Implementation of Reliable High-Speed Islanding Detection, Zone Interlocking, and Source Selection Schemes Using Smart Algorithms

Faridul Katha Basha, Ramanathan Palaniappan, Ashok Balasubramanian,
RadhaKiranMaye Anne, and Michael J. Thompson
Schweitzer Engineering Laboratories, Inc.

Kent L. Oliver
Valero Bill Greehey Refineries

This paper was presented at the 51st Annual Industrial & Commercial Power Systems Technical Conference and can be accessed at: http://dx.doi.org/10.1109/ICPS.2015.7266416.

For the complete history of this paper, refer to the next page.

Presented at the
51st Annual Industrial & Commercial Power Systems Technical Conference
Calgary, Canada
May 5–8, 2015

Originally presented at the
Power and Energy Automation Conference, March 2014

Implementation of Reliable High-Speed Islanding Detection, Zone Interlocking, and Source Selection Schemes Using Smart Algorithms

Faridul Katha Basha
Member, IEEE
Schweitzer Engineering Laboratories, Inc.
340 Office Court, Suite D
Fairview Heights, IL 62208, USA

Ramanathan Palaniappan
Member, IEEE
Schweitzer Engineering Laboratories, Inc.
343 Fountains Parkway, Suite 201
Fairview Heights, IL 62208, USA

Ashok Balasubramanian
Schweitzer Engineering Laboratories, Inc.
3100 Wilcrest Drive, Suite 350
Houston, TX 77042, USA

RadhaKiranMaye Anne
Member, IEEE
Schweitzer Engineering Laboratories, Inc.
340 Office Court, Suite D
Fairview Heights, IL 62208, USA

Michael J. Thompson
Senior Member, IEEE
Schweitzer Engineering Laboratories, Inc.
340 Office Court, Suite D
Fairview Heights, IL 62208, USA

Kent L. Oliver
Member, IEEE
Valero Bill Greehey Refineries
1122 Cantwell Lane
Corpus Christi, TX 78407, USA

***Abstract*—The Valero Bill Greehey Refineries West Plant houses on-site generation and is interconnected to the utility via a looped power system. With the on-site generators not having the capacity to carry the entire plant load, this plant relies on importing power from the utility. Valero upgraded their medium-voltage protection system and was looking for a fast, deterministic, reliable, and cost-effective solution to protect their medium-voltage busbars as well as a local-area measurement-based generator islanding detection system to protect their generator equipment.**

An economical solution was proposed and implemented using automation controllers, which receive information from the new relays using a fiber-optic link and a protection-speed protocol. Multiple techniques on redundant hardware are used to detect the islanding condition and help improve the dependability of the islanding detection scheme, regardless of generation-load mismatch. A unique voting scheme was developed to improve security. The zone interlocked bus protection scheme programmed in the controllers uses directional information to provide high-speed selectivity during bus faults. An intelligent source selection algorithm automatically modifies the bus protection logic depending on the topology of the power system. The protection-speed processing capabilities of the automation controllers enable the high-speed operation of the schemes.

This paper describes the solution implemented at Valero and introduces the algorithms developed to provide a robust integrated protection system that operates with dependability, selectivity, and security.

***Index Terms*—Controller Performance Optimization; Fast Bus Tripping; High-Speed Automation Controller; Islanding Detection; Protection-Speed Communication; Zone Interlocking Scheme.**

I. Introduction

Major industrial refineries in the United States have been improving the design of their electric power systems by upgrading their existing electromechanical-based protection devices with microprocessor-based intelligent electronic devices (IEDs) [1]. The recently constructed medium-voltage switchgear protection and integration project described in this paper is for a large refinery, the Valero Bill Greehey Refineries West Plant, located in Corpus Christi, Texas. The refinery power system relies on on-site generation and imported power from the utility for carrying the plant load. The refinery ties in with the local utility at the 69 kV level and has nine 12.5 kV switchgear units that are fed by the utility through four step-down transformers. Fig. 1 shows the topology of the refinery power system. The powerhouse contains two 12.5 kV on-site generators. Only the main breakers, switchgear tie breakers, and switchgear unit intertie breakers are shown in Fig. 1.

Prior to the upgrade, the refinery had employed electromechanical relays for bus differential schemes for protection of their medium-voltage buses. The upgrade included the use of microprocessor-based relays, which gave the refinery more flexibility for bus differential schemes. After evaluating the options, a high-speed communications-based zone interlocked protection scheme was selected for the upgrade design.

As mentioned previously, Valero local generators supply part of the load demand. Due to the presence of two 69 kV sources, Valero anticipated that the chances of the system being islanded from the utility were unlikely. Given that the utility had turned off automatic reclosing because of local generation, both the utility and Valero decided to decommission the existing topology-based audio-tone transfer trip islanding detection scheme.

However, an event occurred that left the plant with its generators islanded from a part of the utility. Because the reclose feature had been decommissioned, there was no damage to the generators due to a potential out-of-synchronism event. As a result, Valero decided to implement a new generator islanding detection (GID) scheme during the

