Modernization of an Industrial Power Distribution and Automation System- Lessons Learned

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Introduction

Tata Chemicals North America (TCNA) operates one of the world's largest trona mining and processing facilities in Green River, Wyoming. Trona is the most common source of soda ash, which is used to manufacture glass, chemicals, paper, detergents, and textiles. Nearly all the natural soda ash produced in the United States comes from the Trona formation in this area of Wyoming.

The TCNA facility, built in 1968, has an expansive 13.8kV industrial power distribution network. In 2015 TCNA began to investigate the modernization of the network that powers the processes that convert the raw trona into the various finished products that TCNA produces.

The TCNA surface plant converts trona ore to soda ash in a multi-step sequential process. First, the trona ore is crushed and screened to prepare it for processing. The crushed trona is then heated in a kiln which transforms the ore to crude sodium carbonate. Water is added to dissolve the sodium carbonate and the slurry filtered to remove impurities. Water is then evaporated from the purified solution to form soda ash crystal slurry. Any remaining water in the slurry is separated from the soda ash crystals in a centrifuge. The soda ash crystals are then dried in rotary driers and screened to form the final product. Because of this sequential process, a power failure in one area of the facility can stop the entire process. In addition to lost production, when power is lost the process of cleaning out and restarting production is significant. As such, electric reliability is paramount to TCNA's success.

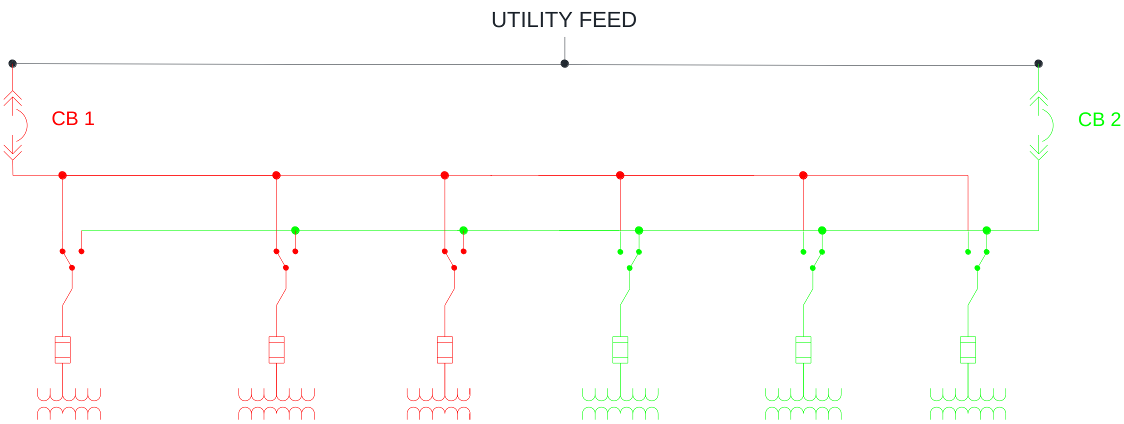
The TCNA facility is a harsh environment. Temperatures are extreme, it's usually windy, and soda ash becomes very caustic when dissolved in water. Together, these factors serve to accelerate the aging and failure rates of power distribution equipment, cables, and electronics.

Existing Design

The existing plant electrical distribution network is comprised of two main 13.8 kV switchgears fed from one utility source and two on-site generators. The original network design consisted of dual radial feeds from the main switchgears to each load center that were manually-switched. The feeder cables are in open cable tray or conduit. Operationally, when there was an outage on one source, plant operators went out to each load center and switch it to the other source. (Figure 1)

The load-break distribution point switches in the existing design were about 80 feet in the air, requiring the operator to operate the equipment from a lift. In addition, soda ash buildup made it difficult to get the connections open. Because of this safety concern, the switches would only be operated de-energized which required shutting down the power to a broader area of the plant.

