Experience with a Point-to-Point Process Bus in a Substation Pilot

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Abstract – IEC 61850 GOOSE Station bus has been in use since the early 2000's with various applications such as controls, interlocking, and blocking with substations across the world running successfully in multi-vendor environments. IEC 61850-9-2 sampled values process bus has been available since 2009 but have yet to gain popularity though. Introduction of IEC 61850 process bus has led the way to real world deployment of digital substations. There have been several papers published and studies done on the design benefits and various tangible and non-tangible savings attained in digital substations as compared to conventional substations. This has interested utilities across the world to start deploying digital substations as pilot projects to realize the benefits, understand the challenges to deploy such systems and have practical experience while comparing digital substation to a conventional system.

This paper discusses AltaLink's approach and experience in deploying and operating one of the first digital substation pilot projects in Western Canada. The project started with a concept design and evaluation of available vendor products. The preliminary design concept was prepared and tested in the lab before selecting the products. A 138kV switching substation consisting of simple bus arrangement with three transmission lines and a capacitor bank was selected for the endeavor.

The paper also discusses performance of protection systems during faults and a comparison to conventional relaying systems is presented.

Index Terms — Digital Substation, Process Bus, IEC 61850, GOOSE, Protection and Control (P&C) Systems, Intelligent Electronic Device (IED), NCIT, MU, PIU, RIO

I. Introduction

GOOSE has been in use since the late 90's, first as UCA GOOSE until the IEC 61850 standard was established in 2004 and since then as IEC 61850 GOOSE for various applications such as controls, interlocking, blocking etc. with substations across the world running successfully in a multi-vendor environment. IEC 61850-9-2 Sampled values and switched Ethernet process bus have yet to gain popularity, even though this technology has been available since the late 2000's first as point-to-point and since around 2014 as point-to-many architectures.

Introduction of IEC 61850 process bus and availability of NCITs (Non-Conventional Instrument Transformers),Merging Units (MU) and Process Interface Units (PIU) have led the way to real word deployment of Digital Substations. There have been several studies done and papers have been published on the design benefits and various tangible and non-tangible savings attained in digital substations as compared to conventional substations. This has interested utilities across the world to start deploying digital substations as pilot projects to realize the benefits, understand the challenges to deploy such systems and have practical experience while comparing digital substation to a conventional system.

This paper discusses AltaLink's approach and experience in deploying and operating one of the first digital substation pilot projects in Western Canada. A 138kV switching substation consisting of a simple bus arrangement with three transmission lines and a capacitor bank was selected for this endeavor. A point-to-point process bus, networked process bus and station bus GOOSE are deployed for protection and control of the entire substation including line protection, capacitor bank protection, bus protection and breaker management protection/reclosing. The aim of the project is to evaluate and learn the state-of-the-art digital substation technology, monitor performance, compare with various aspects to a conventional substation and device a strategy for future deployment.

All primary assets are protected with redundant protection systems which utilize different process bus architectures.

System B is a LAN architecture and consists of, Merging Units (MU), Remote Input/Output Units (RIO), Protection IEDs supporting IEC 61850-9-2LE, IEEE 1588 Clocks and Substation hardened Ethernet switches with fibers connections.

System A is a point-to-point architecture and consists of Process Interface Units (PIU), Protection IEDs supporting point-to-point communications to the PIUs through fibers.

Both system IEDs are inter-connected via Substation hardened Ethernet switches for station bus GOOSE communications and to a substation computer to allow remote SCADA.

II. What is Digital Substation?

The term Digital Substation generally refers to a substation that employs both IEC 61850 Process Bus [1] and Station Bus [2] in its protection & control architecture. In a digital substation, the primary signals such as current and voltage measurements, switchgear position status and control etc. are digitized in the field at the process source and are sent to the protection & control devices and tripping/control signals are sent to the field devices via fiber optic cables as per IEC 61850 9-2 and IEC61850 8-1. The communication between station level devices is achieved using IEC 61850 GOOSE and MMS services.

The goal of a digital substation using process bus is to digitize and send voltages and currents (from VTs and CTs) to the IEDs; and facilitate exchange of equipment status (such as breaker/switch status), alarms and control points (such as breaker/switch trip/close) between primary equipment and the IEDs. The field level process devices (MUs and PIUs) and digital instrument transformers are connected to one or more substation process devices (such as protection IEDs, digital fault recorders (DFRs) or remote terminal units (RTUs)) in a network or point-to-point configuration to perform substation applications such as Protection and Control, asset performance management, dynamic transformer/line loading/rating, substation analytics, wide-area monitoring (WAMS), distributed energy resources management (DERMS), control plane (SCADA) and edge management. Below is a simplified representation of a digital substation using process bus.

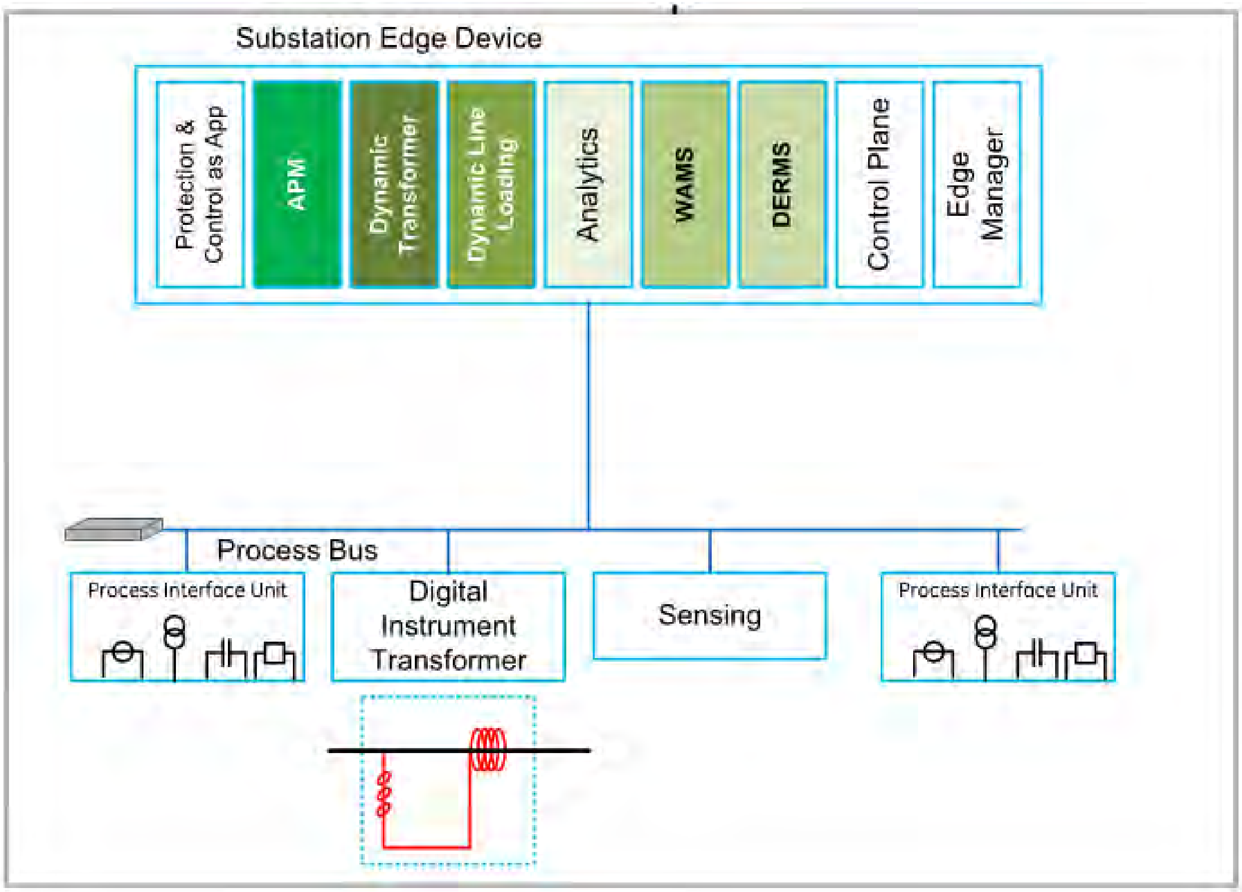

Fig 1: Simplified Digital Substation

A digital substation hence consists of a distributed architecture as follows:

