

When to Island for Blackout Prevention

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Abstract--Cascading outages leading to large-area blackouts can be mitigated using intentional controlled islanding (ICI). An ICI scheme must define the most suitable time to split the system after a severe contingency (i.e., when to island), as well as to quickly determine the set of branches to be disconnected to create stable islands (i.e., where to island). Most of the works in the literature, however, focus on the latter and little has been done to address the “when to island” problem. To fill this gap, this paper proposes a unified methodology to determine the most suitable moment for islanding. First, the proposed methodology uses real-time information to estimate the rotor angles of generators, which, in turn, serve to define the suitable number of coherent generators and the actual coherent groups. It then adopts the concept of area-based Center of Inertia (COI)-referred rotor angle index to determine the actual time of islanding. The unified methodology for determining the number of islands to be created, the coherent generators and the time for islanding is tested using the IEEE 39- and 118-bus test systems. Multiple case studies are presented to demonstrate the adaptability and effectiveness of the proposed unified methodology to different system conditions.

Index Terms--Blackout prevention, coherency identification, generator rotor angles, intentional controlled islanding.

I. INTRODUCTION

INTERCONNECTED power systems are prone to cascading outages that may lead to large-area blackouts. Intentional controlled islanding (ICI) has been proposed by a number of task forces and advisory groups as an effective corrective control action to mitigate these events [1]. ICI, also called system splitting or controlled system separation, is an adaptive control strategy that can be used as a final resort to attempt to save the system from a partial or a complete blackout. ICI is typically used following a severe disturbance and when conventional control systems have failed to keep the system within stability margins. In practice, ICI aims to find, within a few seconds, the set of branches that must be disconnected to split the whole power system and maintain together the coherent groups of generators resulting from the disturbance [2-3].

When adopting ICI, three key aspects must be addressed: “where to island”, “when to island” and “what to do after islanding”. Most of the works [2-7] available in the literature focus on addressing the first one. However, and despite being

recognized that the timely implementation of the ICI scheme (i.e., to answer the question of when to island) is critical for its success, only a few works have attempted to solve the “when to island” problem [8], [9], [10]. These approaches, nonetheless, have carried out offline estimations of the coherent groups of generators. This practice, might lead to inadequate coherent groups given that different disturbances are likely to result in different groups of generators. Indeed, it has been highlighted that determining in real-time the coherency of generators within a multi-machine system can help defining the branches to be disconnected when the islands will be created (and this avoids unnecessary line tripping [5]).

This paper proposes a unified methodology to address the “when to island” problem. The methodology initially uses synchronized system measurements of all generators in the system (i.e., generator speed, output power, voltage and current), provided by Phasor Measurement Units (PMUs), to estimate the generators rotor angles. These rotor angles are then used to define the suitable number of coherent generators, and the generators within each coherent group. The estimation of the generator rotor angles is performed in real-time by extracting time domain solutions of the swing equation. The similarity between each pair of the swing curves is identified using an intraclass correlation analysis (a well-established technique in statistics), which is performed in less than a second time interval. Through the examination of these similarities, the suitable number of coherent generator groups is then determined and the groups are finally formed through a graph minimization algorithm. Once the coherent groups are identified, the proposed unified methodology adopts the concept of area-based Center of Inertia (COI)-referred rotor angle index, widely used in transient stability analysis for tracking the stability of interconnected areas, to determine the actual time for islanding. The time at which the system is defined to be unstable, and hence requires to be split, is defined as the moment at which one of the COI-angle deviates from the traditional threshold of $\pm 180^\circ$. Defining the time of islanding allows the triggering of islanding schemes to split the power system and avoid large-area blackouts.

The unified methodology for determining the number of islands to be created, the coherent generators and the time of islanding is implemented in real-time. To demonstrate its capability and effectiveness in mitigating large-area blackout, the approach is tested using the dynamic model of the IEEE 39-bus test system and carrying out time-domain simulations, considering multiple cases and different system conditions.

This paper is organized as follows. The unified methodology for addressing the “when to island” problem is thoroughly detailed in Section II. Section III then presents multiple case studies to illustrate the adaptability and effectiveness of the proposed unified methodology under different system

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conditions. A discussion is provided in Section IV and key conclusions are finally drawn in Section V.

II. WHEN TO ISLAND

Addressing the question of when to island is critical for the success of the ICI scheme, since an early recognition indicating if a disturbance will evolve into a blackout or not can mitigate the occurrence and cost of blackouts. Hence, possible issues of false alarm and false dismissal have to be handled. In the case of a false alarm, islanding is triggered too early, forcing a stable system to incorrectly be split into islands. In the case of false dismissal, islanding is triggered too late, allowing an unstable system to operate and to probably lead to an uncontrolled cascading blackout. In this section, a general methodology that can be applied in every power system for recognizing and preventing imminent blackouts (by triggering promptly the islanding scheme) is presented. The proposed unified methodology uses the area-based Center of Inertia (COI)-referred rotor angle index, as well as an online estimation of the rotor angles, to first define, in real-time, the suitable number of coherent generator groups and the actual coherent groups. The unified methodology then calculates the COI-referred rotor angle to determine the most suitable time for splitting the system. This timely definition of the time for islanding can then be combined with approaches to determine the points where to island the system.

A. Rotor Angles Estimation Based on Limited Measurements

The transient stability of an n -machine system is described using the classical swing equation given in (1) [11].

$$2H \frac{S_{rated}}{\omega_s^2} \omega_r \frac{d^2 \delta}{dt^2} = P_m - P_e - k_D \Delta \omega_r = P_a \quad (1)$$

where H , in s, is the inertia constant at the synchronous speed ω_s (ω_s in rad/s), ω_r is the generator angular speed in rad/s, δ is the rotor angle in rad, P_m , P_e and P_a are the mechanical, electrical and accelerating power (in MW), respectively, S_{rated} is the generator MVA rating, K_D is the damping coefficient of the rotor, and $\Delta \omega_r$ is the speed deviation in rad/s.

In steady state, $\omega_r = \omega_s$, and hence ω_r can be replaced in the above equation by ω_s . Moreover, it is known that the damping constant has limited effect on the natural frequencies and mode shapes. Hence, (1) can be rewrite as in (2).

$$\frac{2H}{\omega_s} \frac{d^2 \delta}{dt^2} = P_m - P_e = P_a \quad (p.u.) \quad (2)$$

In transient state, the swing equation can be solved in the time domain using an integration technique. In such a case, synchronized system measurements of all generators in the system (i.e., terminal voltage and current, generator speed, electrical power) provided by PMUs (with a rate up to 50 samples/s) are needed. In addition, and given that P_m can be assumed to be constant for a short duration after the fault (in this case for 3 s), the differential equation provided in (3) must be solved.

$$\frac{d^2 \delta}{dt^2} = (P_m - P_e) = \frac{\omega_s^2}{2H \omega_r} \quad (3)$$

Since (3) is now linear (all the terms of the second part of (3) are known), a direct non-iterative solution can be obtained

at each time step (defined in this work as $\Delta t = 0.02$ s) using the well-known trapezoidal integration algorithm [12]. It must be noted that since the trapezoidal integration algorithm is numerically stable [12] large step sizes can be used. The classical trapezoidal integration technique is described in (4).

