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A Hybrid Synchrophasor and GOOSE-Based Power System Synchronization Scheme

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ABSTRACT The design and real-time hardware-in-the-loop implementation of a hybrid synchrophasors and GOOSE-based automatic synchronization algorithm are presented in this paper. Automatic synchronization is performed by utilizing the synchrophasor measurements from two commercial phasor measurement units (PMUs), while the coordinated control commands to automatic voltage regulator and/or turbine governor control and trip command to the circuit breaker are issued using IEC 61850-8-1 GOOSE messages. The algorithm is deployed inside the PMU using the protection logic equations, and direct communication between the PMUs is established to minimize the communication latencies. In addition, the algorithm is tested using a standard protection relay test-set, and automatic test sequences are executed to validate its performance. It is concluded that the hybrid synchrophasor and GOOSE-based automatic synchronization scheme ensures minimum communication latencies, reduces equipment cost, facilitates interoperability, and performs automatic reconnection adequately.

INDEX TERMS Phasor measurement unit (PMU), power system protection, protective relays, real-time control, reconnection, smart grid, synchronization, synchrophasors.

I. INTRODUCTION

A part of a power system might become isolated from the rest of the network either because of a protection relay operation or due to maintenance purposes. Once the fault is removed or the maintenance procedure has been carried out, it is desirable to reconnect the isolated network with the overall grid. The two networks need to be in synchronism in order to be connected together. If the synchronizing process is not carried out adequately, the system will experience transients in the form of large active or reactive power flows through the interconnected tie resulting in inrush currents, overvoltage and system oscillations. This may lead to equipment damage in the generator, prime mover and/or step-up transformer windings because of mechanical stresses and high currents following the poor synchronism of the two asynchronous networks.

Synchronism check ensures that out-of-step sources are not paralleled accidently [1]. Synchronization is assisted by deploying synchronism check protection relays (ANSI 25) that permits tie-line circuit breaker closure only if the voltages at both ends of the circuit breaker are within a specified magnitude, phase and frequency difference limits [2]. These three quantities are also called synchronizing quantities.

To facilitate automatic breaker closure, auto synchronizers (ANSI 25A) are deployed [3]. Auto synchronizers monitor and compare synchronizing quantities between buses. Based on this comparison, the auto synchronizer sends a control signal to an AVR to adjust generator's voltage and to the turbine governor to control the speed of the generator in order to synchronize the two buses. Once the synchronizing quantities are within the allowable limit, the auto synchronizer sends a closing command to the tie-line breaker.

A. PAPER MOTIVATION

Synchronization either manually, or based on synchronism check relays exclusively, is slow and require skilled operators at the controls to adjust voltage and frequency of the generator which needs to be synchronized. Even though auto-synchronizers facilitate automatic synchronization, their major drawback is that they require physical connections to the generator control circuitry or use a propriety communication protocol, and are not equipped with any (graphical) user interface to supervise equipment performance and system state. This makes difficult the integration of these devices in a power system and makes the synchronization solution vendor-and-generator control equipment dependent. These are major drawbacks for inter-operability and standardization of different power system components.

This emphasizes the need for an automatic synchronization process that is interoperable, vendor independent, communicates using standard protocols, minimizes communication latencies, provides holistic view of synchronization process through a GUI and minimizes equipment cost (i.e. does not require any additional controller to perform automatic synchronization).

B. LITERATURE REVIEW

A review of current practices in power system synchronization is presented in [4]. In [5], an automatic reconnection scheme from intentional islanding utilizing remote voltage and frequency signals is proposed. The proposed scheme does not specify the underlying sensing devices, communication method and their associated latencies. In addition, the proposed approach only considers a live-line live-bus (LLLB) scheme and does not optimize the synchronization process if either the line or the bus is dead.

In [6], a tuned controller of variable reactors is developed to realize microgrid tie-line reconnection. This method proposes a deployment of new controller (additional cost) and requires frequent tuning of its thresholds based on transient stability margins in the case of change in system topology. In [7], synchrophasors from PMUs are monitored during the islanding maneuver of an active distribution network. Though the PMUs provided useful information, the reconnection was carried out using a synchro-check relay and the deployed Power Management System (PMS).

A DG synchronization method using PMU measurements at a reporting rate of 10 Hz is reported in [8], where a diesel generator is operated in synchronism with a remote reference signal from a PMU. In this study, the governor and phase-control algorithms are deployed on a PC that communicates with the diesel generator's engine control module (ECM) over a controller-area network (CAN) interface. Only the phase angle and frequency of the diesel generator were controlled and the third synchronizing quantity (i.e. voltage magnitude) was not considered.

A synchronization control strategy for microgird reconnection using synchrophasor measurements is reported in [9]. However, the controller is deployed on a non-real-time operating system (RTOS), which introduces a non-deterministic delay in the synchronization loop. The different communication latencies associated with this algorithm were not taken into account.

C. PAPER CONTRIBUTIONS

The contributions of the paper are the following:

- Utilizing synchrophasors [10], relay-to-relay communication and IEC 61850-8-1 GOOSE messages [11] for synchronization applications. The automatic synchronization algorithm is deployed within a PMU using protection logic equations [12].
- Two synchronization algorithms exploiting synchrophasors are proposed. The first follows traditional sequential checks/actions for synchronization, whereas the second algorithm parallelizes the typical computations and their respective corrective actions to minimize the synchronization time.
- Real-Time Hardware-in-the-Loop (RT-HIL) simulation is performed for analyzing the performance of synchrophasor-based automatic synchronization schemes.
- Finally, the paper demonstrates how the proposed algorithm can be tested using standard substation practices and standard protection relay-testing equipment to facilitate its use by protection engineers.

The proposed algorithm enhances the synchronization process in case of dead-bus conditions through synchrophasor voltage-check functions. This feature is useful for emergency standby systems that require the first generator to close onto the de-energized bus prior to synchronizing additional generators.

