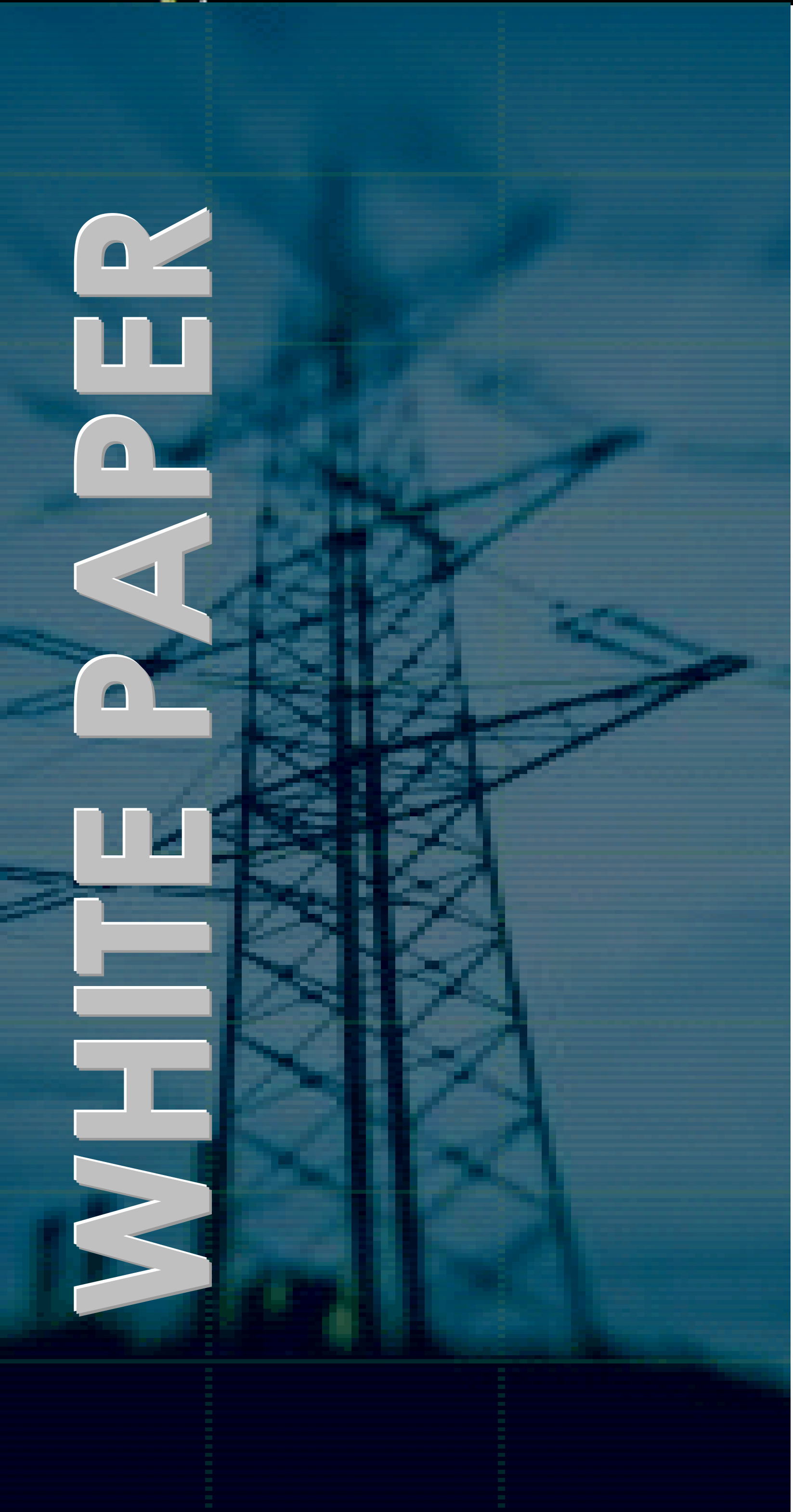
Open Standards, Open Possibilities

Addressing Reliability Through Next Generation Utility Information and Control Systems



