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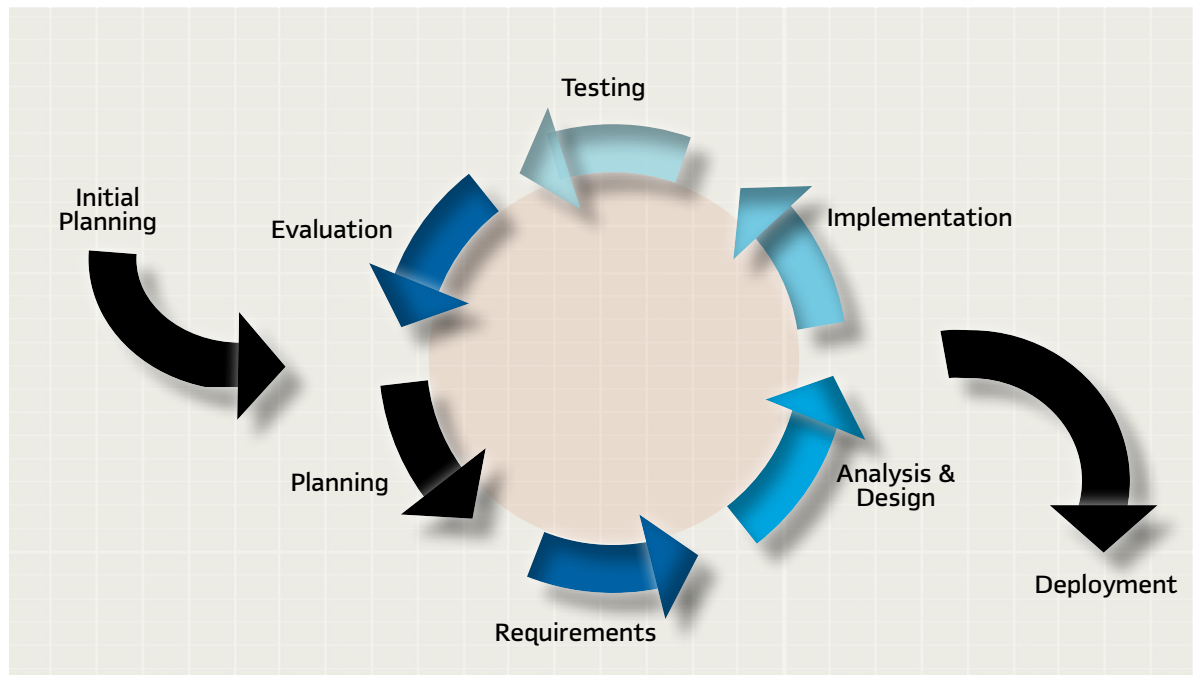
A 20/20 Hindsight Look at Implementing IEC 61850

A Utility Perspective

Substation Automation projects have offered many lessons on many fronts for utilities and the success of recent projects have clearly demonstrated the value of utilizing IEC 61850 technology. The degree of engineering effort and expertise which has been required to make these facilities operationally viable however, has been well

beyond what the glossy visions of trade shows might lead one to believe. This article takes a close, pull-no punches look at the trials and tribulations encountered in projects which have implemented the full suite of IEC 61850 in a multi-vendor environment. With the first round of projects complete, the time for speculation and estimation has passed.

1 Adaptive Method





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“CLEARLY DEFINED POINTS OF INTEROPERABILITY...” Conscious or not, this mantra has for many years been used as the foundation of substation design, operations, and maintenance. Voltages, currents, a-contacts, and b-contacts are as rudimentary to the substation as the alphabet is to the English language and the value they provide the utility is flexibility... flexibility to modularize a problem, distribute the associated work, and select the “best in class” solution for every individual piece of the overall system. While these items may seem trivial to some, their absence will challenge even the most savvy of utilities when deploying new technologies such as IEC 61850 as part of a substation automation system. And if you think the challenges stop there, then think again as tools and techniques will need to be examined and revamped nearly every step of the way.

Such has been the experience of at least one utility in its efforts to shift to utilizing IEC 61850 technology for new transmission facilities. With the project schedule and budget being the most likely casualties of this type of change in design philosophy, accepting up front that the use of the technology in the project would require a different approach was the first step. Even with this “eyes wide open” approach, unanticipated challenges still found their way into the project. And not just the obvious technical challenges one would expect to encounter in this type of effort, but challenges in organizational responsibilities, processes used, engineering tools, as well as the method and type of documentation required.

