Distribution Control Centers in the US and Europe: Commonalities, Differences, and Lessons

Subramanian Vadari, Izudin Džafić, Dan'l Koch, Ryan Murphy, Daniel Hayes Jr., and Tarik Donlagic

***Abstract*—The distribution control center (DCC) has evolved from a sideshow in the traditional distribution service center to a major centerpiece of the utility moving into the decentralized world. Mostly, this is the place where much of the action is happening due to new forms of energy that are coming into the distribution system. This creates the flexibility of operation and increased complexity due to the need for increased coordination between the transmission control center and DCC. However, the US and European utilities have adapted to this change in very different ways. Firstly, we describe the research works done in a DCC and their evolutions from the perspectives of major US utilities, and those enhanced by the European perspective focusing on the coordination of distribution system operator and transmission system operator (DSO-TSO). We present the insights into the systems used in these control centers and the role of vendors in their evolution. Throughout this paper, we present the perspectives of challenges, operational capabilities, and the involvement of various parties who will be responsible to make the transition successful. Key differences are pointed out on how distribution operations are conducted between the US and Europe.**

***Index Terms*—Distribution control center (DCC), power system operation, distributed generation, asset flexibility, volt-var optimization and control.**

I. Introduction

DISTRIBUTION system operation is one of the critical core functions of a utility because it drives a significant portion of customer experience with the utility. This function entails having primary responsibility and authority for the safe and reliable operation of the distribution system. As utilities integrate more and more technologies with the tools necessary to aggregate, assimilate, and optimize the operations of a distributed system, the multitude of field devices and advanced meter infrastructure (AMI) will allow system operator to monitor the events on the power grid in real time so that the operators will know exactly when and precisely where the disruptions on the power grid will occur prior to a customer need to call the utility.

As the technical complexity of operating the power grid continues to rise, supplementing the control center staff with a distribution system operator (DSO) position has proven to be a highly effective model to elevate the overall skill sets required in the new real-time operating environment.

A. The US Perspective

The distribution control center (DCC) works very differently from the transmission control center [1]. The DCC is primarily focused on managing the clearance and developing switching orders for planned and unplanned work. These processes are the primary role of the DCC until now, because there is very little observability into the distribution system and limited controllability as well. Recently, most supervisory control and data acquisition (SCADA) controls for the distribution system is performed out of one SCADA system within the energy management system (EMS) system and managed by transmission operators. In fact, in many utilities, this is still the case.

However, DCCs are getting more and more impacted with the advent of the smart grid [2], distributed energy resources (DERs), and other injections of the technology and business constructs such as microgrids. Newer systems such as advanced distribution management systems (ADMSs) are also being introduced into these control centers. An ADMS dramatically changes the operational effectiveness and becomes the primary tool in the future to enable the DSO to manage their responsibilities. Its functionality will support monitoring and operating the following parts: safe clearance coordination in the power grid; advanced switching module capabilities; DER integration and distributed generation dispatching; grid-edge technologies and Internet of Things (IoTs) to support demand response; and emergency and storm management.

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Figure 1 presents a high-level explanation of the workflow (copyright Modern Grid Solutions®-all rights reserved used with permission). The DCC sits at the nexus of asset management and field operation. The interactions between various operating units in the utility are presented in Fig. 1. The transmission and distribution section aims to operate the power system safely and efficiently, monitor and control the system reliability, coordinate emergency response, authorize execution of planned work on assets, and provide asset and system information. The asset owner organizes financial return as: establish revenue requirement; establish measures for cost, risk, and performance; and measure the performance. The asset strategy and planing defines the right work on the right asset as: balance system performance versus cost; develop objective and fact-based mid-to long-term asset plans. The work and resource management aims to do the work right at the right cost as: optimize the utilization of resources to perform the work; efficiently manage the work through the entire production line lifecycle; and manage unit costs by using dial management. The field execution aims to execute with productivity and quality as: inspect, maintain, and replace assets; and manage and execute the restoration to performance criteria. The enabling functions include external communication, IT, and safety health and claim.