The proposed hybrid scheme ensures minimum communication delays. This is due to the use of synchrophasor measurements internally in a PMU to perform automatic synchronization using logic equations to avoid the delays incurred due to the intermediate Phasor Data Concentrator (PDC) or the IEEE C37.118.2 protocol parser [13]. The proposed scheme uses standard communication protocols for measurements and control actions and therefore ensures interoperability and vendor independence.

D. PAPER ORGANIZATION

The remainder of this paper is organized as follows: Section II presents synchrophasor-based approach optimized for minimum communication latency and the automatic synchronization algorithm. The Real-Time Hardware-in-the-Loop (RT-HIL) experimental setup and deployment of algorithm in the PMU is discussed in Section III. The developed algorithm is evaluated using RT-HIL simulation for a modified IEEE 3-machine 9-bus system [14] in Section IV. Performance assessment using a relay test-set is presented in Section-V. Section VI summarizes the study and suggests roadmap for extending proposed method. Conclusions are drawn in Section VII.

II. SYNCHROPHASOR-BASED AUTOMATIC SYNCHRONIZATION

A. LATENCIES IN SYNCHROPHASOR-BASED APPLICATIONS

Synchrophasor-based applications experience latencies due to synchrophasor computations, communication channels, Phasor Data Concentrators (PDCs) and protocol parsing as shown in Fig. 1. PMU processing delays are fixed and are dependent on the type of transducers, window size of the synchrophasor computing algorithm and the data size which

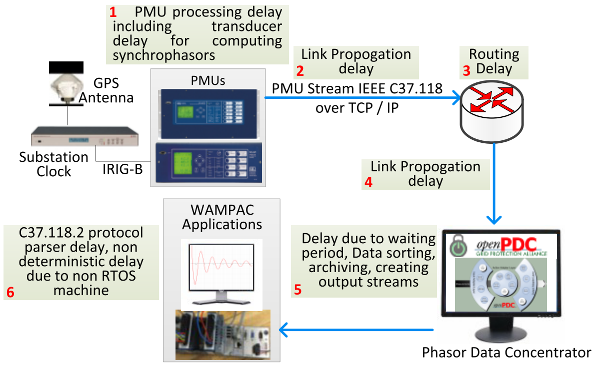

FIGURE 1. Latencies associated with typical synchrophasor-based applications.

needs to be packaged into C37.118.2 frame [13]. These delays are estimated to be around 100 ms and are independent of the communication medium [15]. Using fiber optics as communication medium, the link propagation delay is around 20 ms for a 100 km fiber optic link. For a particular source destination pair and assuming that all the intermediate hops are operational, the router delay is in the order of few milliseconds [16].

PDCs introduce a major delay as it sorts all the incoming synchrophasors using their time tags, optionally alter the frame rate (down sampling), concentrate the incoming streams and provide output streams. Additionally PDC provide archiving functionality.

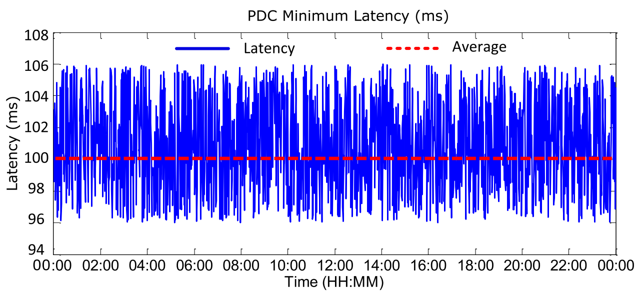

FIGURE 2. PDC latency over a period of 24 hours.

In order to analyze the PDC latency, two PMUs were connected to a PDC through an Ethernet Switch and the PDC was configured to create a concentrated output stream that was received at the workstation in the same subnet. The PDC latencies associated with this stream are shown in Fig. 2 and account to an average delay of 100 ms in total. For monitoring applications, this delay is acceptable; however, for protection and control applications, and in the case of automatic synchronization, this delay can lead to an out of phase reconnection.

B. DIRECT COMMUNICATION BETWEEN PMUs

Most PMUs operate in a server mode, i.e., PMUs send the synchrophasor data to either a PDC or to a workstation in a monitoring and control center. PMUs can also operate in a client mode where, the PMU accepts the synchrophasors from a remote synchrophasor source. This is termed as direct relay-to-relay communication and allows the two PMUs to exchange synchrophasors directly, without the requirement ofan intermediate PDC [15]. Certain PMUs allow engineers to configure custom algorithms for power system monitoring, protection and control using relay logic equations [12] and can be programmed to provide protection and control functions. When operating in client mode, the PMU can execute an algorithm internally, which utilizes both local and remote synchrophasors.

For automatic synchronization, direct communication between PMUs at either side of the tie-line circuit breaker can be established and an automatic synchronization algorithm can be deployed within the PMU, thereby reducing the overall communication latencies and equipment cost.

C. SYNCHROPHASOR-BASED SYNCHRONIZATION SCHEME

A graphical description of synchrophasor-based automatic synchronization scheme proposed in this paper is shown in Fig. 3. Two PMUs are fed with three phase voltages at either end of the tie-line circuit breaker. PMU-A (Server) computes synchrophasors and transmits them in IEEE C37.118.2 [13] to PMU-B (Client). PMU-B compares the remote synchrophasors received from PMU-A with its local synchrophasors and computes synchronizing quantities at both ends of the circuit breaker. If these synchronizing quantities are within allowable limits, PMU-B issues a closing command to the tie-line circuit breaker. This closing command of a circuit breaker is issued through IEC 61850-8-1 GOOSE messages [11]. If the synchronization condition is not met, PMU-B sends a control signals to both AVR and turbine governor control using IEC 61850-8-1 GOOSE messages to bring the synchronizing quantities within the specified limits.

