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A Tabu-search-based Algorithm for Distribution Network Restoration to Improve Reliability and Resiliency

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***Abstract*—Fault restoration techniques have always been a crucial aspect for Distribution System Operators (DSOs). In the last decade, it started to gain more and more importance due to the introduction of output-based regulations where DSOs performances are evaluated according to frequency and duration of energy supply interruptions. The paper presents a Tabu search-based algorithm able to assist distribution network operational engineers in identifying solutions to restore the energy supply after permanent faults. According to the network property, two objective functions are considered to optimize either reliability or resiliency. The mathematical formulation includes the traditional feeders, number of switching operations limit, and radiality constraints. Thanks to the DSO of Milan, Unareti, the proposed method has been tested on a real distribution network to investigate the algorithm's effectiveness.**

***Index Terms*—Heuristic algorithms, power system reliability, power system restoration, resilience.**

I. Introduction

RELIABILITY and resiliency represent two fundamental aspects for Distribution Networks (DNs). On the one hand, reliability measures the network's ability to ensure a safe and stable network operation, reducing the amount of disservice procured to the connected users. On the other hand, resiliency measures the network's ability to withstand critical events such as heat waves, flooding, snow storm, etc…, which can lead to multiple faults with the consequent disconnection of several users for very long times. In the last decade, distribution network reliability and resilience received increasing attention from energy Authorities in Italy and worldwide [1]. As a result, energy Authorities have introduced performance indices to establish DNs reliability, considering both interruptions frequency and duration, introducing a system of bonuses and penalties in an output-based paradigm [2].

In this scenario, fault restoration techniques have acquired new importance to reduce disservices to the users and penalties to the DSOs [3]. Restoration techniques for the Medium Voltage (MV) network section located upstream of the faulted point are already well defined and implemented in literature [4]. Indeed, to achieve this goal, it is sufficient to identify and isolate the faulty element and then resupply the users connected upstream to the faulted point by reclosing the tripped circuit breaker located in the primary substation. Furthermore, with the implementation of communication systems and remote terminal units (RTUs), such operation could be achieved automatically using automation techniques, reducing further the time required to restore the energy supply [5]. On the other hand, restoring the network section downstream of the faulted point is still challenging. Historically, due to the smaller size and complexity of distribution systems, such operations were made by engineers who decided the restoration plan based on their experience. However, as the size of the power system and complexity increased, the problem evolved from a relatively straightforward issue, mainly concerning the time minimization to perform such operations, to a multi-objective constrained problem, where traditional arrangement rarely provides fast optimum solutions. Nonetheless, to determine the best possible configuration, it would be necessary to analyze hundreds of thousands of combinations, requiring a massive amount of time.

Several problem formulations and optimization algorithms have been proposed concerning DN restoration [6]. Among the published papers, authors in [7], [8], [9], [10] and [11] includes the DNs reliability, while authors in [12], [13], [14], [15] and [16] focuses on DNs resilience.

In [7], the advantages of using a two-stage restoration strategy rather than a single-stage restoration strategy following fault inception are shown. In the two-stage strategy presented, a first stage quickly restores a limited set of customers using automated switches, while a later stage restores additional customers using manual switches. The two strategies are compared using a predictive reliability assessment algorithm capable of modeling each strategy. In paper [8], the reliability

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assessment of distribution systems embedded with renewable Distributed Generation (DG) sources has been carried out, emphasizing system uncertainties and optimal restoration strategies. The uncertainties associated with renewable resource power output, time-varying load demand, stochastic prediction errors, and random fault events have been accounted for in the restoration optimization formulation for reliability evaluation. In the article, a parameter-free Particle Swarm Optimization (PSO) technique is applied to address the complexity involved in the formulation. A novel Distribution System Reconfiguration (DSR) model including to enhance the service reliability and the benefit of distribution networks with DGs and Energy Storage Systems (ESSs), is proposed in [9]. First, the impact of sectionalizing switches and tie switches on reliability is considered. Secondly, the concept of "boundary switch" is introduced for quantifying the customer interruption duration. The DSR model is presented to minimize the customer interruption cost, the operation cost of switches, and the depreciation cost of DGs and ESSs. Article in [10] establishes a restoration model based on grid actual situation, which is more realistic for Active Distribution Networks (ADN), considering the user priority level, the load amounts restored, the counts of switch operation, the network loss after the power restoration, and the operation of power sources. In [11], an agent-based approach is proposed to optimize the reliability of a system in the restoration process, considering load balancing as a constraint. A modified restoration strategy based on reinforcement learning, namely, the Wolf Pack Algorithm (WPA), is proposed under the multi-agent framework and communication architecture. First, considering the grid network's constraints and the system's dynamic load, several types of agents are defined and abstracted to imitate physical entities. In addition, integrated with the WPA, the Multi-Agent System (MAS) is subsequently utilized to optimize the system's reliability while considering the trade-off of load balancing.

Regarding resiliency, the paper [12] presents a novel modified Viterbi algorithm to identify the optimal distribution system restoration plan for improving grid resiliency. In the proposed algorithm, the switching operations performed for system restoration are the states with the minimum bus voltage being seen as the cost metric for each state and the extent of load recovery as the observed event. Moreover, an improved flexible switching pair operation is employed to maintain the radial nature of the distribution system. In [13], the authors propose a resiliency-based methodology that uses microgrids to restore critical loads on distribution feeders after a major disaster. By introducing the concepts of restoration tree and load group, restoring critical loads is transformed into a maximum coverage problem, a Linear Integer Program (LIP). The restoration paths and actions are determined for critical loads by solving the LIP. Finally, the method is applied to Pullman's distribution system, resulting in a strategy that uses generators on the Washington State University campus to restore service to the Hospital and City Hall. The authors in [14] propose a new dynamic restoration strategy for distribution systems to enhance system resilience against potential hazards. An efficient reconfiguration algorithm is developed to eliminate the use of integer variables to relieve the computational burden. Model predictive control is implemented to adjust the system topology and DER operation setpoints based on the updated fault information and DER forecasts. Authors in [15] use the concept of Minimum Spanning Forest (MSF) to formulate the restoration problem where each spanning tree in a forest is a Self-Sustained Islanded Grid (SSIG). Specifically, a weight is assigned to each edge in a distribution system based on several factors such as their exposure to vegetation, span length, location, and structures supporting them. Then, an MSF is obtained for the given network by switching off the edges with higher weights to form several optimal SSIGs. In [16], a novel networked MicroGrid (MG)-aided approach for service restoration in power distribution systems. The uncertainty of the customer load demands and DG outputs are modeled in a scenario-based form. A stochastic mixed-integer linear program is formulated to maximize the served load while satisfying the operational constraints of the distribution system and MGs.

