An Inter-Area Oscillation Based Approach for Coherency Identification in Power Systems

Josef Stadler
Institute of Electrical Power Systems
Graz University of Technology
Graz, Austria
josef.stadler@tugraz.at

Herwig Renner
Institute of Electrical Power Systems
Graz University of Technology
Graz, Austria
herwig.renner@tugraz.at

Klaus Köck
Institute of Electrical Power Systems
Graz University of Technology
Graz, Austria
klaus.koeck@tugraz.at

Abstract—This paper proposes a new approach for slow coherency identification in large multi-machine power systems based on inter-area oscillation analysis and electrical proximity. To identify the oscillation modes, the participation factors of the state variables are analysed. The proposed method is applied to a real 1475 bus power system with 50 generators.

Keywords—slow coherency identification, clustering, electrical proximity, inter-area oscillations, REI (Radial, Equivalent, Independent)

I. INTRODUCTION

The changing network structure with decentralised power supplies, converter connected wind farms and large PV systems results in changes in system inertia and leads to a completely new view of the dynamic behaviour of the network. Therefore, dynamic investigations are becoming increasingly important.

Performing dynamic studies in large interconnected grids faces some challenges. For instance dynamic data acquisition might fail since detailed data of generation units are sometimes treated as confidential data. Another challenge in dynamic simulations is a long computation time. For both cases the use of network equivalents is helpful, providing compressed and anonymised data which still holds the basic dynamic properties. Especially in the case of dynamic studies, one is interested only in a limited area, in literature called the internal or the study system. The leftover represents the external system and in between, the border or frontier buses are located.

One strategy in reducing the external system is to find groups of coherent generators and compiling them to dynamic equivalents. This equivalent is a single synchronous machine, having the same average speed, voltage and total mechanical and electrical power as the determined coherent group the machine is replacing. These equivalents can be used to simulate the dynamic behaviour of the power system, without having to reveal the detailed dynamic data of single machines. Thus transfer of essential information to third parties allowing dynamic studies and research work is possible without confidentiality problems.

In the last decades many coherency identification methods have been presented.

In this paper, the approach of the electrical proximity is combined with a new method, based on automatic inter-area oscillation detection.

The result of the coherency identification can be used as input for the construction of dynamic grid equivalents, especially for the application of the REI reduction method.

If the aim of the work is the reduction of the system to the dominant modes, the modal reduction approach [1] can be used. Therefore the system matrix is reduced to the size of the dominant eigenvalues with the consequence that the physical representation of the system is lost. Contrary to that the proposed method gives a reduced power system consisting of grid elements instead of a system matrix.

II. REVIEW OF EXISTING COHERENCY IDENTIFICATION TECHNIQUES

The idea of coherency identification is well known in literature. If the angular difference of generator buses is constant over a specified time window, these generators are defined as coherent [2].

In general, two generators are coherent if, following any disturbance, the difference of the rotor angles $\delta_{ij}$ is constant.

$$\delta_i(t) - \delta_j(t) = \delta_{ij} = \text{constant} = \delta_{ij}^0$$

(1)

Differentiating (1) leads to:

$$\dot{\delta}_i = \delta_j$$

and

$$\dot{\delta}_j = \delta_i$$

(2)

In (2) it can be seen, that the coherent machines must have the same angular speed $\delta$ and the same angular acceleration $\dot{\delta}$.

Utilising dynamic network reduction with coherent groups, the reduction process is a three step procedure [3]:

- Identification of coherent generators
- Network reduction
- Dynamic generator aggregation

Podmore [3] uses in his research the time domain solution of a three phase fault where a transient stability simulation is used as a basis for the analysis. The swing curves are analysed and generators with coherent curves are clustered and form a coherent group. For the generator aggregation the parameters of the equivalent generators are determined using a least-square fit of their transfer functions [4]. A disadvantage of this coherent group detection technique is that the grouping of the generators is not unique but depends on parameters characterising the transient event.

Hussain and Rau presented a new approach based on electrical proximity in [5].
In the process the coupling admittances between the generator-buses are analysed to get information about their electrical proximity (cp. Eqn. (10)). The criteria for the next step are equal acceleration and equal velocity. Therefore two normalised indices are introduced, analysing the inertia and the damping of the generators. Combining the information of the electrical proximity with the two indices mentioned before, coherent generator groups are identified.

