ELECTRIC POWER RESEARCH INSTITUTE

Next-Generation Grid Monitoring and Control

Toward a Decentralized Hierarchical Control Paradigm

Technical Brief

Introduction

Electricity is essential for the modern way of life. The transmission system (the grid) plays a vital role in connecting electrical energy resources to electricity consumers—so its reliability is extremely important. Equally important is its sustainability from all aspects: economic, environmental, safety, and security. Since its inception, grid infrastructure planning, financing, building, and operation have served modern society well. For nearly this entire period, affordable electrification has been based on economies of scale—with large thermal generating plants or huge hydropower plants generating electricity, and transmission grid and distribution systems delivering it to the end users. The infrastructure is designed for reliability using planning criteria. Operational issues and to a large extent operational efficiency are managed by the centralized monitoring and control systems operated by power control centers (PCCs). However, recent changes and trends in electrical energy—both on the generation side, with increasing levels of electricity generation from renewable energy sources such as wind and solar, and on the energy consumption side, with new and more efficient consumption technologies—are changing use patterns and dynamical characteristics of the entire infrastructure. To maintain reliability, these changes will require changes in monitoring, associated analytics, and control of the grid.

This white paper summarizes present state-of-the-art grid monitoring and control technologies, presents expected challenges resulting from emerging trends and transformations in the power system, and discusses desired capabilities and potential benefits of a decentralized hierarchical grid control paradigm that comprises a combination of local-distributed and wide area–central controls.

State-of-the-Art Grid Monitoring and Control

Power system control refers to maintaining system frequency, voltages, and current flows in system elements within acceptable limits as well as operating the system so that it remains stable and within its applicable operating limits following credible system contingencies. Controls can be further divided into *primary* and *secondary* controls.

Primary controls usually consist of fast, closed-loop feedback controls typically relying on local measurements. Synchronous generators' automatic voltage regulators (AVRs) and governor controls are classic examples of primary controls. On transmission systems, static VAR (volt-ampere reactive) compensators (SVCs), static synchronous compensators (STATCOMs), and load tap changing (LTC) transformers are other examples of equipment on which primary controls can be implemented. These controls are generally based on local measurements and sensors and therefore do not have wider area observability. The control actions are also autonomous, and coordination is usually ensured only at the design and implementation stages. Finally, the control range is limited to equipment capabilities.

Secondary controls are usually deployed from PCCs to manage the operation of the interconnected power system; frequency regulation through automatic generation control (AGC) is a classic example. PCC provides situational awareness to the operators with analytic tools that use measurements and equipment status information from the wide area monitoring system. Control centers also enable operators to switch equipment in or out of service to control voltage and power flows as needed to maintain reliability.

Another aspect of power system control is protection. Protection systems must be reliable, secure, and well-coordinated to avoid cascading system failures. Protection is primarily associated with disconnection of the least number of elements to clear faults or short circuits in a very short time and, in many cases for overhead transmission elements, reconnecting them automatically because most of the faults are temporary. At extra-high voltage (EHV) transmission levels, faults are typically sensed and cleared in three to four cycles. The protective relays are physically located at substations, controlling opening and closing operations on circuit breakers to disconnect (trip) or reconnect (reclose) transmission elements. Most protection schemes use local measurements, which cannot address the entire power system that may be affected by a disturbance. At higher voltages, several protection schemes communicate using supervisory logic based on measurements from the far-end substation of the transmission element.

With a system integrity protection scheme (SIPS), system information from both local and remote sites is sent to a central processing location to avoid cascading outages in the power system. SIPS is typically applied to strategic areas of the system in which system protection is of concern. SIPS helps preserve the overall system stability, maintain system connectivity, and/or avoid severe equipment damage and therefore requires multiple detection and actuation devices as well as communication facilities. Advanced detection and control strategies through the concept of SIPS offer a more integrated approach to disturbance management. These advances may encompass improvements building from advanced computing, better communication, and more accurate and higher resolution measurement technologies—which help improve overall system performance.

Electric power grid monitoring and control functions on a networked system basis are performed by PCCs. PCC technologies mainly consist of supervisory control and data acquisition (SCADA) and energy management systems (EMSs).

SCADA System

SCADA provides two functionalities:

- **Data acquisition.** The data acquisition system collects and transmits to PCC measured data of electrical quantities (voltages, currents, and real and reactive power flows) at substations. It also collects and transmits equipment status changes such as opening and closing of breakers, operations of relays, and so on. Measured data are typically reported every 2–10 seconds depending on the polling cycle. Equipment status changes and malfunction alarms are usually reported by exception without intentional time delays.
- **Supervisory control.** Transmission equipment (mainly in the substations but, in a few cases, on lower voltage transmission lines) under supervisory control can receive control signals to open or close from the operators at the PCC.