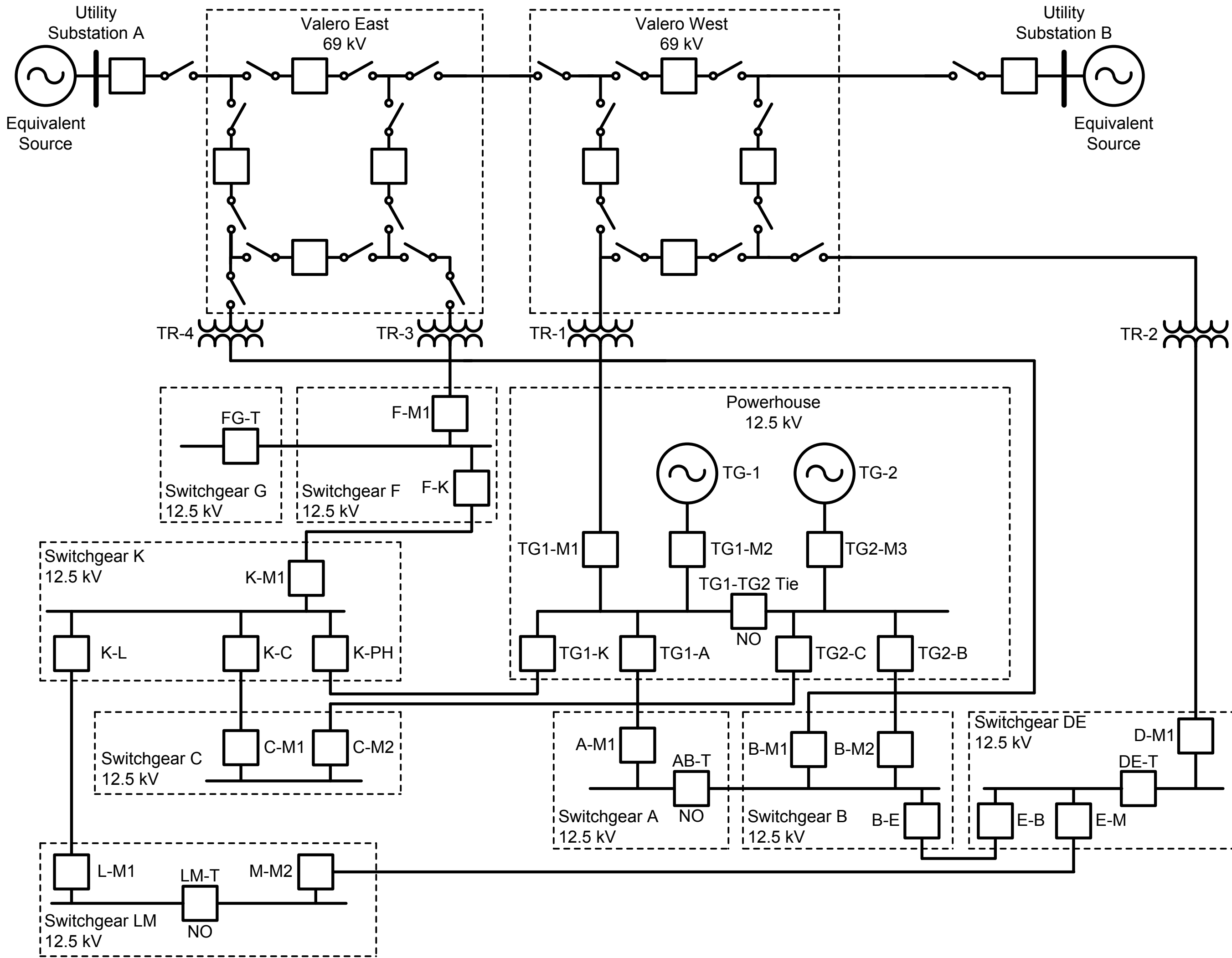

Fig. 1. Valero Refinery Power System Topology

scheduled upgrade project. The refinery performed a scheduled plant-wide outage that allowed new switchgear and infrastructure to be installed to implement the GID scheme. Many other process and utility items shared by multiple units were addressed during the scheduled outage as well. A benefit of the design is that it allows the utility to turn autoreclose back on to restore service automatically versus a manual supervisory control and data acquisition (SCADA) operation by the utility.

To accomplish the upgrade, the selection of protection IEDs, a logic processing device, automation controllers, communications protocols, and a communications interface was very critical. The selection of equipment and protocols needed to provide for flexibility and ease of future system expansion. Valero also desired physical and logical segregation of critical protection data and noncritical data like SCADA (when implemented in the future) in the automation controllers. The implementation of high-speed and reliable communications-assisted protection schemes was required to reduce wiring cost, achieve fewer construction errors, and expedite commissioning time.

This paper discusses the algorithms developed, protocols used, and automation controllers selected for the refinery upgrade project. With the use of a high-speed peer-to-peer communications protocol and subcycle logic task processing capabilities in the automation controllers, smart algorithms were designed and implemented for integrating multiple protection schemes into one device. These protection schemes included a zone interlocking scheme (ZIS) for busbar protection and a GID scheme.

The ZIS discussed in this paper limits fault stress on busbars and transformers by reducing the time it takes to clear a bus fault while maintaining system coordination between IEDs. It also continuously monitors the status of the main incoming source breaker and the topology of the power system. Depending on the topology of the power system, it actively selects the main incoming breaker of the busbar and maintains system coordination. The GID scheme uses locally measured current and voltage signals to detect an islanding condition and protect the generator equipment. The automation controller at each switchgear unit, shown in Fig. 2 in the next section, is programmed to implement the ZIS. The automation controllers at Switchgear B and the powerhouse switchgear (shown in Fig. 1) are set up to implement the GID scheme. This setup is discussed in the following sections.

II. Communications Architecture

A. Communications Architecture Overview

Fig. 2 shows the system communications architecture. Each switchgear unit has its own automation controller. Given the various schemes that were to be implemented, multiple options, including serial- and Ethernet-based communications networks, were analyzed for the communications architecture design. Critical information from the IEDs is collected using a serial peer-to-peer protection-speed communications protocol. This is referred to as high-speed digital bit (HSDB) protocol in this paper. It uses eight bits of logical status information that can be both transmitted and received by the IEDs through a serial communications link. The status information from the digital bits is used in each automation controller to implement the protection schemes described in the previous section. The serial communications channel is also used to distribute IRIG-B time signals to the IEDs connected to the automation controller, as shown in Fig. 2.

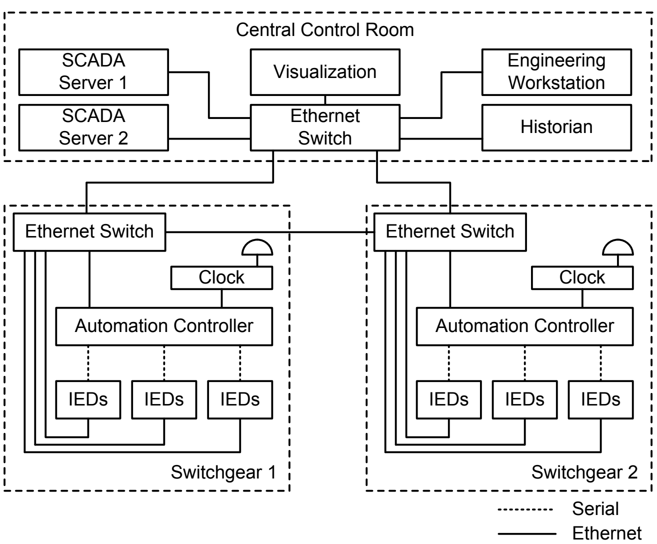

Fig. 2. Communications Architecture

An EIA-232 serial connection has nine pins for communication. Not all of these are required by the standard, so two can be repurposed for IRIG-B time signal distribution between end devices. The time synchronization of IEDs is very important. Analyzing power system faults and performance by comparing data from different IEDs with unsynchronized time clocks can be challenging. IRIG-B inputs can be applied to the IEDs using two distinct methods. Method 1 requires running a separate IRIG-B coaxial cable to each IED in a daisy-chained fashion. Method 2 uses the IRIG-B input to the automation controller and relies on that device to act as a time server to distribute the time signals to the individual IEDs.

The long-term goal for this project is the implementation of a SCADA system. The SCADA system will have multiple capabilities, including remote engineering access, metering, remote controls, alarm functions, event oscillographic recording, and sequential event reports. The disadvantage of employing serial-based communications links is that they are limited to a fixed bandwidth and a single protocol per cable [2]. To implement multiple functions using multiple protocols in the same IED, several different connections to the same IED would be required. Ethernet communication, on the other hand, is packet-based and can handle multiple sessions over a single cable, providing more flexibility and requiring fewer cables. For this reason, Ethernet-based communications will be used for this system. All of the Ethernet-based communications shown in Fig. 2 are planned for future installation.

