Design, Implementation and Commissioning of a Hybrid Substation Automation System Using IEC 61850

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1. Abstract

This paper describes the design, implementation and commissioning of a substation automation (SA) system for a 230/63 kV substation located in the interior of British Columbia, Canada. The automation systems uses nearly 60 multifunction Intelligent Electronic Devices, or IEDs, which are integrated together using a combination of technologies including IEC 61850, DNP3 and LON. The IEDs are comprised of bay controllers, a variety of protection relays, transformer monitoring devices, revenue meters, as well as PC based station HMIs and gateways for remote communications to the regional control center. Together, the IEDs perform all of the control, monitoring, protection and metering functions associated with the station including the implementation of two Remedial Action Schemes.

2. Introduction

In the city of Trail, located in the southern interior of British Columbia, Canada, mining and metals company Teck Cominco Metals Limited operates one of the largest fully integrated lead and zinc smelters in the world. The power required to operate this facility is produced at Teck Cominco's hydroelectric Waneta Generating Station, located approximately 10 km south of Trail on the Pend d'Oriele River.

In 2001, Teck Cominco began a series of projects to upgrade the electrical system used to generate, transmit, and distribute the power produced at Waneta. A major component of these upgrades was the construction of a new substation at the Waneta dam site. This project, the Waneta Hydro Station Project, was started in 2006 and culminated with a new state of the art substation being placed into commercial operation in November of 2007.

As the transmission of power is not core to Teck Cominco's business, there were no pre-existing company standards or practices established for the design of this new substation. Therefore, the designers were free to explore the application of a variety of leading edge substation engineering technologies in order to maximize benefit to the project. One of these technologies selected to provide benefit to the project was an IEC 61850 based substation automation system. The selection of 61850 was based on a number of potential benefits including improved interoperability, better system communication performance, reduced overall system costs, reduced schedule, greater engineering flexibility and future technological longevity.

This paper provides insight into the design of the SA system developed for the Waneta Hydro Station Project including a description of the system architecture, the station human machine interface (HMI) and the DNP3 gateways used to facilitate communications to the regional system control center (SCC). As well, the paper explores the implementation process used to develop the system including the usage of the design tools in the engineering process. Factory testing is also described as well as commissioning tests. Finally, the paper provides a discussion of some of the lessons learned and draws conclusions based on the overall experience of designing and implementing the SA system for the new Waneta Hydro Station.

3. System Design

The new Waneta Hydro Station (WHS) was designed to replace an existing switching station on the powerhouse roof of the Waneta Generating Station. WHS consists of four 63kV buses in a double busbar arrangement and one 230kV bus. The four 63kV buses can be connected together via four bus tie breakers to form a ring. The station also has two 230/63/15kV Autotransformers connected in parallel from either side of the 63kV bus arrangement to the 230kV bus. Connected to the 63kV buses are five 63 kV transmission lines, four generator feeders and two transformer feeders. Connected to the 230kV bus are the HV side of the transformers and one 230kV transmission line. The two 15kV tertiary windings of the Autotransformers provide redundant feeds to station service. The single line diagram for the station is provided in Figure 1 and shows the four bus arrangement with any 63kV element capable of being selected onto one of two buses via motor operated disconnect switches which can be switched under load.

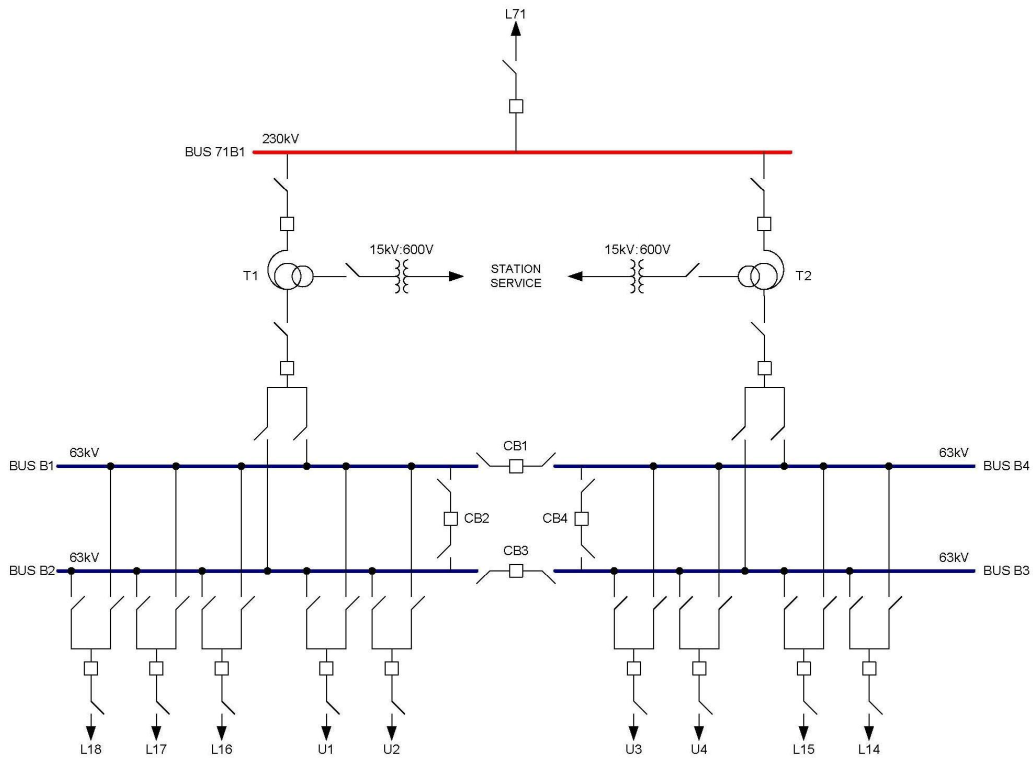

Figure 1: Waneta Hydro Station Single Line Diagram

The substation automation system was designed to provide a number of primary high-level functions relative to the overall design of the station. These include:

- Protection functions for the 6 transmission lines, 4 generator feeders, 2 autotransformers and the five station buses in the event of a fault.
- Synchronization of 3 of the 4 generators. (the fourth generator was synchronized at a 13.8kV breaker located at the generating station)
- Station interlocking to provide for safe operation of equipment to protect not only the equipment but operating personnel as well.
- Local control of the primary equipment from within the station control building.
- Remote control of the primary equipment from the system control center.
- Local and remote monitoring of measured values, equipment status and other quantities to facilitate network operation.

How these functions, as well as others, are provided by the WHS SA system is described in the following sections.

3.1. Design Concept

The Waneta Hydro Station SA system is a networked automation system. A networked automation system was chosen over a traditional system for many reasons including: decreased installation and design costs, higher flexibility and previous experience and success with networked automation systems on other projects.

Recent developments in information and communication technology allows for advanced solutions for SA systems which not only improve the reliability of the system but also reduce operational costs. In today's deregulated markets, networked automation systems help utilities operate their system more economically.

At the time the preliminary engineering was done for the Waneta Hydro Station, the use of IEC standard 61850 was not considered due to the lack of IEC 61850 compliant products available from vendors and the risks associated with implementing a system based on a new standard with limited installations around the world. However, in the time between preliminary engineering and the bidding stage for the SA equipment, vendors had vastly increased their portfolio of IEC 61850 products and had gained experience from applications worldwide. Therefore an evaluation was done on the benefits and disadvantages of using IEC 61850 for this project. Ultimately, the decision was made to implement an IEC 61850 solution based on the following factors: longevity, improved integration capabilities, better long term support, zero cost difference, and no schedule impact.

However, some of the IEDs could not be IEC 61850 compliant. The GIS bay controllers were not available from the vendor with IEC 61850 capabilities at the time, therefore these were kept as previous generation IEDs which communicate over a local operating network (LON). The generator synchronizors were also not yet available from the vendor with IEC 61850 capabilities, these IEDs also communicate using the LON protocol. The 'A' protection of four of the 63kV transmission lines use line current differential protection. In order for this function to operate properly, the IEDs at both ends of the line must be identical. Since the existing relay at the remote end of the line is a previous generation product (installed several years prior) the IED at WHS had to match. Therefore, these IEDs also communicate over a LON network.

The result of all of this is a hybrid station network consisting of 22 IEDs communicating on a LON network and 35 IEDs communicating on an IEC 61850 based Ethernet network.

3.2. System Architecture

The architecture of the Waneta Hydro Station SA system consists of two main types of process networks, IEC 61850 and LON, and two small Ethernet LANs (Local Area Network). The main components of this architecture are shown in Figure 2. All IEDs in the two main networks are time synchronized by a master clock with dedicated GPS receiver which broadcasts a time sync signal over both IEC 61850 and LON networks. In the case of the IEC 61850 network, the time sync signal uses SNTP and guarantees an accuracy of within 1ms.

The decentralized architecture provides all control and interlocking logic in the bay controllers, closest to the process. Therefore it is possible to control and monitor any bay from the IED level and station wide interlocking is available even if the HMI computers have failed. Clear control priorities were implemented to prevent the initiation of simultaneous operation of a single device from more than one of the various control levels. The priority is given to the level closest to the process.

