Improve power reliability through small-scale SCADA systems

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***Abstract*— Supervisory control and data acquisition (SCADA) systems date back to the early 1960s and have been widely used by large utilities since the 1980s to remotely monitor systems in real time. Through the data provided by SCADA systems, investor-owned utilities have been able to improve grid reliability, proactively detect and resolve problems, meet power quality requirements, and support strategic decisions.**

However, SCADA systems no longer need to be relegated to control room settings that support large systems with dedicated staff. The basic technology that supports SCADA can now be cost-effectively scaled to smaller systems with as few as just one substation.

This paper will highlight how smaller utilities may benefit from SCADA functionality, perceived barriers to implementation, typical requirements, technical considerations, and best practices for engaging engineering and construction partners from recent projects.

***Index Terms*—data acquisition, controller, supervisory, intelligent electronic device, SCADA, municipal utilities, cooperative utilities**

I. Introduction

Large-scale applications of SCADA systems have improved safety and reliability, enhanced utility metrics, and benefited the bottom line. Historically, only investor-owned and other large utilities have taken advantage of SCADA systems to build an adaptable, secure, and responsive infrastructure by continuously monitoring status and measurement data from substation and pole-mounted equipment. Yet even today, many municipal and cooperative utilities have not enjoyed the same benefits. It is possible to implement SCADA systems, even for utilities with as few as one or two substations, in a cost-effective and simplified manner.

Today's small-scale SCADA systems gather and record information to support intelligent decisions without needing a major financial investment. Through the information provided in this white paper, municipal and cooperative utilities can harness the potential of automated information gathering to improve decision-making, troubleshooting, and system analysis while reducing maintenance and repair costs.

Any SCADA implementation — whether a new install or an in-place upgrade — must be customized to address a utility's unique needs. The key aspects of these systems are common and include:

- Real-time equipment status, metering data and alarming.
- Historical data trending and storage.
- Remote operation capability.
- System security.
- Communications.
- Implementation and commissioning support.
- Ongoing technical support access.

Successful deployments, demonstrated by recent projects, highlight the need for solutions and services that easily integrate existing equipment with new systems. This requires hardware designed to achieve interoperability and interconnectivity of intelligent electronic devices (IEDs) with a wide range of communications protocols. Software solutions coupled with newly deployed SCADA solutions must provide data access, management, security, redundancy and scalability to support any necessary system functions. It is important to consider engaging an expert team to provide turnkey project management, communications expertise, and implementation support to ensure successful project deployment, providing design, planning implementation, and training for utility staff.

II. SCADA Systems Enable Real Visibility to Support Power Reliability

In general terms, the goal of the electric utility is to provide "safe and reliable electric power at a reasonable cost. The challenge is to find the right balance between low cost and high service quality." [1] Further, as utilities are assessed based on their rates and reliability, actions taken and systems implemented to improve reliability can directly impact the bottom line.

To provide reliable service, it is critical to understand how the distribution grid is operating with accurate real-time data. This information provides the basis required to make effective decisions. While smaller utilities often rely on regular onsite system inspections by operators sent to the field to gather data points, larger utilities have used a variety of monitoring and

[1] Seven-Year Electric Service Reliability Statistics Summary 2007-2013," Oregon Investor-owned Utilities, published June 2014.

control systems to gather equivalent data from multiple geographic locations in a continuous fashion. Utilities can rely on immediate, consistent, and historical data delivered by a SCADA system to make smart, efficient decisions that reduce the duration and frequency of power outages. With solid information, utilities can direct inspections and maintenance more effectively, based on real-time information reflective of what customers are experiencing.

Operational data can be used to significantly impact the utility's System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI) and Momentary Average Interruption Frequency Index (MAIFI). For example, SAIDI can be improved via remote collection of event recorder data by allowing the SCADA operator to provide basic fault data, such as impacted phases and fault current levels, to trouble crews, better equipping them to quickly locate, isolate, and restore faulted circuits. In addition, auxiliary automation applications, such as Fault Location, Isolation, and Restoration (FLISR), may be used in conjunction with a SCADA system to further automate and shorten the fault restoration process. Even the simple ability to remotely operate a single substation breaker can significantly impact the number of affected customers in an outage event by directing field crews to sectionalize the feeder at a midline switch and remotely re-energize it up to the newly created open point. When no outages are present, the SCADA system can further be leveraged to perform Volt/VAR Optimization (VVO) to improve distribution system efficiency. Improvements to SAIFI and MAIFI can be realized through analysis of historical alarm and event data to proactively address recurring momentary faults caused by tree contacts, leaking insulators, etc.