$$\begin{aligned} f'(x) &= \lim_{\Delta x \rightarrow 0} \frac{f(x + \Delta x) - f(x)}{\Delta x} \\ \Delta x \neq 0 &\Rightarrow \frac{\Delta f(x)}{\Delta x} = \frac{f(x + \Delta x) - f(x)}{\Delta x} \\ f''(x) &= \frac{\Delta^2 f(x)}{\Delta x^2} = \frac{f(x + 2\Delta x) - 2f(x + \Delta x) + f(x)}{\Delta x^2} \end{aligned} \quad (4)$$

Applying the trapezoidal integration technique (4) to (3) yields the expressions (5)-(7).

$$\delta''(t) = \frac{\delta(t + 2\Delta t) - 2\delta(t + \Delta t) + \delta(t)}{\Delta t^2} \quad (5)$$

At each time step $k = t + \Delta t$,

$$\delta''(t - \Delta t) = \frac{\delta(t + \Delta t) - 2\delta(t) + \delta(t - \Delta t)}{\Delta t^2} \quad (6)$$

$$\delta(t + \Delta t) = \delta''(t - \Delta t) \Delta t^2 + 2\delta(t) - \delta(t - \Delta t) \quad (6)$$

$$\delta(t) = \delta''(t - 2\Delta t) \Delta t^2 + 2\delta(t - \Delta t) - \delta(t - 2\Delta t) \quad (7)$$

$$\delta(k - 1) = \delta''(k - 3) \Delta t^2 + 2\delta(k - 2) - \delta(k - 3) \quad (7)$$

$$\delta(k) = \delta''(k - 2) \Delta t^2 + 2\delta(k - 1) - \delta(k - 2) \quad (7)$$

with $\delta(-2) = 0$, $\delta(-1) = 0$ and $\delta''(k)$ known.

B. Automatic Generator Grouping

A classical process for identifying the similarity between each pair of the generator swing curves, and thus forming the coherent generator groups, is to compare their trend visually. Typically, this procedure is executed by an experienced system operator. However, an estimation of the generator rotor angles in real-time following by an evaluation of their similarity could help automating this visual process and thus increasing its flexibility. In this paper, the similarity is evaluated based on an intraclass correlation analysis [13] (a well-established technique in statistics) and the coherent generator groups are identified through a graph minimization algorithm.

1) Intraclass Correlation Coefficient (ICC)

The Intraclass Correlation Coefficient (ICC) is a general measurement of agreement or consensus [13]. The coefficient represents the agreement of two or more dependent variables (coders) by comparing the variability of different measurements (or ratings) within variables and between variables to the total variation across all measurements. It is noted that, there are many forms of ICC whose application to the same data can return quite different results. To choose the most appropriate form, three actions are required: a) decide the type of analysis of variance (one-way or two-way ANOVA) that is appropriate for the study [14], b) determine if the differences between the means of the variables are relevant to the study, and c) determine if the unit of analysis is an individual measurement or the mean of several measurements.

For this study, and to identify generator coherency through the assessment of the rotor angle samples, two coders

TABLE I
TWO-WAY ANOVA

Variation	Sum of Square	Mean Squares
Between Columns	$SSC = I \sum_{j=1}^J (\bar{X}_j - \bar{X})^2$	$MSC = \frac{SSC}{J-1}$
Between Rows	$SSR = J \sum_{i=1}^I (\bar{X}_i - \bar{X})^2$	$MSR = \frac{SSR}{I-1}$
Error	$SSE = \sum_{i=1}^I \sum_{j=1}^J (X_{ij} - \bar{X}_i - \bar{X}_j + \bar{X})^2$	$MSE = \frac{SSE}{(I-1)(J-1)}$

(dependent variables) are necessary: the time-step of each sample and the identity of each generator. Hence, a two-way ANOVA has been found to be the most appropriate approach for this study. Table I presents the two-way ANOVA variables. In this table, SSC is the Sum of Square between Columns, SSR is the Sum of Squares between Rows and MSE is the Mean Square Errors. The sets $\mathbf{J} = \{1, \dots, j\}$ and $\mathbf{I} = \{1, \dots, i\}$ denote the generators and the number of samples, respectively. Moreover, in this study, since the rotor angle samples of each generator are independent from the rotor angle samples of all the other generators, the differences between the means of the coders are relevant to the study. Finally, since a single rotor angle sample is obtained at each time-step, it is obvious that the unit of analysis is an individual measurement and not the mean of several measurements.

The variables \bar{X}_i , \bar{X}_j and \bar{X} in Table I are described as:

$$\bar{X}_i = \frac{\sum_{j=1}^J X_{i,j}}{J}, \quad \bar{X}_j = \frac{\sum_{i=1}^I X_{i,j}}{I}, \quad \bar{X} = \frac{\sum_{i=1}^I \sum_{j=1}^J X_{i,j}}{IJ}, \quad (8)$$

Based on the three decisions discussed above, the appropriate ICC form for this study is given by the variance ratio provided in (9).

$$\rho = \frac{\sigma_T^2}{\sigma_T^2 + \sigma_J^2 + \sigma_I^2 + \sigma_E^2} \quad (9)$$

where σ_J^2 is the variance of the deviation from the overall mean of each set of rotor angle samples, σ_J^2 is the variance of the difference of each time-step and each set of rotor angle samples from their mean, σ_T^2 is the variance of the difference from the overall mean of the j^{th} sample, and σ_E^2 is the variance of the sample error.

However, due to the fact that the sampling variability of the PMUs limits the number of samples, the true variance terms are usually unknown. Hence, ICC is estimated from the sample data as in (10).

$$ICC(2,1) = r = \frac{MSR - MSE}{MSR + (n-1)MSE + n(\frac{MSC - MSE}{I})}, r \in [-1,1] \quad (10)$$

where n refers to the number of data sets to be compared ($n=2$ for the purpose of the identification of coherent generator groups). An $ICC(2,1)$ equal to 1 denotes that the pair of generator swing curves is in perfect agreement, while an $ICC(2,1)$ equal to 0 corresponds to random agreement.

2) Graph Minimization Algorithm for Generator Grouping

The generator coherency problem can be described using an undirected fully connected graph-model $\mathbf{G}(\mathbf{V}, \mathbf{E}, \mathbf{W})$. In this

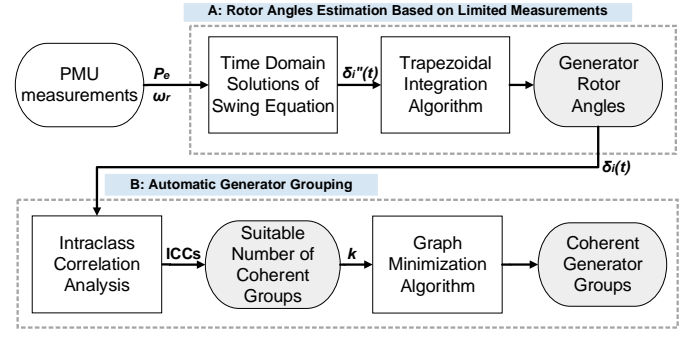


Fig. 1. Identification of coherent generators in real-time

graph-model, the set $\mathbf{V} = \{v_1, \dots, v_n\}$ is set of nodes denoting the machines. The set \mathbf{W} , with elements w_{ij} ($i, j = 1, \dots, n$), is a set of edge weights representing the calculated ICCs. Subgraphs $\mathbf{G}_s(\mathbf{V}_s, \mathbf{E}_s, \mathbf{W}_s)$ with $s = 1, \dots, k$, represent the desired coherent groups ($k = 2, \dots, n$).