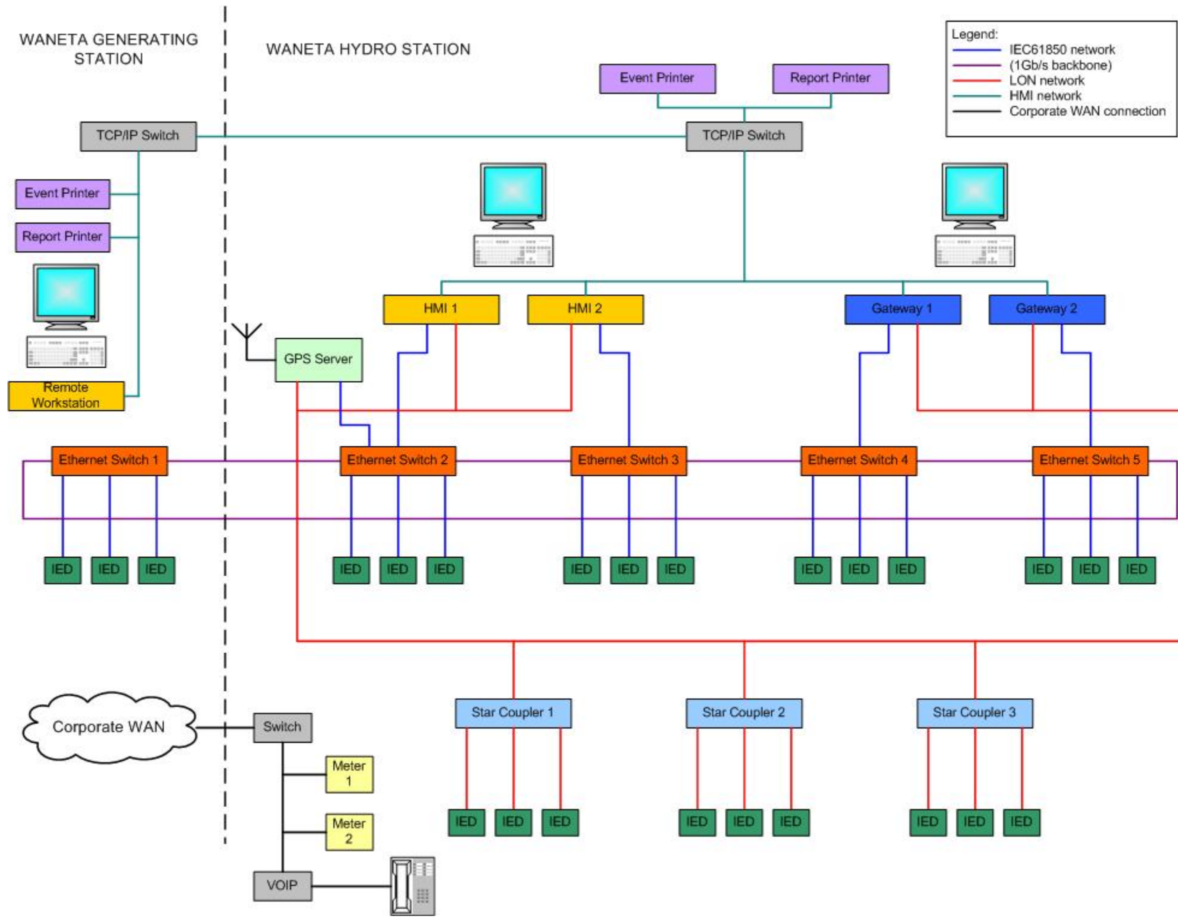

Figure 2: Simplified SA System Architecture

The IEC 61850 network integrates 35 multifunction IEDs and is used for communication of GOOSE messages between these IEDs as well as connecting these IEDs to the station HMI servers and gateways. The architecture of the IEC 61850 network is simple and all the connections between the IEDs are made with fibre optic cables thereby guaranteeing disturbance-free communication. There is no intermediate conversion to another media, which improves the reliability and security of the network. The highest availability of the network is achieved by using a ring configuration connected via industry standard rugged Ethernet switches with redundant power supplies. The IEDs were assigned to the Ethernet switches based on geographical arrangement as well as their application so that the network can be viewed as separate independent segments. This provides added security and increased performance of the network. The backbone of the ring between the switches is connected via high speed Gigabit Ethernet for high bandwidth. This architecture allows seamless integration of IEDs in the generating station to the same station level network in WHS.

The second main network in the system architecture is the LON network and consists of 22 multifunction IEDs, station HMI servers and gateways interconnected in a star topology. This network forms the backbone of the communication to and from the 63 kV GIS bay controllers. In addition, the LON network is used to integrate a few protection IEDs that are not IEC 61850 compatible.

The third network (HMI network) consists of an Ethernet LAN, which interconnects the two station HMI servers, the two gateways, the two station printers, and the remote workstation PC and printers at the generating station. The remote workstation is connected to the Ethernet LAN at WHS via a fibre optic link.

The fourth network consists of a small Ethernet LAN tied to the utility corporate WAN (Wide Area Network) brought into the station via the fibre optic communications system. This network provides remote access to the revenue meters as well as a VOIP (Voice over IP) phone and internet connection to the outside world. As this network is not involved in any of the control or protection aspects of station operation, it is deemed non-critical.

3.3. HMI

The HMI functionality is provided by two Windows based PCs (servers) connected to the station LON and IEC 61850 networks which together, provide direct communication to all IEDs in the station as shown in Figure 2. These servers, running virtually identical SCADA applications, each maintain their own up-to-date representation of the present status of the station as well as a database of historical events, alarms and values. The operator interface to these servers consists of a monitor, keyboard and mouse, which is transferable between the two servers using a KVM switch located on the station control desk. As only one server may have the operator interface connected to it at a time, limiting operator commands to be issued to only one server at a time, the two servers both run in active control mode in a hot – hot configuration.

The HMI provides the following functionality to the operator:

Single Line Displays: Three separate single line screens are provided by the HMI for control and monitoring of all primary equipment at WHS. This includes status indication of all switching devices, display of measured analog quantities, select and execute operation of all controllable switching devices in the station and on-load tap changers as well as animated bus representation indicating energized, de-energized and grounded sections of bus. The single line displays also provide the operator with indication of the most recent alarm received by the server. One of the single line displays is shown in Figure 3.