For the construction of the equivalent machine, the terminal buses of the coherent machines are substituted by an equivalent terminal bus. The parameterisation of the equivalent generator is on the basis of power invariance.

The idea of using inter-area oscillations for identifying groups of coherent generators is called slow coherency method and was first introduced by Winkelmann, Chow et al. [6]. They used the “dichotomic transformation” to separate the slow and the fast modes leading to the solution of the coherent groups.

III. PROPOSED IDENTIFICATION METHOD

A. Modelling

The grouping of the coherent generators is independent of the level of detail of the model and, using faults for coherency detection, also independent of the size of the simulated disturbance [2]. Therefore a simple, classical, linearised mechanical generator model is used [7]. Assuming a lossless network and using the classical voltage-behind-reactance model for the synchronous generator, the structure of the multi-machine power system can be seen in Fig. 1.

![Multi-machine system with simple voltage-behind-reactance model](image)

**Fig. 1. Illustration of a multi-machine system with simple voltage-behind-reactance model of the synchronous generator, the structure of the multi-machine power system can be seen in Fig. 1.**

The linearised system of the mechanical differential equations is given in state space representation with the differential state variables angular speed $\Delta \omega_p$ and rotor angle $\Delta \delta$.

$$
\begin{bmatrix}
\Delta \omega_p \\
\Delta \delta
\end{bmatrix} =
\begin{bmatrix}
-\frac{K_p}{2H} & -\frac{K_t}{2H} \\
\frac{1}{2H} & 0
\end{bmatrix}
\begin{bmatrix}
\Delta \omega_p \\
\Delta \delta
\end{bmatrix}
+ \frac{1}{2H} \Delta T_m
$$

The sub-matrix $K_p$ contains the damping coefficients, assuming linear dependencies. Sub-matrix $K_t$ contains the coefficients for the synchronising torque. Basically, they are determined by the transient reactance, the excitation, and the active power of the respective generator. Furthermore, also the admittance matrix is included, wherein in a first approximation a lossless grid is considered. The mechanical torque change $\Delta T_m$ acts in this state space model as a disturbance variable.

The initial conditions for the simulation are determined using DC Load Flow, so all bus voltages in the grid are set to 1 p.u. and the system is assumed to be lossless [8].

The loads in this research are modelled using constant power loads, and are therefore not included as dynamic parameters in the state space model.

B. Automatic detection of inter-area modes

An interconnected power system is characterised by electro-mechanical oscillations. A distinction between local and inter-area oscillations is made. Local modes are oscillations associated with a single generator or a single power plant. They normally show a frequency range of about 0.7 Hz to 2 Hz. On the contrary, inter-area modes are characterised by a group of closely coupled machines oscillating against machines in other parts of the system. Their frequencies are typically in a range of 0.1 to 0.8 Hz. The frequency and the damping of the inter-area mode depend amongst others on the tie line impedance and the power flow between the areas. If the areas are balanced (equal generation and load in each area) and there is no power transfer between them, the generators oscillate exactly in anti-phase. On the other hand, if the areas are unbalanced, with tie flows between them, the angles between the oscillation phasors are less than 180° [9].

The modal analysis is an important tool for the determination of inter-area oscillations and for stability analysis. Starting with a simple state space model:

$$
\dot{x} = Ax + Bu
$$

Calculating the eigenvalues $\lambda_i$ of the system matrix $A$ leads to:

$$
\lambda_i = \sigma_i \pm j \omega_i
$$

The real part $\sigma_i$ of the eigenvalues represents the damping, the imaginary part $\omega_i$ the oscillation frequency of the mode. Negative values of $\sigma_i$ indicate damped oscillations, whereas positive values represent oscillations with increasing amplitudes.