Energy Management System

An EMS consists of computerized analysis and control systems as well as visualization applications that help operators maintain reliability and efficiency of the grid. It performs the following main functions:

- **State estimation (SE).** Using measured data, equipment status information, and the network models, SE estimates voltage magnitudes and angles at all the network buses and real and reactive power flows in the transmission system elements as well as any real and reactive power injections at the transmission buses. SE's main functionality is to reconcile variations in measurement accuracies and estimate some of the unmeasured or unreported states. The results of the SE are used to alert system operators to any violations of system limitations or system operating criteria, such as overloads, voltage violations (higher or lower than desired), power transfer limit violations, and so on. SE provides a system model that is used as an input for several additional EMS functions, including network security analysis and market management systems.
- **Situational awareness.** Visualization applications provide equipment status and other operational data to the operators either from measurements or from estimation. System operating criteria violations, changes in system status (for example, opening and closing of breakers), equipment alarms, and relay operations are displayed, and visual and sound alarms are provided so that operators can take corrective action as needed.
- **Security analysis.** The purpose of security analysis is to evaluate the security of the system for any potential contingencies (such as a line or generator outage) or changes in operating condition (such as in the power transfer pattern). Security analysis starts with the results of the SE mentioned previously. Real-time contingency analysis (RTCA) is performed every 1–15 minutes (depending on the entity) to identify any potential problems in operating the system under what-if scenarios that include potential contingencies (that is, facility outages) or changes in power transfer scenarios. To operate the system, operators use the RTCA results along with any predetermined operating guidelines designed to address specific operating conditions.

Operator actions could include power transfer curtailment, generation change, switching in or out of equipment, or change in voltage setpoints. In some PCCs, additional security analysis (referred to as *dynamic security assessment*) for voltage and angular stability analysis is performed using near-real-time operating conditions to establish operating limits and provide better situational awareness to the operations staff.

- **Automatic generation control.** AGC manages the required power output of generation units within the control area. It uses real-time measurements such as frequency, actual generation, tie-line load flows, and plant units' controller status to provide generation changes. The two main functions implemented by AGC are load frequency control (LFC) and security-constrained economic dispatch (SCED). LFC function assists in the interconnection frequency regulation and helps maintain a close match between actual and scheduled interconnection tie-line flows into and out of the LFC area in near real time. LFC gathers data to determine frequency and interchange deviations. Deviations in the net interchange flows as well as control area's share of real power in the interconnection proportional to the frequency deviation from the nominal frequency are combined to compute an area control error, or ACE, signal. The ACE signal is used to adjust output levels of the generators in the control area that are participating in the regulation. The SCED system determines economic generation levels from generators in the control area every dispatch cycle (5–15 minutes) required to serve the projected load within the dispatch period without violating any transmission constraints under the operating criteria contingencies. AGC provides desired output levels to each generator in its control area based on LFC and SCED requirements.
- **Synchrophasor technologies.** Many systems have also deployed synchrophasor monitoring, and online applications using synchrophasor measurements are being developed and demonstrated. These include wide area voltage angle monitoring, monitoring for oscillations and damping, and detecting islanding conditions. Several synchrophasor applications are stand-alone applications in PCCs but, in a few cases, are being incorporated into EMSs.

Emerging Trends/ Changes Transforming Resources and End Uses

The current grid monitoring and control technologies—SCADA and EMS—have served the electric power systems and society well over the last 50+ years by improving and maintaining system reliability and economically dispatching large generation plants. The communication and computation technologies that are the foundation of SCADA and EMS have improved tremendously over the years, and PCC technologies have had corresponding advances in improving situational awareness, managing reliability, and optimizing dispatch of resources. However, their basic functions and control architecture have remained the same.

Recently, several technological, societal, and regulatory/policy developments regarding where and how electricity is generated and how it is consumed are complicating this simple structure. As a result, the grid's role, its utilization, its dynamical behavior, and ultimately how it is maintained and financed are expected to change drastically. Following are some of the key developments and changes:

- **Renewable generation.** Growing high penetration of renewable generation, which has several distinctly different characteristics compared to conventional thermal or hydro synchronous generators, presents new challenges. The variability and uncertainty of wind and solar generation—and the inverter interface through which these resources interconnect to the grid—create new challenges for the way the grid is presently planned and operated.
- **Distributed resources.** Increased deployment of large amounts of small renewable and other generation technologies interconnected on the distribution systems also presents challenges to the reliable operation of the bulk electricity transmission system, primarily because of the lack of visibility and control presently achievable with existing infrastructure. Traditionally distributed systems have been composed of loads with limited monitoring. With the advent of distributed generation, new challenges such as reverse power flows and danger of formation of active power islands have made monitoring of the distributed system essential.
- **Demand variability.** Behind-the-meter generation may not be the only factor affecting variability in the demand. Rate incentives, smarter loads, and so on make forecasting and predicting demand in long-term planning and in operational time frames challenging.
- **Electrification.** Large sections of economy, such as transportation and heating, are expected to be switching to electrical energy from the current fossil fuel consumption. Electric vehicle (EV) technology has been quickly evolving in the last five years, with the drive range increasing and the cost of batteries decreasing.
- **Energy efficiency.** Efficiency driven by product innovation and policy incentives has been drastically reducing electrical energy use as well as demand. For example, with compact fluorescent and, later, light-emitting diodes (LEDs), energy consumption for lighting has decreased by 75% compared to that in 1990.
- **Demand response.** Demand response provides economic incentives to curtail demand to the end-use customers, in many cases through

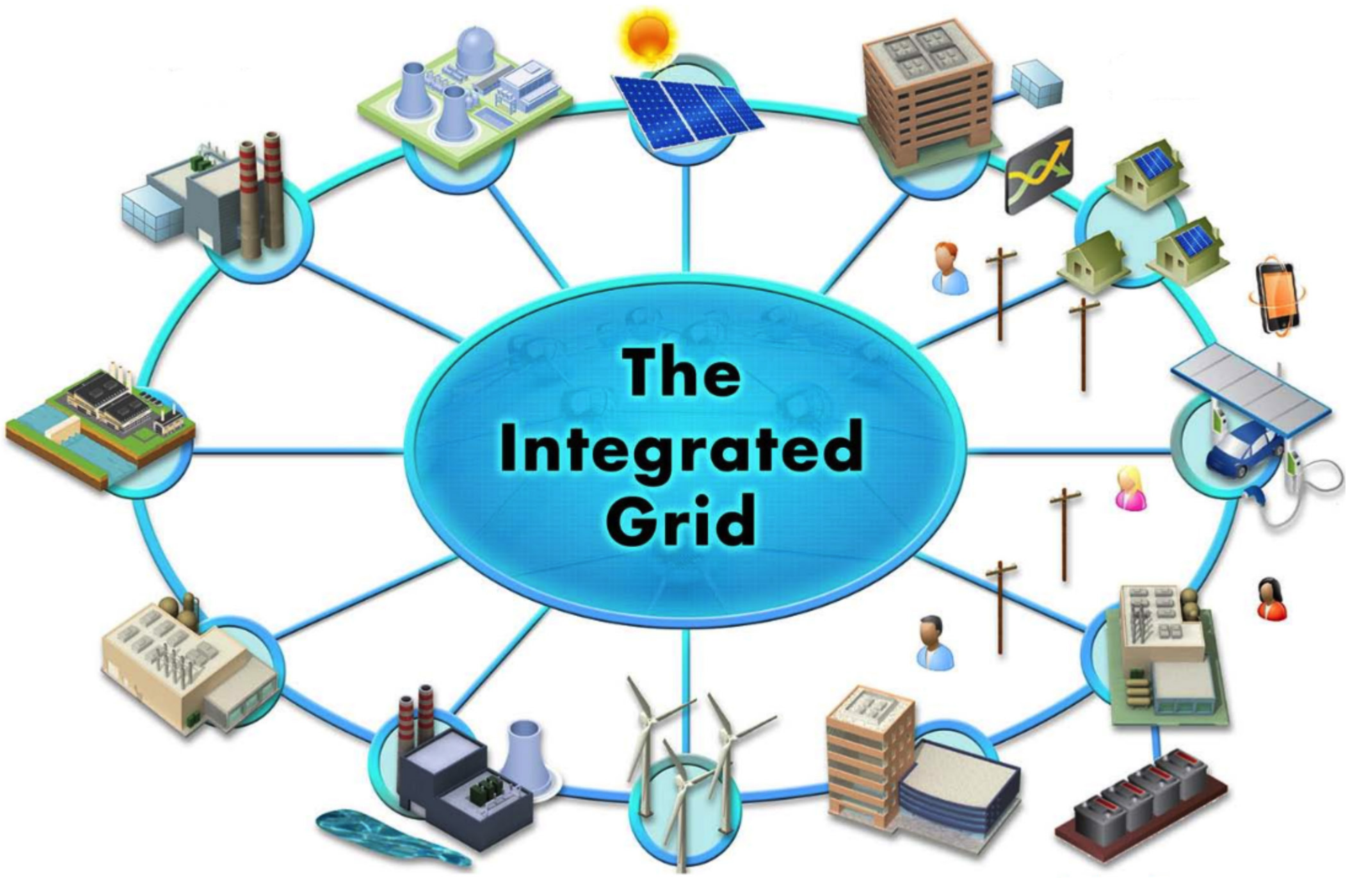

Figure 1 – The emerging integrated grid

aggregators for smaller loads. For utilities, demand response that is dependable, predictable, and visible would be valuable for longer term resource adequacy and as a valuable tool to help maintain real-time operational reliability. In practice, as with any other markets, consumer demand response to price is essential to efficient and competitive market outcome. Demand-managed curtailment service providers (CSPs), integrated into wholesale markets, have been maturing in the United States.

