Analytical Reliability-based Investment and Operation Model for Post-Failure Network Reconfiguration

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***Abstract*—Electricity providers aims to deliver uninterrupted electrical services to their customers at minimum cost while providing a satisfactory quality service. Therefore, the power system reliability is essential in power distribution network planning, design, and operation. This paper proposes a novel mathematical model to improve the reliability of reconfigurable distribution networks via investing and operating tie-lines. While the failure is being repaired, tie-lines allow the network operator to transfer loads from failed zones to healthy zones. Constructing new tie-lines could improve the network's flexibility, aiming to reduce the cost of expected energy not supplied (EENS). The objective function of the proposed method is a trade-off between the investment cost of tie-lines construction in the planning stage, the cost of tie-lines operation (e.g., opening/closing), and the cost of EENS in the operational stage. The model simultaneously evaluates the best combination of investments and network configuration for each contingency while considering network constraints. A multistage mathematical model is developed as mixed-integer linear programming (MILP) to overcome the computational complexity and maintain solver traceability for utility-scale realistic networks. The model can handle the network reconfiguration (NR) considering N-x contingency analysis in the operation stage while deciding the investment in tie-lines in the planning stage. The optimal investment and operation in tie-lines, according to numerical results, can reduce the cost of the Distribution System (DS) while responding with contingencies by 51 to 70%.**

Keywords—reliability, distribution system, optimization, planning, network reconfiguration

NOMENCLATURE

Parameters

$P_{i,j}^{max}$	Maximum active power flow in line *i,j* (kW).
$pf_{i,j}$	Power factor of the flow in line *i,j*.
$VA_i^{max/min}$	Max/Min voltage angle at bus *i* (radian).
$VM_i^{max/min}$	Max/Min voltage magnitude at bus *i* (volt.)
$g_{i,j}$; $b_{i,j}$	Conductance and susceptance of the branch *i,j* (Siemens).
$P_{i,y}^d$	Active energy consumption at bus *i* at year *y* (kWh).
$Q_{i,y}^d$	Reactive energy consumption at bus *i* at year *y* (kVAhr).
$\varphi_{i,j,s}$	Binary parameter defining the status of the NC-line. It is 1 when line is available, 0 otherwise.
$\lambda_{i,j}$	Cost of building tie-line (£/year).
$\theta_{i,j}$	Cost of operating tie-line (£/opp).
ρ_s	Failure-rate of scenario *s* (failure/year).
Dur_s	Average failure duration of scenario *s* (hours/failure).

Continuous variables

$CENS_{s,i,y}$	Cost of expected energy-not-supplied in node *i*, year *y* and scenario *s* (£/year).
$CEENS$	Total cost of expected energy-not-supplied (£).
$COPP_{s,i,y}$	Cost of operating tie-lines *i,j*, year *y* and scenario *s* (£/year).
$COPP$	Total cost of operating tie-lines (£).
$CINV_{i,j,y}$	Cost of building tie-lines *i,j*, year *y* (£/year).
$CINV$	Total cost of building tie-lines (£).
$DSCost$	Distribution System cost because of branches failure (£).
$P_{i,s,y}^{EENS}$	Expected energy-not-supplied in bus *i*, year *y* and scenario *s* (kWh).
$Q_{i,s,y}^{EENS}$	Expected reactive energy-not-supplied in bus *i*, year *y* and scenario *s* (kVAhr).
$P_{s,y}^{slack}$	Active energy provided by substation, year *y* and scenario *s* (kWh).
$Q_{s,y}^{slack}$	Reactive energy provided by substation, year *y* and scenario *s* (kVAhr).
$P_{i,j,s,y}^{losses}$	Active energy losses in line *i,j*, year *y* and scenario *s* (kWh).
$Q_{i,j,s,y}^{losses}$	Reactive energy losses in line *i,j*, year *y* and scenario *s* (kVArh).
$P_{i,j,s,y}$	Active energy trough line *i,j*, year *y* and scenario *s* (kWh).
$Q_{i,j,s,y}$	Reactive energy trough line *i,j*, year *y* and scenario *s* (kVArh).
$VM_{i,s,y}$	Voltage magnitude in bus *i*, year *y* and scenario *s* (Volt.).
$VA_{i,s,y}$	Voltage angle in bus *i*, year *y* and scenario *s* (Radians).

