21, rue d'Artois, F-75008 PARIS
http : //www.cigre.org

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The Resiliency Continuum

A. F. SNYDER, N. PLACER
EnerNex
USA

SUMMARY

Storm damage can wreak havoc on the electrical distribution system and instantaneously create a major impact on those who continuously depend on unfettered access to electrical energy. "Keeping the lights on" is a bedrock principle of utility operations, but is increasingly being challenged by more frequent and turbulent natural disasters. Resiliency is an important topic that is growing in relevancy, both in a traditional sense (i.e., being prepared to survive storm events) but also in terms of a utilities' capability to be prepared for the utility landscape of the future (i.e., grid modernization). The quest for greater utility resiliency is therefor an on-going pursuit that continuously takes shape over time. This paper serves as a useful resource for grid practitioners that are seeking a strategic resiliency framework with actionable checklist items and one that concurrently aligns with evolving grid modernization efforts. The three resiliency categories progressively increase from foundational topics to more forward-leaning initiatives. This time-based progression enables utilities to assess where they fall on the resiliency continuum and steps they can take to advance along this resiliency pathway.

KEYWORDS

Reliability, resiliency, hardening, grid modernization.

aaron@enernex.com

Storm damage can wreak havoc on the electrical distribution system and instantaneously create a major impact on those who continuously depend on unfettered access to electrical energy. "Keeping the lights on" is a bedrock principle of utility operations, but is increasingly being challenged by more frequent and turbulent natural disasters. Historically, utilities have utilized metrics which focus on reliability indices[1] for outage durations and frequency. The utility industry continues to expand its view of operational performance and reliability via the enhanced consideration of new resiliency measures.

What is Resiliency?

In its most basic form, infrastructure resilience encompasses the ability to reduce the magnitude and/or duration of disruptive events.[1] However, it is important to note that resiliency measures themselves do not prevent damage. Instead, they enable electric facilities to continue operating despite damage and/or promote a rapid return to normal operations when damages and outages occur.[2]

A Resiliency Framework

Resiliency is an important topic that is growing in relevancy, both in a traditional sense (i.e., being prepared to survive storm events) but also in terms of a utilities' capability to be prepared for the utility landscape of the future (i.e., grid modernization). The quest for greater utility resiliency is therefor an on-going pursuit that continuously takes shape over time. To help synthesize various concepts of resiliency within the context of an evolving utility marketplace, we have categorized resiliency into a three-part, time-based framework:

1. **Managing Resiliency** (before) – Focuses on a utility's foundational plan to strengthen their distribution system in advance of resiliency concerns
2. **Maintaining Resiliency** (now) – Focuses on a utility's capability to keep the distribution system in an operational state
3. **Modernizing Resiliency** (future) – Focuses on a utility's strategic implementation of grid modernization to be more flexible and adaptive to future grid technology integration and business markets

This paper is intended to serve as a useful resource for grid practitioners that are seeking a strategic resiliency framework with actionable checklist items and one that concurrently aligns with evolving grid modernization efforts. The three resiliency categories progressively increase from foundational topics to more forward-leaning initiatives. This time-based progression enables utilities to assess where they fall on the resiliency continuum and steps they can take to advance along this resiliency pathway.

I. Managing Resiliency - Before

Managing resiliency focuses on a utility's foundational plan to strengthen their distribution system in advance of resiliency concerns. There are several steps that can be proactively taken to strengthen a utility's base resiliency by focusing on distribution system planning and design.

Improve Design and Construction Standards

Finding appropriate design and construction standards should be based on the local conditions of the facilities. Studies from various regions of the country provide a myriad of hardening measures, including undergrounding of overhead facilities, pole and line design, and the application of new technologies, all with the goal to mitigate widespread outages due to tear-down situations from high winds, vegetation, or other natural disasters. Other reports, especially those in coastal areas, emphasized the importance of elevating substations and other vulnerable facilities that are susceptible to flooding.[2]

[1] Common ones are Customer Average Interruption Duration Index (CAIDI), Customer Average Interruption Frequency Index (CAIFI), System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI).