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INTRODUCTION

There is a heightened interest in utility information and control systems throughout the U.S. utility industry, and the reasons are plentiful:

- Until the late 1990s, investment in transmission and distribution (T&D) infrastructure had been declining for two decades, resulting today in an antiquated grid characterized by aging components that are beyond their intended useful life.
- In the wake of the major blackouts of the last ten years, utilities are under growing pressure from customers and regulators to improve reliability of service delivery.
- The introduction of long distance bulk power markets in the 1990s has been straining a high voltage system designed for local electricity transportation.

- A severe shortage of generation capacity is forecast, meaning utilities must acquire the ability to control demand in as real-time a manner as possible.
- Since 2003, the utility industry has adopted the "back to basics" mantra in which the efficient and profitable generation, transmission and delivery of power is paramount.
- Lastly, vendors have in recent years made great strides toward producing systems holding unprecedented opportunity to gain efficiencies and enhance customer service.

Clearly, many utilities need to focus on modernizing their information and control systems. But acquiring or modernizing utility information and control systems is presenting unique challenges as well as some opportunities for utilities. Installed generations ago, many existing systems are functionally outdated or limited in their ability to expand. Given the size and scope of these projects, utilities are concerned about making 'the right choice' given the ongoing evolution of technology and a changing regulatory environment.

As the term "utility information and control systems" indicates, these systems are a critical component of any solution to the current issues. They can include supervisory control and data acquisition (SCADA) systems, advanced metering infrastructure (AMI), demand response (DR), and distribution automation (DA) systems, among others. When combined, these applications can be considered part of a 'smart grid' initiative designed to improve the cost and reliability of the electricity distribution network. These improvements are broadly recognized as imperative. The development and implementation of best available utility information and control systems is a critical component of the ongoing effort by public policy makers and industry leaders to realize the vision of a robust, flexible, efficient and reliable national electricity system.

"utility information and control systems are critical to the ongoing effort to realize the vision of robust, flexible, and reliable national electricity system."

This paper intends to provide a high-level overview of the real-life challenges faced by utilities and a road map for defining the next generation of information and control networking.

UTILITY INFORMATION AND CONTROL SYSTEMS TODAY

Implementing a utility information and control system that embodies the necessary efficiency, cost-effectiveness and performance is impeded by a number of unfortunate characteristics found in incumbent technical solutions. So long as these impediments persist, so will the issue of reliability.

AMI, DR, SCADA and other systems typically operate on different platforms, are built on proprietary protocols and may require different communications networks, increasing complexity and costs. For example, ABB may be used for SCADA, and Itron for AMI. One system will be on radio while another uses cellular telecommunications. Often these solutions are functionally limited by the bandwidth available from their particular technology. The result is inflexible systems that cannot interoperate or share a common infrastructure. Integrating systems requires the costly exercise of developing and installing translation devices or middleware products and generally does not provide significant operational benefits, given the lack of functional standardization.

A utility information and control system comprised of myriad single-purpose networks is hardly the approach needed to solve the critical problem of grid reliability in the U.S. today, yet such systems are today the norm.

Frost and Sullivan surveyed a number of utilities to asses the current state of information and control capabilities and near term plans for extending this functionality. The results shed light on issues these utilities face in addressing their growing need for improving operations.

Large Western US Utility.

One respondent is a leading utility in the West, serving more than 1.6 million customers in six Western states. Its service area covers 136,000 square miles, upon which are laid 15,530 miles of transmission lines, 43,850 miles of overhead distribution lines, 14,510 miles of underground distribution lines, 948 substations and 68 generating plants. All of the operating companies in this utility are centrally managed.