An associated monitoring application to visualize the performance of automatic synchronization is also shown in phasors, analog and digitals wrapped inside the stream in the LabView environment [17]. The monitoring application uses these raw synchrophasors to show plots of voltages, frequency (at either end of the circuit breaker), slip frequency, phase angle difference, status of the circuit breaker and the time at which the close command is issued by PMU-B.

D. AUTOMATIC SYNCHRONIZATION ALGORITHMS

The proposed synchrophasor-based synchronization algorithms improve traditional synchro-check protection scheme by: (a) minimizing synchronization time, (b) incorporating dead-bus / dead-line scenarios and (c) relying on standard communication protocols to ensure interoperability.

Two algorithms are presented: (a) sequential, and (b) parallelized. The sequential algorithm scheme follows sequential checks and associated corrective actions [4], as shown in Fig. 4. Using local and remote synchrophasor voltages, the corrective action in the form of AVR's field voltage modulation is carried out to bring the two voltages

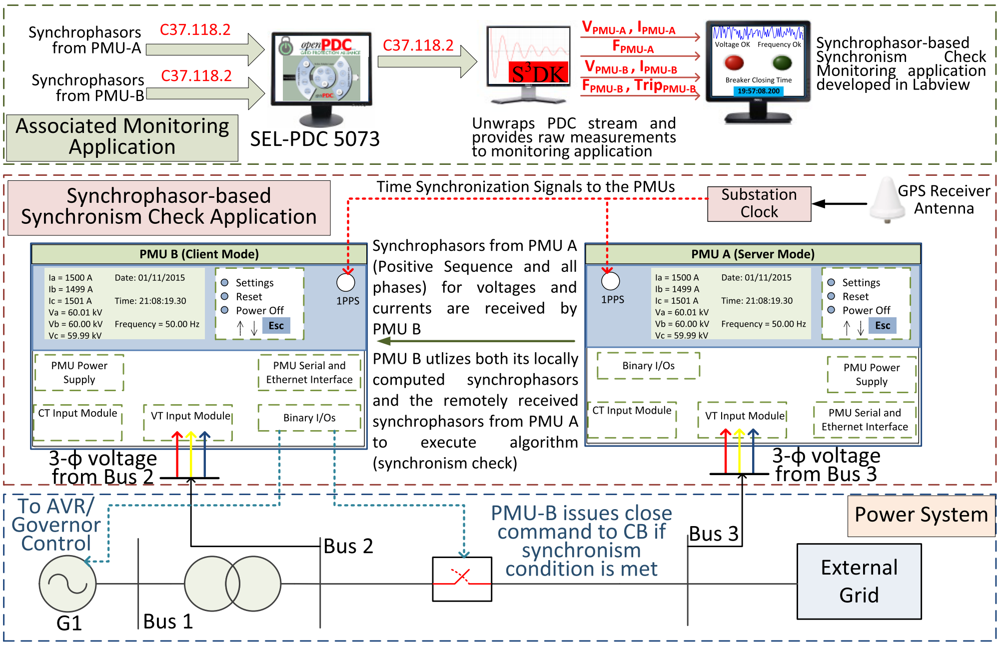

FIGURE 3. Proposed synchrophasor-based automatic synchronization scheme along with its associated monitoring application.

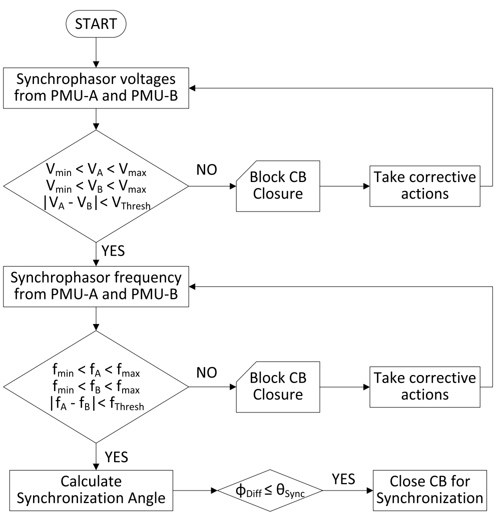

FIGURE 4. Flowchart of the synchrophasor-based sequential synchronization algorithm.

within the allowable tolerance limit V_{Thresh}. The two voltages must lie within a healthy voltage window bounded by V_{max} and V_{min} to allow voltage corrective actions. Once this condition is satisfied, the slip frequency is monitored and the governor's set-point is altered to match the two frequencies. Once the voltages and frequencies are within the allowable tolerance limit, the synchronization angle is calculated using the slip frequency to ensure breaker closing at 0° phase angle difference. Due to the sequential nature of the algorithm, the synchronization process takes longer.

In order to minimize the synchronization process time, a parallelized algorithm is proposed, as shown in Fig. 5, and incorporated within PMU-B. The algorithm simultaneously checks the synchronization quantities, by performing voltage and frequency checks and their respective corrective actions, while taking into account the dead-bus / dead-line scenarios through voltage-check functions. The minimum voltage threshold for energized bus represented by V_{Live} and maximum voltage threshold for de-energized bus represented by V_{dead}, determine whether the bus and/or line is live (energized) or dead (de-energized). Through these checks, the algorithm determines three conditions; (i) Live Line – Dead Bus (LLDB), (ii) Dead Line – Live Bus (DLLB), and (iii) Dead Line – Dead Bus (DLDB).

If both the line and the bus voltages are above V_{Live} and within a healthy voltage and frequency window bounded by $V_{max} \backslash V_{min}$ and $f_{max} \backslash f_{min}$, the algorithm executes, **in parallel**, corrective measures to bring the two voltages and frequencies within the allowable voltage and frequency tolerance limits represented by V_{Thresh} and f_{Thresh}, respectively. The algorithm ensures that there is a slight positive slip frequency between generator and the reference bus to allow the generator to pick up the load instantaneously at the moment of circuit breaker closure and avoiding a motoring condition. Similarly, the algorithm adjusts the generator's terminal voltage slightly higher than the reference bus voltage to ensure that the generator will supply reactive power to the grid thus avoiding any under-excitation (lagging power factor) operation of the generator that might result in out of synchronism condition.