Ethernet networks can be set up in a star, ring, or linear topology or a combination of these topologies. Reference [3] lists the various advantages and disadvantages of each of these topologies. The system design shown in Fig. 2 was developed with the following two types of Ethernet topologies:

- A ring topology to be implemented for the interconnection of intersubstation Ethernet networks.
- A star topology to be implemented for the intrasubstation Ethernet network.

A concern with a network topology like the one described in this paper is the Ethernet network latency. Network latency is defined as the additional time required by the Ethernet switches to forward an Ethernet packet from the source device to the destination device. Unlike EIA-232 communications networks, Ethernet networks do not have the advantages of a point-to-point device connection. Managed Ethernet switches will be used for the Ethernet network topology. Managed Ethernet switches, along with the use of IEEE 802.1Q virtual local-area networks (VLANs), will reduce latency [4]. In addition, the use of Rapid Spanning Tree Protocol (RSTP) will make the Ethernet communications network more robust.

B. High-Speed Digital Bit Protocol

Each IED in Fig. 2 is connected to a unique port on the automation controller using the HSDB communications protocol. The automation controller is capable of supporting up to 31 EIA-232 ports. The HSDB communications protocol is an inexpensive and secure protocol used in numerous protection and control applications [5].

This protocol was chosen because of its inherent performance, reliability, and security features. All of the IEDs selected for this project are equipped with at least one communications interface supporting HSDB protocol. The HSDB protocol includes continuous self-testing and is capable of transmitting and receiving eight digital status points asynchronously through a serial link. There are transmit (TX) identifiers (IDs) and receive (RX) IDs associated with each message, and the transmit ID setting on one device port must match the receive ID setting on the other device port. Fig. 3 shows the use of HSDB communications between two devices.

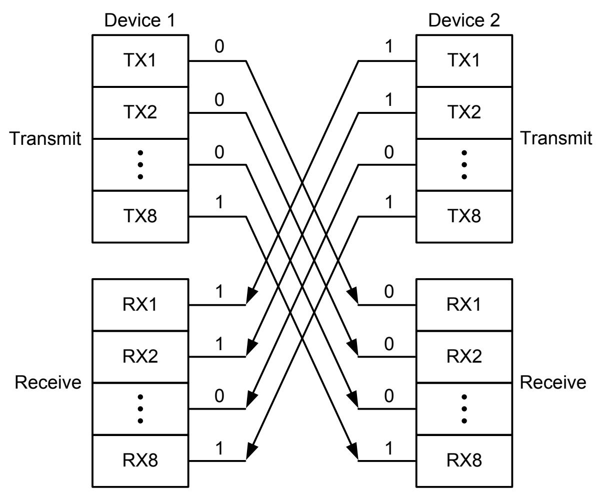

Fig. 3. High-Speed Digital Bit Communications

Each HSDB communications message consists of four bytes (characters). Each byte is made of a start bit, six data bits, one parity bit, and one or two stop bits. There are a total of nine bits per character if one stop bit is used and ten bits per character if two stop bits are used.

HSDB communications are typically used for critical power system protection applications. Received messages in HSDB protocol are checked to ensure data security. The validations for data security include the following:

- Each byte received is checked for parity, framing, and overrun errors.
- The eight received bits are each repeated three times in the four-character message per data sent and are checked for redundancy.
- The encoded ID in the message is checked against the receiving port receive ID setting. This check is for inadvertent miscabling in the field.
- The HSDB protocol ensures that at least one message is received in the time that three messages are sent.
- In order to ensure the security of the application during a communications channel failure, the protocol also employs a channel fail state setting that forces the received data bit to a desired value when the channel fails. The channel fail state value can be either 0, 1, or the Boolean value that was set prior to the channel failure.

The internal channel-okay (CH-OK) bit that measures the health of HSDB communications between two devices is set if all the security checks are good for at least two consecutive messages. Because the HSDB protocol is used for implementing a communications-assisted protection scheme, all logical decisions made in the automation controllers are verified against the CH-OK communications status indication. The bit status will be discarded in the automation controllers if the CH-OK status bit is unhealthy. The CH-OK status bit deasserts immediately when a bad message is received, and the message is rejected. For a more detailed explanation of the security and dependability of HSDB protocol, refer to [6].

III. Zone Interlocking Scheme and Bus Isolation Logic

A. *Zone Interlocking Scheme Overview*

Careful consideration should be given in selecting instantaneous and time-overcurrent elements and in coordinating main and feeder IEDs such that proper selectivity is maintained. Selectivity is achieved if only the breakers that supply the faulted power system network element trip. The remainder of the electrical system is expected to stay intact to supply power to the unaffected areas of the power system. Typically, the time-current curves for the main and feeder IEDs are set up such that they do not overlap. There is an intentional time interval between the feeder IED time-current curves and the main IED time-current curve known as a coordinating time interval. Reference [7] recommends a coordinating time interval of 0.3 to 0.4 seconds for applications similar to the one discussed in this paper.

Fig. 4 shows a typical switchgear layout at the refinery. The switchgear has two main breakers, one tie breaker, and multiple feeder breakers. The tie breaker splits the switchgear into two separate buses, Bus A and Bus B, when it is a normally open (NO) breaker. Each breaker shown in Fig. 4 is protected using an IED capable of communicating with the automation controller for logic processing using HSDB protocol.

A simple and economical ZIS, also referred to as a fast bus tripping scheme, provides reliable high-speed bus fault protection for buses that do not have bus differential protection in place [8]. Implementation of the ZIS only requires a short time delay to allow the feeder relays to block the source relays for an external fault, represented by F1 in Fig. 4. The ZIS is implemented as follows:

- The feeder relays send a blocking signal to the automation controller using HSDB protocol when a fault occurs on the feeder.
- The automation controller, using IEC 61131 logic, connects the blocking signals from all feeder relays with an OR gate and sends a blocking signal to the main relay.
- The overcurrent elements in the main relay are delayed long enough to allow the sensing of the blocking signal.

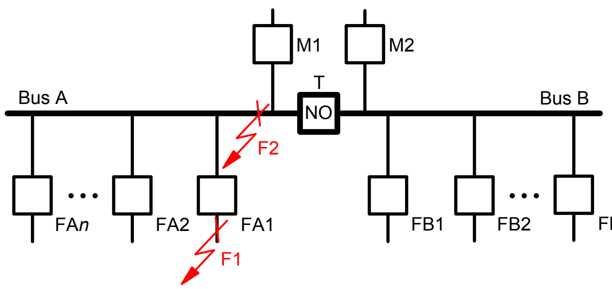

Fig. 4. Typical Switchgear Breaker Layout

The communications latency time and the automation controller processing speeds are discussed in Section V. The feeder relays are set to operate quickly with no intentional time delay. A short time delay is included in the main relay to wait for the blocking signal from the automation controller.