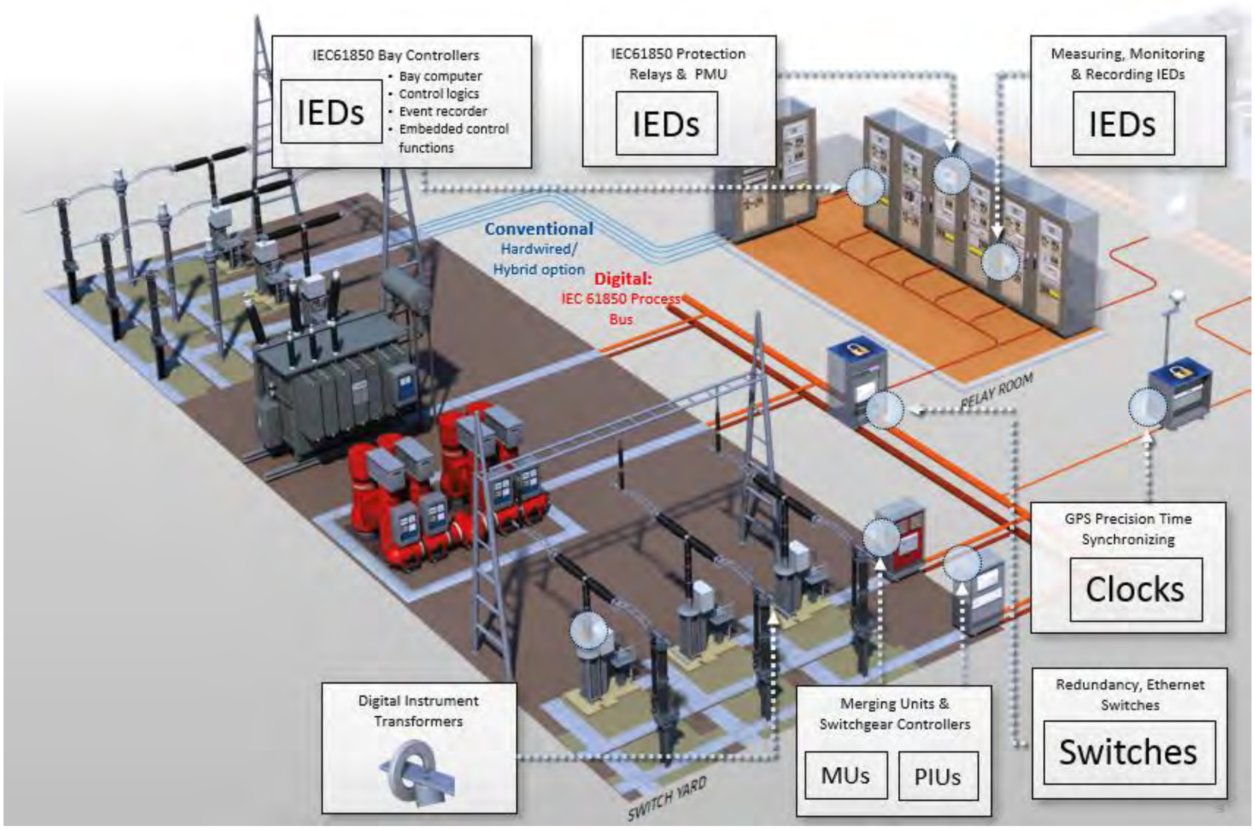

Fig 2: Distributed Architecture of Digital Substation

Digitization of field data is performed by MUs or PIUs. Example connections of a PIU is as follows:

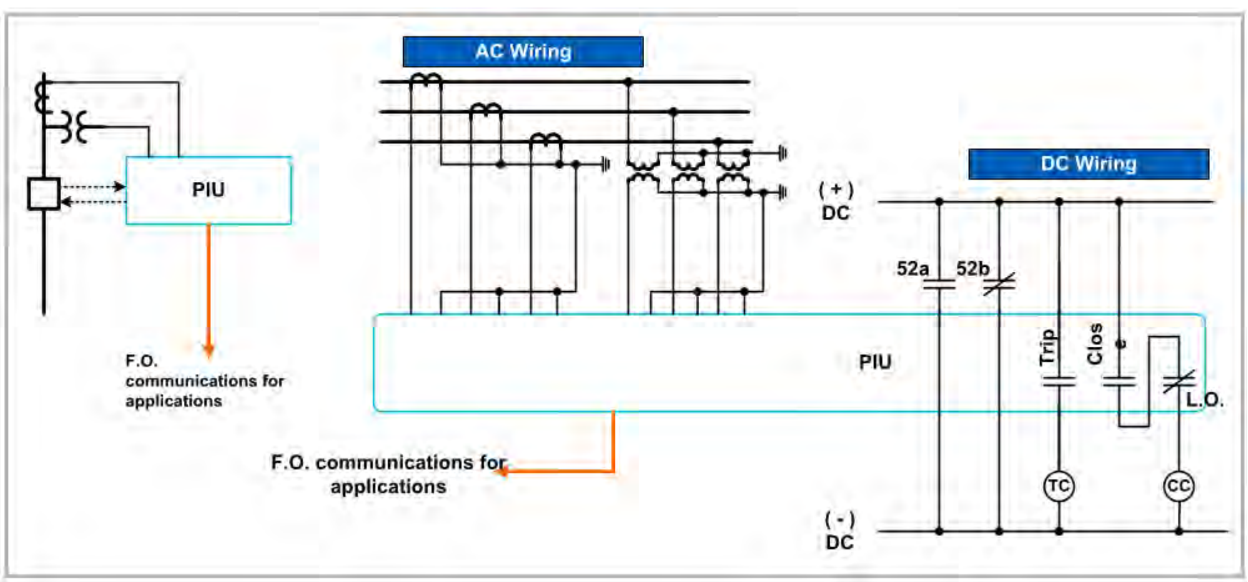

Fig 3: Process Interface Unit (PIU) example

III. Process Bus Connections

Connections between the process bus field devices (MUs, RIOs and PIUs) to the substation application devices (IEDs, DFRs and RTUs) can be either 1-to-many (networked) architecture or 1-to-1 (point-to-point) architecture.

A. 1:Many or Many:1 Architecture (LAN)

In this architecture, one connection to/from modules (all data needs for a single substation component such as a breaker) contain all data. A module can consist of one or multiple MUs, RIOs or PIUs.

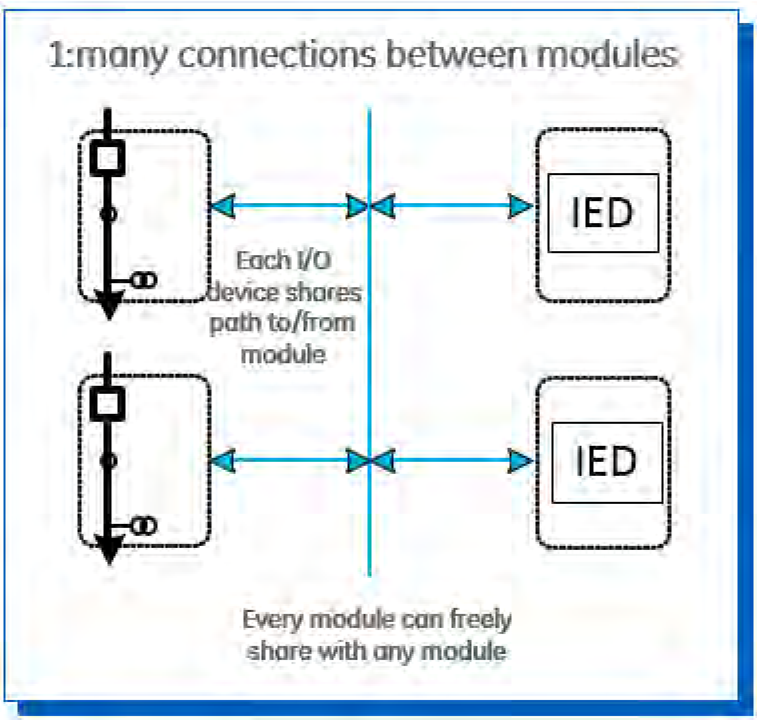

Fig 4: 1:Many Connections Between Devices

This configuration implies the need of a network typically deployed as a local area network (LAN).
This architecture has the following pros and cons:

- Multiple I/O devices (consisting of MUs, RIOs or PIUs) can be applied per bay. If more I/O or analog measurements are needed, another I/O device can be added, wired and connected to the network with minimal configuration.
- Data is available from all I/O devices to all devices connected to the network.
- Number of devices are only restricted to network bandwidth and can be substantially more than the 1-to-1 architecture.
- One or more time synchronizing clock with IEEE1588 or PTP is needed to synchronize all field and application devices.
- A network must be provided, configured, maintained with the following in mind:
    - Bandwidth requirements
    - Communications traffic shaping; i.e. need to have VLANs configured if needed.

- o Reliability. The network might need to be duplicated allowing parallel redundancy protocol (PRP), or high-availability seamless redundancy (HSR) can be used
  - o Ownership. Who owns and maintains this network? Must be part of maintenance plans.
  - o Time Synchronization capabilities is essential
  - o Cybersecurity must be implemented to ensure conformance to NERC CIP.
- All devices must be configured; hence any configuration changes can impact multiple devices.
- This architecture overall MTBF must consider the MTBF of all devices, including field, application devices, clocks and network devices and is typically lower than the MTBF of the 1-to-1 architecture.

A simplification of flow of data can be described as below for this architecture for analogs in the form of sampled values (SV), digital I/O in the form of GOOSE (GO) and time synchronizing signals (1588):