In this framework, the paper presents a tabu search-based algorithm for DNs restoration able to identify reasonable solutions to back-feeding faulty MV feeders. Such solutions are determined in a two-step approach: the first step consists of back-feeding the out-of-service area while the second performs a series of load shifting operations to ensure the best possible network reliability or resilience. The flexibility of choosing reliability or resilience goals can be exploited according to seasonal periods or based on unexpected critical events. Moreover, traditional topological and electrical constraints are included in the approach. In the algorithm, solutions are found acting on Tie Switches (TS), constituted by normally open switches at the end of MV feeders, and Sectionalizer Switches (SS), constituted by normally closed switches located along with MV feeders. The proposed approach has been tested on a 15kV real distribution network located in Rozzano (Milan), owned by the DSO Unareti. The proposed approach has its main benefits in translating the Italian regulation regarding DNs reliability and resilience into an optimization approach. Therefore, the proposed method allows considering two objective functions related to reliability and resilience to give the operational engineers more flexibility in improving the DN security. Moreover, the objective functions modeled the practical approach used by Unareti engineers in the daily network operation and consider network data easily and readily available in the company databases, instead of complex and most often unavailable information required to compute the traditional reliability and resilience indexes, such as SAIFI, SAIDI etc...

The remaining of the paper is organized as follows: in Section II the problem formulation is given. Section III describes the algorithm developed. In Section IV, some numerical results are presented, while concluding remarks are given in Section V. The algorithm's pseudocode is reported in the Appendix.

II. Problem Formulation

The restoration problem can be treated as a temporary reconfiguration problem where the system returns to its original configuration once the fault has been fixed. The transitory topology has to work in safe conditions, minimizing the customers affected by the service interruption. It is worth noticing that the back-feeding feeders used for network restoration face a transitory increase in power, which gives a potentially dangerous over-stress to the electrical components.

Distribution networks restoration problems can be expressed using optimization models. The objective function selected depends on the DSO goal. The paper considers two objective functions inspired by the Italian output-based regulation defined by the Regulatory Authority for Energy, Networks, and Environment (ARERA). The current rules and metrics to evaluate the reliability and resilience of DSOs are described in the technical report "Integrated text of the quality of the distribution services 2016-2023" (TIQE) [17]. The reliability of the DSOs network is evaluated based on the yearly System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI). The Authority applies bonuses or penalties comparing the DSOs indexes with a pre-defined threshold. In addition, the regulation lets the DSOs exclude from the reliability computation the faults which would happen in the so-called "Perturbated Conditions Period" (PCP), which are defined as periods with an anomalous number of faults. Particularly for urban distribution networks, this situation is usually caused by heat waves. Combining the summer high temperature with the increasing air conditioner load can enormously increase the number of outages, bringing the distribution networks working in stressed conditions. These phenomena and the ability of the network to face hazardous fall into the term of resilience [18].

Doing an in-depth analysis of the location of the faults in the last 5 years, it is observed that the MV feeders are, as shown in Figure 1, the part of the Milan distribution network most affected by failures [19].

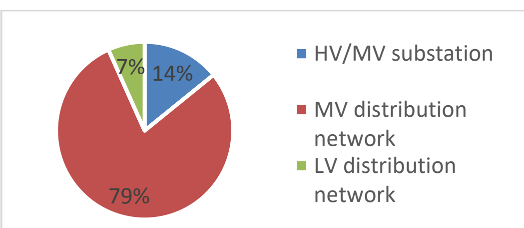

Figure 1. 5-years failures data recorded and its location in the distribution network of Milan.

Almost all the recorded faults affected the MV cables. Only a few faults have been related to HV/MV substations, e.g., short-circuit on bus-bar, triggering of transformer protection devices, and the LV distribution network.

A. Reliability objective function

This section presents the proposed reliability objective function. Considering the failure statistic shown in Figure 1, we defined a risk index for MV feeders, called Feeder Risk Index (*FRI*), which estimates the feeder reliability. The *FRI* of a generic feeder *i* is computed as in (1):

$$FRI_i = L_{fi} \cdot C_{LVfi} \qquad (1)$$

where:

L_{fi} is the length of the MV feeder *i*

C_{LVfi} is the number of LV customers supplied by the feeder *i*

For each feeder, the reliability is estimated by multiplying the feeder extension L_{fi}, assumed to be proportional to the failure probability, by the number of LV customers supplied C_{LVfi}, assumed to be proportional to the impact of faults. For clarity, Figure 2 shows a simplified layout of two MV feeders. For example, the feeder risk index of Feeder1 is $FRI_1 = (L_1 + L_2 + L_3 + L_4) \cdot (C_{LV1} + C_{LV2} + C_{LV3} + C_{LV4})$, while for Feeder2 is $FRI_2 = (L_5 + L_6 + L_7) \cdot (C_{LV5} + C_{LV6} + C_{LV7})$.