Binary and integer variables

$OPP_{s,i,j,y}$	Represents the status of tie-line *i,j*, year *y* and scenario *s*. It is 1 when the line is available, 0 otherwise.

$INV_{i,j,y}$	Associated with the investment in tie-line *i,j* in year *y*. It is 1 when the investment is made, 0 otherwise.
Sets	
Θ	Set of normally closed lines (NC-line).
Ψ	Set of tie-lines (normally open) lines.
E	Set of contingency scenarios.
N	Set of buses in the distribution network.
N_i	Set of buses directly connected to bus *i*.
Υ	Set of years in the planning period.

I. INTRODUCTION

A. Motivation and Background

Energy consumption globally has increased at an accelerated rate over the last three decades[1], with increase in energy demand attributed to the population growth and technological advancement [2]. The current challenges modern power systems face are growing energy demand, aging of present electricity transmission and distribution networks, and the impact of global warming. These challenges and the corresponding countermeasures adopted have had a detrimental effect on the reliability of Distribution Systems (DS) [1], [2]. Power systems reliability is defined as the extent to which the operation of various components in the grid yields electrical energy being provided to the end customers while maintaining standards limits and fulfilment of demand [3]. In the past, the reliability of power systems was mainly investigated upon the transmission and generation, while DS reliability was less investigated. However, literature shows that around 80% of electrical supply interruptions to end consumers has root causes at the distribution level [4]. The power system reliability assessment is essential in the planning, design, and operation of the DS as the ultimate goal of the electrical power utilities is to provide uninterrupted electrical services to their customers at minimum cost while providing a satisfactory quality service [5], [6]. System security and adequacy are the requirements under which the distribution network is considered. System adequacy refers to a static assessment, qualifying the capacity of the system to adequately deliver the energy demanded by the customers by carrying out an evaluation based on the components or equipment being used [7]. Thus system adequacy focuses on the system's design, structure, and installed component capacity [8]. System security of supply refers to the ability of the system to respond to any given contingency or disturbances such as loss of a line, generating unit, and/or transformer substation [9]. Thence, metrics of reliability that concentrate on the system security is called dynamic reliability, while static reliability focuses on the system adequacy attributes [10]. Reliability indices are evaluated for a particular area under various scenarios to find the optimum sizing and siting of newer equipment (e.g., tie-line), which asses the planning and operation methodology [10]. Common methods rely on the analytical predictive reliability assessment described in [11] for standard reliability metrics such as expected energy not supplied (EENS). EENS is defined as the amount of energy in MWh not supplied based on a probability of equipment failure and the interruption duration.

Upgrading existing equipment or implementing redundancy in distribution systems are conventional methods of improving reliability in the power system [9]. These methods require significant capital investment while the cost of EENS was traditionally low because cutting supply to customers was viewed as losing conformity in leisure time. However, EENS has become a synonym for losing productivity during the covid19 pandemic and the new habits of the post-pandemic era, where many people are working from home. Therefore, improving reliability in distribution systems with less capital investment, while minimizing the cost of EENS is required.

B. Review of Related Work

There are several methods proposed in the literature to enhance the distribution systems reliability. These methods include network reconfiguration (NR) and implementation of demand response (DR) programs [10]. Power distribution NR is widely employed for loss minimization, voltage profile improvement, load balancing, and reliability enhancement. NR can be achieved by changing the status of the switches that connect/disconnect the branches aiming at improving the system reliability [10], [11].

