Quantifying Power System Resiliency Improvement using Network Reconfiguration

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***Abstract*—Electricity grid complexity with its diverse critical infrastructures has been continuously evolved into a more complicated network that is vulnerable to unpredictable hazards of internal and external origins. Resiliency assessment of the large-scale smart electricity grids has recently attracted many attentions in electric industry for more efficient daily operations in face of emergencies. This paper aims to quantify the power system resiliency in dealing with grid severe vulnerabilities and extreme emergencies. The suggested approach for resiliency improvement is to harness the existing system infrastructure, with minimum additional cost, through transmission network reconfiguration. The applied concept of reconfiguration is predictively planned and used as a temporary operation mechanism for the main sake of electricity outage recovery. The system resiliency features, e.g., flexibility, capacity recovery and the imposed cost indices, are quantified for each optimal reconfiguration option, helping the system operators evaluate the recovery options and decide on the final plan for implementation considering its impacts on system resiliency requirements. The suggested approach is tested on the IEEE 118-Bus test system under a critical contingency and the results reveal its applicability and efficiency.**

***Index Terms*— Emergency; network reconfiguration; optimization; resiliency; transmission line switching.**

I. NOMENCLATURE

A. Sets

$d \in D$	System demands (loads).
$g \in G$	System generators.
$t \in T$	Time step.
$k \in K$	System transmission lines.
$n \in N$	System buses.
$i \in I$	Iteration number for recovery process.
$\varepsilon \in \mathrm{E}$	Disruptive incident.

B. Variables

$P_{g_n}^t$	Active power output of generator g connected to bus n at time t [MW].
$P_{k_{n,m}}^t$	Power flow through line k between bus n and bus m [MW] at time t.
β_k	Switch action for line k (1: no switch, 0: switch).
$\theta_{n,m}$	Bus angle difference between bus n and bus m.

C. Parameters

$B_{k_{n,m}}$	Susceptance of link k between bus n and bus m.
C_{d_n}	Value of lost load d at each load point n.
d_n	Demand (in MW) at bus n.
M_k	M-Value for transmission line k.
t_d	Time at the end of a disruptive incident.
$P_{d_n,i}^{t\|\varepsilon}$	Active power demand at bus n after the recovery action iteration i in response to disruptive event ε at time t [MW].
P_d^T	Total target active power demand in the system normal operating state [MW].
$P_{g_n}^{\max}, P_{g_n}^{\min}$	Max. and min. generation limit for generator g at bus n [MW].
$P_{d_n lost}^{t\|\varepsilon}$	Amount of lost demand in bus n at time t after disruptive incident ε [MW].
$P_{d_n}^{t_d\|\varepsilon}$	Active power demand at bus n at the end of the disruption time [MW].
$P_k^{\max}, P_k^{\min}$	Max. and min. power flow of line k [MW].
$\theta_n^{\max}, \theta_n^{\min}$	Max. and min. bus angle difference at bus n.

D. Indices

$R_{i,n,d,t}^{\lambda}$	The flexibility of demand d at load point n when adopting the network reconfiguration plan i at time t.
$R_{i,n,d,t}^{\vartheta}$	Recovery capacity of demand d at load point n when adopting the network reconfiguration plan i at time t.
$R_{i,n,d,t}^{\mu}$	Outage cost recovery of demand d at load point n when adopting the network reconfiguration plan i at time t.

II. INTRODUCTION

DISRUPTIVE events, whether they are natural catastrophes, e.g., floods, hurricanes, thunderstorms, etc., or malicious cyber-attacks or even human-caused faults, may have significant impacts on real-time operation of the complex power networks composed of numerous interconnected structural and functional components and structures [1].

Resiliency is defined as the *flexible ability of an electricity grid to restore itself, with little or no human interventions, to its normal and reliable operating condition from any disturbances, outages, or blackouts* [2]. The concept of system resiliency is mostly about the unpredicted rare extreme failures of High Impact Low Probability (HILP) nature. Within the resiliency domain, it is always crucial to think about the challenges associated with both restoration and repair process in response to an outage. Therefore, the task of improving resiliency of the electricity grid in face of emergencies is challenging. Power systems are traditionally planned and operated to be reliable during normal conditions and

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foreseeable contingencies, but may not be adequately resilient to HILP events, such as severe weather phenomena and natural hazards. 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.

