RIVERSIDE INITIATES SUBSTATION AUTOMATION, PLANS SCADA AND DATA WAREHOUSE

By John McDonald, Joe Carrasco and Chiu Wong

Information is the driving force behind a substation automation project now underway at Riverside Public Utilities (RPU) in California. RPU wants information extracted from its substations in greater volumes, at faster rates and with superior enterprise-wide access than is now possible. The automation will be complemented by a new Supervisory Control and Data Acquisition (SCADA) system with a Web-accessible Data Warehouse for enhanced information integration and exchange.

RPU is a municipally owned utility serving 100,000 electric and water customers in Riverside, Calif., with a peak winter load of 500 MW. The electric network consists of 13 substations, 85 miles of 69 kV transmission lines, and 1,100 miles of overhead and underground 12 kV and 4 kV distribution lines. Although it considered buying a combined SCADA, the utility maintains separate systems for its water and electric services.

The utility expects to yield multiple benefits from the planned substation automation and SCADA implementation projects. RPU believes that overall electric T&D operations will become more efficient as operators receive more up-to-date and detailed information on events in the substations. Dispatchers will be able to identify and respond to outages and other problems more quickly, and they will be assisted by engineers and technicians who, for the first time, will have remote access to historical substation data that can be analyzed on their desktops.

To bring the request-for-proposal (RFP) process to fruition on a very tight schedule, RPU contracted with KEMA Inc. of Burlington, Mass., to aid in the selection of suitable vendors for the substation automation components and SCADA system. As KEMA presented the many implementation options to RPU, additional opportunities and benefits became evident to the utility, which led to a rapid evolution in project scope even as the RFPs were being written.

Riverside ultimately awarded the substation automation contract to NovaTech LLC of Lenexa, Kansas. Remarkably, this vendor was able to factory test the first substation automation system within 30 days after receiving the contract. This station should be online by spring 2005.

AVOIDING ISLANDS OF AUTOMATION

As is sometimes common in substation automation and SCADA implementation projects, the existing situation at RPU was complicated slightly by earlier installations of automation components. Specifically, Riverside had purchased a variety of intelligent electronic devices (IEDs) from several vendors for use in its substations. These included digital fault recorders, load tap changer controls, and dissolved gas monitors.

The utility realized that it wasn't taking full advantage of the IEDs because existing remote terminal units (RTU) in the substations communicated only over serial lines and had no capability to integrate IEDs for real-time (operational) data transfer back to SCADA operators. Engineers and technical personnel could retrieve non-operational data only by traveling to the substations or by querying them over dial-up phone lines, both time-consuming and inefficient processes.

RPU feared that continued installation of IEDs without an accompanying SCADA upgrade would create "islands of automation" that would be difficult and expensive to integrate in the future. And there was no central Data Warehouse to store this data in once it was collected. Hence, plans for substation automation and SCADA implementation progressed simultaneously as complementary projects.

Maximizing return on investment in the new IED implementation, therefore, would require upgrading the SCADA and some RTUs and installing a high-speed communications network to make integration possible and worthwhile. Completing the project would be a central warehouse where substation data would be stored for digital access by personnel in multiple departments from various locations.

PLANNING THE AUTOMATION AND INTEGRATION

The $300,000 substation automation contract calls for NovaTech to implement the system, IEDs, and many components at three existing and one new substation. The primary goal of the automation is to achieve information integration by gathering data from the IEDs and field devices within a substation and transmitting it to the SCADA and Data Warehouse for distribution throughout the utility. The automation system will acquire information that is needed to analyze T&D system disturbances and power quality problems, and it will support sequence-of-event reports and oscillographic waveforms.

Each of the four substations will receive about 20 IEDs ranging from transmission line protection and transformer differential relays to dissolved gas monitors and distribution feeder relays. NovaTech is also responsible for supplying data concentrators, IED interface modules, GPS satellite clocks, personal computers, and a SCADA interface. The vendor will also install a high-speed local-area network (LAN) within each project substation to collect IED data for digital transmission using DNP3 protocol over TCP/IP to the SCADA system and to execute control actions.

The primary human-machine interface for the substation automation will be located at the RPU Utility Operations Center (UOC), which is the utility's main dispatch location. Although separate interfaces will be established on personal

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computers for data viewing within each substation, the UOC interface will be the only one with control functionality.