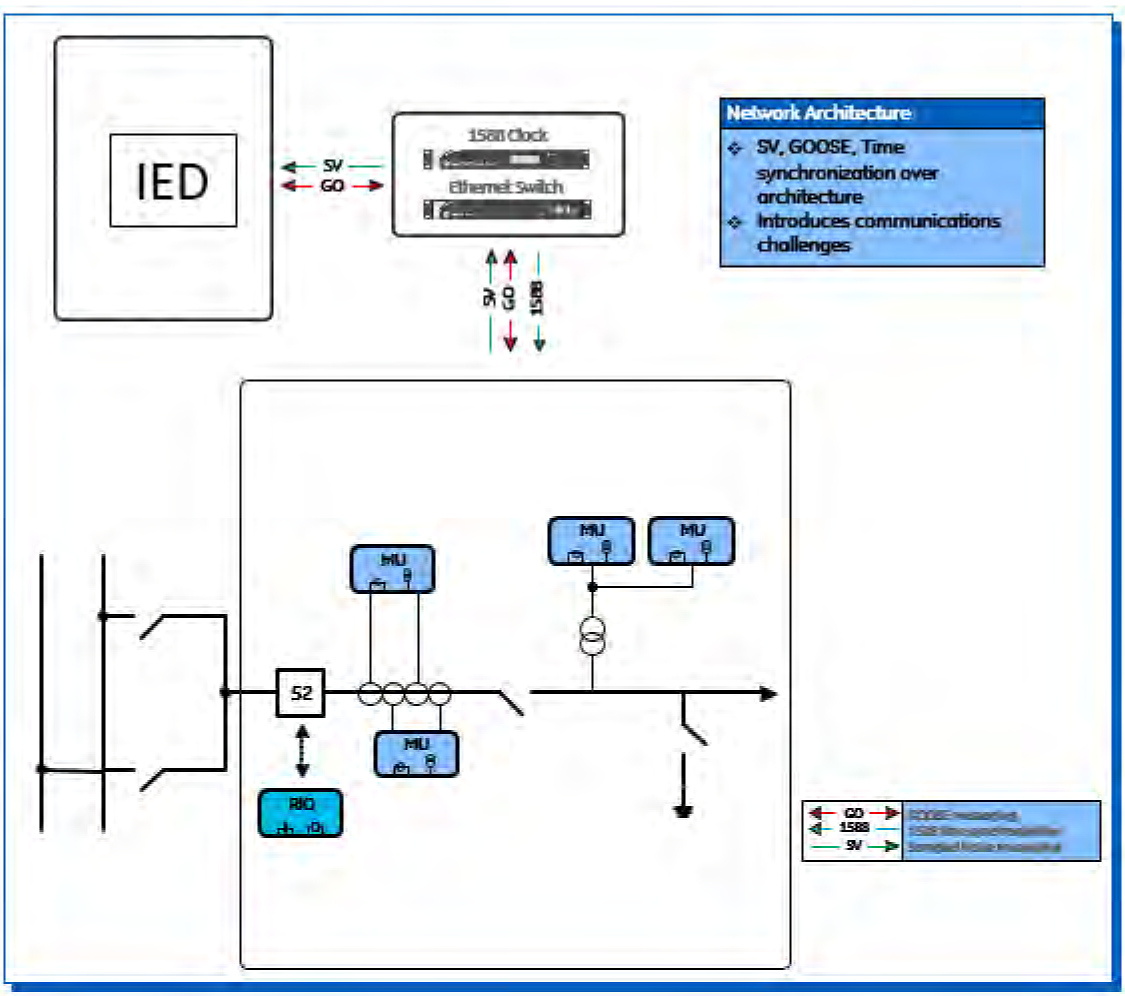

Fig 5: LAN Architecture

B. 1:1 Architecture (Point-to-point)

This configuration, also described as point-to-point architecture, has a direct connection from the field device to the application device:

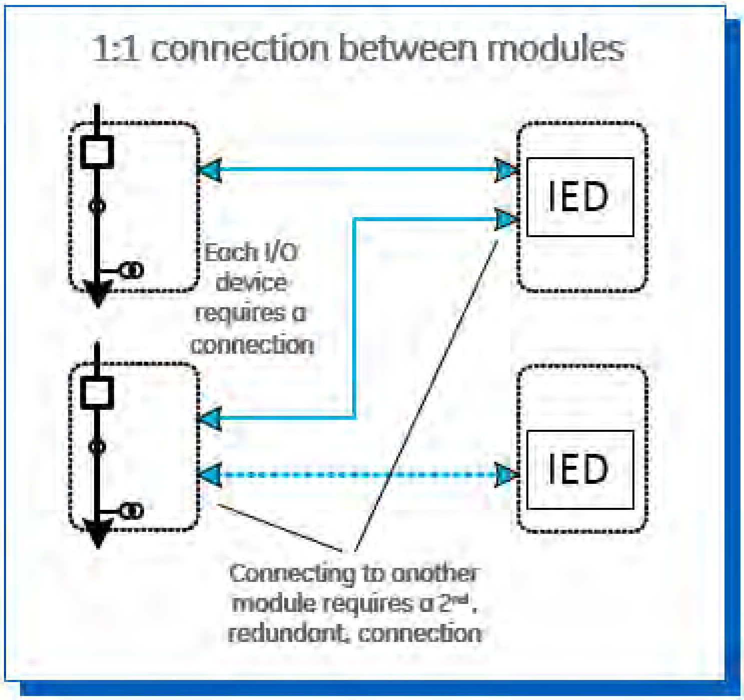

Fig 6: 1:1 Connection Between Devices

In this configuration, there is a direct connection between the field (or bay) device and the application device or IED.

The IED and field device (or PIU) must allow multiple connections ensuring all digital and analog values from the primary equipment bay is captured by the IED and redundancy could be achieved:

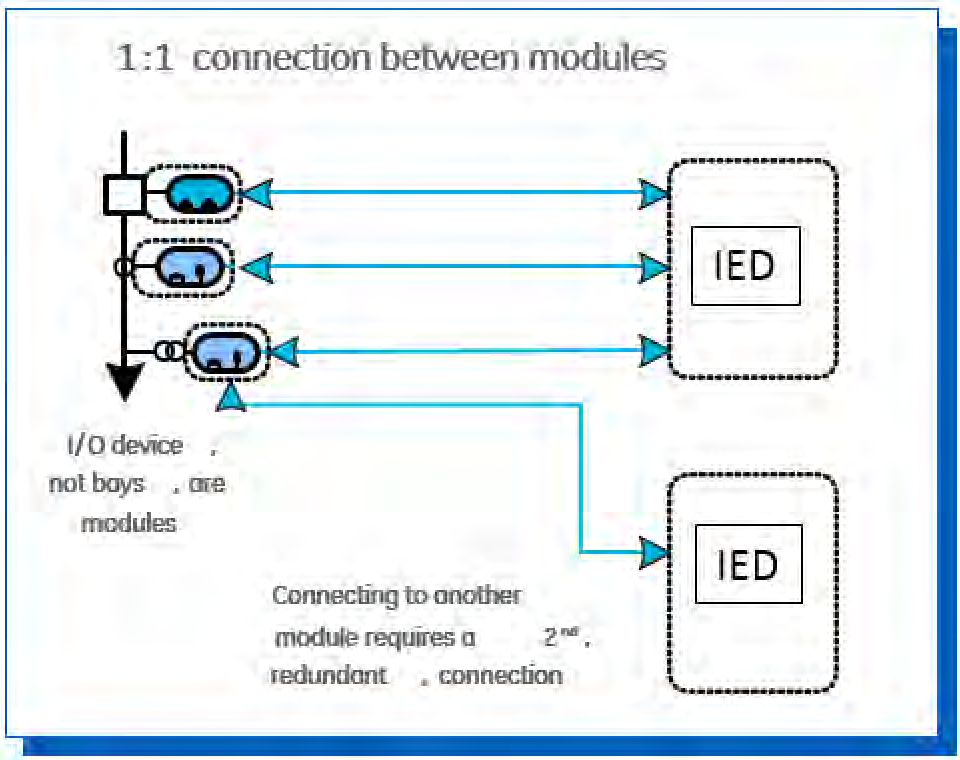

Fig 7: 1:1 Connection Between Multiple Devices

This architecture has the following pros and cons:

- One to one correlation between field device and IED.
- Communications is point-to-point, hence enclosed, simple and intuitive to implement.
- Field devices are configuration free; all programming is done only in the IED.
- No clock is required since time synchronization is applied from the IED.
- No network is required, hence:
  - No network equipment with time synchronizing needed.
  - No cybersecurity concerns since the communications network is closed and not exposed as a network.
- This architecture has the best MTBF for a process bus implementation
- I/O devices and IEDs must support multiple connections.
- More fiber connections are needed between field devices and IEDs, especially if redundancy is required.
- I/O devices must have point count to support application; if not, more devices must be added for higher point count requirements.
- Data of the process bus can’t be readily shared among multiple application devices; a point-to-point connection is needed to each device.

A simplification of flow of data can be described as below for this architecture for analogs in the form of sampled values (SV), digital I/O in the form of GOOSE (GO) and time synchronizing signals (1588):

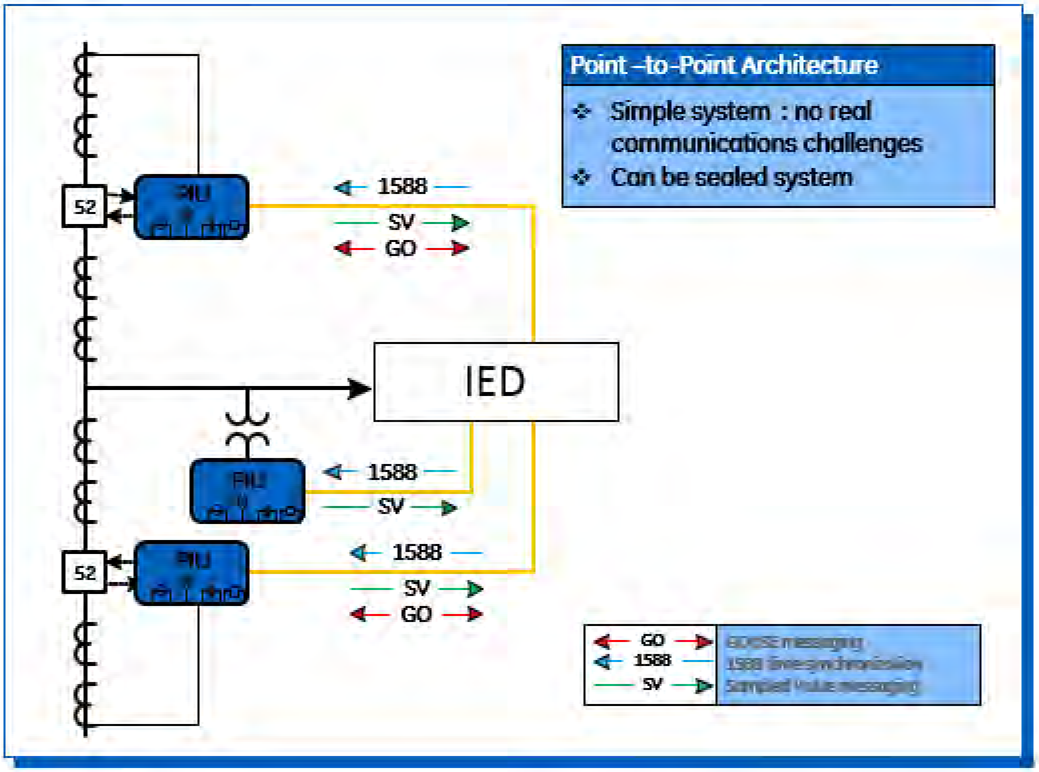

Fig 8: Point-to-point Architecture

IV. ALTALINK'S POINT-TO-POINT PROCESS BUS DEPLOYMENT

A. Introduction and Background

In 2016, AltaLink started work to develop and deploy a digital substation leveraging scheduled control building replacement work at a 138 kV substation; Blackie. This substation was selected as it was scheduled to be upgraded, has a small footprint and is close to company engineering office and field office. Blackie is a 138 kV switching substation with a simple bus arrangement, three transmission lines and a capacitor bank.