Planning for enhanced system resilience has not been well explored, especially in the context of power transmission systems, and thus, attention needs to focus on allocation of tangible resources, tradeoffs among various dimensions of system resilience, the relationship between community resilience and that of the built environment, and data-driven standards ensuring resilience.

Most of the recent approaches proposed for resilience interpretation and definition include aspects of a system withstanding disturbance, adapting to the disruption, and recovering from a state of reduced performance. A practical probabilistic outage and asset management scheme is proposed in [3] to enhance the resilience of the smart electricity grids. An optimal hardening strategy is presented in [4] through upgrade of poles and vegetation management which is planned to enhance the resilience of power distribution networks by protecting the system against extreme weather events. A conceptual framework is developed in [5] for power system resilience based on the importance of the critical infrastructures. A general study is conducted in [6] with the aim of increasing resiliency of the critical electric power grid infrastructures in response to natural disasters. Reference [7] has described an approach for assessing the real-time operational resilience of power systems taking into account how disruptive conditions affect the failure probability of transmission lines. Two resilience optimization frameworks based on system component importance and criticality is presented in [8], [9]. In [10], realizing robust power systems with independent infrastructures for enhanced grid reliability and resiliency is studied and analyzed.

To the best of the authors' knowledge, the past literature were mostly founded based upon the fact that as a consequence of a disruptive event in power systems, part(s) of the network would be out of electricity, some equipment (transmission lines, transformers, customers, etc.) would be out of service for a while, and the researchers have been trying to improve the system resilience by prioritizing the affected equipment in terms of their importance and criticality for system resiliency. The main goal of the past research has been to minimize the outage cost and maximize the system performance through an effective restoration process of the compromised (i.e., failed) equipment. In other words, the restoration plans are suggested to be triggered starting from restoring the equipment with higher priority to system resilience down to the rest. This will lead the system to be restored back to its reliable, secure, and normal operating condition through prioritized maintenance of the failed equipment [11]. The main drawback with the previous methods is the fact that the system still experiences the electricity outage, in case of a severe grid disruption, and the restoration is initiated only through maintenance of the affected components which may be a timely procedure.

Different from the past research on system resilience, the proposed approach in this paper is unique in methodology and perspective. Instead of positioning the operator in a reactive mode in response to outages, the suggested decision-making tool would help, ahead of time, to devise restorative plans if a given contingency (outage) is forecasted to happen. In this context, weather forecasts and environmental patterns would help the operators have a clue on the electric system performance in face of disasters. This study is focused on quantification of the system resiliency improvement in case of emergencies through network reconfiguration. Network reconfiguration is done using the transmission line switching actions, i.e., removing lines out of service and, hence, changing the network topology and the way how electricity flows. The suggested approach is a temporary solution which uses the existing infrastructure, here transmission lines, with minimum additional costs, to timely recover the electricity outages and improve the system resilience very fast while allowing sufficient time for repair and maintenance actions.

III. Proposed Formulation

A. Suggested Metrics of System Resilience

This study considers several features of resiliency and proposes quantitate indices to measure the resilience performance of the electricity grid:

- *System Flexibility*: It demonstrates the level of system resourcefulness which enables a faster recovery process. Network flexibility depends on the component's connectivity and the level of dependency to other elements. In a system with sufficient number of generators in many load points, the re-dispatch process and corrective actions might be considered co-optimally as a temporary remedial solution for stabilizing the system faced by a contingency. The flexibility index is defined as the ratio of the system level of performance following each recovery iteration to that of the system normal condition. In other words, it is defined here as the amount of served demand following each recovery iteration, through topology control, to the system total demand to be met.

$$R^{\lambda}_{i,n,d,t} = \frac{\sum_{i\in I}\sum_{n\in N} \mathrm{P}^{t|\varepsilon}_{d_n,i}}{\mathrm{P}^{T}_{d}} \tag{1}$$