A methodology for evaluating the best post-failure network configuration was presented in [12], based on the algebraic model to assess the distribution system's reliability presented in [13]. A multistage analytical model to expand the network, taking into account the network's reliability was proposed in [14]. A mathematical model for the multistage distribution network expansion planning problem considering reliability was proposed in [15], while [16] described a method to enhance distribution systems' reliability and network performance by optimally reconfiguring the distribution network. Existing reliability indices have been modified by redefining failure rates in the context of undergrounded feeders. Malekshah et al [17] presented a Deep Q-Learning (DQL) approach to solve the dynamic reconfiguration problem by considering reliability in the presence of distributed generators (DG). Franco et al [18] presented a MILP model for radial distribution system conductor size selection and reconductoring. The developed model along with heuristic is used to compute the Pareto front of the conductor size selection and reconductoring problem while considering two separate objective functions. Reference [19] studied the integration of renewable energy resources (RERS) uncertainty and reliability into dynamic expansion planning of distribution network assets including distributed generation (DGs). Several options for feeder, transformer, and DGs installation were examined. Thus, under the uncertainty of demand and renewable energy sources, the optimal expansion plan identifies the best option, location, and installation time for the candidate assets. In order to include reliability costs in the MILP expansion planning model of distribution systems as a viable criterion, [20] provided a linearized model to calculate System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI) , and ENS . Munoz-Delgado et al. [21] developed a method for calculating reliability indices based on MILP, in which the network topology is explicitly represented by decision variables of the optimization process. In addition, a new mathematical formulation for SAIDI, SAIFI and ENS was introduced in this study. Escalera et al. [22] proposed a method for reliability assessment in distribution system considering the penetration of DGs and energy storage systems (ESS). Their method calculates the ENS reduction for critical consumers as a result of using an optimal coordination model that considers DG, ESS, and dispatchable loads under contingencies. Furthermore, the developed analytical technique considered the uncertainties of

ESS generation, demand, and state-of-charge to estimate the SAIDI, SAIFI, and ENS indices. Table I provides a compression between the proposed method and the reviewed state of the art. From the above review, the authors can conclude that none of the reviewed references has developed a multistage planning methodology for post-failure contingency analysis considering linear mathematical programming.

The impact of protection devices is highly correlated to the network's topological configuration. Distribution networks are operated in a radial topology, but mesh constructed. This implies some lines are normally closed (NC) and some others are normally opened (NO), called tie-lines. In this paper, the term "branch" is used interchangeably with the "line", which is not the case in transmission systems. When a failure occurs in the network, Distribution System Operator (DSO) opens the protection devices, either manually or automatically, to isolate the failure from the rest of the system. As a result, zones closest to the substation will have power while the failure is repaired. However, extensive zones downstream of the failure may lose service. To reduce the EENS downstream the failure, the failure zone can be isolated, and some loads can be set apart from faulty area and fed from alternative paths. Since the distribution network can face several failures, several post-failure networks configuration are possible. The status of the grid after the operations mentioned above is called post-failure network configuration. To the best of authors knowledge, post-failure contingency analysis within a multi-stage planning strategy framework that complies of both expansion planning, investing in new tie-lines, and operational planning of the network, finding the optimal configuration for every contingency, have not yet proposed in literature. The network configuration proposed utilize new tie-lines considering AC power flow and linear mathematical model

This paper proposes an optimization algorithm that finds: the investment decisions in new tie-lines, the optimal operation of tie-lines for every post-failure network based on the cost of EENS. Thus, the problem becomes a two-stage model, where long-term decisions are made in the first stage, and short-term decisions are taken in the second stage. Long-term choices, investing in tie-lines, do not change with every contingency scenario. Short-term decisions, closing tie-lines change with every contingency scenario, which is the post-failure network reconfiguration. Every scenario portrays a specific failure situation, where one or several components (lines) are unavailable. The operation problem, closing tie-lines, is hereby referred to as reliability-based optimal network reconfiguration. It is worth noting that all contingency tie-lines operations are subject to the investment decision taken in the first stage. The contingency scenarios are defined by the user and are represented by the state of normally closed lines (NC-lines) after the failure is cleared. NC-closed lines are the branches that are connecting the loads and buses when there are no failures in the system.