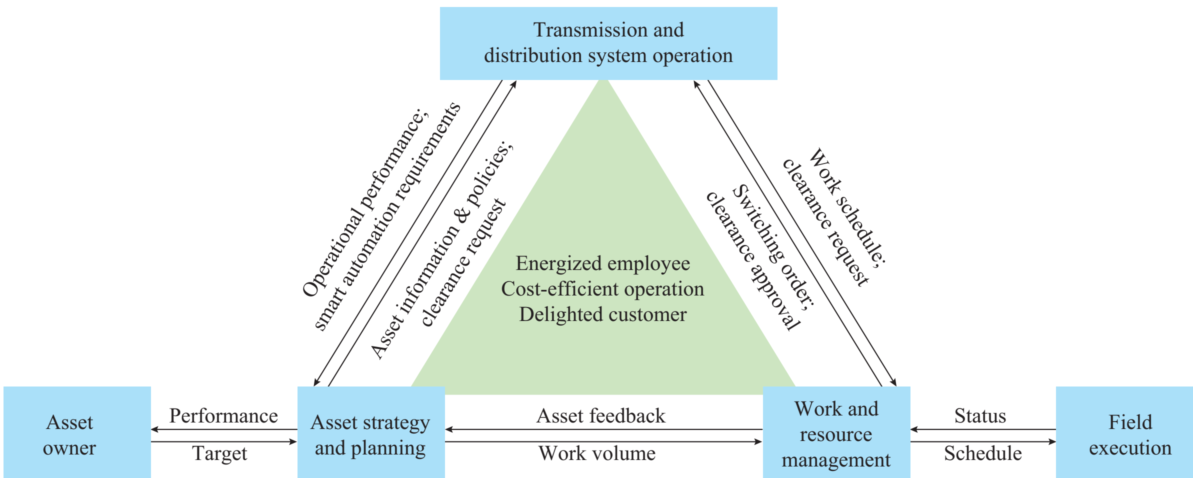

Fig. 1. A high-level explanation of workflow used with permission from Modern Grid Solutions®.

The DCC is organized as follows.

1) Clearance Desk

This desk analyzes the loss of equipment under different system conditions for the entire length of time of the clearance while minimizing the power disruption to the least number of customers. The clearance request comes from asset management which is interested in maintaining a specific piece of equipment or work management responsible for performing new connections.

The next step to an approved clearance is to develop the sequence of steps (operations) to isolate the equipment that is part of the approved clearance request. This sequence of steps is called a switching order. The main objective of the operator at this desk is to develop the switching order.

2) Switching Desk

The switching desk implements switching. In the US, some of the switches may need manual operation from someone in the field while some have the capability of remote SCADA operation. The operator will either interact with field personnel to execute the manual switching or execute the remote SCADA-based switching as appropriate.

3) Dispatcher Desk

The dispatcher works with the filed crew to ensure that they are at the right location to perform the right work.

4) Other Support Desks

The support desks in the DCC are ① the shift supervisor desk or senior dispatcher desk; and ② the operation engineer or analysis desk. The operation engineer is generally available to support the clearance desk with the analysis of complex operations and is generally staffed two out of three shifts to accommodate the volume of the planned work.

B. The European Perspective – Coordinated System Operation Management of Transmission System Operator (TSO)-DSO

In addition to the organizational aspects identified in the US, the liberalized European electricity markets have treated power system as a so-called "copper plate". This means that the electricity market assumes that electrical energy can largely be traded freely, even though the underlying power system is subject to physical limits. The focus is on finding new and innovative ways of operating renewables-oriented and decentralized energy systems, which is all about finding optimal operating and control strategies for the reliable power supply system. The core of such a solution will be the coordinated system operation management of TSO-DSO, i. e. the interaction between the TSO and the DSO.

The large number of decentralized generators are connected to lower-voltage levels and are not available to the TSO for control purposes. Therefore, the challenge is to have the coordinated use of the existing flexibilities such as energy storage or switchable loads, within both transmission and distribution systems. The TSO needs to use the flexibility of hundreds of systems in an underlying distribution system without causing critical states in the underlying system. The operation management strategies include: ① optimal coordination of TSO and DSO; and ② horizontal system management within a particular voltage level. The focus needs to be on the utilization of degrees of freedom that are beneficial to the power system at all levels.

In addition, the EMS is coordinated with market-system-operation management. For this purpose, the capacities of relevant grid connection points are already considered with the trade when purchasing the electricity. The balancing approach of an energy trader not only covers the needs of its customers, but also considers other aspects that are beneficial to the power grid. Under such circumstances, as a possible intervention, the curtailment of renewable energy systems cannot always be avoided. Virtual power plants (VPPs) can be used as a further component for coordinating an optimal EMS. With the appropriate grid-serving and grid operator-supporting concepts, one can contribute to increasing the proportion of wind and photovoltaics (PVs) in the electricity mix.

These concepts are being implemented intelligently in control rooms of the future. It is all about the calculation and utilization of potentials from distributed generation unit, load, or storage, which can be called up in a system-beneficial manner without overloading the capacity of the power system.

The rest of the paper is organized as follows. Section II presents the situational awareness in DCC. Section III takes a detailed look at DCC and their evolution. Section IV sets the stage for Section V by analyzing the need for close cooperation between the transmission and DCC, which is further expanded in Section V. Section VI reviews the role of vendor, system integrator, and subject matter expert. Section VII presents the conclusions.

II. Situational Awareness in DCC – A Commonwealth Edison (ComEd) Perspective

ComEd is divided into four regions: Chicago Main, North Chicago, South Chicago, and West Chicago. Each region is broken up into several subregions with 19 service areas, also known as areas of responsibility (AOR). ComEd has one centralized operation control center (OCC) that monitors and controls all distribution system operations in each of the areas, as shown in Appendix A Fig. A1.

The day-to-day operations of “Normal Blue-Sky” in OCC involves directing scheduled switching and maintenance of the distribution system, responding to un-planned events including customer outages, non-outage calls from the customer and power quality requests. This includes the dispatch of first responder or trouble crews and the management of all repair crews for the events requiring more extensive repairs, previously scheduled maintenance or upgrading. Personnel safety and system configuration control have top priorities for every event managed.

