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Distribution Automation Strategies Challenges and Opportunities in a Changing Landscape

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***Abstract*—With the spotlight on smart grid development around the world, it is critical to recognize the key factors contributing to changing power system characteristics. This is more apparent in distribution systems with the integration of renewable energy sources, energy storage, and microgrid development. Utilities are also focusing on the reliability and resiliency of the grid. These activities require distribution automation (DA) strategies that take advantage of available technologies while promoting newer solutions. It is necessary to create a roadmap for holistic DA strategies in a smarter grid. Sustainable and resilient grid development is a paradigm shift requiring a new line of thinking in the engineering, operation, and maintenance of the power system. International perspectives on DA are also addressed, with the understanding that one solution will not fit all. Integrating technical, business, and policy decisions into the challenges will generate the development of technologies, standards, and implementation of the overall solution. The challenges in the development of industry standards are also discussed. This paper explores the challenges and opportunities in the changing landscape of the distribution systems. Evolution of technologies and the business case for infrastructure investment in distribution systems are covered in another paper by the same authors.**

***Index Terms*—Demand response (DR), distributed control, distributed energy resource (DER), distribution automation (DA), microgrid, smarter grid.**

I. INTRODUCTION

MODERN POWER systems continue to evolve, affected by technology innovations, environmental impacts, regulatory policies, energy usage and resources, and aging infrastructure. The power system changes are more apparent in distribution systems due to a host of challenges that include the integration of renewable energy resources and electric vehicles, energy storage, demand-side management, the use of power electronics-based equipment for lighting and drives, and the impacts of recent extreme weather events [1], [2].

Moreover, utilities are focusing on improving customer service, system reliability, and operational resiliency. Some public policy-makers, focused on supporting distributed generation resources, now require that energy storage devices maintain a certain percentage of load support, further challenging the changing landscape. The availability of cheaper shale gas, in some regions of the world, provides a new opportunity to support renewable energy resources with quick-ramping, gas-based generating stations at the distribution level.

As a result, distribution systems have become much more complex to plan, operate, and maintain. Improved protection and control of those systems has also become imperative. To better manage the grid, major investments have been made in smart grid technologies such as advanced metering infrastructure (AMI), distribution automation (DA), equipment and system monitoring, and more advanced protection and control technologies. Fig. 1 illustrates the vastness and scale of the North American electric grid with respect to geographical area with diverse natural calamity, public policies, varying power-system patterns, etc., which are common to other parts of the world. Fig. 2 illustrates the evolution of a typical electric power system. This paper focuses on the DA strategies for such an evolving system.

Historically, distribution systems have operated in a radial mode due to the simplicity of operation, ease of coordinating the protecting devices, and overall economics. The regulatory requirements to improve reliability indices have introduced concepts such as loop systems, where possible, to support the uninterrupted flow of power to the load. The latter approach, however, includes the inherent complexity of coordinating simple protection devices and requires institutional changes.

The evolving distribution system landscape introduces many new challenges in policies, operation, maintenance, protection, and control from inception to life-cycle support. The development of microgrids has brought new opportunities to the distribution system as well, including contributions to capacity, reliability, and power quality improvement.

Recent technological improvements, coupled with the lessons learned from pilot installations [3]–[7], have clarified

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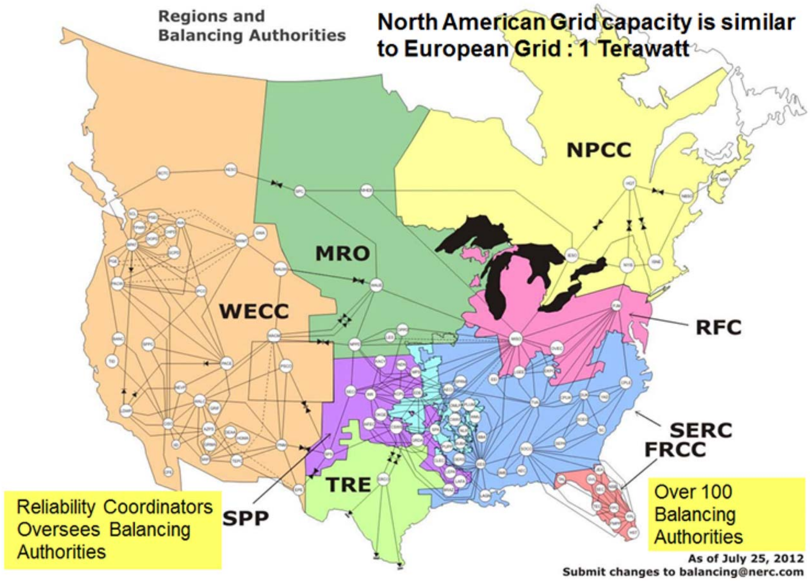

