Better, Faster, and More Economical Integrated Protective Relaying and Control Using Digital Bits and Logic

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BETTER, FASTER, AND MORE ECONOMICAL INTEGRATED PROTECTIVE RELAYING AND CONTROL USING DIGITAL BITS AND LOGIC

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Abstract—Improvements in protection and control via communications methods used to exchange digital bits among devices are common in progressive utilities in high-voltage substations [1]. These improvements are now being incorporated into the process-sensitive electric power distribution systems of large industrial plants. Until now, new equipment purchases for new projects in industrial facilities using microprocessor (µP) multifunction protective relaying technology were typically done as a direct replacement of older technologies or as an updated equivalent. This paper describes a recently commissioned electrical substation design philosophy, including implementation, construction, maintenance, and performance with µP-based protective relaying, metering, and control schemes. These schemes extensively utilize the interdevice digital bits exchange and programmable logic capabilities of time-synchronized µP technology.

Index Terms—microprocessor multifunction protective relaying, interdevice digital bits, logic, integrated, transfer tripping, relay maintenance, documentation, lockout, portable building.

I. INTRODUCTION

The design of an industrial plant's electric power system protection, metering, monitoring, and control using integration technologies has been improving since the advent of µP-based devices and the availability of fiber-optic cables. µP relays include many auxiliary functions beyond their primary function of power system protection. With integration technologies applied, modern protective relays can provide many required substation features, including local and remote metering, local and remote control and status reporting, alarm functions, annunciation, interlocking, event oscillography, SER (Sequential Events Recorder) recording, and automatic control systems. A power system cannot be operated without protection; thus, protective relays are the basis for an integrated substation.

The operational benefits of µP relays over electromechanical and solid-state technology are documented in [2]. The most significant benefit is the ability to provide oscillographic data reports and SER reports that can be visualized and studied with the aid of graphical PC software tools. These reports and tools can be used to operate and maintain as well as continually improve the system's performance.

The first reason for the rapid adoption of µP technology is the inherent and constantly improving processing and communications technologies, which provide the basis for fully integrated µP relaying-based solutions. Technical papers such as [3], [4], [5], [6], and [7] illustrate the popularity of these solutions. The second reason for rapid adoption is the lower initial and ownership costs of µP IEDs over EMRs (electromechanical relays), as summarized in [2]. The lower initial cost is due to the lower cost of the components used, the manufacturing equipment required, and better fabrication techniques. Applying concepts used for protection system design to develop control schemes in µP relays creates a fault-tolerant, robust protection and control system with fewer components and less wiring [8].

The recently constructed integrated substation project described in this paper is inside a large integrated chemical manufacturing complex, located in the western United States. The approach taken in designing this substation's protection, metering, and control systems was to fully utilize the technologies available in µP relays without drastically changing the existing protection, control, and monitoring philosophy. The computing power of the µP relay allows the same power system analog measurements (currents and voltages) to be used in multiple protective function elements, metering elements, SER recording, oscillographic data recording, and control function calculations at the same time in a single µP device without reducing performance. The selected µP relays' embedded technology and interdevice communications eliminate the need for physical LORs (lockout relays), auxiliary relays, control switches, selector switches, transducers, meters, and annunciators. The elimination of these devices significantly simplified the wiring and reduced the long-term costs associated with maintenance.

This paper explores why and how an untraditional integrated system (shown in Fig. 1) was selected and designed to provide the desired functionality of a traditional protective relaying, control, and metering scheme that is more digital with less wiring and fewer devices. The typical perception of added complexity is due to unfamiliarity with the new technology and a lack of design documentation [8]. Rather than decreasing reliability, the solution described in this paper may actually enhance overall reliability. Future modifications to add functionality, enable protection elements, and create or modify programmable logic in the IEDs can be done without additional devices and wiring. This technology shift means that most of the protection, control, and metering system consists of algorithms and logic inside the µP relay, requiring more attention be paid to the µP relay's programming. Furthermore, engineers need to be able to make the transition from developing wired ladder logic schemes to digital logic schemes and then program the µP device using PC-based software tools.

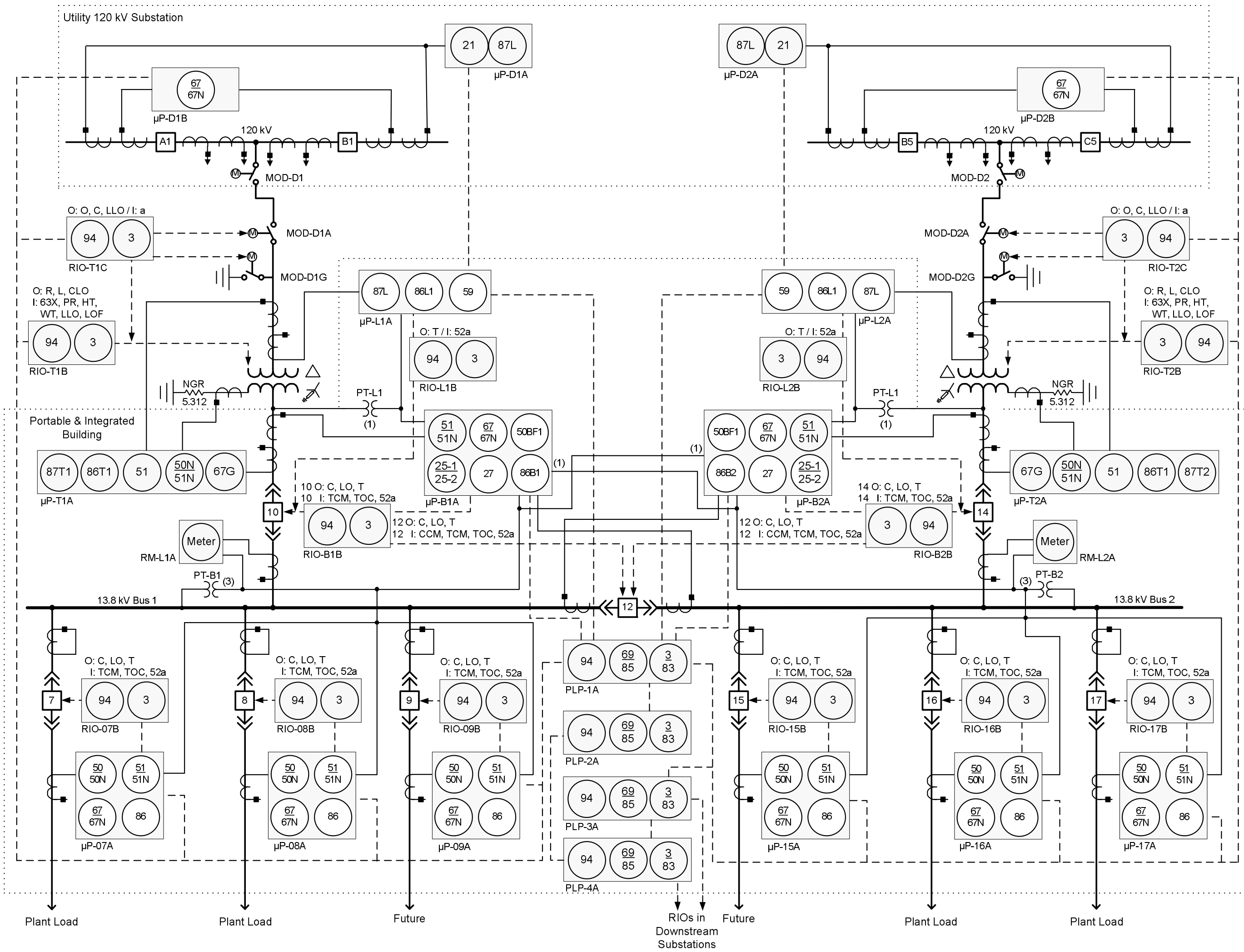

Fig. 1 Substation Partial Relay One-Line Diagram

II. GLOSSARY

The following abbreviations, acronyms, and terms are used in this paper.

