Isochronous Load Sharing Principles for an Islanded System With Steam and Gas Turbine Generators

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ISOCHRONOUS LOAD SHARING PRINCIPLES FOR AN ISLANDED SYSTEM WITH STEAM AND GAS TURBINE GENERATORS

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Abstract **–** A liquefied natural gas facility in the United States is being expanded to allow liquefaction of natural gas and export of liquefied natural gas while keeping intact the existing import facilities. This means adding more loads and steam-based generation to the existing gas turbine generator portfolio. The upgraded system will feature six gas turbine generators and two steam turbine generators in an islanded plant with no grid connection. This paper reveals the fundamentals of how the plant performs isochronous load sharing in an islanded power system with various makes and sizes of generators (steam and gas turbines). The paper details the decentralized generation control system interface methodology with automatic speed governors and voltage regulators. It also presents some topics that are crucial for industrial power systems, especially in islanded configurations, as well as the transient simulations performed in a controlled lab environment to analyze system stability and help finalize the generator modes of operation.

Index Terms — Generation control system, isochronous load sharing, frequency and voltage stability, automatic synchronization, island tracking, islanded power systems.

I. INTRODUCTION

One of the key requirements for islanded power system stability is the ability to monitor and control all of the generators to maintain voltage and frequency. Generation control systems (GCSs) typically perform slow- and high-speed rebalancing actions, depending on the control objective [1]. This paper discusses a decentralized (distributed) GCS applied to an islanded power system with a mix of steam and gas turbine generators from various manufacturers.

The existing facility features six gas turbine generators (GTGs) in an islanded configuration with no grid connection. Five of the GTGs are from the same manufacturer with different ratings. All the GTGs operate at 13.8 kV nominal voltage and can operate in an isochronous load sharing mode. The plant also has four synchronous motors. A new expansion will add to the system two generators that are driven by high-speed steam turbines equipped with gears. The new expansion will also add one 26 MW and two 20 MW variable frequency drive (VFD) operated motors. Fig. 1 shows a simplified one-line diagram of the facility power system without any load representation.

II. GENERATION CONTROL SYSTEMS

The objective of a GCS is to maintain the system frequency and voltage during everyday operations and to provide support during system events. A GCS combines low- and high-speed functions to ensure safe and optimal control of the machines in order to maintain system stability. Control functions such as base loading, droop control, and isochronous load sharing allow the GCS to maintain and regulate frequency for any planned or unplanned system events. Similarly, functions such as voltage control, power factor (PF) control, and volt-ampere reactive (VAR) sharing allow proper regulation of reactive power within a system. Compared with larger grids, islanded power systems require relatively faster-acting control systems during system events to compensate for the reduced overall system inertia. Fig. 2 shows a high-level architecture and distributed controller connections in a case with two steam turbine generators (STGs).

A. Frequency Control System

A frequency control system (FCS) regulates the generators to maintain the system frequency when an accelerating or decelerating torque develops. Such torque develops during a machine step load response for either accepting or rejecting a change in load. Such torque also develops during or after system events (e.g., faults, unexpected load/generation trips).

Fig. 3 shows the frequency, electrical power, and mechanical power responses of an industrial frame turbine and generator for a small load step response [2]. It shows the step change in electrical power along with the time lag between the generator and turbine output.

