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Resilience Maximization in Electrical Power Systems through Switching of Power Transmission Lines

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Abstract: This research aims to maximize the resilience of an electrical power system after an $N-1$ contingency, and this objective is achieved by switching the transmission lines connection using a heuristic that integrates optimal dc power flows (DCOPF), optimal transmission switching (OTS) and contingencies analysis. This paper's methodology proposes to identify the order of re-entry of the elements that go out of the operation of an electrical power system after a contingency, for which DCOPF is used to determine the operating conditions accompanied by OTS that seeks to identify the maximum number of lines that can be disconnected seeking the most negligible impact on the contingency index J. The model allows each possible line-switching scenario to be analyzed and the one with the lowest value of J is chosen as the option to reconnect, this process is repeated until the entire power system is fully operational. As study cases, the IEEE 14, 30 and 39 bus bars were selected, in which the proposed methodology was applied and when the OTS was executed, the systems improved after the contingency; furthermore, when an adequate connection order of the disconnected lines is determined, the systems are significantly improved, therefore, the resilience of power systems is maximized, guaranteeing stable, reliable and safe behavior within operating parameters.

Keywords: DC optimal power flow; transmission optimal commutation; contingency analysis; electrical power system; electrical power system restoration; resilience

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1. Introduction

Extreme weather events endanger basic infrastructure, such as transportation, communications, water supply, gas and electricity, and these affectations can be so severe that infrastructure might collapse and is observable in the number and duration of energy interruptions caused [1], therefore, due to these unforeseen events, the reliability and operation of this infrastructure are compromised [2–5]. Among the different kinds of infrastructure that are compromised due to unforeseen events, recent research focuses on electricity supply infrastructure that is also vulnerable to natural events [6]. Extreme weather events or natural phenomena directly affect the electricity supply infrastructure, which has a direct impact on society and its economy [7], challenging aspects that require the development of models, methodologies and strategies to minimize the effect on electricity supply.

Technological development applied to electricity infrastructure is evidenced in the integration of renewable energy, distributed generation and smart grids in electrical systems, making planning, expansion and operation activities more challenging. The challenge of these new technologies lies in the dispatch of reactive power and how this affects the reconfiguration of power flows, for which in recent years several authors have focused on solving this problem [8].

The authors of [9] focus on solving the non-linearity problem that occurs in reactive power dispatch models through a backtracking search algorithm. The control of reactive power is not only a problem that occurs at the transmission and generation level, but in the distribution stage as well, and this also includes distributed generation. To solve this problem, the authors in [10] propose a manta ray foraging optimization algorithm, which is a bio-inspired technique for reactive control optimization. Other authors focus on controlling active power to improve voltage profiles in highly radialized distribution networks [11].

For [12], seven indicators are key to determining the resilience index of an electricity system, being: (a) the degree of dependence on fuel in generation, (b) measurement of efficiency of generation, (c) measurement of efficiency in electricity distribution, (d) measurement of carbon dioxide emissions in electricity generation, (e) the probability that electricity will be generated from different types of fuel, (f) redundant power for the available capacity in the event of high probability and low impact events, and (g) the degree of dependence on electricity imports.

A resilient power system must be able to execute preventive actions, mitigate the impact of extreme events, respond optimally through automated control procedures, reduce the time to restore electricity service and lead to significant economic savings, according to [13].

The traditional method to evaluate reliability is based on Monte Carlo simulation (MCS), and in [14], a method for contingency classification is presented that is incorporated to evaluate the reliability of the line switching operation. From these methodologies, a classification list of recommended lines, safe lines and critical lines resulting from the analysis of annual rates and events is obtained, determining that the switching of the recommended lines improves the system reliability [15,16].

The mathematical modeling of climate behavior represents various aspects, including the impact on electrical systems affected by extreme weather events, increased demand for electricity, decreased capacity and efficiency in generation and transmission, reduction of potential resources of water, wind and sun for electricity generation [17]. In [18], and research focused on the risks arising from extreme climate change and its impact on energy infrastructure is presented.

The productive environment is centralized in urban areas with consumption between 60% and 80% of the electricity generated, likewise, the economy and comfort of society depend on the continuity of the electricity supply, which is affected by climate change, cyber-attacks, terrorism, technical deficiencies, and unstable markets, among others, according to [19].

Resilience is defined as the ability of a material, mechanism or system to recover its initial state when the disturbance to which it had been subjected has ceased. The ability of a system to plan and prepare to absorb, recover and adapt to any circumstance that may affect it, such as natural phenomena, earthquakes, fires, floods, volcanic eruptions, hurricanes, and typhoons, among other unexpected phenomena, gives the system a resilient quality [20].

Given these adverse circumstances in [21], it is proposed that electrical systems must have sufficient capacity to withstand these disturbances and guarantee the continuity of the electricity supply; therefore, resilience is the ability to quickly recover from interruptions resulting from an extreme natural event or phenomenon.

Various investigations have emerged, and as part of their results, they agree on a definition of resilience. In [22], the researchers consider resilience as the capacity of a system to mitigate the consequences of rare events, predictable or not, but with a high impact.

Resilience also considers a critical aspect such as the cyber-security of electrical systems, and in [23], researchers establish the concept as the ability to maintain the continuity of the electricity supply within a load priority scheme.

No metrics have been standardized for resilience; however, key parameters can be identified from studies of small signal stability, transient stability, power flows and contingency analyses [24].