Figure 1 - Switched Radial Design



The existing distribution control and protection were not integrated with plant operations. This made it difficult and time-consuming to determine the reason for the outage. Often, the plant operators would learn of an electrical outage because a process would stop. The operator would have to go and investigate why the process stopped, which could be one of many electrical or non-electrical reasons. After some investigation of multiple relays, fuses, breakers, etc. the operator would discern there was a loss of the 13.8 kV feed. At this point the operator could begin the process of switching multiple load centers to the alternate source.

The time required to safely identify, isolate, and re-energize the load centers often meant that many hours of additional time would be spent cleaning out partially-processed ore before processes could be restarted. In addition, there was limited information available to plant engineers to determine the root cause of the outage.

Design Objectives

The modernization of the 13.8 kV distribution network was driven by the need to reduce the likelihood and duration of electricity outages to process load centers. Simply, TCNA sought a resilient distribution system. The new distribution network had four major design objectives: Redundancy, Automation, Efficient use of equipment, and Integration with process operations.

Over time, equipment will fail. Since there is no way to prevent equipment failure the redundancy of the new distribution network was the primary objective. Each load center needed access to multiple sources that could be safely and quickly switched in the event of an outage. In addition, the failure of any one piece of equipment should only impact one feeder.

The time required to manually switch load centers often meant that the process would be lost before restoration could be completed. Therefore, the automation of failure identification and load restoration was determined to be an objective. Simply, to the extent possible the distribution network should be self-healing.

The realization of a resilient distribution network is relatively simple with unlimited funds. The challenge presented with this project was to be efficient in the design by minimizing the amount of equipment, cable, labor, and future maintenance. This objective meant realizing more functionality in each piece of equipment that was used.

The final objective was to integrate distribution information into the plant process control system, but without overwhelming an already complex control system. This meant determining the information that would be helpful to operators and provide this information in a way that it integrated with the rest of the process controls.

Guiding all the objectives was safety. Every design objective and implementation strategy had a safety-first objective. This meant that as choices were made they were objectively compared for how they improved safety for TCNA personnel.

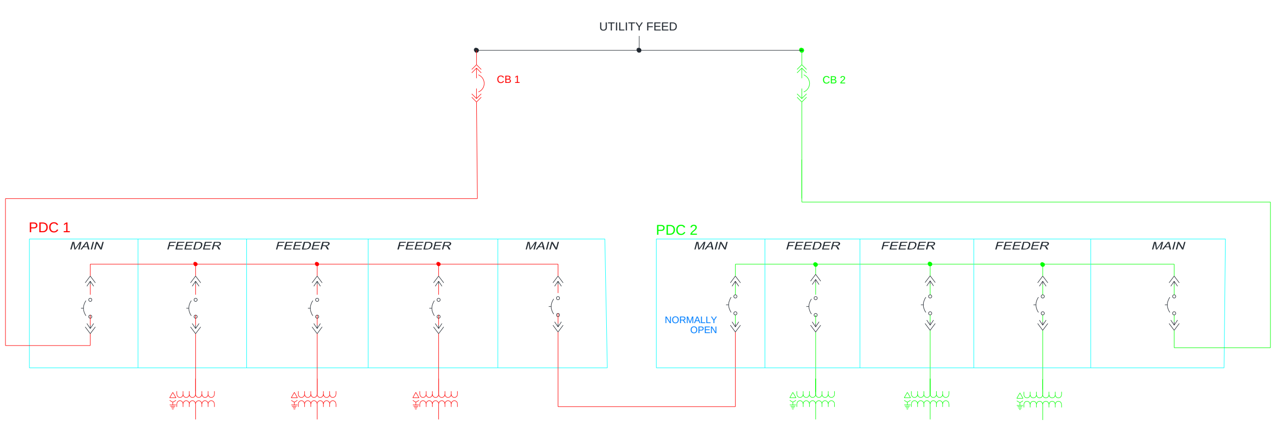
Design

Safety plus the four design objectives drove design choices. The design itself was separated into three distinct areas, Physical, Protection, and Communication. The design choices for each were matrixed to determine the configuration that best met the design objectives.

