Annelie JENAKER
ABB – Sweden
annelie.jenaker@se.abb.com

Rui SILVA
ABB – Portugal
Rui.Da-Silva@pt.abb.com

Peter SIGENSTAM
E.ON – Sweden
VP, Head of E.ON Innovation Centre Distribution
peter.sigenstam@eon.se

CONTROL CENTER TRANSFORMATION TO ENABLE VIRTUAL POWER PLANT IN SWEDEN

Almost all leading global utilities have embraced various aspects of Smart Grid technology in discrete areas such as metering, distribution automation and demand response. Leading Swedish utility E.ON is not an exception. However, E.ON went beyond deploying the discrete Smart Grid technology and implemented a "Smart Grid Control Center" (SGCC) program to modernize traditional control center operations to take advantage of the convergence of smart grid enabled metering, feeder automation, Demand Response Management System (DRMS), Distributed Energy Resources (DER), and Volt-VAR Optimization (VVO) technology.

E.ON Elnat is a distribution company serving more than a million customers in Sweden. This presentation describes E.ON's Smart Grid Control Center vision, deployment experience and discusses the integration of DRMS, DER management and VVO for the deployment of a Virtual Power Plant.

The convergences of various Smart Grid technologies and applications have created unparalleled momentum to improve customer service, energy efficiency, power quality, and reliability. But, power systems have become more complex with increasing generation and consumption variations, automation and control. The role of control center operators has been significantly expanded to more than just ensuring reliability by monitoring and controlling the grid. The modern Smart Grid Control Center operators also need to focus on near real-time T&D system planning, forecasting, estimation, risk analysis.

What is seen in Europe as well as in some other parts of the world is a large take-up of renewable energy connecting to both the transmission as well as distribution networks - this is really one of the biggest challenge for the energy industry in Europe. 10 years back there was for example only a summer situation and a winter situation in Sweden, and it was adjusted for twice a year. Nowadays, this summer and winter situation happens over the course of a day, and it shifts very quickly, and therefore it all becomes more complex.

Modern electricity transmission and distribution networks are undergoing dramatic changes. They have to cope with more distributed and renewable energy resources, more data from smart power equipment and meters, and more regulatory pressure to run efficiently. This all results in more work and stress for network operators. Help is at hand in the form of SCADA energy management systems, advanced distribution management systems, demand-response management systems and advanced business analytics. These systems, when integrated and operated in conjunction, enable utilities to move from reactive to proactive system operations, enabling it to operate closer to its physical limits. The high-speed communication and convergence of IT and OT generates big volumes of data which SGCC needs to utilize effectively to improve decision making to dispatch the load.

Society's quest for sustainable energy is driving a redesign of transmission and distribution networks, from both operational and asset performance perspectives, so that clean, renewable energy resources can be accommodated. Many of these resources are distributed, e.g., rooftop-mounted solar panels or onshore wind generators. Battery storage banks, large and small, also play a role.The new power landscape is a mix of grid-scale and distributed power resources, with an increasing share of small, distributed units – a constellation for which distribution networks were never designed.

The typical distribution network is changing from one that connects producers and consumers in a one-way power flow, to one that carries flow in both directions in a complex, dynamic way.

Traditionally, the operational mode in the control room can be said to be in one of two states: normal or abnormal running conditions. Now there is a third mode, "suboptimal," in which the network is not suffering from major disturbances but some power equipment could be run more efficiently and a number of alarms and warnings are present. The alarms keep the operators busy, leaving less time for switching the network into a more optimized and efficient mode or performing planned maintenance activities. In some control rooms, operators are stressed beyond acceptable levels, increasing the likelihood of mistakes. The utilities must, therefore, seek better support when implementing new SCADA EMS and DMS solutions.

Constantly reconfiguring the network by switching capacitor and reactor banks on and off is one example of how voltage levels can be controlled and kept within the limits set out by the regulator. This is referred to as Volt-VAR Optimization (VVO) in transmission networks. Symmetrical loading of transformers, temporarily overloading lines and dynamic line rating (DLR), are other examples of grid optimization techniques that lead to better use of network assets. But how can operators identify the best time to reconfigure?

Calculating the optimal state of the network fast enough to allow preventive switching has always been difficult. The ideal situation would be to foresee and forestall events that lead to alarm conditions. If a network can adapt faster to changing conditions caused by power flux, it can also be operated in a more efficient way – resulting in better utilization and reduced losses.

By effectively combining readily available forecast data, such as load and weather data, for input into a software tool that calculates and builds production and load profiles for the near future. Adding this information to the network software function that mimics the network, often in an EMS referred to as the state estimator (SE), results in a simulated network. The network switching states are copied from the real-time SCADA system. The output of these calculations is a simulated network that mimics the real network, but with electrical values estimated a number of hours into the future – the same timeframe as in the forecasts.