Fig. 5 shows the following typical communications-assisted logical data flow between the IEDs for Feeder Breaker FA1:

- The feeder relay transmits a blocking signal to the automation controller for a power system fault downstream of Feeder Breaker FA1.
- The automation controller receives the blocking signal from the feeder relay and transmits the block to the main relay as determined by the source selection scheme described later in this section.
- The fast bus block asserts in the main relay, preventing the main relay from tripping for the fault.
- If the feeder protection relay fails and the fault is not cleared by the feeder relay, a timer output asserts after a time delay equal to the normal coordinating time interval and the main relay trips.

Careful consideration should be given to prevent tripping if the blocking relay resets before the tripping relay does [9]. If feeder relays pick up momentarily because of rotating loads backfeeding an internal fault, the resulting blocking signal can slightly delay tripping. Certain loads, such as large synchronous motors, can contribute to an internal bus fault for longer periods of time, resulting in false blocking signals. Directional control elements can be used to differentiate between an internal bus fault and an external feeder fault.

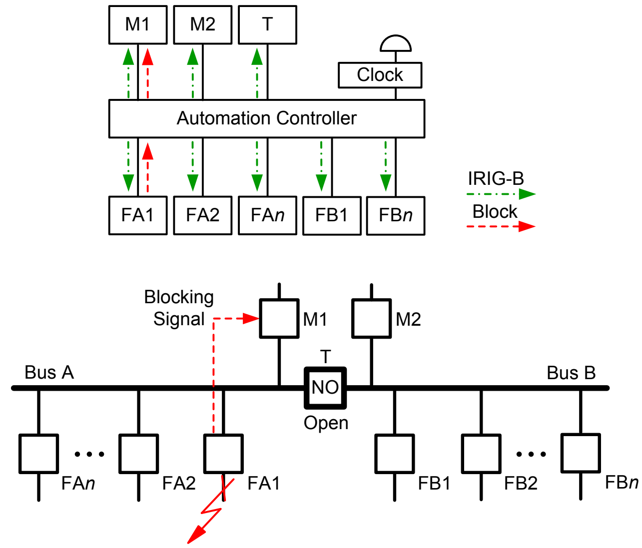

Fig. 5. Communications-Assisted Logical Data Flow for Zone Interlocking Scheme

The decision to send a blocking signal to the IED for Main Breaker M1 and other critical decisions pertaining to the operation of the ZIS are handled by a powerful and robust IEC 61131 programming environment in the firmware of the automation controllers. The IEC 61131 programming environment in the automation controllers allows the entering of custom user logic in structured text (ST), continuous function chart (CFC), and ladder diagram (LD) formats. The ST programming format was used in this project for the implementation of all the smart algorithms.

The ZIS logic is set up such that a blocking signal from the feeder breaker IED will only be sent to the IED for the main breaker that feeds power to the feeder breaker. For a fault downstream of a feeder breaker in Bus A, a blocking signal will not be sent to Tie Breaker T or Main Breaker M2 when the tie breaker is open. However, if Tie Breaker T is closed and the feeders in Bus A are fed from the source in Bus B, then the blocking signal will be sent to both Tie Breaker T and Main Breaker M2. Similarly, for a fault downstream of a feeder breaker in Bus B, a blocking signal will not be sent to Tie Breaker T or Main Breaker M1 in Bus A when the tie breaker is open. If Tie Breaker T is closed and the feeders in Bus B are fed from the source in Bus A, then the blocking signal will be sent to both Tie Breaker T and Main Breaker M1. Fig. 6 shows an overview of the ZIS blocking logic.

The entire ZIS logic depends on the HSDB protocol communications status of the protection IEDs with the automation controllers. The communications supervisory logic in the automation controllers monitors the communications quality flag of every bit of the HSDB protocol from all IEDs. The information from a particular IED is not considered valid if a bad quality flag is set for that particular IED. The bit status for an IED with bad quality is not used in the logic for processing. For example, if a feeder relay has a communications failure, then the blocking signal from that feeder relay is not processed by the automation controller to be sent to the main relay. If the blocking signal is not received for an external fault on the feeder with a communications failure, the scheme will overtrip. If the communications failure is due to a failed relay, this is considered preferable because it clears a feeder fault quickly at the cost of tripping the whole bus. The alternative is to block the whole scheme and rely on time-coordinated clearing of internal faults and faults on the feeder with the failed relay. At the cost of additional complication, logic can be added to a ZIS to provide selective fault clearing for external faults on the feeder with the failed relay and time-coordinated clearing for internal faults on the bus [8].

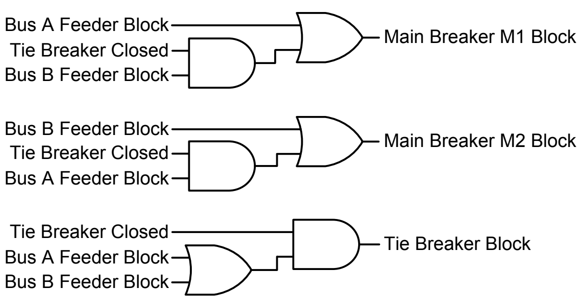

Fig. 6. Zone Interlocking Scheme Blocking Logic

Fig. 7 shows an overview of the communications supervisory logic for the Feeder Relay FA1 blocking signal and the Main Relay M1 trip signal. Similar logic is applied for signals coming from all of the relays. A common communications alarm, indicated by a light-emitting diode (LED) on the automation controller, indicates an HSDB communications failure. In the future, when the SCADA system is in place, the communications of each IED can be sent to the SCADA system.

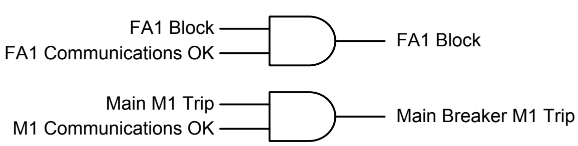

Fig. 7. Communications Supervisory Logic

B. *Bus Isolation Logic*

For the bus fault shown in Fig. 8, the IED for Main Breaker M1 detects the fault. Fast bus tripping will occur, and the IEDs for the feeder breakers will not send a blocking signal. In a typical bus protection scheme, the bus protection IED would trip the main breaker and all the associated feeder breakers to prevent any fault contributions flowing into the bus from the loads. The logic programmed in the automation controller mimics this function by executing bus isolation logic. The bus isolation logic is executed by the automation controller for a bus fault detected by the IED for the main breaker. The IED for the main breaker sends a signal to that automation controller, using the HSDB protocol, indicating that it has identified a bus fault condition. The automation controller, in turn, takes this signal and issues a bus isolation signal to all of the feeder relays. Fig. 8 and Fig. 9 show the communications-assisted logical isolation signal flow from the IED for the main breaker to the IEDs for the feeder breakers for a bus fault condition without and with the tie breaker closed, respectively.