The pilot project included installing new protection relays and SCADA equipment while retaining the existing primary equipment and telecom infrastructure. All protection and control relays were upgraded from mainly from electromechanical to numerical relays to utilize process bus IEC 61850 sample values and GOOSE messaging at process bus and GOOSE at station bus levels.

The digital substation has been operational since November of 2018. Single line diagram (SLD) of Blackie is as follows:

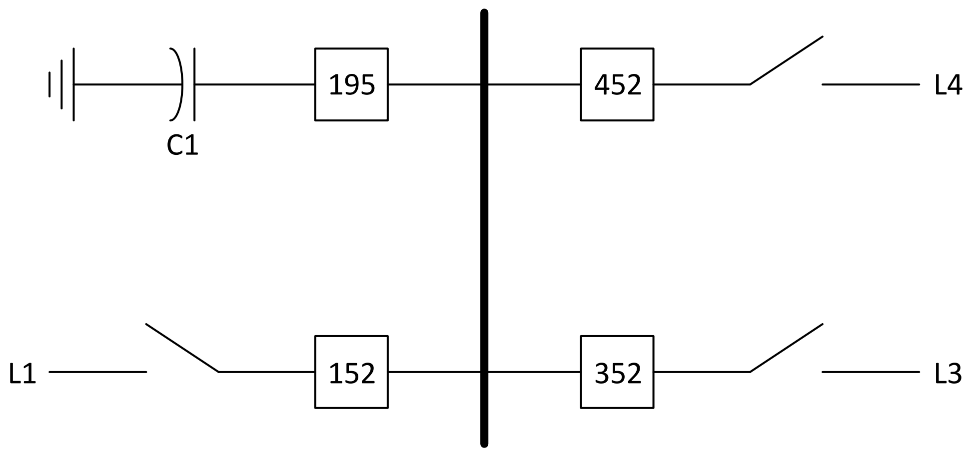

Fig 9: Blackie Substation SLD

The protection and control systems are mostly redundant and consists of two architectures:

1. System B: LAN process bus architecture covering distance-based line protection for the three 138kV circuits, bus protection and capacitor bank protection. The last two are not redundant.
2. System A: Point-to-point process bus architecture covering distance-based line protection for the three 138kV circuits, and four breaker-management IEDs for the four 138kV circuit breakers. Aspects of both systems are noted in the paper; however, the focus of following discussion is point-to-point system:

Both systems are connected to redundant station RTUs via IEC 61850 MMS. The RTUs communicate to AltaLink EMS similar to any other station.

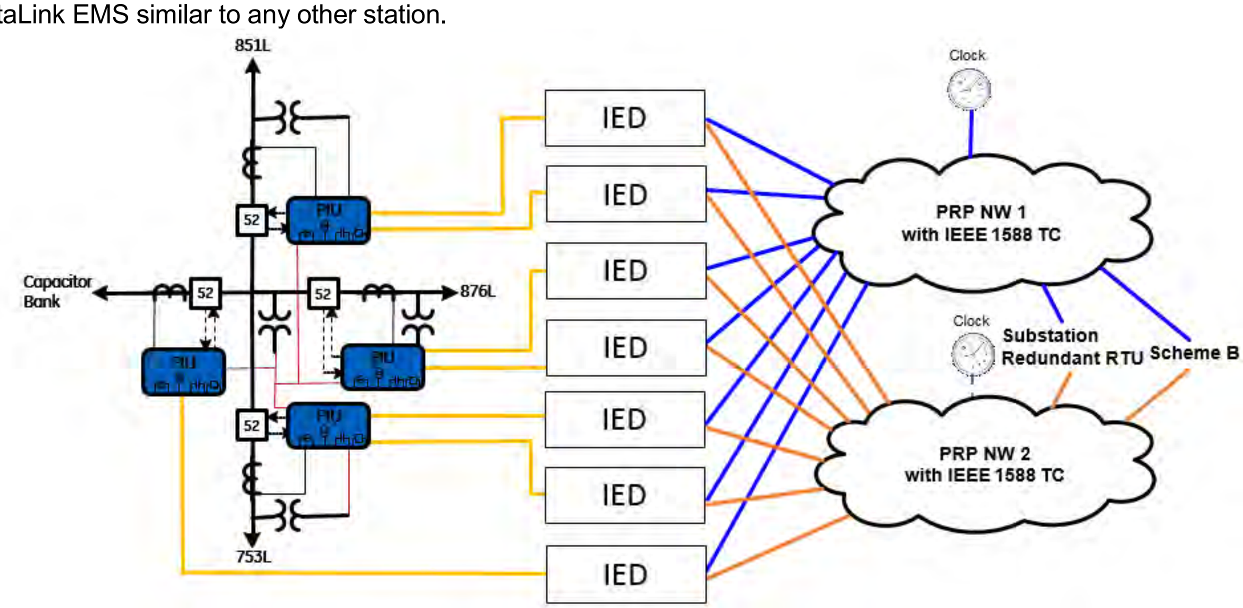

Fig 10: Blackie System A Architecture

System A consists of four process interface units (PIUs) connected point-to-point to three line protection IEDs and four breaker management IEDs. The primary function of the breaker management IEDs is breaker failure protection and auto-reclosing. The breaker management IED associated with the capacitor bank breaker also performs capacitor bank protection to provide redundant protection. The breaker management system is not redundant. All IEDs are connected via two redundant Ethernet networks to each other, to system B and to the substation RTUs all using parallel redundancy protocol (PRP) which forms the station bus network.

The PIUs of system A and MUs, RIOs of system B are all installed in junction boxes physically close to the primary equipment and switchgear in the HV yard, connected via copper wiring to VTs and CTs; and all protection and control digital inputs (status and alarms) and outputs (tripping/closing) from and to primary equipment respectively. PIUs, MUs and RIOs are connected via fiber cables to all IEDs located in the control building.

The two station bus Ethernet networks are fully redundant utilizing PRP and are PTP capable, however system A IEDs utilizes Irig-B for time synchronization. The redundant RTUs and system B IEDs must fail over from the grand master to the backup PTP clock as per the PRP standard.

B. Special GOOSE Applications

As noted above, the bus protection, capacitor bank protection and breaker management functions are not redundant, however backup protection is deployed in other IEDs and utilizing peer-to-peer communications,
The following GOOSE communications schemes were deployed to enhance dependability and troubleshooting:

1. Breaker failure
   All protection IEDs associated with a power systems element would issue tripping directly to the associated circuit breaker via MUs or PIUs, but then initiate breaker fail to the breaker management IED via GOOSE messaging; e.g. the distance IEDs for circuit L3 from both protection systems would detect and trip breaker L3 directly for faults detected on circuit L3 and then initiate breaker fail in breaker L3 breaker management IED. This IED would perform the breaker management function, issue a retrip and issue a breaker fail trip via GOOSE messaging to the other three breaker management IEDs once breaker fail operated. The lines breaker management IEDs also performs reclosing on all trips except from breaker fail.

2. Station Digital Fault Recording
   All breaker management IEDs upon tripping issue a waveform capture trigger (or cross-trigger) to all other breaker management IEDs associated with all the circuits. What this means is that all protection functions from either system A or system B (distance line protection, bus and capacitor protection) sends a trigger GOOSE message to its associated breaker management IEDs L1, L2 and L3 which in turn cross-trigger each other. Hence will waveform capture of all breaker management IEDs be triggered for all detected faults in the station.
   All IEDs are time-synchronized; system A via Irig-B and system B via the PRP networks using IEEE1588 or PTP (precision time protocol), hence will all waveforms be synchronized and can seamlessly be merged to form one waveform for the whole station.

V. ALTALINK'S POINT-TO-POINT PROCESS BUS EXPERIENCE

Prior to selecting process bus solutions, lab testing was performed to determine performance criteria of different protection system architectures and how they compare. Based on available vendor solutions, point-to-point architecture and LAN architecture were selected for System A and System B respectively.
Two different system types also provided opportunity to be able to compare installation, configuration, testing, operation, maintenance and performance. These systems have been operational since November 2018 with comparable performance and reliability as conventional P&C systems.

A. HERE ARE SOME OBSERVATIONS ON ADVANTAGES OF THE POINT-TO-POINT SYSTEM A:

1. Programming of the IEDs were very similar compared to the programming of conventional IEDs. The PIUs are seen as an extension of the IED, and only the voltages, currents, contact inputs and outputs had to be addressed via the PIU. All other protection and control elements, the use, programming and commissioning of it is very similar to conventional IEDs.
2. No process bus network was needed, only direct fiber connections simplifying the PIU as extension of the IED.
3. No external process bus time synchronization clock is needed since the IED perform this directly with the PIU.
4. Much fewer copper cables are needed and kept external to the substation control building.

B. HERE ARE SOME CHALLENGES OF THE POINT-TO-POINT SYSTEM A:

1. PIUs had to be selected to ensure adequate voltage, current, digital inputs and outputs for each power systems component; e.g. the PIU used on each breaker had to have enough voltages, currents, alarming and status inputs.
2. PIUs had to be connected to multiple IEDs, hence each PIU had to have this capability and multiple fibers cables were needed.
3. Station bus GOOSE interoperability was sometimes an issue between System A and System B e.g. some IEDs disregard all GOOSE data if the quality of one message is questionable.
4. Testing of GOOSE messaging had to be incorporated in IED logic in some cases, since the IEC 61850 simulation and testing features were not equally deployed in systems A and B.
5. New injection testing strategies had to be adopted. A testing PIU is used in the relay room, connected to a relay test set and then PIU fiber is connected to IED to be tested. New test procedures for this aspect had to be incorporated.

