Case Study of Redundant Control System at Manitoba Hydro

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***Abstract*—Manitoba Hydro's Portage la Prairie Station originally was T-tapped off of a 230 kV line between the cities of Winnipeg and Brandon in Manitoba, Canada. The station consisted of a single 230 kV breaker, a 230/66 kV transformer, and a 66 kV ring bus with four breakers, supplying three 66 kV feeders. The upgrade of the station, due to load growth, encompassed adding three 230 kV breakers (into a ring configuration), sectionalizing the 230 kV transmission line, and adding a second 230/66 kV transformer and one additional breaker in the 66 kV ring. A solution was required to replace the control system for the expansion of the Portage la Prairie South Station.**

There were constraints with respect to the control building size and the number of new panels that could be installed while keeping the station energized. Also, Manitoba Hydro required that no single failure of any component in the protection and control system (e.g., an IED [intelligent electronic device], HMI [human-machine interface], or a communications cable) could result in a loss of station functionality. Additionally, future expansion plans for the station required a system that would allow for additions to occur with no more than one control element being affected at a time.

This paper addresses the challenges of designing, testing, and commissioning fully redundant control systems. The new system was installed adjacent to the existing protection and control system and was fully tested, utilizing a Manitoba Hydro-built breaker/MOD (motor-operated disconnect) simulator capable of simulating up to 16 devices concurrently. The protection and control system was fully exercised, with a number of programming issues being discovered and corrected. The new equipment installed at the station was connected and tested to ensure proper operation. The benefit of this approach was that the migration from the existing protection and control system to the new system was accomplished in stages with minimal outages. This project approach to integration was done with the anticipation of and in preparation for future IEC 61850 projects.

I. Introduction

Manitoba Hydro is the major energy utility and the chief distributor of natural gas in the province. Manitoba Hydro, headquartered in the city of Winnipeg, serves 521,600 electric customers throughout Manitoba and 261,150 natural gas customers in various communities throughout southern Manitoba. Manitoba Hydro serves a peak electrical load of more than 4,200 megawatts, with total generation in fiscal 2007 of 35.3 terawatt-hours. Manitoba domestic consumption was 21.1 terawatt-hours with a net of 10.59 terawatt-hours exported.

The province of Manitoba has an area of 647,797 square kilometers (250,116 square miles) and a population of 1.2 million, primarily in the south. The vast, sparsely populated service areas and extreme weather conditions influence the design criteria for transmission and subtransmission stations in the Manitoba Hydro system.

II. Manitoba Hydro Design Criteria

The control systems employed at Manitoba Hydro have evolved over the years due to the changing operating environment, the need for additional visibility in the station, and the standardization of design.

Manitoba Hydro implemented the following design parameters in reaction to system occurrences and response times, which could take days, depending on the situation and remote location of the station:

- Redundant protection packages should be from different manufacturers to ensure that any anomalies present in the hardware, firmware, or algorithm do not exist in both systems.
- A failure of any single component in the protection and control system, such as an IED (intelligent electronic device), HMI (human-machine interface), or a communications cable, should not result in a loss of functionality at the station.
- Future expansion or modification plans for a station should require a system that allows for additions to occur that affect no more than one control element at a time.
- The final design implemented should be required to minimize or eliminate costly transmission line outages in the event of a failure or during future expansion or modification.

Up to the early 1970s, traditional control systems used mimic buses with device position indicating lamps, control switches, and analog transducers with associated meters. Multiple electromechanical relays protected the station. Interlocking was hard-wired with auxiliary contacts from all of the breakers and switches; any special interlocking requirements were implemented in operating procedures, as these requirements tended to be too difficult and costly to hard-wire.