When both voltages and frequencies are within synchronizing limits, the algorithm calculates the synchronizing angle (θ_{Sync}) required to compensate for the breaker closure

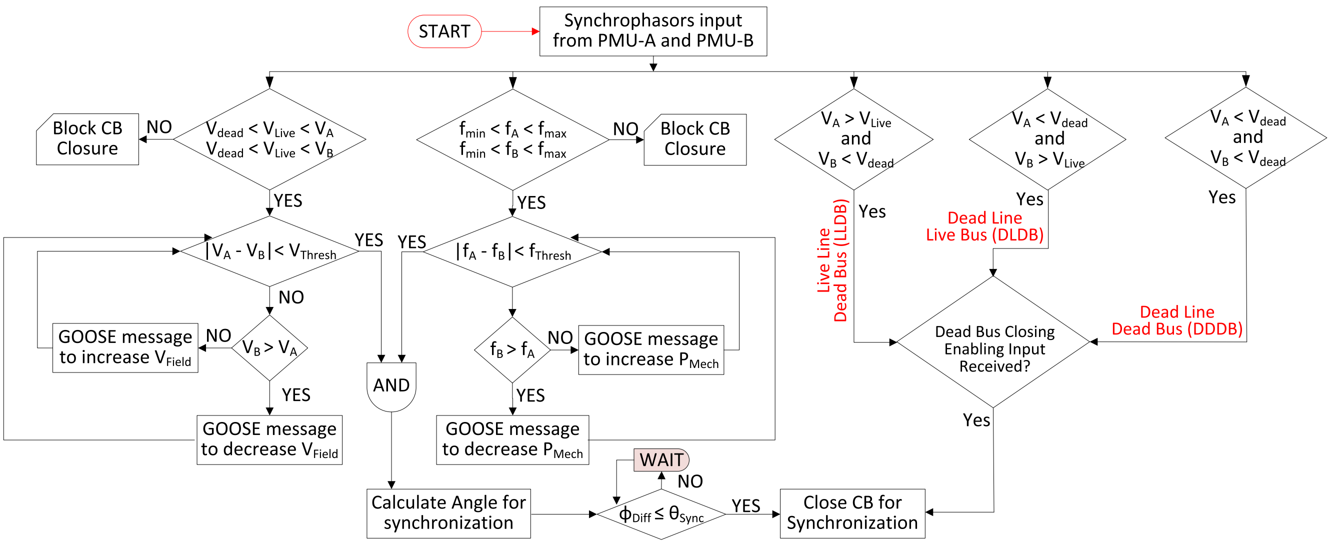

FIGURE 5. **Flowchart for the parallelized synchrophasor based synchronization algorithm.**

time [4] using the following equation.

$$\theta_{Sync} = 360(T_{CB})(F_{Slip}) \tag{1}$$

where T_{CB} is the circuit breaker closing time that is 4 cycles (80 ms) for a 230 kV circuit breaker, F_{Slip} is the slip frequency, i.e. the difference in frequencies between the generator and the reference bus. In this proposed scheme, the breaker closing command is issued through an IEC 61850-8-1 GOOSE message [11], thus eliminating the delay associated with any intermediate auxiliary relays. Once the voltage phase angle difference between the generator and the reference bus (ϕ_{Diff}) is equal or lesser than the synchronization angle (θ_{Sync}), the PMU issues a close command to the circuit breaker to synchronize the systems. The intentional positive slip frequency maintained between generator and the reference bus ensures that the voltage phase angle differences between the two buses (ϕ_{Diff}) will become equal or lesser than the synchronization angle (θ_{Sync}) at a particular point in time.

If either the bus or the line is dead and the operator's manual close is enabled, the algorithm bypasses the synchronization process and closes the tie-line circuit breaker.

III. RT-HIL SETUP & ALGORITHM DEPLOYMENT

A. RT-HIL EXPERIMENTAL SETUP

A modified IEEE 3-machine 9-bus system [14] as shown in Fig. 6 is executed in real-time using Opal-RT's eMEGAsim real-time simulator [18]. Initially, CB-1 is considered open, thus making generator G1 with its local load an isolated system. Two PMUs from Schweitzer Engineering Laboratories (SEL) [19] are fed with three phase voltages and currents from both sides of the CB-1 (Bus-4 and Bus-6).

PMU-B is configured as a client for PMU-A, which receives the synchrophasors (voltage phasors and frequency) from PMU-A (Bus-6) at a reporting rate of 50 frames per second, and computes synchronizing quantities with its local

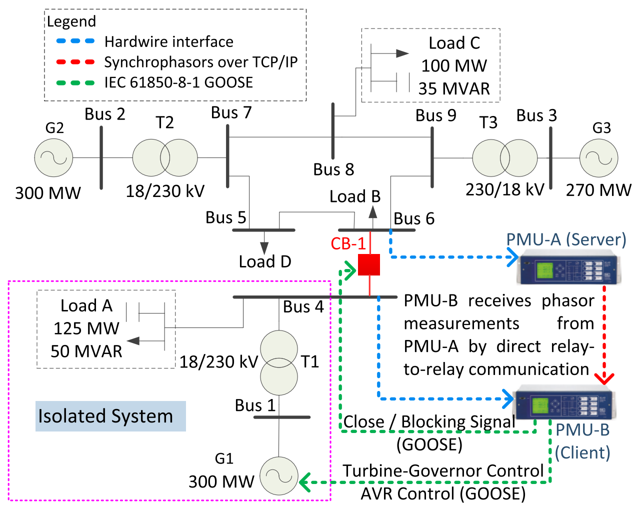

FIGURE 6. **Real-time simulation model and experiment configuration.**

synchrophasor measurements (Bus-4). If these differences are within a pre-specified limit, PMU-B issues a close command to CB-1 through an IEC 61850-8-1 GOOSE [11] message as soon as the phase angle difference between the two quantities equals the calculated synchronization angle [4], i.e. initiating synchronization. If the difference in synchronizing quantities exceeds limits, PMU-B sends GOOSE messages to the turbine governor control of generator G1 to modulate its frequency to match system frequency. Similarly, if there is a voltage magnitude difference between the generator and the grid bus, PMU-B sends GOOSE messages to the AVR of G1 to change its field voltage output to match the terminal voltage of the generator with that of the grid.

