Maintaining Electric System Safety Through An Enhanced Network Resilience

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***Abstract*—Global environmental variations in the past two decades have contributed to a significant deviation of classic ecological patterns, leading to severe electricity outages triggered by extreme weather-driven phenomena. This has highlighted an urgent need for enhancing the resilience and robustness of the interconnected electricity grid against such high impact low probability (HILP) incidents. From the electrical safety point of view, it is essential to increase the operators' awareness on a better understanding of such hazards and grid vulnerabilities, and enhance their preparedness on how to respond or mitigate the probable outages. This paper proposes a temporary, yet agile, restoration strategy in response to the forecasted HILP events, founded based on efficient utilization of the grid existing infrastructure, and aimed at improving its resilience against such extreme emergencies. The applied concept of reconfiguration is proactively planned to recover the electricity outages in a timely manner. In the meantime, two sets of metrics are proposed to quantify both the grid operational and infrastructure resilience. The presented framework aids the system operator to evaluate the outage recovery plans considering their impacts on system resilience and decide on the final implementation. The proposed approach is applied to the IEEE 118-bus test system facing an HILP event, where results reveal its applicability and efficiency.**

***Index Terms*—Decision making, electric safety, mitigation, optimization, recovery, resilience, risk, topology control, transmission line switching.**

I. Introduction

A. Problem Statement and Research Motivation

THE ELECTRICITY grid is considered as the backbone of modern societies and is one of the most challenging and large-scale human-built systems to date. The power grid is a complex, interconnected network of generation, transmission, distribution, control, and communication technologies decentralized through a vast range of geographical regions and, hence, are widely exposed to external threats. The electricity grid can be adversely impacted by natural disasters including severe storms, hurricanes, earthquakes, etc. and/or by malicious events such as cyber or physical attacks, among others [1]. Safeguarding the nation's electric power grid and ensuring a continuous, reliable, and affordable supply of energy are among the top priorities for the electric power industry. The electric sector's approach to protection of the grid critical infrastructure is known as "defense-in-depth," which includes preparation, prevention, response, and recovery for a wide variety of credible hazards to electric grid operations [2]. The industry commonly recognizes that it cannot protect all the grid assets from various sorts of threats. Its priorities are, instead, focused on protecting the most critical grid components against the credible contingencies: to build in system survivability and to develop contingency plans for response and recovery when either human-made or natural phenomena adversely affect the grid operations [3].

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B. Resilience to High Impact Low Probability (HILP) Events

While well-known traditional reliability principles have been widely adopted in practice to have the grid operate securely and reliably under normal conditions and safely withstand credible contingencies (N − 1 criterion), the concept of "resilience" to HILP incidents has remained less clarified and unfocused. HILP incidents include weather-driven natural disasters, as well as cyber physical attacks with significant consequences. An example of an HILP event occurred on August 14, 2003, when large portions of USA and Canada experienced an electrical power blackout, resulting in loss of electric power for days. The outage affected a large area with an estimated 50 million people experiencing the loss of electricity. Estimates of the total costs in USA ranged between 4 and 10 billion dollars [4]. In 2008, more than 2.8 million residential/industrial customers in the Greater Houston area were affected due to a hurricane lasting to electricity outages of a few days to several weeks. This outage resulted in an enormous financial loss estimated at $24.9 billion to the U.S. government [5]. The severe weather-driven events led to significant economic loss approximately $55 billion in 2011, 14 of which contributed to more than $1 billion damage cost [6]. Recently, the Hurricane Harvey, the strongest one in Texas since 1961, produced a year's rainfall within a week causing a substantial electricity outages (around 10 000 MW) and leading to more than 291 000 people without power in Texas, USA [7]. Most recently, the Hurricane Irma struck Florida in September 2017, the strongest one in Florida since 2005, knocking out power to 6.7 million electricity customers (67% of all

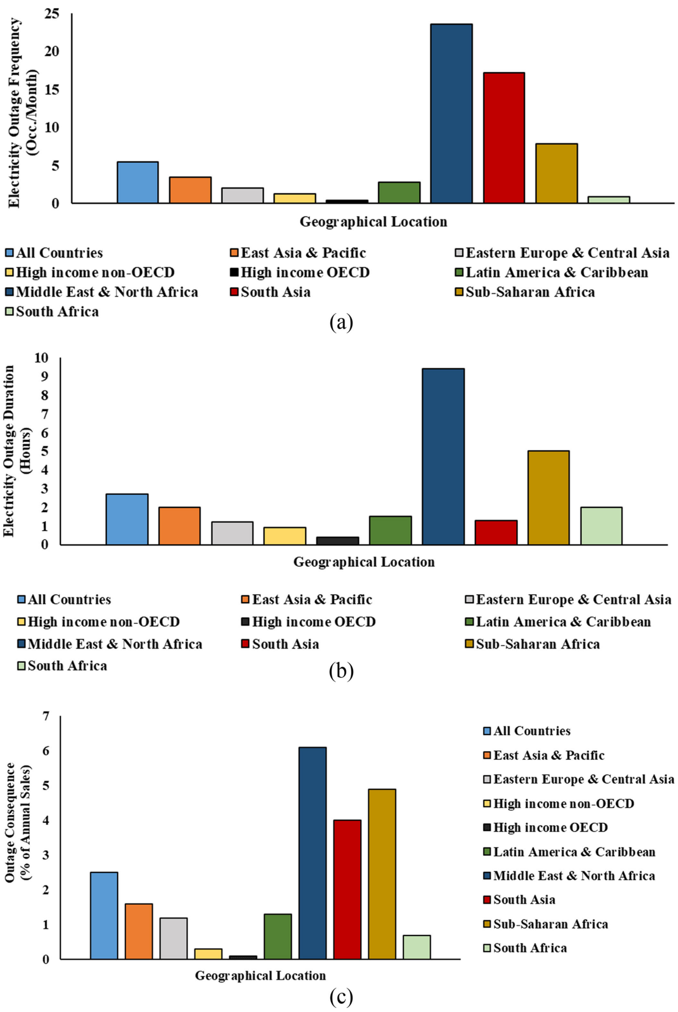


Fig. 1. Power outage statistics of HILP events in 2014 [9]. (a) Electricity outage frequency. (b) Electricity outage duration. (c) Electricity outage consequence.

customer accounts in the state) [8]. Another possible threat to the power grid is cyber-physical attacks. One most likely target for terrorists is the large-capacity centralized sources of power generation, since the loss of a large-capacity generating unit would heavily cut the electrical capacity. Any disruption on major substations with high-voltage transformers can also bring about potentials for major electricity outages.

