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solution that the industry came up with is LVRT, which allows the turbine to keep operating with a voltage drop of 10 percent. And it is becoming a requirement for new turbines connected to transmission.

Much of what the industry says it needs to do was outlined in the U.S. Department of Energy's "20% Wind Energy by 2030" report.

A recent study, conducted for Xcel Energy by EnerNex Corp., examined the cost of meeting 20 percent of electricity needs with wind energy on Xcel's Public Service Co. of Colorado system. Studies in the United States and Europe have concluded there are no insurmountable technical barriers to the reliable integration of wind energy. The cost of adjusting power system operations to accommodate wind energy is typically low. Most studies have found that these costs are under $5 per MWh, or about 10 percent of the typical wholesale price of wind energy, according to the American Wind Energy Association.

SOLAR SITES – FROM MASSIVE TO TINY

Solar generation is largely confined to house rooftops with a few exceptions. As this source moves toward larger power plants, it will face many of the same obstacles as wind. One issue in the west is that large-scale megawatt projects require vast amounts of land that most likely fall under the jurisdiction of the U.S. Bureau of Land Management and will have lengthy and difficult site hearings and siting requirements.

"Photovoltaic [PV], prior to 2006, was about 99 percent distributed and almost all of that less than a megawatt or two," said Mike Taylor, of the Solar Electric Power Association. But now that California utilities have signed power purchase agreement contracts with developers of projects that will exceed 200 MW, the transmission grid will face the same issues it has with wind projects. LVRT is now part of the equation for these projects as well.

Dan Zaweski, head of renewable energy programs for the Long Island Power Authority (LIPA), recently spoke at the Solar Innovations and Investment conference in New York, N.Y.

More imperative is a commercial net metering rate that went into effect at the beginning of 2009. The LIPA program started in 2000 and is one of the most popular in the country. The demand is unabated and not affected by recessionary pressures, Zaweski said.

"A large-scale PV project, from our perspective, really looks like a small-scale fossil project," he added. Large-scale PV projects could mean 500 installations totaling 2 MW—a lot of transactions—sited on everything from school buildings and commercial sites to construction on top of landfills.

"This is nontraditional for us and certainly presents a number of challenges for the grid," Zaweski said. Multiple sources of small generation that don't really have meters that measure the amount of energy produced by the home and sent back onto the grid is an example.

While it may not require the scale of large transmission projects to bring the output to market, it has the burden of being integrated into existing systems because so much of it is generated on the customer's side of the meter.

So whether it's a few kilowatts of solar energy coming from someone's rooftop, or a 1,000-MW wind plant contemplated by the Pickens Plan, integration of renewable energy sources by utilities will be part of their agenda as they comply with new mandates and customer preferences.

William Opalka is a topic center editor-in-chief with Energy Central.

VISION STRATEGY REALITY

Better leverage SCADA

+ SYSTEMS EXPAND TO SUPPORT NEW CHALLENGES AND NEEDS

By Charles W. Newton

IN TWO RECENT 2008 SURVEYS conducted by research firm Newton-Evans, utility officials acknowledged the importance of supervisory control and data acquisition (SCADA), energy management systems (EMS) and related control systems in the development of a smarter grid. Among American officials, the role of the control center and related budgeting for control systems upgrades and new systems from 2008 to 2010 ranked second only to the expenditures planned for advanced metering infrastructure (AMI). Among respondents from the international

DISTRIBUTION NETWORKS

The next three articles consider how utilities can build more intelligence about their distribution networks both today and tomorrow. Charles Newton first discusses ways to better leverage an existing system, SCADA. Then William Gannon shares ComEd's use of midcircuit reclosers to prevent more outages, today. Lastly, Kurt Yeager looks at the possibilities with microgrids.

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community, planning for control center systems came in just ahead of AMI and automated meter reading (AMR) programs.

In fact, when you think about it, a smarter grid is becoming just that thanks in large part to the supporting field digitalization in the substation and sensor-based technology used further down the line to the customer premises. All of this additional information from new sources, including millions of meters, must feed into some central system, and the utility control systems are the systems in place to process all operational data, including some types of data (e.g., power delivery condition status, outage determination) transmitted from AMI installations. Much of the new generation of smart grid equipment can feed information to multiple systems, including specialized systems (protection and control, meter data management), but in every instance the SCADA or distribution management system (DMS) or EMS will be involved in the data flows.

Driven by SCADA-like systems and including EMS and DMS, we see a moderate up-tick in spending for new applications software and better visualization tools to compensate for the "aging" of installed systems. While not necessarily a control center-based system, the outage management system (OMS) is a closely aligned technology development, and will continue to take hold in the global market.

DISTRIBUTION MANAGEMENT APPLICATIONS AND FUNCTIONS

One of the components of smart grid technology is the SCADA-based set of applications called DMS. By mid-2008, a total of seven DMS applications had been implemented by one-third or more of North American utilities participating in a major Newton-Evans study. Led by geographic schematics for distribution feeder map displays (58 percent had implemented), relational databases with SQL access (53 percent) and basic outage analysis (51 percent), additional widely implemented applications included:

- Interface to customer information systems (CIS) (48 percent)
- Mobile data systems for utility crews (40 percent)
- Crew scheduling to aid dispatch for outage work (38 percent)
- Work order system interfaces (33 percent)

Investor-owned utilities (IOUs) led in percentage mentions for most of these, as well as for a few others. For example, 45 percent of IOUs had indicated availability of some level of distribution automation, and nearly one-third of IOUs had developed emergency restoration suggestions for switching purposes.

Planning for the new DMS-related applications centered on AMI and distribution automation. AMI plans were especially strong for IOUs and Canadian respondents.

Planning for implementation of new DMS, distribution analysis and outage management software centered on a few key applications:

- AMI (33 percent)
- AMR integration for outage detection (26 percent)
- Interface from OMS to SCADA for real-time updates (24 percent)
- Additional distribution automation, such as fault detection, isolation and service restoration (23 percent)

Several of the listed distribution analysis applications have been implemented by 40 percent or more of the utilities participating in this year's study. Nearly two-thirds of respondents have installed a short circuit analysis program, and 53 percent indicated having balanced load flow software in place. More than 40 percent cited use of the following: three-phase unbalanced load flow studies, feeder voltage optimization, distribution load forecasting tools, VAR flow analysis and distribution model load allocation software.

DISTRIBUTION AUTOMATION

The objective of rapid transmission of information related to steady state distribution power operations can now be achieved with the inclusion of newer SCADA and DMS capabilities including integrated volt/Var control (IVVR), and detection and isolation of faults at the feeder level (FDIR or FLISR).

OUTAGE MANAGEMENT SYSTEM

An OMS is basically a set of applications software that notifies control systems operations personnel of distribution outages and the location of such outages and even perhaps the cause of the outage, and may also recommend operator or service dispatcher actions to rectify the situation. A fully functional OMS relies on tight linkage with three other major operational systems: SCADA, geographic information systems (GIS) and CIS.

FINAL THOUGHTS

The world of SCADA has expanded to meet the needs and challenges posed by what today is termed the "smart grid." When a utility includes elements of DMS, distribution automation and OMS as functions properly operated by control systems and monitored and controlled by operations personnel, it is clear that the role of SCADA will remain pivotal and central for many years to come.

Charles W. Newton is president of Newton-Evans Research Company.