With responsibility to provide reliable electricity service to more than 1,600,000 customers spread over a large portion of the Western United States, this utility requires a powerful information and control system to do the job properly. Yet, to monitor and control this vast territory, its SCADA system operates on 1980s vintage Intel 286 processors and an Ultrix native UNIX system. The company uses an energy management system (EMS) that is essentially derived from a system installed in 1985. While the software has been updated a few times, it is the same basic technology, and there are no major efforts underway to integrate it with complementary systems. The utility's limited AMI deployments are not only a combination of separate individual networks; they are operated by an entirely different group at a different location. The GIS system is of the mid-1990s. Some of these systems have been interconnected, with gateways and firewalls between them. There is an ongoing project to consolidate systems, but progress is slow and uncertain.

"…traditional solutions lack the capabilities increasingly demanded by control center operators and the industry environment in which they operate."

There has not been a continual upgrading of systems, such that systems today are largely obsolete. Control Center personnel note that consolidating information would make the information more manageable, facilitate data mining and accelerate outage restoration. One operator notes that there are potentially 3000 end points in a substation as compared to the thirty or so currently being retrieved. With remote terminal units (RTUs) reporting back at speeds of only 150 to 9600 baud, control center engineers need an integrated system of utility information and control functions with faster speed and seamless interoperability.

Major Midwest Utility

A large electric utility in the Midwest has been among those utilities embracing automation technologies early on. The utility serves nearly 500,000 customers in 24 counties - a territory of about 4,600 square miles. Delivering that power requires 1,700 miles of transmission lines, more than 10,000 miles of overhead distribution lines, and approximately 3,400 miles of underground distribution lines.

The utility was an early adopter of automatic metering infrastructure, implementing a proprietary fixed wireless AMR system in the early 1990s. In fact, the utility launched an initiative in the 1990s that envisioned an electricity system that was fully automated, a program that is still ongoing. While the utility has implemented a wide number of automated systems, the systems all require different physical networks. Its SCADA system is ABB, though it is being upgraded to ABB's Network Manager platform. It was installed in the 1970's and has been upgraded several times since then. As noted above, the AMR system (provided by Cellnet) is a fixed wireless system, however communications for the SCADA system still uses plain old telephone service (POTS) lines.

Communications for 12 kV and 34 kV substations in rural areas are not complete. The utility is currently relying on Telemetric of Idaho to bring communications to rural substations. Telemetric has a large footprint on analog and digital systems. Unfortunately, however, the communications are not broadband, thus severely limiting the functionality of the SCADA system, and do not leverage the AMI infrastructure.

Throughout its infrastructure this Midwest power company is using multiple communications technologies, including fiber, wireless, hard connection, peer-to-peer communications, cellular, and private radio. It is currently attempting to tie all systems together with the aid of protocol converter devices provided by BOW Networks.

Midsized Public Electric Company

One respondent is a municipally owned public utility providing electric service to a large urban area and the surrounding suburbs. It serves over 160,000 customers (55% inside city limits, 45% outside city limits.) It has 2,257 miles of transmission and distribution lines (1,617 miles of overhead and 640 of underground.) It has 44 distribution substations. The utility's EMS system is the ABB Ranger, which is currently being upgraded. RTUs are GE Harris and BOW Networks is assisting with data integration.

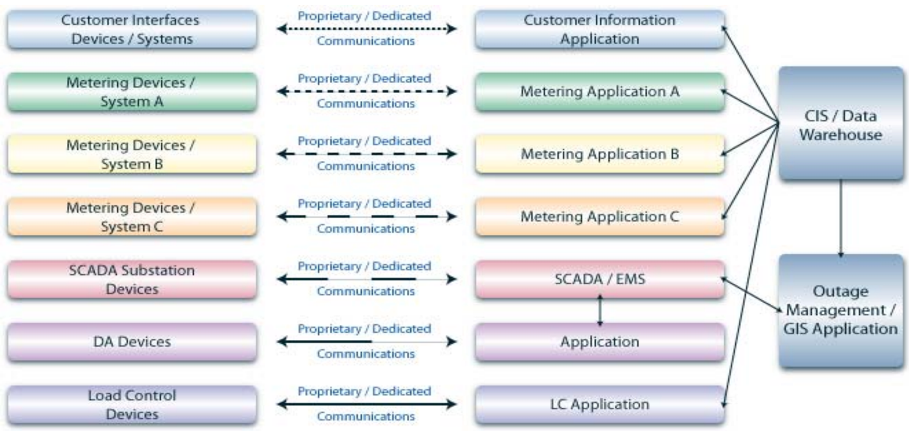
While this municipally owned power provider uses Synchronous Optical Network (SONET) for communications for all of its systems, these systems, including AMI, SCADA/EMS and GIS, are not integrated. That is, all systems make use of the fiber optic cable installed by the city when it entered the cable TV business years ago, but the systems are on different logical networks. There is no data integration and as a result data is not always available when it is needed.