In such emergency scenarios, portions of the electric power system would be adversely affected with a compromised electrical safety, exposing the network to risk under an unstable condition with some equipment out of service. As a consequence of such HILP incidents, strategic centers whose functionality heavily depend on the continued supply of electricity (e.g., health centers, military stations, nursing homes, manufacturers, etc.) are subject to major disruptions that contribute to significant economic loss and, even worse, loss of life for many people in need of special health care and nursing facilities at homes or hospitals. Fig. 1 illustrates statistics of the severe weather-driven HILP phenomena and their consequences globally regarding the extent, frequency, and duration of the power outages [9].

With the lessons learned from the recent blackouts and major electricity outages, it is becoming more and more apparent that further considerations beyond the classical reliability-oriented view are needed to keep the lights on at all times and securing the grid against the HILP phenomena that may lead to cascading events and blackouts. Efforts on enhancing the grid resilience in the face of extreme conditions should focus on both long-term grid hardening (reinforcement, maintenance, etc.) and short-term operational flexibility (islanding operations, dispersed generation, etc.), which will be further discussed in Sections II and III. In the latter category, and to improve the system safety, attention should be paid on how to restore the system performance back to its normal operating condition promptly and improve the system resilience in the face of such disasters. Benefiting from a proper and predictive strategy as a corrective plan in dealing with the aftermath of such fatal phenomena is a necessity for electric utilities.

C. Literature Survey

"Planning" for enhanced system resilience has not been well explored, especially in the context of power transmission systems, and thus, attention needs to be paid on allocation of tangible resources, tradeoffs among various dimensions of system resilience, the relationship between community resilience and that of the built environment, as well as data-driven standards ensuring resilience. Most of the previous research works on enhancing the grid resilience have focused on the upgrade of the system infrastructure (i.e., grid hardening), maintenance/vegetation management in distribution networks, and resource allocations through installation and use of additional batteries and storage units. Several research efforts have been concentrated on the concept and definitions of "resilience" in the electric domain [10]–[13]. Resilience assessment of transmission lines and towers to extreme wind events is explored in [14]. An estimate of power outages due to asset damages under a hurricane threat is provided in [15], where a methodology is suggested to identify the system critical assets for corrective maintenance and agile restoration. A mathematical approach for analyzing the system resilience through re-integration of power systems is discussed in [16]. Decision-making support tools for proactive restoration planning and disaster recovery in power systems are highlighted and studied in [17]. Focused on the distribution grid, [18] and [19] aimed at improving the grid resistivity in restoration process through sectionalization of the distribution system and use of microgrids. Modeling and evaluating the resilience of critical electrical power infrastructure to extreme weather conditions are presented in [20]. Risk-based defensive islanding is suggested in [21] to boost the grid resilience to extreme weather events. A model for cost-benefit analysis of infrastructure upgrades and storm hardening programs is proposed in [22]. Pham *et al.* [23] proposed a restoration plan through the integration of large-scale distribution generations. Grid resourcefulness through optimal generator start-up strategies for bulk power system restoration in emergency scenarios is investigated in [24]. A proactive recovery of electric power systems for resilience enhancement through asset and maintenance management is introduced and explored in [25] and [26].

There are two challenging issues with most of the past works: 1) as it is hard to predict any form of hazards or contingency precisely, dispersed generation and storage units, whose allocation is planned in a long run, may not be readily available in the vicinity of the affected area and in a timely manner; 2) prioritizing the damaged equipment in terms of importance and criticality for system resilience to repair and/or replace may be time-consuming, taking days to weeks depending on the system's ability to bypass the failed substations or disrupted lines. This leads the system to be restored back to its reliable and normal operating condition after the maintenance and replacement process, resulting in longer outage durations.

D. Research Contributions and Relevance to Electric Safety

The electric safety is mainly interpreted as the preventive and proactive steps needed to assure the safety of the existing network infrastructures and human lives before, during, and after an incident. The bulk power grid is typically subject to unpredictable HILP hazards that not only may leave the customers without electricity, but also impose critical threats to health and public safety, and could potentially compromise the national security. The impact of an HILP disruption would be mostly realized on the interdependent communities whose functionality heavily depends on the continuous supply of electricity, e.g., perishable medication and food, cooling and heating systems, transportation, fuel resupply, etc. In some cases, due to the severity of the damaged facility, the disrupted equipment is hard to access (facility is blocked by floodwater or landslides) and either boots-on-the-ground crews dispatch or manned/unmanned aerial vehicle would not be a feasible solution to secure the safety of the crews. To magnify the importance of the system safety and the interactions of various intangible communities, imagine the real-time traffic control and highway obstructions are being perturbed followed by an HILP regional storm, which makes it difficult for the responders to act properly. This chaotic condition surpasses the stress on public safety and hospitals, which are heavily electricity dependent. It is difficult to anticipate further consequences that increase as the electricity outage extends in time.

While such real hazards that may hit the grid anytime and anywhere are difficult to predict, understanding their impacts on the services, sensitive public infrastructure and private utilities, as well as the mitigation toolsets that can proactively help in an agile recovery and improved resilience is of great concern. Different from the past research, the proposed approach in this paper is unique in methodology and perspective. Instead of positioning the operator in a reactive mode in response to HILP outages, a decision-making support tool is suggested that helps, ahead of time, designing restorative plans exploiting the built-in flexibility of the grid. In this context, weather forecasts and underlying environmental patterns can be utilized to trigger the developed decision support toolset to operate. In response, the toolset suggests transmission network reconfiguration using transmission line switching (TLS) actions, i.e., removing lines out of service, hence, changing the network topology. The suggested approach is a temporary, yet agile, corrective solution employing the network existing infrastructure (i.e., transmission lines) with minimum additional costs, to swiftly recover the electricity outages while allowing sufficient time for repair and maintenance actions.