When the frequency and the voltage magnitude at either side of the circuit breaker are matched, the PMU tracks the synchrophasor voltage phase angle (Phase A) of the generator bus and compares it with the grid phase angle. A close command is issued to the breaker using a GOOSE message once the phase angle difference equals synchronization angle.

TABLE 1. Decision table.

Quantity	Settings (pu)	GOOSE message / Description	Change (pu)
Healthy Window	$V_{Live} = 0.8$, $V_{dead} = 0.2$ $V_{max} = 0.1$, $V_{min} = -0.1$ $f_{max} = 0.1$, $f_{min} = -0.1$	Threshold for identifying healthy window	Preset Values
Thresholds	$V_{Thresh} = 0.01$ pu $F_{Thresh} = 0.001$ pu	Threshold values for voltage and frequency.	Preset Values
Voltage	$V_{max} \geq \Delta V > V_{Thresh}$	Reduce AVR set point	-0.002
	$V_{min} \leq \Delta V < 0$	Increase AVR set point	+0.002
Frequency	$f_{max} \geq \Delta F > f_{Thresh}$	Reduce Gov. set point	-0.0001
	$f_{min} \leq \Delta F < 0$	Increase Gov. set point	+0.0001
Breaker Close	$\Delta V < V_{Thresh}$ $\Delta F < f_{Thresh}$ $\Delta\phi \leq \theta_{Sync}$	Issue GOOSE message to close tie-line circuit breaker	Breaker closing enable

B. ALGORITHM DEPLOYMENT

The decision table for the synchronization scheme is shown in Table-I. These thresholds are based on the IEEE Standard C50.13 that provides specifications for salient-pole synchronous generators and requirements for their synchronism with the overall system [20]. Using local and remote voltage synchrophasors, PMU-B generates different GOOSE messages corresponding to different scenarios. Each of these GOOSE messages is configured for a specific action as shown in Table I, e.g. if the frequency of the isolated system is greater than the network frequency, PMU-B will send a GOOSE message to the turbine governor control of the local generator that will reduce the reference power of the turbine, thus curtailing the mechanical power input to the generator and reducing the frequency of the isolated network.

```
PMV01 := FREQPM % Storing local synchrophasor frequency
PMV02 := RTCFA % Storing remote synchrophasor frequency
PMV03 := VAYPMM  % Storing local synchrophasor voltage magnitude
PMV04 := RTCAP01 % Storing remote synchrophasor voltage magnitude
PMV05 := VAYPMA % Storing local synchrophasor voltage phase angle
PMV06 := RTCAP02 % Storing remote synchrophasor voltage phase angle
PMV07 := 0.8 % Setting value of live-bus check threshold = 0.8 pu
PMV08 := 0.2 % Setting value of dead-bus check threshold = 0.2 pu
PMV09 := 0.1 %  Voltage magnitude difference upper bound value = 0.1 pu
PMV10 := -0.1 % Voltage magnitude difference lower bound value = -0.1 pu
PMV11 := 0.1 % Setting frequency difference upper bound value to 0.1 pu
PMV12 := -0.1 %Setting frequency difference lower bound value to 0.1 pu
PMV13 := 0.01 % Setting voltage difference threshold value to 0.01 pu
PMV14 := 0.001 %Setting frequency difference threshold value to 0.001 pu
PSV01 :=  [(PMV01 – PMV02) > PMV14] & [PMV03 > PMV07] & [PMV04 >
PMV07]   % Set PSV01 if difference between local and remote
synchrophasor frequency is greater than 0.001 pu and both the generator
and reference bus are live (energized)
PSV01 status is configured as GOOSE message
```

FIGURE 7. Logic equations used to deploy synchronism check algorithm within PMU-B. Small portion of the algorithm is shown to explain the key steps.

A portion of the algorithm deployed in PMU-B using protection logic equations is shown in Fig. 7. If the difference in local and remote synchrophasor quantities exceeds threshold limits, its associated GOOSE message changes its status. This GOOSE message is configured inside the Simulink model (Fig. 6) to change the reference values for the AVR and/or governor control of generator G1. Once all the synchronizing quantities are within limits, PMU-B calculates the synchronization angle required to compensate for the breaker's closing time to ensure that the phase angle difference (ϕ_{Diff}) across the circuit breaker is 0° at the instant of CB-1's closure. When the phase angle difference between local and remote synchrophasor voltages is equal to the computed synchronization angle (θ_{Sync}), PMU-B issues a close command to the circuit breaker through a GOOSE message.

IV. RT-HIL SIMULATION RESULTS

Performance analysis of the developed algorithm is carried out by performing the following two RT-HIL simulations.

A. SCENARIO 1: IMPRECISE SYNCHRONIZATION

In this scenario, the synchronism check algorithm is disabled and the breaker is closed to consider the worst-case operating scenario (with maximum differences between the local and remote synchrophasor quantities) to analyze the impact of imprecise synchronization on the system states. This scenario will serve to compare when the automatic synchronization algorithm is enabled. This impact is shown in Fig. 8. The plots in Fig. 8 (a-c) show that all thesynchronizing quantities at both ends of the circuit-breaker CB-1 do not match. The voltage difference is 0.06 pu (24 kV), frequency mismatch is 0.01 pu (0.5 Hz) and the generator is out-of phase, with a phase angle of 180°. As shown in Fig. 8c, the phase angles reported by PMUs are wrapped around to ±180° and keep changing if the frequency of the input signal is different from the nominal frequency. At t = 150.6 s, CB-1 is closed, resulting in transients in the form of large active and reactive power flow across the tie-line (Bus 4-Bus 6) as shown in Fig. 8d. Similarly the rotor speed (Fig. 8e) overshoots abruptly and oscillates, which can lead to equipment damage.

