Case Study: Implementation of a Protection, Control, and Automation System Based on IEC 61850

Western Power Delivery Automation Conference

Spokane, Washington

March 27 – 29, 2012

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I ABSTRACT

Over the past 5 years IEC 61850 has gained in popularity in various utilities across the globe for its promise of interoperability, scalability, maintainability and wire reduction. However the application and acceptance of this standard is still in its infancy in the province of Alberta, Canada. This paper presents a case study of one of the first substation automation projects applying the IEC 61850 standard in the province. The focus of this paper is not to discuss the theoretical background of the standard itself. Rather, the purpose is to share and demonstrate the engineering steps taken and lessons learned to successfully implement a fully functional protection and control system based around IEC 61850. The complete system developed for this project includes the following elements:

- 138/25kV distribution substation consisting of two power transformers and ten feeders.
- Integration of 17 IEC 61850 compliant intelligent electronic devices (IED) to perform both protection and control (P&C) functions.
- Substation local area network (LAN) using optical fiber for inter-panel communication and applying the parallel redundancy protocol (PRP) to achieve complete communication redundancy.
- New human-machine interface (HMIs) combining supervisory control and data acquisition (SCADA) and data gateway functionality within the real-time process database of the substation hardened computer.

The paper begins with a high-level overview of the substation configuration and its protection requirements. System automation concepts and apparatus control strategies using the IED and HMI/gateway are described. The specific steps used to engineer inter-IED communication via generic object oriented substation events (GOOSE) and client/server reporting services via manufacturing message specification (MMS) are discussed in details. Next, the factory acceptance tests and site commissioning used to verify the correct operation of the system are described. The paper finishes with a lessons learned section comparing this project with the traditional implementation

II INTRODUCTION

The City of Red Deer Electric Light and Power (The City), a publicly owned distribution company serving the City of Red Deer in Alberta, Canada, planned on a complete refurbishment and upgrade of their existing 25kV distribution substation 14 (SS14) P&C house. The City contracted Phasor Engineering Inc (The Engineer), a privately owned engineering consultant located in Calgary, Alberta, to design a new substation automation system (SAS) for SS14 based on the new IEC61850 technology. The City and The Engineer jointly issued a technical specification [1] for this refurbishing project that contained the following general requirements:

- Transformer differential, bus differential, feeder and load shedding protections and controls in multi-functional IEDs are required
- The selected communication protocol for the station bus between the HMI and IEDs is IEC 61850-8-1 MMS for vertical communication and IEC61850-8-1 GOOSE for horizontal signaling. All protection and SCADA devices therefore shall be capable of integrating with the substation automation system utilizing IEC 61850 GOOSE and MMS communication technology.
- A Redundant IEC 61850 station bus running on a network redundancy algorithm with minimum fail-over time is required to ensure P&C dependability and security. The connected P&C devices must be equipped with dual fiber optic Ethernet ports to connect to the redundant networks. The Ethernet module is capable of sending and receiving the same frames on both channels.

- Substation IEDs will be GPS time synchronized with the substation GPS clock via acceptable time synchronizing protocols (eg. IRIG-B, SNTP).
- Substation dedicated DFR system is not required as all events and recordings will be obtained and time stamped from the IEDs and reported to the SCADA system.
- The SAS shall incorporate the control (select-before-operate), monitoring (event list, alarm annunciation, measurement display, disturbance retrieval, trending) as well as protection functions. The SAS shall also supports remote control and monitoring from SCADA centers via gateways over DNP 3.0 WAN/LAN or serial communication.
- Ethernet switches shall fulfill hardening requirements concerning temperature, electromagnetic compatibility (EMC) and power supply (125 V DC from the station battery) suitable to be installed in substations. The switches will support priority tagging and open standards for ring management such as fast spanning tree.
- In addition to remote SCADA control features, local panel push buttons and selector switches must still be maintained for circuit breaker control, operator local/remote selection, 86 lockout relay reset and feeder live line tagging control as means to provide operators a sense of dependability and ease the transition curve to Ethernet based substation automation technology. Existing transformer tap changer controllers are also to be reused and the IEC61850 on load tap changer (LTC) control features provided by the IEDs must coordinate with the existing controllers in control mode selections and operations.

III SUBSTATION CONFIGURATION

Substation 14 (SS14) is a live and operating station located in the north-east quadrant of the city. The substation consists of two 36.4/56 MVA, 138–25kV, Dy1 connected power transformers supplying ten 25kV feeder circuits. The 138kV section of the station is owned and operated by the transmission company, Altalink, who also selected Phasor Engineering Inc. to upgrade their protection and automation system at this substation. The new automation system for Altalink is based on the DNP 3.0 technology and hard wired IED signaling. A new P&C control house was designed and built to accommodate the two different automaton systems in adjacent rooms. The 138kV motorized disconnect switches (MOD) next to the transformer's HV bushings mark the division between the two asset groups.

In the 25kV distribution station, the two incoming buses are fed by two power transformers interconnected by a tie breaker with the tie operated normally open (no parallel operation of the transformers). Each 25kV bus supplies power to five feeder circuits equipped with independent circuit breakers. Each feeder conductor consists of cable and ACSR sections. The ACSR section limits the ampacity of the feeder to around 520 A. A single line diagram (SLD) of the distribution substation appears in Figure 1.

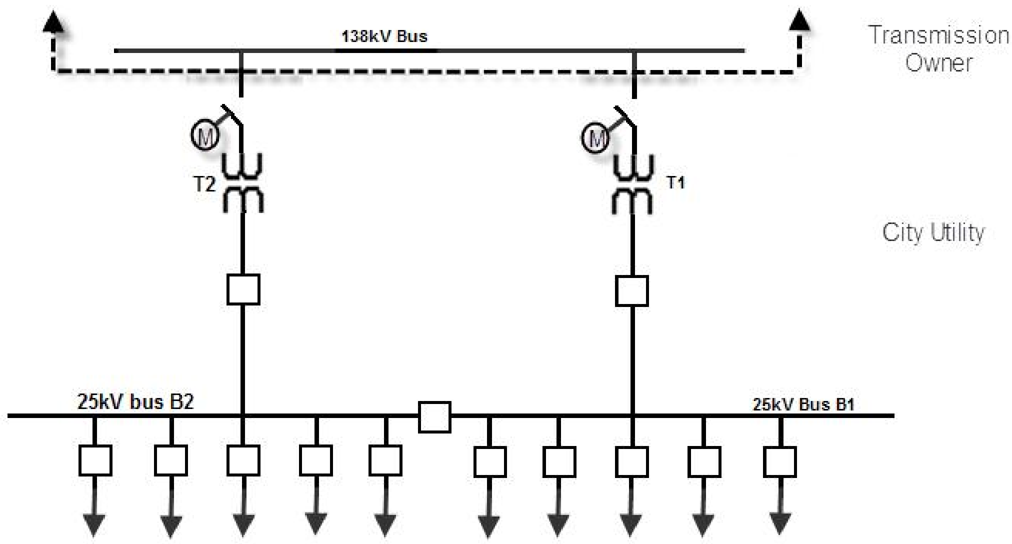


Figure 1 - Single Line Diagram of SS14

IV PROTECTION & CONTROL SCHEMES and IMPLEMENTATIONS

Due to the unfamiliar nature of the IEC61850 technology, The Engineer and The City jointly decided all substation automation (SA) products procured for this project would be sourced from a single vendor. The goal of this decision was to reduce learning curves, limit engineering and operating risks related to interoperability between equipment from different vendors and minimize design, engineering, and commissioning time in order to meet the project's budget and deadlines. Having gained experience and confidence with the IEC61850 technology, The Engineer plans to explore multi-vendor interoperability in future retrofit projects.