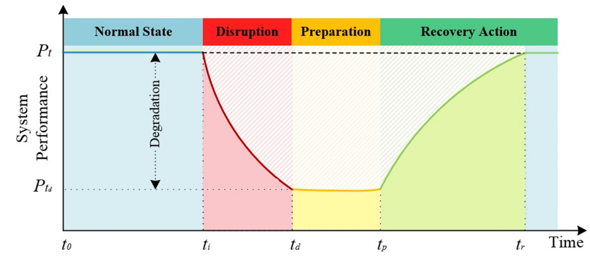


Fig. 2. System interaction states in the face of a critical HILP disruption.

The rest of the paper is structured as follows. A background on the concept of resilience in power systems is introduced in Section II. Section III describes the proposed formulation for resilience-oriented recovery plans through TLS actions, discusses the resilience features of an electric power system, and introduces quantitative metrics for resilience assessment. A case study on the IEEE 118-Bus test system is demonstrated in Section IV and finally conclusions are made in Section V.

II. Power System Resilience

A. On the Concept of Resilience

Resilience is defined as the *flexible ability of the system to reliably restore itself, with minimum human intervention, to its normal operating state following by any disturbances, outages, or blackouts* [10], [11]. The concept of "resilience" mainly considers the unforeseen extreme failures of HILP nature, which cause huge damages and loss to the system, while the concept of "reliability" takes into account credible and most probable contingencies. Within the scope of engineering system resilience, it is always crucial to think about the challenges associated with both restoration and repair process in response to an electricity outage. For an outage of limited scale and consequence, the restoration process can be rapidly conducted, which will then allow sufficient time for the repair to bring the system back to its full operability. On the other hand, in widespread HILP outages, restoration itself may be a significant barrier. Metrics for the definition of power system resilience have not been efficiently explored yet. The most recently used terminologies for resilience are *risk*, *hazard*, *vulnerability*, and *robustness* [27], [28].

Fig. 2 illustrates the notion of resilience in case of disturbances and corresponding indicators. The functional definition of resilience can be represented using categorized districts of this curve as follows.

1) *Normal State:* During the normal operating state $(t_0 < t < t_i)$, the system fully functions as expected. The main concern in dealing with a power system in this interval is continuous assurance of the grid stability and reliability. Having a sufficient estimation of the possible threats and predictive actions accurately planned could enhance the predisturbance resilience of the grid in case a contingency happens.

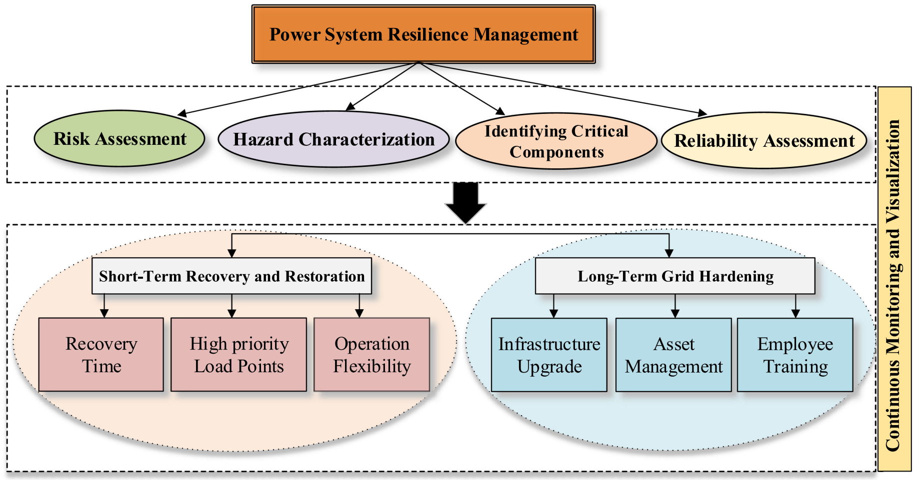


Fig. 3. Short-term and long-term plan management for the enhanced resilience of power systems in the face of probable disruptions.

2) *Disruption State:* At the incident time t_i, an extreme HILP event strikes the system, affecting the grid with one (or several) component(s) out of the service resulting in degradation of the system performance $(t_i < t < t_d)$. The level of performance reduction depends on the outage severity and system architectural design where the concepts of *robustness* and *asset utilization* matter. Robust grids regarding connectivity and resourcefulness, supported by smart grid technologies, can benefit from the operational flexibility required for limiting the resilience degradation when the disturbance is in progress during $t_i < t < t_d$.
3) *Preparation State:* The system operators conduct a fast damage assessment in this state $(t_d < t < t_p)$ to initiate the crew management plans, corrective actions (such as generation redispatch, repair and corrective maintenance, defensive islanding, etc.).
4) *Recovery State:* It is the process of restoring the system performance back to its normal and stable state $(t_p < t < t_r)$. How fast the system resilience can be improved to its maximum level mainly depends on the network connectivity and flexibility, disturbance severity, recovery plans taken, and the operators' training. When the system restores from the disruptive event in the post-disturbance state $(t > t_r)$, the impacts of the disruption on the system performance and resilience need to be assessed and fully analyzed. Such studies allow design and development of adaptive plans that can be taken to enhance the resilience of the critical infrastructure during similar unforeseen events that may happen in future.

B. Task Management for Power System Resilience Improvement

Under the *resilience* premises, Fig. 3 demonstrates the critical task management chart for system resilience in the face of a disruptive event. Following steps should be considered to ensure the safety and resilience of the grid against disruptions.

1) *Identifying the Goals and Metrics:* To maximize the grid resilience and minimize the load outages following a contingency, the first step is to define the metrics for quantifying the system resilience.
2) *Characterizing the Threats:* One significant step in evolving the system to a desired safety and resilience culture is to expand the operators' awareness of electrical hazards across the system (arisen from natural disasters, cyber-attacks, human faults, etc.) and focus on how to make a right decision in a timely manner in response to the predicted vulnerabilities and outages.
3) *Grid Vulnerability and Risk Assessment:* A quantification method based on risk analysis should be attempted to understand the grid operational and infrastructure vulnerability in the face of the hazardous threats with the imposed consequence metrics assessed.
4) *Operational Recovery Decision Making:* Depending on the type and severity of the hazards and the risk metrics quantified, an optimal recovery model should be selected and implemented. A recovery model can include the corrective maintenance actions, replacement of damaged equipment, or operational decisions that use the inherent built-in flexibility of the grid.