For the case of two desired coherent groups ($k = 2$), the aim is to separate the swing curves into positive and negative. This can be achieved by calculating the mean of the rotor angle samples of each generator and then separating the two groups based on the means sign. For $k > 2$, the objective is to group together generators with the highest similarity. Hence, for each subgraph ($k = 2$), the ICC between each pair of generators is firstly calculated. Then, the calculated ICCs are used as edge weights in order to form two fully connected graphs. Considering that the higher ICCs are of interest, all but one negative ICC become zero, and two MSTs with reversed edge weights ($1 / w_{ij}$) are derived that contain only the strongest relations. To form the $k > 2$ groups, the $k - 2$ globally smallest weight edges are selected to be removed from the spanning trees.

3) Suitable Number of Coherent Generator Groups (k)

The automatic generator grouping analysis of this section is completed by determining the suitable number of coherent generator groups (k). It is noted that, for the ICI concept, the parameter k corresponds also to the suitable number of islands to split the system since each of these dynamic groups of generators must be separated into different islands to assist the system's transient stability. The main steps for assessing the suitable number of coherent generator groups (k) are:

Step 1: Set the maximum number of coherent generator groups (k_{max}) equal to the number of generators in the system during a system transient (since each coherent group may contain only a single generator)

Step 2: For the default case $k=2$, find the global minimum ICC (min_{global}) within both the created subgraphs and the next minimum (min_{next}) into its subgraph.

Step 3: If $((min_{next} - min_{global}) \times 100\%) > a$, $k = k + 1$, else stop. The parameter a is a threshold that determines how different the trend of a swing curve is from the trends of other curves. For instance, at the default case ($k = 2$), where the positive and negative swings are directly separated to two groups, if a positive (or a negative) swing is quite different from the other positive (or negative) swings (i.e., the difference of their ICCs exceeds the threshold a), then the particular positive swing should be moved into a third group. The value of the threshold a may vary according to the

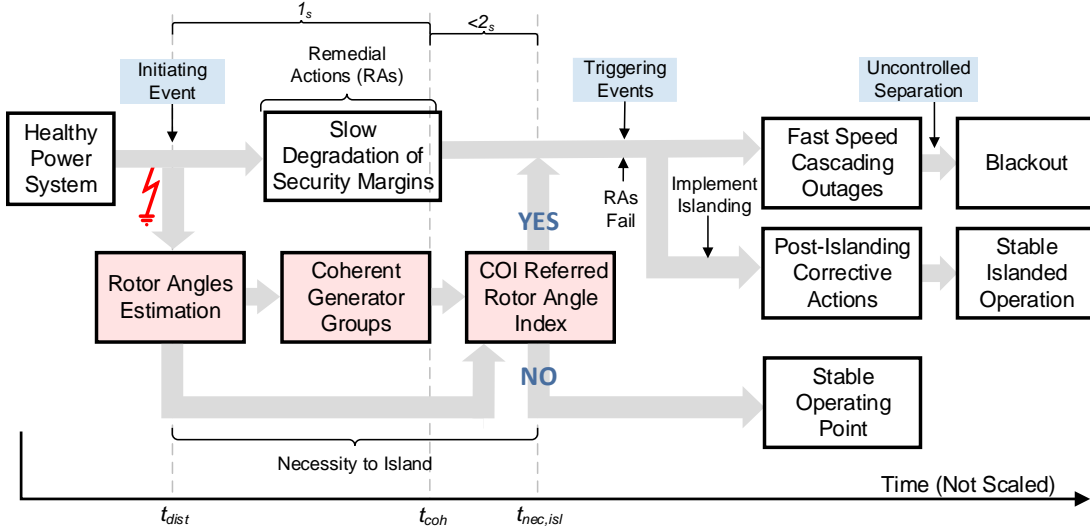


Fig. 2. Time-line showing the implementation of the proposed methodology for determining the time of islanding

inherent characteristics of each network. Its exact value can be set through sensitivity analyses. It is noted that for all the studies that were examined it was found that a threshold of 20 % is feasible.

Step 4: Find the next global minimum and the next minimum into its subgraph.

Step 5: Repeat steps 3 and 4 until $k = k_{max}$.

Combining Section II-A and Section II-B (Fig. 1), a real-time identification of coherent generator groups is feasible. As shown in Fig. 1, an online estimation of the generator rotor angles is firstly performed by solving the swing equation in the time domain using PMU measurements. The pairwise similarity coefficients are then calculated through an intraclass correlation analysis and are used as edge weights to a fully connected graph, where: a) the suitable number of coherent generator groups (k) is determined; and b) the coherent generator groups are formed by deriving its MST.

C. Area-Based COI-Referred Rotor Angle Index

Area-based COI [15-16] is a common transformation used in transient stability analysis for tracking the stability of interconnected areas. Current methods in the literature aim to detect the angle instability of a system by utilizing the area-based COI transformation and combining it along with synchrophasor measurements [17-18]. The area-based COI-referred rotor angle index is associated with the rotor angle of each area of a power grid. It rests on an equivalent inertia that represents the total inertia of the generators in that area. Considering that a multi-machine power system is split into smaller areas during a cascading outage, it is reasonable to assume that an equivalent single machine can represent all the generators located in each area. This can be achieved by deriving the COI of each area. To do that, the area equivalent rotor angle must be defined first. Thus, for a particular area, its equivalent rotor angle is given in (11).

$$\bar{\delta}_j = \frac{1}{N} \sum_{i=1}^N \delta_i \quad (11)$$

where N is the number of generators in that area, $\bar{\delta}_j$ is the area equivalent rotor angle and the δ_i individual rotor angle in

a particular area. In other words, the area equivalent rotor angle is the average rotor angle through all N measurements. Assuming a power system with a number of r areas, the COI of the system can be defined as in (12).

$$\bar{\delta}_{cor} = \frac{1}{H_T} \sum_{j=1}^r H_j \bar{\delta}_j \quad (12)$$

where

$$H_T = \sum_{j=1}^r H_j \quad (13)$$

and H_T is the total inertia in the system and H_j the j^{th} inertia in an area. In COI frame, the area equivalent rotor angle is expressed as in (14).

$$\delta_j^{COI} = \bar{\delta}_j - \bar{\delta}_{cor} \quad (14)$$

The area-based COI-referred rotor angle as given in (14) can be used as a transient stability index (TSI) whose behavior is illustrated by plotting it against time. From the plot, it can be observed that, if the COI-referred rotor angle of any area (δ_j^{COI}) goes out of step after a fault is cleared (exceeds $\pm 180^\circ$), then the area is considered to be unstable. In contrast, if it remains in equilibrium (within $\pm 180^\circ$) then the area is considered to be stable [15-16]. It is important to mention that the formulation of the area-based COI-referred rotor angle index is simple and not complex, and thus suitable for applications in large-scale power systems. Moreover, the particular index abolishes the need to assess all generator rotor angles during severe disturbances, and, thus, fast stability assessments of the entire system can be achieved. Crucially, this paper utilizes the concept of area-based COI-referred rotor angle index to answer the question of when to island. It is not far from reality to assume that the moment where the COI-referred rotor angle of any area goes out of step after a fault is cleared (when it goes unstable), is also the most suitable moment where the unstable power system should be split into islands.