With plans in place to integrate all systems, the utility expects to increase operational efficiencies by accessing data more easily— the need to drive to substations to get data would be eliminated. In the words of the managing engineer,

> *"It's a logical step. When you have multiple systems that are separate and not accessible from the same physical location, it is very inconvenient. When you have the ability to integrate and to provide access to the data, it gives our personnel an advantage for trouble shooting and analyzing data, after the fact."*

Summary of Issues With Traditional Solutions

As illustrated by the cases above, traditional solutions for utility information and control lack capabilities increasingly demanded by control center operators and the industry environment in which they operate. Data is not available when needed. Integration of data requires protocol converters. Bandwidth is often insufficient to transfer the vast amounts of available data. Systems are not real-time, or two-way. **Figure 1**



lists the complex manner in which many systems are configured today. All of these characteristics lead to the increased risk of unplanned power outages, longer outage times, lower customer satisfaction levels, and higher operational costs.

UTILITY INFORMATION AND CONTROL SYSTEMS OF TOMORROW

The Open Standards Approach

Responding to these emerging customer requirements, vendors are increasingly developing systems based on open standards. Open Standards can be defined as:

> *"Publicly available and implementable standards. By allowing anyone to obtain and implement the standard, they can increase compatibility between various hardware and software components, since anyone with the necessary technical know-how and resources can build products that work together with those of the other vendors that base their designs on the standard."*

Open standards foster technological innovation and generate economic benefits for utilities. Using open standards allows for more complete integration within a particular solution (e.g. AMI) and between systems (AMI and DA), lowering both capital and operational expense.

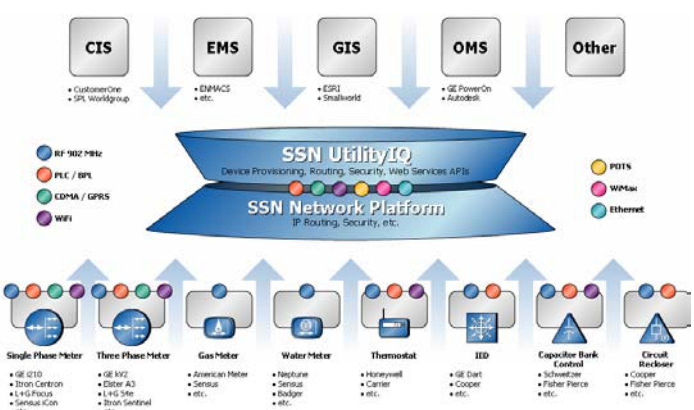
Use of open standards has transformed many industries, including information technology, telecommunications, and cable television. The approach has demonstrated that leveraging open standards lowers cost, accelerates product innovation (e.g., call forwarding) and grows market opportunities. Indeed, utilities have moved aggressively to adopt standards in many aspects of their operations, particularly information technology (IT). As utilities begin to implement advanced information and control networks, adopting an open-systems approach can minimize risk while significantly improving the business case for automation.