Physical Design

The physical design centered on the 13.8 kV connections from the main switchgears to each load center. The incumbent design consisted of multiple radial feeds to each load center. For the upgrade there were two designs presented for this project: a modified radial design and a looped network. The modified radial design was similar to what was already installed, but with optional automation capabilities at each switch. The looped network design (Figure 3) consisted of a main 13.8 kV loop between the two main switchgears with loop-fed Power Distribution Centers (PDC) that feed each load center radially. Note the figures below show the two different designs but do not show all the 24 load centers or three PDCs.

Figure 2 - Looped Network



The original path was to use the switched radial design since it was similar to the incumbent design and offered some simplicity regarding construction and the use of space in the facility. The downside to the design was that it made automation more difficult, limited the amount of information that could be provided to operations, and had a lower level of redundancy. In addition, there was a desire to create a better environment for the equipment by placing them inside climate-controlled buildings. These factors drove TCNA to choose the looped network option.

System Protection

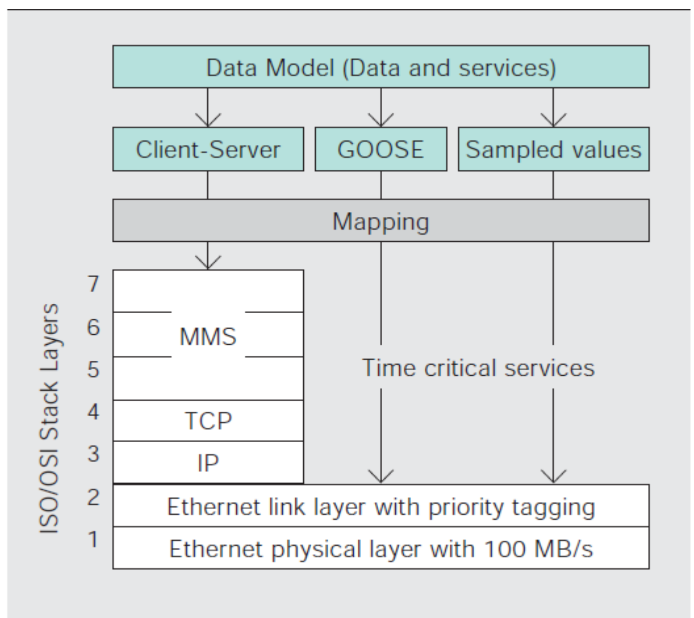
The protection functions and schemes were selected to effectively detect the fault, isolate the equipment involved, and restore power to the rest of the network. The looped network uses switchgear at each PDC to control and distribute power to each load center. This centralized design enabled a number of protection and monitoring technologies to be employed in an economical manner. These include directional overcurrent, differential, and arc flash protection. In addition, the relays and associated simple SCADA computer enabled full power monitoring and control of each load center. Together, these maximized personnel safety and simplified control of the system from anywhere in the facility.

Relay Coordination

The protective relays were all networked to each other using the IEC61850 standard over Ethernet. IEC61850-8-1 provides a feature known as GOOSE, a relay-to-relay communication without involving the SCADA. GOOSE is the acronym for Generic Object Oriented System Event and is a service used for the speedy transmission of time critical information like status changes, blockings, releases or trips between intelligent relays.

IEC61850 communication has a stack structure according to the ISO/OSI layers consisting of Ethernet (layers 1 and 2), TCP/IP (layers 3 and 4) and manufacturing messaging specification, MMS, (layers 5 to 7). The object model and its services are mapped to the MMS application layer (layer 7). Only time-critical services, such as SV (sample values) and GOOSE are mapped directly to the Ethernet 2 link layer (layer 2).