Starting in the early 1970s, Manitoba Hydro introduced a miniature control system primarily to reduce space requirements for control (see Fig. 1). This system consisted of bins with a control card for each controllable device. These cards implemented select-before-operate logic, status indication (red and green lights), flashing green light on trip, synchronizing provision, interlocking interface provision, and recloser control and lockout. The system operated at 24 Vdc, which required electromechanical relays to interface with the switchyard 125 Vdc control voltage. With this generation of the control system, transducers with analog or digital displays were still prevalent for metering data.

Fig. 1. Miniature Control Panels

The latest control systems implemented extensively at Manitoba Hydro are based on a redundant, distributed PLC (programmable logic controller) architecture. The control system runs hot-hot with redundant HMIs and redundant, distributed PLCs. The PLCs are configured with a station master (SM) and multiple zone PLCs. The PLCs interface directly to the yard apparatus at 125 Vdc for all status and control. The SM PLCs are the central point of processing for the station. The select-before-operate control logic, all metering information, and the interface with the RTU (remote terminal unit) and HMIs are via the SM PLCs. The zone PLCs are the collection point for all status records within the respective PLC zones. Within a particular zone, the zone PLC I/O acquires all relevant signals from that zone and controls all apparatus (breakers, MODs [motor-operated disconnects], and circuit switchers). All I/O is separate and fully redundant. All interlocking is programmed into the PLCs. With all status points in the station available, complex protection and automation schemes can be implemented very economically via logic. The zone PLCs contain modules that are capable of controlling the yard apparatus at 125 Vdc and double as tripping relays (94s) for the protection system. The PLC I/O modules can operate independently of the CPU (central processing unit) as a relay while concurrently acting as I/O for the PLC. This provides the benefit of having one operating contact per system. The PLCs communicate with digital transducers to collect all of the metering data for the station.

The redundant systems are each equipped with an off-test-run switch to set the state of the PLC system. When placed in Test mode, the PLCs are physically blocked from operating any apparatus, allowing an environment for safe testing. When one of the redundant systems is placed in Run mode, all operating and dynamic variables (timers, etc.) are synchronized to the running system, and the PLC is enabled to operate the apparatus. This flexibility allows one system to be modified and tested while the other system runs the station. This design minimizes the outages required for changes or future expansion at the station.

III. Portage la Prairie South Station

The Manitoba Hydro Portage la Prairie South Station originally was T-tapped off of a 230 kV line between the cities of Winnipeg and Brandon in Manitoba, Canada (see Fig. 2). The station consisted of a single 230 kV breaker, a 230/66 kV transformer, and a 66 kV ring bus with four breakers, supplying three 66 kV feeders. The upgrade of the station, due to load growth (see Fig. 3), encompassed adding three 230 kV breakers (into a ring configuration), sectionalizing the 230 kV transmission line, and adding a second 230/66 kV transformer, a 66 kV ground bank, and one additional breaker in the 66 kV ring.