C. Contributions

The main contributions of this paper are as follows :

- Proposal of a novel reliability based multi-stage optimization algorithm for the planning and operation of DS. In the first stage, optimal long-term decisions are made to invest in tie-lines. In the second stage, a contingency-based network reconfiguration operational planning is developed.
- From a modelling perspective, a non-enumeration-based formulation is presented for the reliability-constrained distribution network operation and expansion planning considering linearized AC power flow and network constraints.

TABLE I. COMPARING THE PROPOSED METHOD WITH EXISTING METHODS

Reference	Multistage planning model	Linear Mathematical-programming-model	Contingency analysis	Ac power flow	Active power losses
[12]	×	✓	✓	✓	×
[13]	×	✓	×	×	×
[23]	✓	✓	×	✓	×
[15]	✓	×	×	✓	✓
[16]	×	×	×	✓	✓
[17]	×	×	✓	×	×
[18]	×	✓	×	✓	✓
[19]	✓	×	×	✓	✓
[20]	×	✓	×	×	×
[21]	×	✓	×	×	×
[22]	×	×	✓	✓	×
Proposed method	✓	✓	✓	✓	✓

II. ANALYTICAL RELIABILITY OPTIMIZATION MODEL

A. Model Assumptions

In this section the main assumptions and considerations of the model are presented. The proposed model attends the following considerations.

- Every post-failure network configuration solution is constrained by the technical limits, like voltage and branches capacity.
- When there is a failure in a line, it gets unavailable and there is no impact on the rest of the feeder. In a post-failure network, there are three zones: (i) the no faulted area upstream of the faulted-line; (ii) the faulted-line; and (iii) the isolated area downstream of the faulted-line.

B. Problem Formulation

The objective is to minimize the cost of the Distribution System (DS) when the system fails. There are two costs associated with the reliability quantification: the distribution company's cost to have a reliable network and the cost faced by the customers because of the lack of supply. DSO should invest in having a flexible network (investments cost) and making the required reconfigurations when there is a failure (operational cost). Since the algorithm takes long-term decisions, it is necessary to model the conditions during the lifetime of the investment, for the algorithm to decide on the best investment and operation every year y during the period evaluated. Consequently, a two-stage model is suggested in this work to address limits placed in the short term after long-term decisions have been taken. I.e., while the long-term investment in tie-lines is decided, in the short term, given the tie-lines available, the optimal operation is sought.

The EENS cost considers all network's contingencies. Every normally closed line (NC-line) in the distribution network has two reliability parameters: failure rate ρ_s (failures/year) and average outage duration Dur_s (hours/failure). Traditionally reliability parameters (ρ_s . and Dur_s) are calculated using historical information. For the sake of simplicity of the simulation, average failure rates and failure duration of the NC-lines are the same every year. Given the reliability of the components (NC-lines), the optimization problem aims to simultaneously minimize consumers EENS's cost and network's investment and operation. The unavailability of every NC-line is a contingency for the distribution system; thus, the algorithm should consider the impact of *n* contingency in the EENS to every consumer.

The objective function aims to minimize the distribution network reliability-cost, including investment and operation of tie-lines and the cost of Expected Energy-not-supplied. The total cost of the DS $DSCost$, is depicted in Eq.(1). The aim of the algorithm is to minimize $DSCost$.

$$DSCost = CEENS + COPP + CINV \tag{1}$$

The first term represents the cost of Expected Energy-not supplied (EENS), it is the customer's losses because of the power-cut. The second term represents the cost of changing the distribution system's configuration to reduce the failure's impact. The configuration of the network is changed by closing the tie-lines to provide an alternative path to supply energy to the isolated area. This operation cost can be the manpower and equipment required to operate manually the sectionalizes or the cost of automation of the devices to operate remotely. The investment and operation cost differ depending on the availability of telecontrol, thus impacting on the optimization results. The third term represents the investment cost to build tie-lines. Notice the investment decisions do not change with the contingency scenario (s).