CLK – Clock, a satellite-synchronized device that is the source of high-accuracy time information.

CT – Current transformer.

DB – Digital bit, a microprocessor relay register result. A digital bit can equal either logical 1 or logical 0. Logical 1 represents a true logic condition, picked-up relay element, or asserted control input or output. Logical 0 represents a false logic condition, dropped-out element, or deasserted control input or output.

EMR – Electromechanical relay.

Event oscillography – A text-based collection of analog and digital data stored by the microprocessor relay in response to a triggering condition, such as a fault. The data show relay measurements before and after the trigger, in addition to the states of protection elements, relay inputs, and relay outputs at each processing interval. After an electrical system fault, users use event reports to analyze relay and power system performance.

HMI – Human-machine interface.

IED – Intelligent electronic device.

IRIG-B – A time code input that the microprocessor relay can use to set the internal relay clock.

LED – Light-emitting diode.

LOR – Lockout relay.

MOD – Motor-operated disconnect switch.

SDP – Substation data processor, used to concentrate data, translate protocols, and provide enterprise connectivity for SCADA and substation integration.

SER – Sequential Events Recorder report of the latest sequential events. The SER report contains the last 512 or 1,000 entries, including settings changes, power-ups, and selectable logic elements.

SFC – Serial-to-fiber converter, used to convert from a EIA-232 port to a fiber-optic port, in order to enable transmitting and receiving serial data between a microprocessor relay or a protection logic processor and a remote input and output device or another SFC.

SPC – Substation personal computer designed for rugged and harsh industrial environments.

PLP – Protection logic processor, used to receive, process, and transmit device status and remote DB system information using a DB-based serial communications protocol. Received DBs can be used in user-programmed Boolean equations and timers or passed through to another IED to implement an advanced protection and control scheme.

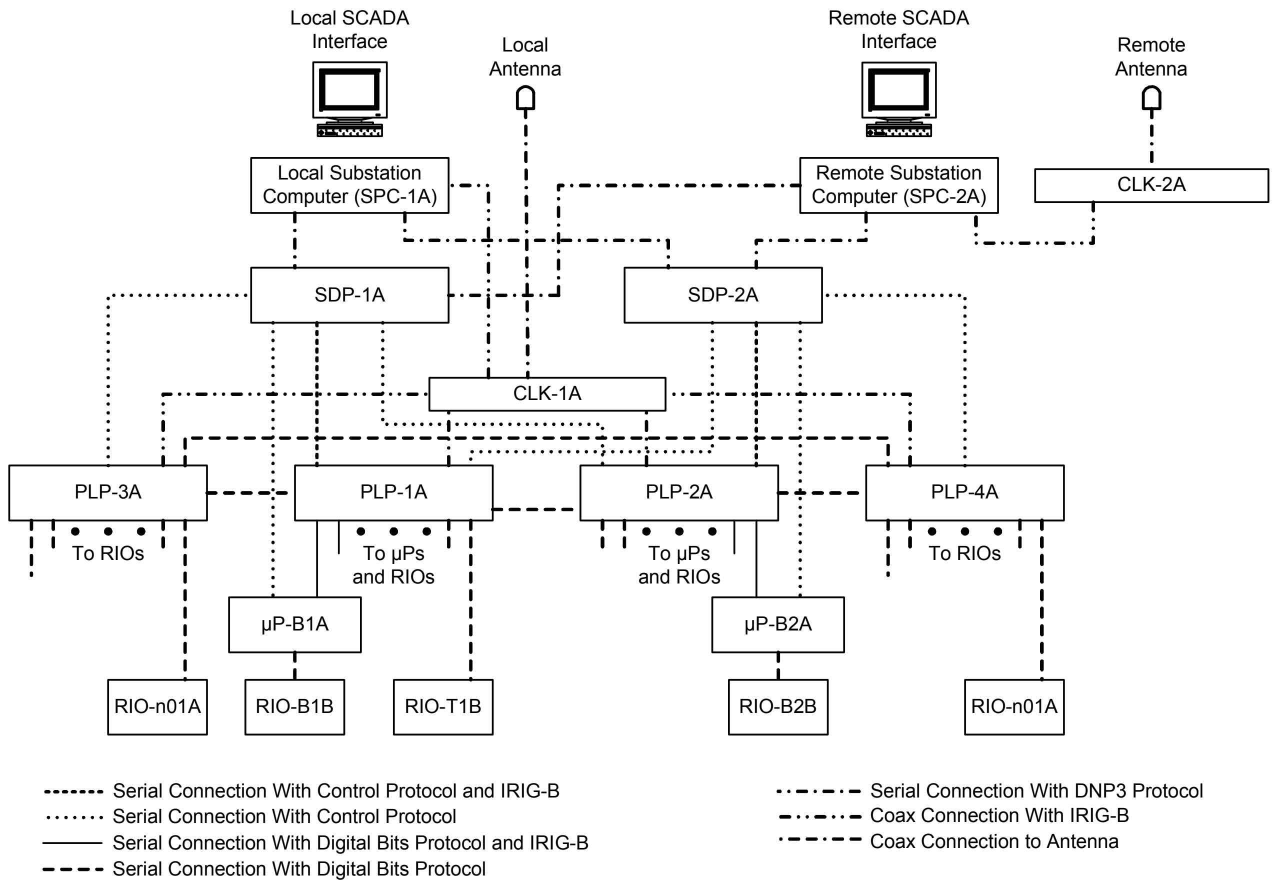

Fig. 2 Overall Communications Diagram

PRCM – Protective relaying, control, and metering.

PT – Potential transformer. Also referred to as a voltage transformer (VT).

RIO – Remote input and output device that uses a DB-based serial communications protocol.

ROK – The digital status bit that indicates the communications channel is healthy and operational. This DB confirms that a DB serial communications port of a microprocessor device is receiving valid DB data from the remote device. ROK deasserts the instant the IED detects any transmission error or any time the IED detects that it has not received a DB message in the time required to transmit three DB messages. The local ROK also deasserts if the remote IED detects an error. Typically, the inverse (not) of ROK is used to create a digital alarm bit to alert operations of an interdevice communications failure.

µP – Microprocessor. A microprocessor is a programmable digital electronic component that has a central processing unit. In this paper, microprocessor is used in reference to the application of microprocessor-based multifunction protective relaying, control, and metering technology.

III. HIGH-VOLTAGE LINE PROTECTION AND CONTROL

A. Protection

As shown in Fig. 1, this substation is supplied from a utility high-voltage (120 kV) substation facility (located several miles from this medium-voltage station), where the transmission lines are connected to two different breaker-and-a-half bays. Differential (87L) elements provide the primary protection for each transmission line. These elements are embedded in line current differential relays (µP-D1A and µP-L1A or µP-D2A and µP-L2A) that trip and lock out their associated breakers and are located on each end of each transmission line. A Zone 2 mho impedance element, located in the upstream relays (µP-D1A and µP-D2A), provides backup protection for each transmission line and transformer. Also providing backup protection are phase and ground directional overcurrent (instantaneous and time-delayed) (67/67N) elements. These elements are embedded upstream on each transmission line in an overcurrent relay (µP-D1B or µP-D2B), which trips and locks out its associated breakers directly and transfer-trips the downstream breaker via interdevice DBs. The line relays will also initiate a fast motor bus transfer on the associated medium-voltage bus via interdevice DBs.