The interface between the substation automation and SCADA system will be programmed so that live operational voltage and current data is received and displayed at the SCADA master. To reduce the volume of data transmitted to the SCADA system and Data Warehouse, the substation automation system is being configured to utilize a report-by-exception philosophy for operational data from all IEDs that function in this mode. This means that analog values will be transmitted only when they change by a significant deadband established by RPU, unless polled directly by the SCADA master. All changes in status points, however, will be sent as they occur. Non-operational data will be transmitted directly to the Data Warehouse.

As required by the project specifications, the substation automation system will accommodate future expansion and integration. RPU plans to eventually automate all of its substations. Until then, the utility wants to extract additional data more easily from the existing IEDs and convey it to the SCADA. As mentioned, the bottleneck is the legacy RTUs which transmit on narrow-bandwidth serial connections to the current SCADA.

The soon-to-be-selected provider of the new SCADA system will also be tasked with upgrading these RTUs so they can communicate with IEDs inside the substations and then transmit this digital data over a high-speed Ethernet to the new SCADA master. Rather than purchase replacement RTUs, RPU will have their electronics enhanced so that field terminations are maintained, but the units will support downstream interfaces with multiple IEDs and then link into a planned fiber network connecting the substations.

The Ethernet will run on a Synchronous Optical Network (SONET) system, which is a fiber-optic ring linking all of the substations. The SONET supports the DNP3 protocol and has enormous bandwidth to allow large volumes of operational and non-operational data to flow out of the substations and control commands to return to the substations. An added benefit of the SONET ring is that transmissions can travel in either direction around the loop, which means that data still moves to its destinations even if the fiber is broken.

SELECTING A NEW SCADA

The current SCADA was purchased in 1996 as a temporary system that RPU planned to use until its needs for a new one could be adequately studied. This study began in earnest in 2002 when substation automation was being considered. RPU realized that a new or upgraded SCADA system was required to communicate via the DNP3 protocol to gather data from the proposed IEDs. The existing system was also unable to communicate with both a primary and backup dispatch center and provide built-in security against unauthorized access and attack.

It was possible to upgrade the existing SCADA system to accommodate these and other advanced functions, but there were downsides to this alternative. The legacy system was considered too difficult and expensive to maintain with internal personnel, and there were questions as to whether the vendor would continue technical support of that model in the future. A detailed financial study led by KEMA revealed that buying a new system would be less expensive than upgrading the existing. The budget for the SCADA implementation is $1.5 million.

In addition to the standard requirements relating to reliability, open architecture, cyber security and upgradeability, RPU has made additional requests of the eventual SCADA vendor. The utility wants the Data Warehouse to have a Web-based interface on the front-end. Personnel with approved access to the utility network can query and retrieve the archived operational and non-operational data on their desktops

This will provide individuals in multiple departments with instant access to substation data that was once difficult to obtain. Each department will be given the freedom to build its own interfaces to view the data and applications to download and analyze the data. RPU expects this capability to greatly accelerate its ability to investigate incidents, determine causes, and spot problems before they cascade into major events.

RPU expects to award the SCADA system implementation and RTU upgrade contract in early 2005. The entire project, including substation automation, is slated for completion by 2006.

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mine when the data is transmitted. If a meter misses one satellite pass, there's no worry because another will be along momentarily to pick up the data.

With this added reliability, there are two scenarios in which satellite can make a striking difference for utilities in the future: substation monitoring and new load research programs. Using satellite communications, utilities have an affordable, reliable way to monitor their own operations remotely in addition to their C&I customers. Previously, this would have been done by driving out to the remote site and reading the meter manually or with a wireless communicator. Satellite frees up additional time that can be spent building and maintaining customer relationships.

At the same time, some rural utilities and cooperatives haven't had the opportunity or resources to embark on load research and reduction programs prior to now. With satellite communications, more near-real-time metering gives these remote utilities the detailed information they need for better load planning and makes these programs easier and less costly to implement.

Finally, utilities interested in implementing a satellite communications system for non-socket metering need to consider the following components to ensure their goals of affordability, reliability and certainty are foremost in the process: a good certified MDMA (Meter Data Management Agent) partner that has a strong understanding of interval data; a solid process for translating the satellite data; reliable field hardware; and software interfaces and any other services they might need.

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