

Comparative Study on the Performance of a Coherency-Based Simple Dynamic Equivalent with the New Inertial Aggregation

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ABSTRACT

Earlier, a simple dynamic equivalent for a power system external area containing a group of coherent generators was proposed in the literature. This equivalent is based on a new concept of decomposition of generators and a two-level generator aggregation. With the knowledge of only the passive network model of the external area and the total inertia constant of all the generators in this area, the parameters of this equivalent are determinable from a set of measurement data taken solely at a set of boundary buses which separates this area from the rest of the system. The proposed equivalent, therefore, does not require any measurement data at the external area generators. This is an important feature of this equivalent. In this paper, the results of a comparative study on the performance of this dynamic equivalent aggregation with the new inertial aggregation in terms of accuracy are presented. The three test systems that were considered in this comparative investigation are the New England 39-bus 10-generator system, the IEEE 162-bus 17-generator system and the IEEE 145-bus 50-generator system.

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1. INTRODUCTION

Transient stability assessment plays a very important role in the planning and operation of electric power systems. It is well known that the standard time-domain simulation or step-by-step (SBS) numerical integration method is the most reliable and accurate method for assessing transient stability since this method can accommodate any degree of power system modeling. But the main drawback of the standard SBS method is its heavy computational burden. This makes the method slow and hence unsuitable for online applications even with classical representation of power systems. Therefore, a number of methods have been proposed in the literature for online transient stability assessment. Direct methods such as the transient energy function method [1] and extended equal area criterion [2]-[6] have been suggested for online applications. To reduce the computational burden of SBS method, the use of truncated Taylor's series expansion has been suggested in [7] and large step-size integration has been suggested in [8]. All these methods use the classical representation of power systems and hence assess first swing stability. These methods are faster than the standard SBS method. They can be made even faster by coupling with them the coherency-based reduction techniques [9]-[20]. To speed up the computation of SBS method using classical representation, a dynamic equivalent power system (DEPS) model for the post-fault system has also been suggested in [21]. However, the equivalent generator for the less disturbed generators in this method is simply a mathematical model having no physical power system structure. Very recently, a coherency-based dynamic equivalent modeling using structure preserving technique has been reported in [22]. According to the author, the procedure is suitable for online studies. Some very new developments in transient stability

assessment are reported in [23]-[25]. There are also research efforts in using parallel processing [26]-[28] to speed-up the time-domain simulations.

In online transient stability assessment, a selected list of contingencies for the current operating condition needs to be evaluated as fast as possible before a fault or disturbance occurs in the system. Therefore, the computation time is very critical. As indicated earlier, the time domain simulation is the most accurate and reliable method for the assessment of transient stability since it can accommodate any degree of modeling. Therefore, to avoid any uncertainty in modeling that may provide inaccurate results, time domain simulation with detailed modeling of power system is the only choice. However, the transient stability assessment by the full scale time domain simulation alone for one pass (all the contingencies in the selected list which may be very long) with respect to the current operating condition cannot be done fast enough cost-effectively. On the other hand, all the fast transient stability assessment methods (transient energy function method, extended equal area criterion, etc.) are based on classical representation of power systems and hence they are limited to short-term assessment i.e. first swing stability assessment [7]-[8], [29]. If a system is first swing stable, the system damping, governor, etc. are expected to damp out the subsequent swings. Therefore, first swing stable system is considered as stable system. However, to avoid any inaccuracy in the results due to the modeling uncertainties arising from the use of classical representation of power systems, the doubtful or critical contingencies need to be evaluated by the full scale time domain simulation. Therefore, fast transient stability methods based on classical representation of power systems, combined with simple dynamic equivalent reduction techniques like the one proposed in this paper can be used to evaluate each of the contingencies in the selected list and identify the critical or doubtful ones which can then be evaluated by the full scale time domain simulation. This process can reduce the total computation time for one pass substantially since the fast assessment methods can be made even faster by coupling with them the simple dynamic reductions. Therefore, even with the increased power of computers, the use of simple dynamic reductions is very important in reducing the total computation time cost-effectively. Further reduction in the total computation time can be achieved by parallel processing. There has been a study [30] on the different capabilities (including the computation time) of six commercial online transient stability packages. Four of these transient stability assessment tools use full scale time domain simulation along with either the transient energy function method or the extended equal area criterion, one tool uses full scale time domain simulation alone, and one tool uses the single machine equivalent method. Five tools have pre-filters to determine the critical contingencies for analysis by the full scale time domain simulation, and they have the capabilities to represent the dynamics of the external equivalent. Four tools use multiprocessor architecture to evaluate multiple contingencies for the same operating condition. Each of the tools provides all modeling capabilities. However, the one tool that uses the full scale time domain simulation alone and does not have pre-filter and capabilities to represent the dynamics of the external equivalent, and does not use multiprocessor architecture was not implemented at any utility company. Further details can be found in [30].

