

Off the Beaten Path

Resiliency and Associated Risk

LARGE-SCALE ELECTRIC GRIDS REMAIN an indispensable critical infrastructure, and the vast majority of people will continue to receive most of their electric energy from such grids for decades to come. The impacts of the loss of a portion of the electric grid range from minor inconveniences for most users when the outage is on a small scale and short lived to potentially catastrophic situations when the blackout covers a large region for a long duration. Since the inception of the first electric grids in the 1880s, much has been done to reduce the likelihood and extent of blackouts. However, they cannot be totally eliminated, and there is usually a tradeoff between reduced blackout risk and increased cost. The focus of this article is on cost-effective ways to reduce this risk and, consequently, improve resiliency.

Keeping the lights on involves designing and operating the electric grid with the goal of simultaneously increasing two related but ultimately quite different concepts: reliability and resiliency. *Merriam-Webster* defines *reliable* as “suitable or fit to be relied on; dependable” and *resilience* as “an ability to recover from or adjust easily to misfortune or change.” Certainly, to be effective, any large-scale electric grid must, at least to some degree, be both reliable and resilient, i.e. available.

Both attributes have been considered either explicitly or implicitly in grid design almost from



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day one. One of the key benefits of interconnecting multiple generators is improved reliability because the lights can then stay on even if one generator fails. Papers discussing more formal considerations of reliability date to at least the 1930s. As for resiliency, any protection device that removes part of the system to save the remainder is contributing to system resiliency. Thomas Edison patented the fuse in

1890, and automatic circuit breakers were invented around 1900, allowing faulted parts of the grid to be automatically removed very quickly.

In moving beyond individual devices to consider the system as a whole, perhaps a good working description of the difference between reliability and resiliency comes from the recent U.S. National Academies report on resiliency:

While minimizing the likelihood of large-area, long-duration outages is important, a resilient system is one that acknowledges that such outages can occur, prepares to deal with them, minimizes their impact when they occur, is able to restore service quickly, and draws lessons from the experience to improve performance in the future.

Resiliency of the Physical System: The Five Operating States

A major aspect of the idea of resiliency can be elaborated upon by considering the power system operating states presented in Figure 1 (which reproduces a diagram from a 1978 *IEEE Spectrum* article by Fink and Carlsen). By far, the most time is spent in the normal (N-1) state, during which there are no limit violations for either the prevailing operating point or credible contingencies (N-1). While the idea primarily addresses the operation of the bulk transmission grid, similar concepts may be applied to the distribution grid—particularly now, when distributed and renewable generation are making the distribution grid resemble the transmission grid in many respects, including bidirectional flows and redundant feeder connections.

Hence, many of the energy management system (EMS) and distribution management system (DMS) tools used in the control center are focused on normal operation, and this is the state



with which operators have the most experience. More rarely, the system moves into the alert, emergency, and restorative states. However, such situations are encountered often enough that control-room personnel train for them and, for the most part, have adequate tools to deal with them. Truly enhancing grid resiliency requires tools to deal with the much more difficult in extremis situations. As noted by the North American Electric Reliability Corporation (NERC) in its 2012 report on resilience, during such an event, the previously interconnected grid may be broken into a number of electrical islands, and the operation of these islands may need to be performed by entities not normally responsible for grid operations.

The degree to which blackouts can be minimized or prevented during such in extremis situations depends on the triggering event itself, as well as the availability of a combination of strategies ranging across time frames—from real-time operations to asset and outage management to potentially planning years ahead. A wide variety of different events can place a system in this operating state, each having its own horizon of warning time. The most common would be the more severe manifestations of relatively typical weather conditions, which could induce large-scale storm systems—potentially including tornados and ice storms. Warning times in such situations would be, at most, hours. Hurricanes can, of course, cause severe damage, but they usually come with a longer warning period of at least a day or more. In contrast, high-intensity earthquakes can cause widespread damage with essentially no warning time.

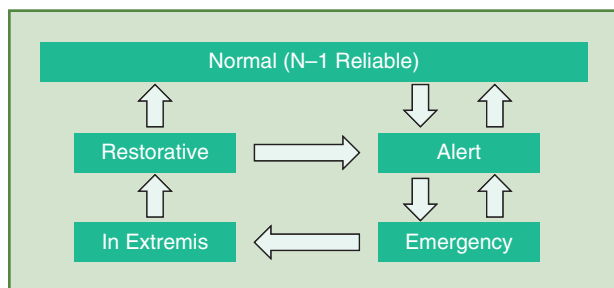


figure 1. The power system operating states (adapted from *IEEE Spectrum*, 1978).

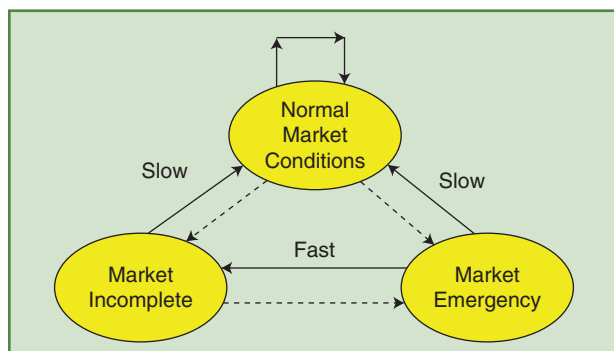


figure 2. Market operating states. (Source: EPRI.)