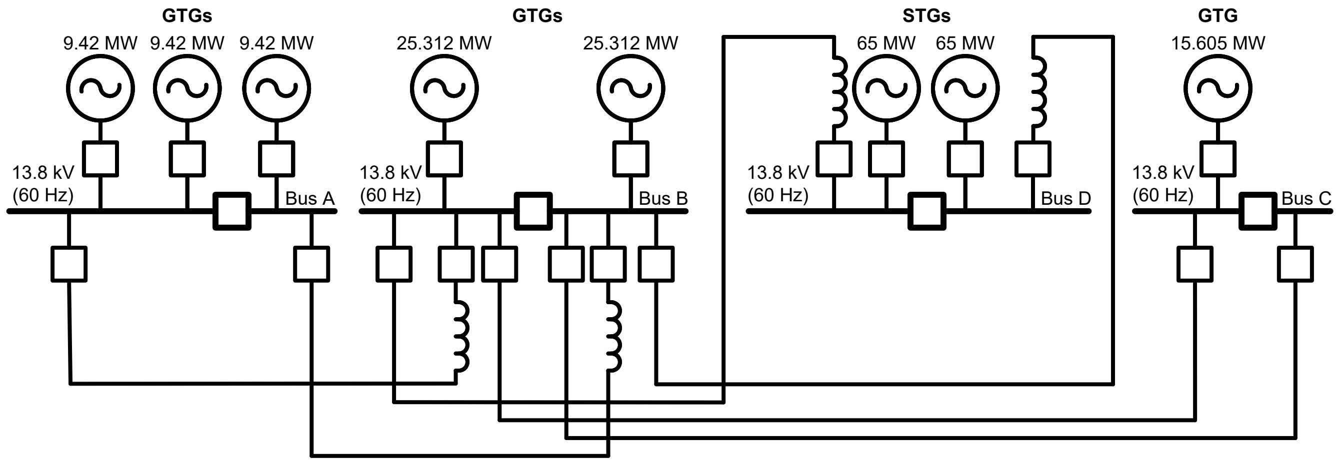

Fig. 1 Simplified One-Line Diagram

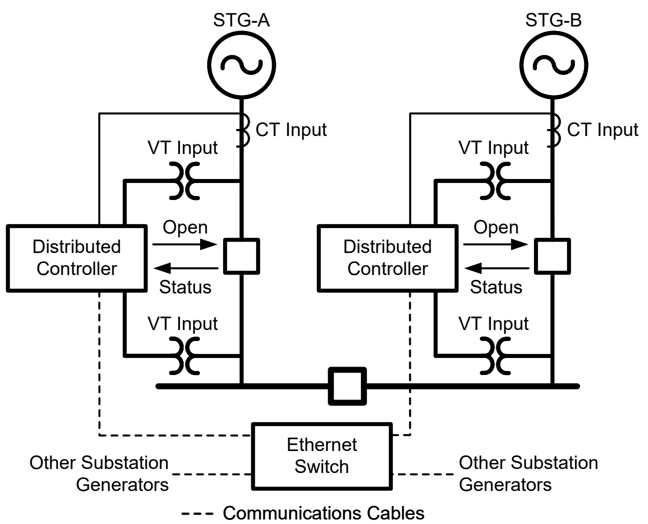

Fig. 2 High-Level Architecture of Distributed Controllers in a Two-Generator Case

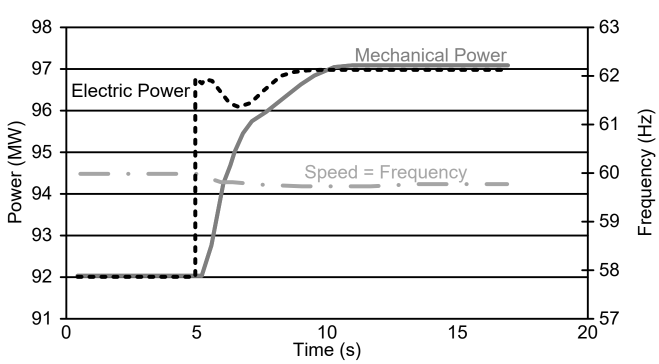

Fig. 3 Small Load Synchronous Machine Step Response

The basic underlying equation that relates mechanical power, electrical power, and speed is as follows:

$$JW_s \frac{dW_m}{dt} = P_a = P_m - P_e \tag{1}$$

where:

J is the combined moment of inertia of the generator and turbine (kg • m^2).

W_s is the synchronous angular velocity (rad/s).

W_m is the rotor angular velocity (rad/s).

t is time (s).

P_a is accelerating power (W).

P_m is mechanical power (W).

P_e is electrical power (W).

A typical FCS operates on a proportional megawatt-sharing philosophy and tries to maintain all units within their respective capability curves. The generators within the facility operate in two out of three available frequency control modes.

1) *Isochronous Load Sharing*: In isochronous load sharing mode, all the generators within the plant are set to isochronous mode on their speed governors. Using a common communications backbone, the distributed controllers connected in the island exchange information and regulate the generators to maintain frequency during load unbalances. In addition to maintaining the frequency, the controllers also perform proportional real power sharing between the units based on their rated MW capacity.

The regulation at each unit is performed by biasing the speed governor using a control signal (typically an analog bias). This bias adds or subtracts into the speed reference (nominal speed) of the governor control itself. The response of the bias signal is defined by a proportional-integral-derivative (PID) control that exists within the GCS controller.

Fig. 4 shows the integration of the bias signal into a typical governor control block diagram.