In [25], through the statistical analysis of event data, frequency and duration of interruptions, and system restoration times, among others, the resilience of the US electrical network is evaluated using a regression analysis through the Lewis–Robinson test. Simple methodologies are generally used to evaluate resilience and its interrelation in the network infrastructure, the fragility and performance of the infrastructure are considered as a measure of resilience, according to [26].

In [27], there is a compendium on resilience engineering that identifies tools for risk management based on the fragility and performance of the infrastructure, the modeling tends to determine the best strategies to minimize the impact on infrastructure energy systems.

A predominant aspect is the duration of the disturbance, which puts the electrical system to the test to absorb and resist the extreme event, a model that integrates contingency analysis, non-conventional renewable energies, smart grids, management and mitigation of risks inherent to climate events is treated in [28], which seeks to minimize the error to quantify the robustness of the electrical system.

In [29], researchers use probability density functions (PDF), the analysis is based on Markov chains, states and probabilistic scenarios for decision-making and operation strategies of the electrical system, the system operators evaluate and adjust these strategies ensuring a minimum cost. In [30], the authors highlight a fault chain-based model to determine a set of sensitive transmission lines, thus identifying them and improving the ability of a resilient system to prevent and resist extreme disturbances, through statistical analysis. From historical data of failures, load-ability and damage of the transmission system, the failure chains are predicted to quantify and evaluate their level of risk.

In [31], the author deals with the impact on the resilience of electrical systems due to excessive restoration times as a result of analysis through probability distribution of historical data with a period of at least ten years; it is identified that the restoration process depends on many factors, for example, the climate, location, type of failure and the availability of maintenance crews, with which the average restoration time tends to be highly variable.

New technologies of smart grids, micro-grids and wide area monitoring applications would allow rapid system restoration; also, ref. [32] determines the impacts of natural disasters on power systems, concluding that the improvement of resilience of the network involves interdisciplinary techniques, among them, statistics, meteorology, power systems engineering, optimization, communications, control, policies and regulations, stresses the importance of research in methods and tools for the forecast of disturbances related to natural disasters.

Finding a global optimal solution to the transmission line optimization problem is a complex task, since there are many local optimal solutions; in [33], the author compares modeling and optimization for transmission lines from classical techniques, heuristic techniques, meta-heuristic techniques and other promising techniques, the analysis considers from the design to the operation and maintenance of the transmission lines, which is complemented by the comparison of several methods of economic analysis, and better results can be obtained by combining two or more optimization techniques.

The EPS requires specialized analysis to minimize its operating costs, which is why the problems of economic dispatch based on optimal power flows become relevant. Authors in [34] propose a new methodology for the evaluation of the problem of optimal power flows using the gorilla troops optimization technique (GTOT).

Similarly, bioinspired heuristic techniques can be used for the problem of optimal dispatch of generation plants, for example in [35], a methodology for the electro-thermal dispatch of power plants is proposed employing a jellyfish search algorithm. Additionally, the authors in [36] propose a multi-objective solution for the electro-thermal dispatch of generation plants.

In [37], the authors consider reliability maximization as a multi-objective optimization problem that aims to increase transfer capacity, improve voltage profiles, and improve power system reliability. Transmission Expansion Planning (TEP) is a large-scale, mixed-integer, non-linear, non-convex problem; Ref. [38] addresses the transmission expansion planning problem through mixed-integer linear programming based on the linear power flow model for losses and costs of the generator from planning and operation, construction costs of lines, also consider security restrictions $N-1$, the balance of power in each node, state of the line, if it exists or should be built, charge-ability of the line, angular difference, generation dispatch limit, the linear model of generation losses and costs, and its objective function aims to minimize the investment cost.

In [39], transmission switching in expansion planning is treated from the approach of a master problem that uses the set of lines and generation units that are candidates for investment, with two sub-problems to alleviate any violation in transmission and optimal dispatch of generation units. In [40], the probabilistic planning of transmission expansion focuses on random and non-random uncertainties especially related to wind load and generation; likewise, the security $N-1$ is evaluated to find the structure of optimal transmission to meet the peak load demand with minimal investment and losses due to energy not supplied, however, the restrictions increase the cost of transmission investment that can be mitigated by incorporating limits on load shedding.

In [41], the authors use genetic algorithms to separately solve two models that consider the uncertainty of the total demand and the demand in each load bar, the methodology provides an optimal plan for expansion of the transmission network, including more accessible plans. From the economic aspect, they satisfy the uncertainty in the demand; likewise, it allows the analysis of the possible location of demand in each bus and thus determines if it is possible to supply a new load in a specific bus.

The purpose of this research is to identify the order of re-connection of transmission lines in a power system after being affected by a contingency $N-1$, for this, a heuristic is proposed with optimal flows of dc power, optimal switching of transmission and contingency analysis; therefore, as a result, the resilience of the power system is maximized by switching transmission lines.

This article is organized as follows: Section 2 defines some aspects of optimal dc power flows and optimal transmission switching; Section 3 formulates the problem, while Section 4 analyzes and compares results in the IEEE test systems. Finally, Section 6 presents the conclusions of this research.

2. Electrical Power System Operation

2.1. Optimal Power Flow

Optimal power flow is a technique that has been widely used in recent years in the analysis and optimization of electrical power systems.
The authors in [42] developed a method for the optimal flow of fully distributed DC power, sub-problems are generated at the level of neighboring bus bars, the study is developed in the RTS96 and IEEE118 systems, obtaining the optimal solution even under a cold start scenario; however, the initial conditions must be close to the optimum.