The goal here is that the details presented in this paper will aid utilities which are just starting the migration to utilizing IEC 61850 technology by providing some perspective on the experiences of other utilities.

Organization

Out of the gate, chances are that one of the first challenges the utility will encounter will be centered on organizational issues. Responsibilities, skill sets of the personnel supporting the project, and widespread buy-in by all affected organizations will present challenges that needs to be addressed.

Responsibilities: “Your switch is in my protection scheme”. “Your protection scheme is in my switch.” The first organizational challenge a utility is likely to encounter is the blurred line between the traditional protection, control and communication responsibilities. For smaller utilities where personnel tend to be cross-disciplinary, this may not factor heavily in the experience. For larger utilities where these functions may be distributed across more than one organization, this aspect has the potential to generate very spirited internal discussions mainly centered on organizational ownership of the Ethernet switches supporting the IEC 61850 GOOSE messaging.

The fundamental issue arises due to the Ethernet switch being considered part of the protection scheme. Does it belong to the telecommunications group or does it belong to the protection and control group? In reality, the responsibilities for the Ethernet switch, as well as the rest of the network should reside with the organization which is best suited to deploy networking technology regardless of the functions

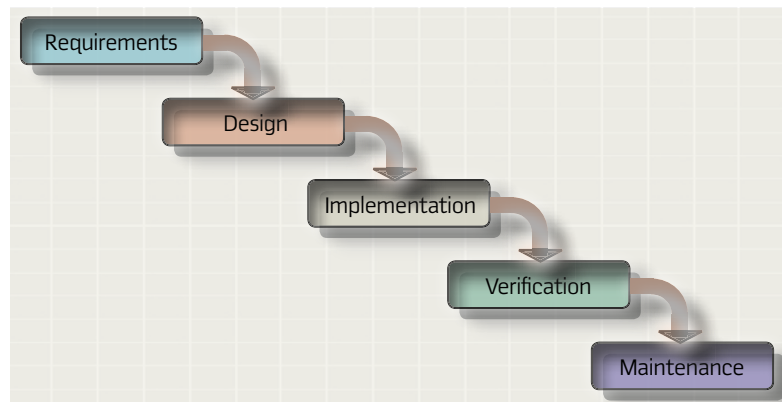
One of the main challenges a utility faces in implementing IEC 61850 is due to the blurred line between traditional protection, control and communications responsibilities.

being supported. If the telecom or IT group was responsible for networks prior to adopting IEC 61850 technologies, then all the pros and cons should be weighed before changing those responsibilities. No matter how the responsibilities are divided, there will always be organizational interface points and interdependencies. As long as functional requirements for the network are clearly defined in the system specification document which is discussed later in this paper, then concerns due to the responsibility for the network residing outside the protection and control group should be minimal. Commissioning testing for the completed system will provide the needed verification of the network meeting the requirements of the protection scheme.

These issues combined with the requirements now in place for North American Utilities with the NERC CIP standards make involvement of the Telecom/IT groups in these types of projects even more critical. So what’s the answer then you ask? It is simple. The P&C department needs the Telecom/IT department and vice versa.

Training: “We don’t have budget for training, we can just learn as we go like we always have.” Although on the job training has been successful in the past with other technolo-

2 Predictive Method



Items classified as Optional in IEC 61850 play an important role in determining the interoperability between IEDs from different vendors.

gies, a more structured approach to training is the best option to minimize project risk for the first IEC 61850 based project for the utility. This means setting aside a budget specifically for training. The utility's goal should be for everyone who will work with, on, or around the automation system to understand the basics of IEC 61850 and networking and at the same time provide a core group of experts more advanced training. As word spreads, utilities may find that interest throughout the company will point out the need for this type of training on a larger scale and not limit it to the project team. To maximize the effectiveness of IEC 61850 training, utilities should also evaluate the level of understanding of networking fundamentals for the affected personnel and address this first if needed.

Buy-In: *"I knew this would never work."* Across the board buy-in from all affected organizations is critical to the success of the project. Like any other change in the company, there may be some that resist it at first. While there may be many reasons for the resistance, communication and education are the common answers. If people understand the basics and feel that they are a part of the project and decisions relating to it, then they are more likely to buy into the change and therefore accept ownership. Like the documentation discussed later in this paper, this buy-in will also support the transition from the engineering personnel to the operations and maintenance personnel at the end of the project.