- *Outage Cost Recovery*: One aspect of the system resilience is the outage cost reduction, i.e., the amount of total customer interruption costs regained after each corrective action. It depends on the types of customers (residential, industrial, commercial, etc.) that are disturbed and recovered via topology reconfiguration. The proposed metric is presented as follows:

$$R^{\mu}_{i,n,d,t} = \sum_{i\in I}\sum_{n\in N} C_{d_n}\left(\mathrm{P}^{t|\varepsilon}_{d_n,i+1} - \mathrm{P}^{t|\varepsilon}_{d_n,i}\right) \tag{2}$$

- *Outage Recovery Capacity*: In most cases within various engineering disciplines, the resilience metric is interpreted as how fast a recovery action can restore the load outages. The outage recovery capacity determines the capacity capability of the network that can handle the recovery process within a certain time interval. In other words, this index indicates the percentage of the recovered demand in each recovery step compared to the total demands lost following to an abrupt disruptive event. This suggested index can be quantified as follows:

$$R^{\vartheta}_{i,n,d,t} = \sum_{i\in I}\sum_{n\in N} \frac{\left(\mathrm{P}^{t|\varepsilon}_{d_n,i} - \mathrm{P}^{t_d|\varepsilon}_{d_n}\right)}{\left(\mathrm{P}^{T}_{d} - \mathrm{P}^{t_d|\varepsilon}_{d_n}\right)}\times 100 \tag{3}$$

B. Network Reconfiguration for Resiliency

It has been demonstrated in previous literature that the topological reconfiguration of the power transmission system, in its normal non-emergency scenarios, may improve the efficiency of power system operations by re-routing the electricity system-wide and enabling re-dispatch of the lower-cost generators [12]-[14]. The non-emergency topology control optimization in DC setting is a mixed integer linear programming optimization problem which tries to optimize the generation dispatch costs taking into account the flexibility of transmission lines with binary variables. However, the concept of topology control optimizations can be utilized in the system emergency scenarios as well to mitigate the possible grid-scale violations (transformer overloads, line over flows, over/under voltage conditions) [12], as well as to recover from the critical disruptions with load outages [15]-[18].

A resilience-based Direct Current Optimal Power Flow (DCOPF)-based corrective topology control optimization is suggested in this paper with the objective function introduced in (4). The optimization objective is to maximize the system resiliency (here, the flexibility feature is employed for demonstration purposes) following to a disruptive event at time t, subject to several system and security constraints, as presented in (5)-(12).

$$P_{g_n}^{\min} \le P_{g_n}^{t} \le P_{g_n}^{\max} \qquad \forall g \in G \tag{5}$$

$$P_k^{\min}.\beta_k \le P_{k_{n,m}}^{t} \le P_k^{\max}.\beta_k \qquad \forall k \in K \tag{6}$$

$$\sum_{g \in \Omega_g} P_{g_n}^{t} - \sum_{m \in \Omega_B} P_{k_{n,m}}^{t} = \sum_{d \in \Omega_D} (P_{d_n}^{t} - P_{d_n lost}^{t|\varepsilon}) \qquad \forall n \in N \tag{7}$$

$$B_{k_{n,m}}.\left(\theta_{n,m}\right) - P_{k_{n,m}}^{t} + \left(1-\beta_k\right).M_k \ge 0 \qquad \forall k \in K \tag{8}$$

$$B_{k_{n,m}}.\left(\theta_{n,m}\right) - P_{k_{n,m}}^{t} - \left(1-\beta_k\right).\mathrm{M}_k \le 0 \qquad \forall k \in K \tag{9}$$

$$\theta_n^{\min} \le \theta_n \le \theta_n^{\max} \qquad \forall n \in N \tag{10}$$