The Next Generation Utility Network

The United States must make up the deficit in transmission and distribution investment that has been accumulating since the 1970s. This is necessary not only to preserve the quality of life of its citizens but also to preserve the U.S.'s competitiveness in the global economy. Utility information and control systems are a vital component of the T&D modernization process. In order to meet the challenges of the 21st century and ensure the reliable delivery of electric service, this next generation system must include the following characteristics:

- Internet Protocol (IP) based networking
  - IP has become the unifying element for all modern networking systems
- Transport agnostic network technology
  - Wireless, power line and wired solutions operating in a heterogeneous network topology
- High Security
  - The electric grid is coming 'on-line' and stringent security policies must be maintained to protect the system from attack
- Multi-Application
  - Similar to modern data networks, this new generation of technology supports a variety of applications over a common 'pipe': AMI, DA, DR and other applications that extend to the customer premise
- Standards-Based
  - IP is critical, but only the beginning. All elements of the solution must be based on known standards or published, fee-free interface specifications to avoid vendor lock-in

Figure 2



Historically, utilities have been on their own when it comes to integrating data from disparate systems. They deal with one vendor for AMI, a second vendor for SCADA, a third vendor for GIS, and so on. These vendors typically focus on one application. Should the customer wish to integrate their existing systems or expand their functionality, they must fashion their own solution to the problem.

One technology company whose products are based upon the promise of open standards is San Mateo, California-based Silver Spring Networks. The heart of Silver Spring Networks' solution is the UtilOS™, an open, standards based operating system for 'smart grid' implementations. It is based on advanced networking and Internet protocols. Field devices running on UtilOS™ such as meters, transformers and capacitor banks can interoperate with other standards-based utility networking systems, applications and networked devices.

The Open Systems approach offered by Silver Spring Networks and other progressive vendors is significant for the industry. Utilities can now develop comprehensive strategies for a variety of 'last mile' applications using products and solutions that are compatible with major IP-based telecommunications technologies. This enables utilities to develop a more compelling business case while simultaneously mitigating risk from obsolescence or vendor lock-in. As the utility's requirements evolve, their information and control systems can evolve with them, creating an extensible platform for years to come. **Figure 2** provides a schematic of Silver Spring Networks' utility information and control systems solution.

TRADITIONAL AND OPEN STANDARDS BASED SOLUTIONS: ROI COMPARED

Return on Investment Analysis

While the comparative benefits of integrated utility information and control systems are intuitively clear, a return on investment (ROI) comparison between today's disjointed systems and integrated systems reveals more clearly the benefits that a shared network can contribute to a utility's bottom line. **Table 1** shows Frost and Sullivan's analysis of the present value (PV) costs, PV benefits, and corresponding ROI measurements (NPV, IRR, ROI and Payback period) for a traditional utility information and control system on the one hand, and for an integrated system on the other. The analysis assumes a 1.0 to 1.5 million-customer utility, a system useful life of fifteen years, a discount rate of eight percent, and an average annual inflation rate of 2.47 percent. Assumed also is a full deployment of four information and control systems: advanced metering, distribution automation, demand response, and integrated lighting control. Future cash inflows are the cost savings resulting from the new system.

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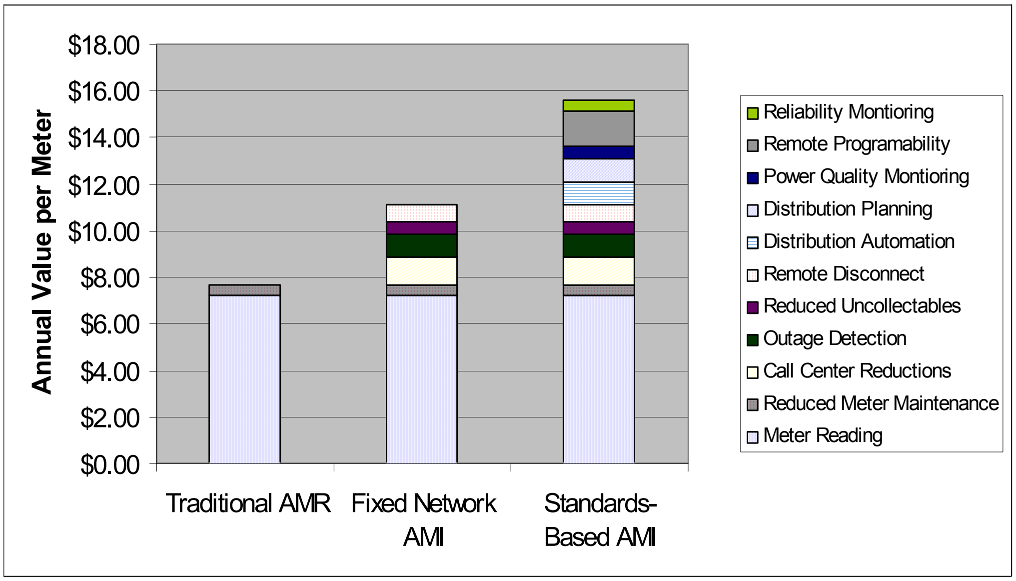
Table 1

