Convergence in the Control Room

Integrating transmission, distribution and outage management systems

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For several years now, a confluence of industry restructuring and advancing technology in the electric power arena has created an environment for innovation in utility control systems. On the one hand, restructuring has moved many utilities from a regulated environment where return on investments was guaranteed through a cost-of-service model to a more market-oriented paradigm where investments must be justified to shareholders. At the same time, IT systems that support transmission and distribution operations have become increasingly more robust. They have also begun to converge, bringing previously separate applications onto a single platform.

This changing environment is ripe for innovation. As a leader in the field ABB has been at the forefront of IT systems development for power transmission and distribution. The result is the integration of distribution and outage management capabilities (DMS and OMS) with the traditionally separate supervisory control and data acquisition (SCADA), and energy management systems (EMS). ABB's Network Manager platform represents the product of this trend.

A brief history of power systems control

Although the roots of power control go back to the 1920s when ABB (at that time ASEA and BBC) supplied its first remote control system for a power plant, it was not until the 1960s and the advent of computerized process control that modern power network control systems, as they are known today, became possible to realize.

Most SCADA/EMS systems at that time were designed exclusively for a single customer. They were proprietary systems, closed off from one another in keeping with the structure of the industry. Regulated utilities presided over specific control areas with only small amounts of power being traded between them. Interconnection was mostly a means to achieve greater reliability by pooling reserves. But power systems were still vulnerable, and there was a need to develop applications and tools for preventing faults from developing into large-scale outages like the New York blackout of 1977.

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In the 1980s, as computing technology advanced, it became possible to model large-scale distribution networks in a standardized way. Similarly, SCADA/EMS systems became more sophisticated, providing transmission operators with better tools to control bulk power flows. In the business world, this was also the era of deregulation. The airline, telecommunications and natural gas industries were all liberalized, and regulators and utilities alike naturally began to consider doing the same for electric power. For this, an entirely new set of IT systems would be needed (mostly to administer the wholesale markets), in addition to enhancements to existing SCADA/EMS technology. Perhaps not coincidentally, the new generation of control systems that emerged by the early 1990's made the prospect of deregulation feasible.

Distribution management systems (DMS) and outage management systems (OMS) have undergone similar changes over the years, largely due to advances in computing technology. DMS originated as distribution-level extensions to SCADA/EMS systems or as stand-alone systems. What distinguishes them from their transmission-level cousins is the addition of applications specific to distribution operations. For example, the ability to model line cuts is very common at the distribution level. Distribution networks are also constantly being reconfigured to accommodate new construction, maintenance and unplanned local outages. They also contain many more power system objects than transmission networks. The unique demands of distribution operations drove the development of DMS to the point where these systems became clearly distinct from SCADA/EMS.

Technological advances also drove the evolution of Outage Management Systems (OMS). Initially, outage management was a fully manual process. Customers would call their local utility to report an outage and paper tickets were used to analyze the calls and define the location and extent of the outage. Ironically, though the data would initially be entered into a computer, the system would print the tickets to be analyzed by human experts. Planned outages (for maintenance, new construction, etc.) were similarly handled using manual processes. Over time, of course, computer network models and analytic algorithms replaced the human "analyzers", and OMS systems developed into the sophisticated tools that they are today.

State of the industry

It's safe to say that restructuring of the electric power industry has not turned out the way anyone would have predicted. But whatever the fate of competitive power markets, it is clear that the business of operating transmission and distribution networks is only becoming more complex. The grid itself becomes more so every day as new generators come online and new transmission and distribution lines are added. This ever-increasing complexity, combined with certain business realities, is forcing utilities to reassess their IT requirements.