In this medium voltage substation only the 138kV transformers require full redundant protection units. The Engineer designed and implemented individual differential and overcurrent protections for the 25kV buses and feeders respectively. A total of eight protection panels and one SCADA panel were designed and built to house all protection, control and networking equipment. A picture of the panel lineup in The Engineers integration shop is shown in Figure 2.

Figure 2 - Sample Panel Lineup

IV.a Transformer Protection Panel

Each transformer protection panel (Table 1) accommodates two identical multifunctional IEDs and other auxiliary lockout and control devices. The main protection features of the multifunction IED include:

- 87T - Transformer differential function. Includes both phase differential and negative sequence differential for sensitive detection of turn-to-turn faults.
- REF - Restricted Earth Fault protection to detect ground faults on the transformer secondary (wye connected winding).
- 51(N) - Phase and ground time over-current elements to protect the transformer against high magnitude external faults and also to provide time delayed backup tripping for faults on the 25kV system.

All transformer protection operations trip the transformer's 25kV breaker through direct hard-wired outputs and send a GOOSE message to the bus protection to initiate breaker failure (BF) protection and operate the trip reinforcement relay of the same breaker (located in the bus panel). 87T and REF operations represent transformer internal faults and will open the HV MOD and send a hard-wired trip to the transformer auxiliary trip and lockout modules provided by AltaLink. These modules trip all the 138kV breakers and initiate a 138kV bus restoration sequence once the faulted transformer's MOD is opened. There is a local/remote selector switch (43) which provides status inputs to the IED for selecting between local (relay HMI or 52CS control switch) and remote (Substation HMI or SCADA Control Center (SCC)) operations of the associated transformer apparatus including the HV MOD, the LV main breaker and the LTC. The reason for this dual local control philosophy was to allow time and opportunity for the City's operation and maintenance personnel to familiarize themselves with the system and gain confidence with the virtual control functions available from the IED's front faceplate HMI. Remote control operations are executed in a "select-before-operate" manner through the IEC 61850-MMS protocol.

The non-electrical transformer alarms are hardwired to the IED from the field and further reported to the station HMI and SCC upon change of states. Only the 'A' IED is implemented for remote monitoring and control duties because redundant control measures are not typically required for a 25 KV system. The odds and consequence of an IED failure are considered no larger than the failure of a centralized remote terminal unit (RTU) I/O board in the previous installation of the SAS.

Panel Type	**Protection Functions**	**Control Functions**
138kV Transformer	Main Transformer Differential (87T) Restricted Earth Fault (87G) LV Over-current backup (51) LV ground Over-current backup (51N) Auxiliary Trip Lockout Relay	Open/Close of HV MOD and 25kV Main Breaker from IED HMI Open/Close of HV MOD and 25kV Breaker from Selector Switch (52CS) Local/Remote Control Selection (43) Lockout Reset Push Buttons (PB) Lockout Indication

Table 1 - Transformer Protection Panel P&C Functions

Each individual power transformer is rated to feed the loads of both buses. The two transformers are not operated in parallel so only single-mode LTC control is implemented. This simplified the LTC control design and implementation as communication between the two LTC controllers was not necessary. The City specified the 61850 LTC control logic node in the IEDs (ATCC) must work in conjunction with the existing LTC controllers located in the transformer cabinets. The existing controllers control the tap changer in "auto" mode only while the SCADA system (HMI or SCC) will be authorized to remotely control the LTC via the IED only when the LTC is switched to manual and remote modes. The LTC auto/manual and local/remote positions are hard-wired as status inputs to the IED. Custom logics were developed in the IED to indicate control mode selections and execute auto or manual LTC control operations of the IED LTC controller.

IV.b Bus Protection Panel

The bus protection panel combines the bus differential multifunctional IED and other auxiliary tripping and lockout devices to implement the protection and control functions shown in Table 2. The two main protection functions are applied in the bus differential relay:

- 87B – Three-phase Bus differential function.
- 50BF – Current based breaker failure protection for each breaker connected to the bus.

The bus differential relay selected is capable of monitoring up to eight three-phase sources and provides high speed differential protection to all terminals connected. 87B operations trip breakers, operate auxiliary trip enforcement relays, initiate breaker failure protections, and operate an auxiliary lockout relay, blocking all breakers on the bus from closing. Bus differential trips are published through GOOSE messages. The feeder and transformer relays subscribe to these messages and trip their breakers. This provides tripping via an alternate path/output contact.

The breaker failure protection feature for each connected terminal is provided by the bus protection IED instead of using separate devices to reduce cost and save space. External breaker failure initiate signals (transformer and feeder protection trips) are subscribed through GOOSE messages. Adjacent breakers are tripped by the bus relay as the result of an operation of a breaker failure element. Operation of a breaker's BF function is also published through GOOSE messages to associated feeder and transformer IEDs to provide an alternate path for BF trips.

Local and external protection trips to the 25kV breakers in the bus zone will operate the "trip re-enforcement" relay equipped with high breaking bridge type contacts to avoid burning of main IED contacts should a circuit breaker fails to open. Operation of the trip re-enforcement relays is triggered by GOOSE messages.

Panel Type	Protection Functions	Control Functions
25kV Bus	Main 3-phase Bus Differential (87B) Breaker Failure Protection for Each Connected Bay (50BF x 6) Trip Re-enforcement Relay for each bay Auxiliary Bus Trip Lockout Relay Auxiliary BF Trip Lockout Relay	Lockout Reset Push Buttons (PB) Lockout Indications

Table 2 - Bus Protection Panel P&C Functions

IV.c Feeder Protection Panel

A single feeder protection panel accommodates up to three feeder protection IEDs and each feeder protection provides the functionality summarized in Table 3. Each IED has the following protection functions enabled:

- 50 – Instantaneous overcurrent set up as part of a fuse saving scheme. This element is set sensitively enough to detect as many downstream faults as possible but high enough to allow for all loading and worst case inrush conditions. This element is disabled during auto-reclose attempts to ensure coordination with downstream fuses.
- 51 – Inverse time overcurrent set up to coordinate with largest downstream fuse and maximum loading while detecting faults and protecting against primary equipment damage.
- 79 – Two-shot auto-reclosing is set up as part of the fuse saving scheme. This function is disabled by a "hot line tagging" switch in the module.

- 81 – Under-frequency load shedding
- Hot Line Tagging Mode - Using the hard switch in the protection panel, the relay setting parameters is changed to setting group 2 during hot line work. In this setting group the recloser is completely disabled and the 50 element pickup is made more sensitive. This provides better protection to personnel performing live line work.

A feeder protection operation will trip and reclose the feeder breaker through hard-wired signals. At the same time, the trip signals are published in GOOSE messages to initiate BF and operate the trip reinforcement relay.

Similar to the Transformer Protection panel, a mechanical local/remote selector switch is used to define the operator control position for any control operation related to the feeder equipment. With the switch in local the feeder breaker can be controlled either with a mechanical 52CS switch or with "soft" control pushbuttons on the IED. In addition, two soft selector switches to turn on/off the auto-reclosing and under-frequency functions are programmed in the IED and are controllable from the IED (when in local) or from the station HMI and SCC(when in remote). The operator position is normally left in "remote" to allow for substation HMI and SCC operation.