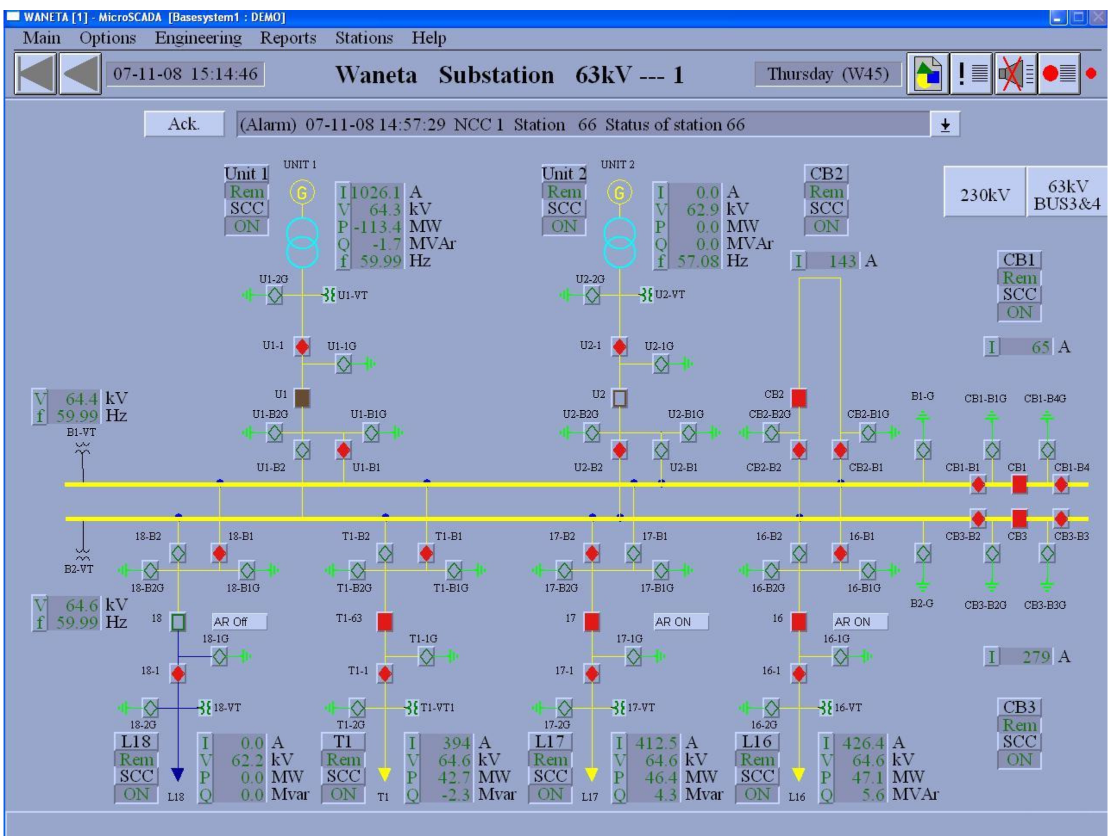

Figure 3: HMI Single Line Display

Events Screen*:* All events received by the servers are stored in a database and displayed on the events screen. These events can be sorted and filtered in a number of different ways to facilitate quick analysis of incidents. All events are also printed on the station event printer.

Alarms Screen**:** An alarms screen provides operators with a listing of the alarms, both active and fleeting, that have been received by the servers. As with the events, the alarms can be sorted and filtered in a number of different ways. A provision is also made for blocking nuisance alarms from filling up the system.

System Supervision Screen: This screen indicates the health of the communication to each IED from the server. Should an IED fail a vertical communication check the system supervision screen would provide an indication that the communication to that particular IED has failed.

Relay Programming: The relay configuration and setting tools for each type of IED in the station are installed on the HMI server. Once the appropriate programming tool is launched, the HMI establishes a connection to the IEDs through the network to facilitate programming and setting changes from the station HMI.

Fault Recording Collection and Viewing*:* Most of the IEDs in the station are equipped with fault recording capabilities. Software applications are provided by the station HMI to upload the fault recording files for viewing and analysis.

3.4. Gateways

Two redundant gateways were provided at WHS on industrial grade, PC based servers separate from the HMI servers thus dedicating them solely for communication with SCC. These servers are provided with flash-drives rather than hard drives in order to increase the mean-time-between-failure (MTBF) and therefore improving the reliability. An RS232 port from each of the servers, is connected serially to SCC at 9600 baud over a digital microwave communication system. The servers are set up as DNP3 slaves and report back to the SCC master in response to DNP3 event poll requests (changed data) and integrity poll requests (all data) each sent at various intervals. Both gateways are running in a hot-hot configuration with either one accepting commands from SCC and acting upon them. The selection of which server is in control is done by an automatic transfer scheme at SCC which will detect lack of response from a gateway and fail over to the other gateway. It is also possible for the operator to block remote control of the station from the control center on a bay-by-bay basis from the station HMI.

In order to limit the bandwidth burden on the communication system, the gateways also performed alarm grouping at WHS, which reduced the approximately 7800 discrete points of data into just under 650.

