Case Study: Smart Automatic Synchronization in Islanded Power Systems

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***Abstract*—Automatic synchronizing systems are used to reconnect multiple islanded power grid sections. These systems are required to function automatically with minimal human supervision because they must dispatch multiple generators simultaneously to reduce slip and voltage difference at the interconnection point.**

This paper describes a smart automatic synchronizing system that can connect multiple generators in an industrial power system during islanded and utility-connected modes via six different bus-tie and utility tie breakers. The automatic synchronizing system performs matching by controlling multiple governor and exciter interfaces within the facility.

Controlling slip and voltage difference across any of six different breakers in any combination is accomplished with up to six different and simultaneous power system islands. The power system studied is a large refinery containing six generators, totaling about 260 MW of generation.

The functionality, operation, and validation of this automatic synchronizing system using real-time digital simulator (RTDS) tests are discussed.

***Index Terms*—Automatic Synchronization; Case Study; Closed-Loop Real-Time Simulation; Exciter Control; Generation Control; Governor Control; IEC 61850 GOOSE; Microgrid; Optimal Load Sharing; Redundancy.**

I. Introduction

An alumina processing facility (refinery) installed a new double-bus, single-breaker gas-insulated substation (GIS) to meet plant growth and reliability requirements. Included in the project was a plant-wide generator control system (GCS) that can perform reliability islanding to ensure uninterrupted power and steam service to the critical process loads throughout the facility. The refinery power system includes six steam turbine generators that can operate in up to six independent microgrids. The focus of this paper is the synchronizing system that is used to resynchronize an island back to the utility grid or to other islands within the facility.

Due to the nature of and the complexity involved in the many possible islanded microgrids, the refinery project included the requirement that no manual synchronization is allowed. For this reason, the automatic synchronizing system had to be fully redundant to allow operations to continue in the event that the primary system failed.

An automatic synchronizing system connects a spinning power system to another spinning power system. Breaker closing ideally happens when the voltage, frequency, and phase angle are within tolerable limits for the two power systems.

The automatic synchronizing system for this project performs the following tasks:

- Identifies the electrical equipment connected on either side of the breaker being synchronized. This includes breakers, buswork, generators, utility tie lines, on-load tap changers (OLTCs), loads, and so on.
- Measures the slip, angle, and voltage difference across the breaker being synchronized.
- Controls multiple governors, exciters, and OLTCs to minimize slip, angle, and voltage difference.
- Closes the breaker once slip, angle, and voltage criteria are satisfied.

The automatic synchronizing system described in this paper automatically synchronizes multiple generators in the power system during any combination of islanded and utility-connected modes. The functionality and operation of the automatic synchronizing system are discussed.

The refinery is an operating facility. Therefore, the new generators, bus and feeder circuits, load-shedding system, and GCS had to be commissioned while not causing major disruption to production processes. To reduce risk, the system upgrade was fully validated in the laboratory by simulating the power system and generator controls using a closed-loop real-time digital simulator (RTDS).

II. Electrical Network for Refinery

Fig. 1 shows a simplified one-line diagram of the refinery. The top half of the diagram, including Buses GIS1A, GIS1B, GIS2A, and GIS2B, shows the new GIS. Generating Units G5 and G6 were also added in the plant power system upgrade. Note that the power system includes six steam generators, totaling 260 MW of capacity. The two utility tie lines can support up to 85 MW each. This GIS transfers power between medium-voltage (11.5 kV) busbars (B1 through B6), utility tie lines, and the two GIS-connected generators (G5 and G6). Note that the 11.5 kV bus is connected to the 132 kV GIS bus with OLTC transformers.

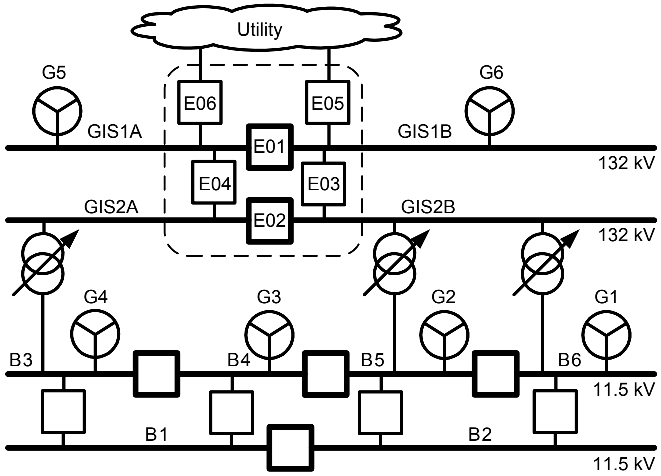

Fig. 1. Simplified One-Line Diagram of Refinery Power System

The power system supports loads on multiple buses, many with no generation. Each of the six generators can support loads independently on different islands, making it possible for six islands to occur simultaneously. These generators also supply power to the GIS bus for loads throughout the refinery. The refinery power system can be connected in various topologies, requiring the automatic synchronizing system to be flexible and adapt to all refinery electrical grid topologies. The automatic synchronizing system controls synchronization for the two bus sectionalizing breakers (E01 and E02), two bus-tie breakers (E03 and E04), and the two utility tie breakers (E05 and E06). Each generator has its own synchronizer for coming online during startup, so the generator breakers are not controlled by the system.

III. Automatic Synchronizing System Design

This section describes the design and functionality of the automatic synchronizing system. This system (shown in Fig. 2) has two major components: the advanced automatic synchronizer (A25A) and the GCS. For redundancy, there are two A25A devices. When a synchronizing scenario is selected, the A25A sends the slip and voltage difference error signals to the GCS.