As discussed in detail in [5] and shown in Fig. 2, the intelligent PLP with associated RIOs and µP relays is utilized to route DBs via serial wire or fiber communications cables at protection speeds between IEDs. The PLP solves Boolean DB logic at high speed (time critical) using a secure, dependable, protection-orientated protocol to create supervised communications protection and control. This supervised communication prevents “false” signals and communications outages from causing false trips or false blocks. Latching DB logic is used to trip and lock out circuit breakers digitally.

B. Controls

Each transmission line has two MODs, one located on each end of the line. These MODs are interlocked via interdevice DBs between the upstream line differential relays and the medium-voltage bus relays. A redundant interlock is routed between the upstream overcurrent relays and the downstream

PLPs (PLP-1A and PLP-2A). The upstream MODs are wired directly to existing control panels and are interlocked via wires to the two associated high-voltage breakers. The MODs located downstream on each transmission line, as well as the motor-operated grounding switches located on the lines between the downstream MOD and the transformer, are interlocked via internal logic in the medium-voltage bus relays. The downstream MODs (-D1A and -D2A) and ground switches (-D1G and -D2G) are capable of being operated locally via pushbuttons at the motor operator of each disconnect switch or remotely via the HMI. The remote MOD controls and interlocks are routed via interdevice DBs from the PLPs to RIOs located in the transformers where the MOD control wires are connected. As diagramed in Fig. 2, this method of digital control and interlocks moves the configuration of the control circuits from physical wiring to logic within the PLPs and RIOs, thus eliminating a significant amount of control wiring and simplifying the dc control circuits.

IV. TRANSFORMER PROTECTION AND CONTROL

A. Protection

This substation's two transformers are supplied from two high-voltage (120 kV) transmission lines. The sudden pressure relay (SPR) as well as the percent restraint differential (87T) elements and the restricted earth fault (REF) (67G) element, embedded in the single transformer differential relay connected to each transformer, provide the primary protection for each transformer. Backup protection for each transformer is located in the upstream relays, as previously mentioned in Section III. A backup protection (51N) element in each transformer differential relay provides protection for the low-side neutral and its resistor. When a trip output from these elements is routed via wiring to the adjacent line differential relays, the line relays will trip and lock out the two high-voltage upstream breakers (A1 and B1 or B5 and C5) and the medium-voltage downstream breaker (10 or 14). The SPRs will also trip and lock out these breakers using DBs routed from the RIOs located in the transformers (RIO-T1B or RIO-T2B) through the PLPs (PLP-1A or PLP-2A) directly to the upstream line over-current relays (µP-D1B or µP-D2B) and redundantly through the line differential relays (µP-L1A and µP-D1A or µP-L2A and µP-D2A). The transformer relays and SPRs will also initiate a fast motor bus transfer on the associated medium-voltage bus via the line differential relays and interdevice DBs.

The transformer differential relays provide time-coordinated overcurrent backup bus protection if the medium-voltage bus main relay fails. The associated line differential relay monitors the medium-voltage bus relay failure via interdevice DBs and enables the transformer differential relay's overcurrent (51/51N of µP-T1A and µP-T2A) elements through control wires. When a trip output from these elements is routed back to the line differential relay via wiring, the line relay will trip and lock out the medium-voltage downstream breaker (10 or 14) via interdevice DBs.

Through the use of control wiring, the DB-capable line differential relays µP-L1A and µP-L2A are integrated with transformer differential relays µP-T1A and µP-T2A, which are not DB capable.

B. Controls

Each transformer's tap-changer control and alarm logic is embedded in the medium-voltage bus relays, which enable both manual and automatic operation. Automatic selection disables all manual tap-changer operations and enables automatic control features, including voltage control on the medium-voltage bus, and a voltage-initiated close-transition bus transfer. Manual operation disables all automatic operations and can be performed locally via the user-controlled pushbuttons or remotely via the HMI. The local controls utilize four µP relay pushbuttons: {AUTO/MANUAL}, {REMOTE/LOCAL}, {RAISE}, and {LOWER}. The transformer tap-changer controls and alarms are routed via interdevice DBs between the medium-voltage bus relays and the RIO devices located in the transformers where the tap-changer control wires and alarms are connected. This moves the configuration of the transformer's tap-changer control circuitry from physical wiring to µP logic, thus eliminating control wiring and again simplifying the dc control circuits. The transformer's tap-position indication (mA signal) is routed via wires from the transformers to the medium-voltage line meters, where it is locally displayed and then digitally routed to the HMI for remote display.

Automatic load tap-changer (LTC) logic was implemented in the µP-B1A and µP-B2A for each power transformer. However, the detailed user-programmed automatic LTC logic scheme in a µP relay is beyond the scope of this paper.

V. MEDIUM-VOLTAGE BUS PROTECTION AND CONTROL

A. Protection

This substation's two medium-voltage (13.8 kV) buses are supplied from the two transformers. The primary protection of each medium-voltage bus is a communications-based enhanced directional overcurrent blocking (DCB) scheme (also called zone interlocking or fast bus tripping) between the medium-voltage bus relays and their associated feeder relays. Each of the bus relays and feeder (downstream) relays has directional instantaneous overcurrent (67/67N) embedded elements enabled.

The bus relay's 67/67N tripping elements are supervised by an embedded two-cycle, pickup-delay timer plus any associated feeder relay's 67/67N blocking elements, which are received via interdevice DBs in the DCB scheme. If the bus relay's instantaneous overcurrent trip elements pick up and are not blocked by a DB from a feeder relay within 2 cycles (see last row of TABLE I that shows the delay must be at least 1.125 cycles), the bus relay will directly trip and lock out the main and tie breaker via the RIO, as shown in Fig. 3. The bus relay will also trip and lock out the associated feeder breakers via interdevice DBs and RIOs.

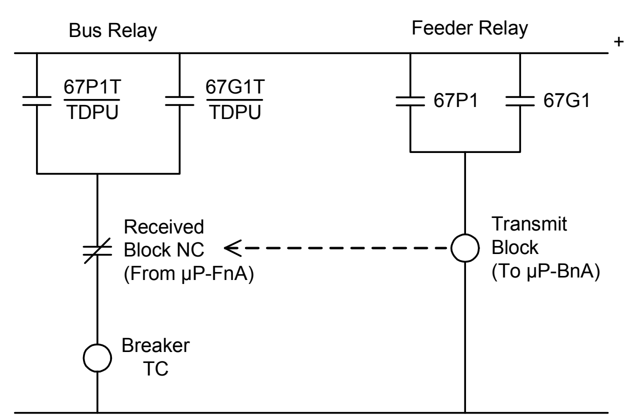

Fig. 3 Control Circuit Representation of Bus DCB Logic Scheme

This bus DCB scheme eliminated the need for bus differential CTs on every feeder position. The overcurrent (51/51N) elements embedded in the medium-voltage bus relays serve as the backup protection for each medium-voltage bus. These relays are connected in a partial differential scheme. This arrangement offers improved metering because relays µP-B1A and µP-B2A have dual three-phase CT inputs to provide summed (bus) and individual input meter data. If the bus relay's overcurrent (51/51N) elements pick up and time out, the bus relay will directly trip and lock out the main and tie breakers via the RIO and the associated feeder breakers via interdevice DBs. These settings are coordinated with the feeder relay overcurrent (51/51N) elements.