D. Proposed Unified Methodology for When to Island

Fig. 2 illustrates the general concept of the proposed unified methodology for triggering the ICI. A severe disturbance on a

healthy power system (at $t=t_{dist}$) can cause the slow degradation of the grid [19]. Although Remedial Actions (RAs) may be applied to avoid this degradation, they may fail, either because they are not sufficient or they may not be implemented on time by operators. This typically leads to fast speed cascading outages, causing the uncontrolled separation of the system and resulting in blackouts.

To mitigate the impact of undesirable blackouts, ICI can be used. Now, in order to trigger promptly such a scheme, the time of defining the necessity to island the system, denoted in Fig. 2 by $t_{nec,isl}$, needs to be determined. The main steps to assess this are:

Step 1: Estimate the generator rotor angles in real-time after the occurrence of a fault (for a $t < t_{dist} + 3s$) using synchronized system measurements of all generators in the system (i.e., generator speed, output power, voltage and current), provided by PMUs, and by extracting time domain solutions of the swing equation (execution of Step A of the methodology presented in Section II (Fig. 1)).

Step 2: Determine both the suitable number of coherent generator groups (k) and the coherent groups exactly at $t=t_{dist} + 1s$, denoted by t_{coh} , by calculating and examining the similarity coefficients between each pair of swing curves through an intraclass correlation analysis and a graph minimization algorithm (execution of Step B of the methodology presented in Section II (Fig. 1)).

Step 3: Use the estimated rotor angles data collected for $t < t_{coh} + 2s$ to calculate and plot the area-based COI-referred rotor angle index of each coherent group (with a time step $\Delta t = 0.02s$). If the index of any coherent group exceeds $\pm 150^\circ$, send a warning signal for a possible islanding. If the index of any coherent group exceeds $\pm 180^\circ$, set this moment as the time of defining the necessity to island. If not, no islanding is needed.

The ICI algorithm can then be used to find the optimal points for islanding. Note that during the islanding blocking to prevent false trips is necessary to ensure the success of the controlled islanding scheme. However, this problem is out of the scope of this paper. Moreover, additional corrective measures (e.g., fast valving and load shedding) may be needed to ensure that each island will retain its security margins during the post-islanding stage [2-5] and thus to obtain a stable islanded operation.

III. SIMULATION EXAMPLES

The proposed unified methodology for when to island is tested in this section using both a small-scale and a large-scale power system (the IEEE 39- and 118-bus test systems). The dynamic data of the generators and the details of the controllers (i.e., exciter and governors) can be found in [20].

A. IEEE 39-bus Test System

The single-line diagram of the IEEE 39-bus test system is presented in Fig. 3. This system has 10 synchronous generators, 34 transmission lines, 12 transformers and 19 constant power loads.

1) Case Study 1

At time $t=1s$, a three-phase to ground fault occurs at bus 2 and is cleared at 1.25 s after local relays open both ends of

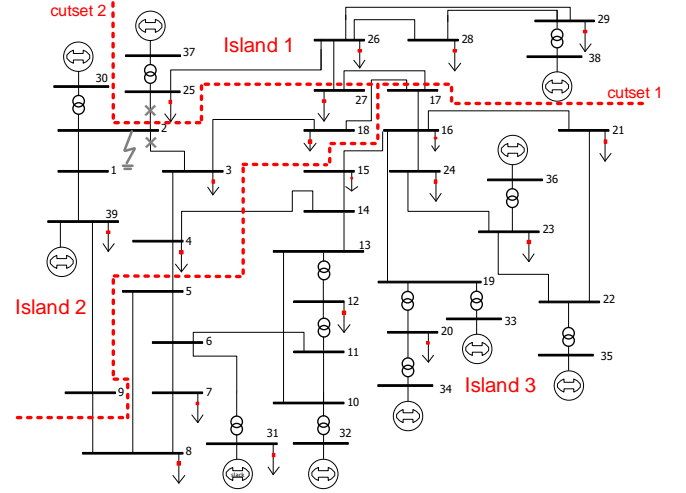


Fig. 3. Case Study 1: IEEE 39-bus test system with optimal islanding solution

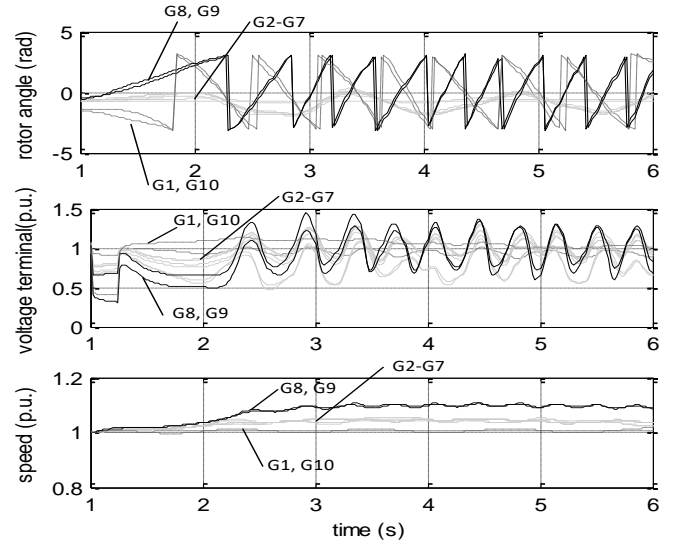


Fig. 4. Case Study 1: IEEE 39-bus test system: Behavior without islanding

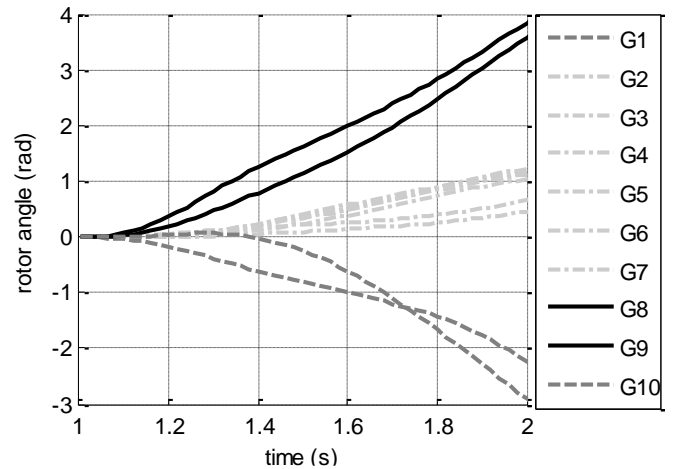


Fig. 5. Case Study 1: Estimated generator swing curves of the IEEE 39-bus test system (for a 1 s time interval after the occurrence of the fault)

transmission lines 2-3 and 2-25. Fig. 4 highlights that this disturbance results to a blackout quickly after the fault I cleared. The generator rotor angles estimated (as described in Section II-A) 1 s after the occurrence of the fault are shown in Fig. 5 (assuming that 50 synchronized measurements of output