The GCS monitors the power system topology and identifies which generators are within each island or utility connection. The GCS receives the slip and voltage difference from the A25A and determines which group of generators to control for the synchronizing scenario that is selected. The GCS provides proportional correction pulses to adjust the governors and exciters of the parallel-connected generator units on each bus section as necessary for synchronization.

The A25A monitors the slip and voltage difference and, once the GCS has reduced them to within the synchronizing acceptance limits, initiates breaker closing at the slip-compensated advanced angle to ensure that the two systems are joined at the instant of zero-degree angle difference.

This synchronizing system can synchronize across six breakers in any island formation to create a larger island from two islanded systems or synchronize an island to the utility grid.

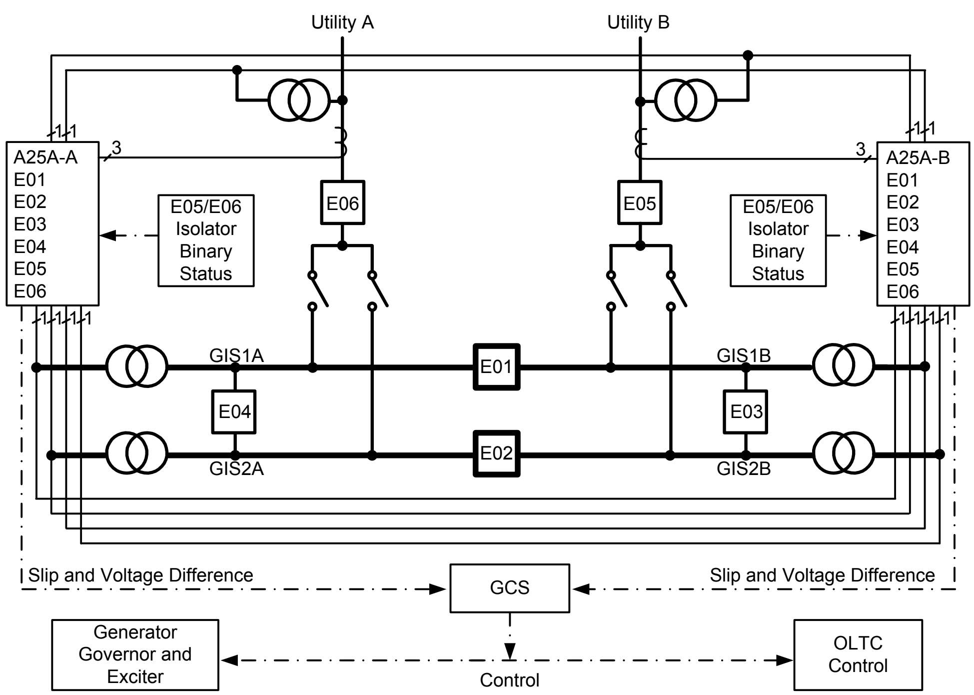

Fig. 2. A25A and GCS Interaction

The synchronizing system described in this paper must identify all island formations and dispatch generators appropriately. Simultaneous steam extraction requirements in tons per hour complicate the generator dispatch during the synchronization. Generator terminal voltages and bus voltages must be kept within manufacturer tolerances simultaneous with MVAR output load sharing between generator excitation systems. This is accomplished by controlling both OLTCs and exciters.

The automatic synchronizing system implemented at the refinery is a fully automatic, closed-loop system that dispatches multiple generators in parallel for synchronization and actively monitors the process until synchronization. The A25A can detect a failed or successful close by monitoring the breaker after the close command is initiated.

One of the features of this system is its ability to calculate advanced angle and issue a close command to compensate for the breaker closing delay. The A25A measures the slip and calculates the advanced angle at which the close coil should be energized. The slip-compensated advanced angle is calculated using (1) [1].

$$\text{ADVANG}° = \left(\frac{(\text{SLIP})\text{cyc}}{\text{sec}}\right)\left(\frac{\text{sec}}{60\ \text{cyc}}\right)\left(\frac{360°}{\text{cyc}}\right)\left((\text{TCLS})\text{cyc}\right) \quad (1)$$

where:

ADVANG is the advanced close angle.

TCLS is the circuit breaker close mechanism delay.

A. A25A Device

The A25A, which is a microprocessor-based protection-grade relay, can synchronize across 6 breakers at the GIS as previously described. For each breaker, there are 2 synchronizing scenarios, resulting in a total of 12 synchronizing scenarios.

In the case of the bus sectionalizer and bus-tie breakers, the two scenarios govern which bus is to be controlled by the GCS to match frequency and voltage. For example, Breaker E01 can synchronize Bus GIS1A to GIS1B, or it can synchronize Bus GIS1B to GIS1A. The GCS must determine which generators are on the bus to be controlled by monitoring the system topology and send matching pulses to the correct governors and exciters.

The utility tie breakers also have two scenarios; these breakers can be connected to either of two buses. For example, Breaker E05 can synchronize Bus GIS1B to the utility grid or GIS2B to the utility grid, depending on the status of the bus isolators. Note that buses connected to the utility grid cannot be controlled.

The A25A also provides underfrequency and overfrequency tripping functions for the buses connected to the utility tie lines. These elements are used to intentionally island the refinery during power system disturbances on the electric utility grid. These elements operate at the set points shown in Table I.