Fig. 1. North American Electric Power Grid. Adapted from http://www.ferc.gov/market-oversight/mkt-electric/nerc-balancing-authorities.pdf

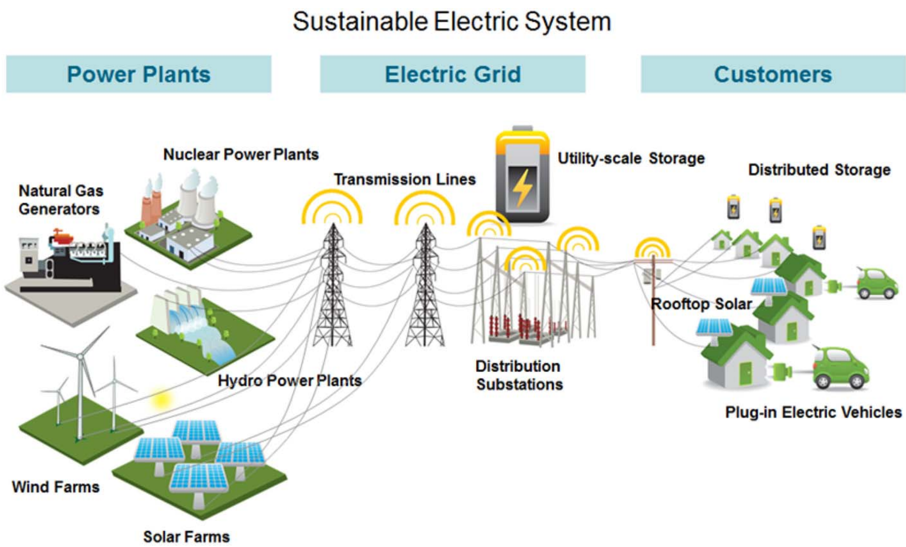

Fig. 2. Evolving sustainable electric power system [1].

the DA requirements and business case needs, which are discussed in a separate paper by the same authors.

II. Challenges

A. Integration of Distributed Energy Resources (DERs)

The integration of DERs has policy, standards, and technical implications that continue to present challenges to stakeholders tasked with developing a DA strategy that can be applied systematically to leverage efficiency in the implementation and benefits of standardization. For this paper, we define DER as consisting mostly of rooftop solar photovoltaic (PV) and diesel generators (30 kW capacity or smaller) at residential or commercial sites and as power sources for microgrids. A DER in this context may or may not inject power to the grid to which it is interconnected. Energy storage in thermal and electro-chemical form is also on the rise in residential and commercial settings. Fuel cells, while largely nascent, may well become a key DER. In contrast, wind turbines typically are employed in farms at utility-scale and feed directly into the transmission system, presenting challenges to long-term planning and scheduling and market influences that are outside the scope of this paper.

Whether the utility/grid operator owns the DER in question may be relevant to its DA strategy. When a DER is owned by the utility/grid operator, it can be configured for minimal impact on current operations and, clearly, its future applications can be planned. But a utility must be prepared for grid-connected DERs that are not under its direct control. From the utility/grid operator perspective, a DER does not contribute to system capacity. It is largely nondispatchable, so it is not available for frequency control. Still, DERs can contribute to capacity deferral.

Policies that encourage solar PV uptake by customers can create challenges. In the European Union (EU), a homogenous DER policy has led to widespread uptake of rooftop PV and useful capacity deferral that serves system constraints and environmental goals. Yet, the EU directive [8] requires that private owners enable/employ reactive power technology to counter solar PVs effect on distribution feeder voltage volatility and other impacts.

In the United States, in contrast, distribution system policy is determined at the state level, which has resulted in a patchwork of policies with which utilities with multistate service territories must contend. For example, in California and Arizona, the PV-integration policies have led to uptake clusters that may cause voltage volatility on specific distribution feeders, undue wear on mechanical protection and control devices, and lower the volume of residential power sold [9]. These scenarios might benefit from volt-var optimization/control strategies, including conservation voltage reduction and integrated volt-var control (IVVC). In contrast to the EU, in California and Arizona, the onus for mitigating distribution system impacts is placed on the affected utility [10]. Government policy changes at the state level might create a more equitable and predictable scenario upon which to base DA strategy.