B. SCENARIO 2: SYNCHROPHASOR-BASED SYNCHRONIZATION

In this scenario, the automatic synchronization algorithm in PMU-B is enabled. When synchronizing quantities constraints are met, PMU-B sends a GOOSE message either to increase or decrease the reference voltage of the AVR to match the terminal voltage of G1 with the grid voltage. Simultaneously, the PMU-B sends GOOSE message to the turbine governor controller to change its reference power to vary the frequency in the isolated system. When both voltage and frequency differences are within specified constraints, PMU-B calculates synchronization angle (θ_{Sync}) using (1) and tracks the phase angle difference between the local and remote synchrophasor voltage. Once this phase angle difference equals the synchronization angle, PMU-B sends a closing command to CB-1 to synchronize the two systems.

Figure 9 (a-c) shows the voltage magnitude, frequency and phase angle differences between local and remote synchrophasors as computed by PMU-B. The phase angle difference shown in Fig. 9c is wrapped around ± 180°

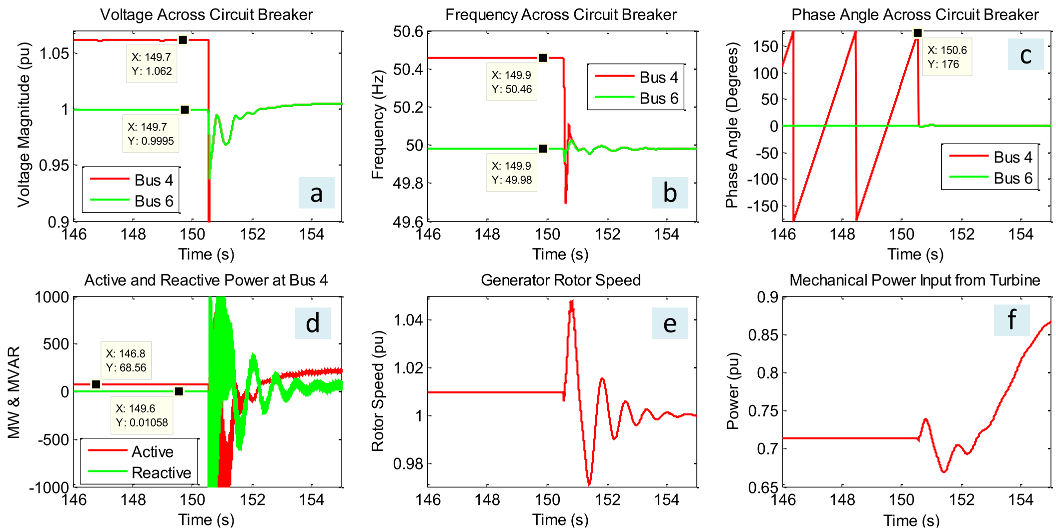

FIGURE 8. System state when subjected to imprecise synchronization.

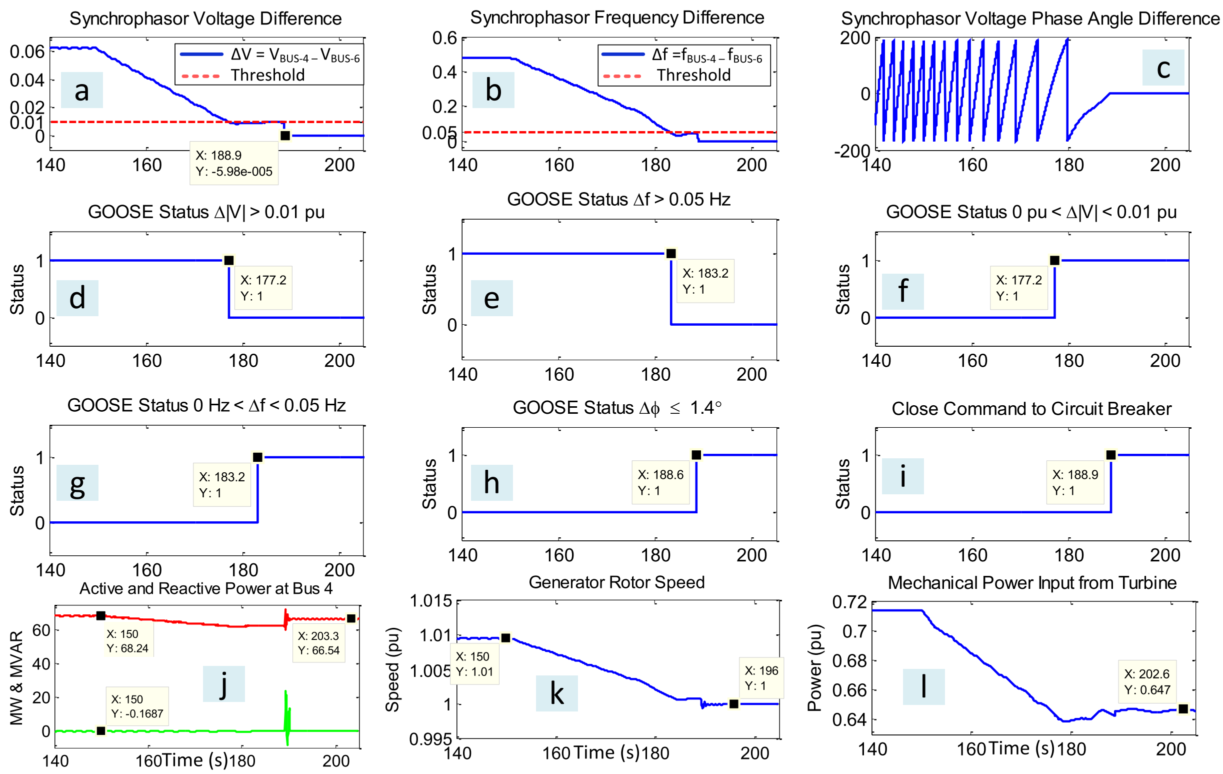

FIGURE 9. Voltage Magnitude, Frequency and Phase Angle differences as computed by PMU-B based on both local and remote synchrophasors (from PMU-A). Different digital signals configured as GOOSE messages for controlling AVR and governor of generator G1 are also shown.