Every scenario (s) represents a network situation where a set of components (NC-lines) are not available. Every scenario can consider one (N-1) or x (N-x) lines unavailable. Eqs. (2) and (3) calculate the total cost and EENS at bus *i* in year *y* respectively.

$$CEENS = \sum_{s}\sum_{i}\sum_{y}\left\{ CEENS_{s,i,y}\right\} \quad \forall i \in N;\ \forall y \in \Upsilon;\ \forall s \in \mathrm{E} \tag{2}$$

$$CEENS_{s,i,y} = P_{i,s,y}^{EENS} \times Dur_s \times \rho_s \quad \forall i \in N; y \in \Upsilon;\ \forall s \in \mathrm{E} \tag{3}$$

Eqs (4) and (5) calculate the total and the cost of every operation ($COPP$) of tie-lines. The DSO will close the best set of tie-lines to reduce *EENS*, when it is profitable.

$$COPP = \sum_{s}\sum_{i.j}\sum_{y} COPP_{s,i,j,y} \quad \forall i,j \in \Psi;\ \forall y \in \Upsilon; \forall s \in \mathrm{E} \tag{4}$$

$$COPP_{s,i,j,y} = OPP_{s,i,j,y} \times \theta_{i,j} \times \rho_s \quad \forall i,j \in \Psi;\ \forall y \in \Upsilon;\ \forall s \in \mathrm{E} \tag{5}$$

Finally, (6) calculates the total cost of building new tie-lines and (7) shows the cost drivers. Sometimes tie-lines are referred as tie-line. Once the investment is decided, the tie-line is available in the operation in the years to come.

$$CINV = \sum_{i,j}\sum_{y} CINV_{i,j,y} \quad \forall i,j \in \Psi;\ \forall y \in \Upsilon \tag{6}$$

$$CINV_{i,j,y} = INV_{i,j,y} \times \lambda_{i,j} \quad \forall i,j \in \Psi;\ y \in \Upsilon \tag{7}$$

Notice, the investments are modeled like OPEX rather than CAPEX. Once the investment is done the subsequent years there is annual depreciation cost $\lambda_{i,j}$ £/year. To prevent the algorithm to reverse decision investment, Eq. (8) guarantee that once the tie-line decision is taken, it is always available in future periods.

$$INV_{i,j,y+1} \geq INV_{i,j,y} \quad \forall i,j \in \Psi;\ y \in \Upsilon \tag{8}$$

C. Power Flow Equations

This section presents the constraints associated with the power balance and technical network limits in (9)-(17). Eqs. (9) and (10) show bus balance of active and reactive power respectively, for all bus bars *i* and scenario *s*. The power flow is modelled with hourly resolution therefore 1 MW of power demand, represents 1 MWh of energy consumption.

$$P_{s,y}^{slack} + P_{i,s,y}^{EENS-} - P_{i,y}^{d} - \sum_{j}\frac{P_{i,j,s,y}^{losses}}{2} = \sum_{j} P_{i,j,s,y} \quad \forall j \tag{9}$$

$$Q_{s,y}^{slack} + Q_{i,s,y}^{ENS-} - Q_{i,y}^{d} - \sum_{j}\frac{Q_{i,j,s,y}^{losses}}{2} = \sum_{j} Q_{i,j,s,y} \quad \forall j \in N_i \tag{10}$$

Eqs. (11) and (12) calculate the power flow $P_{i,j,s,y}$, $Q_{i,j,s,y}$ through the branches and the voltage magnitude $VM_{i,s,y}$ and voltage angle $VA_{i,s,y}$. Notice this a linearization of the AC power flow equations. Further information about the linearization strategies in power systems can be found in [15], [16].

$$\begin{aligned} P_{i,j,s,y} = \varphi_{i,j,s} \times \{ & g_{i,j} \times (VM_{i,s,y} - VM_{j,s,y}) - b_{i,j} \\ & \times (VA_{i,s,y} - VA_{j,s,y}) \} \ \forall s \in E;\ \forall i,j \\ & \in N;\ y \in \Upsilon \end{aligned} \tag{11}$$

$$\begin{aligned} Q_{i,j,s,y} = \varphi_{i,j,s} \times \{ & -b_{i,j}(VM_{i,s,y} - VM_{j,s,y}) - g_{i,j} \\ & \times (VA_{i,s,y} - VA_{j,s,y}) \} \ \forall s \in E;\ \forall i,j \\ & \in N;\ y \in \Upsilon \end{aligned} \tag{12}$$