Net Effects

The factors just described all change the physical characteristics of the grid as well as its utilization leading to an integrated grid (see Figure 1). Following are some of the net effects of these changes in resources and end uses:

- **Stochastic nature of generation and demand**. Renewable generation from wind and solar is weather dependent. In addition, generation interconnections are distributed along the transmission and distribution systems. Net demand is also expected to fluctuate based on behind-the-meter generation, varying price sensitivities among customers, and different levels of efficiency and other technology adaptations. All these factors contribute to the stochastic nature of generation and demand.
- **Large numbers of small resources.** The generation infrastructure is transitioning from the traditional paradigm of a relatively small number of large (500–2600 MW) central power plants to numerous small (kW size to 100 MW) distributed resources across the transmission and distribution system.
- **Reduced system inertia.** Renewable resources as well as many loads are being interconnected to the electrical transmission and distribution systems through inverters, resulting in lower system inertia. Even if the energy resource has rotating parts—for example, wind generation—inverters decouple the energy source from the rest of the grid. Other types of generation (for example, solar photovoltaic [PV]), are completely free of rotating parts—therefore, there is no physical inertia.
- **Large variations in short-circuit currents.** Inverter-based resources have unique short-circuit fault response characteristics that differ from those of traditional rotating machines in which the fault response depends on the machine's electrical characteristics. For inverter-based resources, the fault response depends mainly on the inverter control

strategy. Typically, the magnitude of the short-circuit current is limited to 110–150% of the rated inverter current to protect the inverter power electronics. The power factor of the fault current would vary depending on the inverter controls as well as interconnection requirements imposed by the grid operators, such as ride-through and reactive support during system disturbances. In addition, the availability of the fault contribution can be unpredictable depending on the pre-fault operating condition of the connected resource. When large portions of online resources are interconnected through inverters, the short-circuit current levels in the system will be low. When many conventional synchronous generators are online, short-circuit current levels will be similar to present values. Therefore, depending on the types of generation that are online at a given time, large variations in short-circuit strengths at various buses are expected.

- **Wide and fast variations in grid loading.** Power flow patterns on transmission systems will vary considerably, depending on the output of the renewable generation in different areas. Because weather conditions can cause renewable generation amounts to change drastically and quickly, power flows on the grid can also change in a short time. For example, areas with high solar PV penetration at the distribution level will have a small amount of load served from the grid, or feeders may be feeding back some power on the transmission grid. However, cloud cover (or sunset) will cause all the load in the area to be served off the grid, increasing grid loading to a much higher level in a short time.

Consequences, Challenges, and Needs

Changes and trends in the way electricity is generated and consumed—and the expected persistence and sustainability of those trends as well as their effects on the physical nature of the grid (for example, inertia or short-circuit levels) as well as grid utilization—can have profound effects on reliability and will require many resulting challenges to be addressed. Some of the consequences and challenges resulting from current changes are discussed next.

- **Forecasting.** The stochastic nature of electricity resources, rapidly developing technologies of generation and consumption, and the unpredictability of penetration levels will make it difficult to forecast generation and demand for long-term planning as well as shorter term operational planning. Several other external factors such as regulatory policy, government mandates and incentives, and changing weather patterns will also add to the complexities of this task.
- **Increased monitoring needs.** Large numbers of active resources and loads can have large and fast changes in their states and statuses and will require monitoring numerous control points at high resolution. Handling such large volumes of monitored data—from communications, archival, and analytical points of view—will also be a challenge.
- **Need for faster situational awareness analysis.** Changing states and the multitude of active participants on the grid will require faster analytics capabilities of tools that provide situational awareness as well as timely availability of the monitored data for such analytics.
- **Challenging voltage and frequency control.** Rapid and large changes in generation, demand, and loading levels on the transmission grid will make controlling voltage as well as frequency challenging. When massive distributed generation on distribution systems serve most of the load, the transmission lines will be lightly loaded. EHV lines will produce reactive power that is not consumed by the reactive losses on the lines, resulting in high voltages. When distribution-connected generation rapidly drops off, flows on the transmission lines may increase well beyond their surge impedance loading levels—causing high reactive losses and therefore large voltage drops, potentially causing low voltages. Switched shunt compensation and load tap changers are usually operated with long time delays to avoid too frequent switching operations. Their sizes also may not be adequate to cover extreme load level changes anticipated under heavy distributed energy resources (DER) penetration scenarios.
- **Need for faster and local controls.** Lower system inertia, many active players, and rapidly changing operating conditions may cause reliability and stability issues. Because such threats can manifest in a short time in which operator action might not be feasible, faster automatic controls would be required. In many cases, the time required for monitored data to reach the control center, systems to detect a reliability threat, and control action to be determined and implemented may be too long for the issue at hand. In such cases, local active controls may be required to maintain system reliability.
- **System protection.** Large changes in short-circuit currents from periods of operation with and without many resources interconnected through inverters during various operating conditions, the complex fault response characteristics of inverter-based resources, and rapid dynamic changes resulting from lower inertia will challenge system protection.
- **Cyber security needs.** As monitoring and control locations as well as communication systems used to transfer monitored and control data are increased, exposure to cyber security threats will need to be addressed.