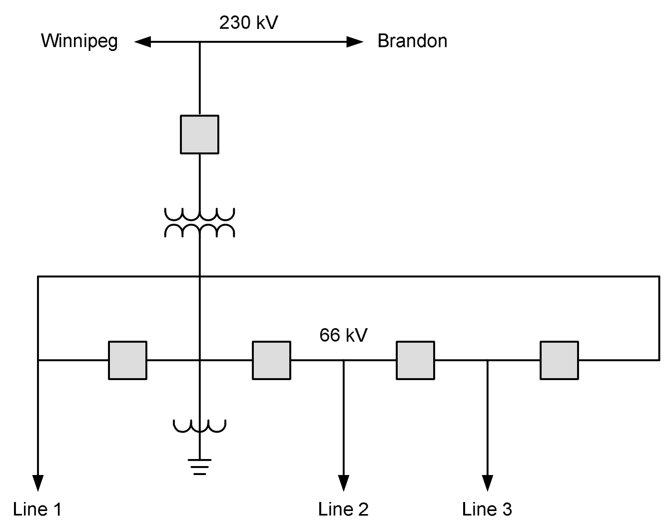

Fig. 2. Portage la Prairie One-Line Diagram Prior to the Upgrade

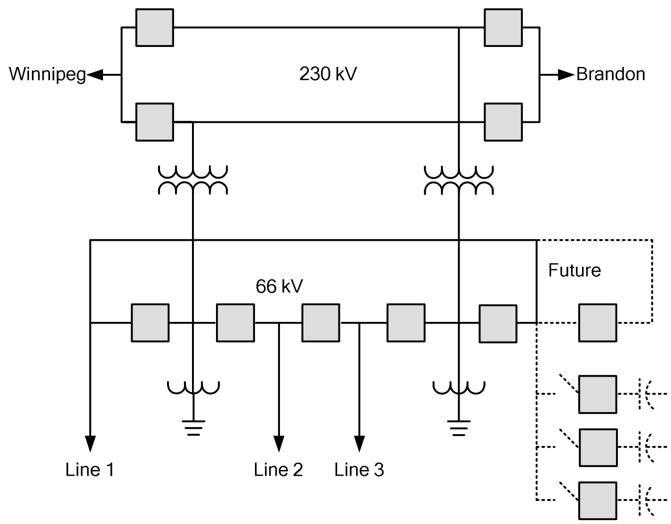

Fig. 3. Portage la Prairie One-Line Diagram After the Upgrade

Constraints included the control building size and the number of new panels that could be installed while keeping the station energized. The design had to minimize the outages taken on the transmission system and ensure the station could continue to supply the 66 kV load. Also, Manitoba Hydro needed to complete the sectionalization of the 230 kV transmission line as quickly as possible to restore the transmission capability. This line is one of the major east-west routes in Manitoba.

The complete protection and control system, excluding the HMIs, RTU, and termination cubicles, required only seven panels (see Fig. 4). These consisted of two panels containing the PLCs and the communications equipment, two panels for transformer protection, two panels for 66 kV protection, and one panel for 230 kV line protection.

Fig. 4. Portage la Prairie South Station Protection and Control System

IV. Control System Design

The control system implemented at Portage la Prairie South Station was a hybrid of the previously implemented PLC control system design. A fully redundant protection and control system was realized by using the front end of Manitoba Hydro's present PLC-based redundant architecture. This front end consisted of a standard RTU installation, redundant HMIs (hot-hot), and redundant PLCs (hot-hot) that act as the main processing system (see Fig. 5). The SM PLCs were equipped with the station I/O primarily to use the apparatus status for interlocking and indication. As in the previous design, the control logic with interlocking was implemented in the PLCs.

Fig. 5. Standard Manitoba Hydro RTU and HMI Installation

The new design involved the use of protective relays as the control I/O device for the breakers, eliminating the additional hardware required for control, namely the zone PLCs. The challenge that Manitoba Hydro encountered was how to implement a redundant control system using the protective relays.

Half the functionality (i.e., tripping) already exists in any relay installation; the other half (i.e., the breaker close functionality) is now available in protective relays. The high-power contacts now available on some protective relays allow installations without the required use of auxiliary relays to handle the tripping/closing current required for breaker operation. Also, the functionality built into relays for breaker control, such as synchronism-check capability, recloser logic, and programmable control logic, completes the list of requirements.

Implementing the control functionality for the breakers required communication between the station PLCs and the protective relays. Communications processors were used to route the appropriate signals from the PLCs to the protective relays. The RTU, HMIs, PLCs, and communications processors were connected via a redundant Modbus Plus® network. Communications processors at each voltage level (230 kV and 66 kV) were implemented in a fully redundant manner (see Fig. 6). The relays, equipped with three serial ports, were connected to Communications Processors A and B in a star configuration via two of their serial ports. The two instances of breaker control logic, including reclosing, in the protective relay were programmed for each instance to work with one of the control systems. All control was implemented with a closed-loop design with feedback of the appropriate signals from the installed IEDs.