VI. PERFORMANCE OF POINT-TO-POINT PROCESS BUS BASED PROTECTION SYSTEM

Since commissioning and cut-over of the digital substation systems A and B, four faults have occurred on the transmission lines L1 and L4. The remote end of L1 is protected with redundant systems; however, only one has one has a numerical relay. The remote end of L4 has electromechanical relays; therefore, event recording and fault waveform capture is not available. In all cases both A and B protection systems operated as expected. Here are some details of these operations:

A. March 24, 2019 – Line L4 Fault

The line L4 is protected with redundant step distance protection systems at both terminals. A permanent Phase B-to-Ground fault occurred on circuit L4 close to the Blackie-end with pre-fault currents of about 59A and the phase B fault current of 2.6kA. The fault was well within the reach of Ground Distance Zone 1 element, for which the system A protection IED operated in 12.5ms. The system B protection Zone 1 Ground element also operated in a comparable operating time. The circuit breaker tripped three-pole in 56.8ms starting from fault inception to the breaker open. Below are the waveforms from system A line L4 distance protection IED:

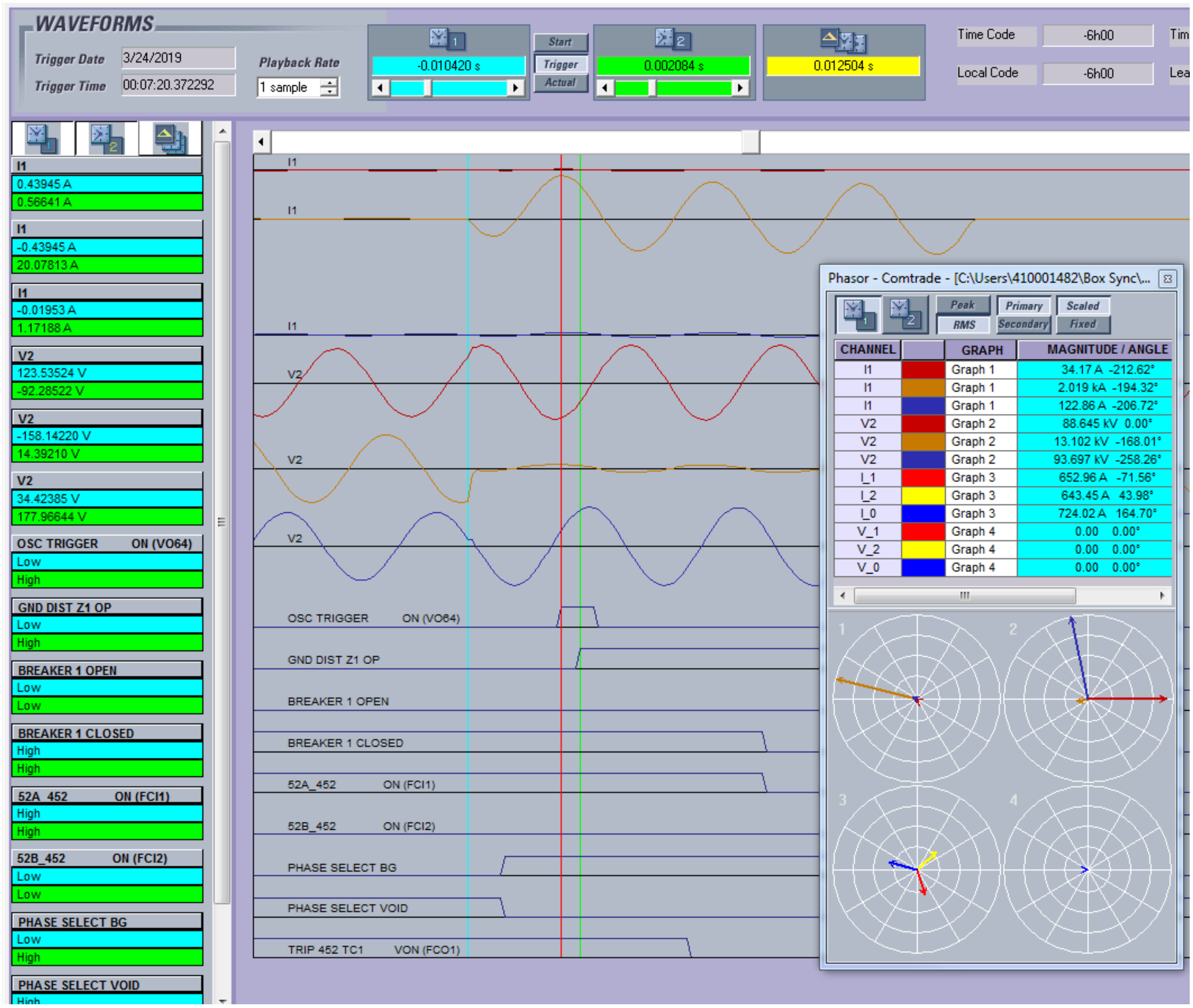

Fig 11: L4 IED Waveform Capture for B-G Fault

The performance of IEC 61850 based protection system is very comparable to that of any conventional distance protection system.

At L4 remote end, the fault was detected and isolated by distance Zone 2 elements.

Since the breaker management IEDs are set to cross-trigger each other, the waveforms for this event is also available. The station capacitor was out of service during this event, hence the associated breaker management IED did not capture waveforms during this event. The breaker management IED for breaker S452, which connects to line L4, and is connected to the same PIUs also recorded the waveforms as follows:

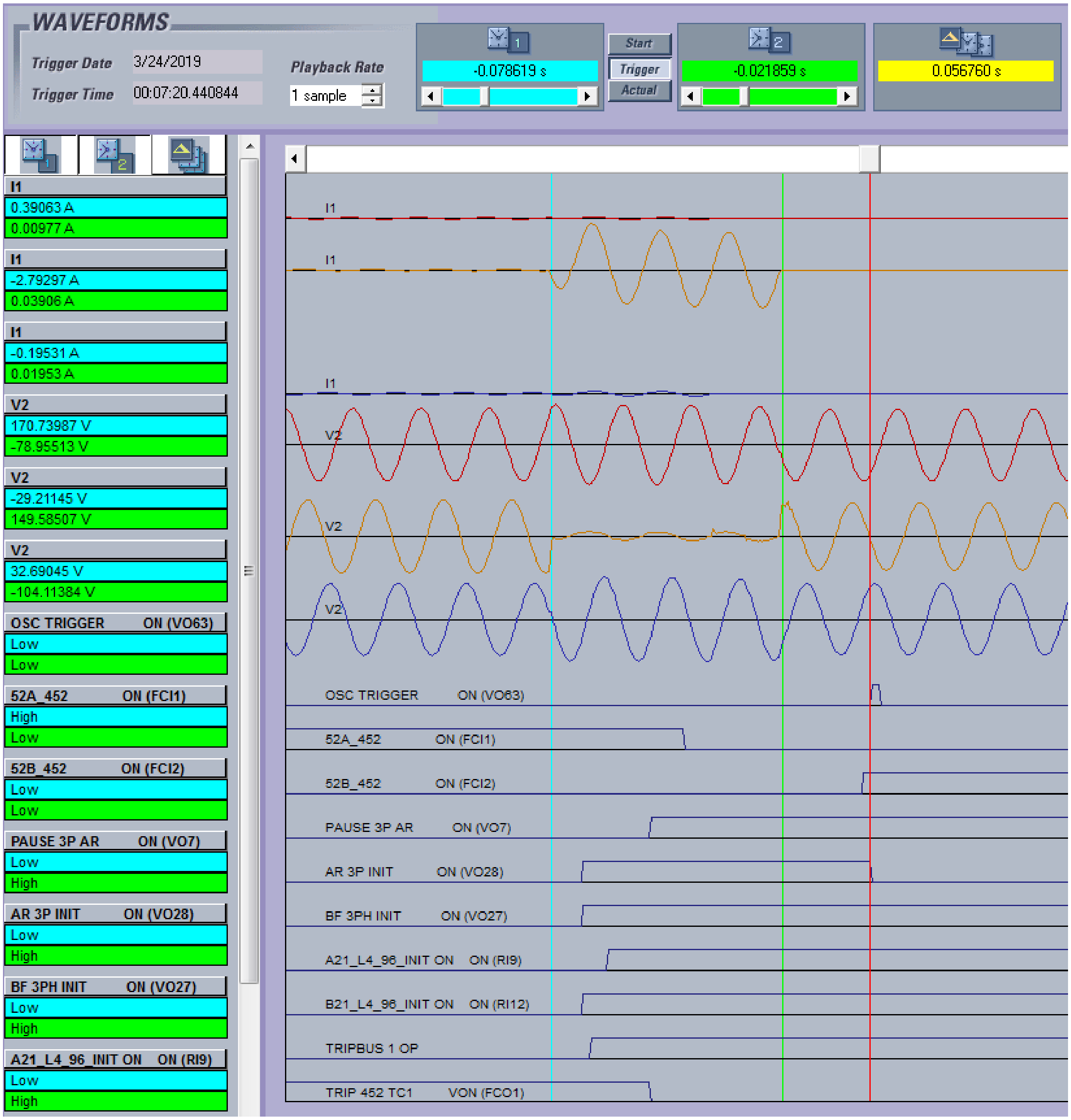

Fig 12: L4 Breaker S452 Management IED Waveform Capture

The breaker fail initiate from both line distance IEDs came in shortly after tripping, which also initiated the auto-reclosing. This terminal performs follow-end reclosing i.e. conditional one live-line detection. The auto-reclosing was unsuccessful from the remote end due to the permanent fault, hence auto-reclosing at Blackie end did not occur.