4. Implementation

4.1. Design Considerations

The design and implementation of the IEC 61850 based protection and control system had a similar approach to a conventional design with a few notable exceptions. There were several concerns pertaining to the selection and handling of GOOSE messages within the design. The decision was made to restrict the use of GOOSE tripping messages due to the lack of operational procedures for dealing with networked tripping signals, insufficient network knowledge and understanding with protection maintenance technicians as well as possible negative cost and schedule impacts. Nevertheless, critical signals used for a generator shedding Remedial Action Scheme (RAS) were sent as GOOSE messages over the IEC 61850 network due to the complexity of wiring that would be required to implement the scheme otherwise. Other non-critical information, for instance signals associated with the tap changer control scheme of the parallel transformers were exchanged between the transformer IEDs over the IEC 61850 network.

One significant concern that had to be addressed during the design phase was developing techniques to block messages sent over the IEC 61850 network during testing and commissioning. Since physically isolating messages sent over the IEC 61850 network was not feasible, all messages originated within an IED were blocked in test mode. Another concern was representation of GOOSE messages in engineering drawings. Since it was not possible to illustrate GOOSE messages in conventional DC schematics, the most appropriate location was found to be the relay logic diagrams which provide a high level generic representation of the logic within each IED including the associated inputs and outputs, both hardwired and networked.

4.2. Implementation of IEC 61850

The IEC 61850 standard itself defines the superset of what an IEC 61850 compliant implementation might contain. The overall engineering process of IEC 61850 is shown in Figure 4. After defining the substation automation structure, with respect to the specification and overall functionality expected from the SA system, a bottom to top approach was used to develop the configuration for all the components of the SA structure. The bottom to top approach refers to forming the SCD (substation configuration description) file as per SCL defined in IEC 61850 from each IED capability file (ICD). In order to maintain the consistency of the engineering process and data flow, the IED engineering tools are used only to perform the IED level engineering while the entire system level engineering including IEC 61850 signal engineering, defining the clients, setting the report control blocks and instances of date sets for various IEDs and GOOSE messaging is done with system level tools.

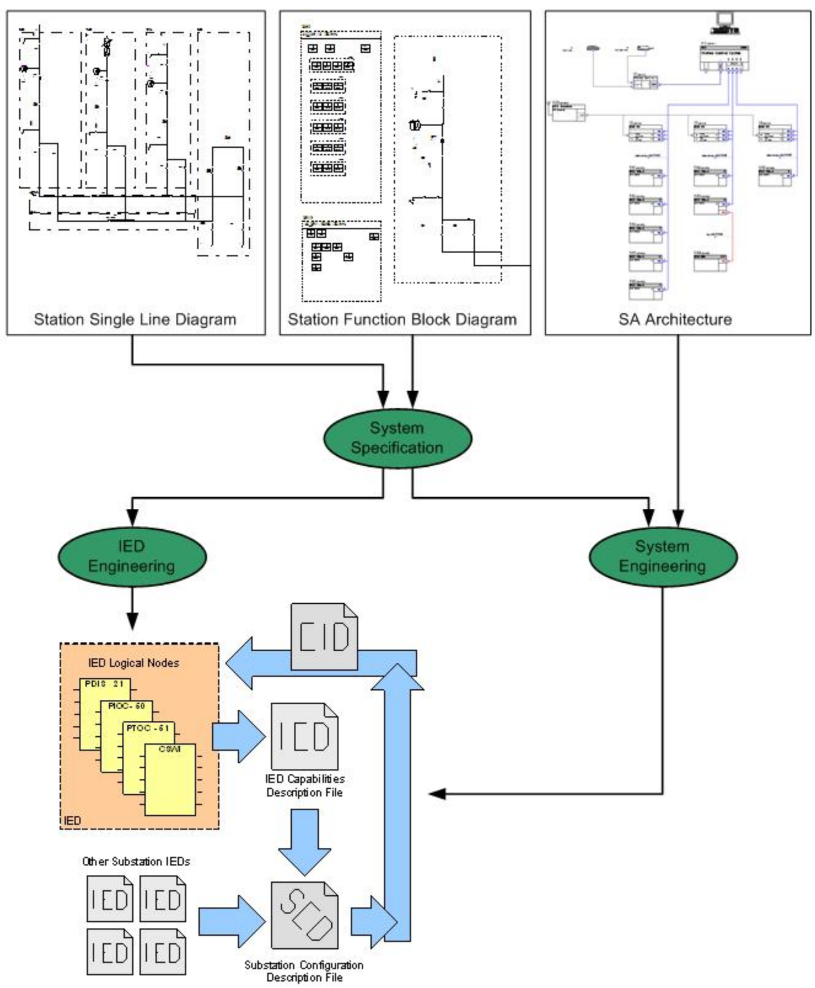

Figure 4: IEC 61850 Engineering Process

5. Factory Testing

The 63kV GIS was designed, manufactured and delivered as a complete system, including local control cubicles complete with bay controllers, from a factory in Germany. The substation automation system was designed, manufactured and delivered as a complete system consisting of protection panels and SCADA/network panels and equipment from a factory in Canada. Since the bay controllers were being provided by one factory and the remainder of the station IEDs were being provided by another factory, two factory tests were required to ensure the integration of all IEDs into the SA system; one in Germany and one in Canada. The common devices in both factory tests were one HMI server and one gateway server.