TABLE I
FREQUENCY-BASED ISLANDING FROM UTILITY

	Frequency	**Pickup Time**
Underfrequency	49.1 Hz	5 cycles
Overfrequency	50.5 Hz	5 cycles

The A25A selects the appropriate incoming and running voltages from its six voltage inputs based on the scenario selected. The large number of voltage transformer (VT) inputs on the relay allows this selection to be performed without any physical switching of the VT signals. Two A25A devices are provided for redundancy. Each A25A is designated as the primary synchronizer for 6 of the 12 scenarios and as the alternate synchronizer for the remaining 6 scenarios.

Both A25A devices have inputs from single-phase VTs from all four buses and each utility tie, as shown in Fig. 2. Both of the 52A and 52B statuses from the synchronizing Breakers E01 through E06 are wired to the terminals of each A25A and are monitored for the validity of the breaker status. Isolator status signals (89A and 89B), shown in Fig. 2, are wired to a separate I/O module and communicated to the A25A devices using the IEC 61850 Generic Object-Oriented Substation Event (GOOSE) protocol. Both 89A and 89B isolator statuses are monitored for the validity of the isolator status, and any incongruence creates an alarm, inhibiting the operator from initiating an automatic synchronizing process. The communications link status between the I/O module and the A25A is monitored internally in the A25A for the reliability of the GOOSE messages from the I/O module.

There are three conditions that the A25A must recognize to close a circuit breaker. They are:

- Synchronizing close (slip is detected, and matching is required).
- Parallel permissive close (both buses are live, but no slip is detected).
- Dead-bus permissive close (one or both buses are dead).

Automatic synchronizing close permissive asserts when voltage and frequency across the breaker are in normal operation; therefore, slip and voltage differences exist across the breaker, and frequency and voltage matching is required. The GCS needs to send raise and lower pulses to the governors, exciters, and OLTCs to bring the slip, voltage difference, and angle on both sides of the breaker within the synchronizing acceptance criteria, as shown in Table II [2] [3].

The parallel permissive close asserts when voltage and frequency on both sides of the breaker are within normal operating range and there is no slip across the breaker. This permissive is used to close a breaker when the two systems are synchronized through another path, such as when three of the bus breakers are closed and it is desired to close the fourth.

TABLE II
SUPERVISION SETTINGS FOR AUTOMATIC SYNCHRONIZING FOR SYNCHRONIZED CLOSE

	IEEE C50.12 and IEEE C50.13	A25A Acceptance Criteria
Angle	±10°	Target 0°
Voltage	+5%	±5%
Breaker Close Time	NA	3 cycles
Slip	±0.067 Hz	±0.04 Hz

A dead-bus permissive close asserts when either bus, or both buses, in the selected synchronizing scenario is dead. The permissive logic excludes a live bus and dead tie line condition for the utility bus-tie breakers to prevent ever backfeeding the utility grid from the refinery.

The synchronizing process can be initiated from multiple places, either from the front panel of the A25A (see Fig. 3 and Fig. 4) or from a remote human-machine interface (HMI). In both cases, the operator makes a selection for the breaker to synchronize the two systems together. Once a breaker is selected, if any three of the permissive conditions described are true, then the **OK TO INI AUTO SYNC/CLOSE** light-emitting diode (LED) asserts and the breaker is ready to be closed. The front-panel LED provides indication in terms of voltage, frequency, slip, and angle to the operator.

The A25A also provides analog data regarding voltage and frequency on either side of the breaker to the HMI and GCS. In the case of automatic synchronizing close, the control signals need to be sent to the generator and the OLTCs to reduce slip and voltage difference so that the breaker can be closed.

Once the slip and voltage difference come within the user-specified synchronizing acceptance criteria, the A25A sends a close command to the close coil at the advance angle to close the breaker. The A25A monitors the breaker for closing, and if the breaker fails to change state, the A25A asserts a close fail alarm to notify the operator. If the breaker closes but opens again immediately, the A25A asserts a close lockout alarm to notify the operator.