As demonstrated in Fig. 3, the resilience of the electricity grid to disruptive events can be enhanced through strategic actions in two chronological paradigms as follows.

1) *Long-Term Grid Hardening:* Due to the continuous exposure of the power grid to external environment and hazardous conditions, it is crucial to plan for strengthening the network resilience over time and making desirable design adjustments. The following strategies are reported in literature: power grid infrastructure upgrade [29]–[32]; tagging equipment [33], [34]; vegetation management [35]; asset management [36], [37]; monitoring technologies [38]–[41]; and crew training and education [42], [43] (see Fig. 3).
2) *Short-Term Response and Recovery:* It includes the temporary remedial solutions in response to a given contingency or threat in power systems. Outage statistics in 2015 reveal that only 33.1% of firms worldwide owned or could share the backup generators in case of emergencies

[9]. A short-term recovery and restoration plan should be preplanned to reduce the outage duration through a faster restoration process. An efficient recovery plan should have the capability to bring the system back to its maximum performance by rapidly feeding the critical load points (LPs) in a prioritized manner.

Several metrics to quantify the grid resilience as well as a short-term mitigation algorithm for fast recovery of the load outages and enhanced resilience to extreme HILP conditions are suggested in Section III.

III. Problem Formulation and Proposed Methodology

A. Proposed Metrics for Power Grid Resilience

This study considers several features of grid resilience grouped under two main concepts: 1) grid connectivity and robustness and 2) grid operational functionality. This paper also proposes quantitative indices to measure the resilience performance of the grid in the face of disruptions. Such quantitative measures can also help in better comparing different recovery options and possible restoration plans (depending on how they affect the overall system safety and resilience), and hence, enhance the operator decision making.

1) Metrics of Graph Spectral Robustness:

1) *Algebraic Connectivity Metric:* The topology of a graph **G** can be represented by the Laplacian matrix. Suppose $[\gamma_1, \gamma_2, \ldots, \gamma_n]$ represents a nondecreasing vector of the eigenvalues of the Laplacian matrix. The algebraic connectivity is defined as the second smallest eigenvalue of the Laplacian matrix γ_2 [44]. We define the grid robustness degree (in %) as follows:

$$R^{\gamma} = \left(\frac{\gamma_2^{S}}{\gamma_2^{S-1}}\right) \times 100 \tag{1}$$

where *s* denotes the system states. This index reflects the algebraic connectivity of the grid after any changes in the network topology compared to the previous state of the grid. In other words, algebraic connectivity indicates the lower bound for grid link or node connections, where the higher the R^{γ}, the better the graph connectivity is.

2) *Grid Sensitivity Metric:* It is a graph-oriented metric that quantifies the grid robustness against any topological changes and is calculated as follows:

$$\begin{cases} R^{\tau} = \left(\frac{2}{N-1}\right) \times \mathrm{Trace}\left(L^{+}\right) \\ \mathrm{Trace}\left(L^{+}\right) = \sum_{i=1}^{n} l_{ii} = \sum_{i=1}^{n} \gamma_i \end{cases} \tag{2}$$

where N is the number of nodes in the network (here buses); L^{+} is the Moore-Penrose inverse of the Laplacian matrix of the grid graph, and Trace (L^{+}) is the sum of eigenvalues for a given grid topology. Note that smaller value for R^{τ} reflects a higher grid robustness, as the network will be less sensitive to changes in its topology. To maximize the grid capacity, one should minimize the node/link criticality of the network. This index can be used to quantify the system reaction to any changes in the network topology [45].

3) *Grid Resistance Metric:* This metric calculates the effective resistance of the grid against any changes in its elements and configuration, e.g., transmission line or node removal, and is defined as follows:

$$\Omega^{\gamma} = N \times \sum_{i=1}^{N-1} \frac{1}{\gamma_i}. \tag{3}$$

The following equation presents the normalized effective grid conductance, always with values within the [0, 1] interval, for better comparisons [46]:

$$C^{\gamma} = \frac{N-1}{\Omega^{\gamma}}. \tag{4}$$

2) Metrics of System Operational Resilience:

1) *Grid Flexibility Metric:* It demonstrates the level of system resourcefulness, enabling a faster recovery process. Network flexibility depends on the components' connectivity and the level of dependency to other elements. In a system with a sufficient number of generating units accessible to many LPs, the redispatch process and corrective actions could be co-optimized as a temporary remedial solution for stabilizing the system facing a contingency. Moreover, the higher access to dispersed generating units, storage units, and fast-start units can be of great help in realizing a faster recovery process. The flexibility index is defined as the ratio of the system's level of performance following each recovery action to that of the system's normal condition. In other words, it is defined here as the amount of served demand following each recovery solution divided by the system's total demand to be met

$$R^{\lambda}_{i,n,d,t} = \frac{\sum_{i\in I}\sum_{n\in N} P^{t|\varepsilon}_{d_n,i}}{P^{T}_{d}} \tag{5}$$

where $P^{t|\varepsilon}_{d_n,i}$ is the active power demand at LP n after the recovery action i in response to the disruptive event ε at time t, and P^{T}_{d} is the target active power demand of the system in its normal and pre-disaster operating condition.

2) *Outage Recovery Value Metric:* A resilient system should be able to minimize the electricity outage costs, i.e., the amount of total customer interruption costs that should be retrieved after each corrective action. It depends on the type of customers (residential, industrial, commercial, etc.) that are disturbed and should be recovered through the restoration plans. The proposed metric to quantify the outage cost recovery is as follows:

$$R^{\mu}_{i,n,d,t} = \sum_{i\in I}\sum_{n\in N} C_{d_n}\left(P^{t|\varepsilon}_{d_n,i+1} - P^{t|\varepsilon}_{d_n,i}\right) \tag{6}$$

where C_{d_n} is the value of the lost load d at LP n (in \$/kWh) and $P^{t|\varepsilon}_{d_n,i}$ is the active power demand (MW) at LP n after implementation of the recovery plan i in response to a disruptive event ε at time t.