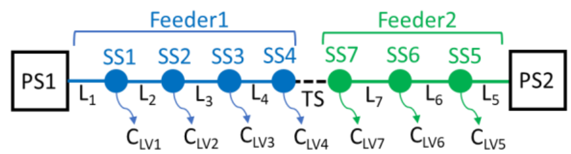

Figure 2. Example of computing the feeder risk index. PS: primary substation bus-bar; SS: secondary substation; TS: tie switch; L: MV branch length; C_{LV}: number of low voltage customers supplied by the SS.

Since the objective function has to measure the reliability of the whole DN, the index reported in (2), which we refer to as the Network Risk Index (*NRI*), is also defined:

$$NRI = \sum_{i=1}^{F} FRI_i \qquad (2)$$

where F is the number of feeders.

Referring to Figure 2, The pre-fault *NRI* is $NRI_{pre-fault} = FRI_1 + FRI_2$.

In order to provide a yardstick as immediate and understandable as possible, the ratio of the *NRI* after ($NRI_{restored\ net}$) and before ($NRI_{pre-fault}$) the reconfiguration is computed. The objective function is therefore to minimize the following expression (3):

$$min \ \frac{NRI_{restored\ net}}{NRI_{pre-fault}} \qquad (3)$$

Considering Figure 2 and assuming a fault on the first branch of Feeder2, the only way to restore energy to the three SSs in green is by closing the TS. Thus, the *NRI* changes as follows: $NRI_{restored\ net} = (L_1 + L_2 + L_3 + L_4 + L_5 + L_6 + L_7) \cdot (C_{LV1} + C_{LV2} + C_{LV3} + C_{LV4} + C_{LV5} + C_{LV6} + C_{LV7})$.

It is worth noticing that the *NRI* demonstrates to be correlated and to measure with a good approximation the SAIFI index, which as mentioned is used in the Italian reliability and resilience regulation, with the advantage of being easily computed [19]. Therefore, the reliability objective function aims to make the feeders' number of users and length as uniform as possible, even in the post-failure topology. In fact, the more the feeders are uniform and, statistically, the less is the impact of a potential failure that could occur when the network has not yet returned to the initial configuration.

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B. Resiliency objective function

Among the extreme weather events, heat waves are the most critical experience for the urban distribution network of Milan [20]. A heat wave is a period of extremely hot weather and climate change makes heat waves more intense and frequent, stressing underground cables. The increase of power demand, caused by massive and contemporary use of air conditioners, and a reduction of the heat transfer from cables to the soil, affect feeder's temperature [21]. Therefore, the weakest part of the feeder chain, the electric power cable joints, experience an increasing number of failures [22]. Heat waves are located in the summertime, mainly June and July.

Although the distribution network is well designed for normal operational conditions, many faults could affect it during heat waves. As shown in Figure 3, a simultaneous fault could cause a prolonged interruption with no possibility of restoration from another feeder. The Unareti experience says that most faults affect the first part of the feeder, the one close to the primary substation (PS) bus-bars, which carries the total power delivered to the users by the feeder itself, e.g., the branch between PS1 and SS1 in Figure 3. In case of an outage on this branch, the power has to come from an alternative path, for instance, the branch SS4-SS7 by closing the TS_1. Feeder 2 has now to carry also the full power of Feeder1, potentially resulting in a simultaneous fault. If a double fault happens on branches PS2-SS5 and SS7-SS4, all the secondary substations (SSs) in red remain unsupplied until one of the two outages is restored. This situation is even more critical in underground cables because finding and repairing the outage could last up to 12 hours.

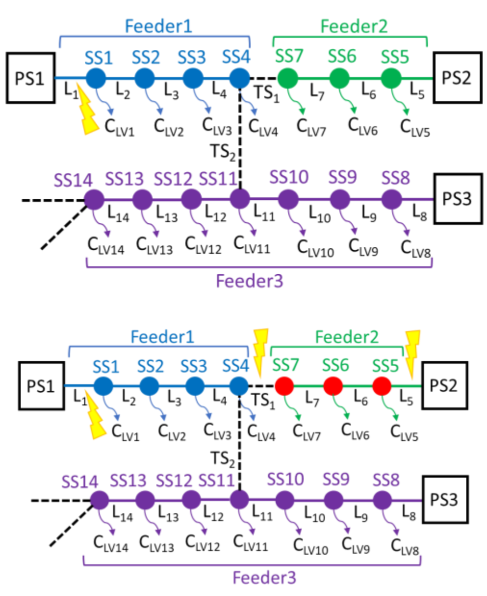

Figure 3. Simultaneous fault and its consequence on the energy supply. PS: primary substation bus-bar; SS: secondary substation; TS: tie switch; L: MV branch length; C_{LV}: number of low voltage customers supplied by the SS.

Following the same approach of the *FRI*, for any of the sections that could suffer from a simultaneous fault, we defined a Section Risk Index (*SRI*) as a measure of resilience. The sections are the network portions comprised of two secondary substations with at least three incident branches or between a primary substation and the first secondary substation with at least three incident branches. Referring to Figure 3, the sections are: PS1-SS1-SS2-SS3-SS4; PS2-SS5-SS6-SS7; PS3-SS8-SS9-SS10-SS11; SS11-SS12-SS13-SS14. Once again, the *SRI* of a generic section *i* can be defined as the product of the failure probability and its impact (4):

$$SRI_i = L_{si} \cdot C_{LVsi} \tag{4}$$

where:

L_{si} is the length of the section *i*

C_{LVsi} is the number of LV customers of section *i*

Failure probability is still proportional to the length of the section L_{si}: longer sections have a higher probability of failure than shorter ones. On the other hand, the failure impact is associated with the number of LV customers C_{LVsi} potentially interrupted in case of a simultaneous fault. Considering the layout in Figure 3, $SRI_1 = (L_1 + L_2 + L_3 + L_4) \cdot (C_{LV1} + C_{LV2} + C_{LV3})$; $SRI_2 = (L_5 + L_6 + L_7) \cdot (C_{LV5} + C_{LV6} + C_{LV7})$; $SRI_3 = (L_8 + L_9 + L_{10} + L_{11}) \cdot (C_{LV8} + C_{LV9} + C_{LV10})$ and $SRI_4 = (L_{12} + L_{13} + L_{14}) \cdot (C_{LV12} + C_{LV13} + C_{LV14})$. The LV customers C_{LV4} and C_{LV11} are excluded from the computations, since the triple connection with other secondary substations protects SS4 and SS11 from the impact of potential simultaneous faults.

