NORTH CAROLINA MUNICIPAL POWER AGENCY BOOSTS REVENUE BY REPLACING SCADA

By John McDonald

The impacts on distribution operations and overall revenue caused by an underperforming SCADA system can easily outweigh the benefits it is supposed to provide. Fortunately — as the North Carolina Municipal Power Agency No. 1 (NCMPA1) discovered over the past year — advancements in SCADA technology have enabled utilities to replace their existing systems with new ones capable of boosting profits and quickly paying off the expense of implementation.

One of two power agencies operated by ElectriCities of North Carolina, NCMPA1 has been distributing electricity on behalf of municipal utilities across the state since 1983. For nine months a year, the peak load is approximately 600-650 MW, nearly 250 MW below generation capacity. To sell the additional power on the wholesale market, NCMPA1 contracts with a power marketing and trading company.

In 1996, NCMPA1 implemented a SCADA system to monitor the operations of its distribution network. This system included installation of 49 meters to measure instantaneous power and energy usage at 47 substations located throughout

the Piedmont area of the state. At each metering site, remote terminal units (RTUs) collected, processed and formatted the meter data values using the industry de facto standard DNP3 protocol for transmission back to the SCADA system master station at the Raleigh, N.C., headquarters.

In each substation, the RTUs served as interfaces between

the meters and a frame relay system. This telecommunications system provided a very reliable 56 kbps link between the substations and the Raleigh control center. The SCADA system also relayed peak load and generation data via FTP to the power marketing company so that it would have quick access to information regarding the availability of excess capacity.

LOSING REVENUES WITH A BUFFER

Power marketing was enabled through the use of "block scheduling" which required a short term (hourly) forecast of excess or surplus energy. In the months and years after the SCADA system was installed, NCMPA1 personnel encountered a growing number of difficulties with it. One of the most serious stemmed from the way the system was designed to operate. The system vendor had set up the SCADA master station to poll the RTUs for load data once every five minutes. Over time, increasing reliability problems with the SCADA system plus the five-minute scan rate caused additional forecasting error.

NCMPA1 recognized the problem and found the only solution was an expensive change of hardware. In the meantime, utility personnel worked around the inaccuracy by constantly holding some power in reserve.

"We were unable to sell a portion of our surplus energy at market prices," said Jim Deaton, Power Operations Manager for NCMPA1, "because we had to maintain a significant buffer of unsold energy to be sure we did not sell more surplus than was actually available in a given hour."

The buffer typically totaled about 25 MW of power the organization could not sell, which translated directly into lost revenue.

"Reliability problems were a result of the inability of the SCADA system to withstand normal North Carolina thunderstorms," said Deaton. "The failure rate was increasingly unacceptable and was a contributor to the overall low reliability problem."

"We realized that additional functionality and reliability were needed," said Ron Brady, NCMPA1 Project Manager.

Additionally, a move to dynamic scheduling was being contemplated that would eliminate the forecasting errors associated with block scheduling. And dynamic scheduling required control area quality SCADA system with 4-second scan rate telemetry.

"We decided to replace the system rather than upgrade," said Brady.

PROPOSING A NEW SCADA

NCMPA1 completed the RFP, vendor selection and implementation in nine months. In early 2002, NCMPA1 contracted with KEMA Inc., an international management consulting and technical services firm based in Fairfax, Va., to provide services preparing for and during implementation of a new SCADA. Together, personnel from the utility and the consulting company drafted requirements for the new system and solicited bids from vendors.

With input from NCMPA1 personnel recounting the historical problems, KEMA analyzed the existing SCADA system. The goal of this phase was to identify operating parameters and hardware components that could be replaced

with more advanced technology that would provide improved performance. This implementation had to be accomplished within a budget of approximately $700,000.

KEMA focused on the issue that was costing the utility lost revenue - the five-minute scan rate. They recommended replacing the SCADA system master station with one capable of a reporting rate of four seconds or less, which is more in line with industry average performance.

The master station is the nerve center of the system. It is a network of computers in the control center that processes the incoming power and energy usage data and feeds it to a terminal for display. By viewing this information onscreen, the dispatcher or other personnel can immediately see the condition of the distribution system and make changes as necessary to keep power flowing to customers.