3) *Outage Capacity Recovery:* In most cases in many engineering disciplines, the most significant resilience metrics involve how fast a recovery action can restore the interrupted function. The outage capacity recovery (in

MW) determines the power capacity that could be restored through the recovery process within a certain time interval. In other words, the suggested index indicates the percentage of the recovered demand in each recovery step compared to the total demand lost following a disruptive event and can be quantified as follows:

$$R^{\vartheta}_{i,n,d,t} = \sum_{i\in I}\sum_{n\in N} \frac{\left(P^{t|\varepsilon}_{d_n,i} - P^{t_d|\varepsilon}_{d_n}\right)}{\left(P^{T}_{d} - P^{t_d|\varepsilon}_{d_n}\right)} \times 100 \qquad (7)$$

where $P^{t_d|\varepsilon}_{d_n}$ is the active power demand (MW) at LP n at the end of the disruption time t_d.

B. Network Reconfiguration for Enhanced Resilience

It has been demonstrated in the previous literature that the topological reconfiguration of the power transmission system, in normal nonemergency scenarios, may improve the efficiency of power system operations by rerouting the electricity system-wide and enabling redispatch of the lower-cost generators [48]. Moreover, power system topology control through TLS actions is proved to be an effective remedy in response to emergency conditions in power systems. By changing the path of electricity flow in the network, harnessing the built-in flexibility of the transmission system through TLS helps mitigate the voltage and overflow violations, transformer overloads, network loss improvement, etc. [47]–[50].

This paper suggests the use of topology control for enhanced network resilience. A resilience-based Direct Current Optimal Power Flow (DCOPF)-based corrective topology control optimization is suggested in this paper for timely recovery of the load outages and enhancing the system resilience in the face of HILP disruptions. The suggested topology control optimization in dc setting (where bus voltages are assumed to be 1 per unit, and the reactive power is neglected) is a mixed integer linear programming formulation. The optimization model tries to maximize the system resilience [see objective function (8)] through optimal scheduling of system generating units as well as network topology (transmission lines connectivity). A binary variable that can take either the value of 0 or 1 is introduced for each transmission line in the network. The optimization output is the optimal resilience feature quantified as well as the optimal generating unit outputs and transmission line statuses. For demonstration purposes, the grid flexibility metric is utilized in this paper to represent system resilience. As can be seen in (8), the optimization objective is to maximize the grid flexibility metric of resilience following a disruptive event at time t. The optimization problem is subject to several system and security constraints presented in (9)–(15)

$$\text{maximize} \quad \sum_{n=1}^{N}\left(P^{t}_{d,n} - P^{t_d|\varepsilon}_{d_n,i}\right) \qquad (8)$$

$$P^{\min}_{g_n} \le P^{t}_{g_n} \le P^{\max}_{g_n} \quad \forall g \in G \qquad (9)$$

$$P^{\min}_{k}.(1-\beta_k) \le P^{t}_{k_{n,m}} \le P^{\max}_{k}.(1-\beta_k) \quad \forall k \in K \qquad (10)$$

$$\sum_{g\in\Omega_g} P^{t}_{g_n} - \sum_{m\in\Omega_B} P^{t}_{k_{n,m}} = \sum_{d\in\Omega_D}\left(P^{t}_{d_n} - P^{t|\varepsilon}_{d_n,i}\right) \quad \forall n \in N \qquad (11)$$

$$B_{k_{n,m}}.(\theta_{n,m}) - P^{t}_{k_{n,m}} + \beta_k.M_k \ge 0 \quad \forall k \in K \qquad (12)$$

$$B_{k_{n,m}}.(\theta_{n,m}) - P^{t}_{k_{n,m}} - \beta_k.M_k \le 0 \quad \forall k \in K \qquad (13)$$

$$\theta^{\min} \le \theta_n - \theta_m \le \theta^{\max} \quad \forall k(m,n) \in K \qquad (14)$$

$$\beta_k \in \{0,1\} \quad \forall k \in K \qquad (15)$$

where K, G, and N are the sets of network transmission lines, generating units, and buses, respectively; $P^{t}_{g_n}$ is the active power output of generator g (in MW) connected to bus n at time t; $P^{t}_{k_{n,m}}$ is the power flow (in MW) through transmission line k between bus n and bus m at time t; $P^{t|\varepsilon}_{d_n,i}$ is the amount of lost demand (in MW) at bus n due to disruptive event ε at time t which is constrained within the limits $[0, P^{t}_{d_n}]$; $B_{k_{n,m}}$ is the susceptance of transmission line k between bus n and bus m; β_k is the switch action for transmission line k between bus n and m (0: no switch; 1: switch); M_k is the Big-M value for transmission line k; and $\theta_{n,m}$ is the bus angle difference between bus n and bus m.

The output power of generating unit g at bus n is limited between its physical minimum and maximum capacities in (9). Constraint (10) limits the power flow across transmission line k connecting bus n to bus m within the minimum and maximum line capacities. Power balance at each node is enforced in (11), and Kirchhoff's laws are incorporated in (12) and (13). Voltage angle limits for each bus are set to –0.6 and 0.6 radians and are constrained in (14). The status of any transmission line k of the system is identified via an integer variable in (15).

Parameter M_k is a user-specified large number greater than or equal to

$$\left|B_k\left(\theta^{\max}_{n} - \theta^{\min}_{n}\right)\right|$$

which is selected to make the constraints nonbinding and relax those associated with Kirchhoff's laws when a transmission line is removed from service. Parameter α introduced in (16) limits the number of open transmission lines in the optimal reconfigured network (i.e., 1-line, 2-line, etc. switches)

$$\sum_{k}\beta_k \le \alpha \quad k \in K. \qquad (16)$$

The optimization engine is able to provide several sets of optimal solutions for any selection of α. Several topology control plans (in the form of a single or a sequence of TLS actions) can be provided for each forecasted disruptive event, considered as the recovery actions to be implemented during the restoration process. Note that the solutions are found in the system operational time frame (e.g., day-ahead) in response to critical contingencies. Each optimal TLS plan will migrate the system into a new operating condition with different levels of resilience and robustness. Depending on the resilience performance of the grid supplied with the provided solutions, the operator can select the final best reconfiguration plan for implementation, i.e., the one that improves the system resilience, safety, and reliability the most.