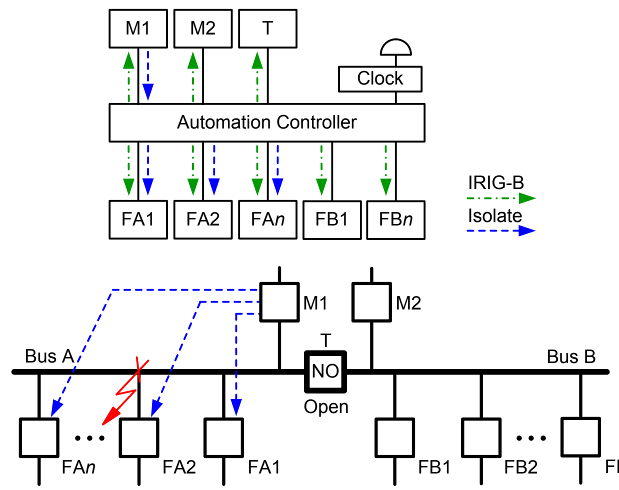

Fig. 8. Logical Isolation Signal Flow for Open Tie Breaker

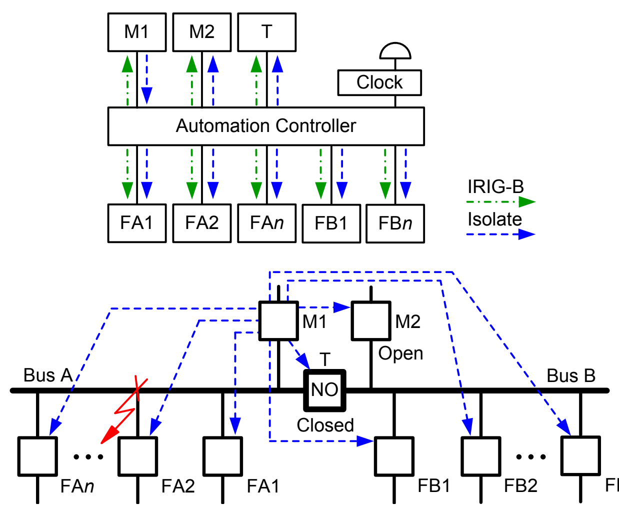

Fig. 9. Logical Isolation Signal Flow for Closed Tie Breaker

With Tie Breaker T open and the bus fault shown in Fig. 8, the IED for Main Breaker M1 sends a bus isolation signal to all of the feeder relays in Bus A. A switchgear interlocking scheme prevents all three breakers (Main Breaker M1, Main Breaker M2, and Tie Breaker T) from being closed at the same time. However, there is a brief dwell time during the close transition from one main breaker to the other when all three breakers are closed. With Tie Breaker T closed and the bus fault shown in Fig. 9, the IED for Main Breaker M1 sends a bus isolation signal to all of the feeder breakers, the tie breaker, and Main Breaker M2.

C. Source Selection Scheme

The source selection logic continuously monitors the statuses of main and tie breakers and the topology of the switchgear. The output of the source selection logic serves as an input to the ZIS logic. The statuses of the main and tie breakers are critical inputs for the functioning of the ZIS logic. The source selection logic constantly tracks the topology of the switchgear and selects the main breaker for each switchgear unit. The source selection logic then passes the present main breaker information to the ZIS.

Fig. 1 shows the power system topology of the refinery. Switchgear B can be fed through four possible sources:

- Switchgear B Main Breakers B-M1 or B-M2.
- Switchgear A Main Breaker A-M1 and Tie Breaker AB-T.
- Switchgear B Feeder Breaker B-E.

The source selection logic monitors the status of Breakers B-M1, B-M2, A-M1, and AB-T. When all of these breakers are open during the maintenance of the powerhouse switchgear, the source selection scheme sends a signal to the IED for Breaker B-E. The signals from the automation controller during these operating conditions are used in the IED settings to select a different settings group. The signal from the automation controller to the IEDs will select the appropriate settings group in the IED for Breaker B-E. The settings group will determine if Breaker B-E will act as a main breaker or a feeder breaker.

IV. Generator Islanding Detection Scheme

Fig. 1 shows the power system topology of the Valero refinery. The two on-site generators, TG-1 and TG-2, are connected to the 69 kV utility system. In the event the utility breakers trip and the tie is lost, the generators will operate as an island. The plant does not have a reliable islanding system to match load to generation, and the generation cannot support the system load. Because there is no load-shedding scheme in place at Valero, it is essential to trip the local generators faster than the utility reclose time. If the utility breakers have reclosing supervision, then a failure to trip the generators faster can result in failure of the reclose attempt. Hence, the load cannot be restored quickly. On the other hand, if there is no reclose supervision, the utility may reclose out of synchronism—resulting in generator equipment damage [10] [11].

The GID scheme designed at Valero employs a combination of local-area measurement-based islanding detection techniques. The dependable operation of a local-area measurement-based GID scheme depends on the ratio of the local load demand (P_L) to the local power generated (P_G) prior to islanding [11]. To ensure dependability of the scheme under all P_L/P_G conditions, the design includes a primary islanding detection scheme (GID-1) and a secondary islanding detection scheme (GID-2) functioning concurrently to account for all cases of P_L/P_G. GID-1 uses a frequency-based element called the fast rate of change of frequency (FROCOF), and GID-2 uses a directional power element and partial topology-based logic to detect an islanding condition. The combination of GID-1 and GID-2 results in a multiprinciple-based islanding detection technique.

Although the GID-1 and GID-2 schemes use different elements to detect an islanding condition, the trip decision is made by a unique voting algorithm developed for each scheme that was programmed in the IEC 61131 logic engine of the automation controllers. Fig. 10 and Fig. 11 show an outline of the logic involved in making an islanding decision for GID-1 and GID-2, respectively.

Because the inadvertent shedding of generation is not desirable, the voting scheme improves the security of the system by requiring multiple relays to detect and agree that an islanding condition exists before a generator trip decision is made. It checks for communications errors, equipment contingencies and outages, and dynamic power system behavior within the refinery in order to make an islanding decision.

A. GID-1 Voting Algorithm

Fig. 10a shows the GID-1 logic that is programmed in the powerhouse and Switchgear B automation controllers along with the ZIS logic. Fig. 10b shows the internal logic for the individual voting blocks in Fig. 10a.

The GID-1 scheme algorithm is built using the FROCOF element outputs from the four transformer (TR-1, TR-2, TR-3, and TR-4) IEDs and the two generator (TG-1 and TG-2) IEDs. When Valero is islanded from the utility, the real power mismatch between the load and the local generation is substantial, resulting in a P_L/P_G ratio much greater than 1. This causes the frequency to drop below nominal. The FROCOF element uses the frequency deviation from nominal and the rate at which the frequency deviates to detect an islanding condition. Reference [10] discusses the characteristic of this element.