The authors in [43] considered interconnected weak power systems that tend to disconnect in the face of extreme events due to their low inertia, as well as the incidence of low and high frequency; for this, based on the optimal power flow limited by separation events, modeled by linear programming of mixed integers, in the test system the improvement of the resilience of the system results from conditions of high and low frequency and levels of inertia in each area.

In [44], the authors present an optimization through optimal stochastic DC power flows with uncertain load and renewable generation capacity, where the reserve of said generators is used within its limits, the results are evidenced in the test systems of 6 and 118 bars in generation costs lower than expected.

In [45], the researchers propose a model that improves the accuracy of the calculation through optimal flows of dc power focused on practical marginal local price markets, the model uses the curve improvement fitting technique that evaluates the losses in the parameters with total lines and lightly loaded.

2.2. Optimal Transmission Switching

In [46], through mixed integer linear programming, the problem of optimal power flows and optimal transmission switching (OTS) is addressed. To modify the transmission topology and optimal generation dispatch binary variables are used to represent the states that describe the physical system. The objective function maximizes the total cost of the system with a number j of lines enabled to switch in the transmission system:

$$TC_j = Max \sum_k c_{nk} P_{nk} \tag{1a}$$

$$\theta_n^{min} \leq \theta_n \leq \theta_n^{max} \tag{1b}$$

$$P_{ng}^{min} \leq P_{ng} \leq P_{ng}^{max} \tag{1c}$$

$$P_{nk}^{min} z_k \leq P_{nk} \leq P_{nk}^{max} z_k \tag{1d}$$

$$-\sum_k P_{nk} - \sum_g P_{ng} - \sum_d P_{nd} = 0 \tag{1e}$$

$$B_k(\theta_n - \theta_m) - P_{nk} + (1 - z_k)M \geq 0 \tag{1f}$$

$$B_k(\theta_n - \theta_m) - P_{nk} + (1 - z_k)M \leq 0 \tag{1g}$$

$$\sum_k (1 - z_k) \leq j \tag{1h}$$

where, k is the transmission lines, n, m are the nodes, g is the generators, d is the loads, θ_n is the voltage angle at the node n, P_{nk}, P_{ng}, P_{nd} are the active power flow to or from line k, generator g, or loads d to node n, and z_k is a binary variable indicating if the line k has been removed from the system. The restrictions consider voltage angle limits, power in generators, power flow limit through the transmission line, the power balance in each node and limit in the number of disconnected transmission lines, as a result, in the test case of 118 bars, a saving of up to 25% is obtained in the economic dispatch.

In [47], the objective function in the approximate OTS model considers minimizing the total costs of electricity generation:

$$Min, P_3 = \sum_n C_n g_n + C' \sum_k \frac{\varepsilon_k}{M_k} \tag{2}$$

where, C_n is the operating cost of the generator n, and g_n corresponds to the power generated by the generator n, ε_k is a decision variable, C is a constant number, and M_k is a very large value. The restrictions contemplate: that the power that enters and leaves a node is equal, the voltage angles in bars, the power flow in lines, the thermal limit of the lines, limits of the generators, and limits of angular difference in bars. The approximate model of OTS in test systems of 14, 39, 57, IEEE 118 and 2383 bus bars provides similar results, but with fewer switched transmission lines. Through the mixed integer programming model with binary variables, ref. [47] addresses the optimal transmission switching under contingency $N-1$, the formulation of the optimal DC power flow under contingency $N-1$ seeks to minimize the costs under the physical constraints of the system:

$$Min, TC = \sum_g c_{ng0} P_{ng0} \tag{3}$$

Being: for $c = 0$ there is no contingency, for $c > 0$ there is a contingency $N-1$; c_{ngc} is the production cost from generator g in state c; P_{ngc} is the power supply from generator g at node n for state c; z_k is the binary variable for the transmit element, 0 open and 1 closed.

The objective function is subject to the angle of the voltage at node n for state c, power balance at the nodes, and limits of transmission lines and generators for each state, from which a reduction of approximately 15% in the cost under contingency $N-1$, switching transmission lines in the generation dispatch.

For [48], in the optimal switching of transmission lines, the computational complexity can be reduced by considering in the algorithm implemented through mixed integer programming a limit of lines selected to be disconnected.

Through mixed integer programming, ref. [49] covers the problem of optimal switching of transmission lines, based on two heuristics: linear programming is solved first and then mixed integer programming, and the procedure removes one line at a time. At the same time, both heuristics depend on the problem of optimal DC power flows to determine a classification of transmission lines for switching.

For [50], transmission congestion management is possible through optimal transmission switching formulated as a mixed-integer nonlinear programming problem, thereby relieving congestion while maintaining voltage safety, identifying the order of the switching operations aside from optimal transmission switching strategies for handling transmission congestion.

The optimal transmission line switching problem treated in [49] is improved through heuristics based on optimal AC power flows [51], and despite being an exact method, it increases the calculation time that is impractical in real situations.

Transmission switching alters the topology of the transmission network, and this is an effective way to reduce operating costs; however, this is achieved by determining a set of suitable transmission lines to be switched, and this process requires in the formulations the inclusion of restrictions and decision variables. Ref. [52] proposes among the restrictions to avoid electrical islands as a result of a set of optimal lines to be switched; however, in an OTS, the computational requirement increases, with the relaxation of the problem in addition that the reliability is not reduced, the computational time improves.