The coherency-based reductions are based on the simple principle that a group of coherent generators (generators which swing together) can be lumped together to obtain an equivalent generator. A number of methods [14]-[20], [31]-[34] have been suggested in the literature for the identification of coherent generators. To apply a reduction technique, the power system is divided into two areas: an internal area or a study area that is retained in the original form, and an external area containing a group of coherent generators that is reduced. The reduction of the external area produces a dynamic equivalent which is a reduced model consisting of an equivalent generator and a network.

For online applications, it is desirable to have a simple reduction method in which the parameters of the dynamic equivalent can be determined with least possible measurement data taken from the external area. Between the two important coherency-based aggregation techniques: New Inertial Aggregation and Slow Coherency Aggregation [12], the former is the simplest aggregation method and requires less computation compared to the latter. However, both the methods require measurement data taken at the original generators of the external area to determine the parameters of the equivalent generator. To overcome the drawback of the necessity of measurement data at the original generators, a coherency-based simple single-generator dynamic equivalent was introduced in [35]. This equivalent is based on a new concept of decomposition of generators and a two-level aggregation of generators. The preliminary results on its performance in terms of accuracy were reported in [35]. With the knowledge of only the passive network model of the external area and the total inertia constant of the original generators in this area, the parameters of this dynamic equivalent can be determined from a set of real-time measurement data taken solely at a set of boundary buses which separates the external area from the internal area. Measurement data at the generators of the external area is not at all needed. This is an important feature of this equivalent. Another important feature is its simplicity that is essential for online applications. The dynamic equivalent has a power system structure and hence it can be represented physically. The use of this dynamic equivalent for coherent generators can greatly reduce the power system model and hence the assessment time. Further reduction of the system model and hence the

computation time can be achieved by extending the use of this equivalent to less disturbed generators. The results on a preliminary investigation on the degree of reduction that can be accomplished by using the proposed equivalent for less disturbed generators, and on the critical clearing time of the resulting reduced or aggregated system are very encouraging as has been reported in [36]. Very recently, an alternative and more justified formulation has been proposed in [37] for the first-level aggregation of the dynamic equivalent of [35]. Further, a thorough investigation was conducted to evaluate the accuracy of the proposed dynamic equivalent when applied to coherent generators. Three different test systems were considered in this investigation. These are the New England 39-bus 10-generator system, the IEEE 162-bus 17-generator system and the IEEE 145-bus 50-generator system. Detailed performance results of this equivalent are presented in [37]. The results clearly indicate excellent quality of the proposed equivalent. In the thorough investigation that was conducted, the performance of the proposed dynamic equivalent aggregation has also been compared with the new inertial aggregation in terms of accuracy. In this paper, these comparative results are presented.

2. FORMATION OF THE PROPOSED DYNAMIC EQUIVALENT AND THE NEW INERTIAL AGGREGATION

The formation of the proposed dynamic equivalent and the new inertial aggregated dynamic equivalent is described here briefly. A power system of n generators is considered. Further, the classical representation of power system is used.

A. Proposed Dynamic Equivalent Aggregation

The detail mathematical formulation of the proposed dynamic equivalent for a power system area containing a group of coherent generators is described in [37]. Here, its formation and the determination of different parameters are described briefly. The proposed equivalent is based on a new concept of decomposition of generators and a two-level aggregation of generators. To form this equivalent, the power system is partitioned into two areas: an internal area or a study area R that is retained in its original form, and an external area C containing the coherent group of generators. The dynamic equivalent is formed for the external area C on the assumption that the passive network model of this area and the total inertia constant of all the generators in this area are known. The partitioning of the system is done in such a way that the two areas are connected to each other only at a set of common buses, called boundary buses. This partitioning is shown in Figure 1. For convenience, the boundary buses are considered as parts of the external area C . For the dynamic equivalent to be valid for all the three system configurations (pre-fault, fault-on, and post-fault), the fault is placed in the internal area R . Any line between the boundary buses and any load at these buses are considered as parts of the internal area R . The mathematical formulation of this equivalent satisfies the swing equations of the coherent group of generators as well as the nodal equations at the boundary buses. The following sets of indices are defined for the external area C .