(synchrophasors are commonly reported in angles $-180°$ to $+180°$ rather than 0 to 360°) [13].

At $t = 150$ s, the automatic synchronization algorithm is enabled. This results in a decrease in synchrophasor voltage and frequency differences between Bus-4 and Bus-6. Once the voltage and frequency is matched within ± 0.01 pu (V_{Thresh}) and ± 0.05 Hz (f_{Thresh}) respectively, PMU-B issues a closing command to CB-1 at $t = 188.9$ s when the phase angle difference (ϕ_{Diff}) becomes equal to the synchronization angle (θ_{Sync}) as shown in Fig. 9c. θ_{Sync} in this scenario is 1.44° and is computed by PMU-B internally using (1). This corresponds to a slip frequency of 0.05 Hz

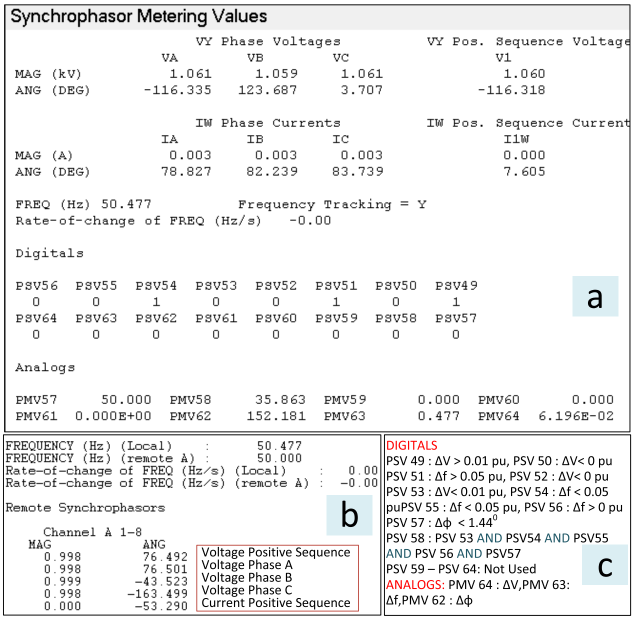

FIGURE 10. HMI of PMU-B showing local and remote synchrophasors.

and a breaker opening time (T_{CB}) of 80 ms. The breaker opening time (T_{CB}) is realized as a fixed delay of 80 ms in the simulation model.

Figure 9 (d,f) shows the different digital status configured as GOOSE messages to indicate the AVR whether the voltage difference between generator and grid is above or within the threshold limit. Similarly, Fig. 9 (e,g) shows the different digital statuses to indicate the turbine governor control whether the difference in frequencies is above or within the frequency threshold. Figure 8h shows the digital status corresponding to $\phi_{\text{Diff}} \leq \theta_{Sync}$ when both the voltage and frequency differences are within threshold limits. When all quantities are within allowable limits, PMU-B considers it as a safe condition for closing the circuit breaker CB-1 and issues a close command at t = 188.9 s using GOOSE message as shown in Fig. 9i, thus synchronizing the two systems.

The synchrophasor-based synchronization results in a smooth synchronization of the two isolated networks as shown in Fig. 9 (j-l). Comparing Fig. 9j with Fig. 8d shows that the synchronization has avoided equipment stress as well as protection operation, while minimizing the power transfer variations. Screenshot of local synchrophasors and digital status computed by PMU-B, remote synchrophasors computed by PMU-A and a description of configured digital and analog values is shown in Fig 10a, 10b and 10c respectively.

V. METHOD FOR ALGORITHM TESTING WITH STANDARD PROTECTION RELAY TEST-SET

The main objectives of this method are the following:

- Testing synchrophasor-based synchronization algorithms using standard protection relay-testing equipment.
- Better understanding and adaption of proposed algorithms by field engineers

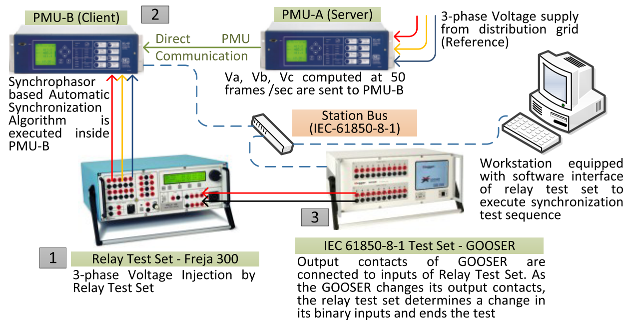

FIGURE 11. Algorithm testing through standalone protection relay test-set and IEC 61850-8-1 GOOSER.

- Showing practical applicability of the proposed algorithms.

This method is demonstrated using a stand-alone protection relay test-set Freja-300 [21]. The secondary injections are provided to PMU-B through Freja-300 as shown in Fig. 11. PMU-A receives a 3-phase voltage input through a distribution grid socket and therefore acts as reference voltage source. As explained in Section-III, PMU-B receives the remote synchrophasors from PMU-A and executes automatic synchronization algorithm. PMU-B publishes IEC 61850-8-1 GOOSE messages that are captured from the network by IEC 61850-8-1 test-set GOOSER [22], which translates GOOSE message to its binary outputs. One of the binary outputs of the GOOSER is connected to the binary input of the Freja-300. When the synchronization conditions are met, PMU-B transmits a changed status of GOOSE message representing breaker close command which is captured by GOOSER and it changes status of its binary output which is sensed by Freja-300 to terminate the test scenario (stops the secondary injections of three phase voltage to PMU-B). For these tests, the reference voltage is fixed at 60 V (secondary injection).