Drivers for integration

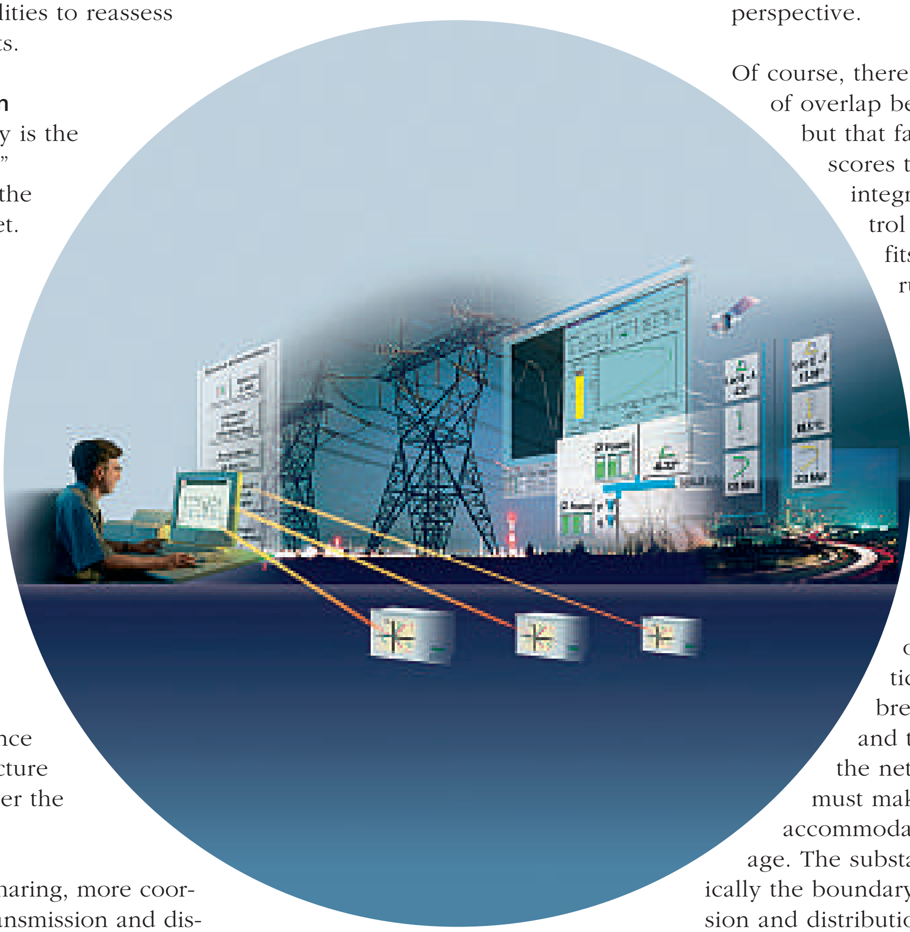
The adage "necessity is the mother of invention" certainly applies to the electric utility market. Depressed revenue streams, regulatory uncertainty and competing investment alternatives have all conspired to make utility resources scarcer than ever, and as a result all departments are being asked to do more with less. In this climate, utilities are looking for investments that will improve the performance of existing infrastructure and reduce costs over the long term.

Better information sharing, more coordination between transmission and distribution operations, enhanced customer service and improved safety are also priorities. Automation, and specifically advanced monitoring and control systems, have delivered improvements across all of these areas. Now, the technologies that enabled those improvements are beginning to converge.

ABB takes action

With long-established products in the SCADA/EMS market as well as DMS, OMS and Generation Management (GMS), ABB was in a unique position not only to identify the convergence trend but also to bring it to fruition. The company drew upon its experience to create one family of solutions for all of these applications: Network Manager.

The objectives of the integration of SCADA/EMS with previously separate distribution and outage management functions were multifaceted. The solution was envisioned as a means to deliver several operational improvements that would in turn have a positive impact outside the control room.



These included:

- Integrated work flow management – With one system to contain operational data, various work groups with different needs (e.g., operation center, field crews, engineering design) could all work from a single data source.
- Connectivity analysis – Large, diverse electrical networks could be managed more precisely, more efficiently and more safely thanks to more comprehensive analyses.
- Greater productivity – The utility workforce would spend less time gathering information and more time applying it.
- Integration of enterprise-wide data – Information flow among customers, operations, engineering and executives would be enhanced.
- Immediate capture of network status – Utilities would have a much better understanding of system conditions at any given moment in time.
- Optimization of network operation – The utility's power delivery system would be utilized in the most effective way from an engineering perspective.

Of course, there is a certain amount of overlap between these items, but that fact merely underscores the significance of integration of utility control systems. The benefits of convergence run to many end results.