It is necessary to limit tie-line capacity attending both the operation decisions (the status of tie-lines) and investment decisions (whether to invest in building tie-line). The limit in the power flow by branch and voltage magnitude and angle are shown in (13)-(17). Eq. (13) limits tie-line capacity of the branch whether the investment was done. Eq. (14) sets the capacity of the branch to zero if the tie-line is not closed in the operation stage ($OPP_{s,i,j,y}$ =0) otherwise is limited to rated capacity. Similarly, (15) sets the limits to power flow in NC-line. Eqs. (16) and (17) set the maximum and minimum values in all busses for voltage magnitude and angle respectively.

$$0 \leq \left| P_{i,j,s,y}/pf_{i,j} \right| \leq INV_{i,j} \times P_{i,j}^{max} \quad \forall s \in E;\ \forall i,j \in \Psi;\ y \in \Upsilon \tag{13}$$

$$0 \le \left|P_{i,j,s,y}/pf_{i,j}\right| \le OPP_{s,i,j,y} \times P_{i,j}^{max} \quad \forall s \in E;\; \forall i,j \in \Psi;\; y \in \Upsilon \tag{14}$$

$$0 \le \left|P_{i,j,s,y}/pf_{i,j}\right| \le P_{i,j}^{max} \times \varphi_{i,j,s} \quad \forall s \in E;\; \forall i,j \in \Theta;\; \forall y \in \Upsilon \tag{15}$$

$$VM_j^{min} \le VM_{j,s} \le VM_j^{max} \quad \forall s \in E;\; \forall j \in N \tag{16}$$

$$VA_j^{min} \le VA_{j,s} \le VA_j^{max} \quad \forall s \in E;\; \forall j \in N \tag{17}$$

Notice the short-term decisions, closing tie-line $OPP_{s,i,j,y}$,vary for every scenario s, but the investment decisions $INV_{i,j}$ cannot be changed in every scenario. The proposed problem was formulated as a mix-integer linear problem (MILP) and solved using CPLEX solver in General Algebraic Modelling System (GAMS) software.

III. Numerical Case Study

In this section, the network data, the reliability parameter and the operation and investment cost of tie-lines are presented. Then the optimization process results, and the sensitivity analysis is presented.

A. Distribution Network and Data

A 16-bus UK generic distribution system (UKGDS) [24] was selected to validate the proposed algorithm. The UKGDS is a 33kV radial MV distribution network having 16 buses, 15 normally closed lines and 4 tie-lines candidates, Fig. 1. The dotted line represents the four tie-line options (TL16, TL17 and TL18, TL19).

The conductance, susceptance, maximum power capacity, the investment and operation price in tie-lines candidates are shown in Table II. The set of contingency scenarios, the lines involved, and the failure rate and average duration failure are shown in Table III.

In Table III, all N-1 contingency situations are considered (con1-con15), there are two double-failure contingencies (con16 and con18), and con17 is a scenario where all the lines are available.

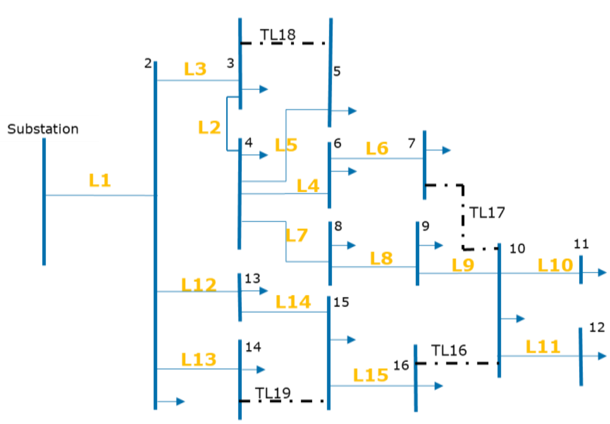

Fig. 1. 16-bus UKGDS single-line diagram.