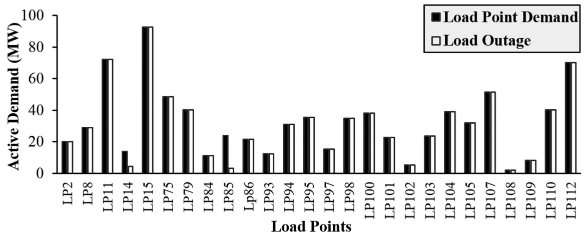


Fig. 4. Impact of G13 contingency on network LPs: load outages and survived demand.

IV. Case Study: IEEE 118-Bus Test System

This research effort is tested and verified through a case study on the IEEE 118-bus test system, which contains a total of 186 transmission lines, 19 generating units, with the total capacity of 5859.2 MW, serving a total demand of 4519 MW. The optimization formulation for fast recovery in the face of HILP events, i.e., co-optimization of the generation redispatch and topology reconfiguration through TLS actions, is implemented with the primary goal of maximizing the system resilience. The optimization problem and the analysis were run on a PC with an Intel(R) Core(TM) 2.9 GHz processor and 8 GB of RAM. The optimization allows the status of each transmission line as well as the optimized generation dispatch to be determined, overall counted as the recovery action. Several optimal TLS solutions taking into account different values for the maximum number of open transmission lines are obtained. This allows benefiting from a sequence of TLS actions that incrementally change the network topology, adjusts the flow of power, and improve the system resilience.

In this paper, one nontrivial contingency, the outage of generator 13 (G13), which is the largest unit with the highest capacity in the studied network, is considered as an HILP disruptive event. Among the total 99 LPs of the system, 26 LPs are partially or fully affected by this weather-driven HILP phenomenon. The initial system-wide load outage caused by the G13 contingency is 805.2 MW, of which only 584.3 MW (72.6% of the system total load outage) can be recovered through the traditional generation redispatch-only practice. Fig. 4 illustrates the load outages as a result of the studied contingency, and the demand survived at each bus. Hence, a co-optimization of generation redispatch and topology reconfiguration is pursued anticipating additional benefits in recovering the load outage in a timely manner.

A. Proof of Concept: TLS for Enhanced System Resilience

The proposed formulation for corrective resilience-based topology control is applied to the studied network faced with the G13 contingency, and various optimal topology control plans for outage recovery are found as depicted in Fig. 5. The suggested recovery plans based on network topology control involve one or more TLS actions in the form of a sequence that incrementally recover the load outage and improve the system resilience. The grid flexibility metric [see (5)], representative of the system resilience, is quantified for each optimal restoration plan suggested via the optimization framework. Further details on the optimal TLS actions as well as their associated benefits in terms of load outage recovery are tabulated in Table I.

Fig. 6 illustratively proves the general concept and demonstrates the advantage of the proposed network reconfiguration strategy using TLS actions for recovery of the load outages and enhancing the system resilience. As one can see from the resilience chart in Fig. 6, the studied network faces an HILP event at time 10, and the system performance (here, the total system demand to be served) degrades to a minimum, resulting in 805.2 MW load outage in 10 min.

At time 20, recovery actions should be initiated by the system operator to maintain the system safety and reliability performance through enhanced network resilience. As previously mentioned, the optimization engine is simulated in the operational planning time-frame (e.g., day-ahead) in response to this critical contingency, and the solution recovery plans are ready to be implemented at time 20. For demonstration purposes, six recovery plans are compared in Fig. 6, where the generation redispatch-only practice following the studied disruption is also included [52].

It can be observed, from Fig. 6, that while the load outage recovery through a 10-min redispatch practice at time 20 is significant (72.6%), all the other five restoration plans can further restore the interrupted loads, some of which leading to almost 100% load outage recovery. To put a figure on this, take the TLS Plan 5 as an example. This recovery plan involves 4 TLS actions that need to be sequentially implemented together with the generation redispatch actions at each level, combined taking a 40 min implementation time leading to the 97.3% recovery of the system load outage ($\sim$25% more than the redispatch-alone practice). Similar observations can be made for other optimal topology control plans presented, which highlights the benefits of employing the built-in network flexibility for corrective recovery and load restoration in this case.

Note: Implementation time requirement for each TLS action involved in a recovery plan is 10 min as it is accompanied by a generation redispatch process and restricted by the ramping up/down requirements of the system generating units. Hence, it takes 10, 20, and 30 min to implement a 1-line, 2-line, and 3-line TLS plan, respectively.

As the suggested optimization framework for outage recovery is able to suggest multiple recovery plans per forecasted contingency, the possibility of having at least one mitigation plan meeting all the other practical requirements (e.g., system stability, circuit breaker reliability, electric safety considerations, etc.) is very high, which is, thus, one more advantage of the suggested framework. With several optimal restoration options available, all of which providing significant load outage recovery, the operator needs to select one of such temporary plans for final implementation. Several key factors such as implementation duration (representative of how fast the system resilience can be improved), the amount of outage recovery (reflective of system robustness), and prioritized LP restoration, etc., could individually or collectively help the system operator make the best decision. In case of the studied example, although TLS plans 1, 2, 4, and 5 can all bring about potentials for some benefits to the grid resilience, they recover the critical LPs, those