In [53], the author states mixed-integer second-order programming via the AC power flow model; however, the AC transmission switching problem is relaxed by including inequalities in the optimal power flow problem of AC power. However, applying an ACOPF would become a mathematically challenging problem due to the restrictions of the power flow and the variables for commutation that would give rise to two non-convexities.

The optimal transmission switching in, ref. [54], is analyzed from the safety aspect in cases of transmission line overloads and voltage stability, the safety level decreases if transmission lines are disconnected in different locations, and the expected cost per outage tends to increase, the economic benefit is expected to be positive by identifying the topology of the network by incorporating probabilistic security constraints in the optimal transmission switching problem.

In [55], the mixed-integer nonlinear programming model through optimal AC power flow addresses optimal transmission switching and security evaluation considering the $N-1$ contingency criterion, the analysis is sequential for contingencies $N-1$ and energy not supplied, this allows estimating a security level for each solution.

From real-time contingency analysis developed in [56], the researchers provide the corrective AC transmission switching, and the methodology also runs time-domain simulations to verify the dynamic stability of the corrective transmission switching solution; that is, through the contingency analysis, the critical contingency that causes potential violations to the system is identified, and the corrective algorithm finds the effective corrective actions to mitigate these violations, therefore, resulting in the reduction of operating costs, improvement of system reliability and the incorporation of renewable resources.

In [57], the authors study the optimal stochastic transmission switching with optimal DC and AC power flows, and compared with the optimal deterministic transmission switching, the stochastic formulations are faster, and among them, using the optimal AC power flow obtains the lowest operational cost and with less calculation time.

In [58], the research covers the optimal transmission switching problem, poses several mathematical models that consider avoiding the switching of unnecessary lines, avoiding the formation of electrical islands in the system, and justifies the occurrence of the Braess paradox in the OTS problem, the results being the reduction of disconnected lines and the non-formation of electrical islands.

Ref. [59] considers the optimal transmission commutation avoiding electric islands and the real load-ability conditions of the lines based on real climate data, the proposed procedure allows the maximization of the reliability and the minimization of the total cost of generation. The study results on the IEEE RTS-96 system to determine the improvement in the system performance and decrease in generation cost.

3. Problem Formulation

In electrical systems, from the user's point of view, the systems must satisfy the demand for active and reactive power at any moment and for the required time, thus the system operators are responsible for the operational planning of the generation, transmission and distribution resources.

Electrical networks are susceptible to low-probability risks, but whose consequences are of great impact if they materialize. As an example, there can be earthquakes, atmospheric discharges, loss of one or several elements of the system, and cyber-attacks, among others. From the technical–operational point of view, electrical systems can have partial disconnections of generation, transmission and distribution links, and large load centers, until finally the collapse of the entire system, a condition that is not desired by any system operator.

Resilience in electrical systems is referred to any internal or external disturbance, is established as any available capacity of the system that can contribute to avoiding total collapse, going from a relatively normal state to a new disturbed state, but depending on its rapid response allows a new quasi-normal state to be reached, and from the technical aspect, the slightest improvement in the systems and subsystems contributes to the electrical system improving its resilience.

This research aims to maximize the resilience of electrical systems, focusing on the heuristics that incorporate the optimal dc power flow (DCOPF), the optimal transmission switching (OTS), the contingency index, and the switching of the lines disconnected looking for the lowest rate of contingencies concerning the variable δ to establish the order of connection of the disconnected lines, improving the response of the system.

In this work development, the following premises are established: transformers and generators are not considered switching elements, no formation of isolated systems, linear cost of generators, resistance and shunt capacitance of lines is zero, and losses and reactive power are ignored. As a stability criterion, a range is established for the voltage angle δ in bars of $\pm\pi/3$ that allows a dynamic behavior to satisfy the recovery of the system by connecting disconnected lines.

In an electrical system, the contingencies are presented from the output of lines, transformers, generators and even loads to order the severity or impact that occurs in the electrical system, and contingency indices are established with which a ranking of contingencies can be determined based on their severity. From the technique proposed by [60] for ranking and selection of contingencies, a variation for the J index of contingencies presented in Equation (4) is considered.

$$J = \sum_{i=1}^{l} \frac{W_i}{m} \left(\frac{\delta_i}{\delta_{i_{max}}}\right)^m \tag{4}$$

where δ_i represents voltage angle of the voltage at the node i, $\delta_{i_{max}}$ is the maximum angular deviation that is allowed for the voltage at the nodes, which has been established to be 0.6 [rad]. W_i is a factor that represents the importance of the element in the EPS that, for the proposed methodology, it is considered that all the elements are equally important, and for this reason, it is assigned a value of 1, and m is an integer value greater than 1 that allows the elimination of negativity conditions, and for the present study, it was assigned the value of 2.

4. Methodology

The proposed heuristic seeks to maximize the resilience of electrical power systems by switching electrical transmission lines, through the optimal flow of dc power, the initial conditions that will allow comparing results are determined, followed by a contingency of the type $N-1$ in transmission lines and DCOPF plus OTS is executed, and depending on the variable δ, the contingency index is determined for $N-1$ and the SW lines disconnected by the OTS.

The procedure has the following steps: to evaluate the connection options of the disconnected SW lines, to determine the first connection option, one line is restored at a time to execute the DCOPF with which a new contingency index J is calculated, and this is executed for each disconnected line. Having completed the procedure with each of the disconnected lines, the contingency index is evaluated, then the line with the lowest value is option one for re-connection.