An emerging area of concern is what NERC calls *high-impact, low-frequency* (or HILF) events. These are statistically unlikely but still plausible events that, should they occur, could have catastrophic consequences on the grid and thus many everyday lives. Included in this group are large-scale cyber or physical attacks, pandemics, electromagnetic pulses (EMPs), and geomagnetic disturbances (GMDs). In such cases, the length of warning time might be essentially zero for cyber/physical attacks and EMPs to hours for GMDs to potentially days or weeks for pandemics.

The following discussion focuses on time horizons for which predictions are available within time frames that allow operators or other utility staff to take actions that can mitigate the impact of catastrophic events by reducing the risk of incurring outages. To illustrate various applications in the planning, operations, and asset and outage management time horizons, we provide examples of advanced EMS and DMS tools that deal with risk reduction and mitigation.

Resiliency in the Economics of Energy Exchange: The Market Operating States

The goal of resiliency for the physical electric grid is to ensure continuous energy exchange between producers and consumers. While the objective of reliability is to “keep the lights on,” the goal of resiliency in the context of energy exchange is to “keep the markets on” at all times.

The history of market deregulation in the United States is long, starting as early as 1935 when Congress passed the Public Utilities Holding Company Act. The act included many new rules regarding the ways in which energy could be sold. As the oil crisis hit in the 1970s, regulators began to introduce energy conservation rules (up until 1974). Despite this, the price of oil remained high. As a result, much of the legislation approved throughout this decade related to utilizing other forms of energy to reduce U.S. dependence on oil or fossil fuels. In 1992, the National Energy Policy Act allowed for private market competition within the wholesale generation of electricity. This, in itself, helped pave the way for true energy deregulation in the United States.

Subsequently, Order 888 in 1996 and Order 2000 in 1999 assured “open-access nondiscriminatory transmission services” and further deregulation by “creating Regional Transmission Organizations” that replaced state operation and control over the transmission grid. The Energy Policy Act of 2005 formed the U.S. Federal Energy Regulatory Commission (FERC) as the primary regulator for energy within every state across the country. The Energy Independence and Security Act of 2009 helped further improve electricity delivery to customers by assuring the development of a “smart grid.” All these efforts resulted in the creation of wholesale and retail markets to allow electric energy producers and consumers to conduct the business of energy exchange for economic benefits. The 2009 law imposed the not widely discussed resiliency requirement to “keep the markets on” at all times and minimize the economic losses from grid interruptions. Figure 2,

used in presentations by D.J. Sobajic and J. Douglas of the Electric Power Research Institute (EPRI) in early 2003, shows an example how the wholesale markets may go into different market states depending the ways in which the physical system states unfold.

Resiliency Quantification: Risk-Based Maps

As the notion of resiliency gets further defined, it is necessary to introduce quantitative ways of measuring resiliency. One possible approach is to define risk as a measure of resiliency. A well-established risk definition commonly used in the engineering fields defines risk as

$$\text{Risk} = \text{Hazard} \times \text{Vulnerability} \times \text{Impacts},$$

where

- ✓ intensity T is the threat intensity
- ✓ hazard is the probability of threat with intensity T
- ✓ vulnerability is the probability of a consequence C if a threat with intensity T occurs
- ✓ impacts are the stimulated economic and/or social impacts if consequence C has occurred.

This approach not only allows the resiliency to be quantified but also defines a framework to assess and mitigate threats for the elements of the grid at risk. Most importantly, the risk can be expressed in monetary values, which further mea-

sures the economic impact of the loss of resiliency. Such a framework is shown in Figure 3.

This framework is illustrated in several applications discussed later in this article, when asset and outage impacts on resiliency are introduced. By selecting proper data analytics, the risk can be predicted, and associated risk prediction maps can be generated that provide guidelines to operators for mitigating risk and, hence, improving resiliency. (The resiliency definition and quantification require further studies beyond the scope of this article.)

Resiliency in Control Strategies: Hierarchically Coordinated Protection

When the electricity grid is in the in extremis state, fast control actions are needed; in most cases, these cause protective relaying systems to “trip” circuit breakers and disconnect faulted parts of the system from service. The protective relaying function is decentralized to substations for faster action and operates in the millisecond time frame. Control center personnel do not get involved in initiating the relaying actions because of the subsecond time-frame response required, but they are greatly concerned with the outcomes of such actions to enable mitigation of impacts and bring the power grid back to its normal operating state. To improve resiliency going forward, fast control actions will also have to be redesigned to allow for hierarchically coordinated protection (HCP). Such a concept was introduced following the