Process

Just as significant as changes in the system design, are the changes taking place in the design process itself. These changes reflect a new way of doing business for the utility – one where small investment in engineering is made up front in the interest of paying big dividends in the long term. Each utility will most likely encounter in their first project a process which is anything but conventional or predictable.

Method: *"What does the process look like and how long will it take? What does the finished product look like?"* A waterfall, or predictive, approach to projects has historically been the main staple for many utilities. Predictive methods focus on planning the future in detail. A predictive team can report exactly what features and tasks are planned for the entire length of the development process. Predictive teams have difficulty changing direction. The plan is typically optimized for the original destination and changing direction can cause completed work to be thrown away and redone. Predictive teams will often institute a change control board to ensure that only

the most valuable changes are considered. While this approach has served the industry well for many years, it may not be best suited for what will be a highly dynamic design process.

In contrast, adaptive methods focus on adapting quickly to changing realities. When the needs of a project change, an adaptive team changes as well and an adaptive team will have difficulty describing exactly what will happen in the future. The further away a date is, the more vague an adaptive method will be about what will happen on that date. An adaptive team can report exactly what tasks are being done next week, but only which features are planned for next month. When asked about a release six months from now, an adaptive team may only be able to report the mission statement for the release, or a statement of expected value vs. cost.

The path taken in evolving to an IEC 61850 based substation automation solution will be full of discoveries at every stage for utilities. To mitigate the impacts of these discoveries, utilities should adopt more agile or adaptive methods to system integration and design.

Data Modeling: *"Here are my relays. How do I fit functions into them?"* vs. *"Here are my functions. What relays do I need?"* When it comes to data modeling of the associated primary and secondary systems within the substation, each utility will ultimately need to determine if it will utilize a top-down or bottom-up approach. Traditional substation design utilizes a bottom-up process where devices are chosen and then the functions are chosen during the integration.

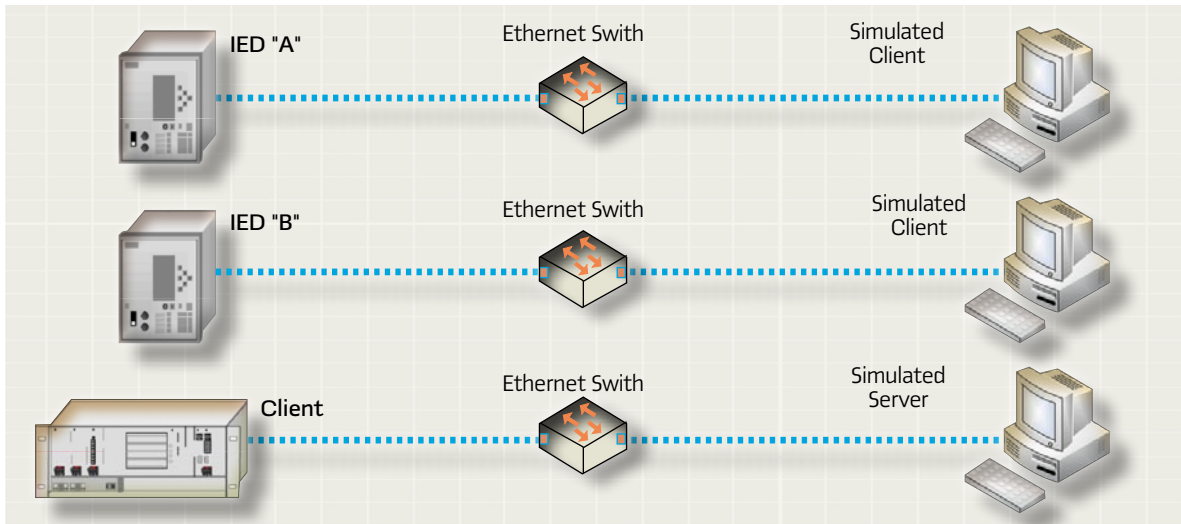
The top-down approach enables the utility to express the functional needs of the substation utilizing the IEC 61850 language. Once these functions are modeled, then devices are chosen which support these functions.