A third example is Australia, where a pro-DER policy [11] was promulgated without utility input, resulting in technical considerations and unintended consequences—including the death spiral of high solar PV uptake, a subsequent drop in demand and rate increases and/or higher network charges, which encourage even greater solar PV uptake and result in consumer hardship [12]. Energy storage technologies may empower customers with solar PV to engage in price arbitrage, further weakening incumbent utilities' business model.

In summary, control and maintaining system reliability on a distribution network populated by high DER penetration has created challenging opportunities for the society as a whole. The Australian example, in particular, underscores how policy and technical challenges can undermine the business case for investing in DA.

B. Energy Storage Planning and Implementation

Energy storage is a technology option to mitigate the intermittent output of PV. Energy storage (electro-chemical, thermal, and mechanical) integration planning and implementation is also subject to policy, standards, and technical issues. Thus, how energy storage is implemented, owned, and administered has implications for DA strategy and its business case.

Fundamentally, energy storage decouples generation and its associated delivery system from load by time-shifting energy, whether that's measured in minutes, hours, or days. Potential benefits of energy storage include load shaping, peak load deferral, supplementary or backup power, power arbitrage, voltage control, and frequency regulation. The business case for energy storage on the distribution system typically relies on its simultaneous or sequential roles in multiple, potentially diverse applications, such as those just mentioned. These conditions for the rational use of energy storage present an array of policy and technical challenges.

In many cases, stakeholder concerns over energy storage have remained unresolved to date. For example, policy-level decisions are needed to address costs, benefits, and ownership among all stakeholders and to support the related investments. Technical challenges include the fact that storage's multiple roles might require significantly different characteristics. Orchestrating storage's multiple, diverse applications in a manner that justifies its still-considerable costs remains a challenge. Efforts on standardization and interoperability are ongoing.

C. Interfacing With Transmission Systems

Historically, transmission and distribution systems have been treated as two different entities though they are electrically connected as one power system. From the public policy and regulatory standpoint, transmission and distribution systems often are also independent entities, based on different views of system reliability, planning, and operations. For example, in North America, oversight of transmission reliability and compliance is under the purview of the North American Electric Reliability Corporation. In contrast, distribution system policies are promulgated closer to the consumer, at the state level. Operationally, the bulk generation and transmission parts of the power system are treated as one entity. Managing this entity has resulted in the development of energy management system (EMS) in the 1970s. Modern EMS functions provide all the automation tools required for the operators to manage the bulk systems in real-time to provide the utmost reliability and efficiency to customers. Similarly, the development of distribution management system (DMS) has been in place since the 1980s.

Since the mid-1980s, the landscape begun to change again with the restructuring of electricity system and markets [13]–[15], followed by the infusion of new technologies such as sensors and DERs. New opportunities have arisen where modern distribution systems have acquired characteristics similar to the bulk power system, including the bi-directional flow of power with mesh and loop topologies. A natural question arises whether the transmission and distribution systems should be treated differently. With bi-directional power flows between distribution and transmission, it will make sense to leverage lessons of the past in various engineering, system modeling, and operation aspects where applicable.

D. Natural Disasters and Their Influences

The effect of natural disasters on critical infrastructure has become an important consideration for many load serving entities. Extreme weather events such as tsunamis, monsoons, hurricanes, large-scale fires, icing, and tornados can destroy equipment and lead to major blackouts, which are costly to restore and/or rebuild the system [16]. Each year, these events inflict significant damage to power infrastructure across the globe, severely impacting customer service. Modern weather forecasting often provides advance warning of impending extreme weather events. Taken together with the historical record, this allows utilities/grid operators to plan infrastructure redesigns to prevent predictable damage. Such redesigns, for example, include undergrounding feeder circuits (versus overhead lines) or building redundant/diverse communication paths (where feasible and practical) to help improve system reliability and minimize service interruptions. Many power service providers now evaluate the cost of emergency system rebuilds versus the cost of designing more reliable, resilient systems in the face of historical trends.