Where, δ_i is the voltage angle on the bus i, P_{ij} is the power flow through the line ij, and P_g is the power dispatched by generator g.

Next, to determine the second connection option, the starting point considers the previously identified connected line, the process of connecting the remaining disconnected lines one line at a time is repeated, then DCOPF is executed and the contingency index is evaluated again; finally, after this process, the one with the lowest value is determined, with which line option two is established for re-connection.

Now with the first and second option lines connected, the remaining ones are restored one at a time, DCOPF is run and the least contingency rate is determined to set option three for the line to reconnect, then the following reconnect options are completed. This procedure is repeated until the disconnected lines are reconnected for contingency $N-1$; with the re-connection options, P_{ij}, P_g, δ_i are obtained to appreciate the improvement of the power system by reconnecting the disconnected SW lines in an order obtained. Figure 1 shows this scheme/methodology.

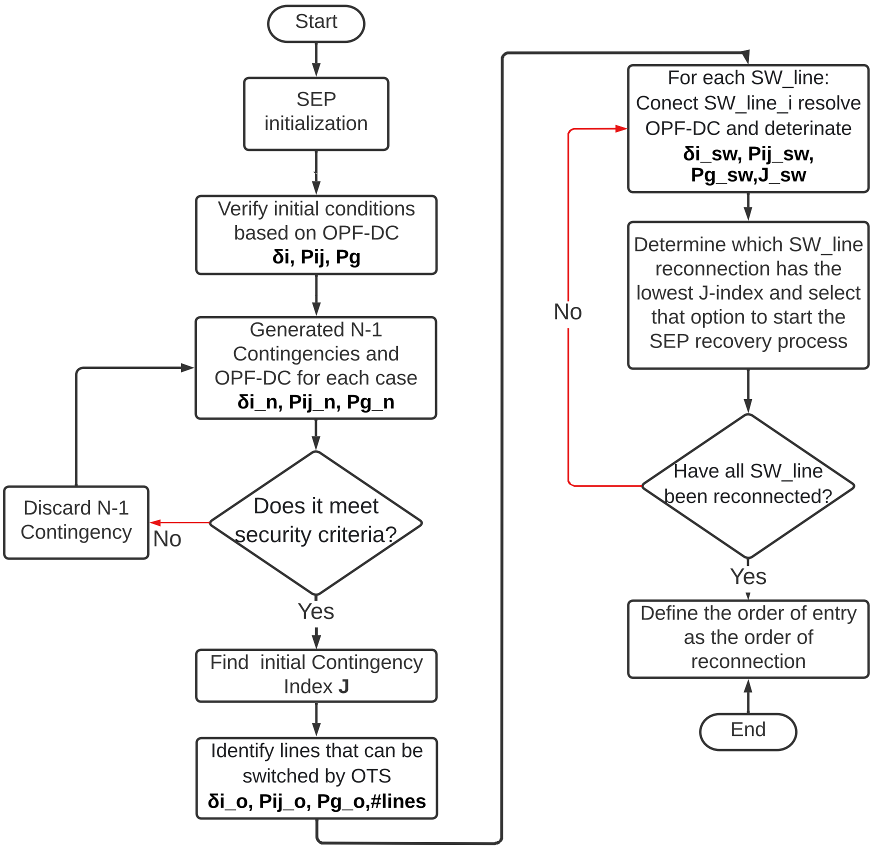

Figure 1. Flowchart for line re-connection.

5. Analysis of Results

The proposal to maximize the resilience of electrical power systems by switching transmission lines was analyzed using three electrical test systems known from the specialized literature. IEEE test and analysis systems correspond to 14, 30 and 39 bus bars. The results are presented in detail for the 30-bar system where the best results were obtained, and for the cases of 14 and 39 bus bars, the results obtained are described as well. The initial topologies and data of the electrical systems have been obtained from [61].

30 Bus Bars System

In the 30-bus IEEE test system, there are 6 generators, 30 bars, 34 candidate lines, 7 transformers, and 20 loads with a total demand of 198 MW, and test system data is shown in the Tables 1–3 and Figure 2. The contingency $N-1$ of the L_{1-2} determines a contingency index J of 0.8612, the execution of the OTS determines the disconnection of seven lines, therefore, the set SW of disconnected lines consists of L_{2-5}, L_{2-6}, L_{8-28}, L_{10-22}, L_{21-22}, L_{23-24} and L_{27-30}, with which the system presents a new contingency index J of 0.4403, and the generation power remains at 1.98 in p.u.

Table 1. 30 bus bar system lines data.