B. Digital Bits

As shown in Fig. 4 and Fig. 5, the PLP uses EIA-232 serial ports to communicate with the other IEDs (µP relay or RIO) in the system. In this case, µP-B1A, µP-07A, µP-08A, and µP-09A are used for the DCB protection scheme. Approximately 0.33 cycles or 5.5 ms of speed is sacrificed when using the RIO device instead of using the µP relay's built-in I/O. Fiber-optic communication is the best choice for the DB data transmission between the PLP, µP relay, and RIO when longer distances are involved because it is impervious to electromagnetic interference (EMI) and radio frequency interference (RFI). SFCs provide the fiber-optic inter-IED communications channels interface. SFCs are selected depending on the application, transmission distance, and fiber connector type required.

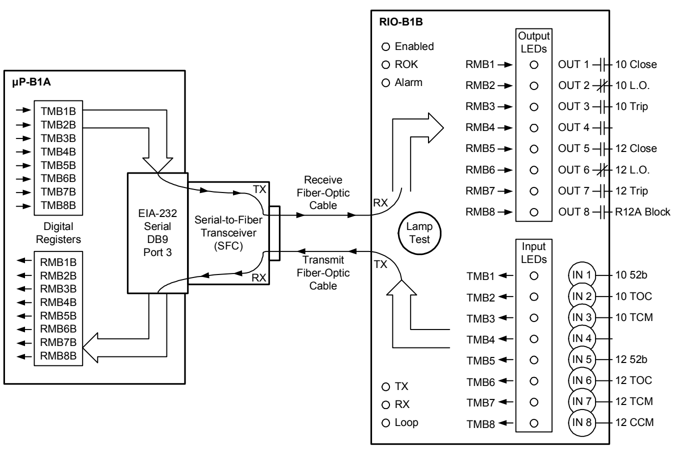

Fig. 4 µP Relay to RIO DB Communication

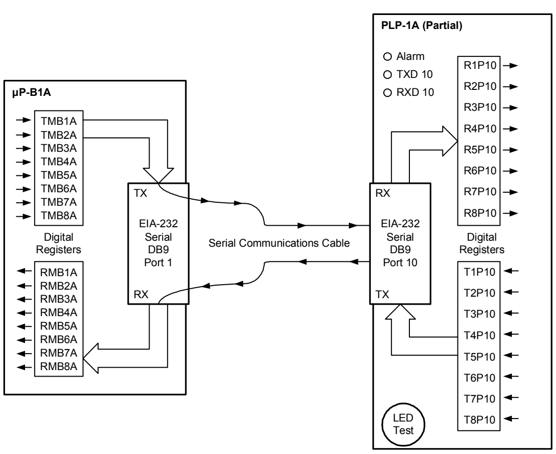

Fig. 5 µP Relay to PLP DB Communication

This DB solution utilizes a protection-speed serial protocol, logic status communications with continuous self-testing over fiber, and copper serial cables to transmit and receive I/O status data in lieu of multiple pairs of copper wires in multiconductor control cables. This IED-to-IED protocol can transmit eight status points (DBs) and receive eight status points (DBs) simultaneously with immediate detection, alarming, and mitigation in reaction to loss of a single message. The protocol also includes built-in monitoring for channel availability statistics. For an explanation of the security and dependability of this protocol, as well as more background on how DBs are transferred between IEDs via serial communications, see [9].

Received DB communications messages are checked several ways to ensure data security. First, each byte is checked for parity, framing, and overrun errors. Second, the eight received DBs, which are each repeated three times in the four character messages, are checked for redundancy. Third, the encoded ID must match the receiving port's RX_ID and TX_ID settings. Finally, at least one message must be received in the time that it takes for three messages to be sent.

C. GPS Time-Synchronized µP Relays

Having synchronized time signals to all the µP relays provides the ability to have comparable power system fault and disturbance event reports, SER records as shown in Fig. 6, test equipment at adjacent substations for synchronized end-to-end testing, and time-accurate reporting for SCADA analog and state-change records. Being able to do time-deterministic root-cause analysis of system events and combine report data from different µP relays to calculate in real time the timing between occurrences related to the same incident has proved invaluable.

The µP relay alias feature provides the ability to create intuitive names for programmed elements and DBs, which is useful when reading SER data or looking at DBs in fault records during post-event analysis.

```
XXX-RB2A-1026                      Date: 03/07/2008  Time: 09:56:09.714
SWGR-XXX                                 Serial Number: 2007082262

FID=XXX-XXX-2-R117-V0-Z008008-D20070223

#      DATE          TIME          ELEMENT               STATE
41   03/07/2008   06:27:42.617   Power-up              Group 1
40   03/07/2008   06:27:42.617   Relay                 Enabled
. . .
20   03/07/2008   09:47:43.454   TMB5B                 ON
19   03/07/2008   09:47:43.521   52AA2                 ON
18   03/07/2008   09:47:43.521   PSV40                 OFF
17   03/07/2008   09:47:43.521   TMB5B                 OFF
16   03/07/2008   09:47:43.623   PSV41                 ON
15   03/07/2008   09:47:43.623   TMB3B                 ON
14   03/07/2008   09:47:43.671   52AA1                 OFF
13   03/07/2008   09:47:43.723   PSV41                 OFF
12   03/07/2008   09:47:43.723   TMB3B                 OFF
11   03/07/2008   09:47:43.957   PSV39                 OFF
10   03/07/2008   09:48:12.129   PSV36                 ON
9    03/07/2008   09:48:12.129   PSV37                 ON
8    03/07/2008   09:48:12.129   TMB1B                 ON
7    03/07/2008   09:48:12.194   52AA1                 ON
6    03/07/2008   09:48:12.194   PSV37                 OFF
5    03/07/2008   09:48:12.194   TMB1B                 OFF
4    03/07/2008   09:48:12.296   PSV38                 ON
3    03/07/2008   09:48:12.344   52AA2                 OFF
2    03/07/2008   09:48:12.396   PSV38                 OFF
1    03/07/2008   09:48:12.632   PSV36                 OFF
```

Fig. 6 SER Report From µP-B2A

D. Protection Speed

The µP relays in this substation sample currents and voltages at 8,000 samples per second (8 kHz) for the bus and feeder relays or 960 samples per second for the line and transformer relays. The protection and control processing interval is eight times per power system cycle for bus and feeder relays and four times per power system cycle for line and transformer relays. The bus and feeder relays also provide fast and secure interdevice communications capabilities, greatly enhancing the operational speed of the communications-based DCB protection scheme. The relationship of the µP relay sampling rate to protection speed (described further in [10]) shows that little improvement in protection speed is gained by further increased sampling rates, due to analog low-pass filter delay and computational latency. The µP relay's interdevice communications capabilities also eliminate the physical LORs, further reducing (improving) the overall clearing time for a transmission line, transformer, bus, and feeder fault.

Previously used relays had slower processors and/or more complicated directional algorithms, which forced the choice of either disabling the directional elements and setting the pickup-delay timer to more than 3 cycles or enabling the directional elements and setting the pickup-delay timer to more than 8 cycles. If the directional elements were disabled, bus fault contribution from large downstream motors could cause the feeder relays to block a bus trip. On the other hand, if the directional elements were enabled, the clearing time for a bus fault would slow down to an unacceptable level. Furthermore, these previous relays did not have interdevice communications capabilities, requiring directly connected wires to enable communication between relays, as well as the use of physical bus LORs to trip and lock out all the breakers associated with the faulted bus. This lengthened the overall bus fault clearing time.