Overhead Distribution Reinforcement
Some of the most effective resiliency management actions are relatively simple and straightforward. Below are some specific actions related to adding structural reinforcement to existing distribution lines and a list of best practices for distribution hardening.

Structural Reinforcement Actions
- Adding guy wires or using steel poles to increase the strength of the lines
- Reinforcing some lines leading to a population center or other critical load
- Adding these improvements as part of the storm restoration process

Best Practices for Distribution Hardening [3]
- Establish and maintain a test-and-treat program for wooden poles.
- Establish a formal feeder inspection program to examine potential feeder concerns.
- Perform third-party attachment audits (e.g., telephone, cable) every five years at a minimum.
- Ensure that foreign-owned poles are held to equivalent standards with clear responsibilities specified.
- Develop standards and processes to ensure distribution pole foundations do not fail before poles (including depth tables for different pole classes and soil conditions).
- Establish systems and processes to ensure poles do not become overloaded as equipment and attachment upgrades occur.
- Develop an explicit decision process for reviewing whether new construction and rebuilds should be built to National Electrical Safety Code (NESC) Grade B (or equivalent) and not to a weaker standard.
- Develop standards for at least one type of non-wood distribution pole (e.g., steel, composite) and install several poles to gain field experience as a viable alternative should this become necessary.
- Develop a plan for trained staff to collect invaluable data on distribution damage sites immediately after a storm subsides that is statistically representative of the entire system.
- Develop a hardening tool kit that consists of a set of approved hardening approaches and appropriate standards, an application guide for their use, and develop field experience via pilot implementation.
- Enact systems and processes that allow the entire system to be gradually hardened through normal work practices of like-for-unlike replacement (e.g., porcelain insulators replaced by composite insulators broken during a storm event or regular maintenance schedule).
- Take targeted actions to identify, monitor performance, and strengthen critical poles that are highly undesirable to have fail during a major storm, not only due to primary damage but also in terms of difficulty to restore (e.g., freeway crossing), cost to restore (e.g., automation equipment), or criticality during restoration (e.g., communications repeater).
- Establish a distribution system hardening program that considers different pole and conductor types and various pole line configurations that can be employed (e.g., covered aerial medium-voltage systems to reduce vulnerability due to major weather events, dense tree areas, narrow right of way, coastal or multi-circuit installations).[4]
- Apply hydrophobic coatings to various components (e.g., non-ceramic insulators) in the transmission and distribution system to shed precipitation, facilitate ice removal, and mitigate water damage.[4]

Undergrounding
Of all the system "hardening" techniques, undergrounding the distribution system can initially appear to be the most obvious solution to increase resiliency. Although undergrounding the distribution system may reduce outage frequency, when outages affecting the underground portions of a system occur restoration times can often increase due to the complexity of the system and difficulty accessing equipment or cables (especially when flooding exists).[2] However, the primary reason that undergrounding is not a "silver bullet" is because it is cost prohibitive. The Congressional Research Service report [5] estimates that the cost of burying power lines is 10 to 20 times more expensive than

overhead cables, with local conditions accounting for the variance. In fact, the Edison Electric Institute reported that there was not a single study that recommended a complete conversion of overhead distribution to underground facilities.[6] The costs associated with a complete distribution system conversion, estimated to be in the billions of dollars, is not economically feasible, and would severely impact customer rates. Therefore, a targeted or selective undergrounding approach is recommended rather than total system conversion. Some of the selective undergrounding recommendations include:

- Undergrounding the worst performing circuits, or section(s) of a circuit
- Determination of what sections to underground based on number of customers
- Undergrounding portions of a circuit that are the most difficult to access (restoration time is related to accessibility)

Some good examples of primary candidates for selective undergrounding include single-phase tap lines that serve remote areas and "rear-lot-line" circuits that are installed along the back of the property in residential neighborhoods. This type of selective undergrounding would address common tree damage scenarios that are difficult to reach and must be cleared before energizing feeder sections. This enables crews to concentrate on the "main-line" three-phase circuits along roadways (generally the first to be cleared), thus facilitating the restoration of large blocks of customers more quickly.[6]