5.1. Control Integration Tests (Germany)

The control integration tests were carried out in Germany in order to verify the proper design and implementation of the integration of the GIS bay controllers with the station HMI and gateway prior to releasing the equipment for shipment to site.

The test setup included the 15 GIS bay controllers, 2 LON star couplers, one HMI server, one gateway server and a laptop running a SCADA application to act as the master to the gateway. The bay controllers were mounted in test racks with all binary inputs wired to switches and all binary outputs wired to LEDs in order to simulate field inputs and monitor output status. The test setup is shown in Figure 5.

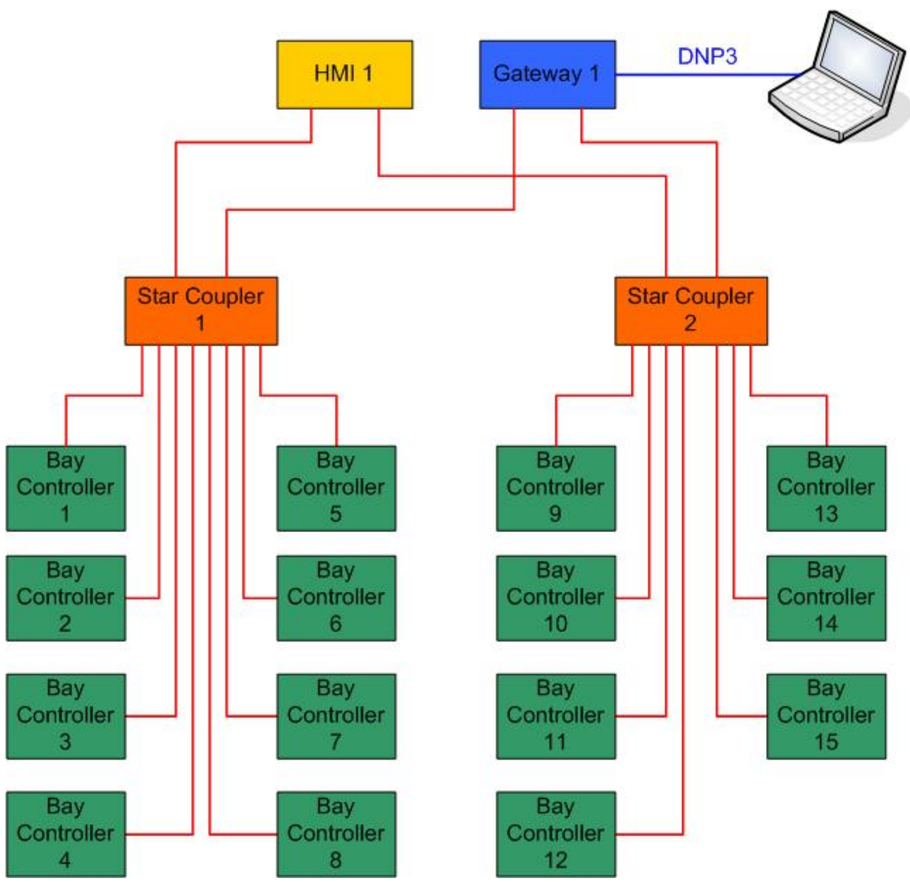

Figure 5: Control Integration Test Setup

The functional testing was carried out over a period of four days and during that time the following tests were carried out for each of the bays:

- ***Operational Tests*** – The operational tests were carried out to ensure that each controllable device (i.e. circuit breaker, disconnect or ground switch) could be controlled in local control mode from the bay controller, in remote control mode from the station HMI and in remote control mode from the simulated SCC via the DNP3 gateway. The tests also verified that the proper indication was shown for each device on the bay controller mimic, on the station HMI and that the correct status was transmitted to the simulated SCC.

- ***Events/Alarms Tests*** – The events/alarms tests were carried out to ensure that all signals from the field devices coming into, or generated from, the bay controllers are indicated correctly on the station HMI and simulated control center via the DNP3 gateway.

- ***Measurement and Metering*** – By injecting defined voltages and currents into each bay controller, the measurement and metering tests verified that measured quantities were correctly and accurately displayed on the bay controller mimic, the station HMI and transmitted via the gateway to the simulated control centre. There was also a dynamic component to these tests in which the injected values were changed and the time it took for that change to register on the HMI and at the simulated SCC was measured.

- ***System Supervision*** – System supervision tests were carried out to check that the loss of communication to an IED resulted in the correct alarm being generated on the station HMI and that the alarm was reset when communication was restored to the IED.

- ***Protection Tests*** - The only protection functions handled by the GIS bay controllers is breaker fail protection for the four bus tie breakers. The breaker fail function was tested to ensure proper response by the IED and that the proper events and alarms were generated.

- ***Interlocking Tests*** – Interlocking tests were conducted to verify the interlocking logic in each of the bays. These tests were conducted on all bays by simulating various device statuses and ensuring that only safe switching operations were allowed. This included interlocks with bay ground switches, bus ground switches, disconnects, breakers, load transfer, and synchrocheck release.

5.2. Protection Integration Tests (Canada)

After the control integration tests were performed in Germany, the remainder of the automation system was tested in Canada, using the same station HMI and gateways computers as used in Germany. The protection integration tests were carried out in order to verify the proper design and implementation of the protection panels and the integration of the protection IEDs with the station HMI and gateway prior to releasing the equipment for shipment to site.