With the help of the participation factors $PF$ [7], determined by piecewise multiplying the right eigenvector $\psi$ by the left eigenvector $\psi^*$, inter-area modes can be automatically identified.

$$
PF = [pf_1 \, pf_2 \, \cdots \, pf_n]
$$

where

$$
\begin{bmatrix}
V_{11} \cdot W_{11} \\
V_{21} \cdot W_{12} \\
\vdots \n V_{n1} \cdot W_{1n}
\end{bmatrix}
$$

The absolute values of the $PF$ linked to the rotor angle $\delta$ are sorted according to their size, denoted by $PF_{max}$ in (7). Finally the minimum number $j$ of generators fulfilling the requirement formulated in (7) is determined for each mode, where $g$ is the total number of generators.
with the sum-of-squares criteria \( (10) \). The mathematical representation is given below, where \( x_i \) are the data points and \( \mu_i \) the centroids of the clusters \( S_i \).

\[
J = \frac{1}{2} \sum_{i=1}^{k} \sum_{x \in S_i} \| x - \mu_i \|^2
\]

The constant \( c \) was heuristically determined to be 0.9. Modes with the highest index number \( j \) are candidates for inter-area oscillations.

This fact is now described in a simple example. Fig. 2 shows two exemplary modes in a power system with 50 generators (see section A for details), modelled according to (3). On the left hand side, a local mode can be seen, where two generators are oscillating against each other. In comparison, on the right hand side, an inter-area mode is shown, where one large group of generators oscillate against another group.

The results are two groups for each inter-area-mode. If there are problems in clustering the eigenvectors in two independent groups (i.e. unrealistic grouping), one idea is to build smaller clusters, and combine these clusters again to two bigger groups.

E. Analysing the electrical proximity

Although oscillating coherent in phase, generators might belong to different geographical areas. This fact can be investigated using the electrical proximity, where the mutual admittance between the generator-buses is analysed. Therefore, in a second step the grouping of the electrical proximity of the generator-buses is performed. The larger the admittance, the closer the machines are coupled. If all machines (g) are coupled via the same mutual admittance, the following equation holds:

\[
|Y_{ik}| = (g-1) \cdot |Y_{ik}|
\]

However, since the electrical distances are different, the electrical proximity index \( \alpha \) is defined:

\[
\alpha_{ik} = (g-1) \frac{|Y_{ik}|}{|Y_{ik}|}
\]

The result is a (g-by-g) – matrix, where each line \( i \) gives an information about the electrical proximity of the generator terminal bus \( i \). In this matrix, each generator exists more than once, so there are no independent groups of electrical near generators. Therefore, applying agglomerative clusters [11], independent generator groups show up.

Creating agglomerative clusters based on the \( \alpha \) matrix, groups of generators with a strong electrical coupling are the result. This bottom up clustering method starts with small clusters, containing only one generator (singletons). In a next step the so called proximity matrix is used for analysing the electrical distance between the clusters and for combining the nearest groups to a new bigger group. This process is performed, until the pre-determined cluster number is accomplished. For the clustering of the electrical proximity the \( k \)-means algorithm also can be used, but with the agglomerative clustering better results could be reached in this research. For the reduction of the load buses again the electrical proximity is used. Therefore the admittance matrix is reduced to the size of the load buses and afterwards the electrical proximity index \( \alpha \) is calculated using (10). With the help of agglomerative clustering finally coherent load groups are identified.

F. Dynamic equivalent

The dynamic equivalents of the identified groups are build using the dynamic REI (Radial, Equivalent, Independent reduction) method [12]. The idea is to insert a fictitious, lossless REI network to make the coherent groups passive (cp. Fig. 3). All loads and generators are aggregated on a new bus \( R \). The parameters of the equivalent generator including its control are calculated using the dynamic parameters of the reduced machines and their controls. In the last step, the resulting passive nodes are reduced using the Ward reduction method [13].
Each coherent group gets its own REI network for generation and for loads to avoid voltage problems at bus R. When separating loads and generation, the voltage at bus R is about 1 p.u. If this separation is omitted, the result is an unrealistic voltage level at bus R, leading to possible problems in load flow calculation [14].

In Fig. 4 it can be seen that there are three dominant modes (highlighted red).

As additional criterion the damping of the mode can be taken into account. Less damped modes are more dominant in the power system than better damped modes.

In the next figure, the compass plots of the three identified inter-area oscillations are shown.

The phasors in the compass-plots reflect the contribution to the inter-area mode, where the normalised length corresponds to the eigenvector weighted with the particular inertia constant of the generator.