Panel Type	Protection Functions	Control Functions
25kV Feeder	Feeder Over-current Protection (50/51) with alternate, more sensitive, settings in line tagging mode 2-shot auto-reclosing (79) disabled by hot line tagging under-frequency load shedding (81)	Open/Close Feeder Breaker from SLD on IED HMI Open/Close Feeder Breaker from Selector Switch (52CS) On/Off Control of line auto-reclosing via IED HMI On/off Control of line 81 load shedding through IED HMI Local/Remote Control Selection (43) Live Line Tagging Selector Switch

Table 3 - Feeder Protection Panel P&C Functions

V AUTOMTAION SYSTEM ARCHITECTURE & SCADA FUNCTIONS

Figure 3 illustrates the SAS system architecture implemented in this project. The IEC61850 station bus interconnects 17 multifunction IEDs and the station HMI/gateway unit through two independent LANs in a double star configuration. One 19''panel is dedicated to the station control, monitoring and communication equipment including the station HMI/Gateway computer, the GPS clock and the Ethernet switches.

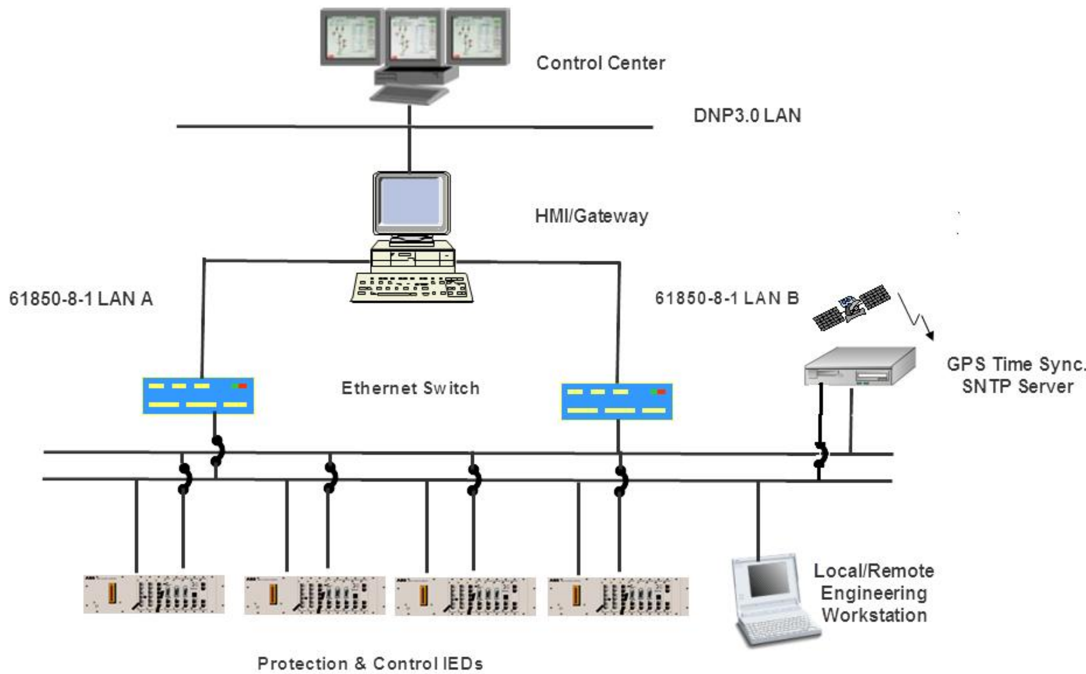


Figure 3 - Simplified SA System Architecture

Each protection IED has two rear 100BaseFX-ST Ethernet modules that support the IEC-61439 Parallel Redundancy Protocol (PRP) [2]. Operating IEC61850 station with PRP provides complete communication redundancy and zero network switch-over time upon any single point of failure. The two Ethernet modules are connected to two separate Ethernet switches that form two independent physical networks. The IED application sends the same Ethernet frames through each of the two modules onto the physically separate networks. The IED receives and processes the first datagram and rejects the second identical datagram that arrives later to achieve the proclaimed redundancy.

The GPS clock broadcasts time synchronizing data frames over LAN A and LAN B to the HMI/gateway and all IEDs using the Simple Network Time Protocol (SNTP), promising up to 1ms accuracy. This accuracy is sufficient for distribution system events and disturbance recording time stamps.

Local and remote workstations and printers can be connected to either LAN to gain access to the IED configuration, settings, event reports and disturbance recordings. Access to the above information can be secured by multi-level authorization and password protections.

The HMI and gateway resides in the same industrial grade PC running Windows XP Professional. This PC has no internal moving components for increased robustness and dependability. The PC is equipped with four 100BaseFX LC and 2 copper RJ45 Ethernet modules. Ethernet modules can be paired using a PRP driver and connected to separate LANs to achieve redundancy. A single process database of data points collected from the IEDs is maintained and shared between the HMI and gateway functionality. The following functions are provided by the HMI/gateway unit:

- Multiple single-line pages can be developed to provide operator interfaces for different monitoring and control operations. An overall SLD and a communication supervision page were developed for this project. The station SLD gives visual indication of the position of all switching devices, the status of all hard and soft local/remote and selector switches, metering information and allows for control operations. A station remote/local switch allows the substation operator to disable controls from the SCC. The SLD also has dynamic busbar coloring. The busbar sections are color coded depending on their state: powered, unpowered, grounded etc. The communication supervision page reports the health of all communication links in the SA system. Screenshots of these pages are shown in Figure 4 and Figure 5.
- Sequence of Events are displayed in the event list based on the trigger options set for the data objects stored in the real-time process database. The events are identified by the IEC61850 substation section hierarchy and logical node descriptions defined in the SCL configuration.
- Equipment alarms are collected from various IEDs, triggered from the process database and displayed in two default alarm lists. The first list separates alarms into active and fleeting ones. The second list maintains a record of all new and old alarms during the time the alarm list remains open. Alarms can be acknowledged individually or in groups.
- Disturbance recording in the IED can be automatically retrieved by the HMI client as part of the services defined in IEC-61850. The stored Comtrade files can be analyzed to verify proper relay operation after system disturbances.
- The gateway functionality of the IEC61850 client provides signal re-routing and protocol conversion to as many as 8 upper level control systems (SCC). The gateway supports a variety of communication protocols for connecting processes to the SCC. This project uses the DNP3.0 via TCP/IP slave function to send and receive data points responding to SCC polling and control operations. To best utilize bandwidth by reducing the amount of data points being transmitted, the alarm grouping tool in the gateway was used.