	Traditional Solution	Integrated, Open Systems Approach
Present Value (PV) COSTS		
Capital Expenditure		
Advanced Metering	$88,500,694	$99,873,205
Distribution Automation	$4,617,255	$4,312,738
Demand Response	$15,235,882	$9,141,529
Integrated Lighting Control	$2,560,974	$2,134,145
Total	$110,914,805	$115,461,617
Capital Operating Expense		
Operations & Maintenace	$47,027,373	$34,459,341.44
TOTAL PV Costs	**$157,942,178**	**$149,920,958**
Present Value (PV) BENEFITS		
Advanced Metering	$64,116,826	$128,233,651
Distribution Automation	$19,342,359	$38,684,719
Demand Response	$68,500,000	$137,000,000
Integrated Lighting Control	$1,781,023	$3,562,046
TOTAL PV Benefit	**$153,740,208**	**$307,480,416**
Net Present Value (NPV)	**($4,201,970)**	**$157,559,458**
Internal Rate of Return (IRR)	**7%**	**25%**
Return on Investment (ROI)	**57%**	**315%**
Payback	**3839 Days**	**1408.7 Days**

ASSUMPTIONS
1.0 to 1.5 million electric meters/customers
15 year system life
8% discount rate
2.47% annual rate of inflation
Period: 2006 - 2020

The most significant savings are in advanced metering and demand response. In the former, a traditional solution holds a present value of $64,116,826, as compared to $128,233,651 for an integrated solution. Advanced metering systems allow for basic real time billing, load profiling /optimization, remote connects / disconnects, and customer premise service interface. They result in large reductions in labor cost, more accurate billing and enable the implementation of revenue producing value-added services. Similarly, demand response programs allow utilities to manage supply and demand of power more effectively, lessening the need to access high cost spot power markets during times of peak demand. As **Table 1** shows, for each information control system, present value benefits are greater with an integrated, open standards-based system than they are for today's traditional system of single-purpose, proprietary networks. Most importantly, the latter approach generates a NPV of $157,559,458 as compared to a negative NPV of

Figure 3



$4,201,970 under the traditional approach. The analysis also shows that the IRR, ROI and payback period are superior under an integrated approach to utility information and control systems. **Figure 3** shows a comparison of capabilities and revenue opportunities of various utility information and control system approaches.

Conclusion

Upgrading utility information and control infrastructure is critical to maintaining the reliability of the electric distribution system in a time of rising costs. By developing a comprehensive last-mile strategy based on an open standards approach, utilities can realize superior commercial benefit from their infrastructure expenditures.

A utility's senior leaders must step to the forefront in guiding this effort, working with multi-functional teams to break through organizational and regulatory barriers that may exist. When properly implemented, utility information and control systems create the infrastructure for the 'smart grid' that can provide competitive advantage for years. The wrong solution may result in premature obsolescence and stranded assets.

Fortunately, appropriate solutions exist today that are robust, open and extensible. How quickly the nation emerges from the current electric power crisis, and how well it avoids problems in the future, depends in no small part on how quickly the utility industry adopts these available solutions.

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