The most dominant mode is characterised by an oscillation between the eastern and the western part in phase versus the central part of the network with an oscillation frequency of 0.84 Hz. Using the k-means clustering algorithm, the grouping of the mode is shown in Fig. 6.

The second characteristic mode shows an oscillation between the north-eastern parts of the grid versus the rest of the network, with an oscillation frequency of 0.76 Hz.
The last dominant mode with 0.58 Hz is described by an oscillation between the east and the west.

![Fig. 8. Mode 3: East - West inter-area mode with 0.58 Hz](image)

The final grid should be characterised by these three inter-area modes. The combination of the determined groups, results in 8 independent groups, displayed in the next figure. Different colours and symbols represent different groups.

![Fig. 9. Combination of the groups determined by the inter-area oscillations](image)

C. Electrical Proximity

For the analysis of the electrical proximity, the 1475-by-1475 admittance matrix is reduced to a 50-by-50 matrix (number of generators) by using the ward reduction [13]. The reduced admittance matrix is used to calculate the electrical proximity index $\alpha$ (cp. (10)). This matrix is clustered afterwards using agglomerative clustering.

In Fig. 10 the groups determined by the electrical proximity and agglomerative clustering are shown. Again, different colours and symbols distinguish different groups.

![Fig. 10 Determined groups using electrical proximity and clustering](image)

The last step in forming suitable groups is to combine the coherent groups from the inter-area oscillation with the groups determined by the electrical proximity.

V. RESULTS

A. Reduced Network

The method explained in section B detects three characteristic inter-area modes. The combination of this information with the electrical proximity, results in 12 different groups of generator buses.

In Fig. 11 the final grouping of the generator buses can be seen. Groups containing only one generator are not considered. They remain unchanged after the reduction process and are marked with red crosses in the graph.

![Fig. 11. Final grouping of coherent generators](image)

After building additional groups for the load buses using electrical proximity the power system is finally reduced to:

- 88 buses
- 4 generators + 11 equivalent generators

B. Modal Analyses

Calculating the eigenvalues of the original and the reduced system, the result can be seen in Fig. 12.

![Fig. 12. Comparison of the original and the reduced system’s eigenvalues](image)

It is obvious, that the number of eigenvalues decreases. The modes of the reduced system are characterised by the same damping and oscillations frequency in comparison to the original system.

Therefore, it can be shown, that the behaviour of the system is not changed drastically by the reduction.
The three dominant inter-area oscillations can be kept. The result of the dominant eigenvalues depicting oscillation frequency and the damping can be seen in the following table:

<table>
<thead>
<tr>
<th>Mode</th>
<th>original</th>
<th>reduced</th>
<th>dev. in %</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mode 1</td>
<td>-0.93±4.80i</td>
<td>-0.95±4.80i</td>
<td>1.64±1.86i</td>
</tr>
<tr>
<td>Mode 2</td>
<td>-0.96±5.29</td>
<td>-0.97±5.50i</td>
<td>0.89±3.92i</td>
</tr>
<tr>
<td>Mode 3</td>
<td>-1.08±3.64</td>
<td>-1.05±3.62i</td>
<td>-2.86±0.49i</td>
</tr>
</tbody>
</table>

The maximum deviation in damping is 2.86 %, in oscillation frequency 3.92 %. Thus, it can be shown that the small signal behaviour of the reduced system is similar to the original system.

C. Analysis in time domain

The differential equations for the analysis in time domain are solved using an ode45 solver. In Fig. 13 and Fig. 14 the responses (differential angular speed and rotor angle) for a selected generator to a transient event before and after reduction are shown. It is obvious that there is nearly a perfect match between the curves for the original and the reduced system.

VI. CONCLUSION

In this work, a new approach for coherency identification of coherent generator groups is shown. The result is a reduced system, in which the reduction process is independent of the position of an analysed fault in the grid. The simulation in time domain shows a very good correlation between the determined time curves. The modal analysis shows only a slight difference in the oscillation frequency and the damping of the inter-area mode (max. 3.92 %). But all dominant modes can be kept and can be found in the reduced system.

In this case the number of buses is reduced by 94.13 % and the number of generators by 70 %. This fact reflects in shortening the computation time and results in an anonymised power system with almost the same small signal behaviour compared to the original system.

REFERENCES