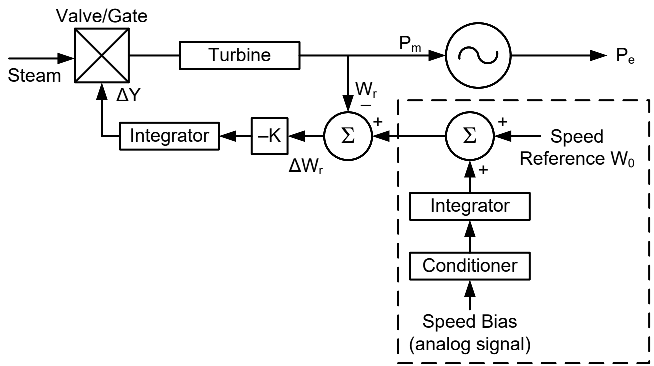

Fig. 4 Block Diagram of an Isochronous Governor With Integrated Speed Bias (analog bias input)

The conditioner block is used to limit and scale the bias for use in the governor control system. The speed bias integrator time constant, limits, and gain are field-tunable parameters for obtaining the desired response from the machine.

Fig. 5 shows a high-level block diagram of the frequency control function within the distributed controller. Depending on the type of control selected, different logic is activated along with the PID loop.

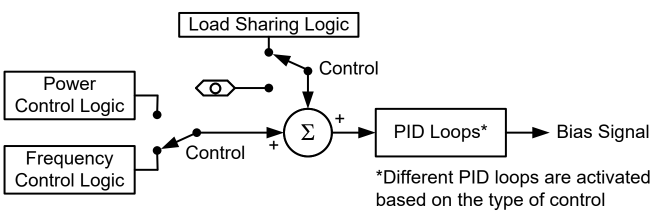

Fig. 5 High-Level Block Diagram of an Individual Distributed Controller

Fig. 6 shows single-unit isochronous governor regulation for different bias conditions. During a control situation, the GCS dynamically calculates the bias set points for each generator before dispatching controls. These set points change dynamically as the system adjusts to a newer settling state after a disturbance of the equilibrium.

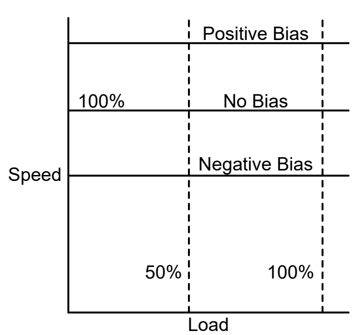

Fig. 6 Single-Unit Isochronous Governor Regulation With GCS Bias

Isochronous load sharing between multiple units provides the ability to reject frequency disturbances and to actively share the load. In cases with fast-acting speed governors that operate in isochronous load sharing mode, generator shedding schemes can mostly be eliminated, assuming the generators have enough head room to swing.

2) *Droop Control*: For stable load sharing between multiple units paralleled to strong sources, droop-based control allows multiple units to operate in parallel by decreasing their speed for increases in load. Droop control is typically observed in units that are paralleled to utility grids. In islanded power systems, droop-only control (without isochronous operation) is not recommended because of its inability to actively maintain the system frequency during system events. It is important to note that droop-only control can be allowed where a system such as a GCS is available to provide functionality similar to an isochronous control.

3) *Base Loading*: Base loading is performed on a generator to follow a preset MW command. This is sometimes referred to as “maintained mode,” where the operator requests a certain output from a few generators while others provide regulation using droop and/or isochronous controls. Generators are typically maintained when they are paralleled to the utility, when they have smaller ratings, or when they do not have the built-in ability to assist with primary frequency regulation.

Fig. 7 shows the response of an STG for different base load transitions. Starting at 37 MW, the machine is stepped through various set points, and the figure shows the response of the speed bias signal, generator frequency, and active power response.

B. Voltage Control System

A voltage control system (VCS) dispatches exciter set points among a group of generators to maintain the terminal bus voltages within acceptable limits [1]. The VCS at this facility is implemented within the same distributed controllers used for the FCS. Similar to an FCS, a VCS issues control signals to every generator to keep them running at the desired megavolt-ampere reactive (MVAR) output level. Even though the external interface between the VCS and the generator exciter consists of raise and lower control signals, there can be different control inner loops within the VCS. For example, during an islanded situation, the VCS implements a generator voltage control inner loop to maintain the island bus voltages rather than implementing a VAR control loop to maintain a fixed VAR output. Similar to isochronous operation for maintaining system frequency, a VCS is required to keep at least one unit (if not more) to maintain and regulate the bus voltages.