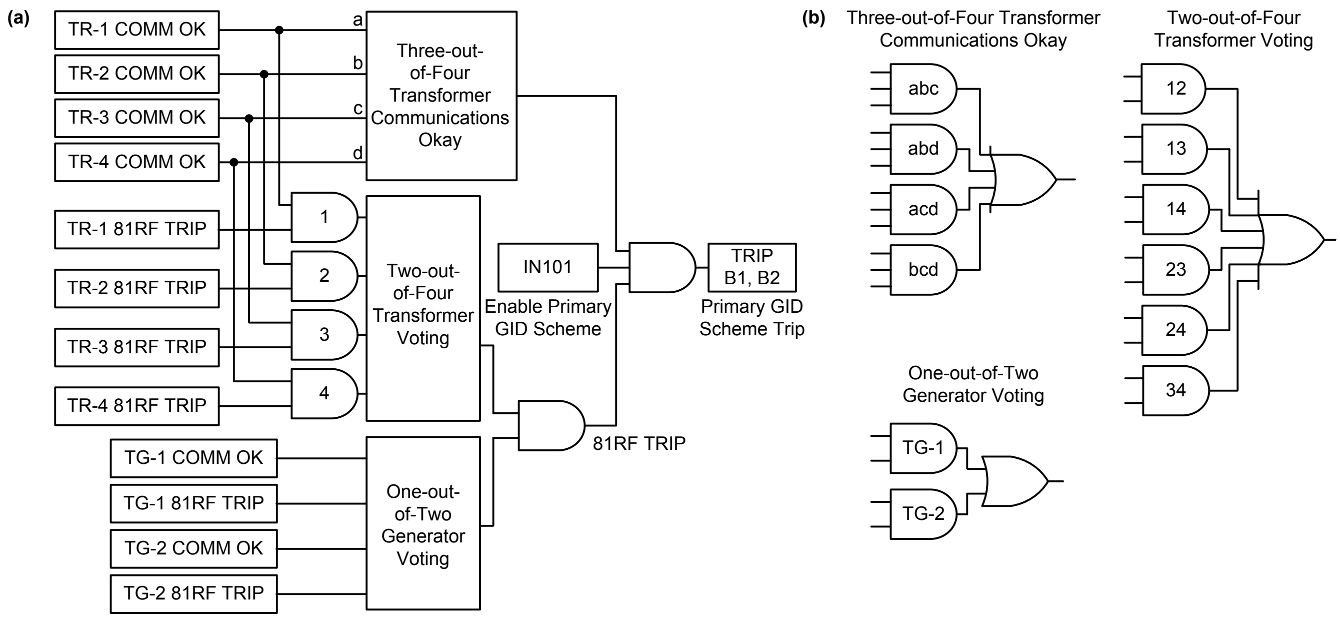

Fig. 10. GID-1: Overall Logic (a) and Expansion of Individual Voting Logic Blocks (b)

The automation controllers receive the outputs of these FROCOF elements using the HSDB protocol. The information received from the IEDs is checked for validity by supervising it with the CH-OK bit. The resultants of the supervised bits are run through the GID-1 voting logic processor to make an islanding decision. The philosophy behind the number of votes required to make a successful decision is based on power system dynamics and the probability of both communications errors and equipment outages at any given time. So for a GID-1 trip to occur per Fig. 10, the following must occur:

- The GID-1 scheme must be enabled.
- Three out of four communications channels from the transformer IEDs must be OK. This ensures that a single channel failure will not interfere with the GID-1 decision making.
- Any one generator IED must detect an islanding condition based on the FROCOF element. This ensures that the scheme will trip during an islanding event when at least a single generator is online.
- Two out of the four transformer IEDs must detect an islanding condition based on the FROCOF element. The two-out-of-four transformer voting accounts for one transformer outage along with a simultaneous communications channel failure between another transformer IED and the automation controller.

The purpose of the voting algorithm is to make sure that all possible contingencies, errors, and dynamics of the overall power system of the refinery are properly accounted for before making a GID trip decision. When GID-1 makes an islanding decision, the trip signal is transmitted via the HSDB protocol to the TG-1 and TG-2 generator IEDs to trip the corresponding generator breakers.

B. *GID-2 Voting Algorithm*

Fig. 11a shows the GID-2 logic implemented in the powerhouse automation controller, and Fig. 11b shows the internal logic for the individual voting blocks in Fig. 11a. This logic uses a voting algorithm similar to that of GID-1 except that it uses the outputs of the directional power elements from the four transformer IEDs that are sent through the GID-2 voting logic processor. When GID-2 makes an islanding decision, it transmits the trip decision to the IEDs controlling all of the 12.5 kV breakers in the powerhouse of the refinery (shown in Fig. 1). This includes the breakers associated with TG-1, TG-2, and the powerhouse bus feeders (not shown in Fig. 1). The reason behind GID-2 tripping the feeder breakers is to account for a TG-1 or TG-2 generator breaker failure condition when either one of the breakers fail after a GID-1 trip has been issued. The directional power elements in the individual transformer IEDs that control the output of the GID-2 logic have a short intentional time delay for this purpose. If one of the generator breakers fails to trip due to a GID-1 trip, the GID-2 logic will detect this condition and then trip all of the feeder breakers associated with the powerhouse bus.

As shown in Fig. 11a, for a transformer IED to contribute its vote toward an islanding decision, the following must be true:

- The transformer must be connected to the utility. This is confirmed by the 52A status of the low-side circuit breaker shown in Fig. 1.

- The directional power element output must be asserted.
- The validity of the HSDB communications between the individual IED and the automation controller must be good.

In order for a GID-2 trip to occur, the following conditions must be true:

- The GID-2 scheme must be enabled.
- Either of the generator breakers must be in service. This accounts for the fact that one of the generators is online during the island or that the breaker failed after an islanding trip by GID-1 was previously issued.
- Three out of four transformer IEDs must detect an islanding condition based on the directional power element, or all four transformer low-side breakers must be open (with one of the generators in service).

The decision to consider three-out-of-four transformer votes toward the islanding decision, as shown in Fig. 11a, is based on the different possible power flow scenarios around the loop during an islanding event. Based on the Valero refinery topology, when the facility is islanded with the generators online, the direction of power seen by the transformer IEDs should ideally be in the direction of export toward the utility. In other words, the transformer IEDs will see a reverse power flow. However, due to the looped network arrangement of the facility with respect to the two utility sources and the two 69 kV substations, one transformer may see the power flow inward toward the facility during an islanding event. This scenario is accounted for by the three-out-of-four voting logic.

In addition to the directional power-based islanding detection, GID-2 also employs a partial topology-based scheme that uses the breaker statuses of the transformer low-side breakers to detect an islanding condition.