$$C_B = \{1, 2, \dots, n_B\}$$

$$C_I = \{(n_B + 1), (n_B + 2), \dots, (n_B + n_I)\}$$

where C_B are indices of all the n_B boundary buses and C_I are indices of all n_I internal generator buses. To form the dynamic equivalent, external area network is reduced to its generator internal buses and the boundary buses. The decomposition of the coherent generators into smaller generators and then the first level aggregation of these smaller generators result in a multi-generator dynamic equivalent with one separate equivalent generator connected to each individual boundary bus. So, the number of first-level equivalent generators is equal to the number of boundary buses n_B as shown in Figure 2. In this figure, $\mathbf{I}_j$ is the phasor current injected into the external area at boundary bus j , $\mathbf{V}_j$ and $\mathbf{y}_j$ are respectively the phasor voltage and shunt admittance at boundary bus j , $\mathbf{y}_{mn}$ is the admittance between two different boundary buses m and n , and $\mathbf{y}_{Uj}$ is the admittance between boundary bus j and the corresponding first-level equivalent generator internal bus. Further, M_{Uj} , P_{Uj} , E_{Uj} , δ_{Uj} are respectively the inertia constant, input mechanical power, internal bus voltage magnitude, and rotor angle of the first-level equivalent generator at boundary bus j . The second level aggregation of the first level equivalent generators results in the single-generator dynamic equivalent of Figure 3. In this figure, M_T , P_T , E_T , δ_T are respectively the inertia constant, input mechanical power, internal bus voltage magnitude, and rotor angle of the equivalent generator. The parameters of this dynamic equivalent are found as follows. The admittance between any two boundary buses i and k is given by

$$\mathbf{y}_{ik} = -\mathbf{Y}_{ik}, \quad (i \neq k) \in C_B \quad (1)$$

and the shunt admittance at any boundary bus j is given by

$$\mathbf{y}_j = \mathbf{Y}_{jj} + \sum_{(k \neq j) \in C_B} \mathbf{Y}_{jk} + \sum_{i \in C_I} \mathbf{Y}_{ji} \quad j \in C_B \quad (2)$$

where $\mathbf{Y}_{mn} = G_{mn} + jB_{mn}$ are the elements of the admittance matrix of external area reduced to the boundary buses and the generator internal buses.

The admittance between boundary bus j and the corresponding first level equivalent generator internal bus is given by

$$\mathbf{y}_{Uj} = (g_{Uj} + jb_{Uj}) = -\sum_{i \in C_i} \mathbf{Y}_{ji} \quad j \in C_B \quad (3)$$

The internal bus voltage magnitude E_{Uj} and the initial rotor angle δ_{Uj} of the first-level equivalent generator corresponding to boundary bus j are obtained from

$$\begin{aligned} \mathbf{E}_{Uj} &= E_{Uj} \angle \delta_{Uj} \\ &= \frac{-\mathbf{I}_j + \mathbf{y}_j \mathbf{V}_j + \sum_{(k \neq j) \in C_B} (\mathbf{V}_k - \mathbf{V}_j) \mathbf{Y}_{jk}}{\mathbf{y}_{Uj}} + \mathbf{V}_j \end{aligned} \quad (4)$$

using the boundary bus quantities referring to the pre-fault system condition. The internal bus voltage magnitude E_T and initial rotor angle δ_T of the second-level single equivalent generator are then obtained respectively as simple average of the first-level equivalent generator internal bus voltage magnitudes and initial rotor angles. They are given by

$$E_T = (\sum_{j \in C_B} E_{Uj}) / n_B, \quad \delta_T = (\sum_{j \in C_B} \delta_{Uj}) / n_B \quad (5)$$