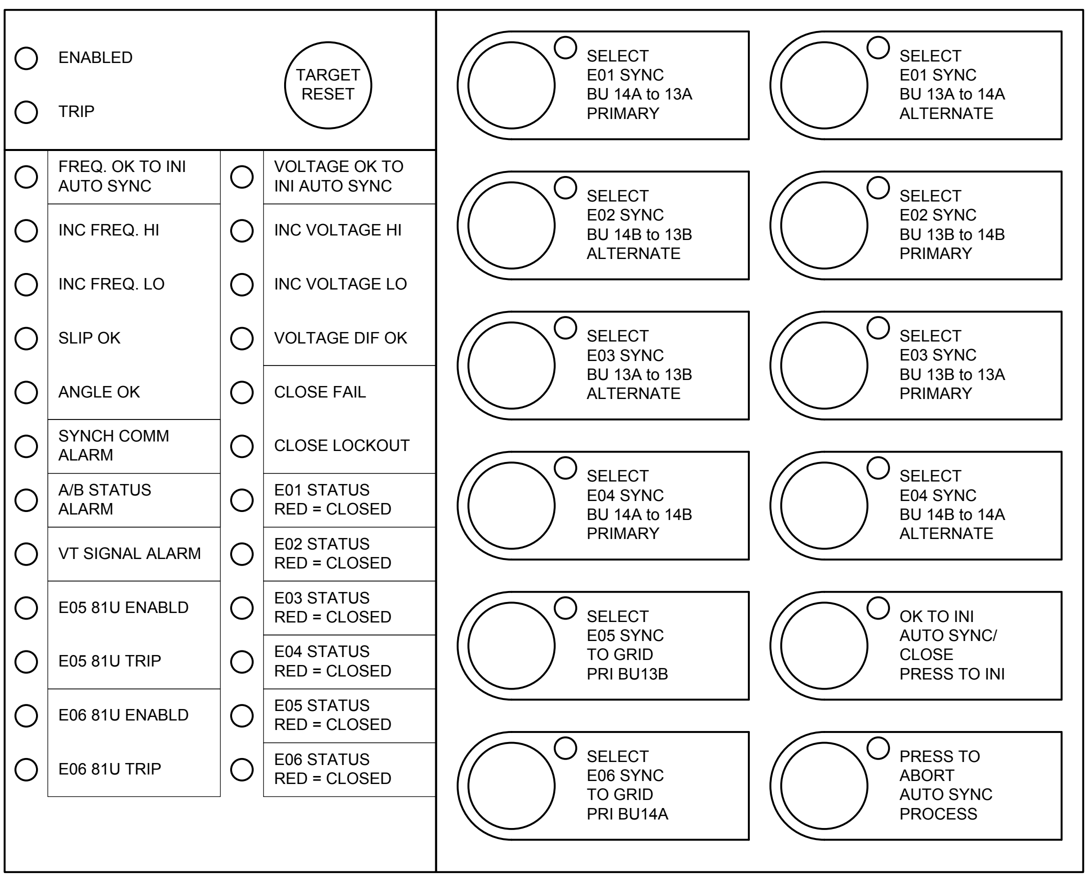

Fig. 3. Front Panel of the Automatic Synchronizer A25A-A

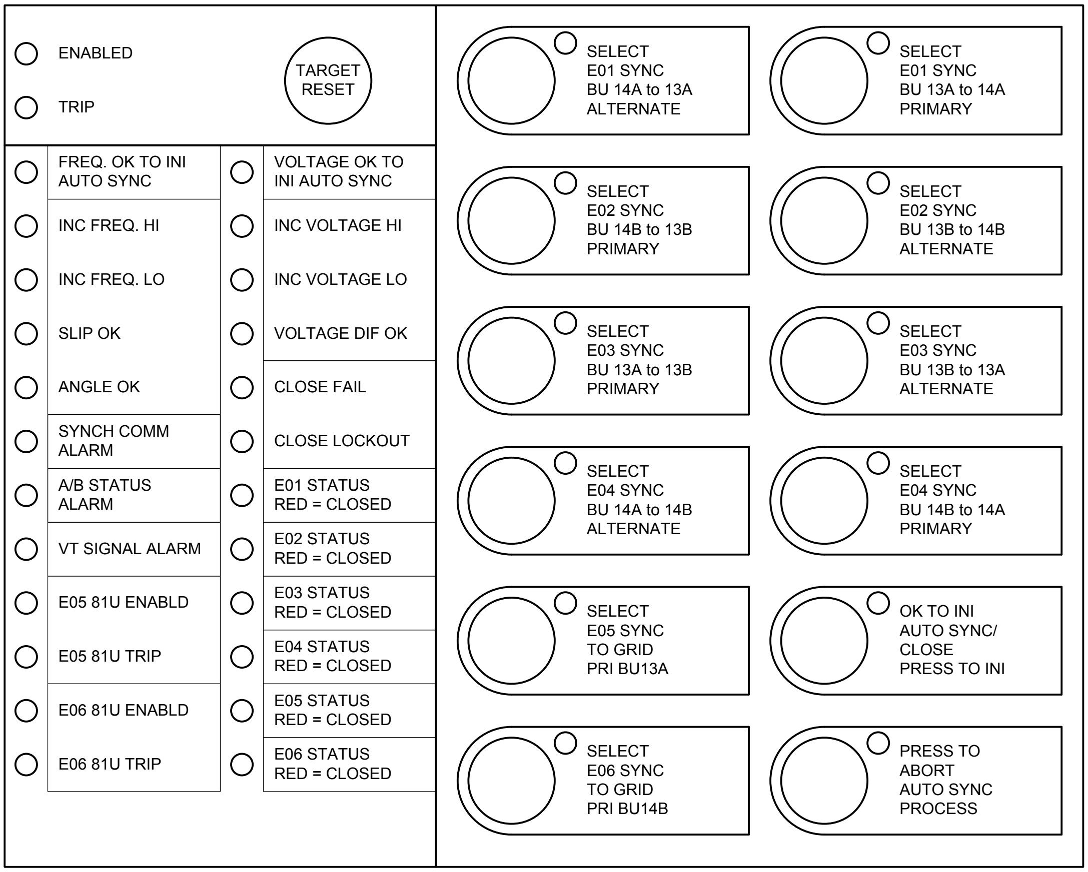

Fig. 4. Front Panel of the Automatic Synchronizer A25A-B

The A25A devices have extensive recording capability. There are 98 logic points for critical logic signals inside the A25A that are programmed to be monitored by the Sequential Events Recorder (SER) function. These logic points have been programmed with human-readable aliases.

The A25A devices record two types of oscillographic records. COMTRADE files contain raw sample data at a 1 kHz sampling rate. Compressed event (CEV) files contain filtered data that are synchronized to the one-eighth power system cycle processing interval of the A25A. The A25A devices are programmed to record a 4-second oscillographic record with 2 seconds of pretrigger capture when triggered. An oscillographic record is triggered when the A25A attempts to close a circuit breaker.

The front-panel display of the A25A provides information regarding the synchronizing process and its parameters along with any associated alarms. Fig. 5 shows the front-panel rotating display that provides any alarms that an operator needs to be aware of before initiating a breaker. The A25A also provides detailed information regarding the breaker selected for the synchronizing process. The right side of Fig. 5 shows the information regarding the breaker. A similar screen for each of the breakers is available in the front-panel display of the A25A.