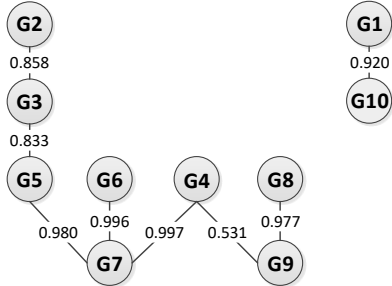


Fig. 6. Case Study 1: Pairwise generator ICCs at each subgraph (default case $k = 2$)

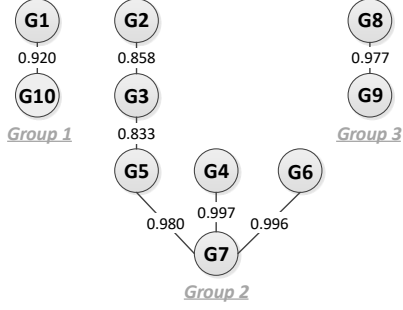


Fig. 7. Case Study 1: Coherent generators of the IEEE 39-bus test system at $t=t_{coh}$

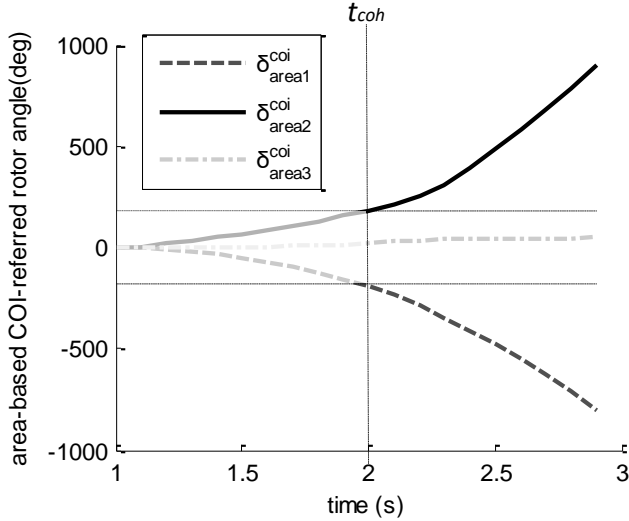


Fig. 8. Case Study 1: Area-based COI-referred rotor angle indices (the calculation of the indices starts at $t=t_{coh}$ where the coherent generator groups are known)

power and generator speed per second are provided by a PMU installed at each generator terminal). As mentioned in Section II-D, exactly at this time ($t=t_{coh}$), both the suitable number of coherent generator groups (k) and the generators within each coherent group are determined based on the automatic generator grouping analysis of Section II-B.

Starting from the default case ($k=2$), and examining the estimated rotor angle samples from 1 s to 2 s: i) the positive and negative swings are directly separated to two subgraphs; ii) the pairwise ICCs are calculated at each subgraph (Fig. 6); iii) the suitable number of coherent generators is determined. It is noted that, after performing a sensitivity analysis, a value of 20% for parameter a was found suitable for this network. For this case study, the suitable number of coherent generator

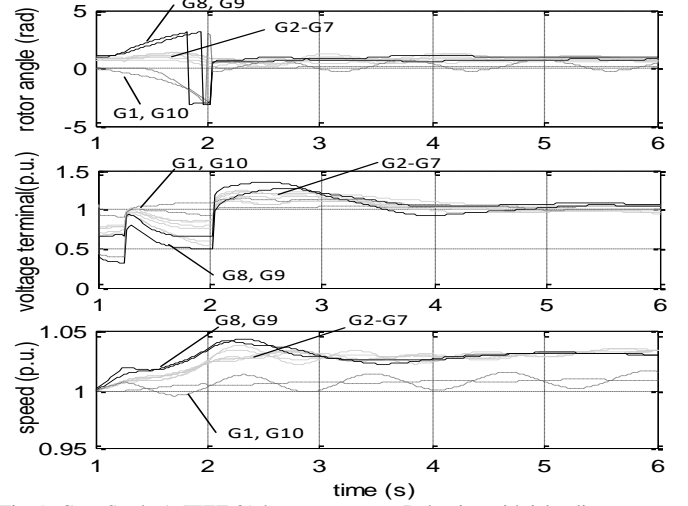


Fig. 9. Case Study 1: IEEE 39-bus test system: Behavior with islanding

groups is found to be 3 and the coherent groups determined are $\{G1, G10\}$, $\{G8, G9\}$ and $\{G2, G3, G4, G5, G6, G7\}$ (Fig.7). Area 1 consists of coherent generators $\{G1, G10\}$, Area 2 consists of generators $\{G8, G9\}$, while $\{G2, G3, G4, G5, G6, G7\}$ are the coherent generators belonging to Area 3. It is noted that the estimation procedure of the rotor angles continues for $t=t_{coh}+2$ s. (utilizing 150 measurements in total for each generator). Thus, it is believed that communication delays in the wide area measurement system will not have a significant effect on the estimation procedure.

Having the knowledge of the generator coherency and using the estimated rotor angles data collected for $t < t_{coh}+2$ s, the area based COI-referred rotor angle index of each coherent group is then calculated (with a time step $\Delta t=0.02$ s). As mentioned in Section II-C, the area-based COI-referred rotor angle indices are plotted to illustrate the severity of the disturbance (to recognize if the disturbance will evolve into a blackout or not). From Fig. 8, it can be noticed that the Area 1 COI-referred rotor angle firstly intercepts the 180° line at $t=2.0$ s. This means that it is the weakest area in the system (first area to go out of step), and therefore, this is the most suitable time according to the proposed methodology where the unstable system should be split into islands. Note that, since the suitable time for islanding is exactly at $t=t_{coh}=2.0$ s where the coherent generator groups have just been determined, the necessity to island the system is immediate; hence, a warning signal for a possible islanding was not sent.