$$0 < P_{d_n lost}^{t|\varepsilon} < P_d^{T} \qquad \forall n \in N \tag{11}$$

$$\beta_k \in \{0,1\} \qquad \forall k \in K \tag{12}$$

The output power of generator g at node n is limited to its physical capacities in (5). Constraint (6) limits the power flow across line k within the minimum and maximum line capacities. Power balance at each node is enforced by (7) and Kirchhoff's laws are incorporated in Equations (8) and (9). Voltage angle limits for each bus set to 0.6 and -0.6 radians are considered in (10). The demand loss at each bus is constrained to the maximum demand in (11). The status of any transmission line k of the system is identified via an integer variable in (12). Parameter M_k is a user-specified large number which is selected to make the constraints nonbinding. Several topology control solutions can be provided for each forecasted disruptive event, as the recovery plans, each of which may contain one or more switching actions. Depending on the resilience performance of the provided solutions, one can select the best reconfiguration plan for final implementation.

IV. Case Study: IEEE 118-Bus Test System

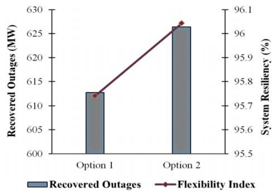
This study has been verified through a case study on the IEEE 118-bus test case that has a total of 186 transmission lines, 19 generating units, with the capacity of 5859.2MW, serving a total demand of 4519MW [3]. The optimization formulation, i.e., co-optimization of the generation re-dispatch and topology reconfiguration through line switching actions, are implemented with the main goal of maximizing the system resilience [see (4)]. It allows the status of each line as well as the optimized generation dispatch to be determined, overall counted as the recovery plan. Several optimal switching solutions taking into account different values for the maximum number of switchable lines (for a given generation and load profile) may be obtained. In each iteration, the network topology changes and the flow adjust itself with the best optimal path considering all problem constraints [see (5)-(12)].

One critical contingency, the outage of generator 13 (G13) which is the largest generating unit in the system, is considered here as a HILP disruptive event and the performance of the suggested formulation in improving the system resiliency is studied. The initial 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 generation re-dispatch-only practice. Hence, a co-optimization of generation re-dispatch and topology reconfiguration are pursued anticipating additional benefits in recovering the load outage in a timely manner.

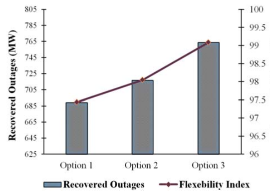
Table I presents various corrective plans suggested through the proposed optimization formulation, each involving one or more switching actions. It is also demonstrated in Table I that how much load sheds would be able to be recovered through adoption of each suggested corrective network reconfiguration plan. Fig. 1(a)-(d) illustrates the resiliency features and quantitative indices [see (1)-(4)] corresponding to each optimized restoration strategy. Fig. 1(a) compares two of the suggested recovery plans involving only one single switching action, in terms of their impacts on the system resiliency. As the results demonstrate, it is possible to restore the system to a level with at most 96% resiliency in 10 minutes through one topology reconfiguration action. Specifically, this plan suggests two options which are able to restore 13.56% and 13.86% of the total demand back to into service, respectively through reconfiguration options 1 and 2 (see table I). Similarly in Fig. 1(b), the best system recovery plan suggested by the optimization framework takes 20 min for implementation and offers 99% resiliency. Regarding this recovery plan with two lines switched off, 15.25%, 15.87% and 16.90% of the load are restored back to the network. Similar observations are made in

$$\max R_{i,n,d,t}^{\lambda} = \left\{ \frac{\sum_{n \in N} \mathrm{P}_{d_n}^{T} - [\sum_{n \in N}\left(\mathrm{P}_{d_n}^{T} - \mathrm{P}_{d_n}^{t_d|\varepsilon}\right) - \sum_{i \in I}\sum_{n \in N}\left(\mathrm{P}_{d_n,i}^{t|\varepsilon} - \mathrm{P}_{d_n}^{t_d|\varepsilon}\right)]}{\mathrm{P}_d^{T}} \right\} \cong \min [\sum_{n \in N} \mathrm{P}_{d_n lost}^{t} - \sum_{i \in I}\sum_{n \in N}\left(\mathrm{P}_{d_n,i}^{t|\varepsilon} - \mathrm{P}_{d_n}^{t_d|\varepsilon}\right)] \tag{4.a}$$