The data collected by SCADA provides utilities with greater visibility and control of their electrical distribution system. This allows for personnel to monitor and interact with equipment at the substation or distribution pole level from a safe distance, avoiding arc flash risks, and in many cases, the need to don cumbersome personal protective equipment (PPE). This visibility into the system also allows utilities to support more robust system monitoring. For instance, door alarms, video surveillance, and access control can be used in conjunction with IED alarming to detect unauthorized substation access, avoiding potential copper thefts, equipment vandalism, and other physical security concerns.

Large, investor-owned utilities have integrated their SCADA systems with real-time network connectivity modeling, enabling power system simulation engines to identify potential outages at the device level before they occur. Examples may include the prediction of transformer and conductor overload conditions, or detection of potential mis-coordination events. This allows utility operations to be coordinated between engineering, planning, and field operations staff to prevent outages from occurring and enable prompt restoration in the event they do occur.

Without an effective SCADA system in place, utilities are forced to identify and address power system issues after an outage occurs, often sending personnel to a substation unnecessarily without any guidance on the root cause of the issue. This approach can add hours to the outage duration before the proper equipment and appropriately trained personnel are even dispatched. With up-to-date information in hand, utilities can dispatch personnel more efficiently in response to system events — in many cases avoiding the drive to the substation altogether.

III. Full-size SCADA System Benefits Can Be Found in Small-Scale Installations

Utilities have long relied on SCADA systems to collect event information. These systems were part of the electrical infrastructure prior to recent "smart grid" initiatives, and the benefits that large utilities have realized from their SCADA systems year after year can now be effectively scaled for smaller systems. Any distribution system can benefit from accurate, up-to-date information about system devices — even those with only a single substation. But, how can these operational benefits be realized efficiently and cost-effectively?

Utilities with a relatively small number of substations have often resisted implementing SCADA systems because their design, implementation, and operation have been perceived as significant barriers to entry. SCADA systems have also been considered "too expensive" for smaller utilities, which may be unable to support complex systems requiring dedicated staff. One often-cited barrier to SCADA deployment is communications. How does data get from the field device to the "back room"? Where dial-up modems, leased lines, and private radio networks were the norm of years passed, recent technological advancements have paved the way for multiple cost-effective, scalable options with systems that can transform the communications-related investment from an up-front capital expense into an ongoing operational expense that directly correlates with the data usage and application requirements.

The basic SCADA system architecture is provided in Fig. 1. At the substation level, data from IEDs is typically collected by gateway or data concentrator devices, usually connected via copper or fiber optic cabling. The substation gateways, and other pole-line devices such as reclosers, voltage regulators, and capacitor bank controls, which provide critical data points on the feeder, are often connected into the system through cellular, multipoint radio, or fiber optic communications paths. With all data made available to the SCADA system in a centralized location, additional applications, including data trending/analysis tools, human-machine interfaces (HMI), and automation schemes such as FLISR and VVO, can easily interface with the system.

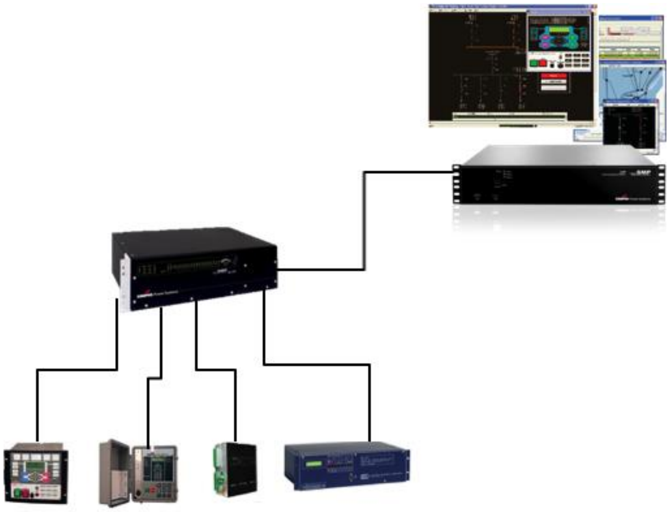

Fig. 1. Basic SCADA system architecture
This basic architecture can scale from single- to multi-substation deployments. As the number of substations increases, the case for a centralized gateway and data repository becomes clear. System operators and field crews can use PC-based, application-specific software, as well as mobile web-enabled devices, to access and control equipment in each substation and view status information for connected equipment, all through a single connection. In smaller deployments, this access can be achieved through a connection to a specific substation gateway. In either case, operators no longer need to be directly in front of equipment to query for information or remotely operate devices, but can do so from a remote operating position.