The mechanical input power P_T of this equivalent generator is obtained as

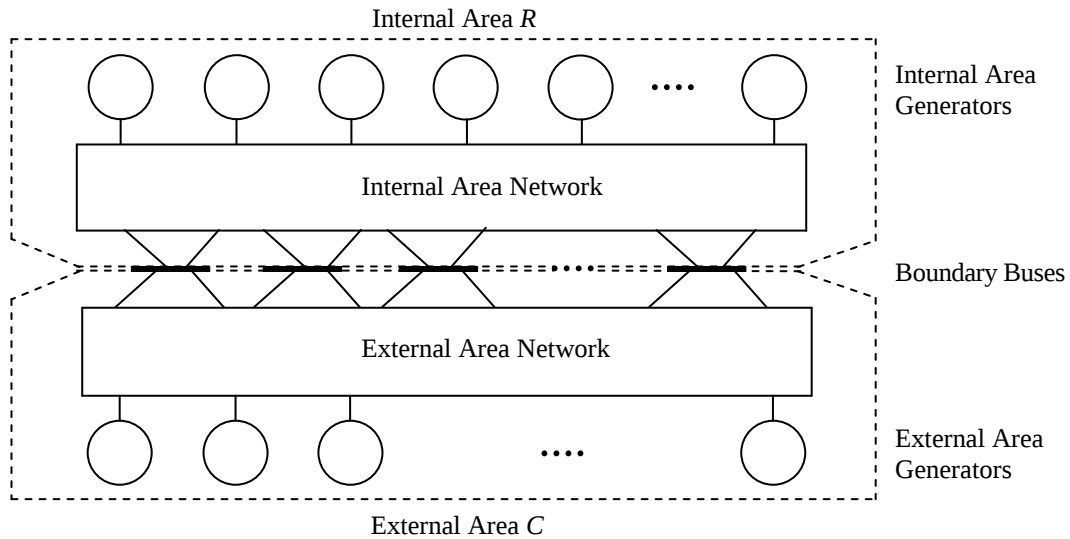


Figure 1. Partitioning of power system for the proposed aggregation method

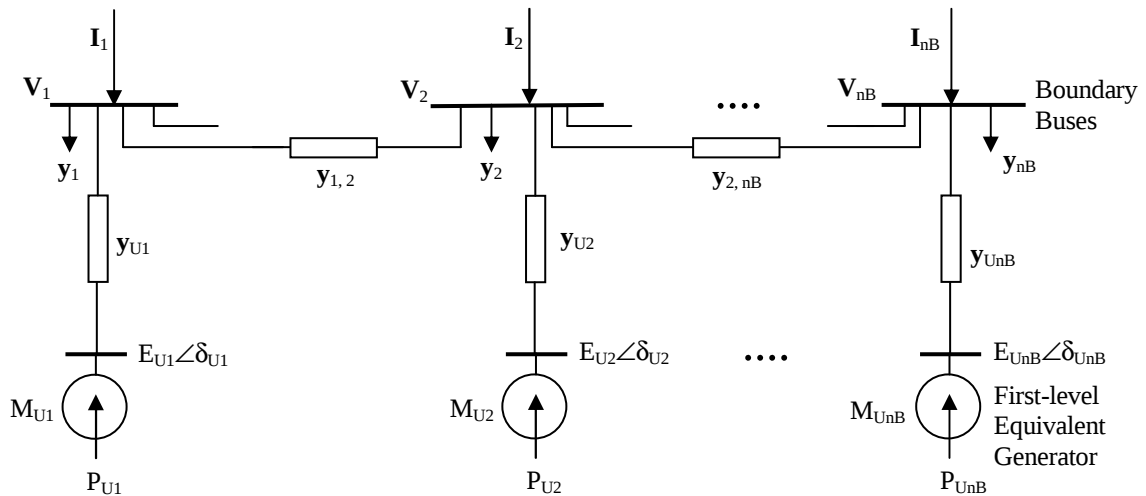


Figure 2. First-level multi-generator dynamic equivalent of a power system external area by the proposed aggregation

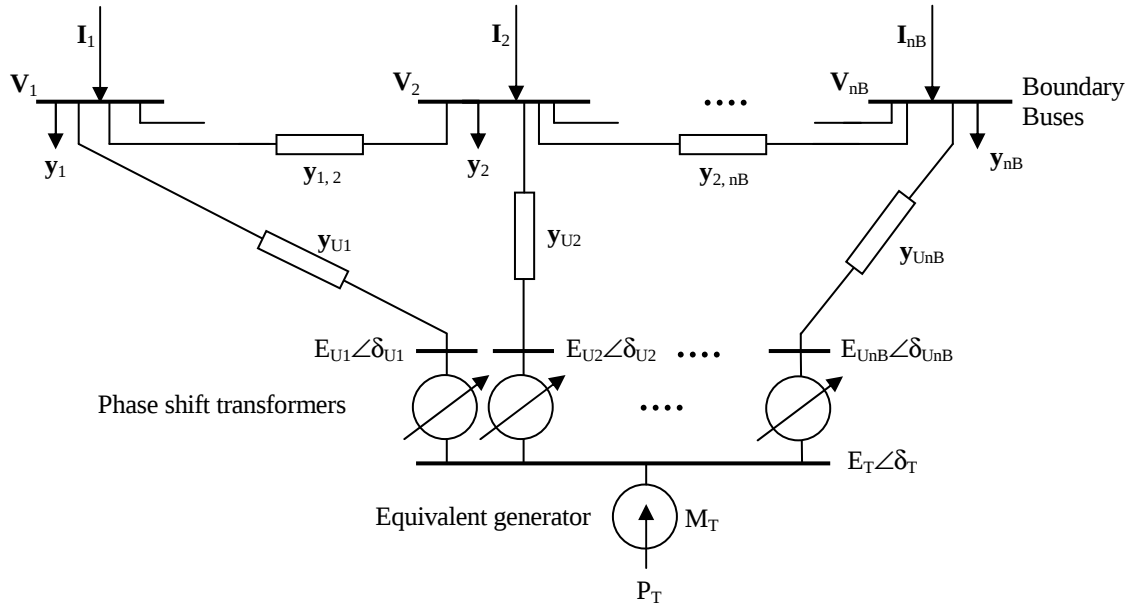


Figure 3. Single-generator dynamic equivalent of a power system external area by the proposed aggregation

$$P_T = \sum_{j \in C_B} P_{Uj} = \sum_{j \in C_B} [E_{Uj}^2 g_{Uj} - E_{Uj} V_j \{g_{Uj} \cos(\delta_{Uj} - \theta_j) + b_{Uj} \sin(\delta_{Uj} - \theta_j)\}] \quad (6)$$

with all the bus quantities referring to the pre-fault system condition. The inertia constant M_T is obtained as

$$M_T = \sum_{j \in C_B} M_{Uj} = \sum_{i \in C_i} M_i \quad (7)$$

where M_i is the inertia constant of an external generator i . The complex ratios of the ideal phase shift transformers are given by