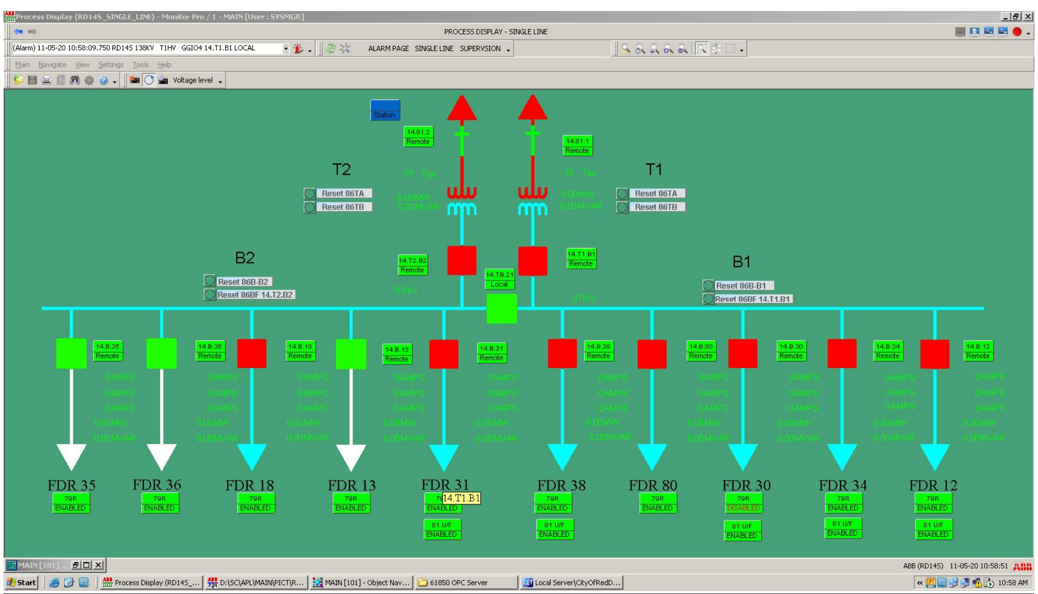


Figure 4 - HMI Station Single Line Diagram

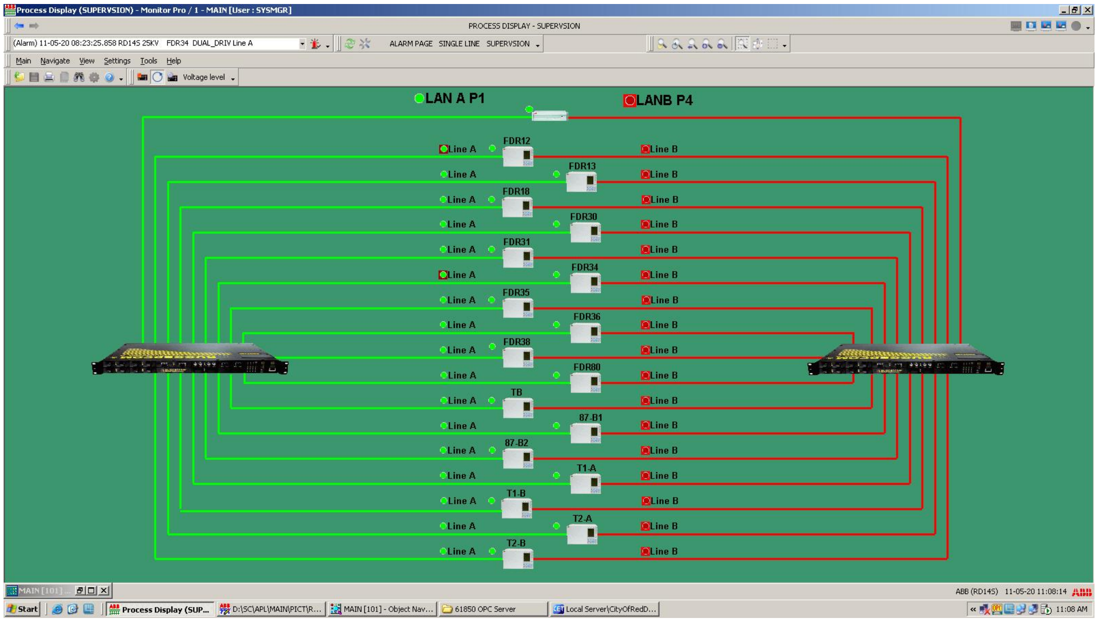


Figure 5 - HMI Communications Supervision Page

VI IEC 61850 SYSTEM ENGINEERING

Figure 6 illustrates the engineering steps taken in this project as defined within the IEC61850 standard. The substation design engineer prepared the conventional protection DC schematics and logic diagrams for each IED. In an IEC61850 project discussions between the protection and SCADA engineers are required prior to starting the system configuration to finalize the protection and control requirements for each IED.

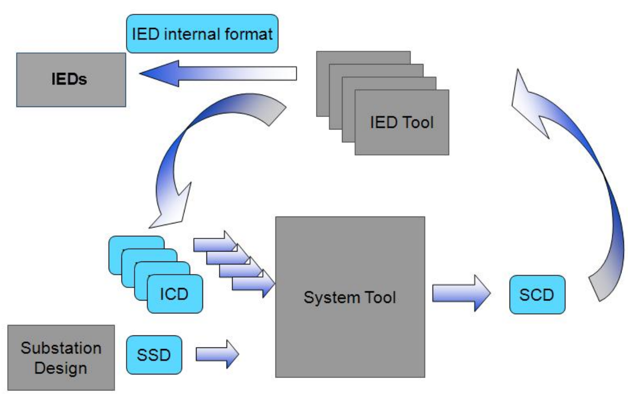


Figure 6 - IEC-61850 Engineering Steps

The first 61850 engineering step was the creation of a project database, defining the substation, voltage and bay level structure and placing each IED in this structure. This was done using the IED vendor specific configuration tool. Next, a thorough review of the required P&C functions to be provided by each IED was conducted. Then, the configuration of function blocks in each IED was finalized. These final configurations were then ready for the next step, system communication engineering.

A Substation Configuration Description (SCD) file is exported from the IED tool. The SCD file includes the substation, communication and IED sections described in the XML language. The substation section displays the substation structure defined using the IED tool as described in the previous paragraph. The IED section typically presents the complete P&C functions and compositions of each IED in a hierarchy (folder structure) of logical devices, logical nodes, data objects and data attributes. The communication section displays the subnet the IEDs and clients belong too. All devices must belong to the same subnet to communicate with one another in an IEC 61850-8-1 station bus. The communication section also defines the IP address and subnet mask parameters for each connected device. The SCD file is imported to the System Integration Tool to begin system engineering and integration. Although the System Integration Tool can be vendor specific, this tool must allow a user to import/export other vendors' ICD (IED Capability Description) files to ensure interoperability between different vendors.

Dataset engineering is performed using the System Integration Tool to define the data to be exchanged between different IEDs and up toward the gateway and station HMI. The selected vendor's product automatically generates default datasets for status and measurement information which reflect the most common user preference of data for reporting back to the SCADA system. Users are given the freedom to add or remove items from the datasets within the dataset size limit. A sample dataset for a feeder IED is shown in Figure 7 below. The first three datasets were created automatically during SCD export and the last one was created manually for GOOSE operation. Each of the items in the user created dataset consists of their value (stVal) and their quality (q). The first item is from the trip matrix function block, TMAGGIO, and is used to signal to the bus relay that the feeder overcurrent protection has operated and trip reinforcement and breaker fail initiation are needed. The other two items in this data set are a request for trip reinforcement without breaker fail initiate, such as for an under frequency trip, and the status of the feeder breaker (used in breaker trouble alarm logic).