IV. Technical considerations and requirements for small-scale SCADA

Like nearly any successful engineering project, gathering of system requirements in advance of implementation is crucial — not only in controlling short-term costs, lead time, and project scope, but also in ensuring the long-term scalability and viability of the system. While most available SCADA solutions bring a certain amount of flexibility, it is still critical to establish system requirements and desired functionality in advance of selecting or installing a solution, to avoid potentially costly last-minute changes and scope creep.

While many important requirements must be developed, perhaps one of the earliest to be considered is communications capability and required functionality. While specific features can be scaled to meet future needs and growth, available communications bandwidth needed to support any supplementary features should be taken into consideration upfront. A well-designed SCADA communications system can be leveraged for other applications such as physical access control, video surveillance, and metering or demand response backhaul. These auxiliary system integrations can be implemented after initial project deployment, so long as the communications system does not become a limiting factor. Another important consideration in choosing a communications methodology is the availability of utility resources to support and maintain the chosen infrastructure. For instance, if fiber optics or traditional SCADA radio are used, the utility may or may not be in a position to construct, maintain, and support this infrastructure in the near and distant future.

There are a number of additional important considerations to take into account when designing a SCADA system that will be effective in meeting the utility's established operational goals while remaining future-proof.

- Will this solution need to monitor a single substation, multiple substations, and/or the entire system through the inclusion of pole-line devices?
- Will the SCADA system be implemented all at once, or incrementally deployed? Incremental deployment may allow for dispersion of system implementation costs and required project resources over a number of months or years.
- How often will updated data from the field be required to make meaningful, actionable decisions? Frequency of field updates can have a significant impact on communications network requirements and costs, resolution of logged historical data, and the system configuration needed to optimize data flow.
- Will the deployed gateways or data concentrators provide direct visualization capability, or will a centralized SCADA software package be used to provide alarming, data trending, and logging in addition to centralized system visualization?
- How will personnel access the system — from inside the substation control house, an engineer's desk, inside the line truck, a home office, mobile devices, or any combination of these and other access methods?
- Does data need to be shared with third parties, such as a generation and transmission (G&T) utility or other applications within the utility? These may include FLISR, VVO, etc.
- What specific security concerns may need to be addressed, from both internal utility policy and regulatory perspectives? Compliance with specific industry security standards may be desired or required.

For utilities without IT departments or for those that may prefer to avoid installing SCADA systems on locally managed servers, a hosted system may be an attractive alternative. This type of deployment collects substation data in the same manner discussed above, but stores it in a secure third-party hosted data center environment. The utility can then use various secure access methods, including web portals protected by Transport Layer Security (TLS) or Virtual Private Network (VPN) access solutions, to gain access to the various tools made available by the SCADA software package. Partnering with a third-party hosting provider eliminates the need to own, operate, and maintain the sophisticated server and network infrastructure required to properly support this type of application.

Any existing legacy system assets that can be leveraged in the new system should also be determined. For example, it may be possible to use existing radios, antennas, remote terminal units (RTUs), cabling, or any other components of an existing SCADA system to maximize investment return and reduce upfront costs.

SCADA system requirements checklist

Regardless of the system size, the following requirements should be identified:

- Communications systems bandwidth (for current and future needs).
- Infrastructure expansion, system scalability.
- IT staff support (if needed).
- Monitoring scope: single substation or entire system (or somewhere in between).
- Monitoring and control access points.
- Centralized SCADA software or substation-based visualization.
- Native vendor tool access.
- Operational data-sharing obligations.
- Applicable security standards and requirements.
- Existing systems that can be leveraged.

By working with an outside engineering team well versed in the latest technologies, even the smallest utilities can reduce the complexities of such a project and make SCADA a reality. A turnkey project approach, from design to installation, can include the necessary hardware, software, and services to achieve a high-performing small-scale SCADA system. Experienced engineering teams familiar with the latest hardware and software components, as well as the potential challenges with integrating legacy equipment, can help control overall project costs and timing. A turnkey or end-to-end solution typically includes:

- Requirements gathering.
- Current system assessment.
- SCADA solution design.
- Onsite commissioning, including installation support and supervision.
- Startup and training for utility staff.