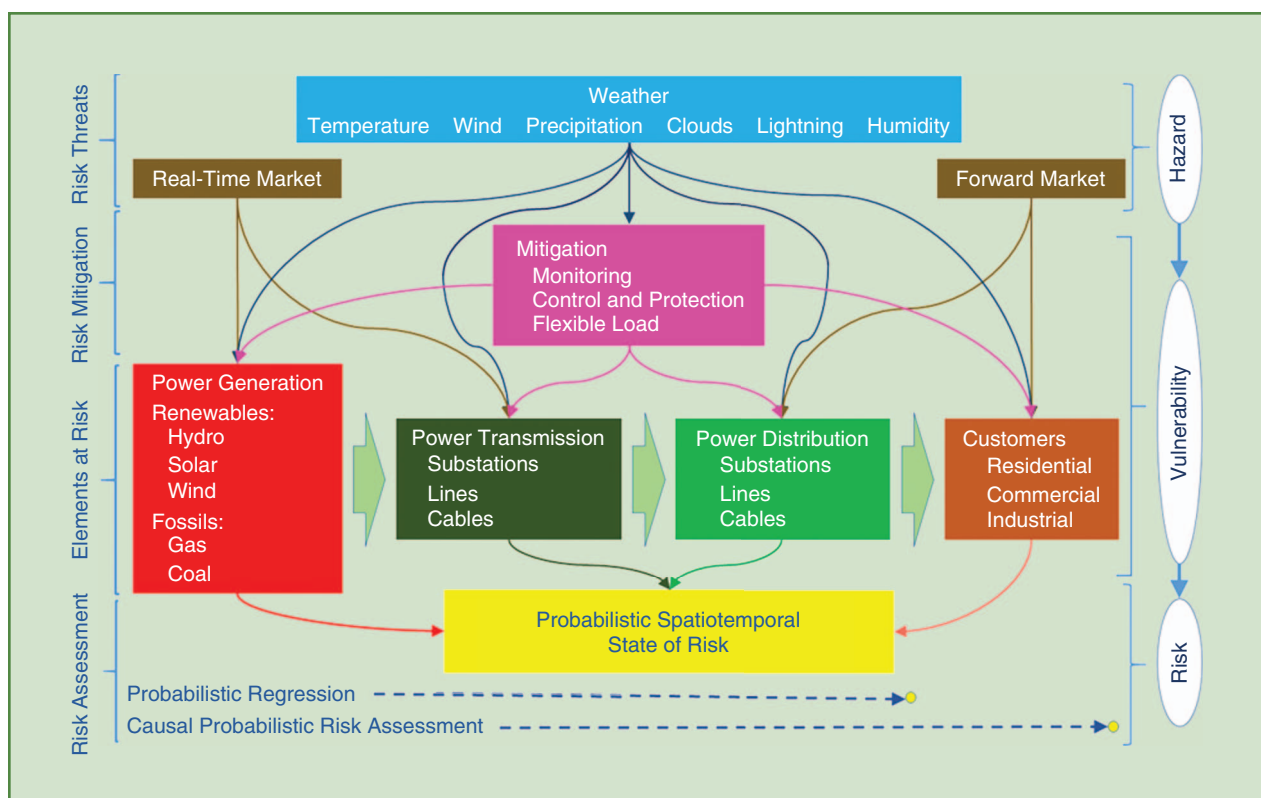


figure 3. A risk assessment and mitigation framework for resiliency quantification.

grid modernization study funded through the Power Systems Engineering Research Center by the U.S. Department of Energy (DOE) in 2003, as depicted in Figure 4.

The most relevant implication of the proposed HCP approach is that the resiliency improvement in fast control actions requires coordination among predictive, adaptive, and corrective protection actions. While adaptive protection has been discussed for many years, particularly in two key initial studies funded by the DOE in the mid-1980s (led by A.G. Phadke and G.D. Rockefeller, respectively), it continues to be explored not only at the transmission level but also for distribution systems and microgrids. Corrective relaying actions are also being contemplated, as experience has shown that relay misoperations can cause major blackouts.

The most promising, and least explored, option is to try to predict faults based on historical data and prevailing weather conditions, which will give operators an option to mitigate consequences by undertaking various preemptive actions to reduce risk of outages and major blackouts. The following sections explore some innovative ways of getting control center operators involved in planning, tracking, and mitigating unforeseen grid conditions that may impact the resiliency of the physical system and electricity markets.

Resiliency in Planning: Using Rare Event Criteria When Developing Modeling and Simulation Tools and Studies

Resiliency starts with planning and design, answering the question of what needs to be done well ahead of any possible event to reduce its adverse magnitude and duration. The electric utility industry has a long history of planning, and the high levels of reliability today attest to its success in this area. However, the majority of this work has been directed toward improving system reliability, mostly focused on designing a system for optimal operations during normal conditions and responding to events similar to those previously encountered. Here, we present several ideas for increasing system resiliency by incorporating criteria that deal with rare events.

From the start of the power industry, modeling and simulation have played important roles. With the introduction of digital computers, much of this power system understanding has been integrated into software of increasing complexity, the capabilities of which include short-circuit analysis, power flow, contingency analysis, security-constrained optimal power flow, and transient stability. Modeling and simulation occur over many time frames, ranging from decades in the future for long-term planning to real-time for operations.