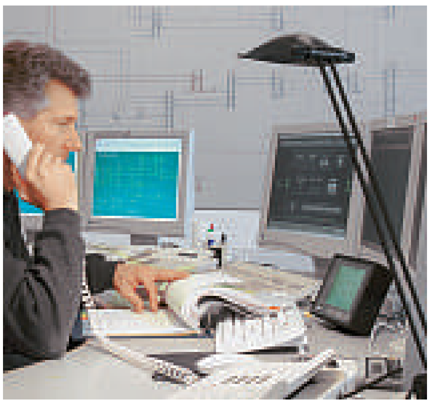
Integration examples

To better understand the impact of integration, we can look to two specific examples. The first is tagging, the practice of identifying a particular substation breaker for service, and thus indicating that the network operator must make adjustments to accommodate the planned outage. The substation breaker is typically the boundary between transmission and distribution and thus requires coordination between the two entities.

In the past, the EMS (transmission) and DMS (distribution) were separated both functionally and, in medium and large sized utilities, physically as well. When, for example, a particular substation breaker needed to be taken out of service, the EMS operator was dependent upon his DMS counterpart to inform him of the outage. This was – and in many locations still is – accomplished using manual processes like phone calls and email. The transmission operator would then tag the corresponding substation breaker on his system and make whatever operational adjustments were needed.

Using an integrated system, the transmission and distribution operators both see the same information – tags only need to be applied or removed once. This reduces the amount of paperwork operators need to complete, increases accountability and improves the tracking of safety documents. Of course, the real benefit lies in the utility's ability to provide more timely and accurate information to customers.

Another example of integration is the convergence of Distribution Management with Outage Management Systems. Traditionally, these were independent of one another – DMS dealt with operational matters like switch orders and load flows while OMS was specifically concerned with trouble call analysis and crew management. Under an integrated system, the outage management function can draw on data from the DMS to pinpoint unplanned outages using advanced fault location algorithms.



Similarly, planned outages combine switch orders from the DMS with customer information from the OMS to automatically provide notification and updates to affected customers via the utility's Customer Information System (CIS). Distribution operators can also use network calculations to avoid accidentally overloading a given line while trying to supply customers from an alternate source. Today, the seamless integration of DMS and OMS functions is a reality, providing operators with a single intuitive interface to navigate between them.

State of the EMS-DMS-OMS "Union"

Since ABB's Network Manager and Network Manager DMS have been available two major utilities in the US as well as Sweden's Sydkraft have already implemented the combined system. The Sydkraft project, dubbed "Eldorado", replaced 20 SCADA systems and multiple geographic mapping systems with a single platform. The resulting cost savings are significant in terms of reduced redundancy alone.

The reasons these utilities sought out an integrated solution mirror the drivers identified above: better coordination between transmission- and distribution-level operations, better customer service, and improved efficiency. These objectives will continue the trend toward unified transmission and distribution control systems, particularly for larger utilities with more complex networks. As the technology continues to advance and costs come down, smaller utilities too will begin to realize the benefits of this convergence.

Where to go from here?

If there is a single concept that represents the point of convergence between the interests of electricity customers, utility operations, and utility shareholders, it is reliability. Blackouts are not good for anyone. Modern utility control systems like Network Manager offer an unprecedented array of tools with which grid operators are able to identify, avoid or mitigate disturbances before they become widespread outages. However, limitations remain.

The next frontier in power systems monitoring and control is a group of technologies that collectively are known as Wide Area Monitoring Systems (WAMS). They are not a replacement for SCADA/EMS/DMS or any of the other applications discussed here, but rather a supplement to them. WAMS utilize sensors called phasor measurement units to take highly accurate (to one microsecond) time-synchronized readings of grid conditions at strategic points across a very large area. These readings are then sent to a central control system which runs continuous online grid security assessments.

WAMS address the time-lag issue by using a GPS satellite to time-stamp each reading as it is taken at its point of origin. Then, when phasor measurements come into the control center from far-flung points on the grid, they can be compiled to present grid operators with a very precise picture of what is happening on the system in real time. More importantly, they can see what is happening beyond their own control area – a major advancement over current methods.

In fact, WAMS can really be seen as a bridge between large sections of the grid that is analogous to the bridge between transmission and distribution that integrated systems like Network Manager provide. ABB has already begun to deploy WAMS. In the coming years, WAMS are likely to become a common fixture in utility control rooms, and eventually a wholly integrated component of power network control systems.

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