To actually split the system, the ICI scheme proposed in [21] is adapted to determine an islanding solution that creates islands with minimum power imbalance, while ensuring that each island contains only coherent generators. The proposed ICI scheme enables the exclusion of critical branches (e.g., transformers) and explores the vast combinatorial space to find the optimal solution. Thus, considering the power flow and actual topology of the system at $t=2.0$ s, the execution of the ICC algorithm determines two cutsets and creates three islands. The two cutsets produced (Cutset 1 and Cutset 2), separate Area 3 from Area 1 and 2, and then separate Area 1 from Area 2, respectively. The combination of these two cutsets forms the final islanding solution marked in Fig. 3 (red dashed lines). This solution was found in approximately 0.024

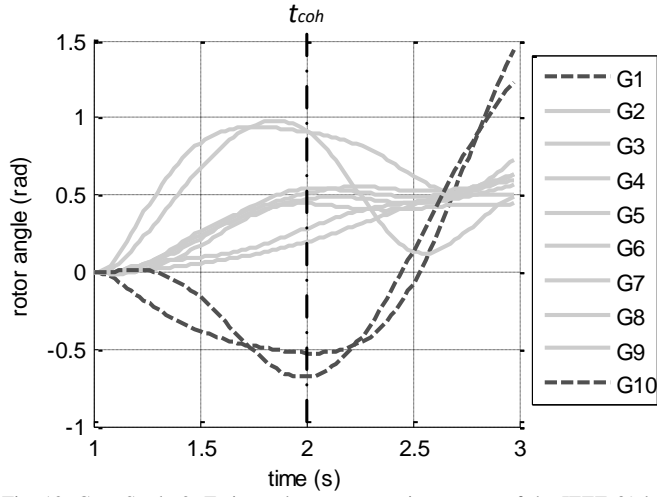


Fig. 10. Case Study 2: Estimated generator swing curves of the IEEE 39-bus test system (for a 2 s time interval after the occurrence of the fault)

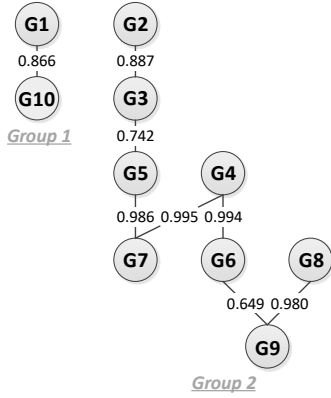


Fig. 11. Case Study 2: Coherent generators of the IEEE 39-bus test system at $t=t_{coh}$

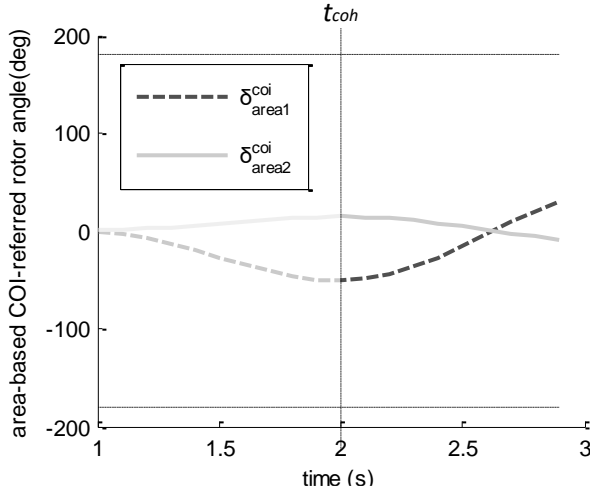


Fig. 12. Case Study 2: Area-based COI-referred rotor angle indices (the calculation of the indices starts at $t=t_{coh}$ where the coherent groups are known)

s. Hence, islanding was actually undertaken at 2.024 s. Fig. 9 shows the dynamic trajectories after implementing the optimal solution. Three stable groups are created. Moreover, the frequencies of Island 1, Island 2 and Island 3 are 1.01 p.u., 1.03 p.u. and 1.03 p.u. respectively. Voltages also reach values close to nominal values. Since the splitting strategy successfully retains the frequency of the islands within acceptable limits and the corresponding voltages within the

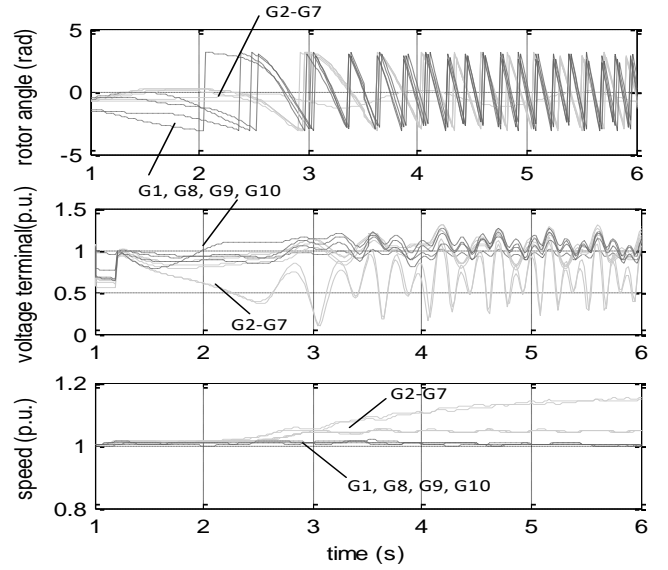


Fig. 13. Case Study 3: IEEE 39-bus test system: Electrical behavior without islanding

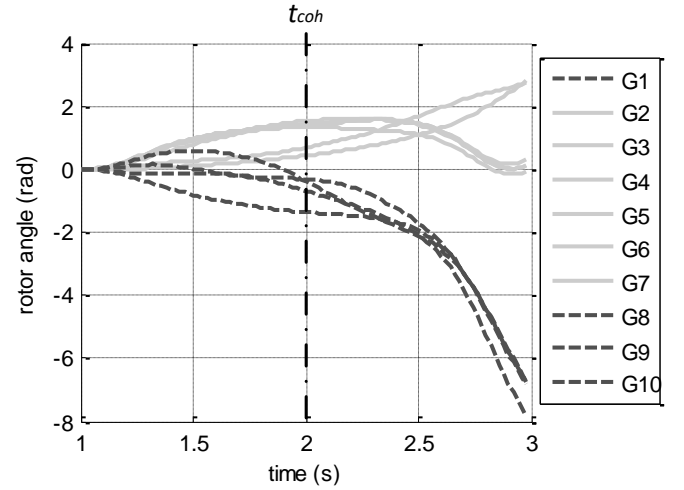


Fig. 14. Case Study 3: Estimated generator swing curves of the IEEE 39-bus test system (for a 2 s time interval after the occurrence of the fault)

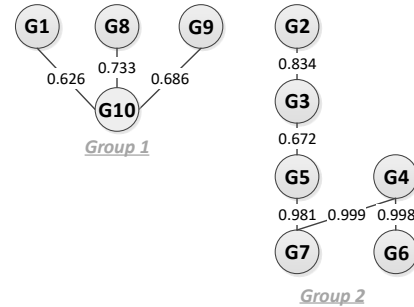


Fig. 15. Case Study 3: Coherent generators of the IEEE 39-bus test system at $t=t_{coh}$

thresholds, it can be concluded that the proposed unified methodology successfully defines the moment of when to island the system.

2) Case Study 2

The same event as case study 1 is also examined here. However, in this case study the fault is cleared by the local relays much earlier, 0.10 s after the fault occurs and not after

0.25 s. Fig. 10 shows the estimated generator rotor angles 2 s after the occurrence of the fault. Using the rotor angle data collected until $t=t_{coh}$, both the suitable number of coherent generator groups (k) and the actual groups are determined. For this case study, the suitable number of coherent generator groups is found to be 2 and the coherent groups determined are {G1, G10} (Area 1) and {G2, G3, G4, G5, G6, G7, G8, G9} (Area 2) (Fig. 11). Then, the area-based COI-referred rotor angle indices of these particular areas are calculated and plotted to assess the severity of the disturbance. From Fig. 12, it can be observed that no area-based COI-referred rotor angle violates the stability limit of the grid. Hence, the generators are considered to remain synchronized to the system after the clearance of the fault, and therefore no controlled system separation is needed.