Next Generation of Grid Monitoring, Analytics, and Control

Limitations of Present Grid Control Paradigm

The existing grid control architecture is built around centrality, on which basis all available information of current system states is collected and/or estimated at a single location (PCC). It also requires a priori information about the dynamic model of the system. Under the emerging grid operational characteristics and trends discussed previously, on a large-scale system over a large geographic area, a centralized monitoring and control system is expected to have high latencies associated with sensing and identifying a reliability threat and then computing and deploying control actions in a timely manner. System frequency, for example, is likely to be much more volatile because of low system inertia and rapid changes in generation and demand. In addition, many different control systems on resources and loads—and fast interactions among them—may cause system stability issues. Similarly, voltage stability issues can also develop at a faster pace, requiring fast remedial controls.

As mentioned, local primary controls are part of the existing control architecture, but they lack observability of a wider area. In addition, they are typically tuned based on specific scenarios using offline studies and so inherently are not adaptive and tend to be suboptimal for varying operating conditions. In most cases, the various local controls are designed and coordinated with other devices for expected operating conditions. In abnormal conditions, local controls may not work as desired and, in some contingency situations, may even exacerbate the problem or cause cascading outages. For example, during EHV conditions resulting from very light loads, a generator's AVR may try to reduce the voltage by causing the generator to absorb too many volt-amperes reactive (VARs), making the generator susceptible to oscillatory instability.

On the other hand, even if massive levels of monitoring and analytics to manage orders of magnitudes of higher numbers of dynamic states can somehow be addressed, PCC-based wide area controls will be unable to meet the speed of control actions required to mitigate disturbances and maintain stability mainly because of lower system inertia resulting in increased volatility.

These factors lead to a conjecture that the present state-of-the-art grid monitoring and control will not be able to accomplish the desired reliability and system efficiency, necessitating the search for new paradigms for grid planning, protection, monitoring, analysis, and control.

Desired Capabilities of Next-Generation Grid Monitoring and Control Paradigm

Having identified expected limitations in the existing grid monitoring and control architecture, the next steps involve identifying the desired capabilities of the future control paradigm and setting an action plan and roadmap to address them.

Data Acquisition and Handling

A major pillar of the next-generation grid monitoring and control infrastructure is the acquisition and handling of large amounts of data. *Data* here refers to both measurements and models.

Many critical applications for future grids would heavily rely on high-resolution, time synchronized measurements. With critical control applications, the reliability and validity of the measurements need to be ensured at all times. Measurement reliability can be ensured only if there is sufficient *redundancy*—the duplication of critical components or functions of a system to increase system reliability, usually in the form of a backup or fail-safe. Redundancy ensures that the core application and its functionality are preserved even when some measurements are lost (for example, because of measurement device, time synchronization/GPS, communications, or IT failures). In addition to redundancy, efficient bad data detection and pseudo-measurements make the estimation results more accurate and reliable.

When complemented with conventional measurements, synchronized measurements help enhance the redundancy of measurement data. For example, with regard to state estimation, some system operators and vendors have been exploring the potential to enhance redundancy by developing state estimators that combine synchronized phasor measurement unit (PMU) measurements with traditional nonsynchronized measurements from SCADA. These hybrid state estimators have the potential to offer not only enhanced redundancy, but also improved accuracy. However, they also introduce greater degrees of both computational and functional complexity because of the need to integrate and support both forms of measurements. Application of linear state estimators, in which only synchronized phasor measurements are used, is being explored in the industry. Linear state estimators have the potential to achieve highly accurate output results very quickly (they can potentially solve at the frame rate of the input data, for example, 60 Hz)—even if formulated as a three-phase linear state estimator. However, to achieve full system observability with acceptable levels of redundancy, the installation of PMUs must increase.