As an important part of this recommendation, the consultant also analyzed the North Carolina frame relay system and concluded it could support transmission of meter data every four seconds. A scan rate more frequent than four seconds probably would have necessitated use of an alternative communications method, which was not an option given the tight budget. Four seconds were considered adequate for NCMPA1 requirements.

Another recommended change involved the metering system. NCMPA1 requested Duke Power Co., who operates a nuclear plant partially owned by NCMPA1 and owns the substation meters, to replace their older meters with microprocessor-based units called intelligent electronic devices (IED). These IEDs are now favored in SCADA design because they digitally convert measured load data directly and are capable of two-way digital communications using an industry standard protocol, such as DNP3, which has become the de facto SCADA standard.

Installation of IEDs eliminated any need for the troublesome RTUs. KEMA recommended pulling the RTUs and interfacing the frame relay access devices (FRADs) directly to the meter IEDs. The FRAD is a simple, low-cost unit that couples the IED to the frame relay communications system. Data in the DNP3 protocol flows seamlessly through the FRAD to the telecommunications network and back to the master station.

In a modification of procedure, the consulting firm also advised the utility to build redundancy into its SCADA operations by splitting the master station, installing one-half at the control center in Raleigh and the other half in another facility in Huntersville, N.C. Typical of SCADA operations today, the two facilities are linked by high-speed T1 lines, which means that both sites are receiving the same data inputs instantaneously. The objective of this is to create a back-up system, whereby either facility can assume dispatch functions in the event the other is disabled by a flood, fire or other disaster.

For further reliability of the overall SCADA system, KEMA recommended installing dial-up communications capability as a back-up at all 47 meter sites.

Based on these recommendations, KEMA and NCMPA1 drew up a request

for proposal in summer 2002. Included in this RFP was a requirement that the selected system must be based on Open Systems Interconnection and industry standards to ensure hardware independence, interoperability with current applications and easy access by NCMPA1 MIS personnel.

IMPLEMENTING THE NEW SCADA

NCMPA1 invited four vendors to Raleigh for demonstrations of their products. This allowed personnel to directly compare systems and to see the full spectrum of SCADA technology. The utility selected Open Systems International (OSI) of Minneapolis to implement the new system in fall 2002.

Before the integrated system was shipped to North Carolina, NCMPA1 operations personnel visited the OSI facility in Minnesota for a factory test of the hardware and software, a crucial, yet often overlooked, aspect of implementation. The first of two goals was for OSI to run the integrated system with all of its modules to ensure that it performed according to RFP specifications. Secondly, the factory test gave NCMPA1 personnel an opportunity to learn the intricacies of the new SCADA system's operation and maintenance. Essentially a tutorial, this served as a practical training session in which OSI programmers and engineers could answer questions and help NCMPA1 digest the volumes of information contained in the training courses and accompanying system documentation.

After the successful factory test in November, OSI delivered the system equipment in December and had the SCADA system operational by January. The positive results were immediate and impressive. The new SCADA system master station achieved the scan rate of four seconds, providing NCMPA1 and its power trading company with extremely accurate details of power and energy usage. On April 1, 2003, NCMPA1 began dynamic scheduling for its surplus energy and for the first time in years, NCMPA1 was able to operate without the 25 MW buffer.

"The new SCADA system allows us to sell virtually all of our surplus energy at market prices, which has resulted in a significant increase in revenues," said Deaton. "It also provides us with highly reliable, four-second load data which has allowed us to move from block scheduling to dynamic scheduling of surplus sales and supplemental purchases."

NCMPA1 estimates that elimination of the buffer and the switch to dynamic scheduling went a long way toward paying off the new SCADA system within its first six months of operation. In addition, the availability of faster and more reliable SCADA system data played a role in helping NCMPA1 to negotiate a more favorable contract with a new trading representative, Southern Company of Atlanta. SCADA system data is relayed to Southern Company via a virtual RTU using leased lines, by FTP over a leased line, and through web access.

Adding to the fast return on investment is the overall greater operational efficiency of power distribution thanks to enhanced functionality of the new system which scores a much higher online performance than the old SCADA system. And the accessibility of the open operating system has helped NCMPA1 MIS personnel with system maintenance.

"The system has proved reliable, easy to operate and easy to modify," said Brady. "The SCADA system is contributing to lower operating costs through improved continuity of service and its redundancy is invaluable."

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