Typically, this timeframe is six to 12 hours ahead of the current time, which is a good balance between acceptable accuracy and the time needed to reconfigure the network. It also allows time for a signal to be sent to participating units in a customer demand-response program. For the first time ever, the network operator is able to foresee alarms and warnings expected in the near future and make informed, proactive decisions. The result is improved network efficiency, more stable operation and fewer outages.

A demand-response management system (DRMS) is a relatively new tool used by utilities to control the balance between the power available and the power needed. The basic idea is to model and aggregate controllable loads into a virtual load that has a lower peak curve. By signalling this load, the utility can control the load profile and better match production at any given hour. It is important to note that, for domestic loads, this solution differs from the older load management systems (LMSs), which controlled loads without the participation or consent of the end users for every switching command that was sent out. The DRMS tool often requires customers to actively sign up to the demand response (DR) program.

Typically, signals are sent from a central system to selected program participants, who are able to set up response profiles that, upon receipt of the signal, automatically execute the selected program curtailment option. Suitable loads to control include electric water heaters and temperature-controlling devices such as heat pumps and air conditioners – a small change in room temperature is hardly noticeable to consumers. Less suitable loads include lamps, electric stoves, televisions and computers – for obvious reasons. In return for their flexibility, customers are often rewarded in some way, which varies by utility. Such incentives are seen as a way to change consumption habits in the long term, which is considered by many experts to be the most important behavioral change of all.

An aggregation of distributed generation resources managed in a way similar to demand-response loads is called a virtual power plant (VPP). The capability of a VPP would, typically, be comparable to that of a grid-scale renewable power plant. Studies are currently being conducted by research institutes in countries with plentiful wind and solar resources to find economical and technical methods for using VPP units as spinning reserves. Large-scale battery storage, with its ability to smooth power peaks and troughs, is one leading candidate here. The control room engineer needs to take these changes into account when planning network operations.

Business analytics solutions have been used for some time to support decision making, primarily in financial matters, but are now finding their way into control rooms to aid technical decision making. An important function of the business analytics solution is to verify that incoming data is both correct and complete. It can then turn a massive amount of data into actionable information.

A new generation of system support is being designed to help utilities manage their increasingly larger and more complex networks, which makes it easier for the operators to follow and foresee changing network conditions. It allows the operators to better manage the increasing quantity of data being made available to them.

From a utility perspective there is already a lot of data available, but it sits in different data silos, and what “big data” really is providing is that it is now possible to connect the data from the different silos and it then becomes possible to optimize and use the data in another way. Also, with the new technologies that is put in place there is velocity as well. It is now possible to do things in real-time with the in-memory technologies, which is opening up a new world as you can become pro-active in operations as well. When the data from the different silos is combined, that is where it is really possible to increase the value of what is already available in the different silos.

More and more utilities are also looking into how you

optimize your assets and investments and where to invest based on more fact-based decision rather than what it has been in the past – decisions based more on a gut-feeling and also input from experienced individuals. This is something that is needed in the future as well, but utilities today also want to add-in a lot more fact-based information e.g. maybe sensors in the field and information from maintenance reports.

The SGCC project is really about making power system operations more pro-active and able to look into the future – the next hour – the next 24 hours – in order to understand where constraints in the network will happen and how these can be mitigated. Therefore, engaging with customers and getting a better understanding of their demand flexibility and also gaining a better understanding of the generation flexibility in the network is of key importance. Of course, this requires a lot of data coming in as you need to be able to forecast, and this makes it all very interesting.

This SGCC project has now been running for a couple of years and E.ON are very happy with the results. In terms of quantifiable results, it conclusively demonstrates grid optimization and reduced grid losses. It is possible to adjust the network in such a way that you can optimize power flows. What is possible to see is that the distribution business is becoming more financially driven from these kind of operational perspectives as well, and therefore forecasting becomes important – not only from the grid bottle neck perspective.

The SGCC needs to have tools necessary to provide real-time performance monitoring, predictive assessment, and proactive course correction of the operating state. The functionality of these tools include: robust, real-time simulation of very large and complex delivery systems accurately estimating critical parameters such as voltage, current, circuit loadings, losses, etc.;

Integrated DRMS, DMS, and DER management can support the capability to model the energy delivery system and its distributed elements, integrate and apply all necessary real-time operations information, dynamically manage connectivity and supporting resources, monitor performance and deliver security, alarm low reliability situations, and proactively recommend operational changes to achieve contract commitments, reliability objectives and improved economy.

Figure 1: The Smart Grid Control Center

The Smart Grid Control Center with VPP enabled E.ON to aggregate DER along with VVO enabled savings to dispatch the load in an optimized way and reduce dependency on Demand Response programs. The VPP provided a much tighter link between what is happening in the wholesale market, what is happening on the retail side with management of the transmission system and the distribution systems. It also enabled E.ON to utilize VPP provided “found capacity” to bid in open market.