The adoption of new technologies, like automated system restoration can assist in improving distribution system service reliability. This approach has its limits. Weather-related damage can not be avoided entirely due to its very nature. Yet, the integration of a weather-prediction system with a substation automation system and at the DMS center may assist in a timely response to rapidly changing weather conditions like microbursts or tornados [17]. Some utilities are exploring the deployment of commercially available weather sensors. These types of solutions, however, require a holistic approach as a part of an integrated system for protection and control to avoid data exchanges between disparate systems that are expensive and difficult to manage.

A weather prediction system specifically designed for wind speed and cloud-cover forecasting can also help forecast the output from renewable sources like wind turbines and solar PV and assist in system control. Looking ahead, greater coordination between utilities and weather-prediction organizations such as the National Oceanic and Atmospheric Administration in the U.S. will pay dividends. Variables in short-term forecasting can include asset level (the height of potentially affected assets), low resolution (1–2 kilometers' radius of expected impacts area), and short windows (15–60 min warning) for weather-related predictions. Longer-term forecasts (24 h to 7 days) will allow assets deployment to counteract weather-related impacts on customer service reliability.

E. Global Perspectives

Critical challenges faced by legacy power system infrastructures have been discussed in earlier sections. Greater emphasis on and the active role of demand-side entities in technical and market-based activities, as well as deployment of advanced situational awareness over the system and components, are needed. Damages due to common threats such as physical security compromises or vandalism losses are also a key factor.

As smart grid technologies are deployed, more distribution networks acquiring automation and resilient operational strategies are being applied. Many DA projects are undertaken worldwide, across the Americas, Europe, and Asia [18]–[25]. Taken together, these projects are difficult to generalize, due to their relatively unique local characteristics. Indeed, general prescription for DA implementation across the world is a challenge. The only certainty is that most utilities/grid operators in both developed and developing countries are proceeding with DA implementation. Electricity service providers will need to develop infrastructure and distribution system automation strategies and roadmaps for the respective systems based on local factors such as reliability requirements and concerns, age and condition of components, grid configuration and loading requirements, existing protection and control equipment, public policies, and economic resources. A successful DA implementation requires the integration of hardware facilities, software applications, and communication technologies, to name a few factors.

Although it may not be possible to prescribe or generalize a universal successful DA strategy, rapid DA deployments worldwide have taught some lessons.

1) DA requires the installation of a huge number of low-cost sensors throughout distribution substations and feeders. The number and location of sensors should be optimized, subject to budgetary limitations, automation aims, and communication facilities. A similar concern applies to other associated devices, e.g., remote-controlled switches.
2) A communication system is the backbone of automation. It must be secure and reliable, with sufficient speed and bandwidth for all projected needs. Reliability and security are particularly important with regard to communication systems involving third-party providers.
3) Interoperability based on standards is crucial for a system dependent on devices from various vendors, and for scalability.
4) Data management must be addressed. Data management encompasses big data-handling, data validation, and archiving, bad data detection and rejection, time synchronization concerns, data confidentiality and sharing, and other issues.
5) Most DA software applications are system-wide and operated in distribution system control rooms, though distributed intelligence also is needed. The operation of microgrids as a form of DA remains technically challenging, although effective hierarchical control algorithms have rendered promising outcomes.
6) Cyber security for the distribution system and protecting customer privacy must be maintained as new technologies are adopted.

These challenges have been addressed in a variety of pilot installations, which have yielded best practices and lessons learned that can be applied to system-wide deployments. DA projects continue to benefit from ongoing technological advancements. More investment and research are required to develop advanced DA-related functions and applications.

III. Opportunities

A. More Investment

Strategic DA investment includes value efficiency and flexibility to support future functionality, while leveraging installed systems to minimize stranded assets. There are no easy, inexpensive, one-off wins in a smart grid roadmap. For instance, lessons learned from many recent implementations have underscored the arduous, expensive efforts required to integrate AMI with DA technologies. Many of these pilot implementations have been co-funded by the U.S. Department of Energy under the American Reinvestment and Recovery Act [26].

To generalize, the findings of these projects suggest that a holistic approach, with strategic investments made in an orderly, well-considered series of steps, should provide the foundation for realizing broad benefits from a DA strategy. Because smart grid innovation in general, and DA in particular, affects other systems and drives changes in business processes, the value of a holistic approach cannot be overemphasized—particularly as it relates to rationalizing investments. In fact, holistic thinking is inseparable from a strategy for DA-based on a positive business case. Benefits and costs that can be widely shared across a utility organization, for instance, improve the business case, and the regulatory reception to it.