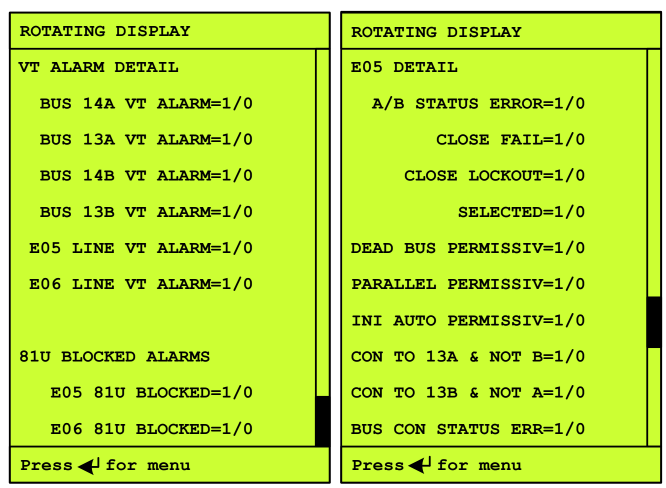

Fig. 5. Front-Panel Rotating Display

B. *Generation Control System*

The A25A does not have sufficient data processing power to dispatch the six governors, exciters, and OLTC controllers in accordance with plant operating requirements. The GCS augments the A25A by providing topology tracking, equal percentage load sharing of governors and exciters, and simultaneous bus voltage regulation. The GCS in this project also supplies a great deal of additional functionality, which is not described here because it is not pertinent to synchronizing.

Because of the diversity of bus-switching scenarios, any of the six governors, exciters, or OLTCs can be on either side of the breaker being synchronized. The function of determining which islanded section these devices are connected to is called topology tracking. Topology tracking requires complete knowledge of all the switching devices. To track all the possible topology scenarios, 82 breaker (52) status inputs and 64 isolator (89) status signals were supplied to the GCS via intelligent electronic devices (IEDs) located throughout the plant, as shown in Fig. 6. These input signals are run through topology tracking and island detection algorithms, as shown in Fig. 7.

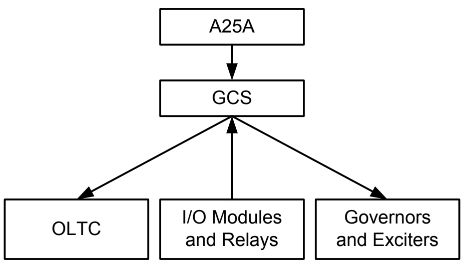

Fig. 6. GCS Communications Architecture

All the breaker statuses, isolator statuses, VT connections, current transformer (CT) connections, and controls are hard-wired to relays and I/O modules located throughout the plant. Breaker and isolator statuses, active power (P), reactive power (Q), voltage (V), and frequency (F) are sent to the GCS. Control signals from the GCS are sent to the generators, exciters, and OLTC controllers via I/O modules. The A25A sends slip, voltage difference, and angle measurements to the GCS.

The refinery in this example required that the generators always be load-balanced to minimize the possibility of tripping during transient conditions, which can occur after separating into an island. The GCS does this by keeping the output from generators on a grid section (island) equally balanced throughout the entire synchronizing process. Part of the reason the load is balanced is to prevent operating any of the six turbines at their upper or lower limits, which lessens the likelihood of tripping a unit offline. For example, should a disturbance such as a large motor load trip occur, a generating unit operating close to zero output could potentially trip on reverse power as the governor correctly tries to close the control valve and prevent frequency overshoot. It is for these reasons that the GCS has an optimal load-sharing algorithm, as shown in Fig. 7.

Load balancing of multiple turbines becomes further complicated because the units involved are from different manufacturers and have different response rates and output ratings (the largest unit is 80 MW, and the smallest is 30 MW). The generators on the 11.5 kV buses also have the limitation of operating in a limited range of output due to the steam extraction requirements of the plant. Equal percentage (optimal) load-sharing techniques are used to overcome these challenges.