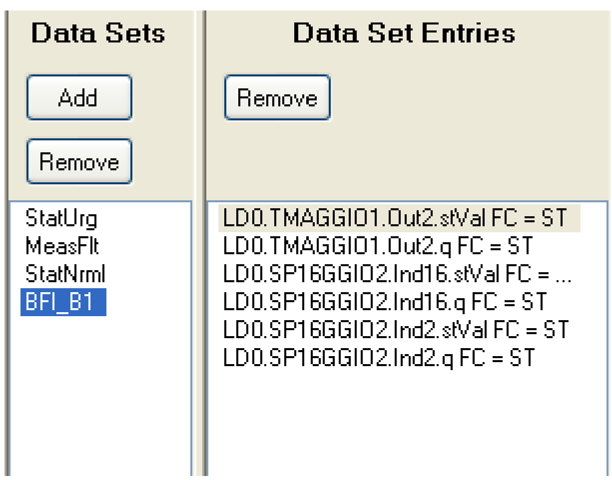
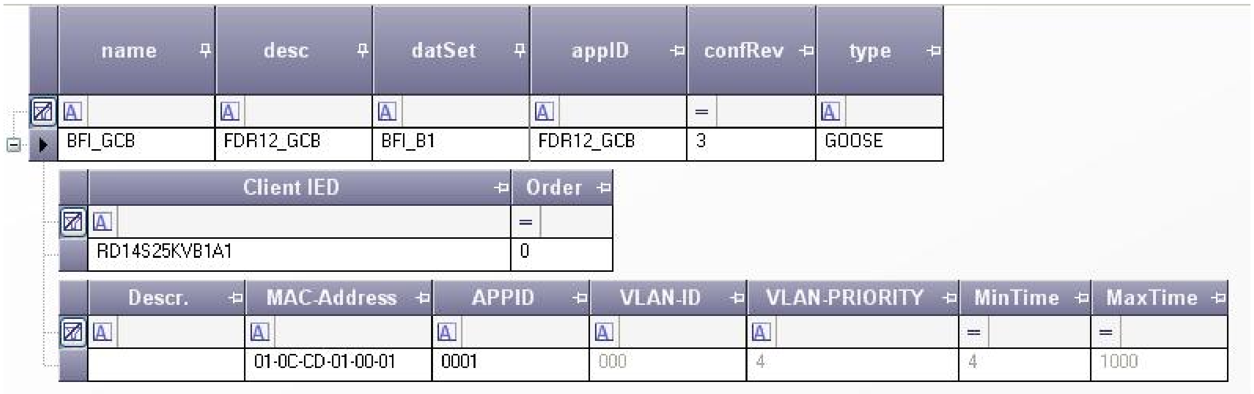


Figure 7 - Sample Dataset Engineering

GOOSE engineering defines the data link layer multicast publisher and subscriber relationship between different IEDs by encapsulating datasets in GOOSE Control Blocks (GCB). Assignment of multicast address, AppID and min/max message transmit interval, and in large systems, VLAN ID and priority tagging information, are required when creating new GCBs. An example of a GCB for a feeder IED is shown in Figure 8 below. Note that the bus protection IED is the subscriber to this GOOSE message for breaker failure initiation. Due to the small size of the system and the fact that the network is reserved for P&C applications only (no voice or internet applications), network bandwidth constraints are not likely to occur. VLAN management and priority tagging are deemed unnecessary and therefore are not implemented in this project.



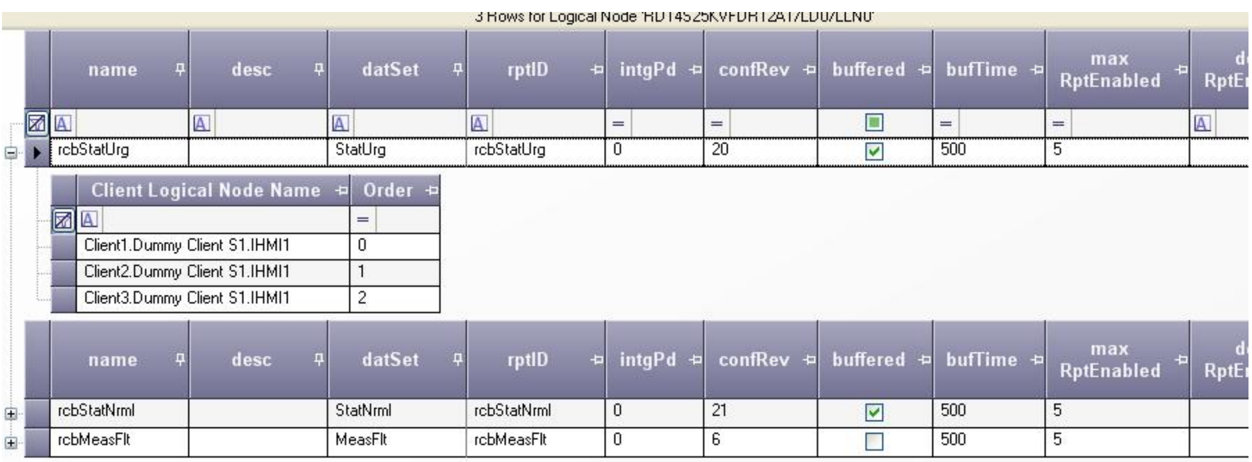
name	desc	datSet	appID	confRev	type
BFI_GCB	FDR12_GCB	BFI_B1	FDR12_GCB	3	GOOSE

Client IED	Order
RD14S25KVB1A1	0

Descr.	MAC-Address	APPID	VLAN-ID	VLAN-PRIORITY	MinTime	MaxTime
	01-0C-CD-01-00-01	0001	000	4	4	1000

Figure 8 - Sample GCB Engineering

Report control engineering defines the client and server relationship and report control parameters in report control blocks (RCBs). The Client icd file must be imported and integrated with the RCBs in this vendor's tool. An example of the RCB for a feeder IED is shown in Figure 9 below:



name	desc	datSet	rptID	intgPd	confRev	buffered	bufTime	max RptEnabled
rcbStatUrg		StatUrg	rcbStatUrg	0	20	☑	500	5

Client Logical Node Name	Order
Client1.Dummy Client S1.IHMI1	0
Client2.Dummy Client S1.IHMI1	1
Client3.Dummy Client S1.IHMI1	2

name	desc	datSet	rptID	intgPd	confRev	buffered	bufTime	max RptEnabled
rcbStatNrml		StatNrml	rcbStatNrml	0	21	☑	500	5
rcbMeasFlt		MeasFlt	rcbMeasFlt	0	6	☐	500	5

Figure 9 - Sample RCB Engineering

The final SCD file is exported from the System Integration Tool and imported back to the vendor specific IED engineering tool. For GOOSE related operations further custom logics were developed in each IED to apply the received GOOSE signals for protection and control operations (eg. BF initiation). Table 4 below summarizes the GOOSE applications among IEDs connected to Bus 1. The resulting IED configurations with GOOSE implementations are then uploaded to the IEDs to complete the engineering steps.

IED Type	GOOSE Published (To)	GOOSE Received (From)
Feeder Protection	Bus IED	Bus IED
	- Overcurrent Trips - Trip reinforcement request for control open or UF element operation - Breaker status	- 87B or 50BF trip (trip feeder breaker)
Transformer Protection	Bus IED	Bus IED
	- Transformer non-electrical protection operation - Transformer electrical protection operation - Non-protection trip - LV breaker status	- 87B or 50BF other than transformer LV breaker (trip transformer LV breaker) - 50BF of transformer LV breaker (clear HV bus)

Table 4 - Sample GOOSE Signals Between IEDs

VII HMI/GATEWAY ENGINEERING

The scope of HMI/Gateway engineering involves constructing a process database, designing and developing a Single Line Diagram for status and control operations, mapping the required data points in the database with those of SLD elements and establishing communication between the database and the processes. Traditionally automation system integration and HMI engineering falls solely on the responsibility of SCADA engineers. The advent of IEC-61850, with its promise of standardized data structure and inter-bay communication, has blurred the line of duty between the SCADA and P&C engineers. In this project, the SCADA engineer from Phasor Engineering undertook the entire P&C configuration, system integration, and HMI engineering work. The P&C team calculated the protection function's set points and supervised factory acceptance testing and commissioning. Therefore, P&C engineers must also have sufficient understanding of networking principles to be able to test and troubleshoot communication dependant protection systems.