II. Maintaining Resiliency - Now

Prolonging resiliency focuses on a utility's capability to keep the distribution system in an operational state. Maintenance has become a central utility activity, as it has a significant impact on customer reliability and the bottom line. Maintenance has evolved to include a deep understanding of failure mechanisms, economic analysis, end-of-life prediction, risk analysis, process measurement, and stakeholder involvement, with a constant reminder to all involved that—while the current strategy is adaptive—it is built on solid engineering principles that stand the test of time.[7] The challenge for utilities is to find the optimal balance between expenditure levels and achieving reliability targets. Economic conditions, regulatory mandates, and reliability or safety events can trigger on-going shifts towards one objective over another. Several maintenance optimization models will be presented that provide different approaches for balancing varying objectives and associated risks.

Corrective (Reactive) Maintenance

Corrective maintenance is essentially the "run until it breaks" approach and is sometimes referred to as reactive maintenance. No maintenance actions are taken to ensure the design life is reached and repair or replacement only occurs when obvious problems or abnormal operations are detected. Typically, there are no expenditures of manpower or capital costs until something breaks, leading to the perception that money is being saved. In reality, this approach can often lead to less prudent capital expenditures associated with having to react to situations that demand a more urgent response (e.g., larger than needed material inventory, expedited shipping for specialty parts, overtime labor rates, additional contract labor, extended downtime costs). Additionally, waiting for equipment to fail typically shortens equipment life, leading to more frequent replacement and most likely more extensive repairs (e.g., costs associated with the failure of secondary devices) than would have been required as part of a more planned and controllable maintenance approach.

Preventive Maintenance

Preventive maintenance is carried out at predetermined intervals, or according to prescribed criteria, aimed at reducing the failure risk or performance degradation of equipment. This type of maintenance approach seeks to sustain or extend equipment life by performing actions on a time or component-run-based schedule that detects, precludes, or mitigates degradation. Preventive maintenance will not completely prevent catastrophic failures; however, the number and frequency of failures will be reduced. Equipment is also more likely to reach its design life and function at optimal levels which can result in energy and cost savings, especially for capital intensive processes. Although preventive maintenance may save or reactive labor costs it can also be labor intensive, involve unneeded maintenance, and can result in incidental damage to periphery components due to increased maintenance cycles. Preventive maintenance periodicity can be flexibly adjusted to optimize various equipment maintenance cycles.

Condition-based (Predictive) Maintenance

Condition-based Maintenance (CBM), sometimes referred to as predictive maintenance, involves the measurement and detection of degradation onset, thereby allowing causal stressors to be eliminated or controlled prior to any significant deterioration in the physical state of equipment. CBM varies from preventive maintenance in that maintenance is based on the actual measured condition of the equipment rather than on a pre-set, time-based schedule (e.g., lubricant replacement based on properties rather than run time).

A well-orchestrated predictive maintenance program will eliminate most catastrophic equipment failure. Similar to preventive maintenance, equipment is more likely to function at optimal levels which can result in energy and cost savings. However, equipment may extend beyond its design life resulting in longer equipment life, decreased equipment and process downtime, and reduced labor costs. Additionally, having quantifiable metrics for equipment degradation enables pre-emptive corrective actions, improved worker safety, and even improve worker morale due to employee-driven corrections. Scheduled maintenance activities will be minimized and overtime costs will be reduced or eliminated. Lean inventory levels can also be kept as parts can typically be ordered as required and well ahead of time to support downstream maintenance needs.