Line i–j	r [p.u.]	x [p.u.]	bij [p.u.]	SIL [MVA]	Line i–j	r [p.u.]	x [p.u.]	bij [p.u.]	SIL [MVA]
1–2	0.0192	0.0575	0.0528	100	16–17	0.0524	0.1923	0	100
1–3	0.0452	0.1652	0.0408	100	18–19	0.0639	0.1292	0	100
2–4	0.057	0.1737	0.0368	100	19–20	0.034	0.068	0	100
3–4	0.0132	0.0379	0.0084	100	10–20	0.0936	0.209	0	100
2–5	0.0472	0.1983	0.0418	100	10–17	0.0324	0.0845	0	100
2–6	0.0581	0.1763	0.0374	100	10–21	0.0348	0.0749	0	100
4–6	0.0119	0.0414	0.009	100	10–22	0.0727	0.1499	0	100
4–12	0	0.256	0	100	21–22	0.0116	0.0236	0	100
5–7	0.046	0.116	0.0204	100	15–23	0.1	0.202	0	100
6–7	0.0267	0.082	0.017	100	22–24	0.115	0.179	0	100
6–8	0.012	0.042	0.009	100	23–24	0.132	0.27	0	100
6–9	0	0.208	0	100	24–25	0.1885	0.3292	0	100
6–10	0	0.556	0	100	25–26	0.2544	0.38	0	100
9–10	0	0.11	0	100	25–27	0.1093	0.2087	0	100
9–11	0	0.208	0	100	28–27	0	0.396	0	100
12–13	0	0.14	0	100	27–29	0.2198	0.4153	0	100
12–14	0.1231	0.2559	0	100	27–30	0.3202	0.6027	0	100
12–15	0.0662	0.1304	0	100	29–30	0.2399	0.4533	0	100
12–16	0.0945	0.1987	0	100	8–28	0.0636	0.2	0.0428	100
14–15	0.221	0.1997	0	100	6–28	0.0169	0.0599	0.013	100
15–18	0.1073	0.2185	0	100					

Table 2. 30 bus bar system loads data.

Node	Pd [MW]	Qd [Mvar]	Node	Pd [MW]	Qd [Mvar]	Node	Pd [MW]	Qd [Mvar]
1	0	0	11	0	0	21	17.5	11.2
2	21.7	12.7	12	11.2	7.5	22	0	0
3	2.4	1.2	13	0	0	23	3.2	1.6
4	7.6	1.6	14	6.2	1.6	24	8.7	6.7
5	0	0	15	8.2	2.5	25	0	0
6	0	0	16	3.5	1.8	26	3.5	2.3
7	22.8	10.9	17	9	5.8	27	0	0
8	30	30	18	3.2	0.9	28	0	0
9	0	0	19	9.5	3.4	29	2.4	0.9
10	5.8	2	20	2.2	0.7	30	10.6	1.9

Table 3. 30 bus bar system generators data.

Node	Pmax [MW]	Pmin [MW]	Qmax [Mvar]	Qmin [Mvar]	Cost [MVA]
1	80	0	150	−20	2
2	80	0	60	−20	1.75
13	40	0	44.7	−15	3
22	50	0	62.5	−15	1
23	30	0	40	−10	3
27	55	0	48.7	−15	3.25

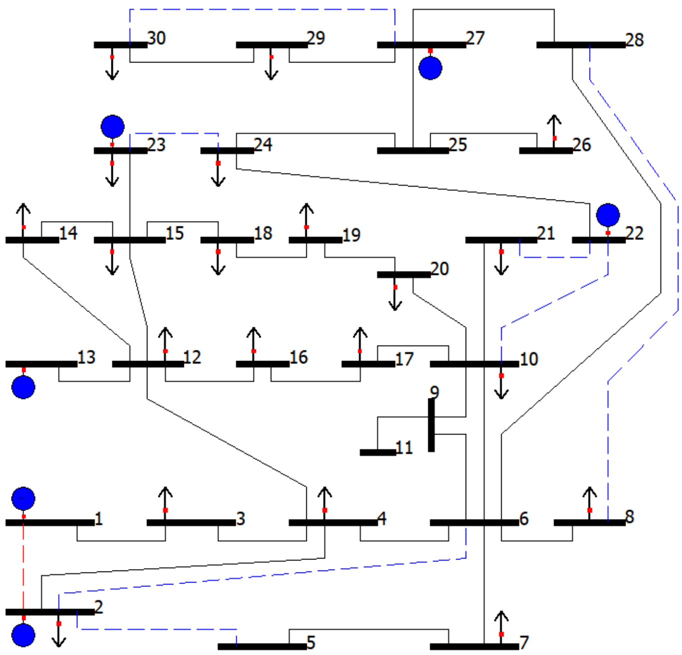

Figure 2. 30 bus bar system, contingency $N-1$ and lines SW disconnected.

To establish the re-connection order of the SW lines, the connection of each line is evaluated when executing the DCOPF, from which the connection with the lowest contingency index J is identified, and in Table 4, the order of re-connection is detailed.

Table 4. Line reconnect options for the 30 bus bar system.

Re-Connection Option	Line	J	SW
1^{ra}	L_{23-24}	0.3745	7 disconnected lines
2^{da}	L_{10-22}	0.3185	6 disconnected lines
3^{ra}	L_{2-5}	0.3053	5 disconnected lines
4^{ta}	L_{1-2}	0.2105	4 disconnected lines
5^{ta}	L_{2-6}	0.1453	3 disconnected lines
6^{ta}	L_{27-30}	0.1379	2 disconnected lines
7^{ma}	L_{8-28}	0.1363	1 disconnected lines
8^{va}	L_{21-22}	0.3186	0 disconnected lines

Figure 3 represents the different combination possibilities, likewise the line with the lowest contingency index J that determines the connection sequence is identified.