$$\alpha_j = E_T / E_{Uj} \quad j \in C_B \quad (8)$$

B. New Inertial Aggregated Dynamic Equivalent

The details on this dynamic equivalent are available in [12]. Here, its formation is described briefly. In this method, the dynamic equivalent for a coherent group of generators is formed at the internal buses of these coherent generators. To form this equivalent for a group of coherent generators, the power system network is partitioned into two areas: an internal area R and an external area C . This is shown in Figure 4. As can be seen in this figure, the internal buses of the coherent generator group are the boundary buses which separate the internal area from the external area. So, the external buses of the coherent generator group are in the internal area. To form this dynamic equivalent for the external area, the internal buses of all the coherent generators are connected to a fictitious bus through ideal phase shift transformers. Since the creation of two additional buses in [12] is just to preserve the conventional power network representation and does not affect the computation, these buses are not considered here. It can be seen in [12] that the phasor voltage of the fictitious bus is same as the phasor voltage of the equivalent generator internal bus that is created through the inclusion of these additional buses. Therefore, in this presentation, the fictitious bus is considered as the internal bus of the equivalent generator. This dynamic equivalent is shown in Figure 5. In this figure, M_T , P_T , E_T , δ_T are respectively the inertia constant, input mechanical power, internal bus voltage magnitude, and rotor angle of the equivalent generator. The internal bus voltage magnitude and the initial rotor angle of this equivalent generator are given by

$$E_T = E_T \angle \delta_T = (\sum_{k=1}^{n_i} M_k E_k) / (\sum_{k=1}^{n_i} M_k) \quad (9)$$

where n_i is the number of coherent generators, M_k is the inertia constant of a coherent generator, and E_k is the phasor voltage at the internal bus of a coherent generator in the pre-fault system condition. The equivalent generator mechanical input power P_T is given by

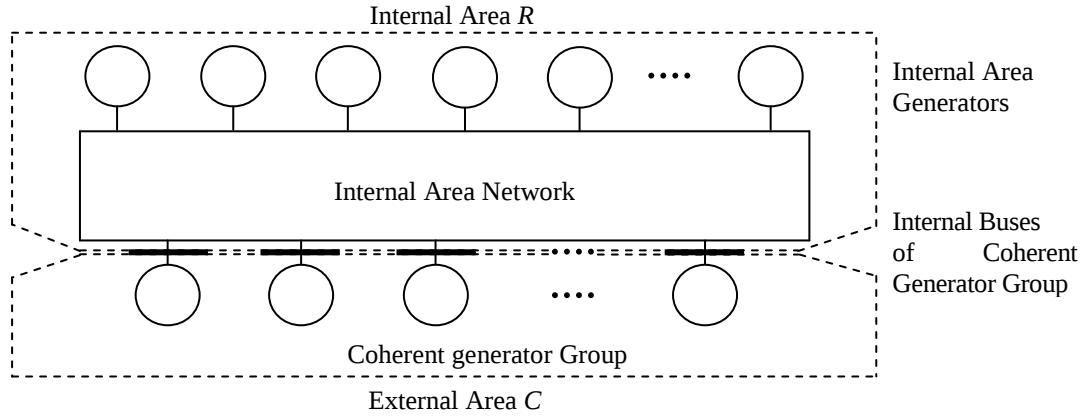


Figure 4. Partitioning of power system for the new inertial aggregation method

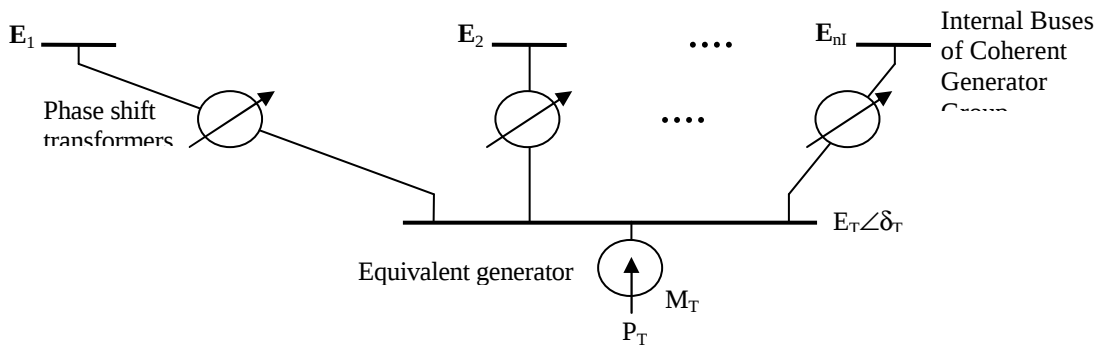


Figure 5. Single-generator dynamic equivalent of a power system external area by the new inertial aggregation