TABLE I
SPEED COMPARISON OF VARIOUS BUS PROTECTION SCHEMES

Scheme	Protection Devices	Minimum Secure Relay Time (Cycles)	Comment
EMR High-Impedance	EMR 86B LOR	1.5 + 0.8 ≈ 2.3	LOR With Slow Coil
µP High-Impedance	µP Relay 86B LOR	1.0 + 0.5 ≈ 1.5 *	LOR With Fast Coil
µP Low-Impedance	µP Relay 86B LOR	1.0 + 0.5 ≈ 1.5 *	LOR With Fast Coil
µP DCB Bus Hardwired	µP Relays	0.625 (67P) 0.625 (67N)	Using "a" (Cold Coil) Contact
µP DCB Bus Hardwired	µP Relays	0.500 (67P) 0.500 (67N)	Using "b" (NOEH, Hot Coil) Contact
µP DCB Bus Protection via Direct Copper	µP Relays	0.500 (67P) 0.500 (67N)	Serial Comm. at 38400 bps, Not Practical
µP DCB Bus Protection via Direct Fiber Optics	µP Relays	0.375 (67P) 0.500 (67N)	Serial Comm. at 38400 bps, Not Practical
µP DCB Bus Protection via PLP	µP Relays PLP	1.125 (67P) 1.000 (67N)	Serial Comm. at 38400 bps

* as stated in [11]

The above µP DCB bus protection via PLP scheme's blocking signals from feeders are not supervised by the ROK communications channel health digital register as some suggest [12] because this added security is for an unlikely double contingency condition (a feeder fault and a communications failure at the same time). When the µP relay or PLP detects an error in a received DB message, it discards the entire message and deasserts the ROK register. The receive DBs in the byte message will then take on their respective default receive values until DB communications are restored. The default receive values can be set by the user to "1," "0," or "X" (previous value), depending on the application. A µP relay, PLP, and RIO have an unavailability of 1.2 minutes per year for a mean time to repair (MTTR) of 5 hours [2]. Furthermore, [13] suggests that a point-to-point fiber-optic transceiver connection has a mean time between failures (MTBF) of 600 years (0.167 percent per year failure rate), using an MTTR of 5 hours, which would be an unavailability of 30 seconds per year. If failed IEDs and failed fiber transceivers or cables are promptly replaced, the likelihood of a bus trip for an unblocked feeder fault is highly unlikely and hence not considered a condition to protect against. It is worth noting that [13] shows that wire connections in the substation possibly have an unavailability of 100 minutes per year, if tested every two years.

E. µP Relay CT Connection Considerations

Due to the communications-based DCB protection scheme, the transformer differential relays are connected to the CTs above the medium-voltage main breakers. This keeps the transformer differential relay from clearing a medium-voltage main breaker fault before the medium-voltage bus protection (communications-based DCB protection scheme) can trip and lock out the associated bus, thus preventing the fast motor bus transfer from closing back into the faulted medium-voltage main breaker through the medium-voltage tie breaker. If the main breaker fails to trip, the main breaker's breaker-failure (50BF1) element embedded in the bus relay is enabled to trip the transmission line and medium-voltage bus. The feeder relays are connected to CTs located on the load side of the medium-voltage feeder breakers to remove the chance of a block signal being sent during a medium-voltage feeder breaker fault.

F. Controls

The main breaker and tie breaker control logic is embedded in the medium-voltage bus relays and is capable of being operated and monitored automatically or manually. Automatic main-tie-main (MTM) operation disables all manual MTM operations and is used to enable the three automatic open-transition bus transfer schemes: fast bus transfer, in-phase bus transfer, and residual bus transfer. Manual MTM operation disables all automatic MTM operations and can be performed locally via the user-controlled pushbuttons or remotely via the HMI. Fig. 7 shows that the MTM controls utilize eight µP relay pushbuttons: {AUTO/MANUAL}, {REMOTE/LOCAL}, {MAIN BREAKER CLOSE}, {MAIN BREAKER TRIP}, {TIE BREAKER CLOSE}, {TIE BREAKER TRIP}, {CLOSED-TRANSITION BUS-TRANSFER to TIE BREAKER}, and {CLOSED-TRANSITION BUS-TRANSFER to MAIN BREAKER}. The main and tie breaker controls are routed via interdevice DBs to a RIO located in the switchgear. The {CLOSE} (PB2 and PB8), {TRIP} (PB3 and PB9), and {TRANSFER} (PB4 and PB10) operator control pushbuttons are programmed with a three-second safety time delay to allow time for the operator to move away from the front of the switchgear after pressing the pushbutton. This three-second safety time delay, in conjunction with arc resistance switchgear, further reduces exposure to the arc-flash hazard.

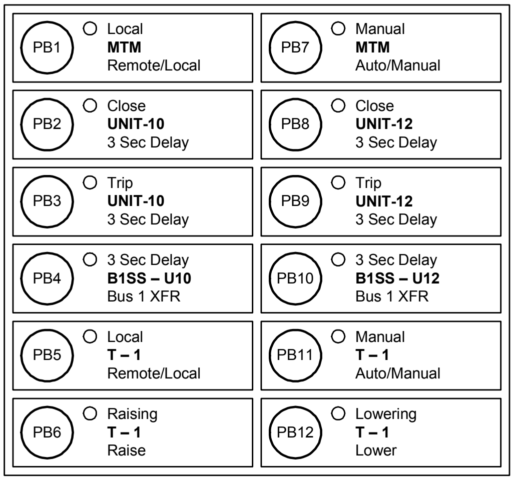

Fig. 7 Bus µP-B1A Front-Panel Pushbuttons

Fig. 8 shows the µP-B1A front-panel target LEDs programmed and labeled to provide necessary trip and alarm indication.

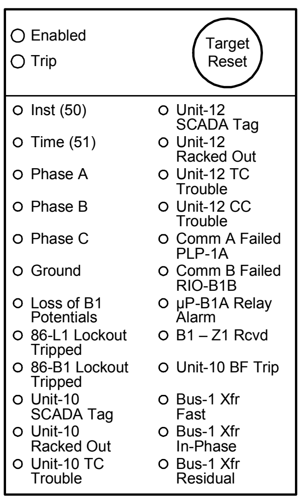

Fig. 8 Bus µP-B1A Front-Panel Targets

VI. MEDIUM-VOLTAGE FEEDER PROTECTION AND CONTROL

A. Protection

Six medium-voltage (13.8 kV) feeders, three per bus, are supplied from the two medium-voltage buses. Each medium-voltage feeder is protected by the overcurrent (51/51N) elements embedded in the feeder relay, which is connected to the CTs on the load side of the associated feeder breaker. If the feeder relay's overcurrent (51/51N) elements pick up and time out, it will directly trip and lock out the feeder breaker and can also trip and lock out downstream breakers via interdevice DBs as required. These settings are coordinated with the downstream protection elements.

B. Controls

Feeder breaker control logic is embedded in the medium-voltage feeder relays, which are capable of being operated locally via the user-controlled pushbuttons with multicolored LEDs or remotely via the HMI. The local controls shown in Fig. 9 utilize three µP relay pushbuttons: {REMOTE/LOCAL}, {FEEDER BREAKER TRIP}, and {FEEDER BREAKER CLOSE}. The feeder breaker controls are routed via interdevice DBs to a RIO located in the same switchgear section. The {CLOSE} (PB2) and {TRIP} (PB3) operator control pushbuttons are also programmed with the previously mentioned three-second safety time delay.