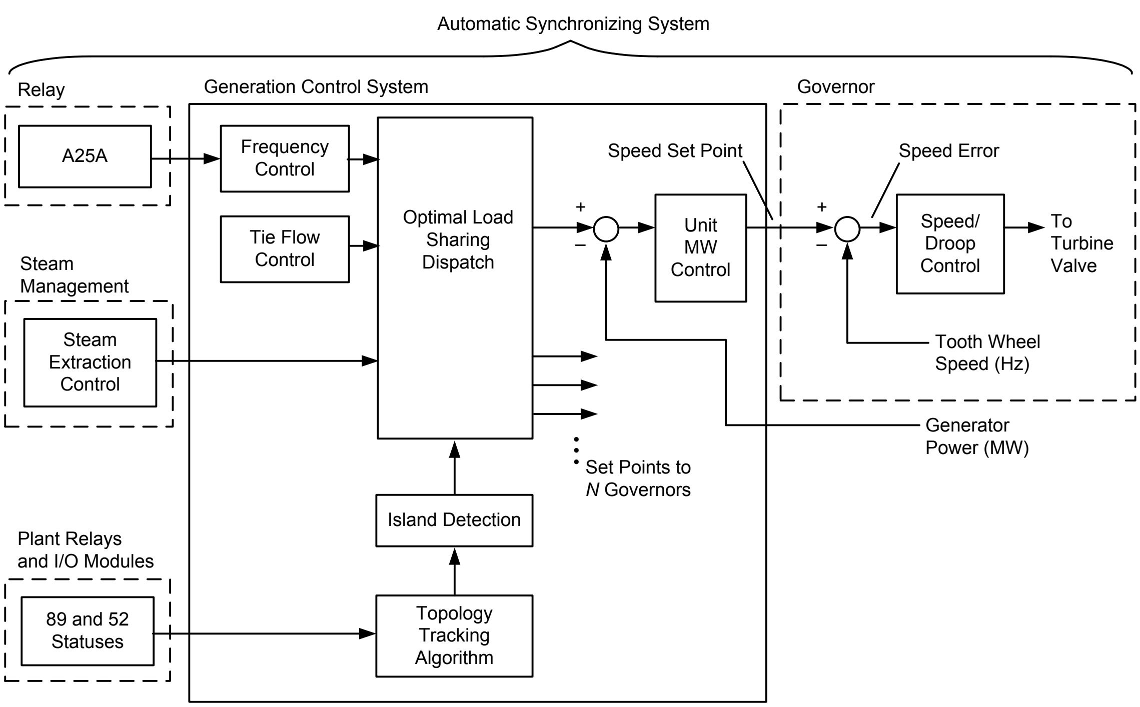

Fig. 7. Partial GCS Control Loop Architecture

To further complicate matters, it is common for generators to have unstable operational areas or undesirable areas of operation. The solution to this problem is to create artificial upper- and lower-limit boundaries that are user-settable limits, as shown in Fig. 8. Equal percentage (optimal) load-sharing techniques load all the turbines to an equal dispatched location within the lesser of the upper and lower bounds, the capability of the turbine, and the capability of the generator. The turbine capability is entered by the user, and the generator capability is derated according to cooling water temperature measurements.

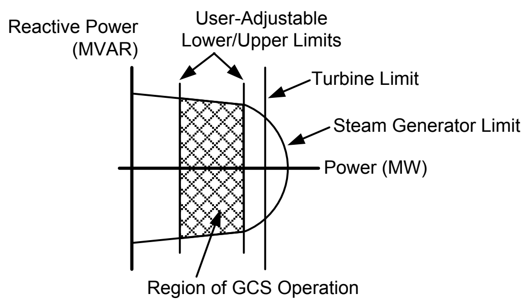

Fig. 8. Region of GCS Operation

The GCS also provides optimal exciter load (VAR) sharing and simultaneous bus regulation of all the buses in Fig. 1. Similar to optimal load (MW) sharing, the optimal exciter load (VAR) sharing equally shares the VAR contribution percentage from each generator. Unlike exciter load (MW) sharing, however, the exciter VAR contribution is limited by terminal and bus voltage magnitudes. To accommodate this, an adaptive volt/VAR-sharing algorithm regulates the OLTC to keep exciters away from their upper and lower bounds simultaneously, ensuring that the generator stator terminals remain inside equipment ratings.

C. *Human-Machine Interface*

The automatic synchronizing system installed at the refinery also has an HMI for remote automatic synchronizing. The front panel of the A25A was replicated in the HMI screen. Operator training was minimized by making the HMI and A25A front panel identical in look and feel. The LED display and pushbuttons shown in Fig. 3 and Fig. 4 are replicated in the HMI along with voltage, frequency, and analog variables, as shown in Fig. 9. The incoming and running frequencies reflect the frequencies of the incoming bus and the running bus. The automatic synchronizing system controls the frequency and voltage of the incoming bus to match the running bus by controlling the governors, exciters, and OLTCs on the incoming bus.

The HMI also provides alarms regarding communications failures, incongruence of the breaker status, close failures, VT failures, and overfrequency and underfrequency trips.

Capability curves for each generator, such as the one shown in Fig. 10, are included in the HMI. The capability curves show the desired set point and current operating point for the GCS MW (load) and MVAR (excitation) controls. The turbine capability is shown as the vertical line. The synchronous generator capability curves are dynamically updated with live generator cooling water temperatures.

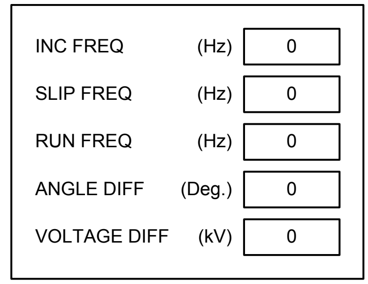

Fig. 9. Analog Variable Display for HMI

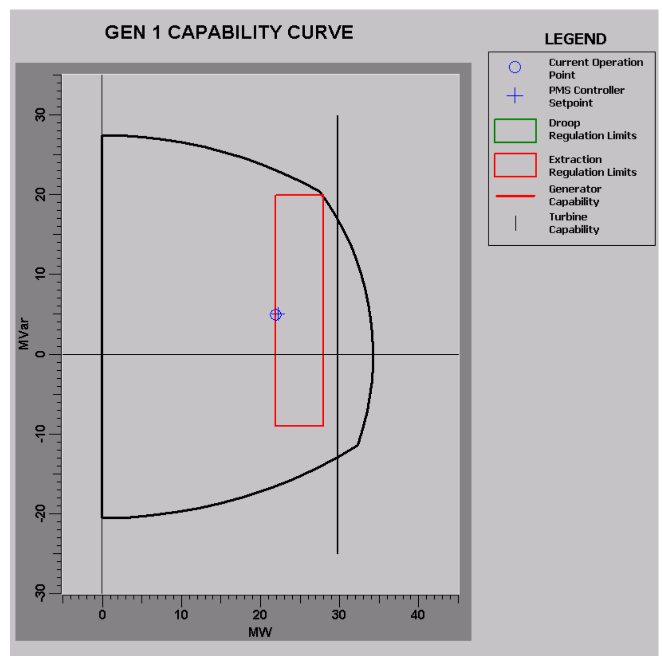

Fig. 10. Generator Capability Curve

IV. SYSTEM VALIDATION

Prior to installation of the advanced automatic synchronizing system at the refinery, complete testing was performed in a laboratory. An RTDS model was created to validate the functionality of the synchronizing system. This model included six custom governor, exciter, and turbine models, detailed load modeling, and a detailed electrical system model, which included all generators, turbines, exciters, breakers, loads, transformers, cables, and buses.