$$P_T = \sum_{k=1}^{n_i} P_{mk} = \sum_{k=1}^{n_i} P_{ek} \quad (10)$$

where P_{mk} and P_{ek} are respectively the mechanical input power and internal bus pre-fault steady-state real power of a coherent generator. The equivalent generator inertia constant M_T is obtained as

$$M_T = \sum_{k=1}^{n_i} M_k \quad (11)$$

The complex ratios of the ideal phase shift transformers are given by

$$\alpha_k = E_T / E_k \quad k = 1, 2, \dots, n_i \quad (12)$$

3. INVESTIGATIVE RESULTS ON THE COMPARATIVE STUDY OF PERFORMANCE

To compare the performance of the proposed dynamic equivalent with the new inertial aggregation equivalent in terms of accuracy, both the methods were tested and evaluated on the New England 39-bus 10-generator system, and the IEEE 162-bus 17-generator and 145-bus 50-generator systems. A number of three-phase short circuit fault cases on each of the test systems were considered in this investigation. In each fault case, the coherent generator groups were identified using the corresponding critically unstable trajectories of the full system as obtained by the SBS transient stability simulation method up to a time when the system exhibited instability. These trajectories were processed by the clustering algorithm of [14] to obtain the coherent generator groups. Since a good-quality dynamic equivalent provides approximately the full (original or unreduced) system trajectories, a single measure of the performance of any dynamic equivalent in terms of its accuracy is the difference (error) between the trajectories of the aggregated (reduced) system and the full system. Therefore, the performance of each of the methods in terms of its accuracy was evaluated by comparing the trajectories of the retained generators in the aggregated system with those in the full system in terms of errors (differences). To obtain the aggregated system corresponding to a particular aggregation method for a fault case, each of the coherent generator groups identified in that fault case was replaced by its respective dynamic equivalent. All the transient stability simulations in this investigation were carried out using a time step-size of 0.01 s. The results of the comparative study on the accuracy that was conducted on the three test systems are presented here. Table 1 shows the results on the New England 39-bus 10-generator

system, Table 2 shows the results on the IEEE 162-bus 17-generator system, and Table 3 shows the results on the IEEE 145-bus 50-generator system.

Table 1. Average absolute errors: New England 39-Bus 10-Generator System

Line tripped between buses *Faulty bus	No. of generators along with the coherency tolerance in different coherent groups	No. of generators retained	Fault clearing time (FCT) and average absolute error (AAE)			Fault clearing time (FCT) and average absolute error (AAE)		
			FCT (s)	AAE (degrees) (min – max)		FCT (s)	AAE (degrees) (min – max)	
				Proposed aggregation	New inertial aggregation		Proposed aggregation	New inertial aggregation
*29 - 26	4(2.1 ⁰), 3(3.79 ⁰)	3	0.08	0.057 - 0.732	0.048 – 0.707	0.10	0.067 – 0.935	0.057 – 0.916
*29 - 26	8(9.47 ⁰)	2	0.08	0.248 – 1.514	0.112 – 1.133	0.10	0.325 – 1.028	0.168 – 0.476
*25 - 2	2(3.13 ⁰), 4(3.47 ⁰)	4	0.14	0.054 – 0.284	0.045 – 0.304	0.17	0.046 – 0.565	0.033 – 0.514
*20 ¹	2(3.12 ⁰), 4(4.37 ⁰)	4	0.21	0.026 – 0.169	0.014 – 0.242	0.26	0.037 – 0.211	0.023 – 0.292
*31 ¹	2(2.97 ⁰), 4(3.19 ⁰)	4	0.24	0.026 – 0.226	0.010 – 0.178	0.29	0.023 – 0.257	0.007 – 0.206
*31 ¹	7(7.71 ⁰)	3	0.24	0.131 – 0.271	0.094 – 0.363	0.29	0.046 – 0.323	0.104 – 0.428
*10 - 13	5(8.30 ⁰)	5	0.23	0.054 – 1.645	0.025 – 1.260	0.28	0.232 – 3.128	0.127 – 2.279
*2 - 1	3(3.92 ⁰)	7	0.17	0.043 – 1.104	0.097 – 1.202	0.21	0.016 – 1.291	0.061 – 1.282
*27 - 17	2(2.09 ⁰), 3(5.62 ⁰)	5	0.19	0.017 – 0.444	0.006 – 0.415	0.23	0.018 – 0.514	0.004 – 0.466
*4 - 14	2(5.26 ⁰), 3(7.97 ⁰)	5	0.25	0.161 – 1.421	0.180 – 1.469	0.30	0.083 – 1.339	0.075 – 1.340
*6 - 11	4(8.66 ⁰)	6	0.22	0.169 – 1.342	0.178 – 1.097	0.27	0.134 – 1.517	0.140 – 1.081