Similarly to the *NRI*, for a generic feeder *j*, we defined the index reported in (5), which we refer to as the Feeder Sections Risk Index (*FSRI*):

$$FSRI_j = \sum_{i=1}^{S} SRI_i \tag{5}$$

It is worth noticing that *S* is the number of sections subject to increased power whenever feeder *j* is used for back-feeding an outage feeder. Considering the layout of Figure 3, and supposed to back-feed Feeder 1 using Feeder3, the section SS11-SS12-SS13-SS14 is not included in the computation of the *FSRI* of Feeder 3, since only the section PS3-SS8-SS9-SS10-SS11 sees an increased power when Feeder 3 back-feed Feeder 1.

The resiliency objective function has been defined to reduce the cascade faults probability. Therefore, the objective function is defined to minimize the *FSRI* of the feeders used to back-feed the outage feeder. As already mentioned, unlike the reliability objective function, only the length and LV customers of the sections belonging to the back-feeding feeders subject to increased power flow are computed. Moreover, the *FSRI* is weighted by the power measured at the beginning of the feeder, assuming that higher power increases the probability of faults [23], ending up with the expression (6):

$$min \frac{\sum_{j=1}^{F} FSRI_j \cdot P_j}{\sum_{j=1}^{F} P_j} \tag{6}$$

Where *F* is the number of back-feeding feeders that carry the increased power flow P_j. Thus, the resiliency objective function aims to choose the least risky back-feeding feeders from the point of view of possible multiple failures, which would lead to end-users disconnection for a long time. Therefore, the most resilient routes are preferred, the feeders that expose the shortest routes and with the lowest number of users non-counter-powered.

C. Operational constraints

In order to ensure a safe operation of the network even after the restoration process, the algorithm has to consider constraints related to the network topology and its operation, including nodes and line limits. The constraints considered are reported below:

I. *Radial structure.* DNs are operated radially to avoid difficulties in fault detection, isolation, and feeder protection coordination. Thus, the radiality of the network shall be maintained during the switching operation and at the end of the restoration process.

II. *Buses voltage limits.* Buses voltage must be kept within the operating limit, which standards suggest being +/-5% of the nominal voltage value. The algorithm, therefore, considers inequality (7). V_k is the voltage at the bus k; V_{min} and V_{max} the minimum and maximum voltage value allowed at the node k, considered as $0.95 \cdot V_k$ and $1.05 \cdot V_k$ respectively.

$$V_{min} \leq V_k \leq V_{max} \tag{7}$$

III. *Branches current limit.* Branches current must be maintained within the operating limit to avoid overheating. Since the repair time of the outage components could take time, particularly in underground cables, inequality (8) is considered. Therefore, the current flowing on branch i, I_i, as to be lower than the rated current, $I_{i,Rated}$.

$$I_i < I_{i,Rated} \tag{8}$$

IV. *Switching operations.* The number of switching operations must be limited in order to reduce both switching costs and restoration time. Thus, as depicted in (8), a maximum number of five switching operations is allowed.

$$N_{switchmax} \leqslant 5 \tag{9}$$

III. TABU SEARCH-BASED ALGORITHM

The algorithm developed is based on tabu search [24], a meta-heuristic algorithm used to solve optimization problems. The main advantage of TS with respect to conventional genetic algorithm and simulation annealing lies in the intelligent use of the past history of the search to influence its future search procedures. TS can be viewed as an iterative technique that explores a set of problem solutions by repeatedly moving from one solution x_0 to another solution x_1 located in the neighborhood $N(x_0)$ of x_0. Thus, starting from an initial solution x_0, the tabu search procedure iteratively finds a neighborhood of the current solution $N(x_0)$ made of a set of candidate solutions. Each candidate's objective function is evaluated, and the one with the best value is selected to be the current solution. The procedure is repeated starting from the new solution until a stopping criterion is satisfied. Tabu search is based on the concept of "tabu" as actions that could lead to a counter-productive path towards obtaining better solutions, or specifically, actions that could lead to already visited solutions. A peculiar characteristic of such an algorithm is that it allows actions that deteriorate the current objective function value to avoid being stuck in a local optimum point, which may cause the algorithm to get trapped in cycles. To overcome this issue, memory is used to store a list of attributes that characterize the chosen solution and classify such attributes as "tabu". Thus, a candidate of the neighborhood can be selected as a successive solution only if it has attributes not contained in the memory, which, for this reason, is also named "tabu list".

In the following, an overview of the implemented algorithm is presented. Referring to the layout of Figure 4, given the DN data and the faulty branch, the algorithm builds a virtual version of the network topology and identifies the unsupplied area, e.g., the two secondary substations shown in red. Then, it identifies the open branches available for back-feeding the unsupplied area, the tie switches. In the case of Figure 4, those switches are named TS_1 and TS_2. Each TS corresponds to a possible starting solution, which is stored in the Long-Term Memory (LTM). Finally, the algorithm computes the objective function of each solution either by equations (3) or (6). Moreover, the following current and voltage violations and dangers are computed:

- *Current violation:* when the current of the branch i (I_i) is greater than its rated current $I_{i,Rated}$ (10).

$$I_i > I_{i,Rated} \tag{10}$$

- *Current danger:* when the current of the branch i (I_i) is greater than 75% of its rated current $I_{i,Rated}$ but smaller than its rated current $I_{i,Rated}$ (11).