As the level of uncertainty rises for the grids of the future, measurement and estimation of dynamic states will also become a necessity. High-resolution, synchronized measurements enable dynamic state estimation (DSE) in power systems. For a robust and accurate DSE, advances are required in model estimation as well as SE techniques. For example, enhanced Kalman filter–based techniques have been proposed in the literature for DSE.

As discussed previously, grids of the future will look at distribution grids very differently from the distribution systems of today. With distributed generation connected at low voltage levels, it becomes imperative to ensure visibility down to the distribution level where traditionally there is limited monitoring. Because this will multiply extensively the amount of data, this visibility must be achieved without introducing excessive levels of complexity or detail. Distribution system SE is challenging because of the large number of nodes and limited number of measurements. Use of micro-PMUs is being explored in the industry for advanced distribution system monitoring.

In addition to electrical data, integration of other data types—such as weather—into operational models is expected to become imperative because of the increased levels of uncertainty in future systems as a result of increased renewable penetrations. Frequently, critical operational decisions in near-real time frames depend heavily on the forecasts themselves, and, in the operational time frame, uncertainty of forecast is primarily statistical. With increased solar and PV integration in the generation mix, dispatch and reliable system operation would need more accurate weather forecasts for system operators to stay prepared for any eventualities. Furthermore, given the lack of correlation between these sources of uncertainty (for example, wind and PV generation), multiple sources of uncertainty must be combined in an efficient and accurate way.

With respect to models and model management, to account for the impact of distributed resources to the transmission system, the aggregated impact of the distribution system must be modeled in an operations environment. To achieve this, new and advanced data aggregation and disaggregation capabilities would be required. In addition, with wide area dynamics spread to distribution levels, dynamic equivalents would become necessary—and efficient model reduction techniques will be solicited. Data/model aggregation and disaggregation will also be critical in performing distributed controls, because aggregated model information would have to be communicated among local and central controllers. Information and data transfer standards are being revised, and new data/information sharing protocols such as the common information model (CIM) are being researched.

As mentioned, data sits right at the heart of this digital transformation. Although organizations have long been constrained in their use of data—mainly because of incompatible formats, limitations of traditional databases, and the inability to flexibly combine data from multiple sources—grids of the future will require greater "data agility." This data agility will be essential when dealing with the more complex, multivariable problems that will be faced. Greater data agility requires more flexible databases and more scalable real-time streaming platforms. This requires efficient data processing architectures and potentially a comprehensive assessment and restructuring of how electricity companies obtain, process, store, and manage their data.

Data Analytics, Situational Awareness, and System Security Assessment

Assuming fast, validated, and reliable data, the next pillar of the next-generation grid monitoring and control infrastructure is data analytics. This will provide system operators with enhanced situational awareness and system security assessment for secure and efficient control of the grid.

As a result of the increased penetration of inverter-based resources, which introduce complex nonlinear dynamics because of the nature and operation of their individual converter controls, future grids will require additional methods to increase situational awareness. *Situational awareness* refers to the ability to identify, process, and comprehend information about how to survive in an emergency. Increased situational awareness helps give the system operator a better perception of the various elements in the system that will boost preparedness and provide decision support for mitigation of reliability threats. In this context (and as discussed previously), high-resolution PMUs are being deployed at strategic locations within the power system, with reporting rates up to 60 phasors/second to help provide a systemwide dynamic view. These high-resolution data enable advanced monitoring capabilities through new EMS applications such as phase angle monitoring, oscillation detection and mode monitoring, event detection and localization, system stability monitoring, subsynchronous resonance detection, and a variety of other applications that will help enhance situational awareness.

Security assessment refers to the analysis and quantification of the degree of risk in a power system's ability to survive imminent disturbances (contingencies) without interruption to customer service. It has always been an essential part of power system operation and will become even more important in the presence of myriad uncertainties in grids of the future. Security assessment covers both steady-state and dynamics. Dynamic security aspects cover voltage, rotor angles, and frequency deviations that are computationally burdensome and have conventionally been performed offline for forecasted operating conditions. However, for maximum use of assets, future grids operating near their security limits would require online assessments that rely on current operating scenarios to provide near-real-time security status and computation of operating boundaries in order to take timely control actions to maintain system stability. New applications that provide early event detection and characterization of abnormal operating conditions are also envisioned. Advanced high-speed computing technologies will help realize such applications.