¹No line removed

Table 2. Average absolute errors: IEEE 162-Bus 17-Generator System

Line tripped between buses *Faulty bus	No. of generators along with the coherency tolerance in different coherent groups	No. of generators retained	Fault clearing time (FCT) and average absolute error (AAE)			Fault clearing time (FCT) and average absolute error (AAE)		
			FCT (s)	AAE (degrees) (min – max)		FCT (s)	AAE (degrees) (min – max)	
				Proposed aggregation	New inertial aggregation		Proposed aggregation	New inertial aggregation
*5 - 129	4(5.21 ⁰), 2(2.30 ⁰), 2(4.73 ⁰)	9	0.23	0.009 – 0.116	0.013 – 0.105	0.28	0.040 – 0.139	0.037 – 0.128
*124 ¹	5(5.32 ⁰), 2(2.86 ⁰), 2(5.18 ⁰)	8	0.40	0.074 – 0.267	0.093 – 0.483	0.48	0.037 – 0.532	0.035 – 0.650
*6 ¹	6(5.05 ⁰), 3(4.38 ⁰), 3(4.65 ⁰), 3(5.50 ⁰)	2	0.23	0.251 – 0.281	0.250 – 0.265	0.28	0.294 – 0.273	0.239 – 0.311
*42 - 109	10(5.06 ⁰), 2(4.96 ⁰)	5	0.35	0.445 – 1.418	0.492 – 1.432	0.42	0.304 – 1.669	0.404 – 1.693
*130 ¹	6(5.01 ⁰), 4(3.84 ⁰), 3(2.93 ⁰), 2(4.86 ⁰)	2	0.32	0.085 – 0.809	0.087 – 0.778	0.39	0.126 – 0.255	0.133 – 0.229
*26 - 149	5(5.08 ⁰), 3(4.86 ⁰), 2(0.90 ⁰), 2(1.76 ⁰)	5	0.21	0.024 – 0.681	0.011 – 0.640	0.26	0.004 – 0.711	0.022 – 0.669
*95 - 97	14(3.86 ⁰)	3	0.31	0.350 – 0.920	0.383 – 1.033	0.38	0.240 – 0.544	0.266 – 0.598
*52 - 116	5(3.53 ⁰), 2(0.89 ⁰), 2(1.63 ⁰), 2(1.69 ⁰), 2(3.96 ⁰)	4	0.36	0.041 – 0.134	0.078 – 0.145	0.44	0.008 – 0.145	0.023 – 0.146
*27 - 125	6(3.25 ⁰), 3(3.47 ⁰)	8	0.18	0.084 – 1.786	0.084 – 1.776	0.22	0.151 – 0.789	0.146 – 0.782
*112 - 120	5(7.77 ⁰), 3(7.55 ⁰), 2(5.69 ⁰), 2(7.94 ⁰)	5	0.21	0.046 – 0.410	0.034 – 0.390	0.26	0.069 – 0.466	0.014 – 0.447
*110 - 141	3(1.13 ⁰), 2(1.43 ⁰), 2(4.21 ⁰), 2(4.37 ⁰)	8	0.27	0.002 – 0.107	0.003 – 0.078	0.33	0.002 – 0.112	0.006 – 0.080
*126 - 37	4(3.47 ⁰), 2(2.16 ⁰), 2(2.50 ⁰), 2(2.64 ⁰)	7	0.16	0.056 – 0.363	0.067 – 0.372	0.20	0.053 – 0.515	0.055 – 0.519

¹No line removed

In these results, the difference between an aggregated system trajectory and the full system trajectory of a retained generator is provided in terms of an average absolute error (AAE) between the two trajectories [12] as obtained by

$$\sigma = \frac{1}{T} \int_0^T |\delta_a(t) - \delta_f(t)| dt \quad (13)$$

where σ is the average absolute error, δ_a and δ_f are respectively the rotor angles in the aggregated system and the full system in synchronous frame, and T is the period of study. This average absolute error was computed over a study period equal to or a little greater than the length of time taken by the critically unstable full system to actually exhibit instability. Further, this error was computed for two different fault clearing times with the lower one referring to the critically unstable condition of the full system. The other fault clearing time was at least 20% higher than the lower one. In all the tables, column 2 shows the number of generators in each coherent group along with the coherency tolerance chosen. Further, the average absolute errors in the tables are shown in terms of the minimum and maximum values among the average absolute errors of all the retained generators. In two fault cases of the New England System, the results are also shown with varying coherency tolerances. However, the results on the accuracy of the proposed aggregation method as shown in the tables are presented in [37]. They are repeated here for the purpose of comparison of the two aggregation methods. It can be seen from the tables that the errors and hence the accuracy of the two methods are similar.