$$0.75 \cdot I_{i,Rated} < I_i < I_{i,Rated} \tag{11}$$

- *Voltage violation:* when the voltage of the node k (V_k) exceed the limits of ±5% of the rated voltage $V_{k,Rated}$ (12).

$$V_k < 0.95 \cdot V_{k,Rated} \vee V_k > 1.05 \cdot V_{k,Rated} \tag{12}$$

- *Voltage danger:* when the voltage of the node k (V_k) is between the limits of ±5% and ±2,5% of the rated voltage $V_{k,Rated}$ (13).

$$0.95 \cdot V_{k,Rated} < V_k < 0.975 \cdot V_{k,Rated}$$
$$1.025 \cdot V_{k,Rated} < V_k < 1.05 \cdot V_{k,Rated} \tag{13}$$

According to the objective function and the eventual violations and dangers, the most fitting solution, i.e., the one with the best objective function and the lowest number of violations and dangers, will be selected as the starting solution x_0. For example, TS_1 in Figure 4 is selected as the starting solution while the other option remains in the LTM, available for later investigation. The radiality constraint is always satisfied since the algorithm closes a single TS towards an unsupplied and isolated network section.

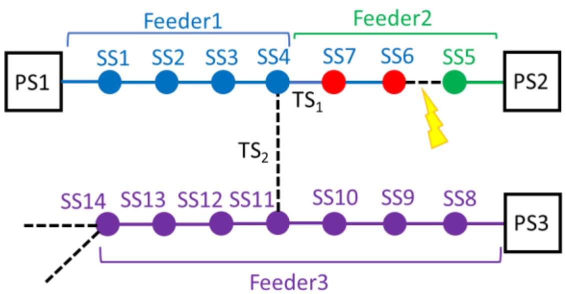

Figure 4. Example of the starting solution related to TS_1. The solution is included in the LTM.

From the starting solution x_0, the algorithm finds the neighborhood $N(x_0)$. The neighborhood is made by the possible solutions that can be obtained from the current solution throughout a single action. Considering action the changing of the network topology throughout the opening and closure of a couple of tie-sectionalizer switches, if such switches were chosen randomly, the neighborhoods would be made by several unfeasible solutions. In fact, all the solutions always have to fulfill the radiality constraint to give a feasible DN operating layout. Therefore, considering Feeder1 shown in Figure 4 as the back-feeding feeder, a neighborhood radial solution can be obtained performing the following operations: opening the sectionalizer switch SS_{F1} making a portion of Feeder1 temporary out-of-service; resupply the out-of-service portion of Feeder1 by closing the tie switch TS_2, to connect the unsupplied portion to Feeder3 (Figure 5). It is worth noticing that, to guarantee the radiality constraint and restore the energy supply to all the customers, the closed TS must always be located downstream of the SS open. The selected neighborhood considers the feeder subject to the highest number of violations and, subsequently, dangers. In fact, the algorithm's goal is to perform a load shifting from the feeder characterized by violations and/or dangers to another feeder, balancing the feeder's extension and load.

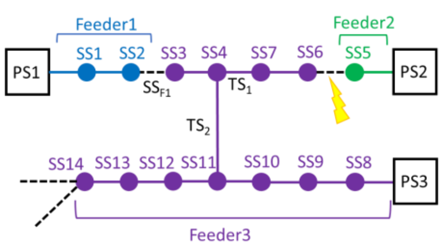

Figure 5. Example of the neighborhood related to the switches SS_{F1}-TS_2. The solution is included in the STM.

Whenever a new feasible solution is found, a solution that fulfills all the operational constraints, its objective function is compared with the available best solution and eventually marked as the new best if the objective function is improved. The neighborhood solutions are stored in the STM used to keep track of the solutions already checked to avoid visiting the same solution multiple times. Every time a better solution is found, the network constraints are also evaluated considering the load data of the next 24 hours to ensure that the proposed solution can guarantee a safe operation for a time long enough to repair the outage component, otherwise, the solution is rejected. The procedure is repeated for a given number of iterations: if no feasible solution is obtained, the algorithm takes the second-best initial solution from the LTM and repeats the whole process. The Pseudocode of the proposed algorithm is reported in the Appendix.

IV. CASE STUDY

This section reports the results of applying the proposed algorithm to a real distribution network located in the north of Italy. The considered DN, whose layout is shown in Figure 6, supplies 127 secondary substations, represents with oval shapes, using eighth MV feeders arising from a couple of primary substations, drawn as red squares. The open branches are highlighted in yellow; in yellow are also the thirty-six secondary substations remotely controlled, while the others, drawn in blu, can only be operated manually. The network serves 11000 LV customers and consists of 70 km of MV underground cables. The simulations were performed considering a total power of 24 MW which corresponds to the peak hour of June 2019.

The restoration algorithm performance has been verified simulating several faulty branches. For simplicity, only the results of a fault on the branch colored in red in Figure 6 is reported in the paper. The algorithm coding has been done in Python and runs on a personal computer with AMD Ryzen 5 2500U processor and 8 GB of RAM (6,90 GB usable). As stopping criterion, a maximum number of 30 iterations has been selected.