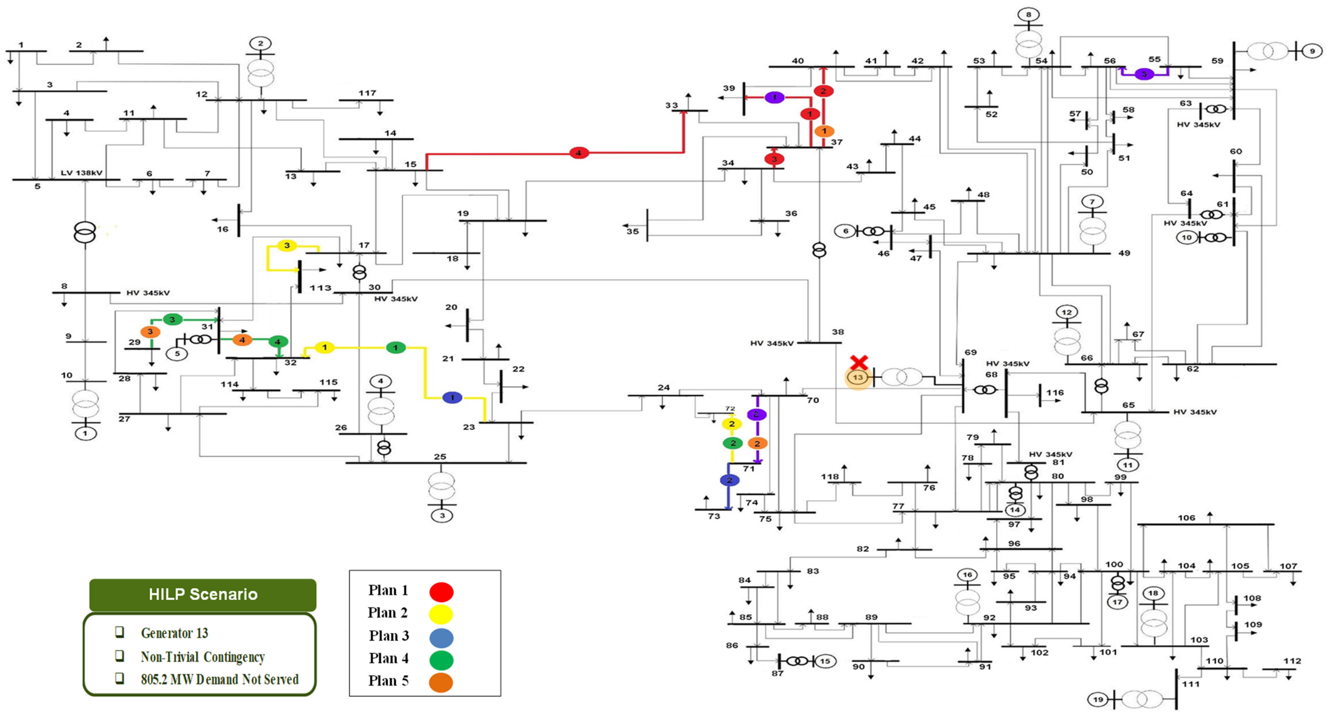


Fig. 5. Optimal TLS sequences for enhancing the grid resilience in the face of the HILP event (outage of G13).

TABLE I
LINE-BUS CONNECTIVITY OF THE RECOVERY PLANS FOR CONTINGENCY G13: IEEE 118-BUS TEST SYSTEM

Line	From Bus	To Bus	Recovery Plan	Sequences of Optimal TLS Actions	Recovered Outage (MW)
40	29	31	RDO*	N/A	586.452
41	23	32	TLS Plan1	[52]-[53]-[50]-[44]	752.409
42	31	32	TLS Plan2	[41]-[112]-[178]-RD	753.57
44	15	33	TLS Plan3	[41]-[113]-RD	799.2
50	34	37	TLS Plan4	[41]-[112]-[40]-[42]	764.439
52	37	39	TLS Plan5	[53]-[110]-[40]-[42]	783.146
53	37	40	Grid Flexibility Features: Resilience State following Each Optimized Recovery Plan		
79	55	56			
110	70	71			
112	71	72	*RDO: Re-Dispatch-Alone Practice		
113	71	73	*RD: Re-Dispatch Action		
178	17	113	*[x]: Transmission Line to be Switched Off.		

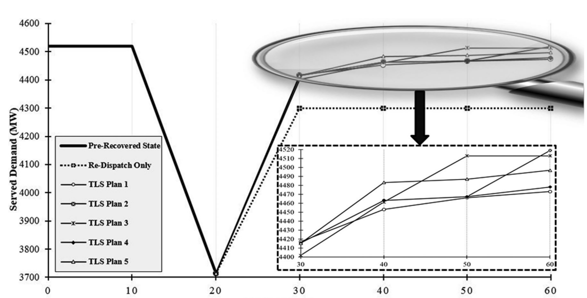


Fig. 6. Load outage restoration through optimal corrective TLS plans.

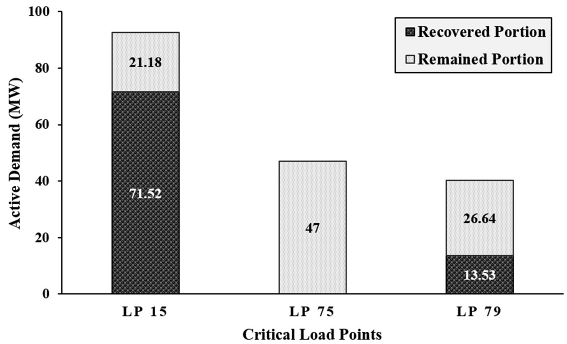
with the highest restoration priority, differently. In other words, critical LPs may be restored faster in some recovery plans than the others.

In other special circumstances, e.g., less survivable systems, the system functionality might fall below a certain operating point following an HILP incident. In this case, it is vital to select the fastest temporary restoration plan first to bring the system back to its operational mode, regardless of other longer optimal plans with the highest outage restoration benefit. Thus, selection of the best plan for implementation also depends on the network configuration, customer types that are interrupted (e.g., commercial, industrial, residential, etc.), the operator's judgment and preference, as well as the goal he/she is seeking to improve the system overall safety and resilience.

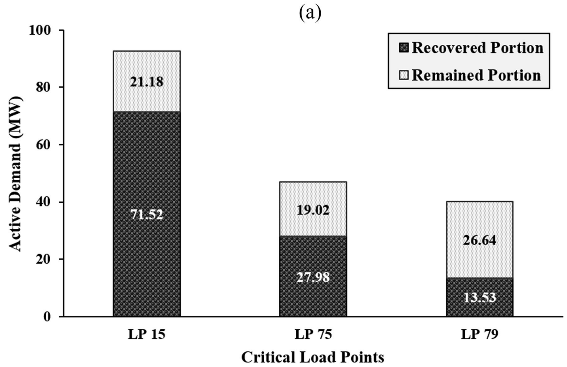
B. Impact of TLS on Restoration of Critical LPs

As discussed earlier, the interrupted demand following an HILP incident may be of different types and criticality, thus imposing different outage costs and socio-economic consequences. The system operator must be aware of the grid geology and be prepared for which restoration strategy to follow. Identifying the system critical LPs in each region can be of great help in realizing a faster recovery and higher resilience. The impact of optimal network reconfiguration on the recovery of the critical LPs of the studied network facing the HILP incident is further analyzed in this section. Of all disrupted LPs, three of them are considered critical since LP15, LP75, and LP79 feed the industrial, commercial, and military demand sectors, respectively. The optimization objective (8) is adjusted to find the optimal restoration plans to recover the load outages in a timely manner considering the LP criticality.