Holistic thinking about DA-related investments also recognizes that foundational investments must sometimes be made without immediate, full benefits, in order to enable broad benefits in the future. For instance, roughly half of the 48 000 distribution substations in the U.S. have no automation. Yet, investment in substation automation is fundamental to enabling situational awareness and self-healing technologies on the distribution system that directly affect reliability indices and key performance indicators.

Substation automation typically occurs in steps: installation of intelligent electronic devices (IEDs), which support three functional data paths—operational, nonoperational, and remote access. Integrating IEDs with both central and distributed intelligence, taking advantage of the IEDs' two-way communications capabilities, is essential to realize their full value. This requires determining which applications to run at the substation level to optimize its operation and that of downstream, distribution feeders and which applications should run at the central control facility. The potential redundancy inherent in enabling the choice between central and distributed intelligence itself offers improved flexibility and, thus, increased value for the investment.

B. Resilient Transmission and Distribution System

The need for system resiliency has become critical following several recent natural events, which had dramatic impacts on consumers and inspired a new view of power infrastructure. But natural disasters are only one major cause of high-impact outages; human-caused outages remain an issue. In December 2005, IEEE Spectrum published a summary of wide-spread blackouts around the world not caused by natural disasters [27]. To this list, we may add two more outages, whose scale was unprecedented: in 2009, an outage in South America impacted 87 million people, and in July 2012, two outages in India each affected nearly 40 GW of load.

The development of a resilient grid is a paradigm shift which requires a new line of thinking in the engineering, operation, and maintenance of the grid. Developing resiliency also requires significant investment in infrastructure, testing methodologies, and human resource investments for life cycle support. Fortunately, infrastructure development introduces new opportunities for developing and testing emerging technologies, like active distribution planning with demand-side resources [28], including cross-sectional training of resources to design, produce, install, operate, and maintain new equipment and systems. Given the imperatives to improve reliability and resiliency, it is equally important to rationalize the investment for infrastructure improvement.

C. Improvement of Reliability Indices

DA technologies can positively impact traditional reliability indices such as system average interruption duration index (SAIDI), system average interruption frequency index (SAIFI), customer average interruption duration index (CAIDI), and momentary average interruption frequency index (MAIFI). The application of DA technologies offers utilities the capability of restoring service to customers on the healthy portions of a feeder in under 5 min. This capability improves SAIDI, SAIFI, and CAIDI scores in the U.S. while the momentary service interruption does impact MAIFI. Utilities gladly accept this compromise because of fines and/or regulatory good standing focus more on SAIDI, SAIFI, and CAIDI scores.

A holistic DA system contains many components: a DMS [29], an outage management system (OMS), a geographic information system (GIS), a customer information system, AMI, and others. A suite of applications is run on the DMS for system protection and control including service restoration following a disturbance. A DMS, that receives meter data, can address voltage and reactive power (var) fluctuations. DMS, integrated with a supervisory control and data acquisition (SCADA) platform, can support advanced applications. An OMS hosts the network model (populated by GIS data on utility assets) that provides insights on affected customers. The OMS typically has three sources of input: 1) phone calls from customers; 2) change of status from the DMS, following a feeder breaker outage notification; and 3) social media driven by customers. The third input can contribute to improved reliability indices in the presence of DA, to some extent as a simplified substitute for AMI. Without a smart meter's last gasp communication, a utility must rely on other sources of information to know that a customer has lost power. Encouraging customers to inform the utility, via social media, that an outage has occurred and the ability to accompany it with a geo-tagged photo of the cause, when possible, can help define the location, nature, and extent of the outage, speed the utility's response, and allow it to send a field crew properly equipped to address the specific cause. Properly integrated, this suite of technologies can move the needle on reliability indices and produce value.

D. Demand Response (DR) Implementation

DR programs alter the amount and/or profile of energy consumption with the objective of social or customer benefits. DR has a long history, primarily applied at the transmission level and associated with bulk industrial consumers. These types of DR programs have typically supported the system operating reserve requirements. Today, however, emerging DA tools can implement DR schemes at the distribution level and allow the diverse loads and business models of residential, commercial, and small industrial end-users to benefit from the DR programs. Embedded digital systems along with affordable communications infrastructures have enabled distributed intelligence on the demand side.