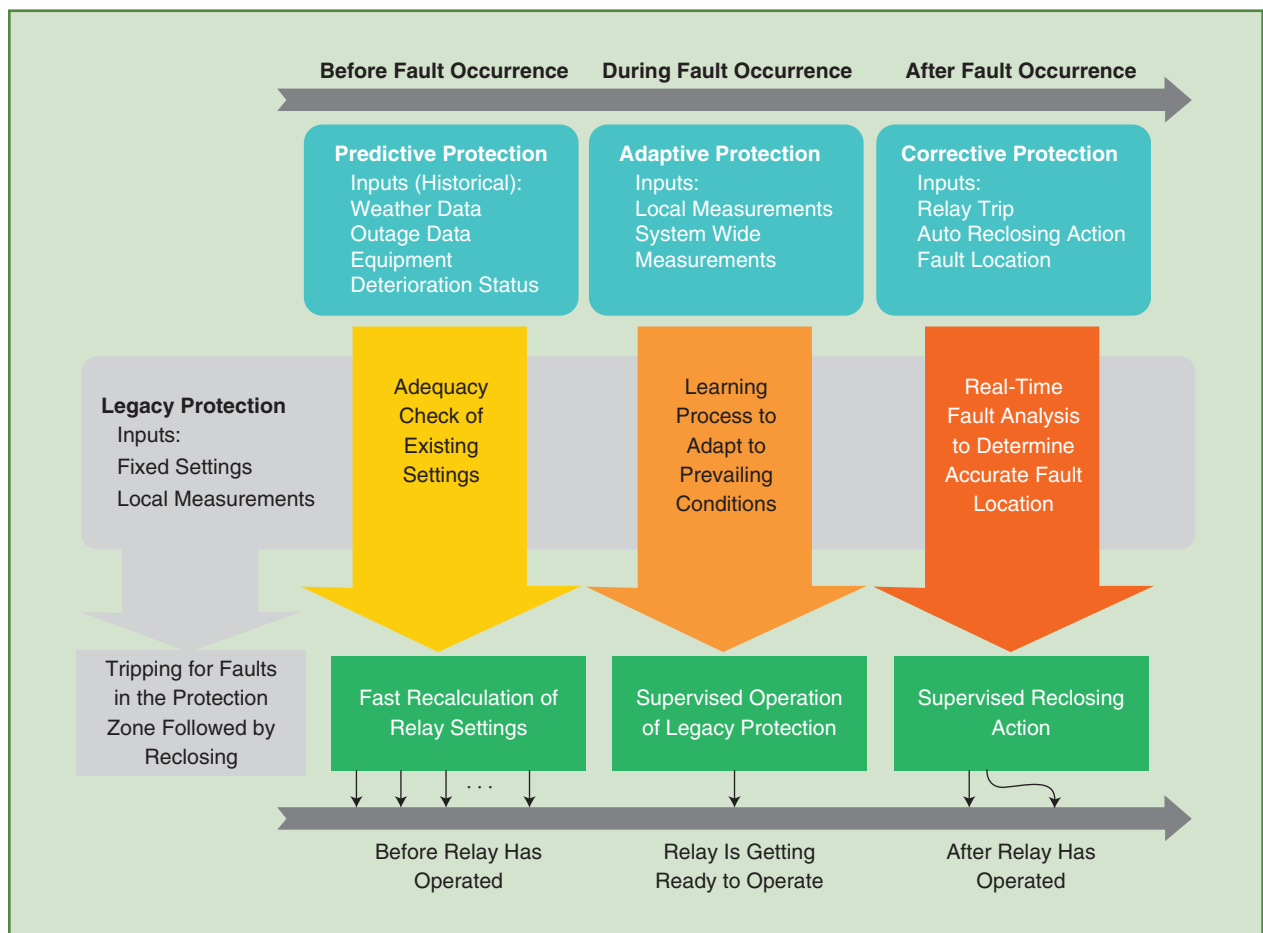


figure 4. HCP for improved resiliency.

Building on this foundation, enhancing resiliency presents the challenge of modeling and simulating systems in very unusual and often highly stressed situations. There is also the need for more multidimensional modeling. Severe events are likely to affect not just the electric grid but also other infrastructures as well. At times, there is a need to model some of the underlying dynamics of the disturbance itself, such as in the case of severe storms and GMDs. This leads to the need to develop cosimulation platforms that can model interactions between the power system and other critical infrastructure, including control systems.

Key to the research and development needed for the creation of simulation tools for improved resiliency is access to large-scale, realistic models of electric grids. While some of this information has been available in the past, because of the U.S. Patriot Act of 2001, data relating to the U.S. electric power grid are now considered critical energy/electricity infrastructure information (CEII), with access much more restricted. While most researchers can obtain some information, e.g., with nondisclosure agreements, these restrictions can sometimes hinder the free exchange of models and results.

A solution is to develop entirely fictional (synthetic) models that match the complexity of the actual grid models but contain no CEII. This is now starting to occur, due in large part to the DOE's Advanced Research Projects Agency–Energy (or “ARPA-E”) Grid Data program. The challenge for this research is to determine the wide multitude of germane characteristics of actual grid models and then mimic these in entirely synthetic models that can be freely shared. A quite useful characteristic of such synthetic models would be for them to include realistic geographic coordinates so as to allow coupling between the power grid and either other infrastructures or the actual geography.

One approach is to use an electric load distribution that matches the actual population in a geographic footprint, then employ public data on the actual generator locations, and finally use algorithms to create an entirely synthetic transmission grid. As an example, Figure 5 shows a 10,000-bus model entirely synthetically sited geographically in the western United States; the system has a total of seven different nominal transmission voltages (765, 500, 345, 230, 161, 138, and 115 kV). In the fig-

ure, the green arrows show the real power flow, and the contour shows the per-unit substation voltages.

Enhancing power grid resiliency requires being able to accurately simulate the impact of a wide variety of events on the power grid—and, potentially, on its coupled infrastructures. The events most likely to stress power system resiliency share two characteristics.

First, they have a significant impact. From a modeling perspective, this means that they strain the power grid in new and often unexplored areas. A consequence is that they will also mostly likely stress the power system modeling software. The degree of power system impact often requires detailed modeling of physical systems associated with the initiating event. For example, correctly modeling the impacts of large earthquakes requires coupled modeling between the power grid and seismic simulations.

Second, because the events are low frequency, there may be little historical information to accurately quantify the risk. From a model perspective, some of the more extreme events could be considered extreme manifestations of more common occurrences. Thus, a large-scale physical attack could be considered a more severe manifestation of more regular disturbances, such as those due to weather. Others, however, such as the grid impacts due to an electromagnetic pulse caused by a high-altitude nuclear explosion, would be entirely novel.