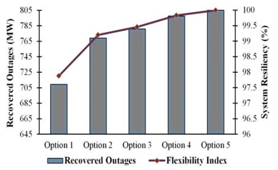
$$\max R_{i,\mathrm{d},\mathrm{n},t}^{\lambda} \cong \min[1 - \frac{\sum_{i \in I}\sum_{n \in N}\left(\mathrm{P}_{d_n,i}^{t|\varepsilon} - \mathrm{P}_{d_n}^{t_d|\varepsilon}\right)}{\sum_{n \in N} \mathrm{P}_{d_n lost}^{t}}] = \max\left\{ \sum_{i \in I}\sum_{n \in N} \frac{\left(\mathrm{P}_{d_n,i}^{t|\varepsilon} - \mathrm{P}_{d_n}^{t_d|\varepsilon}\right)}{\left(\mathrm{P}_{d_n}^{T} - \mathrm{P}_{d_n}^{t_d|\varepsilon}\right)} \right\} \tag{4.b}$$



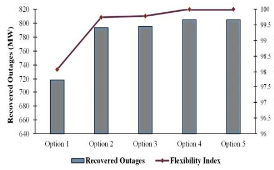
2(a). 1-line switch recovery plan 1.



2(b). 2-line switch recovery plan 2.



2(c). 3-line switch recovery plan 3.



2(d). 4-line switch recovery plan 4.

Fig. 1. The resilience-based system recovery plans using the transmission network reconfiguration.

TABLE I
SWITCHING LINES AND RESOURCEFULNESS OF THE RECOVERY PLANS

Recovery Plan		Switched-Off Lines	Incremental Rate of Demand Restoration (%)
Plan 1	Opt.1	51	13.56
	Opt.2	115	13.86
Plan 2	Opt.1	51-116	15.25
	Opt.2	51-112	15.87
	Opt.3	115-141	16.90
Plan 3	Opt.1	51-116-119	15.70
	Opt.2	51-112-64	17.02
	Opt.3	115-141-132	17.28
	Opt.4	115-141-112	17.65
	Opt.5	51-112-111	17.82
Plan 4	Opt.1	51-116-119-111	15.90
	Opt.2	51-112-64-114	17.56
	Opt.3	115-116-132-133	17.60
	Opt.4	115-141-112-114	17.82
	Opt.5	51-112-64-110	17.82

Fig. 1(c) and Fig. 1(d) taking into consideration that the execution times are 30 and 40 minutes, respectively.

The optimal selection of the resulted options depends on the type of the system configuration, the customer types that are interrupted (e.g. commercial, industrial, residential and so on), training level of the operator, and the goal the operator is seeking based on the resiliency improvement obtained through each suggested restorative plan. One needs to note that practical implementation of each recovery switching action takes roughly 10 minutes considering the generation dispatch adjustment and ramping up/down requirements of the generating units. Thus, it gives another restriction for deciding the appropriate recovery action according to the time needed for implementation which actually implies the outage time duration. In some cases, e.g. less survivable systems, the performance of which falls below a certain operation point due to a disruptive event, it is necessary to execute the fastest temporary recovery action first to bring the system back to its operational mode fast enough regardless of the additional benefits that could be possibly realized if additional time for execution of the best resiliency plan was available. However, in most cases, the economic solution is to assure the highest system resiliency rapidly regardless of the time sensitivity.

V. CONCLUSIONS

Resiliency is the ability for either macro or micro grids to restore itself, with little or no human interventions, to normal, reliable operations from any disturbances, outages, or blackouts. A resilient grid can be better realized via advanced hardware and smart software technologies as well as streamlined processes and efficient decision making strategies. This paper strives to propose a resilience-based smart grid application of harnessing the full control of transmission assets, in case of emergency scenarios. The suggested context utilizes network reconfiguration through transmission line switching as a temporarily corrective tool in dealing with the forecasted contingencies. Several resilience metrics corresponding to each proposed reconfiguration plan were quantified in this paper aiding the operator to make a more efficient decision on which one to implement. Results revealed that one can select one or some of the suggested recovery options to restore the load outages and improve the system overall resiliency very fast.

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