TABLE II. Parameters of the Distribution Network

Line	From	To	$g_{i,j}$ (S)	$b_{i,j}$(S)	$P_{i,j}^{max}$ (MW)	$\theta_{i,j}$ (£/opp)	type
Line 1	bus1	bus2	0.04	0.08	6.00	n/a	NC
Line 2	bus4	bus3	0.04	0.28	2.50	n/a	NC
Line 3	bus2	bus3	0.04	0.28	2.50	n/a	NC
Line 4	bus4	bus6	0.10	0.23	1.50	n/a	NC
Line 5	bus5	bus4	0.01	0.02	4.00	n/a	NC
Line 6	bus7	bus6	0.08	0.21	1.50	n/a	NC
Line 7	bus8	bus4	0.09	0.24	1.50	n/a	NC
Line 8	bus8	bus9	0.04	0.06	1.50	n/a	NC
Line 9	bus10	bus9	0.11	0.44	1.50	n/a	NC
Line 10	bus10	bus11	0.19	0.39	1.50	n/a	NC
Line 11	bus10	bus12	0.32	0.73	1.50	n/a	NC
Line 12	bus13	bus2	0.04	0.17	0.2	n/a	NC
Line 13	bus14	bus2	0.10	0.32	0.15	n/a	NC
Line 14	bus13	bus15	0.05	0.17	0.15	n/a	NC
Line 15	bus16	bus15	0.08	0.18	0.15	n/a	NC
TL 16	bus16	bus10	0.08	0.18	0.15	500	Tie-line
TL 17	bus7	bus10	0.08	0.18	0.15	500	Tie-line
TL 18	bus3	bus5	0.08	0.18	0.15	500	Tie-line
TL 19	bus14	bus15	0.08	0.18	0.15	500	Tie-line

TABLE III. Set of Contingencies Scenarios

Contingency	From	To	Failure	Failure type	ρ_s	Dur_s
con1	bus1	bus2	Line 1	n-1	2.47	4
con2	bus2	bus3	Line 3	n-1	3.74	4
con3	bus3	bus4	Line 2	n-1	3.71	4
con4	bus5	bus4	Line 5	n-1	3.01	4
con5	bus6	bus4	Line 4	n-1	4.74	4
con6	bus6	bus7	Line 6	n-1	0.83	4
con7	bus8	bus4	Line 7	n-1	3.00	4
con8	bus8	bus9	Line 8	n-1	1.38	4
con9	bus9	bus10	Line 9	n-1	4.21	4
con10	bus10	bus11	Line 10	n-1	4.53	4
con11	bus10	bus12	Line 11	n-1	0.82	4
con12	bus2	bus13	Line 12	n-1	4.88	4
con13	bus13	bus15	Line 14	n-1	4.96	4
con14	bus15	bus16	Line 15	n-1	3.71	4
con15	bus14	bus2	Line 13	n-1	2.83	4
con16	bus14	bus2	Line 13	n-2	0.30	4
	bus8	bus4	Line 7			
con17	n/a	n/a	n/a	NoF	0.10	n/a
con18	bus6	bus4	Line 4	n-2	0.30	4
	bus6	bus7	Line 6			

where NoF denotes no failure.

B. Simulation Results

Since every simulation provides a lot of information, first operation results for the first year will be analyzed and then the investment and operation model results.