There are four major roles inside the OCC that support daily operations.

1) Shift managers oversee all events and maintain the communications with ComEd leadership. They are also responsible for monitoring all conditions that could potentially impact the performance on the system such as distribution system loading, equipment performance, weather forecasts, access concerns, e. g., large-focus media events, safety events, etc. These factors could result in the need for additional changes in resources, and each of which requires its own evaluation. The monitoring and analysis of the conditions may also result in proactive implementation of the Emergency Response Organization (ERO) for anticipated larger-scale events.

2) The senior substation operator (SSSO) manages the subtransmission or distribution system “inside the fence” at all substations for voltages of 138 kV and below. The SSSOs monitor and control the system through SCADA system remotely or manually with area operators in the field.

3) The senior DSO (SDSO) manages the 4 kV and 12 kV distribution system from the circuit breaker of the substation out to the end of the feeder, including monitoring and controlling the distribution automation (DA) system. They maintain the system configuration control and monitor all customer outages using the outage management system (OMS), paired with the mobile dispatch system to communicate the events with field crews. On a normal day, an SSSO will manage up to 3 AORs of substations and will have up to 4 SDSO operators.

4) There are arrangers in the OCC that supports the system operators and works with the planning organization to write and process all requests of scheduled switching order. They also use the SCADA and OMS applications to plan all scheduled work. There are up to two arrangers responsible for planning the work for each of the 19 AORs.

In addition to the four roles, the OCC also has information desk technicians (IDTs) that support the shift managers and operators. They are responsible for a wide range of communication tasks including safety notifications, executive awareness, weather forecasts, personnel/resource notifications, equipment failures, and work order processing.

The ERO exists to monitor and proactively open the emergency operation center (EOC) to supplement DSO during emergency events deemed too large for the OCC to handle effectively. In most cases, the emergency event is a storm. More than 1900 employees make up the ERO. It consists of 8 response teams (A-H) covering 4 regions, the EOC and joint information center (JIC), and several support organizations.

The ComEd service territory covers over 11000 square miles in northern Illinois, the US, including the Chicago metropolitan area. ComEd is committed to safely delivering reliable electricity throughout more than 400 municipalities and 25 counties and serves approximately 4.1 million customers which include the city of Chicago.

III. DCCs and Their Evolution – A Puget Sound Energy (PSE) Perspective

Utilities throughout North America and the European Union are facing a host of challenges, drivers of change, and lots of opportunities. In many cases, these are equal parts increasing customer values and expectations, and changing the regulatory requirements and the emergence of new distributed energy technologies, which dramatically changes the landscape and significantly alters the way in which utilities must plan and operate the distribution system. These are all with an ever-increasing emphasis on an interaction with the customer like never before.

These challenges faced by the utilities today are numerous, accumulating at the DCC to one degree or another. Appendix A Fig. A2 shows the DCC desk at PSE used with permission from PSE.

A. Increasing Technology and Automation

Technologies such as fault location, isolation and service restoration (FLISR), AMI, fault location and automatic reclosing technologies are being implemented in large quantities.

These new devices allow the utility obtain greater visibility and real-time control over power equipment, and they also permit bi-directional communication between the devices in the field and a centralized operating platform. FLISR technologies support and enable the utility's ability to monitor, proactively diagnose failed sections of infrastructure ahead of field investigation, and control parts of the distribution system that are not previously possible [3], [4]. AMI technologies allow utilities to gain the insight into residential and feeder-level loading profiles and continued unlocking of a host of opportunities to optimize power flows on the distribution system, which includes evolving demand response programs manually and automatically at the individual customer level. AMI integration with an OMS also offers a strong boost to grid resiliency through improved metering functionality and advanced outage prediction capabilities within the OMS.

The impacts of increasing technology and automation on the DCC are as follows: as the field-facing technology advances in complexity and quantity, it is critical that the trust in this technology at the control center advances as well. A DSO holds, at the highest possible level, that their primary purpose is to ensure the safety and health of all people working on or near the power system. From a broad safety perspective, trusting in the technology is paramount. Absenting this trust, the technology will be intentionally disabled, underutilized and/or mitigated through the unnecessary deployment of field personnel to "baby sit" and monitor the equipment. The success in truly realizing the benefit promised by new grid technologies lies in the strong adoption at the control center. AMI has a profound impact on control center operations. AMI data measure the energy, which cannot be treated as other real-time measurements. AMI is taken as an input to short-term prosumer forecast (STPF) and then delivered as pseudo-measurement with probably higher weighting to distribution system state estimator (DSSE) [5], [6].

B. Declining Load

Houses and buildings are becoming more energy-efficient, so they consume less energy. In addition, the introduction of DERs into the system is making the customer load more dynamic and less predictable.

The impacts of declining load on the DCC are as follows. As DERs continue to gain momentum, the need for traditional investments toward a safe and reliable primary distribution system are as important as they have ever been. As the 3rd party energy sources continue to shift the quantity, nature, and direction of power flows at the distribution feeder level, the amount of data, status, and system visibility that are required for an operator to respond to unplanned events and manual operation of the system are becoming significant. Deeper consideration in this real-time operation begins to make it clear on how a fully integrated ADMS must be acknowledged as a critical tool to enable the technology for DER integrations.