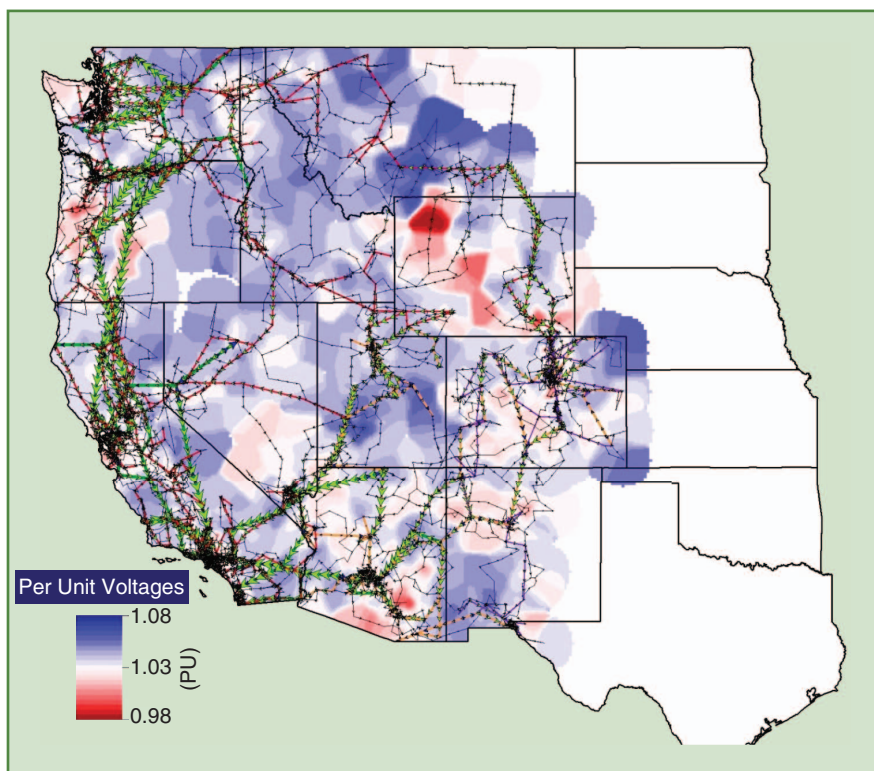


figure 5. Synthetic models, such as this 10,000-bus model located in the western United States, allow for the study of power grid resiliency without the disclosure of confidential information about the actual grid.

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One example is the study of the impact of GMDs on the high-voltage electric grid. GMDs, which result from corona mass ejections from the sun, cause low-frequency (much lower than 0.1 Hz) variations in the Earth’s magnetic field. The changing magnetic field then induces electric fields on the Earth’s surface, with the magnitude and direction of these electric fields determined by the conductivity of the Earth’s crust going down several kilometers. These electric fields then cause low-frequency, geomagnetically induced currents to flow in the high-voltage transmission system, potentially causing half-cycle saturation in the high-voltage transformers. A GMD with a maximum electric field of about 2 V/km caused a blackout in Quebec, Canada, in 1989. Much larger GMDs occurred in North America in 1859 and 1921, with magnitudes estimated by some as being up to five times those of the 1989 event. Such a GMD occurring today could cause a severe event, with potentially long-term power outages.

The potential for GMDs to impact the electric grid has been known since at least the early 1940s, and the incorporation of GMD analysis within the power flow was first proposed in 1981. However, power grid GMD assessment is still an active area of research and development, with much progress in the last few years through interdisciplinary work and active industry and government involvement. As a result, GMD analysis has now been integrated into commercial power system planning tools, including power flow and transient stability analysis software. However, determining the magnitudes of the severe events to model can be challenging because historical records are often incomplete or nonexistent. Determining the scenarios to consider for human-caused severe events, such as a combined cyber and physical attack, is even more challenging.

Resiliency in Operations and Operations Planning: Visualizing Massive Amounts of Data

In addition to planning considerations, much can be done in the area of real-time operations of the electric grid to enhance resiliency. With the advent of the smart grid, the electric grid is getting more intelligent, offering more sensing and embedded controls. This is certainly beneficial, but a consequence is increased grid complexity. While this automatic control is helpful, any consideration of power system operations needs to recognize that human operators are still very much “in the loop” and will continue to be so for many years. Therefore, enhanced operational resiliency needs to

consider tools to enhance the capabilities of the operators and engineers running the system.

One of the undesirable consequences of large-scale interconnects is that disturbances in one portion of the system can rapidly affect the entire system. The normal operating state can rapidly become an emergency or in extremis state, during which quick, informed intervention by a human operator is essential. Hence, operators need to maintain situational awareness. As shown by the loss of situational awareness that was one cause of the 14 August 2003 North America blackout, there is a need to develop better techniques to help human operators manage the unique operating challenges posed by in extremis conditions. A key resiliency need in the operations area is better data analytics and visualizations to help operators manage the potentially quite unusual conditions they might encounter during in extremis situations.

The degree to which operator action can prevent or minimize a blackout depends on the severity of the event and its time frame. Some large-scale blackouts cannot be prevented by operator action. For example, during an earthquake, an unanticipated event can cause severe damage within seconds. Here, visualization would be most helpful in the restorative state because there is nothing the operator can do to prevent physical damage due to an earthquake. Conversely, slow-moving weather systems, such as hurricanes or ice storms, give operators plenty of time to act, but blackouts still cannot be fully prevented. For example, 2102’s Superstorm Sandy in the eastern United States caused 8.5 million customer power outages with damage estimated at \$US65 billion.