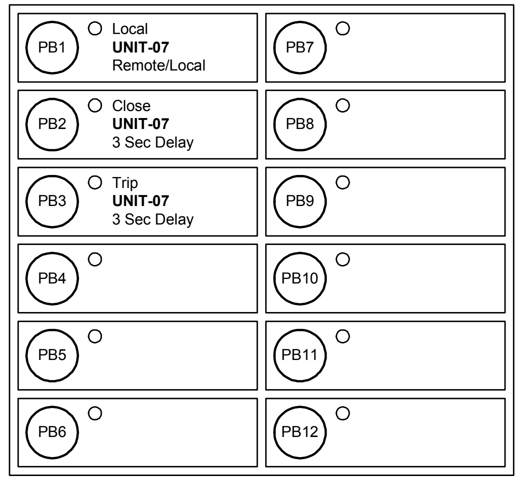

Fig. 9 Feeder µP-07A Front-Panel Pushbuttons

Fig. 10 shows the µP-07A front-panel target LEDs programmed and labeled to provide necessary trip and alarm indication.

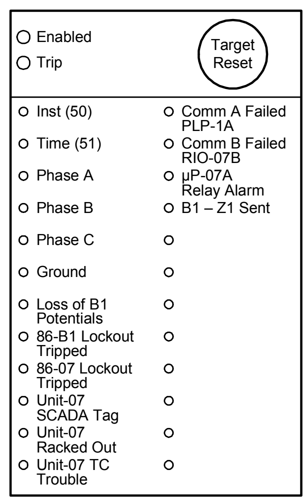

Fig. 10 Feeder µP-07A Front-Panel Targets

VII. REMOVAL OF PHYSICAL LOCKOUT RELAYS

A. Faster Fault Clearing Times

This substation's protection schemes clear faults quicker by directly tripping and locking out their associated breakers. This is accomplished by utilizing embedded µP logic, interdevice DBs, and multicolored LEDs to provide the same functionality as physical LORs. Using the protection communications protocol eliminates the cost and associated wiring of installing LORs and improves protection speed by eliminating the LOR operation delay. The µP relays directly trip and lock out their associated breakers with embedded logic and interdevice DBs, plus their multicolored LEDs indicate which zone is locked out. These front-panel target LEDs are illuminated on all µP relays associated with the locked-out zone to provide operators with obvious and simple indication of what zone is currently locked out. The {TARGET RESET} pushbutton on the initiating µP relay must be operated to reset the locked-out zone, which in turn drops out all indicating LEDs. The PLP multiplies and propagates the locked-out tripping and interlocking functions to other IEDs. This further reduces wiring and improves reliability.

B. Lockout Zones

This substation's protection schemes have specific zones of protection, which are individually locked out after a fault in their zone occurs.

As shown in Fig. 11, Transmission Line 1 and Transformer 1 share a common zone of protection, thus utilizing one 86-L1 digital lockout. 86-L1 is initiated by the following protection elements: 87L-A1, B1 (87L/21-Z2); 67L-A1, B1 (67/67N); 50BF-A1 (50BF); 50BF-B1 (50BF); µP-L1A (87L); µP-T1A (87T/REF/51N); SPR-T1 (63X); and µP-B1A (50BF1). 86-L1 trips and locks out the two upstream high-voltage breakers and the downstream medium-voltage main breaker and initiates a fast motor bus transfer on medium-voltage Bus 1.

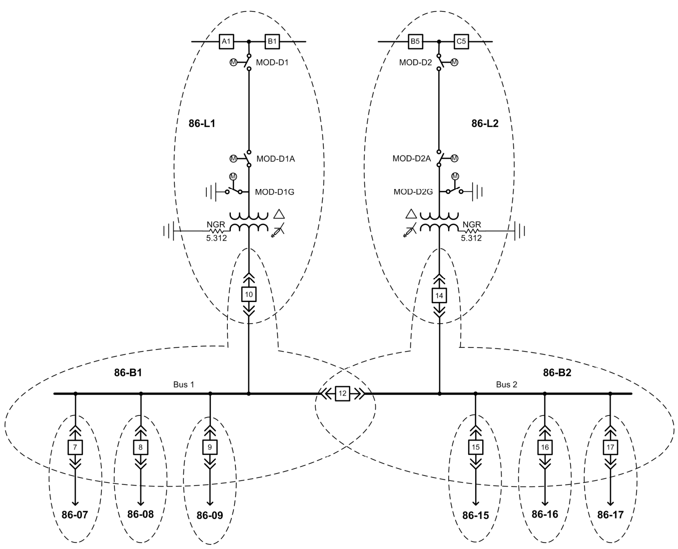

Fig. 11 Lockout Zones Diagram (86-L1, 86-L2, 86-B1, 86-B2, 86-07, 86-08, 86-09, 86-15, 86-16, and 86-17)

Transmission Line 2 and Transformer 2 share a common zone of protection, thus utilizing one 86-L2 digital lockout. 86-L2 is initiated by the following protection elements: 87L-B5, C5 (87L/21-Z2); 67L-B5, C5 (67/67N); 50BF-B5 (50BF); 50BF-C5 (50BF); µP-L2A (87L); µP-T2A (87T/REF/51N); SPR-T2 (63X); and µP-B2A (50BF1). 86-L2 trips and locks out the two upstream high-voltage breakers and the downstream medium-voltage main breaker and initiates a fast motor bus transfer on medium-voltage Bus 2.

Medium-voltage Bus 1 has one zone of protection utilizing one 86-B1 digital lockout. 86-B1 is initiated by the following protection elements: µP-B1A (communications-based DCB protection scheme/51/51N/50BF1) and µP-T1A (51/51N). 86-B1 trips and locks out the medium-voltage main breaker, tie breaker, and all three feeder breakers associated with Bus 1.

Medium-voltage Bus 2 has one zone of protection utilizing one 86-B2 digital lockout. 86-B2 is initiated by the following protection elements: µP-B2A (communications-based DCB protection scheme/51/51N/50BF1) and µP-T2A (51/51N). 86-B2 trips and locks out the medium-voltage main breaker, tie breaker, and all three feeder breakers associated with Bus 2.

Unit-07 medium-voltage feeder breaker has one zone of protection utilizing one 86-07 digital lockout. 86-07 is initiated by the µP-07A (51/51N, 50/50N) protection element. 86-07 trips and locks out the Unit-07 medium-voltage feeder breaker and can also be used to trip and lock out the associated downstream breaker(s). All other medium-voltage feeder breakers utilize identical digital lockout schemes.

VIII. PORTABLE AND MODULAR INTEGRATED BUILDING

A. Portable

The medium-voltage portion of the substation was designed to be prefabricated, allowing it to be completely constructed and precommissioned at the switchgear manufacturing facility and shipped to another location. When the substation was delivered to its final location, it was connected to the upstream and downstream equipment, recommissioned, and then placed in service in a very short period of time. This building contains the medium-voltage, arc-resistant switchgear, its auxiliary equipment, and the protection and controls for much of the upstream and downstream equipment. A prefabricated and portable medium-voltage substation provides the flexibility to relocate it in the future due to plant shutdowns, upstream or downstream reconfigurations, or emergency power restoration at another location.

The µP relays and meters are mounted on the switchgear control compartment doors that conform to the 19-inch equipment rack practice (IEEE Standard 1101.10-1996) for mechanical interchangeability to facilitate easier modifications if the substation is relocated or reconfigured in the future (see Fig. 12). Essentially, the configuration of the protection and control circuitry was moved into the µP relay and PLP programmable digital logic schemes, where any future modifications are less expensive to make and easily achieved via PC software.