C. Shifting Regulatory Landscape, Policy, and Customer Expectation

The regulatory policies in many countries, states, and provinces are shifting rapidly, so that the utilities must have strategies, processes, and tools in place that are nimble enough to enable appropriate responses to the mandates.

The customers expect to reduce our carbon footprint and are efficient in power generation and distribution. They also expect to decrease our outage time, and are proactive and conscientious of how we conduct the business around energy matters and maintain the affordability.

The impacts of shifting regulatory landscape, policies and customer expectations on the DCC are as follows. One of the biggest opportunities an individual customer has to align the values with energy consumption is through the direct investment in local, and renewable DERs, e. g., including behind-the-meter DERs and aggregated front-of-the-meter DERs. The DCC is the quiet engine that must run in the background to integrate safely and reliably growing number of DERs.

Additionally, during a service interruption, the DCC is the hub for the real-time information and data that the customers desire. This data includes a timely flow of transparent information to include the cause of the interruption and estimated time of restoration (ETR).

D. Technology Pace of Change

The old paradigm has regulators and utilities who control the pace of innovation through collaborative research. Startups and other fast-paced companies now greatly influence the business environment. Some of these technologies such as FLISR are embedded within the primary grid, while other technologies such as microgrids, behind-the-meter batteries, and smart inverters are implemented by customers.

The impacts of technology pace of change on the DCC are as follows. The pace of adoption at the DCC is the underlying foundation for utilities to be positioned to lead the way with new technology implementation and customer offerings. The factors of control center adoption include but are not limited to: control center restructuring and position alignment to permit dispatch functions of distributed generation; attraction and training of system operator; and new procedure development and ongoing system operator support in the design and implementation of new technologies for power systems.

E. New Sources of Supply

DERs and other non-wires alternative (NWA) approaches are creating new sources of supply and consumption at the utility. Customers now can generate some or all the power internal to the premises, and store or even deliver it back to the power grid. In addition to creating load variability, it also creates a 2-way power flow situation in a mostly radially designed power grid for 1-way power flow.

The impacts of new sources of supply on the DCC are as follows. The power grid is getting more complex as grid technologies advance and power generation moves from a centralized radial power flow model to a distributed model. Within designed operating parameters, controlling through this change safely is getting more and more complex. A system operator must be equipped with the right tools and trained to reliably operate a dynamic power system, while simultaneously securing safe working conditions for all field personnel and local community members.

F. Voltage Fluctuations Caused by Renewable Generation

During one period, Germany is on frontier for renewable energy installment. PVs are installed almost everywhere, which causes terrible voltage fluctuations and threatens to stop the Energiewende transition. The energy transformation, widely known as the “Energiewende” in Germany, is the country’s planned transition to a low-carbon, nuclear-free economy. But there is much more to it than phasing out nuclear power and expanding renewable energies in the power sector.

The impacts of voltage fluctuations caused by renewable generation on the DCC are as follows. The variability in renewable generation introduces large reactive power and voltage fluctuations in distribution systems. Traditionally, voltage regulation is done by local voltage controllers through set-points and the operation of tap changers through SCADA [7]. This option is not possible anymore. Distribution centers now rely on automation process that dynamically calculates set-points for the local voltage regulators, transformer tap changers, and capacitor banks [8], [9]. Volt-var optimization (VVO) is becoming one of the key applications [10].

G. New Technical Constructs

New technical constructs such as microgrids are being implemented within a utility’s footprint. These microgrids could be either utility implemented, or customer implemented. Similarly, the potential exists for external aggregators to operate a customer microgrid and interact with the utility as an independent entity.

The impacts of new technical constructs on the DCC are as follows. The emergence of microgrids, with a utility source interconnection, creates a new operating challenge within DCCs. The system operator must understand the dynamic capabilities of the interconnected system, and the system operator must maintain the visibility of the status of the microgrid. If a generating source within the microgrid becomes unavailable (planned or unplanned), the SO will need to understand the operating procedures required to re-configure the power grid to maintain uninterrupted service to the customer. The design of interconnection and the corresponding operating procedures, i. e., manually or automatically, must be well established and mutually understood by both the microgrid owner and the utility to ensure that service levels remain high.

H. Workers Retiring and Fewer People Joining Workforce

Automation in the field and within the control center allow utilities to streamline operations while creating more values for customers.

The impacts of workers retiring and fewer people joining the workforce on the DCC are as follows. As the industry looks to the future workforce, a few difficult questions come to mind. With the impending ubiquity of grid automation and advanced operational technologies, what skill sets do new employees require? What impacts does this have on the universities and trade schools that are creating the next generation of the utility employee or power system engineer? The workforce of the future will be very different from that of today. They need to be technology-savvy because much of the automation is based on electronics, software and artificial intelligence, which requires different treatments than those of today’s equipment.