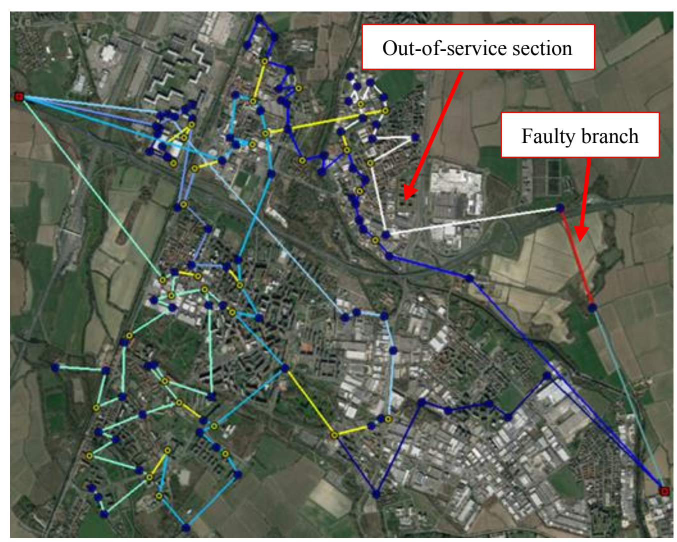

Figure 6. Layout of the 15kV DN taken as a study case. The considered faulty branch is depicted in red

As already mentioned in Section III, one of the restoration problem's main constraints is always having a radial structure. Starting from the faulty branch, such constraint is always satisfied since the algorithm will close a single TS towards an unsupplied and isolated network section. For the load shifting instead, to guarantee the radiality constraint and restore the energy supply to all the customers, the closed TS must always be located downstream of the SS open.

A. Reliability objective function

In the reliability objective function approach, the algorithm's goal is to minimize equation (3). As shown in Figure 7, the restoration starts closing the tie switch TS_1, to back-feed the out-of-service section, white highlighted in Figure 6. However, the consequent layout is not a feasible solution causes some operational constraints are violated. Therefore, the algorithm starts performing load shifting: the couple TS_2-SS_2 reduces the extension of the back-feeding feeder, and the operation of the DN shows only two dangers. The algorithm performs three switches operations, and the objective function is 1.17 (therefore the $NRI_{restored\ net}$ is 18% worst than the $NRI_{pre-fault}$). The network layout of the first feasible solution is shown in Figure 7. Figure 8 shows in blue the value of the objective function in each iteration and the best objective function found in the dotted red line. As displayed, the best feasible solution is obtained after fourteen iterations and the algorithm suggested the switches operations represented in Figure 9. Concerning the first initial solution shown in Figure 7, the back-feeding feeder changed, TS_1 has changed, and five switch operations are suggested. Thanks to the STM, the algorithm autonomously changes the back-feeding feeder to obtain a better solution. As a result, the objective function decreases to 1.08, corresponding to an $NRI_{restored\ net}$ 8% worst than the $NRI_{pre-fault}$, which is a good result considering that the network is working in N-1 contingency operation. Table I reports the *FRI* and the *NRI* for pre-fault layout, the first and the best feasible solutions. The faulty line is originally on feeder OP1204 which, obviously, improves its *FRI*. The algorithm shares its LV customers and extension among feeders AS00151, AS00152, and OP1201. Feeder AS00151 slightly reduced its extension and customers, which are shared, together with the extension and customers of the faulty feeder, with feeders AS00152 and OP1201 that increment their *FRI* by 115% and 380%, respectively.

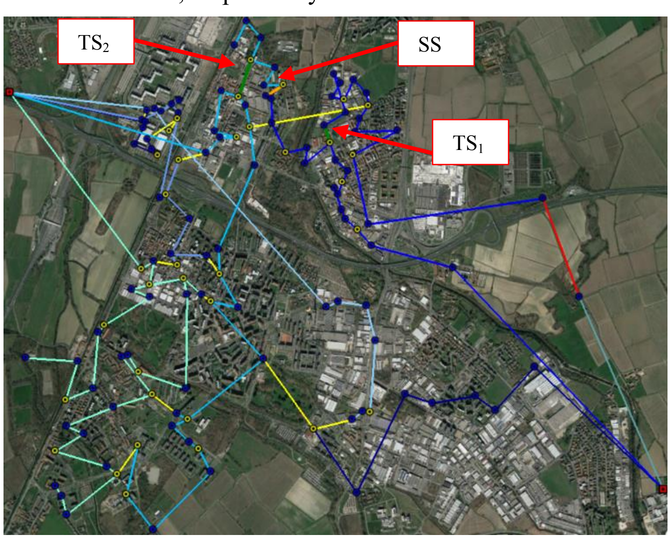

Figure 7. First feasible solution. The green color indicates the closure of a previously open switch (TS); the orange color the opening of a previously closed switch (SS).

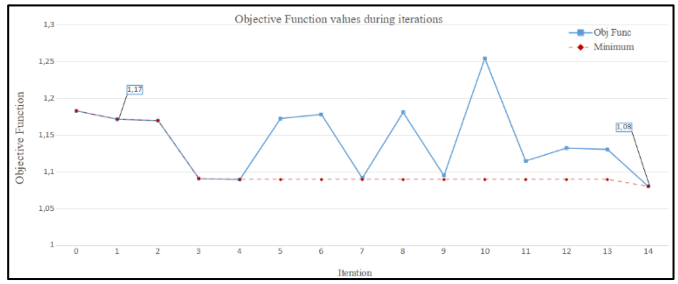

Figure 8. Objective function values through the iterations. For the sake of clarity, only the first fourteen iterations are shown.

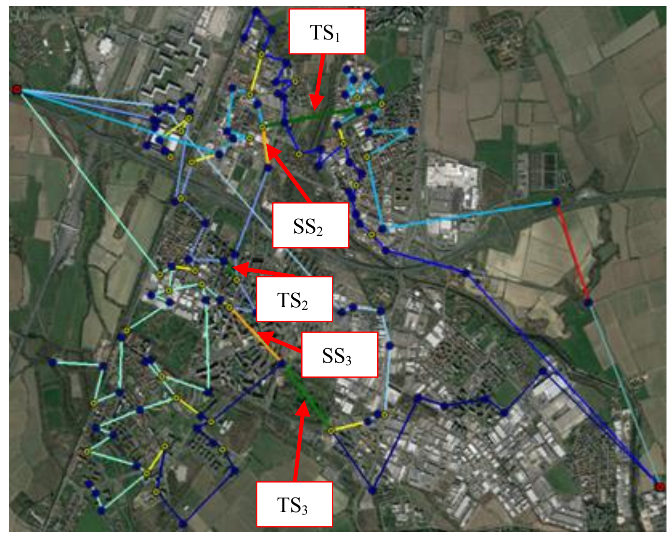

Figure 9. Best feasible solution. The green color indicates the closure of a previously open switch (TS); the orange color the opening of a previously closed switch (SS).