Both GID-1 and GID-2 are enabled or disabled using a toggle switch input to the automation controller contact inputs, IN101 in Fig. 10 and IN201 in Fig. 11. In the future, Valero will include controls from SCADA to mimic the functionality of the existing hard-wired contact inputs. For redundancy, the GID-1 logic is also implemented in a backup automation controller located at Switchgear B and will send the trip signals via HSDB protocol to the IEDs that control the TG-1 and TG-2 breakers. The two functionally equivalent redundant automation controllers executing the GID scheme are set up in a hot-hot dual-redundant fashion. However, due to the limitations of serial fiber, the GID-2 scheme is not included in the Switchgear B controller. Therefore, scheme redundancy is provided by both the GID-1 and GID-2 schemes programmed in the powerhouse automation controller, and equipment redundancy (in the event of a failure of the powerhouse controller) is provided by a secondary automation controller located at Switchgear B.

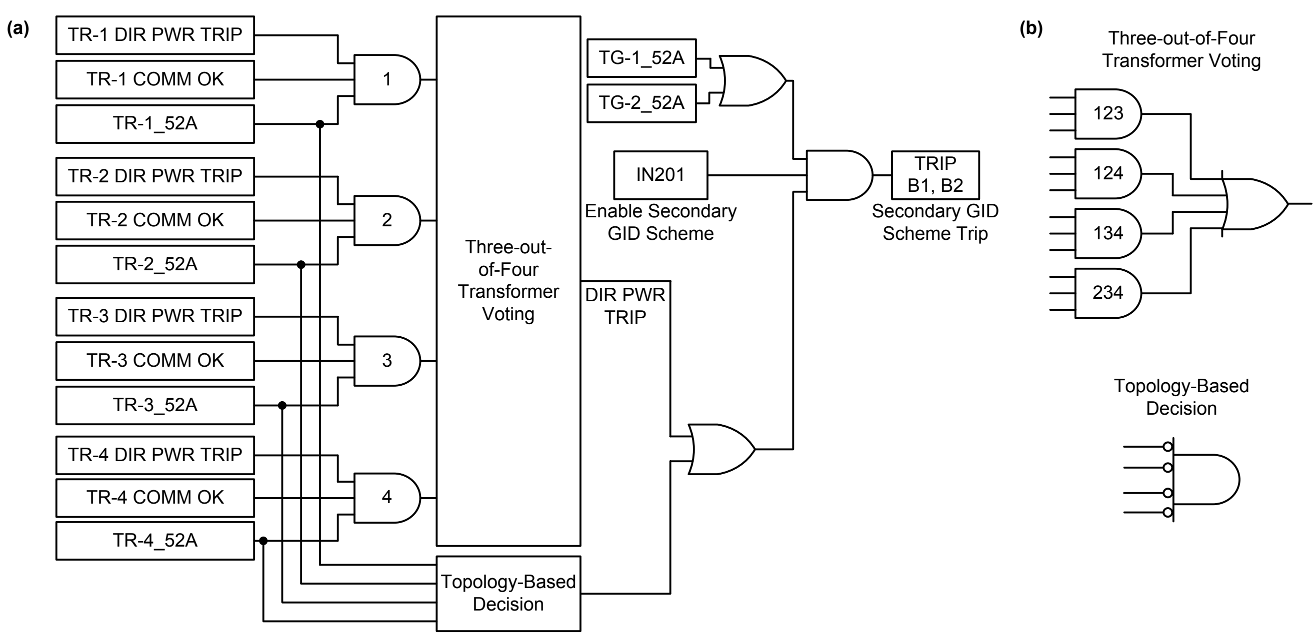

Fig. 11. GID-2: Overall Logic (a) and Expansion of Individual Voting Logic Blocks (b)

V. Managing the Automation Controllers for Optimal Performance

As mentioned in the previous section, the GID scheme must be quicker than the reclosing time intervals of the utility transmission line breakers in order to prevent equipment damage due to a possible out-of-synchronism close [12]. The ZIS and the source selection scheme must also be fast enough to isolate faults selectively. Therefore, a critical consideration during the design of this protection system for Valero was the processing time of the automation controllers.

As mentioned previously, the scheme chosen for GID was based on local-area measurements. Local-area-based islanding detection using FROCOF elements has been observed to have a much faster response compared with conventional generator protection elements or wide-area-based schemes [10] [12], especially when the P_L/P_G active power ratio is in the range of $0.8 > (P_L/P_G) > 1.3$ [11], which is typical of the case with Valero. In order for the scheme to be faster as described in [10] [12], the processing time and therefore the latency introduced into the overall scheme operation time due to the automation controllers, are critical [10] [12]. Also, Valero wanted controllers that are capable of processing high-speed protection functions separately and independently of relatively low-speed, noncritical functions like SCADA.

Automation controller processing time is dependent on the programming burden of the controller. A higher number of connected devices and larger blocks of programming mean more codes to process per task cycle before a subsequent task cycle can be processed. A higher programming burden can introduce additional latency in processing an entire cycle of codes, devices, and communications protocols. In order to achieve high performance and separate critical and noncritical task processing, an automation controller with parallel task processing capabilities was chosen. It uses two separate processing task cycles, a main task cycle and an automation task cycle. The automation controller executes individual tasks at every task cycle time interval to which they are assigned. A task in an automation controller can be any special logic like GID or ZIS or SCADA data gathering required for the operation of the system. The two task cycles run independent of each other, and information from either task cycle can always be cross-referenced.

The automation task cycle time interval is used for tasks that are required to be executed at protection speed. The GID, ZIS, source selection scheme, and HSDB protocol communications to the IEDs are processed using a high-speed automation task cycle time interval. On the other hand, slow-speed, noncritical, Ethernet-based SCADA communications are processed using a slower main task cycle time interval. By separating the critical tasks from noncritical tasks, the programs and functions that need to be processed per task cycle are reduced and the processing burden is shared by the two individual parallel task cycles.

HSDB protocol communications between the automation controllers and the IEDs are set up to be transmitted and received at a rate of 38,400 bps. The speed at which the smart algorithm decisions are made and the data time delay incurred in using HSDB protocol between communications devices depend on the following delays:

- The processing interval of the transmitting IED.
- The data transmission delay from the transmitting IED to the automation controller.
- The logic processing interval of the automation controller.
- The data transmission delay from the automation controller to the receiving IED.
- The processing interval of the receiving IED.

Table I summarizes the estimated back-to-back two-way data delay time measured from the time TX is asserted in one IED to the time the corresponding RX is received and processed in the other IED.

Table I
Smart Algorithm Timing

Action	Delay (ms)
Typical delay of 0.25-cycle processing interval at transmission devices	<5
HSDB message latency (from transmitting IED to automation controller)	<2
Automation controller update	<4
HSDB message latency (from automation controller to receiving IED)	<2
Typical delay of 0.25-cycle processing interval at receiving devices	<5
Total	**18**

With a high-speed peer-to-peer communications protocol and the near instantaneous processing time of the automation controller capabilities, a high-speed response is obtained for all of the protection schemes (ZIS and GID) implemented at Valero.

VI. Conclusion

This paper discusses a practical example of an integration scheme that employs multiple high-speed communications-assisted protection schemes in automation controllers. Listed below are some key considerations from the paper:

- Using modern microprocessor-based IEDs and automation controllers, communications-assisted protection schemes were designed that greatly reduced the use of copper conductors and wiring.