PSE is an energy utility company based in the U.S. state of Washington that provides electrical power and natural gas to the Puget Sound region. The utility serves the electricity to more than 1.1 million customers and provides natural gas to 750000 customers. The electricity and natural gas service area of PSE spans 16000 km.

IV. EMS/ADMS – The Next Generation

EMS/ADMS solutions for TSOs and DSOs are used worldwide in regulated and deregulated electricity markets, which offer a high degree of flexibility. Modern solutions already contain several load flow based analysis that can consider more complex equipments such as high-voltage direct current (HVDC) for transmission and smart inverters for distribution.

Utilities are phasing out conventional power plants and increasing the amount of distributed generation at both higher- and lower-voltage levels. Along with this trend goes the fact that the degree of freedom given by conventional power plants, which TSOs use to exercise their system responsibility, is becoming less widely available. To make up for this deficiency, new applications are coming into play that effectively integrate decentralized generators into power system operations.

Many of the renewable generation plants are mostly connected at lower-voltage levels and will exist in large number with lower nominal power, making it difficult to integrate on individual basis for TSOs and system balancing authorities as before. In the future, decentralized assets can contribute substantially to grid services [11]-[13]. The strong expansion of distributed generators has led to significantly changed load and generation patterns in the distribution systems.

These expansions allow the DSOs to receive important information about their operation. In addition, these extensions enable the TSOs to reliably use the degrees of freedom provided by distributed generators and their operators.

Such major changes require a significant interaction and integration between the ADMS and EMS, as shown in Fig. 2 (copyright Modern Grid Solutions®-all rights reserved used with permission), where GIS stands for geographic information system, RTU stands for remote terminal unit, CA stands for contingency analysis, OPF stands for optimal power flow, SC stands for short circuit, ECM stands for equipment condition monitoring, LSM stands for load survey balancing, FLB stands for feeder load balancing, and API stands for application programming interface. New functions are being added to both EMS and ADMS for the use in the control rooms, which enable the distribution systems to be operated optimally with these new generation patterns.

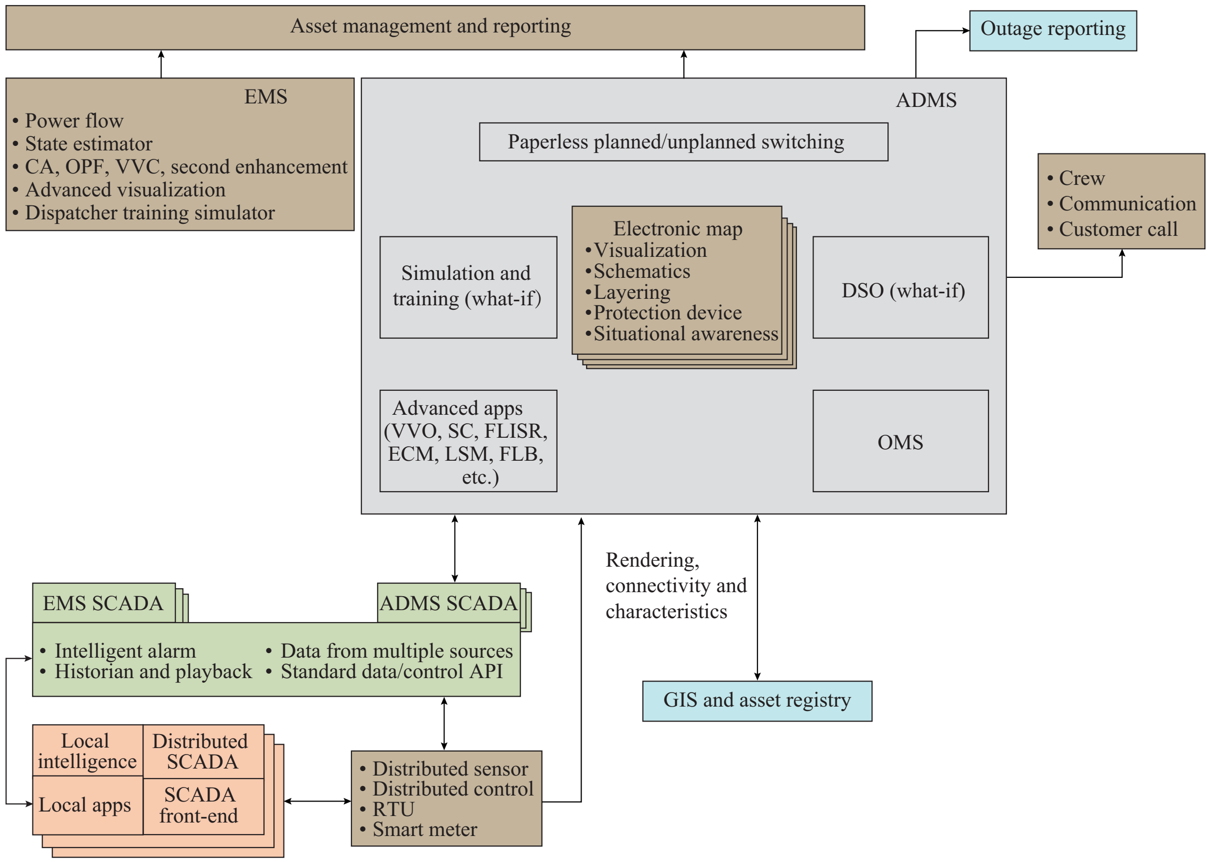

Fig. 2. An Integrated EMS/ADMS architecture used with permission from Modern Grid Solutions®.