The vendor's HMI/Gateway product utilizes the OLE for Process Control (OPC) interface to communicate with the 61850 servers (IEDs). The OPC interface, also known as the OPC server, creates a common data interface between the 61850 servers and clients. The use of the OPC standard enables third parties to develop an OPC server communicating in Manufacturing Message Specification (MMS) over TCP/IP that is independent of the vendors' applications. In terms of HMI/gateway application, this measure provides users with flexibility of low cost interfaces to connect processes to the HMI servers, event/alarm lists and trending reports, etc. To configure the OPC server and establish communication with the process devices, the vendor's software package is utilized to construct the substation structure defined by the IEC61850 standard. The substation configuration data has already been prepared and exported from the System Integration Tool in the SCL format as described in the previous section. The scd file can be imported to generate the data models for each IED (Figure 11). Dataset and report control information is also displayed in the data structure in the OPC server configuration software. A properly configured OPC Server is capable of communicating with IEDs in real-time, updating data attribute status or issuing control commands (eg. open/close breakers). Figure 10 displays the communication process between the HMI/Gateway and the IEDs.

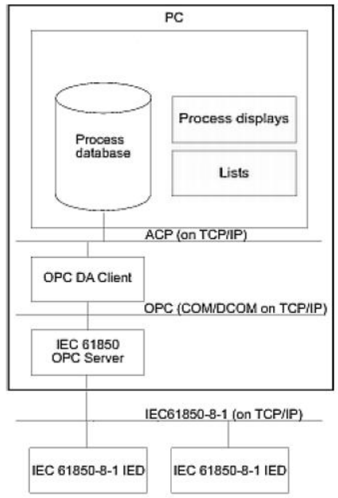


Figure 10 - Communication Procedures Between HMI/Gateway and IEDs in IEC-61850[4]

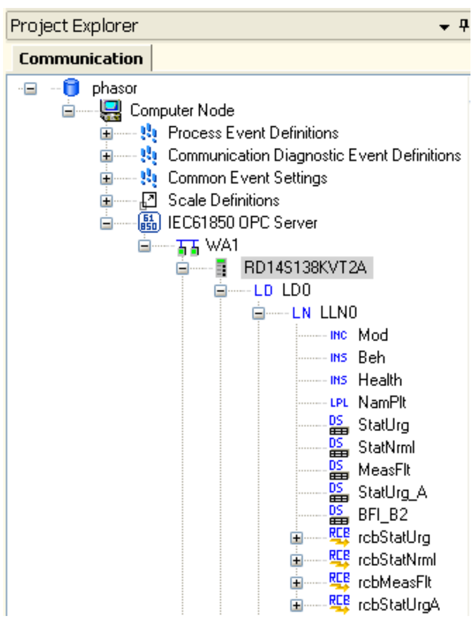


Figure 11 - Substation Data Models in OPC Server Configuration Software

An OPC Data Access Client, located in the same physical hardware, acts as an interface between the OPC data exposed by the OPC Server and the base system process database. The use of the OPC standard permits any OPC client to retrieve IEC-61850 data from any OPC server via the OPC protocol and leaving the HMI base system proprietary to the vendors. Data objects of each IEC 61850 IED are defined to belong to a specific OPC group and communication station representation. The OPC DA Client configuration tool is used to map the 61850 data attributes of each IED from the OPC Server to the process database in the base system through the vendor's proprietary addressing system.

The process database consists of process objects. Each process object is linked to one or several indication or control objects on the process display (SLD) using a scripting language. Each process object represents a logical node of an IED and consists of several indices. Each index represents an IEC-61850 data attribute of a certain data type (indication, analog, binary outputs) and receives its value updates from the OPC DA Client based on the station number (Unit Number) and object address (Block and Bit number) configuration. Process objects can be created manually from the standard library or by using the automated SCL importer tool. Both methods were adopted in this project to create data points. The SCL importer tool is an efficient way to create a large amount of process objects corresponding to the logic nodes defined in the Substation Section of the scd file. The manual method was used to create a limited number of objects targeting a specific application usually after new logic nodes were added to the IED functionality and/or when re-importing the entire scd file was considered unnecessary and time consuming.

HMI engineering involved the design and development of the operator single-line diagram for indication, control, and supervision purposes. Each process object can be linked to standard or customized ANSI/IEC animated process symbols via an efficient drag-and-drop procedure. The process symbols retrieve their status update and execute the control command through the OPC Server, OPC client and process database chains of communication.

Gateway engineering consisted of mapping data from the process database to the format defined by the slave protocols, in this case, DNP3.0. The gateway module routes the indication signals from the processes to the different SCCs and the command signals in the opposite direction. A signal cross-reference tool is used to perform such signal mapping. The following procedures were followed[5]:

- Define the SCCs and the information related to it, for example, the information of SCC (name, IP) and the slave protocol to be used (DNP3.0).
- As stated previously the gateway and HMI modules share the same process database for a pool of process data. Verify that the desired indication and command data points are correctly displayed in the mapping tool.
- Create new alarm points by grouping various indication points in the process database.
- For indication type signals, define the DNP3.0 address, extra scaling and data handling requirements for each signal ie Object and Variation.
- For command type signals define the DNP3.0 indices to which the gateway should receive commands from the SCC and other information such as types of command (eg. secured command with five output objects) and purpose of each output (open select, close select, open execute, close execute, cancel).

Table 5 below summarizes the indication and control signals served by the IEDs to/from the HMI and gateway.

IED Type	Indication	Control
Bus Protection	- 86B lockout indication - 86BF Lockout indication	- 86B reset lockout control - 86BF reset lockout control

	- protection alarms	
Feeder Protection	- Breaker position - local/remote control mode - Auto-reclosing on/off indication - UFLS (81U) on/off indication - protection and apparatus alarms	- Breaker open/close commands - On/off auto-reclosing control - On/off UFLS (81U) control
XFMR Protection	- HV MOD positions - HV MOD local/remote status - LV breaker positions - LV breaker local/remote status - 86LO Indication (transformer faults) - OLTC tap positions and manual/auto mode - protection and apparatus alarms	- HV MOD open/close commands - LV Breaker open/close commands - 86T lockout reset control - OLTC manual Raise/Lower commands

Table 5 – Summary of HMI Control Functions and Indications

VIII PARALLEL REDUNDANCY PROTOCOL (PRP) [2]

System redundancy is critical in high-voltage substations to maximize availability by avoiding any single point of failure. In traditional centralized SA systems redundancy in protection is achieved through duplication of protective devices (eg. main A and main B). Naturally, all hard-wired critical communication links to the remote terminal units can also be duplicated by doubling the wires. Redundancy by this method is reliable but costly. Part of the purpose of IEC-61850's networked communication approach is to reduce wiring and installation costs within a substation control house. An Ethernet network accomplishes redundancy through network reconfiguration protocols residing within the Ethernet switches. The Rapid Spanning Tree Protocol (RSTP), in which the Ethernet switches maintain a list of all possible network path and reconfigure the network path once the original one has failed, is one such example. The disadvantage of RSTP is the reconfiguration delay, typically ranging from tens of milliseconds to multiple seconds depending on the number of Ethernet switches in the network. This time delay in data switching is unacceptable for time-critical power system protection applications such as GOOSE messaging transmitting trip signals or IEC-61850-9-2 process bus transferring current sample values.