The RTDS model was validated by comparing model performance with known site conditions. This included the comparison of short-circuit fault currents, governor and turbine response characteristics, exciter response characteristics, and load reactive and active power consumption as a characterization of voltage and frequency.

Several studies were done using the model, providing insight into plant operation, vulnerabilities, and the system response for many contingency events. Studies were also completed to determine optimal set points for the power management system load-shedding system and GCS controllers.

The real-time model also permitted the A25A devices and GCS to be tested as a live simulation in the user-observed factory acceptance test. As shown in Fig. 11, this was accomplished by connecting the GCS and A25A to the simulation hardware.

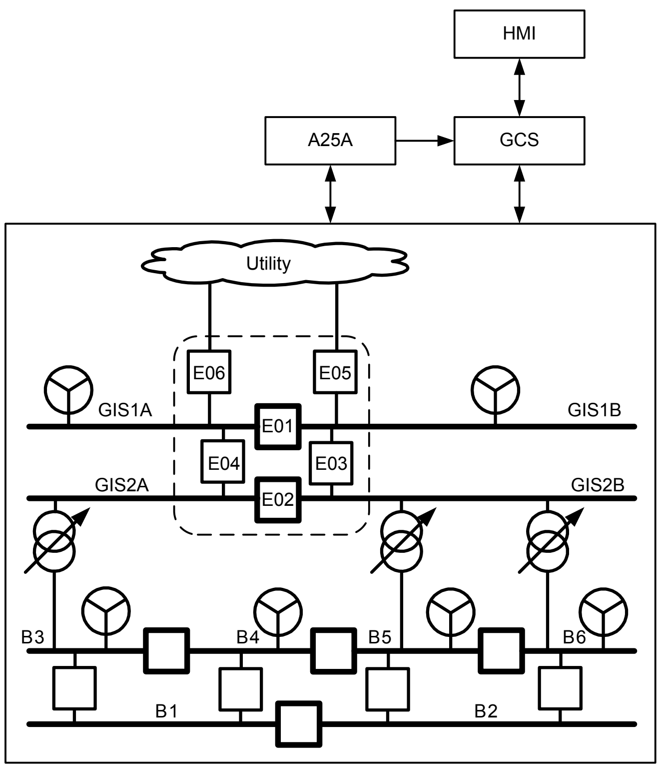

Fig. 11. Closed-Loop Real-Time Simulation

A real-time model allowed the authors to model the dynamics of the refinery power system with a simulation time step sufficiently fast to test all closed-loop controls of the automatic synchronizing system. Thousands of test cases were run, improving the likelihood that all systems will react as expected under the most adverse field scenarios. This testing method also minimized the commissioning time and expense in the large control and protection system, something especially valuable in an operating facility.

Several communications protocols were used in the testing and implementation of the automatic synchronizing system for the refinery. The communications protocol used between the A25A and I/O module was IEC 61850 GOOSE. Transmission Control Protocol/Internet Protocol (TCP/IP) was used for communication from the controllers to the HMI. The breaker statuses and VT connections were brought to the A25A and I/O modules using the hard-wired I/O from the real-time simulation hardware. The low-level injection voltages from the real-time simulation hardware to the A25A provided VT connections.

Several test scenarios were created for all the breakers, including dead-bus close, parallel permissive close, and automatic synchronizing close. These scenarios allowed an opportunity for the careful observation of the dynamic response of the power system after synchronization, which is especially valuable for a dead-bus close scenario. These tests proved that the functionality of the A25A and GCS fit the specifications of the refinery. Two of the test cases are described in the following subsections.

A. Case A: Island-to-Island Synchronization

In the case of island-to-island synchronization, Breakers E01, E02, E05, and E06 were opened so that the system was islanded from the utility and the refinery was split into two separate islands. Breaker E01 was selected to synchronize. Across E01, on GIS1A and GIS1B, bus voltage difference, frequency difference, and angle difference were present.

Breaker selection was performed using the HMI. Once the synchronizing scenario was selected, the **OK TO INI AUTO SYNC/CLOSE** LED indicated the system was ready for synchronization. Once initiated, the A25A began sending the breaker selection, voltage difference, and slip to the GCS. The GCS then sent control pulses to the governor, exciter, and OLTC to match the voltage and frequency across the breaker. The GCS controlled the incoming bus. However, in this case, the selection of the incoming bus was somewhat arbitrary because neither side of the bus was connected to the utility.

While the GCS reduced slip and voltage difference, the A25A monitored the process and provided the operator with continuous feedback using the front-panel display and the HMI. Once the A25A detected that the synchronizing acceptance criteria were satisfied, the A25A sent a breaker close command to close the E01 breaker at the slip-compensated advanced angle. In this scenario, an event report and SER reports were generated in the A25A.

Fig. 12 shows the slip across Breaker E01 during the automatic synchronizing process. At 30 seconds, the automatic synchronizing process was initiated; it was completed at 190 seconds. The starting slip was –0.21 Hz, and then at 90 seconds, it was less than 0.02 Hz, which was within the acceptance band. The automatic synchronizing system waited for the compensated breaker angle to come to zero. At 100 seconds, the slip went from negative to zero to positive. This process continued until the angle criteria were met. The instant the angle difference was nullified, which was at 190 seconds, the system transformed from two separate islands to one large island.