CBM also comes with certain disadvantages. An increased upfront investment in diagnostic equipment is required along with on-going staff training. More equipment means more parts that can potentially fail, regular hardware or software upgrades, and a firm commitment to make the program work by all pertinent staff. All of these added cost components can sometimes result is savings potential that are difficult to justify to management. However, studies have estimated that properly functioning CBM programs can provide a savings of 8% to 12% over a program utilizing preventive maintenance alone.[8] Depending on a facility's reliance on reactive maintenance and material condition, it could easily recognize savings opportunities exceeding 30% to 40%.[9]

Reliability-centered Maintenance

Reliability-centered maintenance (RCM) is a systematic engineering framework that prioritizes and optimizes equipment and resources to increase equipment reliability and cost-effectiveness. RCM recognizes that not all equipment in a system are of equal importance from a process or safety perspective and that equipment has varying degradation mechanisms and failure probabilities. It combines predictive and preventive maintenance techniques along with root cause failure analysis to precisely pinpoint and eliminate potential problems. SAE JA1011 [10] establishes a minimum process criteria standard for RCM that is based upon a specific operating context.

RCM is highly reliant on predictive maintenance but also recognizes that maintenance activities on equipment that is inexpensive and less important to facility reliability may best be left to a reactive maintenance approach. Therefore, many of the benefits and disadvantages of predictive maintenance are realized but in a more efficient and cost effective manner by prioritizing reactive maintenance on less critical components. Probability of sudden equipment failures are reduced but may not be as comprehensively monitored as predictive maintenance. Additionally, the incorporation of root cause analysis techniques can increase equipment reliability by reducing repeated failure mechanisms, but typically involves greater upfront commitment and training of staff to apply a more rigorous analysis method and process.

Performance-focused Maintenance

Performance-focused Maintenance (PFM) is a full-spectrum maintenance philosophy that broadly covers various facets of maintenance including technical, financial, business, customer, and regulatory aspects. PFM does not require the replacement of an existing maintenance strategy (e.g., RCM, CBM) and can be comprehensively applied (e.g., in-depth maintenance approach analysis) or implemented in a specialized manner (e.g., correction of a specific maintenance issue). While traditional maintenance approaches focus on asset preservation and reliability, PFM seeks to establish maintenance targets that match strategic service-level requirements (e.g., comprehensive equipment performance and maintenance contributions) towards reaching an organization's business goals. This holistic approach is taken to overcome some of the existing shortcomings of maintenance approaches, such as: cost without considering value, short-term equipment issues vs. long-term corporate planning, inconsistent maintenance business cases and disparate asset data, reliance on historical asset data, and insufficient attention to risk and vulnerabilities.

III. Modernizing Resiliency - Future

Modernizing resiliency focuses on a utility's strategic implementation of grid modernization to be more flexible and adaptive to future grid technology integration and business markets. Grid modernization can be an expensive and complex endeavor affecting a multitude of stakeholders many of whom have conflicting interests and goals. To realize a future state of grid modernization, multiple value streams will need to be leveraged to justify the investment cost. Evolving grid technologies provide an opportunity for resiliency to grow from its traditional roots, as covered to this point, to a future state that is marked by progressive layers of enhanced grid system management. This progression toward a more comprehensive and holistic future and view of resiliency will be presented in three stages of evolution:

1. Operational Technology (OT)
2. Information Technology (IT) and OT convergence
3. Energy market convergence.

Operational Technology (OT)

Improved situational awareness and control of grid equipment significantly enhance a utility's ability to reduce the impacts of major events and speed up restoration efforts. In the context of infrastructure hardening, among the most cited benefits is the ability of the system to detect outages and remotely reroute electricity to undamaged (un-faulted) circuits.[11] Through automated distribution technologies utilizing reclosers and automated feeder switches, faults can be isolated for greater system reliability with fewer customers affected. This involves the redesign of the distribution grid as a looping system that provides channels for rerouting power and several key technologies can be deployed:

- Fault location, isolation, and service restoration (FLISR) systems (centralized or distributed)
- Intelligent Electronic Devices (IEDs) (e.g., line sensors and smart relays)
- Energy Management Systems (EMS)
- Distribution Management Systems (DMS)
- Supervisory Control And Data Acquisition (SCADA) systems for transmission and distribution
- Advanced Meter Infrastructure (AMI)
- Meter Data Management Systems (MDMS)
- Outage management systems (OMS)
- Geographical Information Systems (GIS)
- Mobile Workforce Management systems (WFM)
- Communications Networks

IT/OT Convergence

Although OT-focused deployment increases resiliency in a traditional operational sense, grid modernization efforts also provide new categories of resiliency and optimization on a more holistic level. This progression begins with the desire to aggregate various OT technologies, communications, and IT networking together to enable more direct and comprehensive monitoring and control capability. This move towards enhanced aggregation not only creates more redundant and integrated systems but these operational technologies typically require a more robust IT backbone. Hence an IT/OT convergence begins to take a form that simultaneously helps to strengthen vulnerabilities from both and operational and data management perspective to create a more robust and integrated grid.