A typical VCS operates on a proportional MVAR-sharing philosophy and tries to maintain all units within their respective capability curves. The generators within the facility operate in two different voltage control modes.

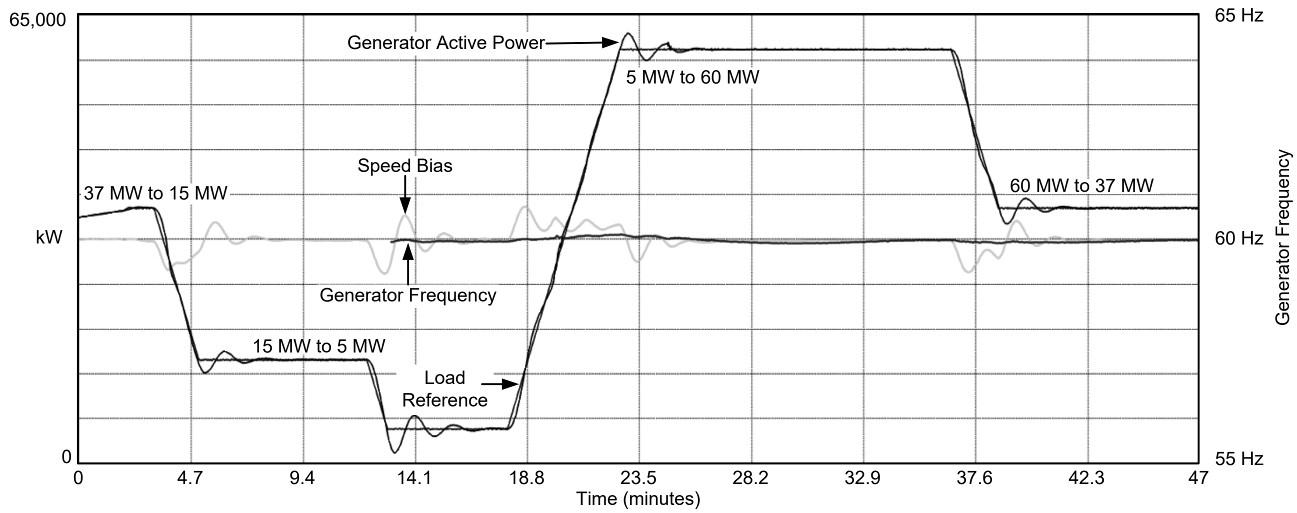

Fig. 7 Base Load Tests on a Single STG Model Using Real GCS Controller Equipment

1) *Voltage Control With VAR Sharing*: In this mode, the primary objective of the VCS is to maintain the bus voltages at each generator terminal and to proportionally share the MVAR based on the unit ratings. The distributed VCS dynamically calculates the individual set points for each excitation system and biases the excitation reference to achieve the desired set point. Fig. 8 shows the interfacing of the bias (raise/lower pulses) with a typical generator excitation system. When the bias signal is an analog input, the interface is similar to what is shown in Fig. 4.

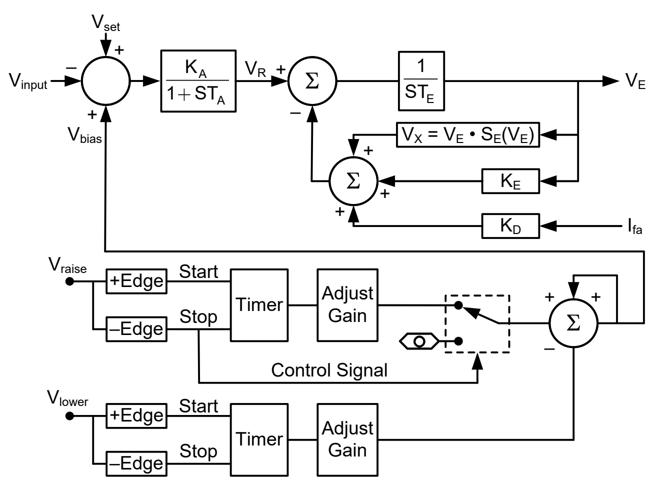

Fig. 8 Block Diagram of an AC Exciter With Integrated Voltage Bias (digital bias input)

2) *PF Control*: In this mode, every distributed controller follows the operator set point on a per-machine basis. This mode is typically used when the generator is in parallel with the utility and needs to maintain its power factor throughout the real power operating range. During PF control, the controller does not try to maintain the bus voltage and does not need to exchange information with the rest of the controllers because no sharing is occurring. This mode is only recommended when there are other machines available to provide voltage support and balance the system reactive power needs.