Table 3. Average absolute errors: IEEE 145-Bus 50-Generator System

Line tripped between buses *Faulty bus	No. of generators along with the coherency tolerance in different coherent groups	No. of generators retained	Fault clearing time (FCT) and average absolute error (AAE)			Fault clearing time (FCT) and average absolute error (AAE)		
			FCT (s)	AAE (degrees) (min – max)		FCT (s)	AAE (degrees) (min – max)	
				Proposed aggregation	New inertial aggregation		Proposed aggregation	New inertial aggregation
*59 – 72	18(3.23 ⁰), 7(3.56 ⁰), 6(3.64 ⁰), 4(3.35 ⁰), 2(1.39 ⁰), 2(2.24 ⁰)	11	0.23	0.007 – 0.429	0.008 – 0.426	0.28	0.024 – 0.442	0.023 – 0.438
*104 ¹	21(2.79 ⁰), 10(3.47 ⁰), 9(3.40 ⁰), 7(3.28 ⁰)	3	0.19	0.055 – 0.159	0.044 – 0.149	0.23	0.043 – 0.111	0.031 – 0.101
*76 – 77	20(3.28 ⁰), 16(3.87 ⁰), 3(2.15 ⁰), 3(2.62 ⁰), 3(3.18 ⁰), 2(0.11 ⁰)	3	0.16	0.810 – 0.979	0.815 – 0.840	0.20	0.686 – 1.149	0.648 – 1.146
*135 ¹	42(1.60 ⁰), 3(3.41 ⁰)	5	0.15	0.011 – 0.666	0.011 – 0.671	0.18	0.023 – 0.917	0.023 – 0.922
*58 – 98	13(3.97 ⁰), 5(3.01 ⁰), 4(3.41 ⁰), 4(3.51 ⁰), 3(3.32 ⁰), 3(3.38 ⁰), 2(0.57 ⁰), 2(0.81 ⁰), 2(1.53 ⁰)	12	0.23	0.049 – 1.360	0.027 – 1.309	0.28	0.046 – 1.719	0.035 – 1.668
*80 – 92	44(3.14 ⁰), 2(3.23 ⁰), 2(3.69 ⁰)	2	0.22	0.073 – 0.077	0.072 – 0.078	0.27	0.028 – 0.077	0.028 – 0.078
*108 – 75	24(3.88 ⁰), 16(3.14 ⁰), 2(0.09 ⁰)	8	0.23	0.073 – 1.076	0.073 – 1.076	0.28	0.014 – 1.148	0.013 – 1.148
*74 – 106	14(3.82 ⁰), 4(3.46 ⁰), 4(3.98 ⁰), 3(1.63 ⁰), 3(1.68 ⁰), 3(2.89 ⁰), 2(0.84 ⁰), 2(2.27 ⁰), 2(2.91 ⁰)	13	0.21	0.029 – 0.923	0.011 – 0.852	0.26	0.086 – 1.396	0.028 – 1.321
*94 – 60	42(3.61 ⁰), 2(1.01 ⁰), 2(1.76 ⁰)	4	0.07	0.543 – 2.168	0.533 – 2.164	0.09	0.668 – 2.122	0.655 – 2.115
*132 ¹	36(3.98 ⁰), 7(2.85 ⁰), 3(3.93 ⁰), 2(1.55 ⁰)	2	0.23	0.218 – 0.336	0.218 – 0.336	0.28	0.148 – 0.230	0.148 – 0.230
*101 – 69	26(3.99 ⁰), 13(3.61 ⁰), 8(2.23 ⁰)	3	0.25	0.126 – 0.872	0.123 – 0.871	0.30	0.110 – 0.879	0.107 – 0.879
*115 ¹	43(3.13 ⁰), 3(0.85 ⁰), 2(1.42 ⁰)	2	0.30	0.127 – 0.217	0.128 – 0.217	0.36	0.037 – 0.241	0.037 – 0.241

¹No line removed

In addition, each of the two aggregation methods was investigated by comparing its respective

aggregated system with the full system in terms of the following aspects: (a) critical clearing time range, (b) the generator that loses synchronism first corresponding to a fault clearing time for which the full system exhibits critically unstable condition, and (c) the generator that has the highest maximum absolute first swing corresponding to a fault clearing time for which the full system exhibits critically stable condition. All these results were obtained using COA frame of reference. In each of the fault cases presented here, the results on the mentioned aspects obtained by both the aggregation methods were found to be same as those of the full system. However, it is important to note that the errors between aggregated system trajectories and full system trajectories of the retained generators are also measures of the results on the mentioned aspects. This means that if the errors are high, then the results on the indicated aspects obtained by an aggregation method will be different from those of the full system. Regarding the computation speed, the author believes that the computation time by both the aggregation methods will be similar. So this aspect has not been considered in the investigation.

4. CONCLUSION

The performance of a proposed coherency-based simple dynamic equivalent aggregation method has been compared with the new inertial aggregation method in terms of accuracy. Three test systems that were considered in this study are the New England 39-bus 10-generator system, and the IEEE 162-bus 17-generator and 145-bus 50-generator systems. The comparative performance results obtained in this investigation have been presented here. The results clearly indicate that the accuracy of the proposed dynamic equivalent aggregation method is similar to that of the new inertial aggregation method. However, like any other dynamic equivalent aggregation, the accuracy of results by the proposed dynamic equivalent depends on the coherency tolerance. The proposed dynamic equivalent is expected to be useful in online applications.

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