IEC-62439 defines a set of Ethernet-based protocols providing high availability with minimum switch-over time. PRP is one of the network redundancy protocols defined in this standard with a seamless redundancy property. In PRP the redundancy is implemented in the "device" level, as opposed to RSTP where the redundancy protocol is implemented within the Ethernet switch. Each device with double-attached-node (DANP), such as Dual Ethernet ports, is connected to two independent Ethernet networks (see Figure 12) operating in parallel. The source device sends Ethernet fames over each LAN and the receiving device consumes the first frame received and discards the second frame. The two LANs may have different topologies and performance. Since one data frame will be discarded at the MAC layer before reaching the upper layers of the OSI model, from the Ethernet switch's perspective there is still only one IP address despite the two physical Ethernet ports. Due to the fact the source sends data frames via two separate LANs in parallel, there will be no reconfiguration time for any single-point failure, thus making zero reconfiguration delay a reality. The PRP network architecture implemented in this project is shown in Section V.

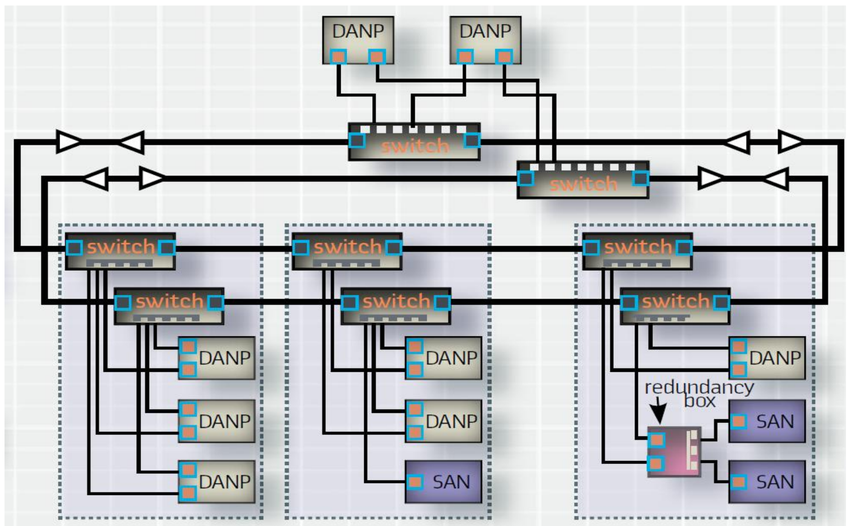


Figure 12 - Example PRP Connections in a ring structure

IX FACTORY INTEGRATION TESTING AND SITE COMMISSIONING

The factory acceptance (pre-commissioning) testing was conducted in The Engineer's integration shop. Once the construction of all panels was complete and the panel wiring was verified the panels were powered up and the IEDs were connected to the LANs A & B. A test breaker for each real breaker in the substation was wired to the appropriate IEDs. These test breakers were capable of accepting trip and close signals and providing 'a' and 'b' breaker status. That is, test breakers for each feeder were wired to the feeder IEDs and test breakers for the transformer LV breakers and tie were wired to the transformer and tie breaker protection panels.

The system setup described above is essentially the fully functioning P&C system except for the connection to the customer's control center and wiring to any primary equipment. Any number of operating or faulted conditions could be simulated by closing or opening the appropriate test breakers and supplying analog voltage and current signals to the IED using a standard relay test set. Additionally, all the control functionality, alarms, metering, etc. from/to the substation HMI, IED front faceplate HMIs, and local control switches were able to be verified ahead of time in the shop rather than on site.

To help keep the project on schedule and because traditional methods of relay testing are "tried and true", factory acceptance testing proceeded in a largely traditional manner with the addition of a couple GOOSE message monitoring techniques. Voltage and current analogs were supplied to one or more IED(s) to simulate a fault or a normal operating condition and the proper operation (or restraint) of the IEDs was confirmed and/or timed using the hard wired relay outputs. For example a feeder fault and subsequent breaker failure was simulated by supplying fault current to both the feeder and bus relays. It was seen that the feeder and bus relays attempt to trip the faulted feeder's breaker instantaneously (the bus relay trips due to its re-enforcement functionality) and then after the breaker failure delay all the other breakers on the bus are tripped.

The IED vendor also supplied a network analyzing tool for monitoring the GOOSE traffic in the station bus. A laptop was connected to one of the substation LANs and the IED configurations can be auto detected and browsed online. Next, when a test is run the monitoring tool can be used to confirm if the correct GOOSE message(s) were sent/not sent and that the timing of these messages relative to one another makes sense. The output of the GOOSE monitoring tool for the example of the faulted feeder/breaker failure scenario described above is shown in Figure 13. The red line in the top half of the figure shows the trip operation of the feeder IED and the bottom half shows the operation of the breaker failure function. The blue line depicts the measurement of the time delay (270 ms) between the two signals, which matches the set point closely.

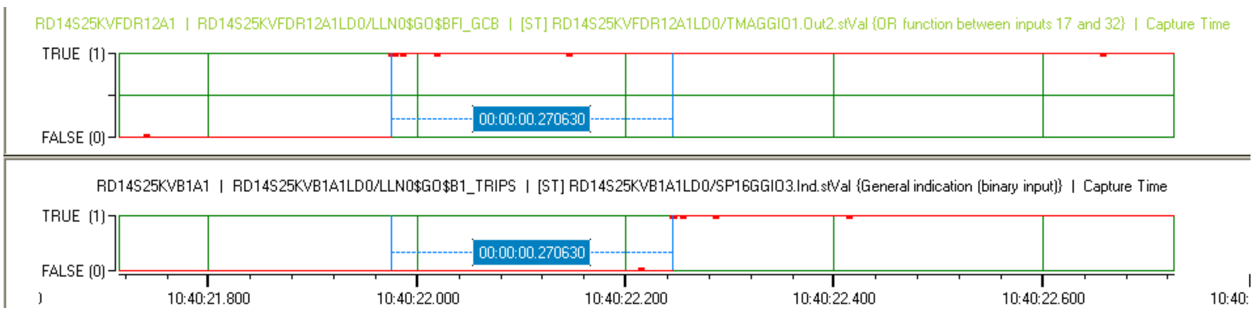


Figure 13 - Screenshot from the vendor's GOOSE traffic monitoring tool

Another method used to monitor GOOSE traffic was to connect online to the IEDs using the relay software and monitor the outputs of the GOOSE Receive function blocks in the IEDs themselves. This simple method was the one typically used to confirm changes to an IED's configuration or when trouble shooting a suspected configuration error. This method is not considered sufficient to prove the system is fully functional as the refresh rate in the IED software is slow and unknown and there is no way to accurately time the GOOSE traffic.

The most advanced method of monitoring GOOSE traffic used on this project was employed on site during re-testing of previously in service relays after additional functionality was added to some of the IEDs at the request of the City (after the IEDs were originally commissioned). The relay test set used by the Engineer is capable of publishing or subscribing to GOOSE messages. The SCD file is first imported into the test set software and then any attribute in the data set can be published or monitored by the test set by configuring the data attribute as a virtual input or output. For example, a breaker fail initiate from a feeder IED can be configured as a virtual input to the test set. Fault current can then be simulated to the feeder protection and the time until the breaker fail initiate signal can be measured by the test set.

With all IED protection functions, inter-IED communication (GOOSE) and HMI-IED communication (MMS) previously verified as part of the factory acceptance testing, field commissioning activities were limited to a cursory verification of the previously tested functionality, complete testing of the controls from/indication to the City's control center and the normal verification of wiring between the protection panels and the outdoor primary equipment. In reality there were some additional tests conducted in the field in order to verify configuration changes resulting from small changes to functionality requested by the City late in the project.