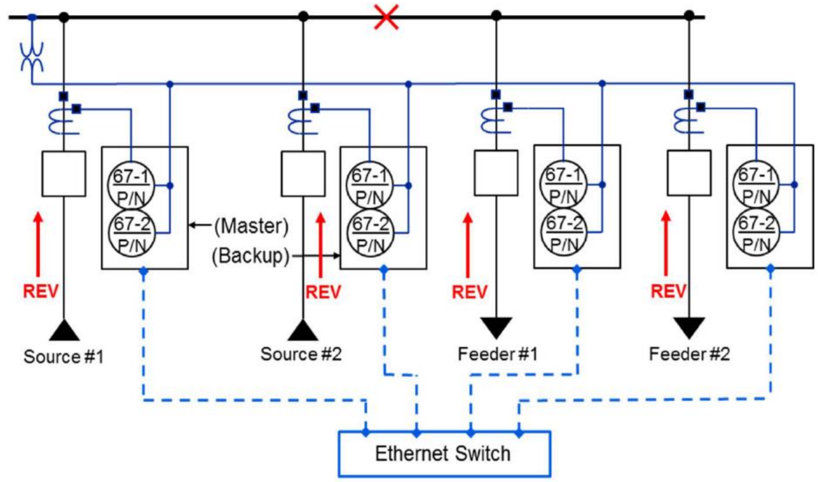
Figure 3 - IEC61850 Data Model



This design enabled a higher level of selectivity by using directional relaying for the main loop coupled with a simple Fault Detection, Isolation, and Restoration (FDIR) logic. Simply, the relay supervision SCADA uses fault data from the relays to automatically isolate the damaged cable and restore power to the loop in under one second.

The relay scheme also enabled the application of a no-cost fast bus protection scheme using the bus-blocking technique. Each relay shares the status of its high-speed directional (forward and reverse) overcurrent elements over GOOSE. Simple logic in the relays on the main breakers takes this information to determine if the fault is internal or external to the switchgear. If the fault is internal, it trips all breakers without delay. If not, it allows the individual relay to trip based on its time-current curve.

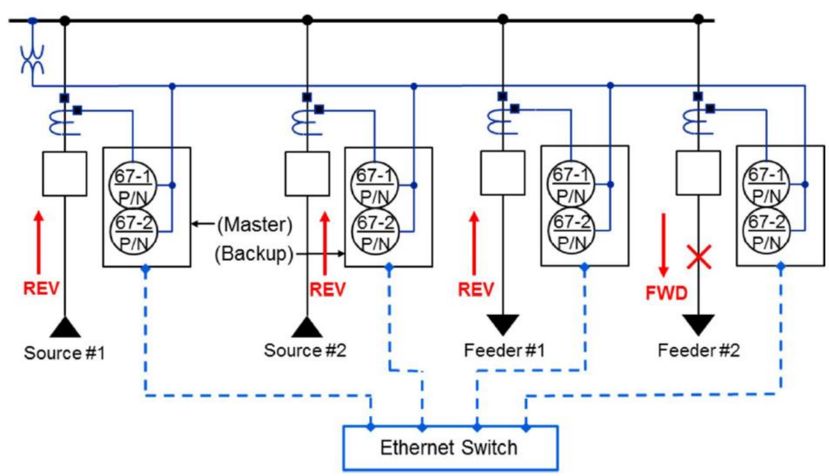
Figure 4 - Bus Blocking during Bus Fault



The principle of operation is to have all contributing circuit breakers tripped when at least one reverse direction (REV) element is detected and not any forward direction (FWD) element is pending.

Should there be a through fault (e.g., feeder fault), the individual FWD of the associated relay operates to trip its own circuit breaker only.

Figure 5 - Bus Blocking during External Fault



Augmenting the high-speed bus-blocking scheme is a dedicated optical arc flash detection system. This system detects an arc flash event and trips the main breakers in <2.5 milli-seconds (ms). The relays on the main breakers then trip all the feeders using GOOSE signals. Coupled with three cycle breakers, the net result is the removal of all energy sources in about 52 ms. The speed of the system nearly eliminates collateral damage to the switchgear and assures there is no arc flash risk to personnel.