A natural result of this convergence is the deployment of grid systems which function to control or aggregate other existing grid systems. Some examples of aggregating grid systems include Advanced Distribution Management Systems (ADMS), Distributed Energy Resource Management Systems (DERMS), and Demand Response Management Systems (DRMS). An ADMS provides real-time situational awareness of the electric grid and customer outages, and is accessible by field personnel during the restoration process. ADMS integration with AMI meters provides control room operators with real-time outage information at the individual customer level that enables them to check for service restoration and power quality and notify customers via various communication platforms. ADMS can also include grid optimization applications for locating faults and automatically restoring the distribution grid (FLISR), DMS management, conservation voltage reduction (CVR), and Volt-VAr optimization (VVO). These functions can significantly enhance field awareness, optimize grid capability, and reduce recovery time and effort.

Energy Market Convergence

The OT/IT convergence will occur over the course of several years and the pace of transition across the utility industry will be driven by varying utility drivers, both internal and external. There are common grid modernization themes but no single formula; therefore, each utility will need to determine a preferred grid modernization approach. Utilities must also consider factors that span beyond technology to consider geographic, political, regulatory, and customer concerns. The integration of hardware, software, and communications infrastructure provides a more broadly capable platform for technology to more effectively interact and engage utility customers. This convergence between technology and people results in increased business channel potential and the evolution of enhanced energy services. As these energy services expand, they will likely span across multiple types of energy sources (e.g. electric, water, gas), involve new types of solutions providers, and attract new types of customers. The result is a future state of advanced market convergence of people and technology. The definition of resiliency therefore continues to evolve into a more holistic concept. A utility's competence related to resiliency will not only be based on technical aptitude of operational and information technology, but also in terms of business acumen as it relates to people and markets.

One example of how OT/IT advancements could help advance technology into a future state of market convergence are microgrids. Microgrids are essentially miniature versions of the electric grid that include localized generation (different combinations of diesel generators, gas turbines, fuel cells, solar photovoltaic and other small-scale renewable generators), storage, and controllable load management devices. A microgrid can isolate itself from the utility grid or an undamaged branch of a utility circuit can be isolated to support customers while damaged sections are being restored. The microgrid senses loads and fault conditions and can reroute power to as many critical areas as possible given any situation, which is sometimes referred to as "self-healing".

Since most microgrid generators are connected to the utility grid, connected facilities can purchase energy and ancillary services from the utility and sell locally generated electricity back to the utility grid during times of peak demand. Additionally, several types of organizations that have a high demand for energy or a critical need for energy resiliency to avoid significant financial, safety, or security issues have an increasing interest in microgrids. Some examples are government facilities (federal, local, military bases), hospitals, data centers, research institutions/universities, commercial campuses, or densely populated urban centers. This combination of isolated two-way energy networks along with a growing involvement of different types of business entities begins to form the basis for transactive energy exchange. Although there is increasing industry interest in the microgrid concept, deployment has been limited largely due to unattractive financial returns. The evolution of transactive energy markets and new energy services could help to address current financial microgrid roadblocks. In this way, microgrids could become a primary enabling technology to bridge the OT/IT and market convergence divide.

IV. Conclusion

This paper has made the case for and presented a resiliency framework targeted at strategic and tactical efforts to ensure safe, reliable electric power delivery. The time-based framework is equally applicable before, during, and after any type of grid contingency that impacts that delivery, and provides guidance for the gamut of utility and vendor personnel empowered to ensure this delivery.

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