The control loop parameters for achieving the desired PF are separate from the voltage control parameters. This way, two independent loops are established and tuned for fast-acting and slow-acting controls.

C. Island Tracking System

Controlling multiple generators within an island requires a smart island tracking system to correctly enable the control modes on the governors and exciters. Island detection is traditionally performed by tracking the system topology using breaker statuses (52A and 52B). In this application, these statuses are brought into a centralized location to properly identify islands and to update the distributed controllers. When provided with such information, the controllers correctly identify the groups of generators that need to be controlled in every island.

D. Synchronization System

The distributed GCS controllers within the plant provide the ability to synchronize across individual generator breakers and some of the critical tie breakers. Breaker closing and generator control for synchronization are performed automatically after the user selection and initiation [3]. This is an important function to help the plant successfully reconnect because the islanded plant itself can get further segregated into subislands following particular events or even during normal operating conditions. After the events are cleared and the islands are stabilized, the automatic synchronization system can control the governor and exciters automatically to match the phase, voltage, and frequency error between the islands. Once the closing criterion is met (along with the availability of operator permissives), the controller that has access to the generator breaker provides the close command.

III. COMMUNICATIONS ARCHITECTURE

Modern power management systems are a complete integration of protection, control, and automation devices [1]. GCSs are no different when it comes to how to monitor and control generators. Communications play a vital role in both centralized and decentralized architectures. Because of the necessity of measuring local quantities and making a wide-area decision, various intelligent electronic devices (IEDs) send measurements to a centralized controller, or controllers located at the generators constantly exchange critical information pertinent to each generator. Because of the criticality of the application, such communications networks need to be dedicated and isolated from noncritical traffic in order to avoid network overloads, lost data packets, and failure [4]. Dedicated bandwidth is crucial for guaranteeing round-trip times for high-speed functions [5].

The facility applies a distributed GCS with controllers located at each generator. These controllers are connected via copper Ethernet connections to local managed Ethernet switches within the substations. The substations are further connected via a combination of single-mode and multimode fiber connections to form an isolated, star-connected network. Each distributed controller provides two physical network connections for redundancy. This forms an A network and a B network across the system, each with dedicated Ethernet switches.

IV. COORDINATION WITH THE PROTECTION AND CONTROL SYSTEM

Proper coordination of all the protection and control systems is critical for ensuring smooth plant operation. The GCS was designed considering the plant load-shedding system, intertie tripping system, and generator and load protection systems. This ensured optimal control of the system frequency and voltage at all times. Improper coordination often leads to unnecessary tripping and could have a detrimental effect on the stability of the system.

In addition to the generator and load protection systems, the plant has a primary contingency-based load-shedding system, a backup frequency-based load-shedding system, and an intertie tripping system based on available generation and overload conditions.

V. TESTING USING A REAL-TIME HARDWARE SIMULATOR

To verify and validate the GCS performance, the authors developed a computer simulation model of the plant in a commercial real-time hardware simulator. The simulator provides the ability to connect the actual controllers (real equipment) under test in a closed-loop fashion with the plant model. This allows for the exchange of measurement and control signals in real time to evaluate the true performance of the GCS functions. Fig. 9 shows a block diagram of the simulator testing setup.

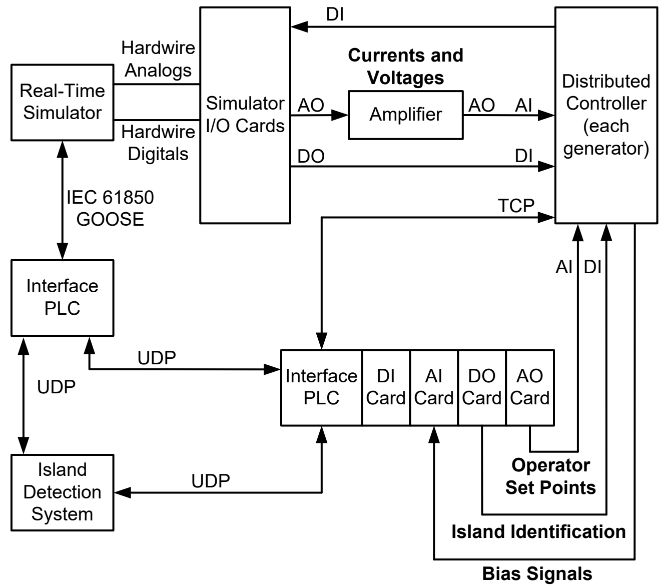

Fig. 9 Block Diagram of the Simulator Testing Setup

The model itself contains detailed plant information, including generator electrical and mechanical parameters, actual governor and excitation models and parameters (obtained from the manufacturer), network impedances, detailed load models (static, induction, and synchronous motors), and voltage- and frequency-protection systems. This level of detail allows for accurate testing of the controller performance for various system events and conditions.