The vast majority of issues uncovered during field commissioning were related to interfacing the new system with the City's control center and various challenges with the older outdoor primary equipment. Once installed on site and connected to the LAN(s) the system functioned exactly as it did in the shop during the factory acceptance testing. Since inter-IED communication is handled via GOOSE and IED-HMI communication is handled via MMS there was very little inter-panel wiring to be verified on site. This resulted in a reduction in time spent on site commissioning.

X LESSONS LEARNED

As alluded to above, the engineering steps taken to successfully design and implement this IEC 61850 based SA system required a different sequence of engineering steps than a traditional substation. The steps used to develop this system were described previously but it is now explained why defining the 61850 messaging requirements at the beginning of a project is a step worthy of extra emphasis. Since much of the inter-IED communication which would normally be handled with hard wired inputs and outputs is now handled using GOOSE messages adding a signal from one relay to another is relatively simple because there is no need to identify spare IED inputs/outputs, pull cables between panels, terminate any wires nor mark up any prints. However, since updating the 61850 configuration in the IEDs required a complete re-write of the devices' configuration file it was necessary to perform a functional re-test of the IEDs after any such changes. So although changes can be, an indeed were, made to the 61850 communication configuration late in the project the added time spent re-testing the devices demonstrated the importance of developing detailed requirements at the start of the project to avoid the need to re-test IEDs.

An issue raised by field commissioning staff which the engineer plans to address in future 61850 projects relates to the way in which the 61850 GOOSE messages are documented in the design prints. When removing a relay from service, field staff is accustomed to consulting a DC schematic to discover what relay outputs are used and which cutoff blades need to be opened to isolate the device to prevent mis-operations during testing or other maintenance tasks. Field staff is used to seeing a LAN connection only being used for SCADA alarming and control or remote access type functions. In this project the GOOSE signals sent and received over the LAN are documented on each device's logic diagram and also on the scd file. However, since the field staff indicated they do not typically consult logic diagrams when isolating a device and could be oblivious of the scd configuration, this style of documentation may not be sufficient. The addition of a note on the DC schematic and/or labels affixed to the protection panels in the substation were discussed as possible mitigations to the risk of mis-operations due to incorrect device isolation. The quality bit contained in a GOOSE data frame when an IED is put in "test mode" can also be used to block GOOSE operations in the subscribing IEDs. Nevertheless, until the 61850 GOOSE system is common and personnel become familiar with it, extra warning labels and documentation standards are required to minimize the risks.

An unanticipated complication arose due to a conflict between the City's requirement to keep the existing stand alone transformer tap changer controllers and also apply the IEC-61850 compatible tap changer controller in the IEDs. Without going into overwhelming detail the issue can be described as follows: The City required the new SA system to control the existing tap changer controller through hard wired signals going to and statuses coming from the transformer junction boxes where the existing controller resides. The vendor's system includes a simple method of interfacing a tap changer controller in the IED with a graphical control interface (raise, lower, etc.) in the Station HMI system. However this convenient IED/HMI tap changer controller was intended to control a tap changer and not a tap changer controller. A few creative logics were implemented in order to "fool" the SA systems tap changer controller into controlling another controller rather than the tap changer itself.

Finally, one of the main enhancements to SA system engineering, troubleshooting and maintenance provided by IEC 61850 is the standardized nomenclature of various P&C functions and their abstract data models. By using standardized data attributes in GOOSE messages, the data contained in the dataset is self-descriptive and can be applied in the subscribing IED without the need to cross-reference for the meaning of the data sent by the publishers. Such standardization of signal names could improve efficiency during commissioning and save time when troubleshooting the SA system. For signals not defined in the IEC 61850 standard, the generic logic node GGIO is implemented by each vendor to allow for reporting and exchanging of those substation signals (eg. external transformer alarms) over the network. In the IED engineering stage of this project, GGIO objects were used in many instances where standard IEC 61850 logic nodes could have been applied to take advantage of the benefits mentioned above. Refer to Figure 7 for the dataset using TMAGGIO and SP16GGIO to send protection trips and breaker status via GOOSE messaging where the standardized PTRC and XCBR logic nodes could be used. The reasoning behind such implementation was based on the consideration that only protection operations should initiate BF protection. In a feeder IED GOOSE application as depicted in Table 4, only over-current operations initiate the BF protection. Control and under-frequency load shedding operations would only open the breaker and operate the reinforcement relay. Since there is only one PTRC instance available in this IED firmware, it was then decided to use the GGIOs to separate the two different tasks. Similarly, a SPGGIO was selected to transfer the 52a status from the feeder IED to the bus IED for use in the breaker trouble alarm logic. A single-point binary signal is sufficient to develop such alarm logic and the double-point signal provided by the standard data attribute (XCBR.pos.stVal) is not deemed necessary. Indeed, more efforts could be spent on making sure the standardized data models were utilized to their full extent. However, due to realistic time and budget constraints it was decided by The Engineer to leave this experience as a lesson to improve upon and as training to this new and powerful substation automation technology.

XI CONCLUSIONS

The majority of this IEC-61850 project proceeded in a manner similar to a traditional substation. Additional demands were placed on engineers and field staff to step outside of their previous experience and learn to apply this new technology. Relatively unfamiliar software tools presented additional challenges when configuring the system but this issue is not unique to 61850.

Once the system was running, it operated as intended. Messaging via GOOSE and MMS operated reliably and the parallel redundancy protocol delivered redundant communications with no switching time in the event of a LAN failure. This project proved to us that 61850 is ready. Third parties can successfully purchase, install and operate a system based on 61850.

Engineers considering applying 61850 to their own projects should carefully evaluate the pros and cons before deciding if it makes sense for their particular project. This evaluation should include determining if they have sufficient time and resources to dedicate to training/learning in order to become proficient at applying the standard. If one does decide to implement a system using 61850 devices we expect they will find their system operate reliably and as designed.

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BIOGRAPHIES

Blair Vincent graduated from Memorial University of Newfoundland Canada in 1987 with a Bachelor degree in Electrical Engineering. He is currently a licensed Professional Engineer as a member of APEGGA . He worked 13 years with the Newfoundland Power (Fortis) as the Distribution Engineer, Substation Design Engineer and Substation Standards Engineer. Blair moved to Alberta in 2000 to pursue a career in SCADA with TransAlta, now Altalink. He moved to Jacobs in 2008 to work on various SAGD oil sands projects and now is the Principle Substation automation Engineer with Phasor Engineering.

Mike Reynen received his Bachelor of Science degree in electrical engineering from Queen’s University in Ontario Canada in 2007. He then attended the University of Calgary in Alberta Canada where he completed a thesis advancing an islanding detection method for distributed generators and received his Master of Science degree in electrical engineering in 2009. Since joining Phasor Engineering his primary activities have been the development of protective relay settings as well as relay testing and commissioning.

Jack Chang is a technical regional manager for ABB Inc. in the Substation Automation Products business unit serving customers in western Canada and northern regions. He provides engineering, commissioning and troubleshooting support to customers applying ABB’s high-voltage protective and automation devices. Prior to joining ABB, Jack worked as a P&C project engineer in two highly specialized consulting firms in the field of HV substation design and as an engineering consultant to a public owned utility in their transmission expansion and upgrade projects. He is experienced in P&C planning, layout design, SLD, AC, DC schematic development, relay setting calculation and coordination, power system modeling and studies, and system testing and commissioning. Jack is a registered professional engineer in the province of Alberta, Canada. He received his B.Sc in Electrical Engineering and an M.Sc with thesis work focusing on real-time power system transient simulation using EMTP.