3) Case Study 3

At time $t=1$ s, a three-phase to ground fault occurs at bus 17 and is cleared after local relays open both ends of transmission lines 16-17, 17-18, and 17-27 at 1.20 s (0.20 s after the fault occurred). Fig. 13 highlights the behavior of the system after the clearance of the fault. It is clear that the generators' speed increases and the terminal voltages become significantly lower. Thus, it can be concluded that the system needs to be split, if the blackout is to be avoided.

Using the estimated rotor angle data collected until $t=t_{coh}$ (as described in Section II-A) (Fig. 14), the suitable number of coherent generator groups (k) is found to be 2 (based on the automatic generator grouping analysis of Section II-B). The coherent groups determined are {G1, G8, G9, G10} (Area 1) and {G2, G3, G4, G5, G6, G7} (Area 2) (Fig. 15).

Using this information about the coherent groups along with the estimated rotor angles data collected for $t < t_{coh} + 2$ s, the area-based COI-referred rotor angle indices are calculated and plotted to recognize if the disturbance will evolve into a blackout or not (Section II-C). From Fig. 16, it can be seen that the Area 1 COI-referred rotor angle is the first to intercept the 180° line at $t=2.76$ s. Therefore, this is the critical time for islanding the system. It is noted that at $t=2.65$ s, a warning signal for a possible islanding is sent (as described in Section II-D).

Considering the power flow and actual topology of the system at $t=2.76$ s, the implementation of the ICI algorithm identifies the optimal solution (for minimum imbalance) across the lines 5-6, 6-7, 4-14, 17-18 and 17-27 (red dashed line in Fig. 17). This solution was found in approximately 0.017 s; islanding was undertaken at 2.777 s. The post-islanding behavior of the islands is shown in Fig. 18. From the generator rotor angles, it can be obtained that two stable groups are created. Fig. 18 further shows that the generator speeds (0.981 p.u. and 1.107 p.u. respectively) are close to their nominal values, while the generator terminal voltages are successfully kept within the desirable limits (which are defined as $\pm 10\%$ deviation from the nominal value). Thus, it can be concluded that the decision when to island the system successfully prevents the total system blackout.

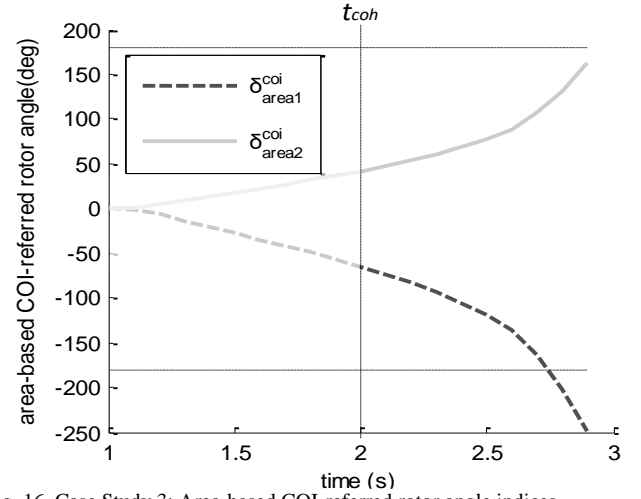


Fig. 16. Case Study 3: Area-based COI-referred rotor angle indices

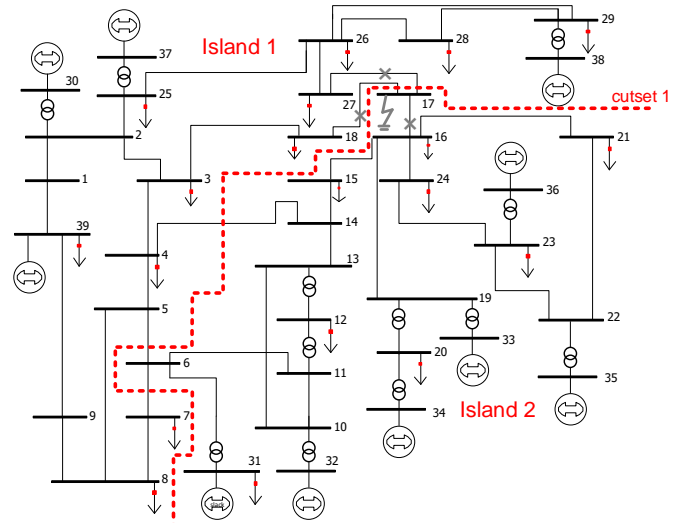


Fig. 17. Case Study 3: IEEE 39-bus test system with optimal islanding solution

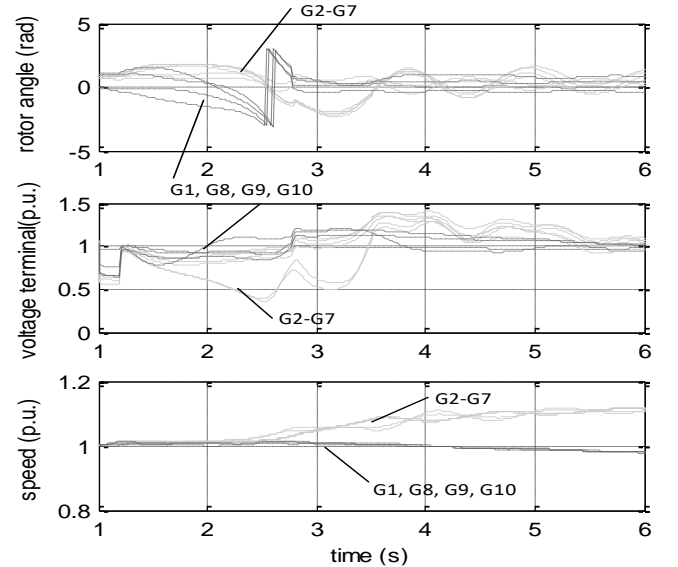


Fig. 18. Case Study 3: IEEE 39-bus test system: Electrical behavior with islanding

B. IEEE 118-bus Test System

The second test system used to demonstrate the efficiency of the proposed unified methodology for when to island is the IEEE 118-bus test system. The topology of the system is shown in Fig. 19. This test system contains 19 synchronous generators, 177 transmission lines, 9 transformers and 91 constant power loads.