To have such a system architecture, processes for communication exchanges, and control algorithms that enable distributed generation to be integrated into the future control systems of system operators need to exist. To accomplish this, the distributed generators must have the degrees of freedom in the form of controlled variables, e.g., the flexibility in change of injected active and injected/absorbed reactive power that respond to a control command. Data points describing these degrees of freedom extend the existing database and the existing data model of the power grid that operators have in their control systems. For the use of the additional data and degrees of freedom, new control functions or extensions of the existing functions in the control centers of the system operators are required. These control functions need to be defined, and the ways to implement them prototypically must be explained.

V. Concept of Decentralized Energy System Operation (TSO-DSO Interoperability)

One concept of a future energy system operations is provided in this section. System flexibility, communication requirements, and concepts of system automation in such a system are briefly described [14].

A. Flexibility

The term flexibility describes the ability of a system subscriber to have its active or reactive power deviating from a reference operating point or reference profile in response to a control command. It can be assumed that this ability will become more important in an energy system that is increasingly dominated by distributed renewable generators. A political goal is that for renewable producers, trading flexibility in the existing or future markets becomes a functioning business model [15].

Currently, there are various products on the energy and power reserve markets, which are referred to as flexibility products due to their properties and usage. This includes primary, secondary, and tertiary controls (reserves) as well as short exchange products (quarter-hour and hourly products) from the intraday energy market.

The reference power profile, based on which flexibility is measured, is understood to be the power profile that the system participant would cause if there is no flexibility request.

This reference can be defined as a forecast profile that has to be submitted in advance by the system participant. Conventional power plants typically have reference profiles that are constant over long periods of time (hours and days), which are located at the optimal operating point of the power plant. The reference profiles of wind or PV systems can fluctuate very strongly.

These general properties can be found in the existing flexibility products. Auctions are held for short-term products on the energy market as well as for secondary and tertiary reserves, which happen earlier than the flexibility interval, in which the flexibility is called up. This lead time is, for example, one week in the case of secondary reserve and one day in the case of minute reserve (until 10:00 a.m. of the previous day) [16]. Asset flexibility allows certain levels of referent power fluctuations for the power grid. At a given timepoint, the operating point of an asset changes in response to a communicated control command.

The flexibility of a decentral plant is its ability, upon a control command, to deviate from a reference power injection and to increase or decrease its power within a defined control range. To reliably provide such flexibility from several individual plants, a coordinated process is necessary. Local limit violations such as voltages outside the allowed voltage band and currents exceeding the rated currents must be safely avoided. The individual plants must communicate their flexibility control range prior to the validity time interval.

When planning the distribution system operation, the DSO will consider the flexibility ranges in the grid safety calculation. An important outcome of the safety calculation is a set of (possibly smaller) flexibility control ranges containing only operating points that are feasible without violating the operation limits. These limited flexibility control ranges, which do not lead to a local limit violation, are termed as certified control ranges with upper and lower bounds for the active and reactive power. The objective of this function is to maximize the certified flexibility.

B. System Communication Architecture

Various communication architectures are feasible for incorporating the flexibility concept in the grid operations. An example of a feasible approach would be a decentralized, VPP aggregation architecture. The central part of such a communication architecture variant is a VPP. The VPP connects many DER units to its own SCADA/EMS and offers their aggregated power or control to a TSO. At the same time, it coordinates the operational plans of the units with the DSO. The schematic of such an architecture is presented in Fig. 3, where ICCP stands for inter control-center communication protocol, RPS stands for reserve power supplier, RES stands for renewable energy source, STO stands for storage, BLD stands for blackout load decision, and AMG stands for actively managed grid.

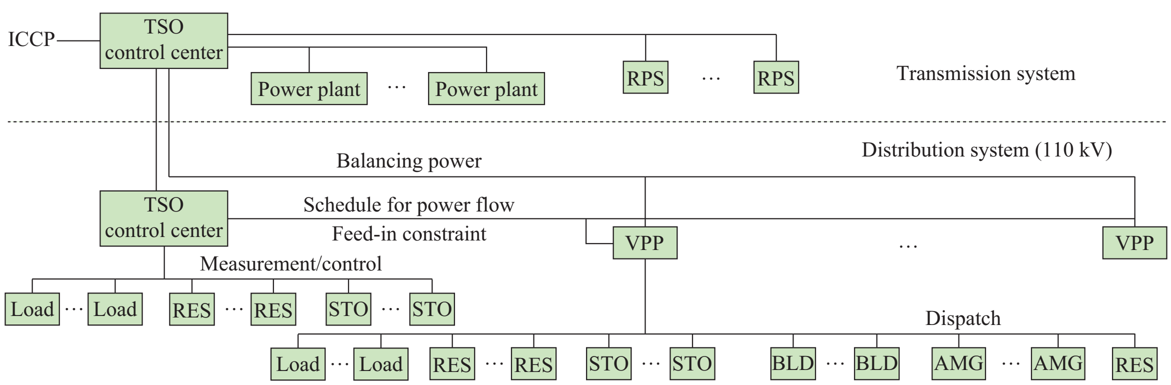

Fig. 3. TSO/DSO communication architecture with VPP at its core.

