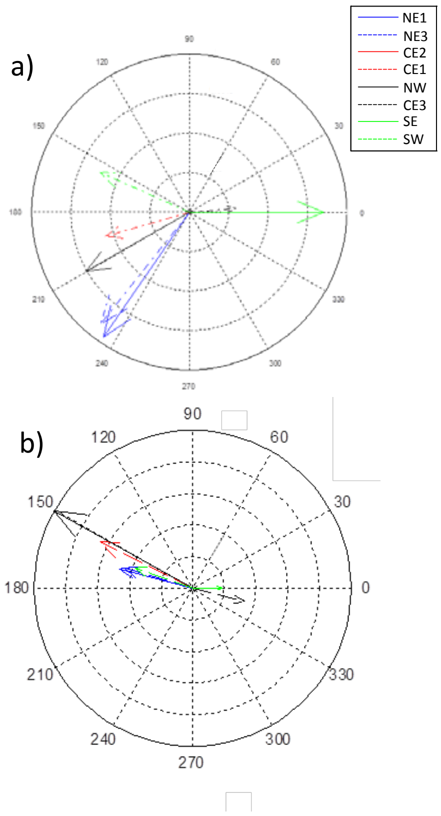


Fig. 10. Estimates of the 0.85 Hz (East-West) mode shape, voltage reference angle in location CE2. a) measurement-based estimate, b) estimate based on a detailed simulation model.

Acknowledgements

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