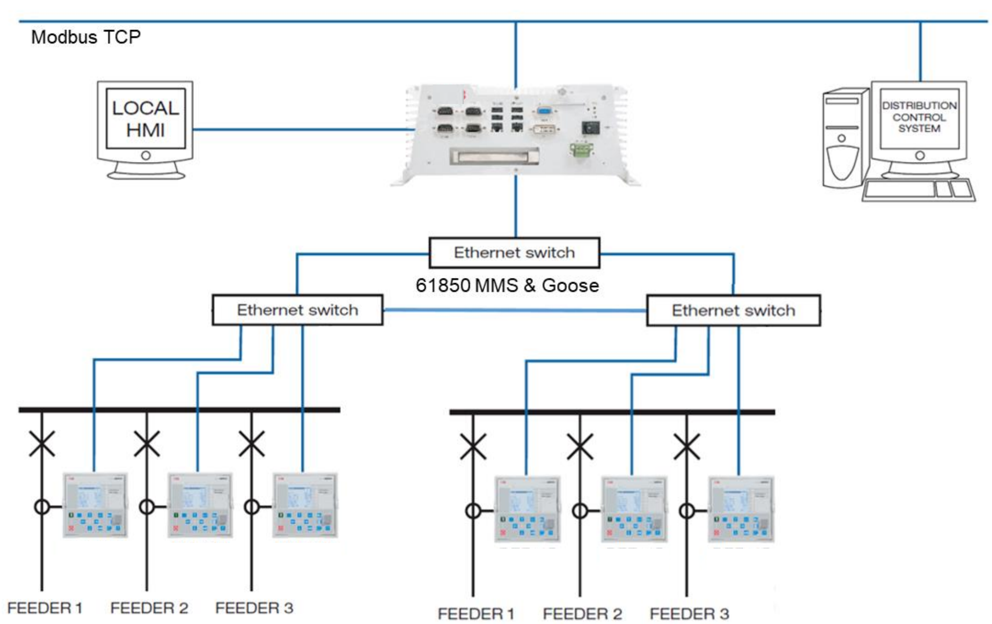
The relay design above required that each PDC have voltage sensing. The availability of a voltage signal enabled full power monitoring for each of the load centers using the feeder relays without additional cost. This, coupled with the relay's breaker condition monitoring and incipient cable fault detection monitoring, enables TCNA to analyze the performance of the power distribution system over its lifetime.

Communication and Control

The communication network consisted of a dedicated redundant fiber loop between the two mains and three PDCs. The only physical connection to other networks is via a separate connection between the SCADA computer and the plant control system. This design maximizes security and potential bandwidth conflicts.

The communication protocols use in the project is a combination of IEC61850 GOOSE, IEC61850 MMS, and Modbus TCP. GOOSE is used for time-critical signals between relays and SCADA. The IEC61850 MMS is used for metering, alarms, and other higher bandwidth information. The Modbus TCP connection is between plant control system and SCADA.

Figure 6 - Communication Architecture



The SCADA computer necessary for the FDIR implementation brought with it several other opportunities. The SCADA computer aggregated information from the relays, enabled remote control of breakers via its web-based HMI, and served as a communication gateway to TCNA's process control system.

The SCADA computer receives all status, event, and alarm signals from the relays. It uses this information to create a web-based HMI that can be accessed from anywhere on the network. This enabled the placement of simple panel-mounted touchscreens in the PDCs running a web browser to control and monitor the system. This feature enables operators to open and close breakers without being in proximity of the breaker, which enhances operator safety.

Making information available to plant operators was a major design objective. The SCADA computer uses a data table to make information from the individual relays available to plant controllers. Simply, data points from the IEC61850 data table are mapped to a Modbus register table that can be polled by the plant control system. The data available is determined by which values are mapped.