While the bottom-up method is effective for meeting the functional requirements within the substation fence, the resulting modeling presents barriers to integrating the substation data into the enterprise collective. If the utility expects to realize the value of utilizing IEC 61850 technology inside the fence as well as within the enterprise, then it should consider adopting a more top-down approach to data modeling.

Device and System Testing: *"These devices all support IEC 61850, doesn't that mean they have to be interoperable?"* It sounds logical but it is far from the case. The truth of the matter is that when IEDs from more than one vendor are involved in the project, then more of the items classified as optional in the standard will come into play. A little upfront investment in a lab facility by the utility will prove to be absolutely invaluable by providing a testing "sand box," especially if the system integration is being done with in-house resources. This, along with utilizing structured testing integrated within the design process, will help utilities mitigate risk to the project since full-scale testing might not be practical prior to the final system being built. This is especially true if it is the utility's first project involving IEC 61850. One of the most significant lessons learned from early experiences is that type testing of just the devices may simply not be enough in the realm of 61850. This is an engineering stan-

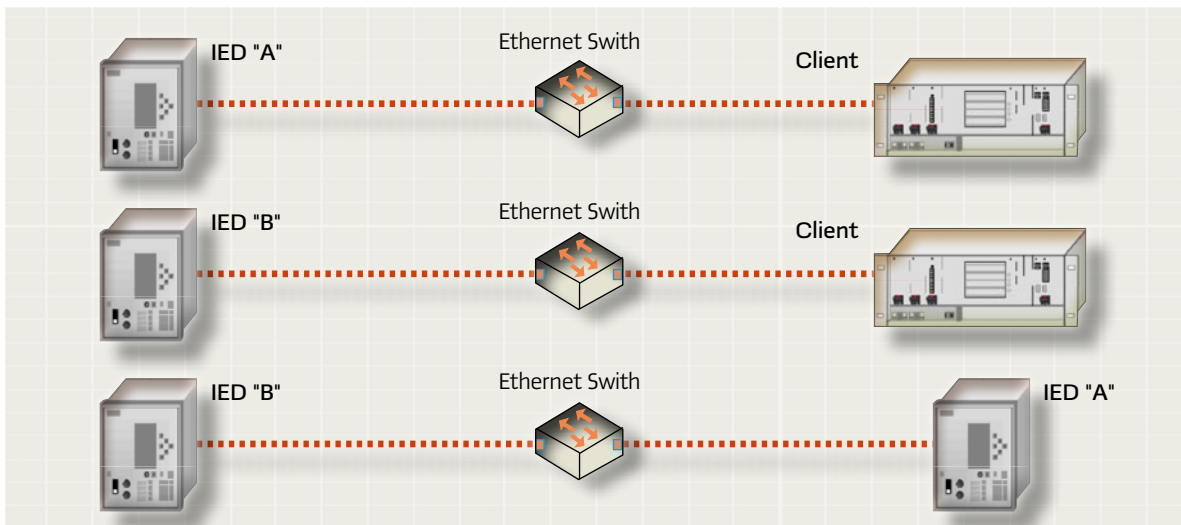
It is essential that all people involved in an IEC 61850 project understand the principles and benefits of the standard.

3 Individual Device Testing

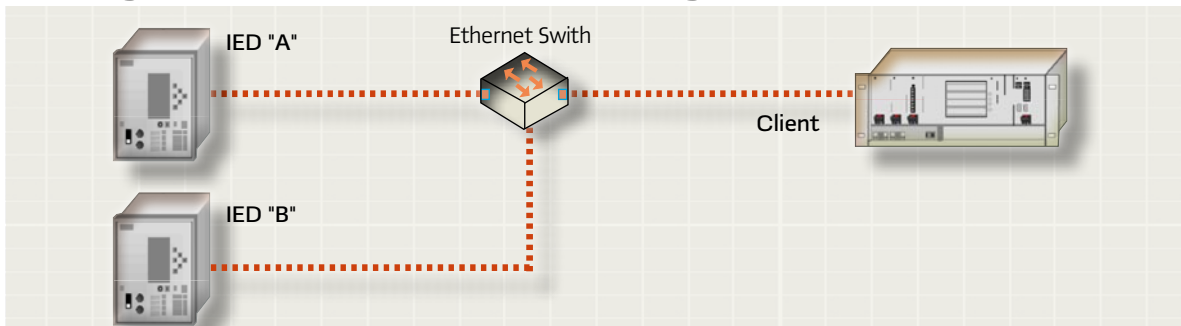


Testing should be integrated as part of the overall engineering process in order to ensure the successful operation of individual devices and distributed applications.