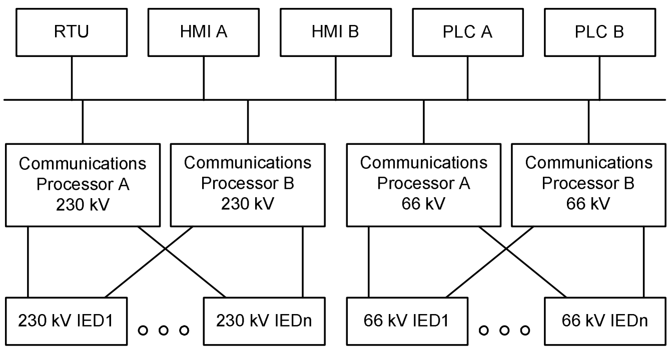

Fig. 6. Portage la Prairie South Fully Redundant Control System Architecture

Manitoba Hydro accomplished control of the MODs at the station with I/O boxes, using the same serial communications protocol and programming interface as the protective relays for ease of implementation and troubleshooting. Also, automation controllers were used to implement a master/follower scheme for the two transformer tap changers, one with ±10 steps and the other with ±16 steps. The automation controllers were installed at each transformer and connected to the communications processors via fiber-optic cabling. These controllers provided the transformer alarms and tap step used in the master/follower scheme as well as local/remote indication.

The dc distribution system was zoned with Protection Zones A and B along with Control Zones A and B. The dc Control Zones A and B are monitored by the dc monitoring available in the protective relay. The distributed control system logic utilizes a select-before-operate scheme that emanates from the PLC. Additionally, an off-test-run switch is used for each control system, A and B, to provide a signal to the PLC and each protective relay to indicate the status of that particular system. At the relay, putting the switch into the test position only disables the output contacts for control but not the protection function. This allows for the testing of the control system through the various levels of programming without having to disable any protection functionality.

Logic was incorporated into the system to monitor the health of the synchronism-check supplies. This logic ensured that a breaker was not closed onto what was mistakenly determined to be a dead bus in the event of a blown fuse in the potential supply.

Manitoba Hydro decided to use the protective relays as the source for all metering values at the station. The metering values, displayed locally on the relays and on the HMI, were sent to the control center via the RTU.

Breaker failure protection was implemented in a distributed system, consisting of a central logic processor and the protecttive relays via the third serial port. Manitoba Hydro's experience with breaker failure systems indicated that most trips are caused due to testing mistakes by not adequately blocking the tripping signals. To remedy this situation, each protective relay was programmed with the ability to be put into test mode. The "in test" status of a relay is sent to the central processor, which acts as a tripping matrix to block the sending of tripping signals to the appropriate relays. Additionally, a breaker failure system in the test switch was installed to put the whole breaker failure system in test mode.

During the initial stages of acceptance testing, extensive use was made of the SER (Sequential Events Recorder) capabilities in the IEDs to troubleshoot the operation of this prototype system. In this system, all of the logic elements used in the protection IEDs were monitored via SER.

The control system functionality was verified using a station simulator connected to the control system to mimic all of the operating devices in the station.

The last component of the system was the termination cubicle, which connected all the interior and exterior cabling (see Fig. 7). This cubicle provided a test point for the entire control system and a marshalling cubicle that allowed for easy installation of jumpers. The use of jumpers in the termination cubicle will allow future changes to the station to occur with little to no recabling for installed equipment. At the bottom right-hand side of the panel are four device simulators to aid in future testing, which can represent any combination of breakers, circuit switchers, or MODs. These simulators are implemented for a fully redundant system, including redundant control and indication.

Fig. 7. Portage la Prairie South Termination Cubicle

V. Installation and Testing

One existing panel at the station had to be temporarily relocated to make room for the new panels to be installed. The new protection and control system installation occurred without taking an outage in the station. All the new protection and control panels were installed and cabled to the termination cubicle. Fig. 8 shows the control panel installation in progress.