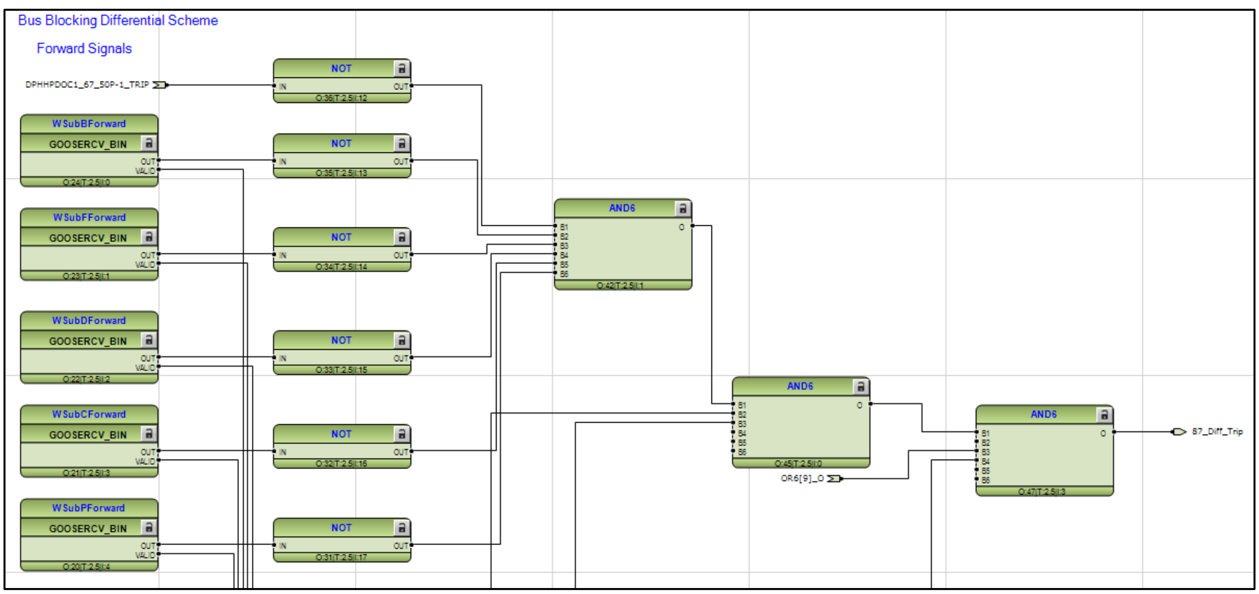
Implementation

The use of a communication-based control and protection system provided many benefits to TCNA. It reduced the amount of wiring and equipment, simplified installation, and enabled the monitoring of all signals without additional programming or equipment. However, this methodology increased the complexity of the relay programming and associated testing. Moving from wired connections to data connections fundamentally changed how the project was implemented.

The implementation of IEC61850-based communications has its advantages and disadvantages. Unlike other communication methods like Modbus or DNP, you don't type register addresses in a device then test them after they are connected. In IEC61850, you share configuration files between and among devices. The advantage is that you never have to look-up or type register addresses. You just select the signals that are available. This greatly reduces human error potential.

The downside of this engineering methodology is that it requires a significant amount of planning, coordination, and process. Prior to programming the logic in the individual relays you should have the coordination design completed. This includes naming convention for new variables, determining the logic, and knowing all the communication variables (e.g., IP addresses, App ID) prior to beginning the programming process.

Figure 7 - Relay Logic Example



After all the configuration programs for the relays and SCADA were completed and downloaded to the devices, testing could commence. In the case of this project, we had 29 devices in four different locations. This made full system testing prior to installation not possible. However, we were able to test the relays in each PDC. This enabled the full testing of the bus blocking and arc flash transfer trip schemes prior to shipment.

The SCADA integration and FDIR testing did not commence until the PDCs and fiber connections between the PDCs were installed. This brought some minor challenges for both relay to SCADA communications and SCADA to plant controls integration. These were mainly due to the fact we could not connect all the relays before installation nor did we know the details of the plant controls prior to installation.

Lessons learned

There were several lessons learned as part of this project, both during implementation and after commissioning was complete.