4 Integrated Functional Testing



5 Integration and Performance Testing



standard of astounding breadth and depth, intentionally designed to accommodate as many configurations and methodologies as possible. Vast portions of the object models are marked as “optional” in the standard so as not to be prescriptive with regard to product lines. Unfortunately, this same flexibility can be extremely daunting when first trying to discern how to represent your individual design. And in order to implement that design, you will, in fact, end up requiring some portion of those “optional” objects. This will be up to you and the vendor to negotiate.

Utilities should consider at least three levels of testing prior to the final commissioning/site acceptance testing:

- **Individual device testing** verifies that the selected IEDs meet the utility’s requirements before the detailed engineering and integration occur. This testing basically uses a simulated client to test a real server and a simulated server to test a real client. In order to keep the variables to a minimum, only a limited network setup between devices is used in this phase to test device behavior during basic scenarios or failure modes (Fig. 3).

- **Integrated functional testing** is similar to the individual device testing except that the simulated device will be replaced with a real device. The goal for this testing is to verify basic interoperability between the various devices which will be utilized within the substation automation system (Fig. 4).

- **Integration and performance testing** uses the actual network devices planned for the substation. This testing is aimed at verifying that the final design of the substation automation system meets the requirements identified in the System Specification Document (Fig. 5).

Documentation

Documentation can be perhaps one of the most significant areas of culture change within the utility as part of evolving to IEC 61850 based substation automation systems. Two specific instances worthy of note are the necessity of a system specification document as well as updated operations and maintenance procedures. Early adopters have initially overlooked or not identified these as high value items. Looking back however, not only did the utility realize these initial assumptions to be wrong, it quickly realized how directly tied these items were not only to the overall success of the project, but the reliability of the power system and safety of personnel as well.

System Specification Document: *“We have never created a system specification document before, why do we need to start now?”* There is a good chance you will find yourself uttering these same words in the future. The value for a system specification document may not be clear when the engineering process begins. This may be due to a utility’s decision that the system integration responsibilities are being kept in-house and not out sourced or due to not understanding its criticality. For many utilities, life begins with planning sketches and very few predetermined details prior to starting the engineering and integration process.

It will quickly become clear however, that in order to foster communications between the various groups involved

Utilities should consider device, integration and performance testing.

within the utility as well as between the utility and its suppliers, a system specification document is essential. Not only is it essential, it should be created as one of the very first steps of the project. Once developed, strict revision control of this document is paramount to minimizing rework downstream in the project due to miscommunications and changes. Utilities may find it a challenge at first when attempting to create a system specification document if they have little or no previous experience in creating these type of documents or no good examples to use for reference.

Operations and Maintenance Procedures: *“Let’s see what this button does. What happens if I click this?”* It sounds absurd to think about in a substation environment but this is exactly the effect of inadequate operations and maintenance procedures. Without them, personnel are forced to “reverse engineer” parts of the system to perform even the most routine of tasks. This too is an area that is often not given near the amount of attention needed in the early part of these types of projects.

One of the largest paradigm shifts for the utility in this type of system design arises from the integrated systems and somewhat hidden interdependencies between them. With the traditional designs of the past, one group could isolate a particular device or system and perform maintenance functions without affecting adjacent systems. Now that protection, control, and data acquisition is not being performed on a common substation local area network (LAN), this traditional “air gap” isolation which has been one of the standard tools utilized to create a clearance zone in the industry for many years, is not practical. In order to provide the operations and maintenance personnel the same safeguards and flexibilities given to them with traditional designs, the utility’s existing operations and maintenance procedures will need to be updated and new ones created if needed to fill in any gaps. Documentation not only plays a vital role in the engineering process, it is critical to the process of transitioning the facilities from being supported by the engineering personnel to being supported by the operations and maintenance personnel. Without adequate documentation, engineering personnel are vulnerable to play an extended support role for the facilities, long after the project closure occurs. Without adequate documentation, operations and maintenance personnel are at increased risk of misoperation. Most important however is that without adequate documentation safety is at risk.

Tools

“IEDs come with their respective programming tools so what more do we need?” Technology has provided a seemingly endless variety of software tools that we use on a daily basis and it’s easy to take them for granted. That is at least until