Fig. 12 Switchgear Control Compartment Door

B. Modular

This particular medium-voltage substation was able to be shipped in one piece due to its weight and length. However, this basic substation design will be used on future projects, allowing for up to six additional feeder breakers on each bus, which could increase the overall length to 82’ 0” and greatly increase the weight. In this case, the substation could be designed to be modular so that it could be shipped in multiple sections, thus easing the transportation restrictions due to building weight and length.

C. Integrated

The medium-voltage portion of the substation was designed to completely utilize the full integration capabilities of µP technology: system protection, automatic and manual controls, local metering, local alarm annunciation, local event oscillography, and local SER reporting. To fully realize these capabilities, the design team extensively utilized interdevice DBs, which securely share information between µP relays at protection speed, allowing interdevice logic schemes to greatly enhance system protection and controls. Some of these schemes are high-voltage MOD interlocks, upstream and downstream transfer tripping, the communications-based DCB protection scheme, monitoring of the upstream and downstream breakers, and providing synchronism-check closing of all downstream breakers. In the future, it will be easier to extend a bus with less regard to the geographical location of the new breakers, due to the utilization of the interdevice logic schemes and the communications-based DCB protection scheme.

D. Integrated Items Not in the Portable Building

The substation system components that are external to the portable building are the upstream high-voltage circuit breakers, external fiber-optic cables, some high-voltage relaying, metering, controls, MODs, transmission lines, power transformers, neutral resistors, downstream medium-voltage circuit breakers, and RIOs in downstream substations.

IX. SEPARATE AC AND DC CIRCUITS WITH I/O DEVICES

In this substation, all µP relays (except the transformer differential relay, due to its inability to utilize interdevice DBs) have an associated RIO installed, primarily due to the small maintenance staff available at this site. There is a high probability that a testing technician and/or test set will not be readily available to replace these devices quickly if an IED fails. By utilizing the RIO and detailed test procedures (see Section XIII), the replacement and testing of the µP relay and RIO have been simplified so the maintenance electrician can safely and independently maintain this substation with limited test equipment.

Reference [2] provides details on typical measured MTBF, mean time between removals (MTBR), initial quality (IQ), and maintenance indicator (MI) quality measurements for µP relays.

A. µP Relay

Replacement of a µP relay is simplified by routing the ac wires through test switches prior to terminating them on the µP relay and by eliminating its dc control circuits. This site has the IED settings software application installed and a database file located on a server and available to multiple notebook computers. The database file contains all the settings of the programmable IEDs. After loading the settings from the database and comparing them to the original settings, the only tests necessary on the spare µP relay are a metering test verifying the ac circuits and a processor timing test using the µP relay’s internal SER report.

B. Remote I/O Device

The replacement of a RIO is simplified by routing the dc wires through test switches prior to terminating them on the RIO. The testing of a RIO is performed by using an interdevice DB tester, which verifies that each output and input operates correctly. Then any contacts used for protection can be time-tested using the SER report in the associated µP relay.

X. DOCUMENTATION

A design drawing package for a medium-voltage substation includes electrical documentation, such as electrical one-line diagrams, meter and relay one-line diagrams, three-line diagrams, dc schematic diagrams, wiring diagrams, interconnection diagrams, cable lists, physical arrangement diagrams, and building layout details. This integrated design required the creation of protection and control communications diagrams and individual device as well as interdevice logic diagrams. As explained in [8], there are several ways to document the PRCM scheme’s logic in diagrams. This substation used a variation of Option 2 to ensure adequate reference documentation for operation and maintenance. The IED contact I/O and communications link I/O are both diagramed to show internal and external IED protection and control logic.

A. Device Logic Diagrams

The configuration of this substation’s protection and control schemes has intentionally been removed from the wiring schemes and integrated into the µP relay’s digital logic schemes. This digital logic must be documented in the same fashion that wiring schemes are typically documented to allow more experts (not just protective relaying experts) to help troubleshoot problems or make decisions on future enhancements.

B. Device-Specific Logic Diagrams

Device-specific logic diagrams document only what is located in the particular IED. These diagrams are complementary to the device’s dc schematic diagrams and are located adjacent to one another in the substation’s document package. See Section XIII for an example device-specific logic diagram.

C. Interdevice Logic Diagrams

Interdevice logic diagrams become necessary when using interdevice DBs, due to the device-to-device integration. To show the interconnected logic, these diagrams document protection and/or control schemes involving several devices using interdevice DBs. These diagrams are essential for initial design, laboratory simulations, factory acceptance testing, on-site testing, commissioning, troubleshooting, and future enhancement considerations. See Section XIII for an example interdevice logic diagram.

XI. TESTING AND MAINTENANCE

A. µP Relay and RIO Laboratory Validation Testing

As explained in [12], the best method to develop and test extensive µP relaying and control schemes comprehensively after necessary logic diagrams have been created is to construct a complete time-synchronized laboratory simulation with all the μP relays, RIOs, PLPs, CLKs, ac secondary voltage and secondary current, dc power, and interdevice communications connected. Furthermore, a test plan is needed to address the laboratory, factory, and field testing and commissioning of the entire system. As part of the initial design, all the test rack-mounted μP relays and RIOs were connected together in the laboratory through wiring and communications cables. The integrated protection and control scheme's functionality and performance were verified by performing logic and timing tests in parallel with developing schemes and detailed design drawings, which included verifying the user-controlled pushbuttons, multicolored LEDs, and display information. The μP relay's integrated protection elements were verified for pickup value and its associated RIO output-contact timing. Each of the substation's μP relays was functionally tested through its test switches in the laboratory to develop individualized, automated tests and necessary supporting detailed test procedures. These automated tests and procedures will be used in the future to simplify the maintenance of these relays, such as to verify relay status or to replace a failed relay. Developing and testing standard, advanced μP protection and control schemes with adequate programming flexibility prior to starting detailed design of this substation project eliminated the guesswork in μP relay and device selection. It also ensured that the process unit owners' desired protection and control objectives for process unit availability and survivability were realized on-site, rather than trying to make what was purchased (and was indicated should work) actually work. Through this approach, the strengths and weaknesses of the schemes were learned, and the possibility of unforeseen issues occurring during construction was reduced. See Section XIII for an example detailed test procedure.

B. Self-Diagnostic Alarms

The IEDs (μP relay, PLP, SDP, RIO, CLK, and meter) continuously run self-diagnostic tests to detect out-of-tolerance conditions. These tests run simultaneously with the μP protection and automation logic but do not degrade the device's performance.

The IED reports out-of-tolerance conditions as a status warning or a status failure. For conditions that do not compromise functionality yet are beyond expected limits, the IED declares a status warning and continues to function normally. A severe out-of-tolerance condition causes the IED to declare a status failure and enter a device-disabled state. During a device-disabled state, a μP relay suspends protection element and trip/close logic processing and de-energizes all control outputs. When disabled, the ENABLED front-panel LED is not illuminated.

A μP relay signals a status warning by pulsing the HALARM DB (hardware alarm) to logical 1 for five seconds. For a status failure, the relay latches the HALARM DB to logical 1. The μP relay will restart on certain diagnostic failures. When this occurs, the μP relay will log a diagnostic restart in the SER, and the HALARM DB will assert for five seconds.