The breaker management IED for L1 on breaker S152 captures the following waveforms:

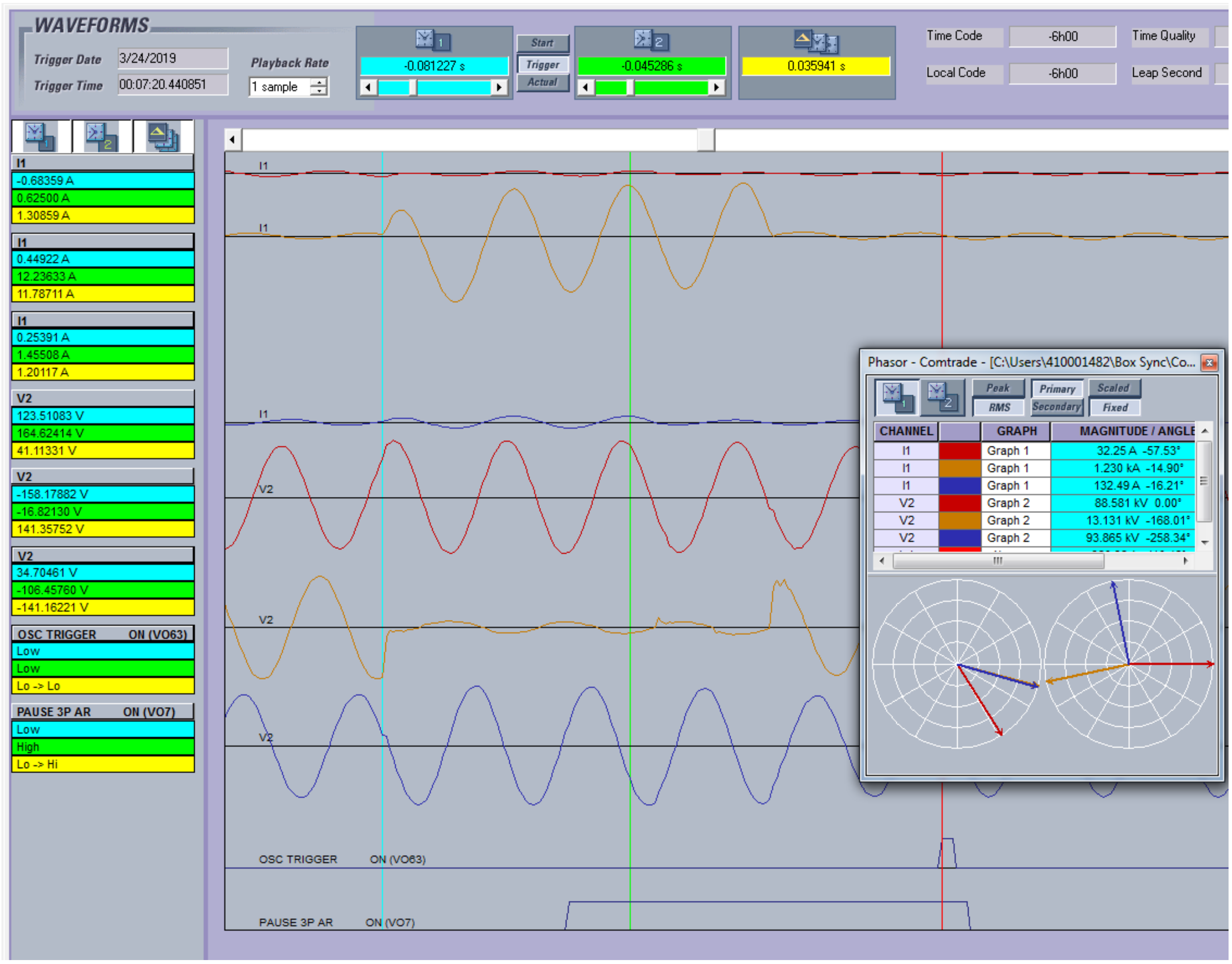

Fig 13: L1 Breaker S152 Management IED Waveform Capture

The significant sag in bus voltage, is a clear indication that the fault was close to the Blackie-end of the circuit. It is also apparent that this circuit did not experience a trip.

The waveforms from L3 breaker S352 management IED are as follows:

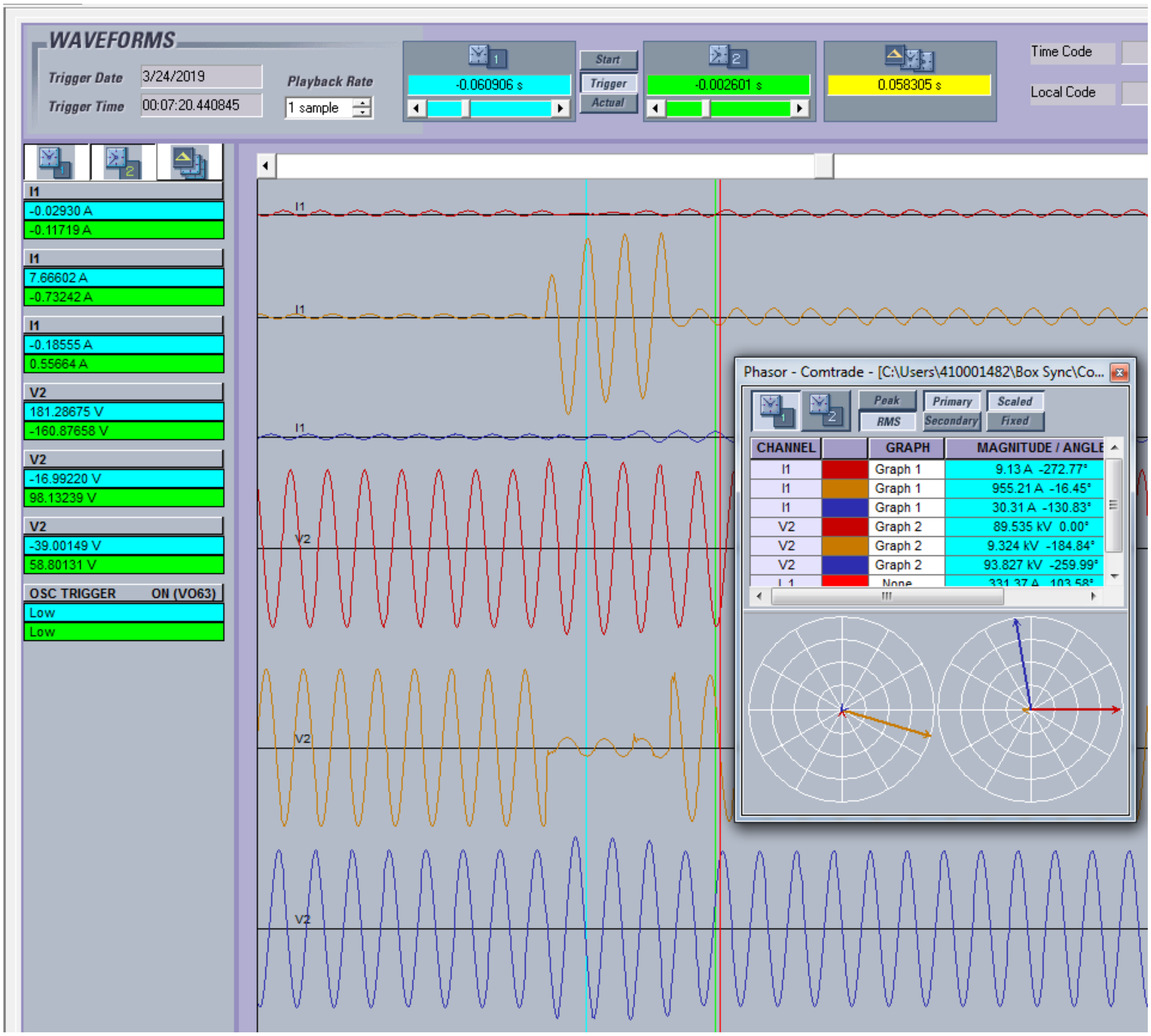

Fig 14: L3 Breaker S352 Management IED Waveform Capture

Line L1 and L3; and bus protection systems did not operate and remained secure during this event.

B. January 15, 2019 – Line L1 Fault

The line L1 is protected with redundant step distance protection systems at both terminals. A permanent Phase B-to-C fault occurred on line L1 close to the remote-end. Pre-fault currents were about 71A and the fault current was about 1.8kA. The fault was detected by the Phase Distance Zone 2 element, for which system A protection IED operated in 368ms. System B protection IED also operated upon Zone 2 Phase element pickup in a comparable operating time. The circuit breaker tripped three-pole in 408ms starting from fault inception to breaker open. Below are the waveforms from line L1 system A protection IED:

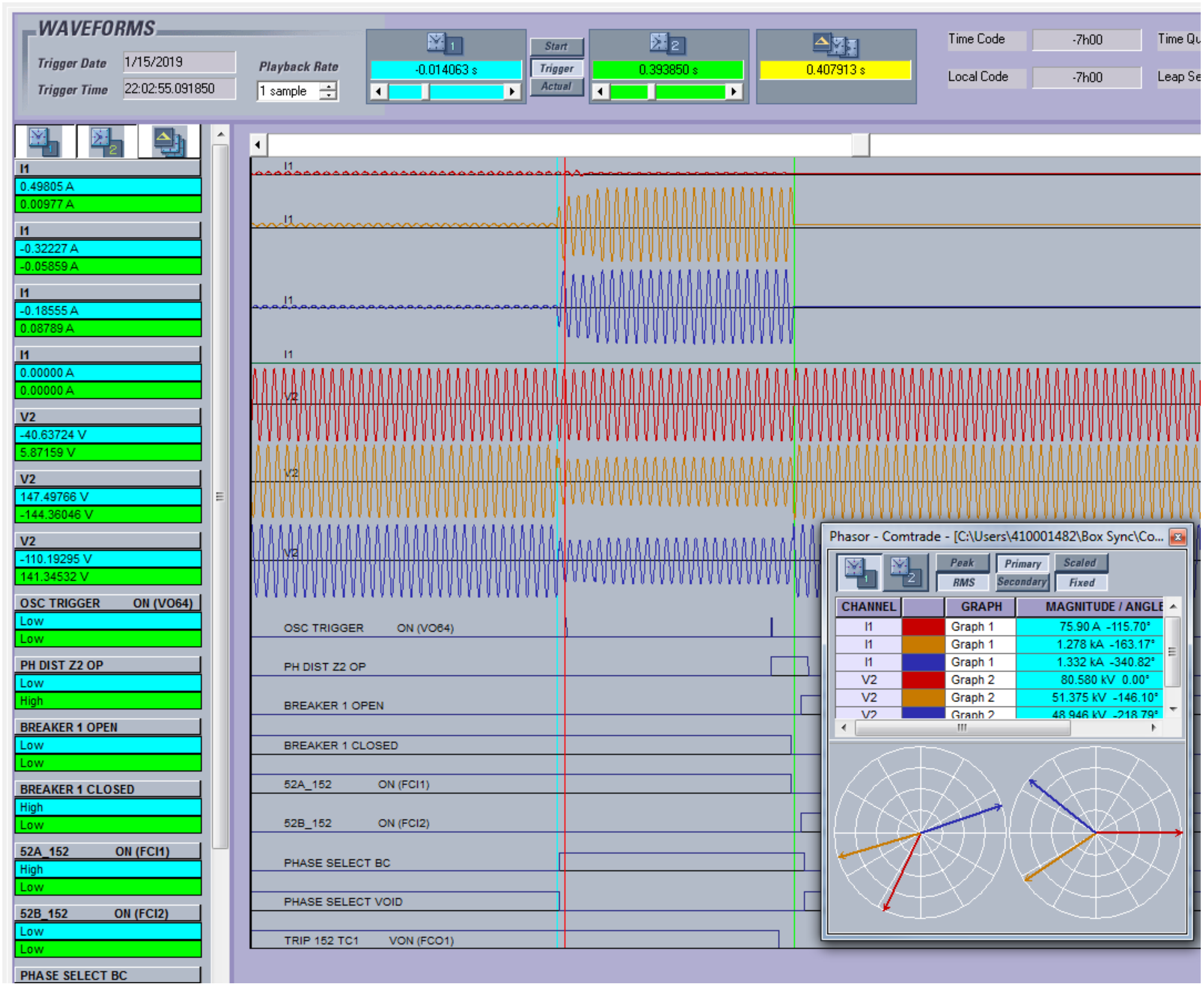

Fig 15: L1 IED Waveform Capture of Phase B-C Fault

Again, the performance of IEC 61850 based protection system is comparable to that of a conventional step distance protection system.

The remote end protection systems detected the fault and tripped upon phase distance zone 1 operation.

Since all protection IEDs are set to cross-trigger the three line breaker management IEDs, the event waveforms for those IEDs were also available. The station capacitor bank was again out of service during this event, hence the capacitor bank breaker management IED did not capture the event waveforms. The breaker management IED for breaker S152, which connects to line L1, did trigger however only the sequence of events is available:

0 days 0 h : 0 m : 0.341827 s

Event Number	Date/Time	
1596	Jan 15 2019 22:03:55.503825	AR DISABLED
1595	Jan 15 2019 22:03:55.503825	AR LO
1594	Jan 15 2019 22:03:55.499657	BLOCK AR On (VO6)
1593	Jan 15 2019 22:03:55.499657	DUMP TIMER On (VO5)
1592	Jan 15 2019 22:03:00.188758	PAUSE 3P AR On (VO7)
1591	Jan 15 2019 22:03:00.188758	AUX OV1 DPO
1590	Jan 15 2019 22:03:00.140965	AR 3-P/2 RIP
1589	Jan 15 2019 22:03:00.138762	PAUSE 3P AR Off (VO7)
1588	Jan 15 2019 22:03:00.138762	AUX OV1 OP
1587	Jan 15 2019 22:03:00.138762	AUX OV1 PKP
1586	Jan 15 2019 22:02:55.798344	TRIP 152 TC1 DOff (FCO1)
1585	Jan 15 2019 22:02:55.794150	TRIP 152 TC1 Off (FCO1)
1584	Jan 15 2019 22:02:55.652448	BF 3PH INIT Off (VO27)
1583	Jan 15 2019 22:02:55.650245	A21_L1_96_INIT ON Off (RI9)
1582	Jan 15 2019 22:02:55.644114	B21_L1_96_INIT ON Off (RI12)
1581	Jan 15 2019 22:02:55.512727	AR 3P INIT Off (VO28)
1580	Jan 15 2019 22:02:55.510757	A21_L1_79_INIT ON Off (RI8)
1579	Jan 15 2019 22:02:55.504390	B21_L1_79_INIT ON Off (RI11)
1578	Jan 15 2019 22:02:55.502424	Osc Trigger Off (VO63)
1577	Jan 15 2019 22:02:55.500220	OSCILLOGRAPHY TRIG'D
1576	Jan 15 2019 22:02:55.500220	Internal Osc Trigger Off (VO64)
1575	Jan 15 2019 22:02:55.500220	Osc Trigger On (VO63)
1574	Jan 15 2019 22:02:55.498273	Internal Osc Trigger On (VO64)
1573	Jan 15 2019 22:02:55.498273	BREAKER 1 OPEN
1572	Jan 15 2019 22:02:55.492465	52b_152 On (FCI2)
1571	Jan 15 2019 22:02:55.485747	TRIP 152 TC1 IOff (FCO1)
1570	Jan 15 2019 22:02:55.481603	BREAKER 1 PHASE A INTERM
1569	Jan 15 2019 22:02:55.474967	52a_152 Off (FCI1)
1568	Jan 15 2019 22:02:55.458540	TRIP 152 TC1 VOff (FCO1)
1567	Jan 15 2019 22:02:55.454397	B21_L1_79_INIT ON On (RI11)
1566	Jan 15 2019 22:02:55.452409	B21_L1_96_INIT ON On (RI12)
1565	Jan 15 2019 22:02:55.452409	AR RIP
1564	Jan 15 2019 22:02:55.450205	TRIP 152 TC1 IOn (FCO1)
1563	Jan 15 2019 22:02:55.450205	TRIP 152 TC1 DOn (FCO1)
1562	Jan 15 2019 22:02:55.450205	TRIP 152 TC1 On (FCO1)
1561	Jan 15 2019 22:02:55.450205	TRIPBUS 1 OP
1560	Jan 15 2019 22:02:55.450205	TRIPBUS 1 PKP
1559	Jan 15 2019 22:02:55.448264	AR 3P INIT On (VO28)
1558	Jan 15 2019 22:02:55.448264	BF 3PH INIT On (VO27)
1557	Jan 15 2019 22:02:55.446037	A21_L1_79_INIT ON On (RI8)
1556	Jan 15 2019 22:02:55.446037	A21_L1_96_INIT ON On (RI9)
1555	Jan 15 2019 22:02:55.104210	PAUSE 3P AR On (VO7)
1554	Jan 15 2019 22:02:55.104210	AUX OV1 DPO

Fig 16: L1 Breaker S152 Management IED Sequence of Events

The breaker failure initiate from both line distance IEDs came in shortly after tripping. The auto-reclosing did not initiate since the fault was detected in distance zone 2.

The event waveforms from breaker management IEDs for breaker S352 and S452 were equivalent compared to case A taking into account the different fault and duration.

C. January 27, 2019 – Line L4 Fault

A permanent Phase A-to-Ground fault occurred on line L4 more than half-way to the remote-end. Pre-fault currents were about 80A and the peak A-phase fault current about 1.17kA. The fault location was close to the reach of Ground Distance Zone 1 element, for which system A protection IED operated in 31.7ms. System B also operated upon Zone 1 Ground distance element picked up in a very comparable operating time. The circuit breaker tripped three-pole in 50ms from inception of the fault till the breaker open. Below are event waveforms from system A protection IED:

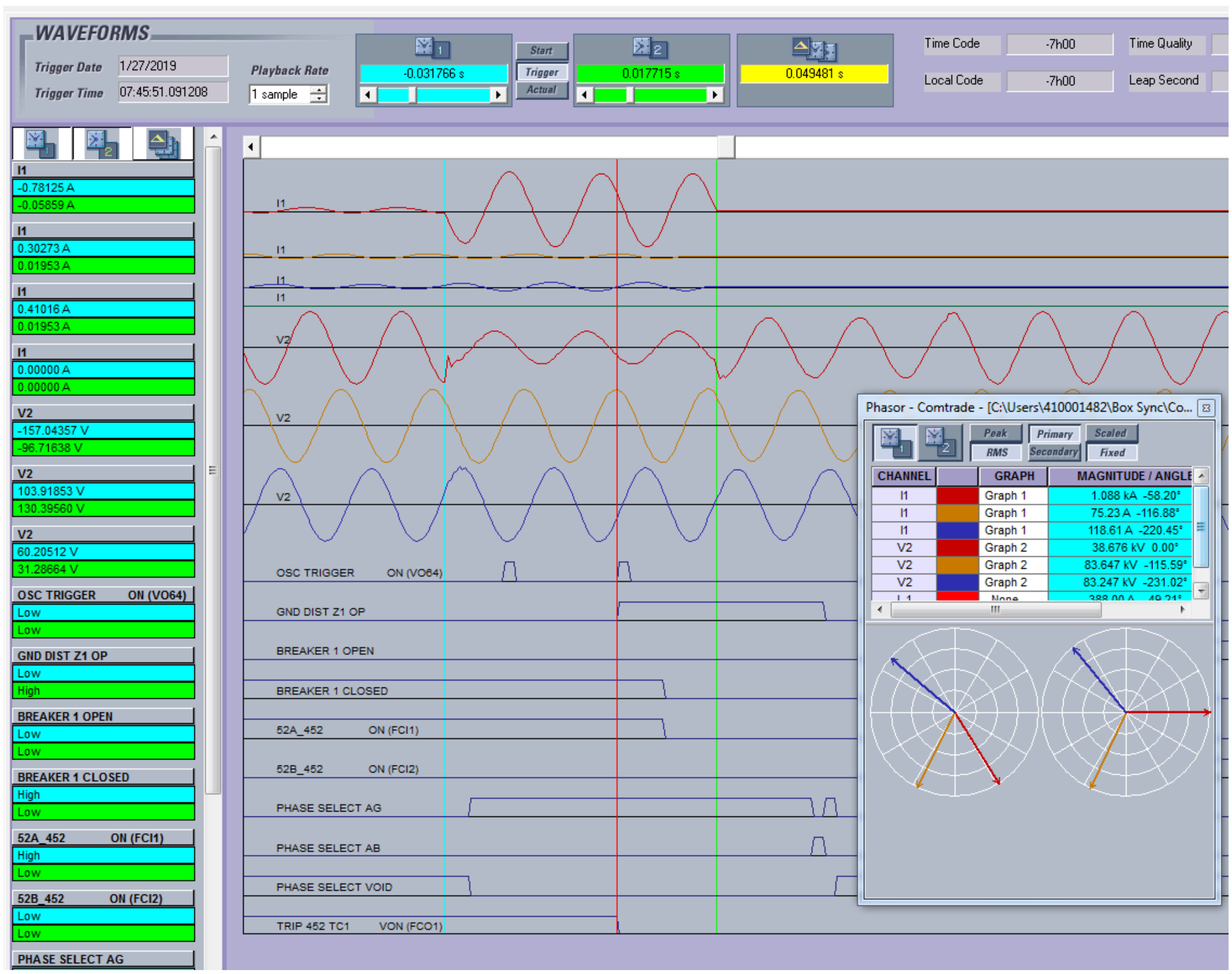

Fig 17: IED Waveform Capture for L4 Phase A-G Fault

Again, the performance of IEC 61850 based protection system is comparable to that of a conventional distance protection system.

The three line breaker management IEDs were cross-triggered during this event. The information obtained and conclusion made from their event recording is consistent with that of L4 protection system IED.

D. June 5, 2019 – Line L3 Fault

The line L3 is protected with redundant step distance protection systems at both terminals. A temporary Phase C-Ground fault occurred on line L3 within zone 1 reach from both ends. At Blackie, pre-fault currents were about 35A and the peak Phase-to-Ground fault current around 1.54kA. The fault locus was within Ground Distance Zone 1 element reach, for which system A protection IED operated in 22.3ms. The L3 circuit breaker tripped three-pole in 57.3ms from fault inception to breaker open. Below are the event waveforms from system A protection IED:

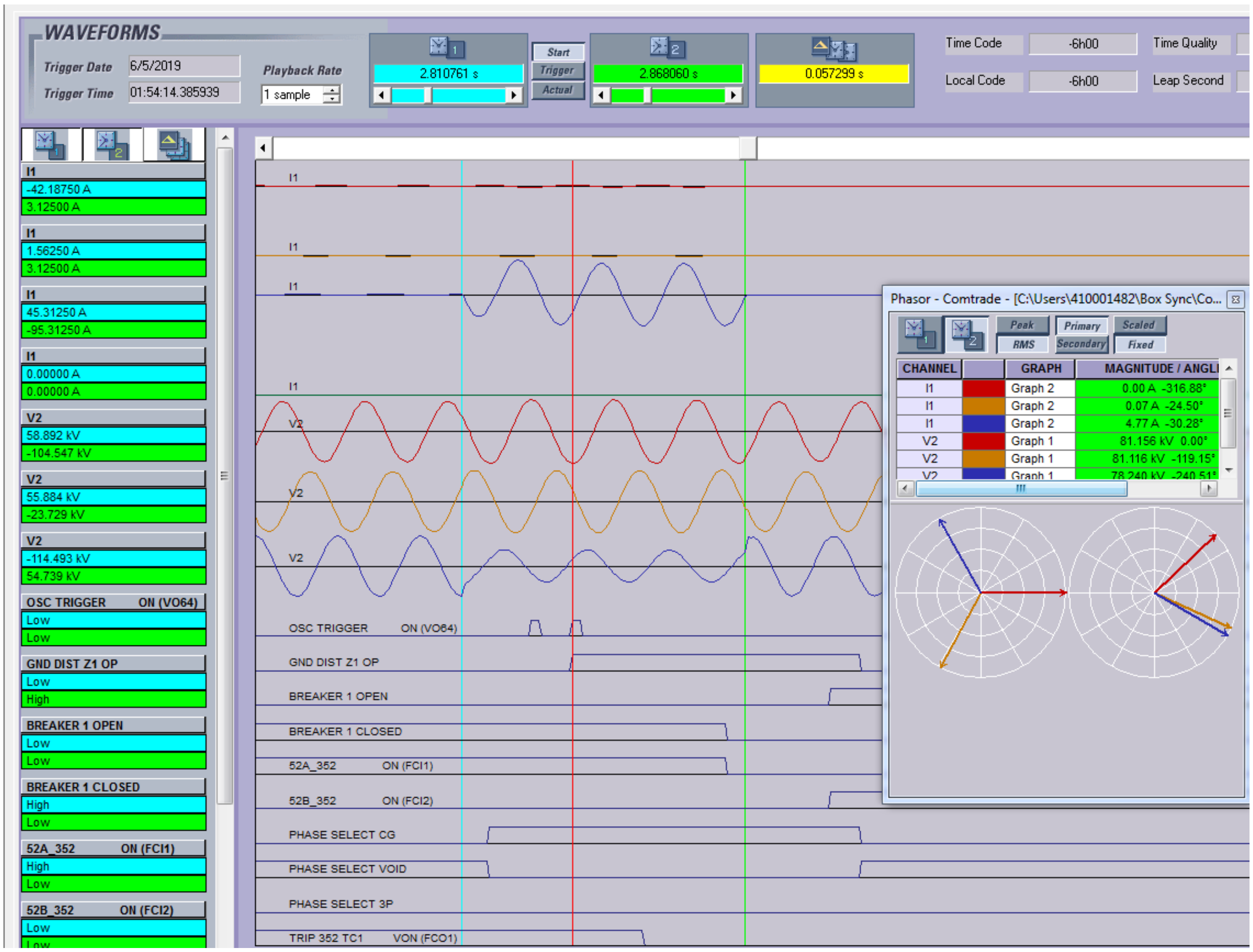

Fig 18: Blackie L3 IED Capture of Phase C-Ground Fault

At the remote end, the protection systems operated for Phase-to-Ground fault with Zone 1 Ground distance element in 21.8ms. Pre-fault currents were about 33A and peak phase-to-ground fault current about 1.6kA, very similar as the Blackie-end.

VII. Conclusion

IEC 61850 process bus based applications can provide substantial cost savings in protection and control systems; however most of these benefits are more impactful in greenfield or new installations compared to brownfield or replacement systems. Furthermore, IEC 61850 implementation could impact roles and responsibilities of various groups across the organization. The groups associated with the following aspects should be involved during the design, implementation, commissioning and operational stages:

- Protection & Control Engineering
- SCADA and Telecom Engineering
- Substation Engineering Design
- Equipment Specifications
- Substation Construction
- Protection System Maintenance
- Equipment Maintenance

IEC 61850 station – and Process bus do bring new challenges that should be reviewed during planning, specification and design stages:

- All aspects of station bus GOOSE data, including description and quality should be reviewed between all IEDs and systems for interoperability e.g. some IEDs disregard all GOOSE data if the quality of one message is questionable.
- Testing and simulation of GOOSE messaging should be reviewed for all IEDs to ensure proper interoperability if it is intended to be used in system testing.
- New commissioning and maintenance testing strategies must be adopted. A lot of papers are published in this regard.
- IEC 61850 is an evolving standard and expected to have ongoing additions and updates, which may impact interoperability between different vendor IEDs. Therefore, complete interoperability should be tested and confirmed based on intended applications before selecting multivendor solutions.

The process bus P&C systems installed at AltaLink's Blackie substation have proven to have reliability and performance comparable to that of conventional P&C systems during normal power system operation and system disturbances; whether using a point-to-point or LAN architecture. Using IEC 61850 capabilities, reduced copper wiring and allowed increased flexibility and interaction between system A and B.

VIII. References

[1] IEC 61850-9-2 Ed.2.0 2011 - Communication networks and systems for power utility automation - Part 9-Specific communication service mapping (SCSM) – Sampled values over ISO/IEC 8802-3

[2] IEC 61850-8-1 Ed.2.0 2011 - Communication networks and systems for power utility automation – Part 8-1: Specific communication service mapping (SCSM) – Mappings to MMS (ISO 9506-1 and ISO 9506-2) and to ISO/IEC 8802-3

[3] IEEE Std C37.238 - 2011 - IEEE Standard Profile for Use of IEEE 1588™ Precision Time Protocol in Power System Applications

Authors' Information

Chu Cheng graduated in 2014 from University of Calgary with a Bachelor of Science degree in Electrical Engineering. Since graduation, she worked for AltaLink as a Protection & Control engineer in AltaLink Asset Management department for 4 years then transition to Project Development group as a Protection and Control Engineer. Chu focuses her work around high voltage protection and control setting design and testing involving transmission line protection, transformer protection, and various high voltage equipment protection. Chu is a member of IEC TC 57 working Group 10, and she is also part of the IEC Young Professionals Programme. Chu is a registered professional engineer with the province of Alberta.

Nicholas Belzile graduated in 2005 from the Northern Alberta Institute of Technology with a Diploma in Telecommunication Engineering Technology. Since then, he worked for three years as a Telecommunication Technologist for ATCO Electric. In 2009, he joined AltaLink where he started his career as a Protection and Control Technologist, and was indentured into the Power Systems Electrician Apprenticeship; he attained his journeyman status in 2013. As a P&C Technologist, his primary roles consist of maintenance and trouble response, however he has participated in a multitude of protection upgrade projects. In 2018, he was tasked as the lead commissioning tech for AltaLink's Pilot IEC61850 Digital Substation project at 253s Blackie. As of June 2019, he became the work leader for the Field Protection and Control Technologist team in southern Alberta. Nicolas is a Certified Engineering Technologist with the Association of Science and Engineering Technology Professionals of Alberta.

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