During implementation, there were a couple of IEC61850 configuration errors that were not identified during testing of the PDCs individually. The first was that overlapping relay App IDs (similar to IP addresses) were created during programming. Since the relay configuration files were done separately for each PDC this was not realized. When the relays were all connected, we noticed GOOSE errors that were unpredictable. After a significant amount of time troubleshooting, we determined the source of the problem. Importantly, any time you make a change to a communication variable like App ID you must reboot the relay. This both takes time and is difficult to do if the system is energized since you will be without protection during the reboot.

The implementation lesson learned is two-fold. First, include this variable in your network address sheet. We settled on mirroring the App ID to the last two digits of the IP address. Secondly, have IEC61850 GOOSE analyzer running on your computer during testing. Had we had this we would have immediately known what the problem was.

The other lesson learned on the IEC61850 was related to the values provided to the SCADA computer via IEC61850 MMS. The value stored in that data point can be the raw value (per unit) or the scaled value (primary). This selection is done in each relay and requires a reboot to make the change. Since we did not commission the SCADA until after energization, we were not able to make this change immediately. The customer had to make the change at each relay during their next outage.

In both these cases, had we been able to test the completed system prior to energization we would have saved a significant amount of time during commissioning and afterwards.

Realized Benefits

After commissioning was complete and the system turned over to operations staff at TCNA, they began to realize some benefits outlined in the design objectives. Most were centered on being able to better understand the status of their processes and immediately ascertain the cause of events.

There was also a benefit that was not a design objective, the ability to take either of the main switchgears out of service without taking an outage. As part of an unscheduled maintenance activity, TCNA needed to take one of the main switchgears out of service. They were able to simply go to one of the HMI panels, close the normally-open tie breaker, and open the main switchgear breaker. The ability to momentarily parallel the two main switchgears enabled a bump less transfer of the load. Prior to the upgrade, each load center would have to be momentarily turned off while it was switched to the alternate source. This would have required a major coordination effort and some loss of production.

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Biographies

Bradley M. Nickell P.E. currently works with utility and industrial clients on electric power system design in the Intermountain West with a focus on building resilient systems using ABB Power Products. Previous to this he served as the Director of Transmission Expansion Planning and Renewable Integration at the Western Electricity Coordinating Council (WECC). In this role he led the Western Interconnection-wide Electricity Planning process. His 25 years of electric power experience includes serving as the Technology Manager for Wind Energy Systems Integration at the U.S. Department of Energy and numerous technical and managerial roles within the industry. Bradley holds a BSEE from Iowa State University and an MBA from the University of Colorado.

Raghu K. Nadipalli is the Field Application Engineer for ABB Inc. Electrification Products division based in Dallas, TX. He started his career with Tata Chemicals in Green River, WY in 2008 as the plant electrical engineer. Over 9 years he worked on numerous upgrade projects & new installations in the areas of power generation, distribution, protection, and automation. In 2017, he started his current role with ABB, serving customers in North Texas region with product application, one-line optimization, specification review etc. Raghu holds a BTech. in Electrical & Electronics Engineering from Jawaharlal Nehru Technological University, an MSEE from University of Idaho and is an active member of IEEE.

Kevin Sims is the Electrical Engineering Supervisor at Tata Chemicals' soda ash production facility in Southwest Wyoming. Kevin and his team manage electrical and control projects as well as assist operations and maintenance activities. Before this role he worked in construction and operations in the oil and gas industry.

Joemoan (Joe) Xavier is currently the Global Product Manager – ANSI for ABB Digital Substation Products & Systems business based out of Camas WA. Prior to this role, Joe served as the US West Region Technical Manager for ABB Distribution Protection & Automation. He started his career as a relay engineer and has over 28 years of experience with Power Systems industry. Joe holds a Bachelor of Technology degree (with Distinction) in Electrical & Electronics Engineering, from Mahatma Gandhi University India. He has co-authored and presented several technical papers on Protection, Automation, IEC 61850 applications and is an active member of IEEE PES – Power Systems Relaying & Controls Committee.