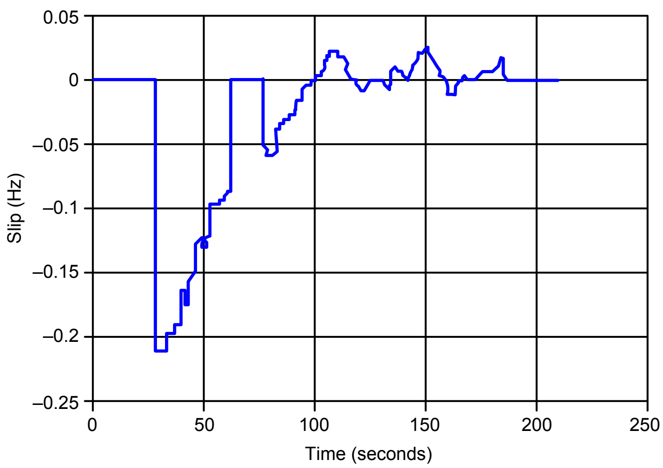

Fig. 12. Slip During Island-to-Island Synchronization

B. Case B: Island-to-Utility Synchronization

In the case of island-to-utility-connected power system synchronization, E03 and E04 were closed and Breakers E01, E02, and E05 were opened so that the island on GISA (GIS1A and GIS2A) with multiple generators was islanded from the utility and GISB (GIS1B and GIS2B) with multiple generators was connected to the utility via E06. The refinery was split between two islands. GISA and GISB where utility was connected to GISB bus while GISA was islanded. Breaker E01 was selected to synchronize. Across E01 on GIS1A and GIS1B, bus voltage difference, slip, and angle difference were present.

Breaker selection was performed using the HMI. The front-panel rotating display shown in Fig. 5 provided indication as to the selection. Once the breaker was selected, the **OK TO INI AUTO SYNC/CLOSE** LED indicated the system was ready for synchronization. Initiation of this process resulted in the A25A communicating with the GCS regarding the breaker selection, voltage difference, and slip. The GCS then sent controls to the governor, exciter, and OLTCs to match the voltage and frequency on both sides of the breaker. The GCS controlled the incoming bus. However, in this case, the selection of the incoming bus was GISA because the GISB bus was connected to the utility.

During the process of control signals being sent by the GCS, the A25A monitored the synchronizing acceptance parameters and provided operator feedback using the front-panel display and front-panel LEDs.

When all of the synchronizing parameters shown in Table II were met, the A25A sent a breaker close command to close the breaker at the slip-compensated advanced angle. The breaker status was monitored for a successful close.

V. Conclusion

Synchronization between multiple generators and utility tie lines or between the multiple generators in an isolated system creates a need for a smart and flexible automatic synchronizing system that is composed of both an A25A relay and a GCS controller.

The fully redundant automatic synchronizing system installed at the refinery improved the reliability and accuracy of breaker synchronism across all six GIS breakers without the need for physical VT switching

Testing of the automatic synchronizing system provided critical insight into the system operation. The real-time digital simulation of the model power system allowed for a better understanding of system functionality and provided a valid test in terms of meeting the specification of the design, which reduced the amount of labor and expense during commissioning of the system.

VI. Acknowledgments

The authors gratefully acknowledge the contributions of Dr. Abdel R. Khatib and Jordan Bell from Schweitzer Engineering Laboratories, Inc. for providing support during testing.

VII. References

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[3] IEEE Standard C50.13-2005, IEEE Standard for Cylindrical-Rotor 50 Hz and 60 Hz Synchronous Generators Rated 10 MVA and Above.

VIII. BIOGRAPHIES

Scott M. Manson received his M.S. in electrical engineering from the University of Wisconsin–Madison and his B.S. in electrical engineering from Washington State University. Scott worked at 3M as a control system engineer for six years prior to joining Schweitzer Engineering Laboratories, Inc. in 2002. Scott has experience in designing and implementing control systems for electric utility customers, refineries, gas separation plants, mines, high-speed web lines, multiaxis motion control systems, and precision machine tools. Scott is a senior member of IEEE and a registered professional engineer in Washington, Alaska, North Dakota, Idaho, and Louisiana.

Ashish Upreti is a protection engineer in the engineering services division at Schweitzer Engineering Laboratories, Inc. in Pullman, Washington. He received his bachelor's degree and master's degree in electrical engineering from the University of Idaho. He is a registered member of IEEE and has experience in the field of power system protection and automation, including power management schemes for large-scale industrial power plants.

Michael J. Thompson received his BS, magna cum laude from Bradley University in 1981 and an MBA from Eastern Illinois University in 1991. He has broad experience in the field of power system operations and protection. Upon graduating, he served nearly 15 years at Central Illinois Public Service (now Ameren), where he worked in distribution and substation field engineering before taking over responsibility for system protection engineering. Prior to joining Schweitzer Engineering Laboratories, Inc. (SEL) in 2001, he was involved in the development of several numerical protective relays while working at Basler Electric. He is presently a principal engineer in the engineering services division at SEL, a senior member of IEEE, chairman of the substation protection subcommittee of the IEEE PES Power System Relaying Committee, and a registered professional engineer. Michael was a contributor to the reference book *Modern Solutions for the Protection, Control, and Monitoring of Electric Power Systems*, has published numerous technical papers, and has a number of patents associated with power system protection and control.

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