TABLE I. FEEDER RISK INDEXES COMPARISON

Feeder	Feeder Risk Index (*FRI*)		
	Pre-fault layout	***First feasible solution***	***Best feasible solution***
OP1201	4170	4170	20130
OP1203	13463	35427	13463
OP1204	**13770**	**5**	**5**
AS00151	25373	35460	24966
AS00152	5967	5967	12747
AS00153	26	26	26
AS00163	511	511	511
AS70154	43143	43143	43143
Tot. (*NRI*)	**106423**	**124709**	**114991**

B. Resiliency objective function

In the resilience objective function approach, the algorithm's goal is to minimize equation (6). As shown in Figure 10, two are the TSs available to select the initial solution: the first one, TS_1, is located in the middle of the out-of-service area, leading to a *FSRI* of 618, sum of the three *SRI* of feeder AS00151 sections (Figure 10); the second one, TS_2, is at the end of the out-of-service area and is characterized by an FSRI equal to 2474. In the second case, the back-feeding is made through a more extended section belonging to feeder OP1203. Thus, the algorithm starts selecting the back-feeding related to TS_1, whose objective function is computed as follows:

$$OF = \frac{FSRI_{AS00151} \cdot P_{AS00151}}{P_{AS00151}} = \frac{618 \cdot 5.53}{5.53} = 618$$

It is worth noticing that the power flow on the feeder AS00151 increases from 3.14 MW in the pre-fault layout to 5.53 MW.

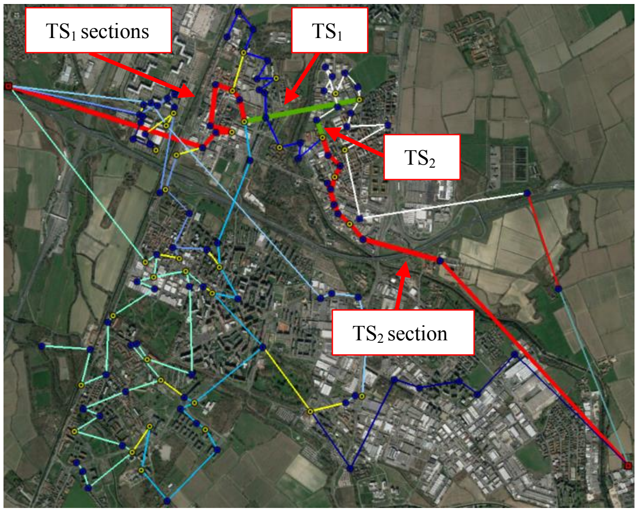

Figure 10. Feeder's section, in red, and the related TSs highlighted in green.

Since the initial solution is unfeasible, the algorithm shifts load to find a solution that fulfills the operational constraints. Information about the first feasible and the best feasible solutions are reported in Figure 11 and Figure 12. At first, the load of the feeder AS00151 is shared with feeder AS00152, decreasing from about 5.5MW to less than 4 MW, ends up with the first feasible solution. The objective function becomes:

$$OF = \frac{FSRI_{AS00151} \cdot P_{AS00151} + FSRI_{AS00152} \cdot P_{AS00152}}{P_{AS00151} + P_{AS00152}} = \frac{618 \cdot 5.53 + 676 \cdot 3.96}{5.53 + 3.96} = 647$$

Moreover, the algorithm performs a further load shifting, moving load from feeder AS00152 to feeder AS00153. The resulting objective function is:

$$OF = \frac{FSRI_{AS00151} \cdot P_{AS00151} + FSRI_{AS00153} \cdot P_{AS00153}}{P_{AS00151} + P_{AS00153}} = \frac{618 \cdot 5.53 + 649 \cdot 4.65}{5.53 + 4.65} = 635$$

Feeder AS00152 is no longer included in the objective function cause its power is reduced concerning the pre-fault condition (1.51 MW < 2.28 MW).

Therefore, the objective function changes from 618 in the initial unfeasible solution to 647 (first feasible solution) and 635 (best feasible solution). Figure 12 shows the network layout of the best feasible solution, where the five operated switches are highlighted in green and orange. At first, the TS$_1$ is closed to resupply the out-of-service section by the feeder AS00151. Later, the switching couple TS$_2$-SS$_2$ shifts part of the load from the feeder AS00151 to AS00152. Finally, using the switching couple TS$_3$-SS$_3$, the algorithm shifts some of the load from the feeder AS00152 to AS00153.

Figure 11. *FSRI* and power flowing on the related feeder for the initial solution, the first feasible and the best feasible solutions.

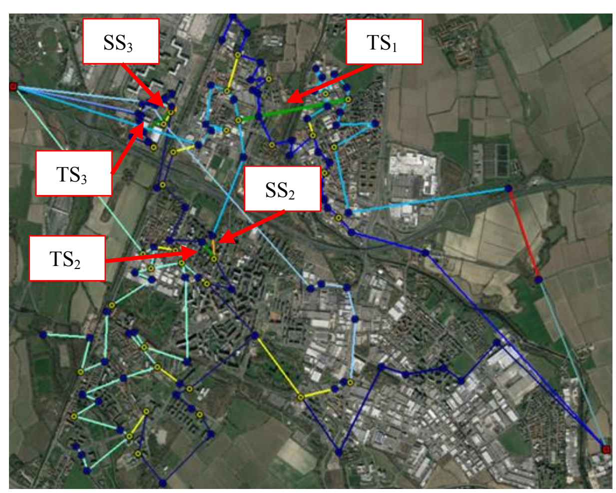

Figure 12. Best feasible solution. The green color indicates the closure of a previously open switch (TS); the orange color the opening of a previously closed switch (SS).