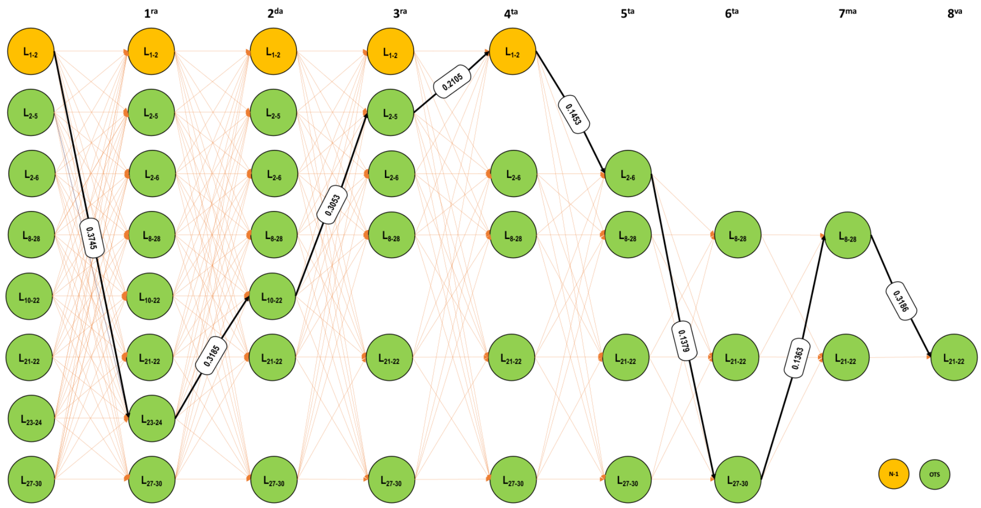

Figure 3. Re-connection lines for the 30 bus bar system.

The variation in the angle of voltage δ in bus bars is presented in Figure 4 for the 30-bus system in a normal state. Additionally, a new contingency state $N-1$, the change of state with the result of the OTS, and finally the connection options of the disconnected lines SW for system restoration are shown as well.

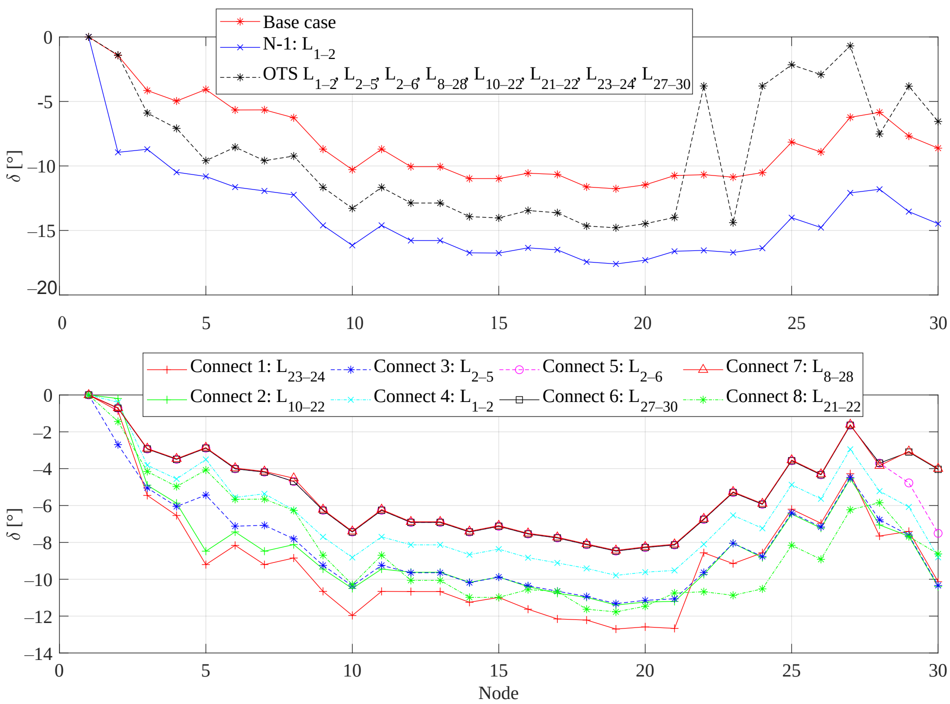

Figure 4. Behavior of the voltage angle δ in the 30 bus bar system.

Regarding power flows through the transmission lines in a normal state of the system, the total demand is satisfied, when changing the topology of the system when the contingency of the L_{1-2} occurs, it is evident that power flows are redistributed without affecting demand when the OTS is executed, and lines are disconnected, which improves the system response, power flows are redistributed, and load capacity is reduced on some of the lines, to name a few, L_{1-3} , 32%, L_{3-4} , 33%, see Figure 5; likewise, the load-ability in other lines of the system is increased. By seeking a connection order for the disconnected lines, the condition of the system is improved and the power flows are redistributed in a better way, an aspect that maximizes the resilience of the system without affecting the demand in the various cases.