When choosing an integration partner, it is important to consider the following:

- Available references for projects of a similar scope and magnitude.
- Experience with hardware, software and IED design.
- Breadth of product and service offerings to provide a truly turnkey experience.
- Facilities and infrastructure to support factory and onsite acceptance testing.
- Project management experience and expertise
- Financial stability.

V. Case Studies in Brief

The concepts discussed in this paper were recently applied to two separate turnkey small-scale SCADA system projects, starting with concept generation and culminating in full system deployment and commissioning. In the first case study, the utility is a five-substation municipal utility located in the Northwest U.S.; the utility's primary goals were to access system loading information outside of normal business hours using a mobile web-enabled device, and replace an outdated SCADA system display primarily used for dispatch operations in the utility's main office location. In the second case study, the utility is a 12-substation electric cooperative in the Midwest U.S.; the primary objective for this utility was to implement a new SCADA system under its own control, to replace its current sub-system level access to the G&T utility's SCADA system.

A. Case study 1:

This project required a SCADA solution for all five of the utility's substations, with centralized data aggregation and display and historical data storage and trending capability. The customer's key objective was to access system-wide loading information through a mobile device after normal business hours. Key customer requirements revolved around the interface for mobile monitoring and control, as well as data display and analysis capabilities for users in the utility's main office.

This was not a complete replacement project. The customer required that the new system use an existing broadband ultra high frequency (UHF) radio system connecting the main office to all five substations. Beyond the backhaul communications, as much of the existing substation equipment as possible had to be reused to reduce costs, including IEDs, terminal servers and network equipment. The new system also needed to support legacy SCADA protocols used by aging field equipment.

Integrating old technology with new systems can have its drawbacks, yet the potential cost savings involved often outweigh the technical challenges. In this case, the technical challenges related to deficiencies with the original communications system installation, programming issues with aging equipment and minimal availability of documentation. The original system used only a partially compliant communications protocol implementation, and as such, the utility was unaware that the existing system was suffering from a number of data integrity issues and likely had been for a number of years. During commissioning of the new system components, operational issues with the existing radio system were promptly identified, including intermittent fading and other signal issues, the effects of which had previously not been attributed to the radio system. Further complicating matters, the existing system was designed and implemented by staff that had long since left the organization.

The newly implemented SCADA solution provided immediate exception-based updates from all substation IEDs, and facilitated trending and analysis functionality. Each substation was equipped with an updated communications gateway device, which allowed both serial and Ethernet connections to be made to various substation IEDs; pre-existing serial fiber loops and RS-485 bus networks were directly connected, so there was no need for rewiring. Each substation gateway was connected to the broadband radio access point in its substation, which provided the backhaul connection to a centralized communications gateway device in the utility's main office. This communications gateway served as the primary data source for a newly installed SCADA software package, providing a system-wide one-line diagram, real-time data display and historical data trending. In addition, the centralized gateway was also configured as a web server to host a web-enabled, system-wide one-line diagram, offering remote data access and basic remote control from any web-enabled mobile device. Finally, a cellular modem was connected to the gateway and provisioned into a private carrier network, allowing other cellular devices in the same private network to access the web-enabled one-line diagram interface. The utility chose to provision a portable "Wi-Fi hotspot" device into the private cellular network, so after-hours access could be shared among staff as needed.

Lessons learned:

Overall, the implementation of the SCADA solution for this utility was highly successful. This can be attributed to the utility's collaboration with a knowledgeable and experienced engineering services team with members who were able to successfully navigate the integration of a wide array of legacy equipment into the new system through:

- Advanced troubleshooting and implementation services.
- Immediate recognition of existing issues and the ability to make recommendations for mitigation.
- Direct involvement in discussions with the cellular carrier to ensure proper private cellular network configuration.