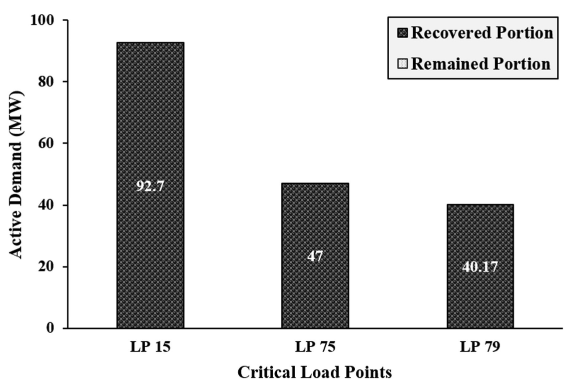
Fig. 7(a)–(c) illustrates how the proposed optimal recovery actions are able to restore the aforementioned critical LPs incrementally. As it can be seen in Fig. 7, LP15, LP75, and LP79



(a)



(b)



(c)

Fig. 7. Demand restoration of critical LPs through the implementation of an optimal corrective TLS sequence. (a) Critical LPs restoration via first TLS action: L52. (b) Critical LPs restoration via second TLS action: L52-L110. (c) Critical LPs restoration via third TLS action: L52-L110-L79.

were serving a total demand of 92.7, 47, and 40.17 MW, respectively, under a system normal operating condition. With the HILP incident stroked at G13, all three of these LPs are fully interrupted with 100% load outage consequence. The proposed optimization engine is able to suggest a recovery plan, among several others, consisting of a three-action TLS sequence (L52-L110-L79) that, if sequentially implemented, can iteratively recover the demand associated with the target critical LPs (this suggested restoration plan is demonstrated in violet circles and lines in Fig. 5). Fig. 7(a) shows how implementing the first TLS recovery action (opening transmission line 52) helps the LP restoration, with which 77.15% and 33.67% of the interrupted demand in the critical LP15 and LP79 are recovered, respectively, within 10 min. However, the demand at LP47 still remains fully interrupted with no recovery with this single TLS

TABLE II
GRID ROBUSTNESS ANALYSIS FOR EACH SUGGESTED RECOVERY PLAN IN RESPONSE TO CONTINGENCY G13

Recovery Plan	Grid Resistivity	Grid Connectivity	Grid Flexibility	Grid Conductivity
BC*	2.2414	0.07440	6.324	0.0075
Plan 1	2.5147	0.07433	6.188	0.0067
Plan 2	2.3903	0.07414	6.222	0.0071
Plan 3	2.2950	0.02910	6.256	0.0073
Plan 4	2.4148	0.07414	6.188	0.0070
Plan 5	2.4099	0.07421	6.222	0.0070

* Base Case Condition

action. Subsequently, second TLS action within the suggested recovery sequence is implemented (opening transmission line 110, while transmission line 52 remains switched-out), and the interrupted demand in LP75 is recovered by 59.52% in 20 min [see Fig. 7(b)], while no additional recovery could be realized for LP15 and LP79. Eventually, the suggested restoration sequence can be fully implemented in 30 min by performing the third TLS action (opening transmission line 79, while transmission lines 52 and 110 are remained switched-out), and according to the results presented in Fig. 7(c), the entire interrupted demand in all critical LPs of the system is fully restored in 30 min. Note that the TLS actions include switching the line out of service by opening the circuit breakers as well as a 10-min generation redispatch implementation, combined realizing incremental benefits in terms of outage recovery and power grid resilience.

C. *Grid-Scale Resilience Analysis*

Generally speaking, an electric power grid with a higher number of transmission lines (i.e., a higher level of network redundancies) provides a more flexible control over energy delivery with an increased power flow capacity. This higher flexibility offers higher elasticity to reroute the power flow system-wide, bypass the damaged equipment, and means to mitigate the risk of cascading failures and grid-scale outages. Quantifying the network robustness is important for decision making on corrective restoration plans (either through topology control or microgrid operations) for enhanced resilience. Therefore, the grid resistivity and other robustness metrics are calculated as supplemented resilience metrics for each optimal recovery plan suggested through the optimization engine. Table II demonstrates the resilience metrics on grid robustness for each recovery plan formerly proposed in Table I, where each network topology control plan impacts the system resilience differently. The network possesses the highest robustness in the base case condition. In general, the lower the resistance index is, the lower the system sensitivity is to any transmission line removal. The higher the other indices in Table II are, the better the grid capability is to withstand any topology changes. As the HILP incident strikes the network, its robustness changes. With several different optimal restoration plans proposed, the operator should consider selecting a final recovery plan that not only assures the highest outage recovery in a faster time frame, but also offers higher grid resilience. For instance, the proposed plan 3 is a recovery option composed of two TLS actions. While it restores 99.25% of the interrupted demand, the network connectivity is much less than that for other plans as the switched lines are connected to a critical LP with a fewer number of transmission lines attached. So, switching out a line from that bus might put the grid at risk if another contingency occurs during restoration.

V. Conclusion

Resilience is the ability of the system to restore itself, with little or no human intervention, to a safe and reliable operation from any disturbances or outages. With the increasing exposure of the electricity grid to several sources of hazards arisen from natural disasters or malicious cyber-attacks, realizing an enhanced resilience is essential through deployment of advanced hardware and software technologies as well as streamlined recovery processes and decision-making strategies.

This paper strived to propose a resilience-based smart grid application of harnessing the full control of transmission assets in the face of emergency scenarios. The suggested approach employs the network reconfiguration as a temporarily corrective tool in dealing with the forecasted contingencies for load restoration. Several resilience metrics corresponding to each proposed recovery plan were quantified aiding the operator to make a more efficient decision on which one to implement. Results revealed that implementing the suggested recovery options restores the load outages and improve the system overall safety and resilience very fast.

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