DR takes two basic forms: 1) price-based; and 2) incentive-based [30], [31]. In the price-based approach, the end-user becomes aware of electricity price, either in real-time or ahead of time, through direct communication with supplier or the utility, which enables the end-user to make intelligent decisions about energy consumption. The consumption details may or may not be available to the distribution system operation center. Price-based DR programs are based on the economic objectives of end-users—the natural response to expensive peak-time prices is to reduce electricity consumption which also tends to reduce system-wide revenues. Incentive-based DR programs (synonymous with direct load control technology), refer to the voluntary participation by end-users in allowing utility control of some appliances in exchange for tariff discounts or other monetary incentives. A load control switch installed at the end-user location is the agent for connecting appliances to the control center and applies commands from upstream. This type of DR triggers the prompt participation of demand-side entities, offering the utility both short- and long-term advantages. The utility can also avoid peak-time penalties by effective dispatching of controllable appliances. In fact, load control capability is important for the operation of an islanded microgrid, where the generation resources are limited and inherently intermittent. In longer-term horizons, effectively utilizing available generating resources can defer the expansion of capital-intensive peak generation support resources.

Both types of DR program call for DA facilities, but at different levels and for different goals. In price-based DR, DA is needed to transmit price signals and possibly the demand schedules between the system operator and end-users. In incentive-based DR, DA conveys the willingness of end-users to participate in DR programs to the system operator and enables the utility to be aware of the status of affected appliances and determine whether to turn them on or off. In both DR programs, automation systems play key role. For example, in price-based DR, activating and aggregating the potential responses of small end-users is critical. Likewise, for incentive-based DR, control of modest loads dispersed over a vast area requires system-level automation.

DR expansion requires sufficient incentives for customer participation. Electricity typically is priced based on cost, but not on its value. The value of electricity, however, is different for different customers. Thus, a reexamination of pricing strategy can help drive DR program participation.

E. Sustainability and Energy Efficiency

Concerns over environmental sustainability and capacity issues have influenced the policies to expand the deployment of the renewable energy resources at the distribution level. The major distinction between traditional generation and sustainable renewable resources generation is the variable and intermittent nature of the latter. The difficulties that accrue from intermittent generation could be partly overcome by the geographically distributed generation units, the integration of energy storage equipment, and the application of quick-ramping gas-based generating stations. When intermittent resources impact network frequency/voltage control and stability, however, the implementation of DA technologies can help. The uncertainty and intermittency of renewable generation units reduce security margins and force operators to utilize more effective monitoring and control algorithms enabled by DA systems. As hundreds of such units would be dispersed in networks, their control and monitoring should be effectively designed in a decentralized manner. Yet, a high penetration of distributed, intermittent generation units can lead to bi-directional power flows, which in turn require more advanced protection systems.

The intelligent control and operational resiliency provided by DA technologies significantly improve distribution network efficiency. In an automated environment, the system operator can optimally adjust the network configuration subjected to the associated scenario outages, physical and regulatory limitations, and load distribution. Typically, minimizing distribution network losses is the goal of optimization efforts. DA and reactive power compensation diminish the reactive component of currents, as far as possible. Although the amount of energy savings may appear minimal in the short-term, energy savings over a longer period could become significant.

New pricing strategies based on a fresh look at energy valuation, in light of DA technologies, could decrease energy waste on the demand side. This is especially true in developed countries, where electricity is relatively inexpensive and consumers have yet to compare that cost to the cost of other essential commodities. The availability of energy efficiency-related products such as advanced LED lighting systems, variable speed motor controls, and more efficient cooling and heating systems might help consumers embrace utilities' energy efficiency goals.

IV. Industry Standards and Issues

Technology, policy, and standards comprise the three legs that support smart grid in general and a sound DA strategy in particular. Standards and guides applicable to DA strategy are evolving for DER integration, interoperability of storage, protection, control, and communication. In this section, we are focusing on four distinct technical challenges related to the integration of DERs. The interconnection between a grid and DER is governed by a finite number of industry standards development organizations, including the IEEE, Underwriters Laboratories, and the International Electro-technical Commission.

The IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems, published in 2003, is most pertinent to DA [32]. IEEE 1547 describes a uniform set of criteria and requirements for interconnecting DERs to the grid, including operations, maintenance, testing, and safety. Utility/grid operator concerns over the following related issues are driving further work on IEEE 1547.