Many, if not most, potential large-scale blackouts have time frames that could allow for effective operator intervention. A primary reason for this is the underlying power system dynamics, including the time constants associated with thermal heating on transmission lines and transformers, the operation of load-tap-changing transformers, and generator overexcitation limiters. During the unusual situations associated with severe events, wide-area power system visualization will be crucial for providing operators and engineers with the big picture of a grid that may be operating in a state they have not previously encountered. There may be multiple electric islands, transmission line flows may differ substantially from normal, and the voltage profile could be quite unusual.

Over the years, much has been done in power system analytics and visualization to improve situational awareness, and this remains an active area of research. While a full discussion is beyond the scope of this article, one approach that has been helpful is the use of dynamically formatted one-line

elements, such as dynamic pie charts, to indicate overloaded or open transmission lines or transformers. This will cause the information to “pop out” by taking advantage of pre-attentive processing to ease the search for system limit violations, such as overloaded lines. The technique is demonstrated in Figure 6, which represents a portion of a 2,000-bus synthetic model covering much of Texas. Dynamic sizing and coloring are used so pie charts on lines loaded above 100% of their limits increase in size and are colored magenta, whereas open lines are indicated by a large black circle with a green

“X.” A contour is also used to show the voltage variation across the region.

Resiliency in Asset Management: Tracking State of Equipment Deterioration and Risk of Asset Failure

While typically not a function of the control center, asset management has profound impacts on resiliency. Monitoring of the status of assets—in particular, because the assets in the U.S. grid are, on average, 30–40 years old—needs to become

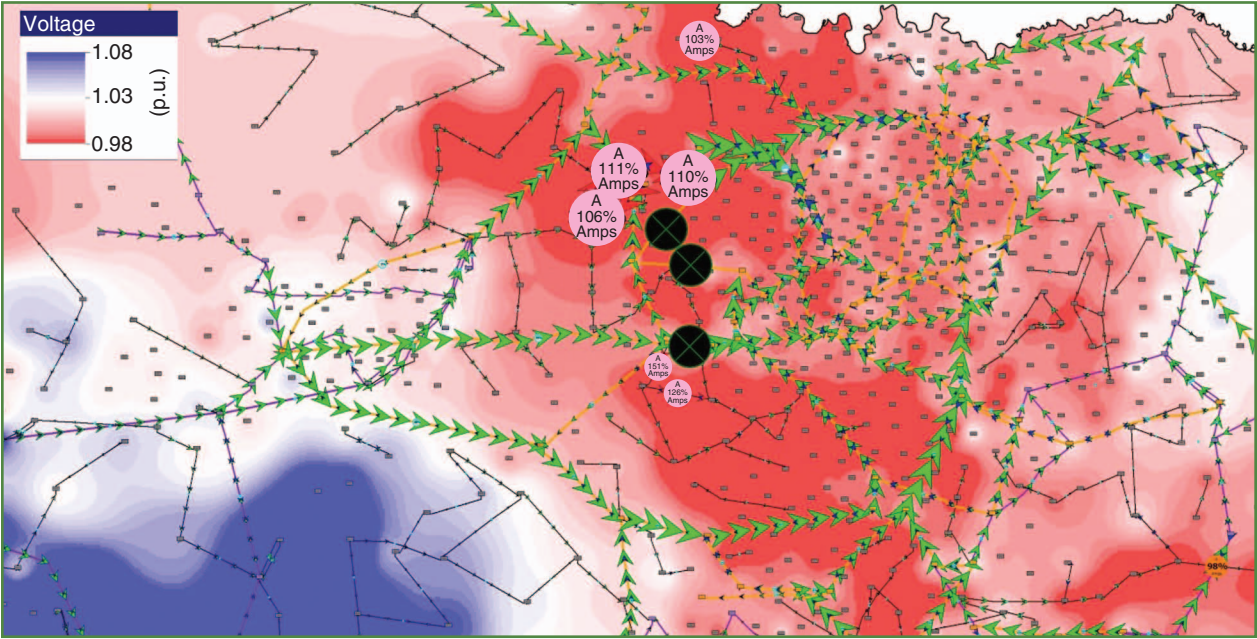


figure 6. A wide-area visualization combining a number of overloaded lines, open lines, and low voltages.