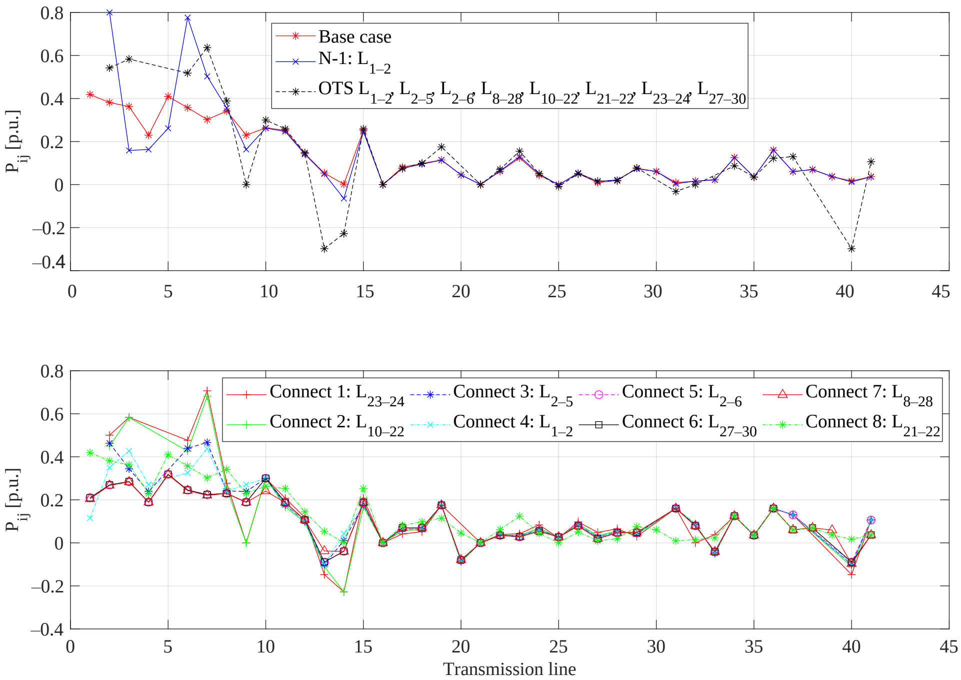

Figure 5. Power flows behavior in the 30-bar system.

The generators of the 30-bar system are dispatched based on their costs; however, in all cases, they satisfy the entire demand of the system.

Through the analysis of the results obtained from the IEEE test systems, the application of the heuristic that links the DCOPF, OTS and index J of contingencies allows us to maximize the resilience of power systems through the switching of transmission lines after a $N-1$ contingency, respecting the operating restrictions of the system.

In the IEEE 14-bar test system, the contingency $N-1$ involving the L_{2-3} presents the highest contingency index J of 0.5243, see Table 5, the OTS determines commutable to the L_{12-13}, the new contingency index J is set at 0.5239, the generation power remains at 2.59 in p.u., for the re-connection order the L_{2-3} is the first option in reason that the contingency index J as a function of the variable δ is 0.3634.

For the IEEE 39 bus test system, the contingency $N-1$ with the L_{2-25} produces a contingency index J of 0.3737, the OTS determines the lines SW disconnected L_{3-18}, L_{16-24} and L_{26-29}; therefore, the system presents a new index J of 0.6832, the power generated is 61.5 in p.u., the order of re-connection to maximize resilience corresponds to: (1) L_{2-25} with a contingency index J of 0.3544, (2) L_{16-24} with a contingency index J of 0.401, (3) L_{26-29} with a contingency index J of 0.315, and (4) L_{3-18} with a contingency index J of 0.3836.

Table 5. Test systems to maximize resiliency.

System	$N-1$	J_{N-1}	OTS	J_{OTS}
IEEE 14 bus bars	L_{2-3}	0.5243	1 line disconnected	0.5239
IEEE 30 bus bars	L_{1-2}	0.8612	7 lines disconnected	0.4403
IEEE 39 bus bars	L_{2-25}	0.3737	3 lines disconnected	0.6832

In the analysis of the results, lines that presented a higher contingency index J were discarded because they included the disconnection of transformers, which is not considered in this investigation. Although the result of the OTS improves the system after a $N-1$ contingency, by determining the line re-connection order that allows the electrical power system to be strengthened, by identifying the lines that improve the system, and above all the order of connection allows us to maximize the resilience.

Concerning the generation in the test systems, the costs of the generators condition the dispatch and participation in each of the analyzed scenarios. This is because the DCOPF seeks to minimize costs, and in this sense, the order of priority depends on the declared costs for each generator.

6. Conclusions

The optimal switching of transmission lines is currently a technical aspect inherent to the operation of power systems, and several investigations have supported its benefits; however, in relatively small power systems it is not even considered an applicable option, probably due to the technical–operational procedures in force for decades, of the heuristics applied in the test systems with the execution of the OTS the systems change to a new relatively stable state, the restrictions and assumptions are respected, followed by the maximization of the resilience of the voltage angle behavior when connecting each of the disconnected lines.

From the operational point of view in quasi-real-time, instantaneous simulations are required, hence several investigations propose the application of optimal DC power flows, the results being quite successful compared to optimal AC power flows; likewise, the DCOPF requires less computational time.

Although electrical power systems can withstand the output of certain defined elements, they must have the capacity and resources to recover, this being the purpose of resilient systems. The system's dynamic behavior has been prioritized by limiting the angle of the bus voltage in a range of $\pm\pi/3$ with which stability problems are avoided; likewise, by applying contingency $N-1$ and evaluating its impact on the elements of the system, determining its severity through the ranking of contingencies, guarantees the system reliability. On the other hand, further degrading the system is avoided by not forming isolated areas or zones that allow for service security.

The development of robust power systems does not always guarantee economy and reliability; in other words, their resilience. This aspect encompasses several methods or techniques that favor the recovery of the system under certain disturbances; among many, switching has been analyzed for transmission lines, identifying the order of re-connection of the disconnected elements, favoring dynamic, reliable and safe behavior.

It is important to consider future studies that include transformer switching, interconnection lines between large systems, reactive compensation equipment, using optimal ac power flows, and real-time analysis.

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