The "real-time OPF" [17], [18] function is a real-time application that runs in the control center of the TSO, which minimizes line losses, considering voltage ranges and line thermal loadings. Besides, it uses the flexibility available to the TSO from the connected underlaying distribution systems as additional degrees of freedom.

In this architecture, the VPP takes on both the roles of control reserve providers and energy suppliers (power plants). Since the generation units of these VPPs are mainly connected at the distribution system level, the existing schedule management system must be expanded to include the mechanisms that enable the respective DSO to prevent system bottlenecks in its system area. These extensions consist of communications between the DSO and the VPP as well as the balancing authority.

The additional communication channels present the DSO information of the load and generation schedules occurring in its system area. In addition, the DSO learns at which system nodes this load and generation will occur. The operation plans communicated by the VPP are checked in a system security calculation by the DSO.

The described communication processes show the need to integrate the data points from DER from other underlying system levels into the control room. The aim is to avoid a unit control conflict between a DSO, which wants to avoid a local system bottleneck, and the TSO, which must be able to reliably call up the flexibility as the reserve power or for the congestion management purposes at the underlying system levels of the DSO.

C. Automation

Adequate communication capabilities are needed to make this expansion towards the new EMS/ADMS architecture necessary as well as an expansion of the data exchange, especially between TSOs, DSOs, and VPPs. The definition of the data exchange content, their sequence, and the extensions of advanced EMS applications together form an automation concept for a strongly decentralized energy system.

Table I shows advanced applications in VPP control rooms. The "real-time OPF" [17], [18] function is a real-time application that runs in the control center of the TSO. It minimizes line losses, considering voltage ranges and line thermal loadings. It uses the flexibility available to the TSO from the connected underlying distribution systems as additional degrees of freedom.

TABLE I
ADVANCED APPLICATIONS IN VPP CONTROL ROOMS

Application name	Description/cost function	Degree of freedom	Constraint
Day-ahead schedule	Determine optimal unit commitment schedules for all units Guarantee flex-ibility margin and nominal profile Conform to feed-in constraint Minimize the costs and maximize the revenues	Units' generation/loading: PP/DG unit Storage unit (battery unit and other storage) Energy contract Load unit (flexible load)	Constraints are defined at the unit parameter level and the reserve conditions for the area, e.g.: Power balance equation of each topological node The maximum/minimum power of the units The maximum power ramp-up of the units Availability of primary energy The maximum/minimum energy content of storage units The maximum emissions allowed

The "day-ahead contingency power flow" function is part of the operation planning of the DSO [19]. It uses the schedules of the decentralized generation received from the VPP. With the system statuses determined from the schedules, when the TSO requests and does not request the flexibility, this function calculates whether the distribution system can be operated in such scenarios. If this is not the case, the function calculates the lowest limitations of the flexibility intervals offered, which would enable a safe operation. The "day-ahead scheduling" runs in the control room of the VPP in the operation planning. This function is the unit dispatch of a VPP. An overview of the advanced applications and concept for EMS, TSO and DSO control rooms is shown in Tables II-IV, respectively.

TABLE II
EMS APPLICATIONS REQUIRED FOR THE PROPOSED MODES OF OPERATION

System operation	Application name	Description/cost function	Degree of freedom
At transmission level	Real-time OPF REGEES extension	Minimize voltage deviation Minimize power loss Manage the congestion	Generator bus voltage, tap... Distribution grid flexibility
At distribution level	DG-DACF	Determine the feasibility for day-ahead schedules of VPP Calculate time-dependent feed-in constraint	Imposed flexibility limitations/voltage band and branch thermal limit
	VVC	Minimize power loss Minimize voltage deviation	Flexibility for local distribution systen
	Online GCP flexibility potential	Calculate aggregated flexibility of DERs at grid connection points	Voltage (magnitude and angles) and branch current
VPP	Day-ahead scheduling	Determine the schedule for all units Guarantee flexibility margin and nominal profile Conform to feed-in constraint	Units' generation power...

VI. ROLE OF VENDOR, SYSTEM INTEGRATOR, AND SUBJECT MATTER EXPERT

While the discussion of systems and their implementations are very important, there is another dimension to DCCs. ADMS, as the primary system in a DCC, has the interfaces to most of the utility ranging from systems such as asset management, GIS, customer information system, and AMI. In addition, when outages happen, the outage response mechanism of the entire utility also comes into play. As a result, several non-utility entities play an important role in the success of a DCC.

Vendors: vendors of these ADMS systems play an important role in the development of these systems that are not just capable of delivering on the algorithmic systems but also the complex workflows in the control center.

System integrators: system integrators play an important role in the implementation process. They take the system developed and delivered by the vendor and ensure that its operations are in conformation with the utility's business practices. Four components of their contributions are listed below.