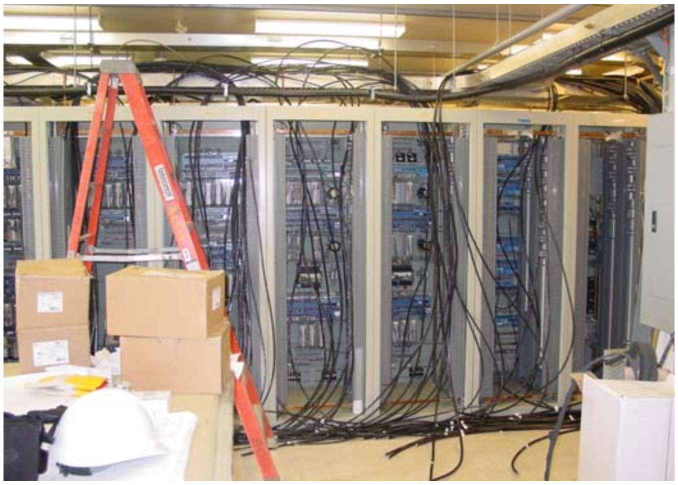

Fig. 8. Portage la Prairie South Protection and Control Panels During Installation

Manitoba Hydro designed and constructed the station simulator to allow testing of significant additions, complete replacements, or new station control systems. The station simulator was designed to simulate sixteen devices, breakers or MODs, and all associated disconnects for a fully redundant control system. The simulator is a PLC with associated logic that allows testing of the entire control system, including variable timing delays for the a and b contacts on trip and close operations to test status discrepancy alarms.

The station simulator was connected to the termination cubicle (see Fig. 9) to simulate the four 230 kV and five 66 kV breakers, four MODs, and all disconnects that were to be installed in the station. Extra time was needed to get the first breaker test to work due to coordinating the communications settings for the various devices and resolving programming issues. Once it was established that the first breaker was working properly, the changes required to get the first breaker working were applied to the rest of the system. Timing tests of the control system were performed to provide a better understanding of the latency between the various IEDs and the system as a whole. Testing the protection functionality yielded several programming inconsistencies; the most significant of these was the improper configuration of breaker failure settings in one relay that caused the wrong breakers to trip. Fortunately, with the station simulator in place, all of the problems were discovered and corrected in an expeditious and safe manner. During the testing with the station simulator, it became apparent that the SER records generated by the system were a valuable and time-saving tool.

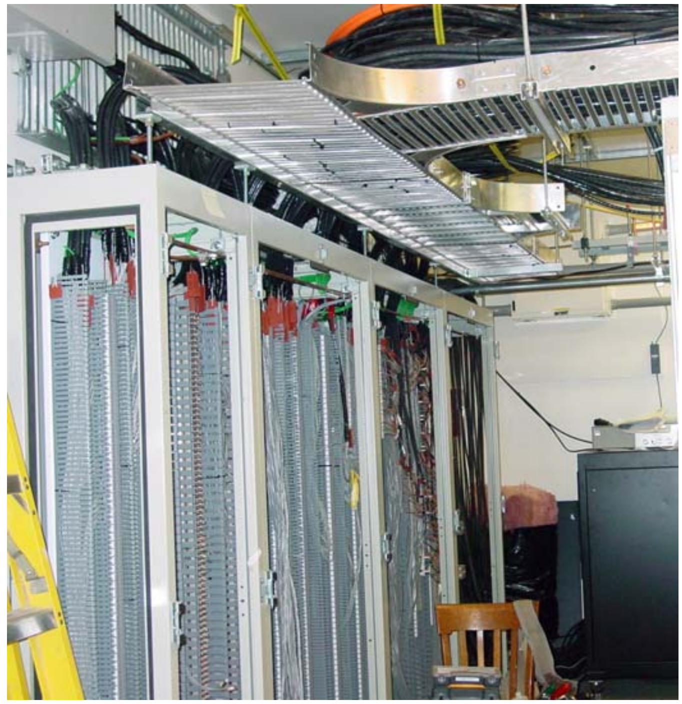

Fig. 9. Termination Cubicle With Station Simulator (in Black)