Before performing the closed-loop tests, the authors validated every component in the model and the full model itself. Generator validation tests included load rejection, load acceptance, full-speed no load, and exciter step tests for each unit. Similarly, transformers, lines, and loads were validated to ensure correct representation. Finally, the authors validated the overall system for load flow cases and performed a few dynamic performance tests that included observing the system response for events such as generator tripping, and intertie tripping.

In addition to closed-loop validation tests, the model also allowed tuning of the various PID loops within the GCS to achieve an optimal performance. Fig. 10 shows an example of tuning performed on a single STG for a load-tripping condition. It shows the response of a single STG for different proportional and integral gains of its distributed controller.

Before performing integrated system tests, the authors used the model to tune and test every generator by using their GCS controllers. This provided the starting-point PID values for each distributed controller. A large variety of tests were conducted using the closed-loop simulator and actual distributed controllers for various generation loading conditions. Some of the tests included generation tripping, load tripping, large load startups, inadvertent loss of interties, single-phase and three-phase faults at various plant locations, loss of excitation and prime mover, arc-flash events triggering the opening of multiple breakers within the system, and closely timed events (back-to-back contingencies).

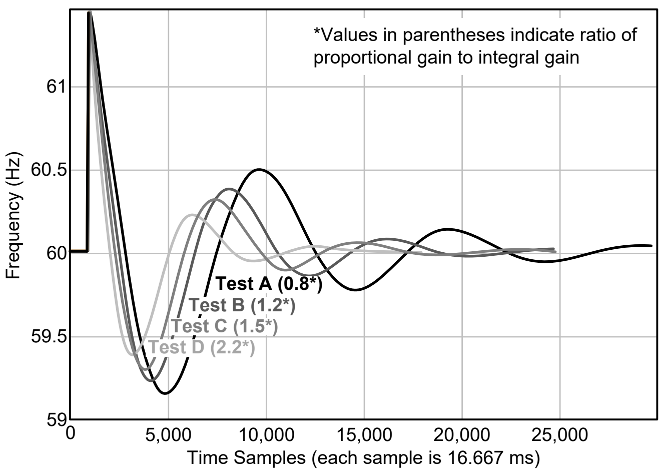

Fig. 10 Frequency Control PID Tuning of a Single STG for a Large Load (21.3 MW) Trip

The following is the test sequence for every simulation run.

1. Adjust generation and load, and initiate simulation using a typical load flow.
2. Trigger the event by either applying faults and clearing them or by directly opening breakers.
3. Analyze the system response in terms of frequency and bus voltages in every island.
4. Record the minimum and maximum frequencies, the minimum and maximum voltages, and the interaction of the GCS with any local protection or control systems.
5. Verify the controller performance and record any observations, including round-trip times, expected versus actual control action, and so on.
6. Confirm the behavior of protection systems based on the nature of the test case.

As an example, Fig. 11 shows the response of the system generators (all operating in isochronous load sharing mode and voltage-control VAR sharing) for a three-phase fault on a helper motor running at 11.3 MW. The event resulted in the motor tripping and a loss of load on the system. This test shows that the minimum and maximum system frequencies and generator bus voltages are well within the allowable limits and that the system quickly settles at a new steady state.

Fig. 12 shows another simulation run with three back-to-back events. In Event 2A, the GCS controller on one of the two STGs is disconnected from the communications network. At the same time, another generator is intentionally tripped to verify the STG response. The two STGs start to drift apart in terms of their real power output for the loss of generation. The tripping of generation causes an expected opening of the interties between the existing and new plants, which triggers load shedding. This is shown by the two different system frequencies that are established.

In Event 2B, the network connection on the STG controller is reestablished, and both STGs return to proportional real power sharing and participate in isochronous control.

Finally, in Event 2C, the autosynchronization system closes the tie breakers. The success of the synchronization can be verified by observing the system frequency.