B. Case study 2:

The second case study explores a different type of project with a number of special considerations. In this case, an existing limited SCADA solution was in place to read basic substation meter data, but only the G&T utility had primary access to the collected data. Knowing that the IEDs in its substations were capable of providing much more accurate data that was useful for planning and system management, the utility opted to pursue a new SCADA system. This system would collect data from substation IEDs in lieu of the antiquated substation meters, provide an interface for real-time monitoring and remote control, and use the new system to pass the required data to the G&T utility. The utility personnel had no expertise in SCADA systems or communications, but had a team that was willing and eager to learn. All information technology services for the utility are contracted to a third party, prompting the involvement of another team in the design and planning process. Upon initial inquiry, the utility had already explored the costs associated with deploying fiber optic links to its substations and found them to be prohibitive; instead, the utility wanted to understand the alternatives for substation communications. Finally, the utility expressed the desire to approach implementation in a phased approach due to constraints on capital funding.

The key requirements for this system included:

- Ability to provide an easy-to-understand system overview (HMI) for utility personnel from various departments.
- Sharing of system loading information gathered from newly connected IEDs with the G&T utility using the existing communications channel in place at the utility's main office.
- Providing an interface for data trending and storage for historical analysis with a minimum of one year of recorded data.
- A means to gather demand data from substations and feeder line locations where no other metering IEDs were currently installed.

With no existing SCADA system connected to the substation IEDs, there was no legacy communications infrastructure to integrate for data collection. The entire system was to be designed and implemented to provide the necessary end-to-end communications paths. Because the utility staff wanted heavy involvement in the design and implementation process, the chosen design would need to consider the utility's existing expertise and desired layout for expansion and serviceability. Additionally, as the G&T utility's SCADA system used leased lines to gather substation meter data and deliver it via a secure VPN tunnel to its operations center, the new system would need to gather and provide the necessary feeder device data directly to the G&T SCADA system through the VPN connection, bypassing the need for the leased lines, ultimately allowing for their decommissioning. Finally, because the utility's IT operations were outsourced, third-party IT consultants needed to be involved from the outset to ensure a smooth implementation.

This utility's implemented SCADA solution incorporated:

- Small form-factor communications gateway device in each substation.
- Fiber optic Ethernet switch and cellular modem in each substation.
- Private cellular network commissioned by the cellular carrier.
- Communications gateway in the back office to aggregate field data and allow the G&T utility to access demand information.
- SCADA software package providing a system-wide one-line diagram, real-time data display and historical data trending.
- Power-harvesting overhead line-mounted sensor devices for auxiliary demand monitoring.

Lessons learned:

Having experienced, on-the-ground engineering support was crucial to the success of this project, as well as the following:

- An analytical communications study was performed to evaluate traditional multipoint radio, fiber optic and cellular communications paths to maximize customer value.
- Onsite commissioning included shadowing by and training of utility personnel to set up, use, and modify the system.
- Coordination of commissioning activities supported by the vendor's engineering services team, the utility, and the utility's IT contractor to minimize labor costs.

VI. CONCLUSION

"In the United States, a typical customer expects to have power at all times. In reality, a utility is able to make power available between 99.9 and 99.999 percent of the time." [2] Even if this expectation is not realistic, there is still an increasing public emphasis on utility reliability. SCADA programs have been shown to help support reliability goals cost-effectively.

SCADA systems in small (and large) applications provide critical functionality to reduce electrical outage duration and enhance personnel safety. Regardless of the size of the application, the SCADA system can scale to be economically installed.

SCADA systems help utilities in three key ways:

- Continuous, real-time monitoring to support reliability and efficiency initiatives.
- Real-time monitoring of changing conditions, allowing utilities to make timely decisions.
- Tracking of long-term trends to support effective and proactive planning and maintenance activities.

To support the implementation of SCADA systems in utilities where internal expertise and personnel resources are limited, working with an embedded engineering services and support team can provide for expedited solution delivery with a high degree of post-implementation satisfaction. An added benefit of working with a vertically integrated vendor that has extensive experience with IED design, automation solutions, and an engineering services team is the reduced likelihood of miscommunications and conflict that can occur when dealing with multiple vendors. Teams with experience in designing, deploying, and supporting varied systems in diverse operating environments are able to anticipate unforeseen requirements and challenges and affect a positive implementation process drawing on lessons learned in past projects.

While an emphasis on requirements is paramount, implemented SCADA solutions should not be rigid, or static, by design. Instead, effective SCADA systems must be able to be fine-tuned, scaled and modified as a utility's requirements evolve. All hardware and software components should be specified with room for expansion in the areas of storage, number of supported devices and data points, etc. Drawing on the products, services and experience available in the industry, the benefits of even the largest SCADA systems can be realized by smaller utilities through the deployment of small-scale SCADA system solutions.

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