The simulation scenario is defined as two consecutive three-phase faults. At time $t=0.01$ s, a three phase to ground fault occurs at bus 33 and is cleared by tripping the transmission line 15-33 at $t=0.36$ s. The second three phase fault occurs at bus 23 at $t=0.1$ and is cleared by tripping the line 23-25 at $t=0.62$ s. Using the estimated rotor angle data collected for 1 s after the occurrence of the first fault (i.e., until $t=t_{coh}=1.01$ s for this case study) (Section II-A), the suitable number of coherent generator groups (k) is found to be 2 and the coherent groups determined are $\{G10, G12, G25, G26, G31\}$ (Area 1) and $\{G46, G49, G54, G59, G61, G65, G66, G69, G80, G87, G89, G100\}$ (Area 2) (Section II-B). The area-based COI-referred rotor angle indices are shown in Fig. 20 (calculated using the estimated rotor angles data collected for $t < t_{coh} + 2s$ and plotted to illustrate the severity of the disturbance) (Section II-C). As it can be noticed from Fig. 20, the Area 1 COI-referred rotor angle is the first to intercept the 180° line at $t=1.602$ s. This means that this is the time at which Area 1 is defined to be unstable, and therefore, this is also the most suitable time according to the proposed methodology where the unstable system should be split into islands. It is noted that at $t=1.472$ s, a warning signal for a possible islanding is sent (as described in Section II-D).

The validity of the results obtained in this work for the IEEE 118-bus test system is verified by comparing them with the results obtained from an existing methodology in the literature for when to island [10]. More specifically, for the same simulation scenario, and based on the concept of *feasible islanding time interval* (FITI) as a time interval, the authors in [10] have found that the most suitable time for islanding the system is at $t=1.59$ s (Table II). The FITIs were determined using a Controlling Unstable Equilibrium Point (UEP) based method that evaluates the synchronism of the island to be created. Consequently, from Table II, it can be seen that the critical time for islanding the system identified by both methodologies is almost the same.

IV. DISCUSSION

The simulation results presented in this work highlight the effectiveness of the proposed unified methodology in triggering promptly the ICI scheme in real-time. For the IEEE 39-bus test system, the validity of the results was verified by examining the post-islanding electrical behavior of the formed islands. More specifically, as mentioned in Section III-A, since the splitting strategy successfully retained the frequency of the islands within acceptable limits and the corresponding voltages within the thresholds, it can be concluded that the proposed unified methodology successfully defines the moment of when to island the system.

On the other hand, the validity of the results obtained for the IEEE 118-bus test system was verified by comparing them

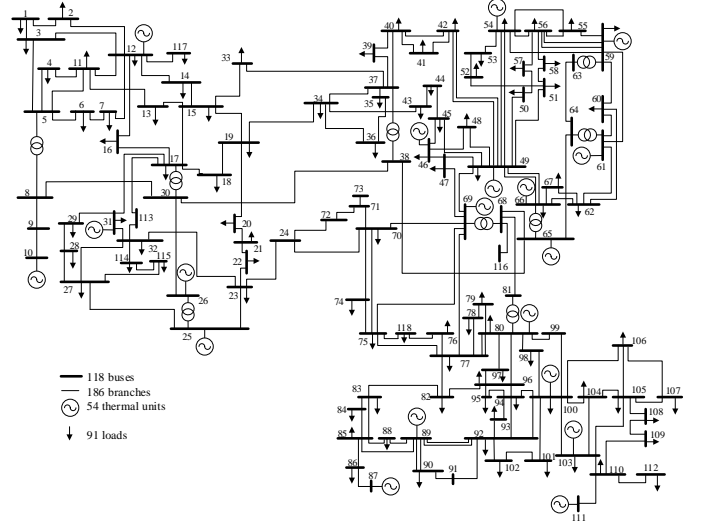


Fig. 19. IEEE 118-bus test system: Single-line diagram

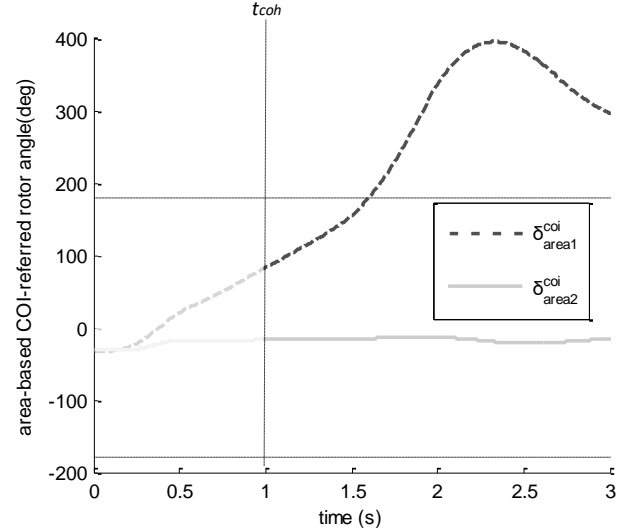


Fig. 20. IEEE 118-bus test system: Area-based COI-referred rotor angle indices (the calculation of the indices starts at $t=t_{coh}$ where the coherent groups are known)

TABLE II RESULTS COMPARISON ON IEEE 118-BUS TEST SYSTEM	
	Critical Time for Islanding (s)
Proposed Methodology	1.602
Methodology from [10]	1.59

with the results obtained from an existing methodology in the literature for when to island [10]. The comparison shown that both methodologies identify almost the same critical time for islanding the system. However, the method proposed in [10] can't be performed in real-time since it requires both the offline identification of the coherent generator groups and a pre-defined islanding solution (cutset). In addition, as shown in [21], an improper offline identification of the coherent groups might lead to false alarm or false dismissal for triggering the ICI scheme. At this point, it is important to mention that such issues are avoided by the ability of the proposed unified methodology to identify the coherent generators in real-time (through the real-time estimation of the rotor angles).

To determine the actual time for islanding, this work adopted the concept of area-based Center of Inertia (COI)-referred rotor angle index (widely used in transient stability analysis for tracking the stability of interconnected areas) and combined it along with synchrophasor measurements. The reason is that the calculation of the area-based COI-referred rotor angle index requires only the generator rotor angles data in real-time. Since an estimation of the generator rotor angles is already performed in this paper (Section II-A) for the identification of the coherent groups, the estimated rotor angles data can also be used for detecting the angle instability of the system. Consequently, all the steps of the proposed methodology are executed sequentially without delays, and thus the determination of the most suitable moment for islanding is feasible. Nevertheless, other stability indices, such as the security and voltage stability indices defined in [22-23] can be considered in future works.

V. CONCLUSION

Controlled islanding offers a real prospect to decrease the possibility of occurrence of large scale blackouts as a measure of last resort. In this paper, the critical question of when to island, which has not been fully explored in the literature, is investigated. The proposed methodology utilizes the concept of the area-based COI-referred rotor angle index to illustrate the severity of the disturbance in order to recognize if a disturbance will evolve into a blackout or not. It is not far from reality to assume that the moment at which a particular area is said to be unstable, is also the moment where the ICI scheme should be triggered to split the unstable system into islands. The calculation of the area-based COI-referred rotor angle index requires the knowledge of the generator coherency and the rotor angles. Hence, the proposed methodology identifies also both the suitable number of coherent generator groups and the actual coherent groups based on an online estimation of the rotor angles. Different case studies are examined for illustrating and testing the unified methodology using both a small-scale and a large-scale power system (the IEEE 39- and 118-bus test systems). The simulation results demonstrate its adaptability and effectiveness in triggering promptly the ICI scheme in real-time and thus in minimizing the impact and cost of large-area blackouts under varying system conditions.

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