In this context, machine learning and pattern recognition and/or data mining techniques for big data analytics are also being explored for applications surrounding grid baselining, grid health monitoring, and security assessment. These are data-intensive applications that would not only include system-level measurements from PMUs, but also equipment-level data from sensors, relay data, and very-high-frequency resolution data from fault recorders.

Distributed Hierarchical Controls

Finally, for high levels of security and efficiency of the next-generation grid monitoring and control paradigm, it is expected that automatic controls that comprise a combination of local-distributed and wide area–central controls—within a decentralized hierarchical control architecture—will be required.

Distributed controls were first deployed in process industries that have many individual control loops and where safety and reliability were critical. In such applications, numerous autonomous controllers are distributed throughout the plant, controlling various subsystems while coordinating with various processes. In such cases, a central controller monitors overall plant processes and provides slower outer loop control. In other infrastructures, such as urban traffic networks, digital cellular networks, and supply chains, the trend is for decentralized computations and decision making to provide control, based on hierarchical controls.

A similar control architecture is envisioned for the electrical power system. Because speed of control in emerging systems (as discussed previously) is essential—and local primary controls can be fast but lack visibility and coordination over neighboring areas during largely varying operating conditions—local area controllers would be ideal for emerging system needs.

Taking advantage of the observability and controllability offered by emerging high-resolution sensors and monitoring capabilities as well as smart agents–based computing and control capabilities, a decentralized hierarchical control paradigm in which controllers at a local area level may work almost autonomously to control local reliability issues would be a crucial pillar of the next-generation grid control paradigm. Smaller area distributed controls acting in a cooperative manner can be implemented for a common systemwide control objective, such as optimal dispatch or voltage schedules. Research is needed to explore multivariable, multi-objective, and adaptive controls designed for efficient mitigation of local issues and rapid implementation of global objectives.

Coordination of these local controls with centralized controllers would be also necessary. It is envisioned that the local

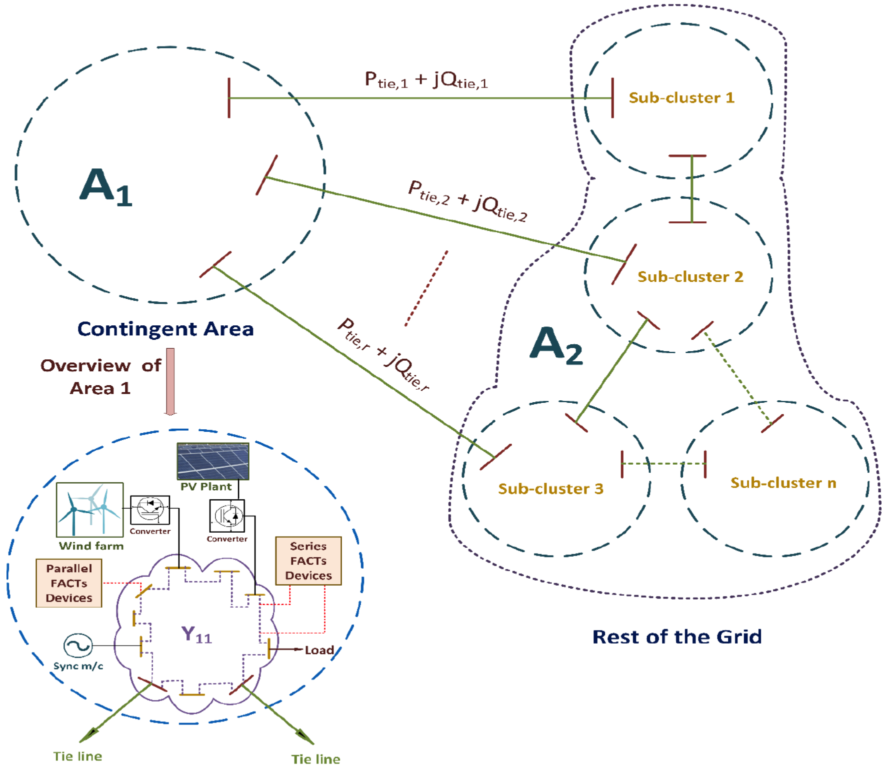

Figure 2 – Local area control based on local controllable resources

area controllers will collect high-resolution, granular, monitored data from many devices for their control actions and provide aggregated data to the central control center. Control center–based controllers will provide a slower outer loop control for all local area controllers for the most efficient security-constrained operation of the power system under its control. For example, such control commands can be in terms of generation dispatches based on optimal voltage objectives for a pilot bus in each local area. The local control agents will segregate and distribute outer loop control needs provided by the central control center to the individual devices in the form of required setpoints under its control.