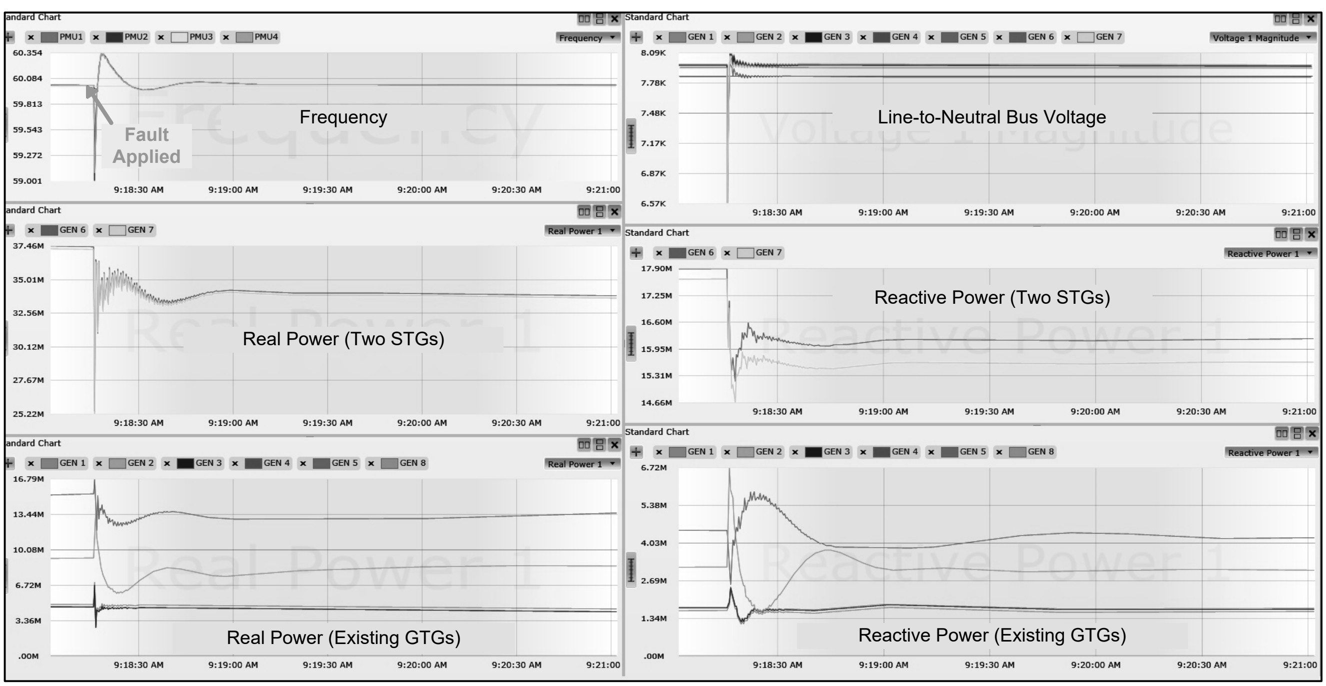

Fig. 11 Simulation Data Showing the Effect of a Three-Phase Fault on a Helper Motor