- The scheme uses an EIA-232 interface for protection-speed peer-to-peer communications and an Ethernet interface for a future SCADA system. The Ethernet network provides for easy future expansion of the integration system.
- A fast, reliable, and secure HSDB protocol was employed to be used over the serial connection. The advantage of serial-based communications is that they are capable of distributing IRIG-B time signals to the IEDs, maintaining accuracy of the time signals and synchronizing all of the IED internal clocks to the satellite clock time.
- The ZIS provides a high-speed tripping for bus faults. It achieves selectivity by blocking tripping of the incoming source for a feeder fault. The source selection logic dynamically tracks the topology of the switchgear and delegates the incoming source information as an input for the ZIS algorithm.
- The GID scheme uses local-area-based measurements for detecting an islanding condition. Scheme redundancy is provided by implementing both GID-1 and GID-2 schemes. As discussed in Section IV, a voting algorithm was developed to ensure the secure operation of the scheme.
- Automation controllers with parallel task processing capability were chosen. All critical protection logic is implemented using a high-speed automation task cycle time interval. Noncritical SCADA data will be collected using a slower task cycle time interval.
- The schemes are easy to modify without additional equipment and wiring requirements.

VII. References

[1] J. J. Novak Jr. and R. D. Kirby, "Better, Faster, and More Economical Integrated Protective Relaying and Control Using Digital Bits and Logic," proceedings of the 55th Annual Petroleum and Chemical Industry Technical Conference, Cincinnati, OH, September 2008.

[2] A. Kulkarni, J. Payne, and P. Mistretta, "Integrating SCADA, Load Shedding, and High-Speed Controls on an Ethernet Network at a North American Refinery," proceedings of the 60th Annual Petroleum and Chemical Industry Technical Conference, Chicago, IL, September 2013.

[3] G. Scheer, "Comparison of Fiber-Optic Star and Ring Topologies for Electric Power Substation Communications," proceedings of the 1st Annual Western Power Delivery Automation Conference, Spokane, WA, April 1999.

[4] IEEE Standard 802.1Q-2011, IEEE Standard for Local and Metropolitan Area Networks – Media Access Control (MAC) Bridges and Virtual Bridged Local Area Networks.

[5] M. Gugerty, R. Jenkins, and D. J. Dolezilek, "Case Study Comparison of Serial and Ethernet Digital Communications Technologies for Transfer of Relay Quantities," proceedings of the 33rd Annual Western Protective Relay Conference, Spokane, WA, October 2006.

[6] K. C. Behrendt, "Relay-to-Relay Digital Logic Communication for Line Protection, Monitoring, and Control," proceedings of the 23rd Annual Western Protective Relay Conference, Spokane, WA, October 1996.

[7] IEEE Standard 242-2001, Recommended Practice for Protection and Coordination of Industrial and Commercial Power Systems.

[8] H. J. Altuve Ferrer and E. O. Schweitzer, III (eds.), *Modern Solutions for Protection, Control, and Monitoring of Electric Power Systems*. Schweitzer Engineering Laboratories, Inc., Pullman, WA, 2010.

[9] S. Bricombe, G. Lewis, and M. Thompson, "Stanford University, Palou Substation Modernization Project," proceedings of the 31st Annual Western Protective Relay Conference, Spokane, WA, October 2004.

[10] D. Salmon, M. Zeller, A. Guzmán, V. Mynam, and M. Donolo, "Mitigating the Aurora Vulnerability With Existing Technology," proceedings of the 36th Annual Western Protective Relay Conference, Spokane, WA, October 2009.

[11] J. Mulhausen, J. Schaefer, M. Mynam, A. Guzmán, and M. Donolo, "Anti-Islanding Today, Successful Islanding in the Future," proceedings of the 63rd Annual Conference for Protective Relay Engineers, College Station, TX, March 2010.

[12] G. Dalke, A. Baum, B. Bailey, J. M. Daley, B. Duncan, J. Fischer, E. Hesla, R. Hoerauf, B. Hornbarger, W. Lee, D. J. Love, D. Mccullough, C. Mozina, N. Nichols, L. Padden, S. Patel, A. Pierce, P. Pillai, G. Poletto, R. Rifaat, M. K. Sanders, J. M. Shelton, T. N. Stringer, J. Weber, A. Wu, R. Young, and L. Powell, "Application of Islanding Protection for Industrial and Commercial Generators – An IEEE Industrial Application Society Working Group Report," proceedings of the 59th Annual Conference for Protective Relay Engineers, College Station, TX, April 2006.

VIII. Biographies

Faridul Katha Basha received his BE in electrical engineering from Anna University, India, in 2008 and an MSEE in power systems from the State University of New York at Buffalo in 2011. Since his graduation, he has been employed with Schweitzer Engineering Laboratories, Inc. as a protection engineer. Faridul is also a registered professional engineer. His expertise includes protection and automation engineering for utilities and industries. He has more than two years of experience in protection design, fault studies, and relay settings.

Ramanathan Palaniappan received his bachelor's and master's degrees in electrical engineering from Madurai Kamaraj University, India, in 2001 and Illinois Institute of Technology, Chicago, in 2008, respectively. He joined Schweitzer Engineering Laboratories, Inc. (SEL) in 2010 and is presently a protection application engineer. His areas of interest are power system protection and analysis. Prior to joining SEL, he was with S&C Electric Company as a design engineer in the power system services division. He is a member of IEEE.

Ashok Balasubramanian received his BE degree in electrical and electronics engineering from the University of Madras, India, in 2004 and an MS in power systems from the University of Alaska, Fairbanks, in 2006. Upon graduation, he worked in the process automation industry in Alaska for more than three years, where he worked on process automation projects and gained experience integrating programmable logic controllers with microprocessor-based protective relays. He joined Schweitzer Engineering Laboratories, Inc. in January 2010 and is currently an automation engineer in the engineering services division.

RadhaKiranMaye Anne received a BE in electrical and electronics engineering from Andhra University, India, in 2001; an ME in electrical engineering from Osmania University, India, in 2003; and an MS in electrical engineering from the University of Missouri, Kansas City, in 2008. She joined Schweitzer Engineering Laboratories, Inc. in 2009. Her expertise includes protection scheme design, power system modeling, transmission line protection, and relay coordination studies. She has more than three years of teaching experience and is a member of IEEE.

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 the 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.

Kent L. Oliver received a BS in electrical engineering from Kansas State University in 1990. He worked for 10 years in an industrial chemical facility as a manager of instrument and electrical projects as well as manager of the facility instrument and electrical maintenance teams. He has worked the last 13 years for Valero Bill Greehey Refineries as manager of all power system projects, including multiple process unit additions and a complete electrical infrastructure replacement for a second refinery.

Previously presented at the 51st Annual Industrial & Commercial Power Systems Technical Conference, Calgary, Canada, May 2015.

20150220 • TP6652-01