A. Anti-Islanding

Anti-islanding detection is intended to prevent impacts from a generator into the power system during faults or other major abnormal conditions. Synchronized generators that fluctuate with intermittent DER can lead to voltage instabilities, requiring the utility/grid operator to install costly capacitor banks, and voltage regulators. Controlling the impact of DERs on a distribution system circuit can be hampered by a lack of utility/grid operator visibility into customer-owned DERs, affecting both parties' operations. IEEE 1547s anti-islanding provisions originally were written to prevent unintentional islanding of a grid-connected DER. Separate language is provided in the standards for intentional islanding. Ongoing revisions to IEEE 1547 will clarify distinctions between the two.

Anti-islanding, a crucial component of distribution protection system, will remain a component of an amended IEEE 1547. Originally, however, IEEE 1547 encouraged very sensitive trip-off settings. Standards-compliant, grid-tied DERs typically shut down automatically when an outage occurred, to prevent unintentional islanding. But sensitive trip-off settings meant that a minor fault could lead to DER deactivation. Given high DER penetration, however, hair-trigger settings for anti-islanding can lead to problems for both the utility/grid operator, in terms of voltage and system frequency instability, and customers running a DER, in terms of premature activation of backup generation. Draft amendments to IEEE 1547 would allow a wider ride-through tolerance, so a DER continues generating power despite frequency fluctuations on the grid. IEEE 1547 amendments also will probably include provisions designed to enable intentional islanding, where island-able DERs are designed to function both connected to and disconnected from the grid.

The crucial distinction between anti-islanding and intentional islanding is that once a system is intentionally islanded, anti-islanding requirements no longer apply. An islanded DER system, disconnected from the grid, no longer presents a safety concern. IEEE 1547.4 will contain recommended practices for intentional islanding. IEEE 1547.8 will also address the functionality of DER such as microgrids, which are designed to be intentionally islanded.

B. Fault Current Contributions

Not all synchronously connected distributed generators have protection equipment in place to minimize damage due to short circuits in distribution systems. The best practices for ensuring standards compliance and proof of reliability and interoperability, described earlier, are applicable concerns. And new testing methodologies and simulation tools can swiftly establish the value and safety of new technology. Recently developed, affordable DER interconnection technologies and controls are being pilot tested to determine proper isolation of the DER following a fault on the distribution system.

In the islanded mode, the resulting fault currents could be very close to steady-state currents (e.g., about 0.8–1.5 per unit) from voltage-source inverter-connected devices, such as battery-based energy storage systems and PV panels that are often the dominant sources in low- and medium-voltage microgrids. This type of fault is similar to a high impedance fault that occurs in traditional distribution grids. Therefore, the number of high impedance faults will dramatically increase, which poses protection and automation challenges.

C. Voltage Instabilities

Voltage instabilities can occur when synchronized generators fluctuate to follow microgrid loads or when intermittent renewable energy resources such as solar PVs ramp up or down based on sunshine or cloud cover. Managing these instabilities might require capacitor banks and voltage regulators, which may be costly considering life-cycle upkeep. The IEEE 1547 (IEEE P1547a) describes use of inverters to provide voltage compensation. The IEEE 1547 working group is in the process of addressing practices relating to abnormal voltage and frequency conditions resulting from DER interconnections.

D. DER Control Limitations

The standards amendment process is also expected to address the lack of visibility that a utility/grid operator has into DERs owned and operated by customers. The lack of coordinated supervision and control can lead to sub-optimal operations for both parties. While standards typically address interconnection requirements, policies may have to address the utility/grid operator's costs resulting from DER-driven voltage instabilities and encourage customer- and/or third-party cooperation in providing utility/grid operator visibility into variable DERs.

V. Conclusion

The distribution system landscape has been transitioning for some time. Rapid changes in the distribution system require a new line of thinking for engineering and managing operations. They also introduce many new challenges to policies, operation, maintenance, protection, and control from inception to life cycle support. The development of a resilient grid to meet public, regulatory, and overall requirements is a paradigm shift which must be met with new strategies. DA is a key ingredient for fulfilling those requirements and developing new strategies.

International perspectives on DA reflect that one solution will not fit all circumstances. Different countries may adopt different models based on their socio-economic situations and social priorities. Integrating technical, business, and policy decisions is necessary to facilitate the development of technologies, standards, and the implementation of cost-effective solutions.

Evolution of technologies and the business case for DA are explored in [33].

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