Remote IED status indication is communicated via the two SDPs to the SPCs. The μP relay SALARM DB (software alarm) is pulsed for software-related conditions; these conditions include settings changes, access level changes, and alarming after three unsuccessful password entry attempts. The SPCs continually monitor the entire system for HALARM or SALARM alarms and, when detected, report them to the operator. For a hardware alarm, a technician or electrician can be dispatched to the substation to remove and replace the failed IED with a spare per the site-specific procedure for that IED.

C. μP Relay and RIO Factory and Site Testing

Utilizing automated tests and test procedures, all the μP relays and RIOs were functionally tested through their test switches prior to commissioning the substation at the factory and once again at the site. This not only verified the status of the μP relays but also verified the wiring to and from the test switches.

D. μP Relay In-Service Testing

Each of the substation's μP relay's individualized test procedures include directions to remove the relay from service, replace the relay, upload settings into the relay, download settings from the relay, compare the uploaded and downloaded settings (reducing μP settings checking time and increasing the accuracy of applied settings), run the individualized automated tests utilizing the associated RIO with a test set, save the test data, and place the μP relay back into service. In order to keep the MTTR short when a test set or relay technician is not immediately available, these procedures also include a simplified metering test to verify the ac wiring to the relay and a processor timing test using the SER in the μP relay in lieu of the automated tests.

IED settings files need to be carefully controlled and maintained. Occasionally, because protection and automation logic settings are part of the same settings file for a single IED, automation logic settings are accidentally overwritten (changed) when protection settings are entered, or vice versa.

E. RIO In-Service Testing

Each of the substation's RIO's individualized test procedures include directions to remove the device from service, replace the device, set the control (DIP) switches on the device, verify the inputs and outputs using an interdevice DB tester, run the timing tests utilizing the associated μP relay's SER, document the test data, and place the RIO back into service.

XII. SUBSTATION COMMISSIONING

A. μP Relay Preliminary Commissioning

This substation's protection and control schemes were easily developed and tested in a laboratory environment with all of the devices connected together. A breaker simulator and transformer tap-position simulator were used to verify the protection and control schemes' operational compatibility and coordination. By moving the majority of the substation's protection and control configuration from the wiring into the μP relay's digital logic schemes, the design team was able to verify and prove these schemes before the substation was built.

B. Factory Commissioning

This substation's protection and control schemes were preliminarily tested and commissioned at the switchgear manufacturing facility before the substation was shipped to the site. The factory commissioning allowed the verification of all auxiliary support equipment and its associated wiring, CT/PT circuits, and the μP relay's digital logic schemes integrated with the actual breaker wiring schemes. The necessary operating and maintenance procedures were developed, and hands-on training for the technicians responsible for the operation and/or maintenance of this equipment was initiated at the factory. The IED features allow automatic testing techniques with modern test sets to quickly and efficiently test many relay elements in repeatable programmed tests. The results of the automated tests are stored electronically for future reference.

C. Site Commissioning

Once this substation was delivered to the site, it was immediately inspected for transportation damage and loose terminations and then connected to the two station-service 480 V power sources, which supplied auxiliary power to the substation while the substation battery system was being installed and commissioned. The upstream transformer, downstream medium-voltage cables, and fiber-optic cables were then connected to this substation, allowing a complete commissioning of the substation's protection and control schemes. During the final testing and commissioning at the site, new procedures were developed, and the previously developed operating and maintenance procedures were verified again. This offered a final opportunity for hands-on training for the technicians responsible for the operation and/or maintenance of this equipment.

D. Substation Energization

This substation was energized in two stages. Stage 1 included the initial energization of Line 1, Transformer 1, Bus 1, and Bus 2. Two feeders on Bus 1 and two feeders on Bus 2 were individually connected and sequentially energized, thus moving the entire site load over to this substation and simultaneously removing the site load from Transformer 2, allowing it to be relocated to this substation. Then all downstream remote breaker controls and monitoring were commissioned.

Stage 2 included initially energizing Line 2 and Transformer 2, as well as verifying the phasing across Bus 2 main breaker stabs. The automated motor bus transfer (MBT) logic on medium-voltage Bus 1 and Bus 2 was then verified while in service.

XIII. ADDITIONAL DOCUMENTATION

The following additional information in Adobe® PDF file format can be obtained directly from the authors:

1. A detailed test procedure, with specific steps for replacing and testing μP-07A and RIO-07B.
2. A device logic diagram for μP-07A.
3. An interdevice logic diagram for Bus 1.

XIV. CONCLUSIONS

1. Industrial electrical engineers can develop, as part of the initial design (not afterwards as is usually the case with μP technology), enhanced schemes to improve performance and availability and to obtain the added benefits of fully utilized μP relay technology in substation protection and control schemes.
2. Automatic and manual (remote or local) control, power system monitoring, oscillography, SER reporting, and local annunciation are inherent in the μP relays.
3. The new schemes described may reduce short-circuit clearing times, which can reduce arc-flash energy, equipment damage (increasing transformer life), and process voltage sag durations.
4. Using μP relays with internal MBT logic provides a definite reduction in restoration time for upstream faults and system failures and an improvement in power quality and electric service reliability.
5. The new schemes eliminate equipment such as RTUs, PLCs, physical control and lockout relay switches, and at least 50 percent of the control wiring.
6. The enhanced communications-based primary protective relaying and control design requires additional documentation such as interdevice logic diagrams, communications diagrams, and detailed test procedures for each IED device.
7. The compact design with a reduced control building footprint allows for the building to be modular and portable. Minimal field wiring interconnections are now possible in a single marshalling cabinet. μP relays can be easily reprogrammed to adapt to a new location, configuration, or expansion of the local substation.
8. Using μP relay technology and RIO IEDs for faster, enhanced, embedded, and communications-based primary and backup protective relaying and control schemes contributes to a safer and more reliable, maintainable, and economical substation.
9. Engineering design costs and time savings are expected to be achieved on subsequent projects that use this design or similar schemes.

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XVI. VITAE

John Novak (M '07) received an AS degree in Electrical Technology from Brazosport College, Lake Jackson, Texas in 1984. He started his career for Dow Chemical at Freeport, Texas in 1979 as a process operator and entered the electrical training program from 1981 to 1984. He received his AS degree by attending school in the evenings. He was accepted into the meter and relay department in 1985, where he calibrated protective relays, meters, and transducers. From 1987 to 1997, he joined a SCADA project team to upgrade an energy management and control system, where he helped commission a dispatch control center and install 70+ RTUs in many substations and power houses. During this time, he also designed and commissioned several automation schemes to provide load shedding for the power houses as well as to provide spinning reserve support for the local utility company. In 1997, he began designing and commissioning high- and medium-voltage protection and control schemes for several company sites in the United States.

Richard Kirby, P.E. (S '90, M '96, SM '06) received a BSEE from Oral Roberts University, Tulsa, Oklahoma in 1992. He started his career as a junior electrical engineer in Botswana, Africa and worked for a consulting engineering firm before choosing to return to the United States for further education. In 1995, he earned his Master of Engineering degree from Rensselaer Polytechnic Institute, Troy, New York. He then worked as a distribution planner and later a protective relaying and control engineer at the Detroit Edison Company, Detroit, Michigan. In 1997, he joined The Talbot Corporation, an electrical contracting firm in Livonia, Michigan. In 1998, he became a licensed Professional Engineer in the state of Michigan and joined Black & Veatch in Ann Arbor, Michigan. In 2002, he joined the General Electric Company and relocated to Houston, Texas. He became a licensed Professional Engineer in the state of Texas in 2003. In 2004, he joined Schweitzer Engineering Laboratories, Inc. as an application engineer in Houston, Texas. He is an IEEE Power Engineering Society and Industrial Applications Society member.

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