For the tests, all of the assembled control and protection panels complete with all of the IEDs, the station HMIs and gateways, the LON and IEC 61850 networks (except the GIS bay controllers) were connected together in the manufacturer's facility exactly as they would ultimately be connected at site. A relay test set was used to provide three phase voltage and current signals to the IEDs for checks of the metering and protection functions.

Since the protection IEDs were relatively new to both the consultants commissioning personnel and the manufacturer the majority of time spent was focused on the testing of protection IEDs and their protection functions and schemes. Also, most of the control functionality for WHS is provided by the GIS bay controllers, only the control of three 230kV bays were provided from the factory in Canada. The protection functions within the relays were tested using the relay test set to verify that the protection functions within the IEDs work correctly and that the appropriate events and alarms generated by the protection functions were correctly indicated on the IEDs and on the station HMI. Due to time allotted for the testing, it was not possible to test each individual relay. As a compromise, one of each typical panel was tested.

Overall, both factory tests went well and provided a number of benefits to the project. The main advantage was the confidence gained in the operation of the system as a whole.

The second advantage was that a number of deficiencies were uncovered during the course of the factory tests. The majority of these deficiencies were minor and were able to be rectified and re-tested prior to the end of the factory tests. Identifying and correcting these deficiencies in the factory meant that fewer problems would be uncovered during on-site commissioning, saving both time and money.

Finally, the factory testing was attended by the engineers who would ultimately be responsible for commissioning the system in the field. For these engineers, it was an opportunity to get hands on and become more familiar with the operation of the equipment. This experience not only benefited them down the road during the actual commissioning, but also provided valuable insight during the preparation of the commissioning procedures and scheduling of the commissioning activities.

6. System Commissioning

Overall, the commissioning of the Waneta Hydro Station SA system followed the same basic tests as were conducted in the factory tests, with the main difference being that the system was connected to the field devices such as the HV apparatus and telecommunications equipment.

Prior to the on-site testing, a gateway benchtest was conducted at the regional system control centre. This involved setting up one of the WHS gateway servers at SCC and connecting it directly to the SCC communications port. Then two sample bays, one LON bay and one IEC 61850 bay, were tested. The tests were conducted over 2 days and covered all of the various types of signals (alarms, statuses, telemetry and commands). The benchtest proved to be extremely valuable not only to prove the compatibility between the gateway and the SCC Master SCADA, but also to sort out details of how the operators at SCC wanted the signals to be programmed (format codes, alarm class codes, etc.) Following the benchtest, the gateway was returned to site and installed in its final configuration.

The first step in the commissioning of the SA system was to establish communication between the station HMIs and gateways and all of the IEDs on both the LON network and the IEC 61850 network. From this point, the commissioning progressed on a bay-by-bay basis.

Commissioning of the bay controllers began with verifying the position indication of all primary equipment in the bay controller, the station HMI and in the gateway database. Verification of the position was done visually and operation of the equipment was done at the bay controller thus also verifying proper control at the bay level.

The next step was to verify all other inputs into the bay controllers including binary inputs to ensure they trigger the proper alarms and/or events on the station HMI and in the gateway database and secondary voltage and current injection tests to verify the accuracy, scaling, VT and CT ratios, dynamic response time, power calculations and power flow directions in the bay controller and also on the station HMI and in the gateway database.

Once all the inputs to the bay controllers were verified at the bay controller, on the station HMI and in the gateway database, and proper control from the bay controller was verified, the tests moved to the station level. First, control of all devices was tested from the station HMI and verified visually to ensure the proper device was being controlled. At this point, the station interlocking was tested in a fashion similar to that done during the factory tests, all conceivable scenarios resulting in invalid interlocking were tested to ensure that the switchgear could not be operated in an unsafe manner. Interlocking logic is programmed in the bay controllers, at the closest level to the device, therefore it was only necessary to test the interlocking from one control location. Also at this stage, system supervision was tested to ensure communication of all IEDs was properly monitored and the proper alarms were generated.

The commissioning of protection IEDs was carried out on a bay-by-bay basis similar to the bay controllers. The field inputs into each IED were verified first at the IED itself and then on the station HMI and in the gateway database. Protection and metering functions were verified for correct operation and again the signals being sent up to the station SCADA were verified on the station HMI and in the gateway database. Once the tests on the individual IEDs had been completed, scheme checks were done to make sure all protection schemes function properly.

The final stage of tests was performed at the system level and involved the testing of communications with SCC. During previous tests, all of the data transmitted from the IEDs (status indications, alarms and telemetry values) was verified in the gateway database. Once the data was verified in the gateway database, verifying the data to SCC was simply a matter of manipulating the data in the database to indicate the change of status point, alarm or telemetry value. Once all of the statuses, alarms, alarm groupings and telemetry signals were verified, remote control from SCC was tested.

Once one station HMI and gateway were completely tested, the databases were copied to the second HMI and gateway. Since the databases had been proven in the first HMI and gateway, only a random sampling of tests were performed on the second HMI and gateway to verify proper operation.