In the proposed control structure, the local area controller would be a controller—preferably at a major substation in an area—providing monitoring and control for the local area. Any disturbance in the local area would be sensed by the local area controller, which would determine its consequences and mitigate any emerging reliability threats by taking control actions on the devices available in its control area—confining the effects of disturbance and eliminating the risk of cascading events (see Figure 2). If the control range from the resources within its control area is not sufficient, it can request assistance from the neighboring area controllers. In addition to assisting one another, the local area controllers would be coordinated so that there are no negative control interactions in the system.

Of course, control actions taken by local area controllers may be suboptimal because their primary objective is to manage reliability. Therefore, control center–based controllers would provide these optimization functions. The hierarchical outer loop slower control of the centralized controllers would reposition the system states for economically efficient (optimal) operation. Local area controllers would aggregate monitored high-resolution data from their control areas and provide them to the control center. They would also disaggregate

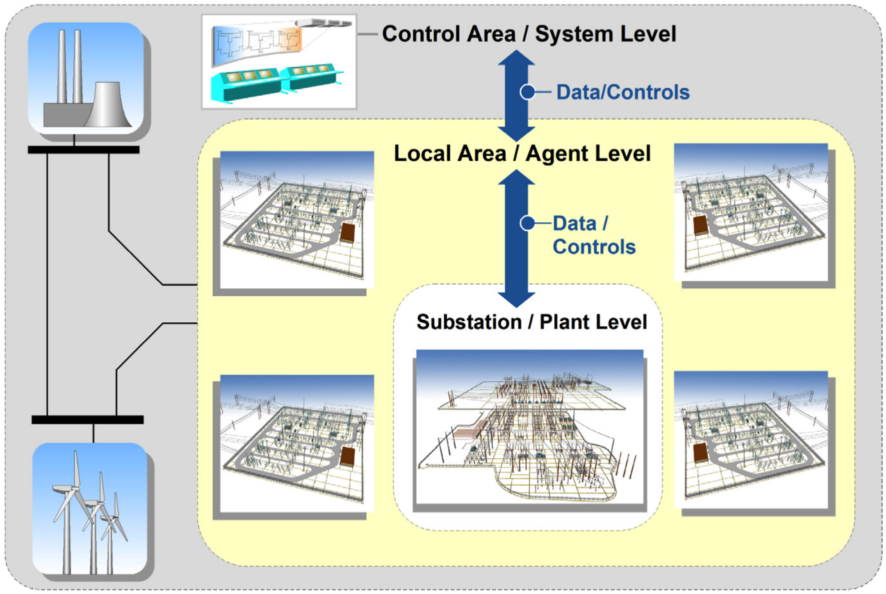

Figure 3 – Decentralized hierarchical control architecture

control objectives (for example, generation dispatches or scheduled voltage at a pilot bus) from the central controller to different elements within their own control area.

A decentralized hierarchical control would also facilitate participation of control services residing at the distribution level. Smart inverters with advanced control capabilities could participate in this control paradigm through distribution-level agents or distribution management system (DMS) and distributed energy resource management system (DERMS).

A pictorial view of the envisioned decentralized hierarchical control paradigm is presented in Figure 3.

Controlled islanding/system separation that deliberately separates the system into two or more electrically isolated islands may be a subset of automated controls. This action is considered a potential solution for preventing the uncontrolled system separations that can occur under highly stressed system conditions and that are usually followed by a complete or partial blackout. In effect, the transmission system operator preempts the uncontrolled system separation with a controlled separation in which the "islands" created by this separation are designed to maximize the likelihood of their survival after the separation (for example, by considering active power balance, post-separation dynamics, and availability of active/reactive power control resources). Future grids could depend on controlled islanding as a measure of last resort when faced with in extremis conditions and cascading failures. However, controlled islanding is challenging, and solutions must combine online and offline analysis to determine the answers to some key questions:

- **Where:** Which lines should be opened to create the islands?
- **When:** When should each island be created? Stressed dynamic conditions at the time the islands are created can play a key role in determining their survival.
- **How:** What pre- or post-islanding actions should be taken (for example, load shedding)?

The optimal answers to these questions may need to be determined during the initial stages of a system collapse. They will reveal how best to island the system to maximize the likelihood of each island's survival and preserve as much of the system as possible under extreme conditions.

For greatest applicability and efficiency of this distributed hierarchical control paradigm, coordination of all these controllers with system protection functions should be considered. With fast action times (on the order of milliseconds) for both the controllers and the protection system, appropriate coordination should be in place to avoid undesirable interactions that might jeopardize the security of the system.

Finally, robustness and accuracy of the controllers under impaired data quality should be investigated. Even with advanced techniques for data acquisition and handling, it is expected that—as described previously—missing or bad data will still exist within the massive numbers of data streams. The controllers should be designed so that impaired data do not have adverse effects on system reliability.

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