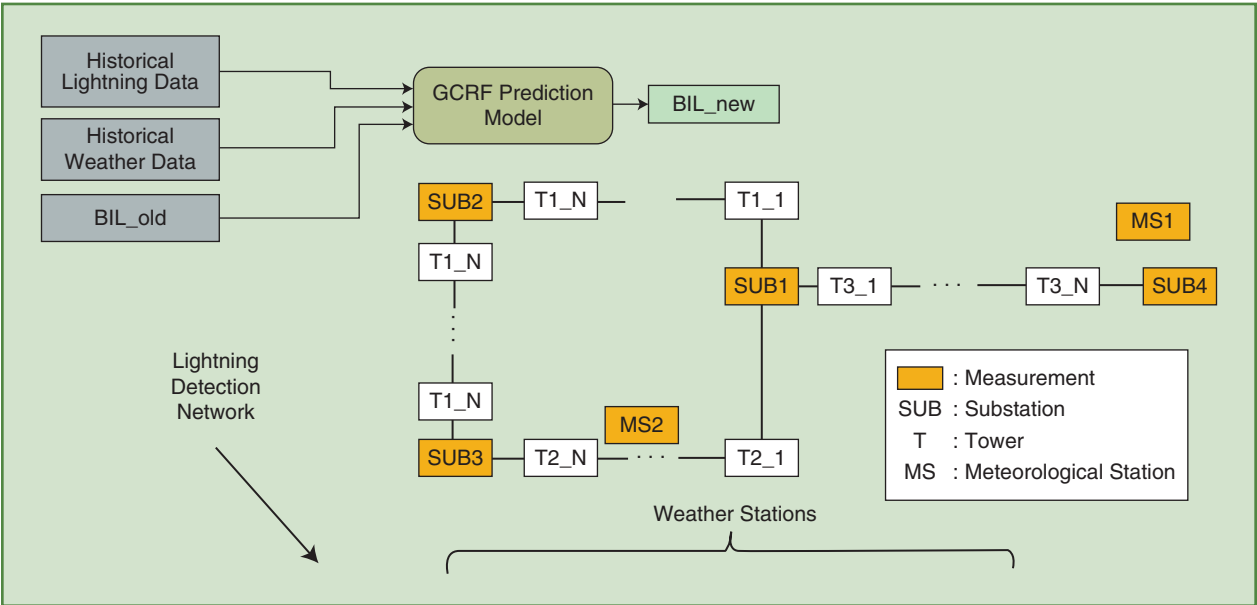


figure 7. Graph-based GCRF data analytics for computing BIL_new based on BIL_old and weather conditions.

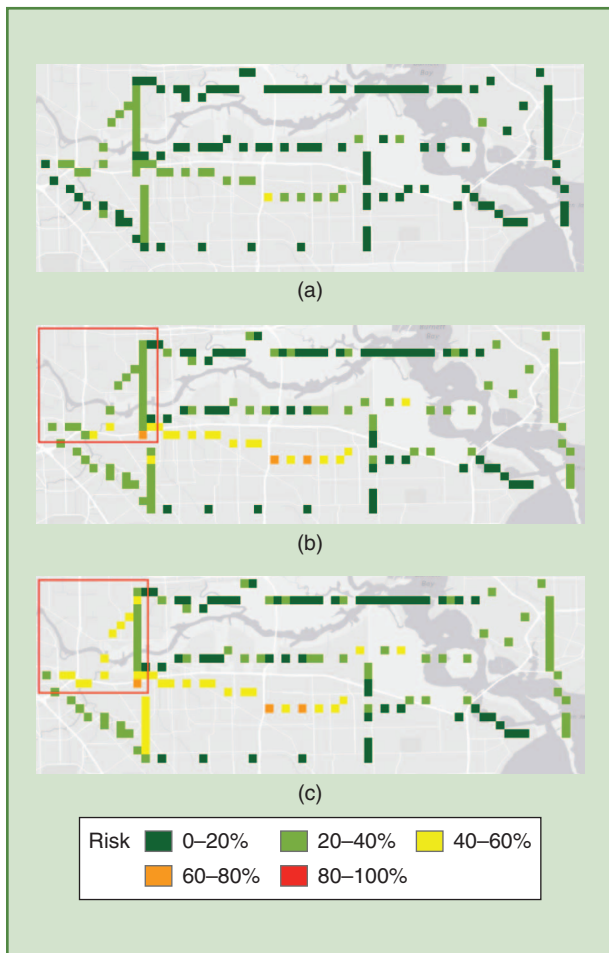


figure 8. The risk as of (a) 1 January 2009, (b) 31 December 2014, and (c) January 2015 (prediction).

an integral part of everyday grid operation. Operators must be aware of grid component health conditions to develop mitigating control strategies, should the risk of component failures start increasing. This leads to a new risk-based framework for online monitoring of assets. The following example illustrates the new online approach to tracking the state of transmission line insulators and developing an operator decision-making framework for acting to mitigate the risk of insulator failures. This approach integrates asset management actions to optimize design and repair strategies as well.

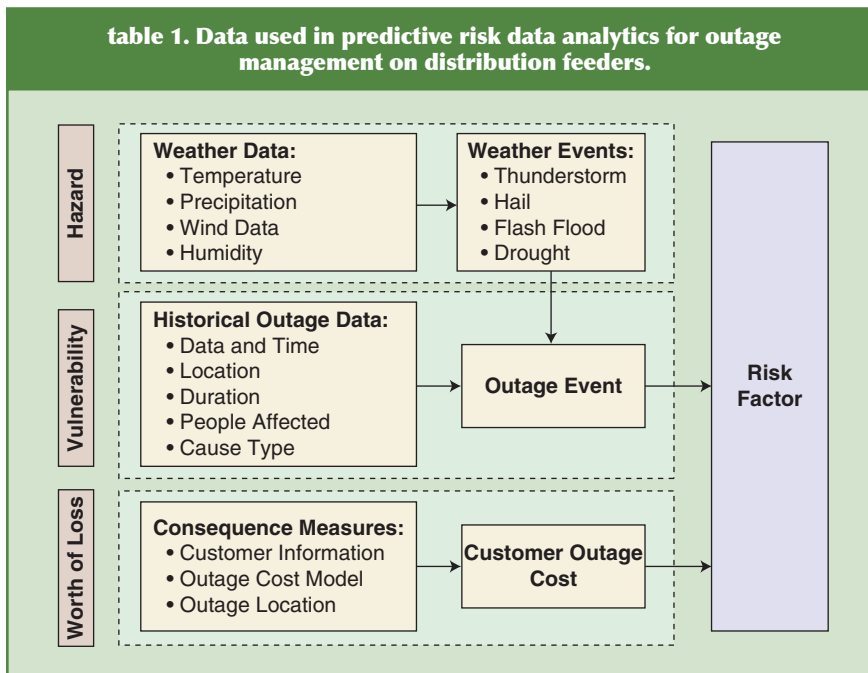
The proposed approach assumes that the deterioration state of a large number of insulators on transmission lines is tracked continuously in both time and location. The suggested spatiotemporal approach helps differentiate the insulators that are deteriorating faster and posing a risk of failure because their operating and environmental conditions create a high hazard. To differentiate declining performance characteristics, the basic insulation level (BIL) is tracked for each insulator and correlated to factors causing the insulator to be vulnerable to failures. An example of the computational framework extracted from an ongoing study at Texas A&M University is shown in Figure 7. The goal is to calculate BIL_{new} using BIL_{old} by taking into account the historical lightning and weather data that a given insulator has experienced over time. A particular data analytics framework—Gaussian conditional random fields (GCRF) invented by a study partner, Z. Obradovic at Temple University—is used to calculate BIL_{new} . This is a graph-based calculation paradigm that processes data in each node of the graph associated with a measurement point where data are collected. The calculation correlates data at each point with the impacts that data at other points may have on the measurements. The