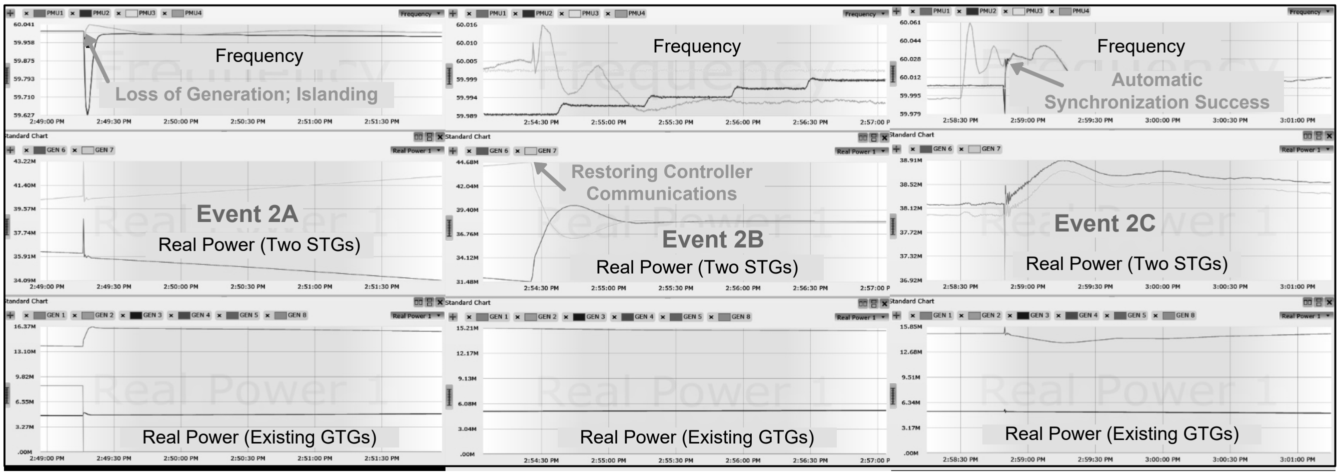

Fig. 12 Simulation Data Showing Three Back-To-Back Events (loss of controller communications, tripping of a single generator, and load shedding; restoring of controller communications; and automatic synchronization)

Overall, the authors performed approximately 100 different simulation tests during project development and factory acceptance testing. These simulations provided qualitative conclusions and results regarding the system performance and evaluated the controller performance itself. The benefits ranged from fine-tuning the GCS to recommending effective system operational modes for various plant operating scenarios.

Some of the key benefits of using simulations are as follows:

1. Provide a safe environment to develop and tune the various loop variables prior to integration and commissioning of the actual hardware.
2. Help develop a realistic starting point for all tuning prior to real-world tuning during commissioning.
3. Provide an environment for plant owners (operations, engineering) to develop “what-if” case scenarios to examine various possibilities (faults, process upsets, and so on).

Allow operations to avoid risky combinations of generation, knowing that the islanded facility is not as robust as other combinations that might provide more upset-ride-through capabilities.

Some of the lessons learned in terms of system operations include the following:

1. To provide the highest chance of survival during some events, always operate one of the two STGs in isochronous load sharing mode.
2. For an STG in fixed load control, do not operate the unit close to its maximum MW value (results in faster instability during system events).
3. Operate at least one of two existing 25 MW units in isochronous load sharing mode to provide stability during islanding situations.
4. Revise the underfrequency set points of the existing plant to avoid nuisance tripping during certain island conditions.
5. To avoid overloading the intertie lines during certain operating topologies, always operate one STG in isochronous load sharing mode.
6. Design fast load-shedding systems with appropriate power measurement filter time constants to avoid all known failure modes. Examples include untrustworthy transducer measurements during voltage transients and meter data aliasing when polling data from IEDs.
7. The distributed GCS is tuned to operate well with the load-shedding system and the generator protection systems, thus avoiding any unnecessary oscillations within the system. Final tuning may be required during onsite commissioning.
8. For most of the event conditions, the new STGs provide enough dynamic stability support to run the older units above 50 percent capacity to meet emission compliance requirements.
9. The generators are tuned well enough to survive low load loss events even when the load-shedding system is unavailable.
10. Due to the controller design limitations, operate as many units as possible in isochronous load sharing mode to avoid the possibility of inadvertently putting a fixed-load unit in a single island.

VI. CONCLUSIONS

GCSs play an important role in islanded power systems. Fundamental building blocks of a GCS include frequency and voltage control functions, the ability to track system islands, and autosynchronization across critical breakers.

The key to isochronous load sharing between generators is applying the same type of controllers using a common backbone for continuous control of their speed governors. Such a platform provides the ability to perform robust primary frequency control and to share the output proportionally.

In addition, this paper presents the details of VCSs and highlights the necessity of autosynchronization systems. The paper identifies the benefits of testing using a real-time simulator for controller validation, for understanding power system dynamics, and for finalizing generator modes of operation.

As of this writing, onsite commissioning has not yet been performed. The authors plan to present the commissioning test results once they are available and will also compare the lab results against the field results.

VII. ACKNOWLEDGMENT

The authors would like to acknowledge the support of Ashish Upreti and Bharath Nayak during the closed-loop testing. The authors would also like to acknowledge the manufacturer's support with the setup of the distributed controllers for controlled lab testing.

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IX. VITAE

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Brandon Bosley earned his B.S. in electrical and computer engineering in 2013 from the University of Missouri - Kansas City. Upon graduation, Brandon joined Kiewit Engineering & Design Co. He is currently an electrical engineer working on the execution of engineering, procurement, and construction projects, with a focus on the design of power generation plants. He is a member of the Eta Kappa Nu Honor Society.

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