It was important to check communication between IEDs in the generating station and substation for differential schemes as well as communication of IEDs to the station HMIs and gateways since these IEDs were on a remote portion of the 61850 network, connected to a switch located in the generating station.

The automatic tap changer control scheme of the parallel transformers was tested during commissioning to make sure all inter-IED signals were exchanged properly and interlocking of tap changer schemes worked flawlessly. It was not possible to test this scheme in the factory as it was difficult to completely emulate the complete tap changer control scheme. The interlocking signals, tap position indications, master/follower selections, tap up/down commands and monitoring information transmitted over the IEC 61850 network were tested to verify proper tap control. Tests were carried out to ensure that tap positions can be efficiently controlled at different levels of control hierarchy; at local HMI, station HMI and system control center.

The remedial action scheme (RAS) associated with the 230kV line and generators was a special scheme that had to be implemented and tested during commissioning. Since all signals associated with the remedial action scheme were exchanged over the IEC 61850 network, it was not possible to physically block output signals from different IEDs; this is a challenge commissioning teams may have to face in the future when all schemes in a substation are implemented on an IEC 61850 architecture.

7. Lessons Learned

The Waneta Hydro Station Project reiterated lessons learned on previous projects utilizing non 61850 networked based substation automation systems however, the selection of IEC 61850 provided some new insights on the application of this new technology.

The most significant lesson learned on this project is that 61850 works! The system was successfully designed and implemented using 61850 for both vertical communications between IEDs and the station HMI and gateways, as well as horizontal communication GOOSE messaging between IEDs for interlocking, tap changer control as well as for implementation of a distributed remedial action scheme involving a number of different IEDs in the station.

As with any new technology, before it can be applied in the most efficient manner, there exists a learning curve, which is steepest at the early stages of adoption that limits the full realization of the benefits associated with the technology. IEC 61850 is no exception and there was difficulty experienced on this project as a result of lack of understanding, experience and documentation associated with the application of this new technology. While not resulting in any overall delays to the project, these problems did result in significant additional effort and resources being required in order to overcome challenges and stay within the original schedule.

Another issue identified during the implementation of this project is that software tools play a critical role in the development of 61850 solutions. These tools are also early on in their development life cycle and improvements made in these tools will greatly aid the engineering process in the future.

Another aspect that adopters of 61850 need to deal with is the changing requirements for documentation in addition to SCL language. The traditional documentation set for substation control and protection systems (single lines, ac/dc schematics, wiring diagrams, etc.) needs to be rethought to reflect the new distributed networked systems made possible by IEC 61850. Network architecture diagrams, simplified logic diagrams showing the intent of the application including GOOSE messaging (and not the specifics of the IED programming) as well as GOOSE messaging tables may need to become elements of the documentation set of substation automation systems utilizing IEC 61850.

The ability to run factory acceptance tests on networked equipment allowed for significant testing to be performed verifying key interfaces prior to shipping equipment to the field. The HMIs and gateways were tested to the 63kV GIS control system at a separate facility from the main protection and control system. Later these same gateways were benchtested to the control center SCADA master before being deployed to the field. These tests were very valuable in identifying problems early and thereby avoiding any major surprises on the deployment of this equipment to the field.

Significant training and expansion of the skill sets of field technicians, tasked with maintaining and troubleshooting problems in the field is required. As the adoption of 61850 blends traditional concepts of transmission system control and protection together with modern information systems technology, field technicians need to be equipped with the knowledge required to understand how these new systems function and how to effectively troubleshoot problems.

8. Conclusions

The hybrid architecture utilized in the design of the substation automation system at Waneta Hydro Station delivered a platform with a high degree of reliability which allowed successful integration of an IEC 61850 based network with a LON network. The successfully implemented IEC 61850 based architecture will be a good example for future projects that will use this new technology or for a hybrid solution such as expansion of an existing system by adding a new IEC 61850 portion.

The integration of IEC 61850 based IEDs showed the challenges a designer has to face when adopting a new technology; nevertheless this technology will solve a lot of problems designers have had to face integrating IEDs from different manufacturers. IEC 61850 based systems will significantly improve device integration efforts and reduce the time and costs associated with the engineering and commissioning of SA systems.

Integrated testing carried out at the factory verified that control and protection functions worked as designed and the IEDs, HMIs and gateways communicated properly as expected. The functional tests provided a high degree of confidence in the system prior to it even leaving the manufacturing facility. On site, commissioning was done in a stage wise manner starting with individual components, then subsystems and finally the full system.

Overall, the design, testing and implementation of the Waneta Hydro Station substation automation system was very successful. A tightly integrated hybrid system was placed into service, which met all of the design criteria.

Authors:

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Mark Mihalchuk P.Eng. - Mark was born and raised in Winnipeg, Canada. He received a Diploma in Electrical Engineering Technology (with honours) from Red River College, then went on to the University of Manitoba where he obtained his BSc degree in Electrical Engineering (with distinction). After graduation, he joined Teshmont Consultants in Winnipeg, where he worked in the areas of project management and the design, specification and commissioning of high voltage substations and substation automation systems. Today he is a Senior Engineer in the Substation Automation Department at Teshmont. From May to September 2007, he was on site as a part of the commissioning team for the Waneta Hydro Station Project, focusing on the commissioning of the substation automation system.

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