nodes where data are measured are shown in yellow. The designation Tx_N relates to the n transmission lines with m towers each.

For each of the nodes, a set of variables X is defined, and the GCRF data analytics uses the network branches to establish the graph correlations between the measurement nodes where each individual insulator is located. As a result, BIL_{new} is computed for each insulator at any given moment in time, which allows operators to see the risk of a specific insulator failing at a particular time. This type of information also instructs the asset management planning group to initiate work orders that mitigate the situation by replacing all insulators at a high risk of failing.

Such time-evolving risk maps may be created to track the status

table 1. Data used in predictive risk data analytics for outage management on distribution feeders.



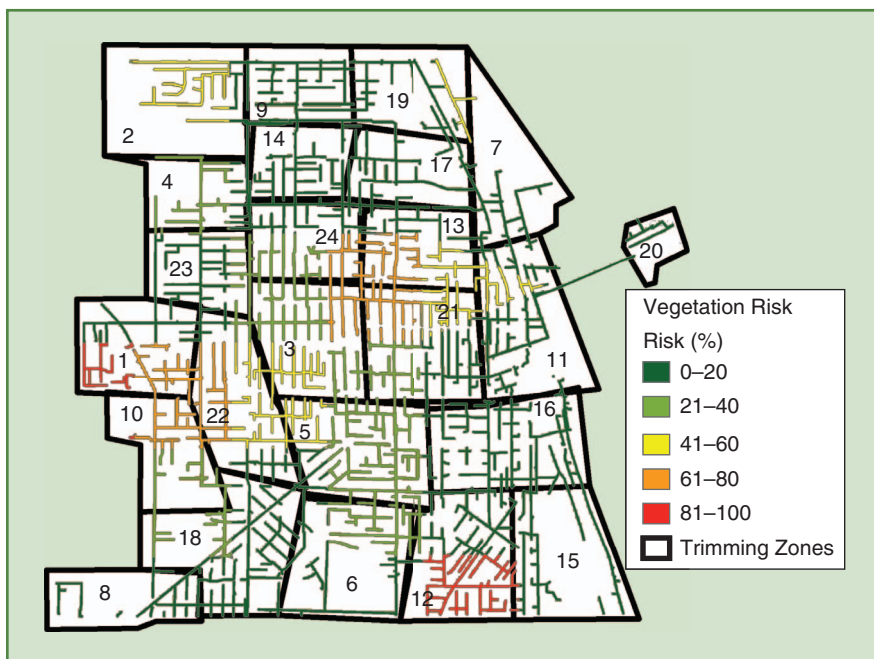


figure 9. Predictive risk maps for vegetation-caused outages.

of assets (in this case, transmission line insulators), as shown in Figure 8. We can observe from the rectangular marker on the network that the individual risk changes with time and affects various insulators differently.

Once the ability to track a large number of assets and predict their risk of failure becomes a standard EMS/DMS function, the resiliency affected by random asset failures could be improved by a decision-making tool that identifies a repair-and-replace strategy. This could become an integral part of the control strategy that keeps the grid in normal operating conditions.

Resiliency in Outage Management: Predicting Faults and Optimizing Pro-Active Mitigation Measures

The outage-management risk-based framework can be illustrated using the vegetation management task in distribution systems. Another ongoing study at Texas A&M University has focused on using the data shown in Table 1 to predict outages due to weather impacts. As a result, risk maps with a high risk of outages due to vegetation can be predicted, as shown in Figure 9 for a town in Florida. The various colors on the feeder sections indicate the level of risk, and the numbering of various feeder sections indicates an optimal order of tree trimming aimed at reducing the risk of outage. Being predictive in nature, such data analytics techniques would allow DMS operators and maintenance crews to coordinate their mitigation actions and keep the distribution grid in normal operating conditions.

In summary, future control centers—whether at the transmission, distribution, microgrid, renewables, or any other

level—need to change to accommodate resiliency requirements and subsequently offer tools for monitoring and maintaining system resiliency. EMS and DMS designs conceived in the late 1960s and late 1990s, respectively, are no longer adequate to deal with unfolding grid dynamics, grid expansions, and emerging electricity markets. The set of techniques and technologies discussed in this article point toward possible opportunities in future developments aimed at improving grid resiliency.

For Further Reading

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