Three different standard tests are carried out using this setup. Figure 12a shows the result for voltage/frequency boundary test. This verifies the minimum and the maximum border for voltage and frequency difference, which results in successful synchronization. As shown in Fig. 12a, these boundaries are ± 0.6 V (± 0.01 pu) and $\pm$ 0.05 Hz (0.001pu). Fig. 12b shows the result of the lead time i.e. the close command that is sent in advance by PMU-B to compensate for the breaker opening delay. The results show a lead time of 83 ms corresponding to an advance angle (θ_{Sync}) of 1.5° for a slip frequency (Δf) of 0.05 Hz, which closely matches to the computed θ_{Sync} of 1.44° in PMU-B.

To verify the synchro-check capability, a phase (slip) angle window of $\pm$ 10° is configured in the algorithm. The test sequence is executed and it changes the phase angle in small steps to validate the synchronization window. As shown in Fig. 12c, the developed algorithm successfully passed this test.

VI. DISCUSSION

The proposed scheme is intended for automatic synchronization of radial portions of a power system in which one

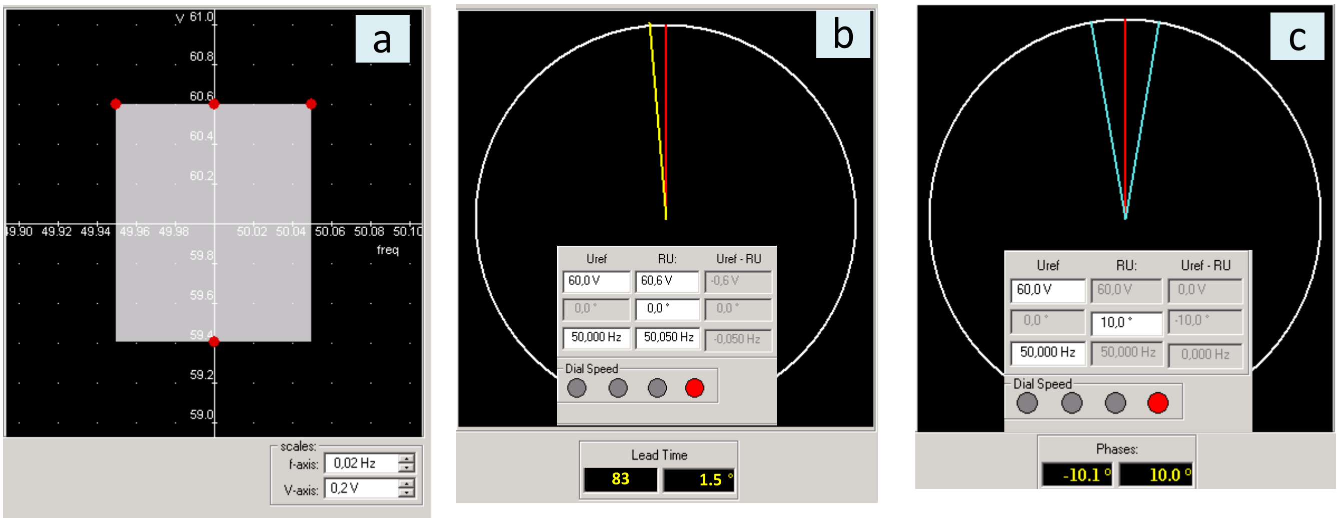

FIGURE 12. Testing using a standalone relay test-set and a IEC 61850-8-1 GOOSER.

generator of the isolated system has a determinant influence on the synchronizing quantities. This is the case in countries with very large power generation units, for example, in Finland, where four nuclear reactors provide nearly 30% of total electric power [23]. Such a topology is also quite typical of distributed generation applications where the synchronizing quantities can be directly controlled by a single generator (DG).

The case where multiple generators influence on the synchronizing quantities, the control commands from the PMU executing the automatic synchronization algorithm, should send GOOSE messages to different generators in a coordinated manner to alter their field voltage and/or governor's set-point to closely match the synchronizing quantities of the two network. Such automatic synchronization scheme will require routing of GOOSE messages over Wide Area Network (WAN), as different generators will presumably be geographically spread. This can be achieved through techniques like tunneling, protocol conversion and encapsulations [24]. However a realization of such an automatic synchronization scheme requires extensive studies related to control command coordination, communication network, cyber-security and quality of service (QoS) requirements.

As modern power system protection relays/IEDs are equipped with PMU functionalities, the proposed scheme can utilize these synchrophasor measurements internally to offer automatic synchronization subjected to minimum communication latency and reduced equipment cost as it neither requires a dedicated hardware nor physical connections to carry out synchronization.

VII. CONCLUSION

The design, implementation and testing of a hybrid synchrophasor and GOOSE-based automatic synchronization algorithm using the RT-HIL simulation approach is presented in this paper. Local and remote synchrophasors are utilized internally in a commercial PMU that execute the algorithm deployed using protection logic equations. The PMU/relay coordinates with AVR and/or turbine governor controller to match the voltage and/or frequency of the generator bus with the grid bus using IEC 61850-8-1 GOOSE messages.

The proposed approach eliminates the requirement of a synchronism check relay or a specialized auto-synchronizer to perform synchronization between two systems and therefore minimizes overall equipment cost. The algorithm utilizes standard protocols i.e. IEEE C37.118 (synchrophasors) and IEC 61850-8-1 (GOOSE) to identify and initiate synchronizing sequence, thus it is interoperable and vendor independent. The algorithm ensures minimum communication latency by establishing direct communication between the PMUs. The methodology for testing proposed algorithms using standard protection relay-testing equipment confirms its practical applicability and seamless adaptation in the field.

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