As the protection and control system was being installed and tested inside, crews erected the buswork and apparatus and installed all new yard cabling. After the system had been proven, the new apparatus was connected and tested. A series of outages were taken at the station to allow one element at a time to be transferred from the old to the new system. During this transition, the station continuously carried load and supplied the local area.

VI. Conclusion

The design, installation, testing, and commissioning of the Portage la Prairie South Station has proven that an innovative and economical control system that utilizes protective relays as the field I/O interface for apparatus is practical and possible. This project's control system was conceptualized to explore various aspects of station integration. Also, this system impressed the change in roles and responsibilities on an organization, as previously discrete functions (protection, control, and metering) were incorporated into an integrated system.

Maintenance personnel have provided positive feedback on every aspect of the station operation. The station has been in service since May 2007 with no issues in the protection and control system operations. One incident that occurred was the inability to close in one of the 230 kV transmission lines due to the phase angle difference being greater than the setting value. This worked exactly as designed but was considered an inconvenience by the operating staff. The most surprising result of this project was the operating staff's insistence that the numerous SER points (over 800) in total, used during the testing process be left in place for troubleshooting purposes. The numerous SER points that exist in the control system give comfort to the operating and maintenance staff and seem to reassure them that the control system continues to work as intended.

As a result of this project, Manitoba Hydro recognized that the maintenance and future design work on station controls integrated into a system such as that presented here require an understanding of the system as a whole. Standardizing with consistent design parameters and similar IEDs installed in many stations leads to familiarity and ease in troubleshooting. The adoption of the IEC 61850 standard on future projects and consistent design parameters will lead to increased productivity and increased return on investment for the utility.

The benefits of a redundant hot-hot control system have been demonstrated in Manitoba Hydro for the past decade. The initial use of PLCs programmed to work in a redundant hot-hot configuration and future use of IEC 61850-based systems that will operate hot-standby with the ability to split the systems to run hot-hot will continue to provide benefits to the utility. The reduction in outage time and the ability to test a control system without taking an outage are the key benefits of this approach.

For future projects, one beneficial capability would be the implementation of breaker/MOD simulation capabilities in the controlling IED device via software. This capability would greatly enhance the designer's ability to develop and test control system programming. The ability to test protection and control schemes with an IED on a designer's desk, rather than having to wait until the full system is installed or having to connect a simulator to the IED, would enhance the design process.

VII. Biographies

Daniel J. G. Blanchette received his B.Sc. in Electrical Engineering from the University of Manitoba in 2008. He has been employed by Manitoba Hydro since 1989. He has held a number of positions in the Station Design Department, with over 10 years of experience in substation controls and automation. He is presently in the Engineering Contract Management Department, responsible for leading a team in the administration of engineering and procurement contracts. Mr. Blanchette is an engineer-in-training in the Province of Manitoba and is a member of the IEEE.

Michael J. Dood earned his B.S. in Electrical Engineering from Michigan Technological University in 1979. In 1979, he was employed by Wisconsin Electric Power Company (WEPCo), where he was a senior engineer in the Distribution Automation Group. His responsibilities at Wisconsin Electric included substation automation design and implementation, distribution automation, and SCADA. He also has over 15 years of experience in substation design and project management. In June 1998, he took a position at Schweitzer Engineering Laboratories, Inc. (SEL) as an integration application engineer. His responsibilities include training and assisting SEL customers in their substation integration and automation efforts. Mr. Dood is a registered professional engineer in the State of Wisconsin. He is a Senior Member of the IEEE and is an active member of the PES Substation Committee.

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