1) Process: one of the most important aspects of implementing the ADMS is ensuring that the system works under a broad range of operating conditions such as blue-sky, grey-sky and emergency/restoration. This requires that the processes are appropriately defined at the right level of detail to ensure that all the right personnel know what to do under potentially stressful situations.

TABLE III
ADVANCED APPLICATIONS IN TSO CONTROL ROOMS

Application name	Description/cost function	Degree of freedom	Constraint
Real-time OPF extension	Minimize limit violations: Minimize voltage set-point deviation Minimize transformer/line overload Minimize power factor violation Optional additional objective: Minimize power loss Minimize active power consumption Minimize reactive power consumption	On-load tap (discrete/local control): Transformer tap Capacitor tap (banked) Reactor tap (banked) Switch status of capacitor banks /reactor (non-banked) Transmission storage (active power) Controllable load (active power) Active and reactive power flexibility from DGs, PPs, and loads allocated for congestion management	Bus voltage limit The maximum/minimum tap position Branch/transformer thermal limit Active power limit for generator Reactive power limit for generator Storage state of charge of battery Flexibility limit of load/generation
Day-ahead contingency power flow	Determine the feasibility of day-ahead schedules of PP and VPP Consider network reconfiguration to comply with provided schedule	Switch status	Bus voltage limit The maximum/minimum tap position Branch thermal limit

TABLE IV
ADVANCED APPLICATIONS IN DSO CONTROL ROOMS

Application name	Description/cost function	Degree of freedom	Constraint
Day-ahead contingency power flow	Determine the feasibility for day-ahead schedules of VPPs Consider network reconfiguration to comply with provided schedules Calculate time-dependent feed-in constraint	Switch status of normal open switch (NOS) Limitation of flexibility interval	Bus voltage limit The maximum/minimum tap position Branch thermal limit
VVC	Minimize limit violation: Minimize voltage set-point deviation Minimize transformer/line overload Minimize power factor violation Optional additional objective: Minimize power loss Minimize active power consumption Minimize reactive power consumption	On-load tap (discrete/local control): Transformer tap Capacitor tap (banked) Distributed generator (bus voltage set-point) Controllable load (active power) Distributed storage (active power) Active and reactive power Flexibility from DGs and loads allocated for congestion management by VPP	Bus voltage limit The maximum/minimum tap position Branch thermal limit Active power limit of generator Reactive power limit of generator Storage state of charge of battery Flexibility limit of load/generation

2) Technology: the complex interfaces all need to work under the situations explained above, i.e., both with volumes and the performance timeframes. For example, during large power outages, the call volumes can be in the range of a few hundreds of thousands in an hour. The call systems and their integrations with the OMS need to handle them.

3) People: with the process and technology requirements, people need to be aware of the processes involved, their roles and actions. An example is during the emergency or restoration. When this happens, at least in the US, everyone in the utility takes on a "storm role" virtually. They perform this role maybe once or twice a year, and their normal knowledge of the systems and processes will be low. Adequate training and experience with the systems and processes are critical.

4) Subject matter expert: as utilities are heading into uncertain territory as explained in the early segments of this paper, the need to ensure that the availability of the right kind of subject matter expert within the utility portfolio is critical for any utility. These are the people who are not only looking at the situation today but ensuring that the actions taken today do not preclude the utility from doing something in the future. They are keeping an eye on the future.

VII. Conclusion

Together with other emerging demands on the power grid like NWAs, vehicle-to-grid, grid-edge systems and community choice aggregation, these challenges are placing increasing demands on DCCs and further challenge the operational flexibility available to the system operator. Accordingly, utilities are increasing their investments in integrated systems or ADMS, distributed EMSs and microgrid management systems (MGMS) as the foundational tools to integrate, monitor, and control the current technologies as well as those in the future.

While a majority of the change is happening in the distribution system, it is important to note that transmission/wholesale functions such as balancing authority still need the access to all the generation information and the appropriate controls that go with it. This requires a lot of coordination between the TSO and DSO, which in turn requires deep integration between the EMS and ADMS.

This paper attempts to provide a view into how this integration and coordination is done taking two specific views into consideration: the US perspective and the European perspective. It has described how this is done in the US, and Europe by pointing out commonalities, differences, and equally important, lessons learnt from different ways of implementing these systems.

APPENDIX A

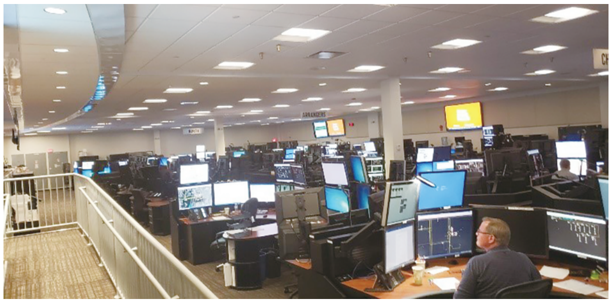

Fig. A1. OCC of ComEd used with permission from ComEd.

Fig. A2. DCC desk at PSE used with permission from PSE.

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