V. Conclusion

The paper presents a Tabu search-based algorithm able to assist operational engineers in identifying solutions to restore the energy supply after permanent faults. To optimize reliability or resiliency, the algorithm can consider two objective functions according to the network property. The proposed approach suggests the most valuable tie switch and the load switching operations that improve the considered objective function. Thanks to the collaboration with the DSO of Milan, Unareti, the proposed method has been tested on a real distribution network to investigate the algorithm's effectiveness. The results demonstrated that the algorithm can suggest a robust, fast, and feasible restoration plan. Moreover, since the switching operations are different considering the reliability or the resilience approach, the simulations' outputs confirm the validity of considering two distinct objective functions. The method developed could potentially be the basis of an automatic real-time tool to support the control room operators in restoring energy supply after a permanent fault, maximizing the distribution network reliability or resiliency.

Appendix

Algorithm Pseudocode

1. load input data
2. create network graph
3. Function *Determine out-of-service area (Faulted line)*
4. initialize *Long Term Memory*
5. Function *Generate Starting Solutions (Out-of-service Area)*
6. set *Current Solution = Best Initial Solution* and *k = 0*
7. Function *Compute OF (Network configuration, Reliability or Resiliency, TS, SS)*
8. *Best Solution* check
9. initialize *Short Term Memory*
10. **while not** Stopping *Criterion*
11. *k = k + 1*
12. Function *Determine feeder for load shifting (Network configuration)*
13. Function *Generate Neighbourhood (Selected feeder)*
14. set *Current Solution = Most fitting neighbourhood solution*
15. update *Short Term Memory*
16. *Best solution* check

Function *Generate Starting Solutions (Out-of-service Area)*

1. **for** each *node* **in** *out-of-service area*
2. determine *edges* of *node n*
3. **for** each *edge e*
4. **if** *edge* **is open**
5. *edge = Tie Switch*
6. close *Tie Switch*
7. determine the new network layout
8. Function *Compute OF (Network configuration, Reliability or Resiliency, TS, SS)*
9. update *Long Term Memory*
10. restore initial layout

Function *Generate Neighbourhood (Selected feeder)*

1. **for** each *node* **in** *load-shifting feeder*
2. determine *edges* of *node n*
3. **for** each *edge e*
4. **if** *edge* **is open**
5. *edge = Tie Switch*
6. **for** *edge* **in** *ordered edges in load-shifting feeder*
7. **if** *edge* **is not** *Tie Switch*
8. *edge = Sectionalizer*
9. close *Tie Switch* and open *Sectionalizer*
10. determine new network layout
11. **if** configuration already analysed
12. go back to 7
13. **else**
14. Function *Compute OF (Network configuration, Reliability or Resiliency, TS, SS)*
15. restore initial layout
16. **else**
17. **stop**

Function *Determine out-of-service area (Faulted line)*

1. Find *faulted feeder*
2. **for** each edge in *faulted feeder*
3. **if** exist closed path from edge to source
4. edge status = "*in service*"
5. node_1 status and node_2 status = "*in service*"
6. **else**
7. edge status = "*out-of-service*"
8. node_1 status and node_2 status = "*out-of-service*"

Function *Determine feeder for load shifting (Network configuration)*

1. **for** each *feeder* **in** network layout
2. set *voltage violations at feeder* = 0, *current violations at feeder* = 0
3. set *voltage dangers at feeder* = 0, *current violations at feeder* = 0
4. **for** each *node* **in** *feeder*
5. **if** voltage violation
6. *voltage violations at feeder* +1
7. **if** voltage danger
8. *voltage dangers at feeder* +1
9. **for** each *edge* **in** *feeder*
10. **if** current violation
11. *current violations at feeder* +1
12. **if** current danger
13. *current dangers at feeder* +1
14. sort feeders by higher number of violations and dangers
15. select first *feeder* in list

Function *Compute OF (Network configuration, Reliability Tie Switches, Sectionalizer Switches)*

1. **for** each *feeder* **in** network layout
2. set *FRI* of *feeder* = 0
3. set *length* = 0, *LV_users* = 0
4. **for** each *edge* **in** *feeder*
5. *length = length + edge_length*
6. **for** each *node* **in** *feeder*
7. *LV_users = LV_users + node_LV_users*
8. *FRI_feeder = length * LV_users*
9. Compute *NRI*
10. Calculate *OF* value

Function *Compute OF (Network configuration, Resiliency, Tie Switches, Sectionalizer Switches)*

1. **if** *Sectionalizer Switch* **is** null
2. set *length* = 0, *LV_users* = 0
3. **for** *edge* **in** ordered edges of back-feeding feeder
4. **if** *edge* **is not** *Tie Switch*
5. *length = length + edge_length*
6. **else**
7. stop
8. **for** *node* **in** ordered nodes of back-feeding feeder
9. **if** node **is not in** *Tie Switch nodes*
10. *LV_users = LV_users + node_LV_users*
11. **else**
12. stop
13. *SRI = length * LV_Users*
14. *Power* = power at feeder source node
15. Calculate *OF* value
16. **if** *Sectionalizer Switch* **is not** null
17. **for** each *feeder* **in** network layout
18. **if** power at feeder source node > power at feeder source node of starting solution
19. set *length* = 0, *LV_users* = 0
20. **for** *edge* **in** ordered edges of back-feeding feeder
21. **if** edge **is not** *selected Tie Switch or Sectionalizer switch*
22. *length = length + edge_length*
23. **else**
24. stop

```
        for node in ordered nodes of back-feeding-feeder
            if node is not in selected Tie Switch or Sectionalizer switch nodes
                LV_users = LV_users + node_LV_users
            else
                stop
        SRI_feeder = length * LV_Users
        Power_feeder = power at feeder source node
    Calculate OF value
```

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