TABLE IV. PERFORMANCE OF THE SYSTEM FOR EVERY CONTINGENCY SCENARIO

Scenario		Without tie-lines (Base case)			With four tie-lines active					Savings (%)
	P^d (MWh)	$TEENS$ (MWh/year)	$CEENS$ (£/year)	$DSCost$ (£/year)	$TEENS$ (MWh/year)	$CEENS$ (£/year)	$NOPP$ (£/year)	$COPP$ (£/year)	$DSCost$ (£/year)	
con1	26.09	26.09	147,153.23	147,153.23	26.09	147,153.23	-	-	147,153.23	0%
con2	26.09	18.89	161,073.79	161,073.79	-	-	1.00	3,740.08	3,740.08	98%
con3	26.09	12.89	109,164.83	109,164.83	-	-	1.00	3,714.74	3,714.74	97%
con4	26.09	2.13	14,661.98	14,661.98	-	-	1.00	3,012.88	3,012.88	79%
con5	26.09	0.97	10,465.85	10,465.85	-	-	1.00	4,742.03	4,742.03	55%
con6	26.09	0.38	722.88	722.88	0.38	722.88	-	-	722.88	0%
con7	26.09	2.79	19,056.06	19,056.06	-	-	1.00	2,999.33	2,999.33	84%
con8	26.09	1.28	4,031.47	4,031.47	-	-	1.00	1,382.91	1,382.91	66%
con9	26.09	1.11	10,681.25	10,681.25	-	-	1.00	4,206.86	4,206.86	61%
con10	26.09	0.33	3,414.21	3,414.21	0.33	3,414.21	-	-	3,414.21	0%
con11	26.09	0.24	456.33	456.33	0.24	456.33	-	-	456.33	0%
con12	26.09	6.50	72,276.79	72,276.79	-	-	1.00	4,875.48	4,875.48	93%
con13	26.09	6.30	71,221.40	71,221.40	-	-	1.00	4,958.33	4,958.33	93%
con14	26.09	3.00	25,359.36	25,359.36	-	-	1.00	3,707.51	3,707.51	85%
con15	26.09	0.07	434.52	434.52	0.07	434.52	-	-	434.52	0%
con16	26.09	2.85	1,952.05	1,952.05	0.07	46.02	1.00	300.00	346.02	82%
con17	26.09	-	-	-	-	-	-	-	-	n/a
con18	26.09	0.97	662.11	662.11	0.97	662.11	-	-	662.11	0%
Total	**26.09**	**86.79**	**652,788.11**	**652,788.11**	**28.14**	**152,889.31**	**11.00**	**37,640.14**	**190,529.45**	**71%**

TABLE V. OPTIMAL OPERATION AND INVESTMENT IN NETWORK RECONFIGURATION

Case	$\lambda_{i,j}$ (£/year)	Tie-lines (Num.)	$DSCost$ (£/year)	$CEENS$ (£/year)	$COPP$ (£/year)	$CINV$ (£/year)	tie-lines
Case 1	-	4	190,529.45	152,889.31	37,640.14		TL16; TL17; TL18; TL19
Case 2	2,000	4	198,529.45	152,889.31	37,640.14	8,000	TL16; TL17; TL18; TL19
Case 3	5,000	4	210,529.45	152,889.31	37,640.14	20,000	TL16; TL17; TL18; TL19
Case 4	7,500	3	218,753.27	163,355.15	32,898.11	22,500	TL16; TL18; TL19
Case 5	10,000	2	224,740.97	166,967.38	37,773.59	20,000	TL16; TL18
Case 6	20,000	1	237,311.91	187,426.68	29,885.23	20,000	TL16

The distribution system operation performance for every contingency is shown in Table IV, assuming $\lambda_{i,j} = 0$.and $\theta_{i,j} = 500$. When there are tie-lines, the DSO can transfer loads from faulted areas, closing tie-lines. For every contingency the performance of the reconfiguration process, with and without tie-line is calculated. For every contingency, the total energy consumption of the feeder $P^d = \sum_t P^d_{i,y1}$ is compared with the total expected energy-not-supplied $TEENS_y = \sum_s \sum_i P^{EENS}_{s,i,y1}$. The number of operations in the tie- lines $NOPP = \sum_{i,j} \sum_s OPP_{s,i,j,y1}$ and the associated cost is calculated. It worth nothing that:

- The *EENS* in very contingency depends on the loads affected (MWh) and the branch's failure rate (failure/year) considered in the contingency. For example, con1-con3 are severe cases because almost all customers get affected.
- In contingency 17 all lines are available thus, there is no *EENS*.
- In double failure scenarios, con16 and con18, *EENS* is very low because the number of failures per year, with two lines unavailable, is very low. It is the event is very severe but is unlikely.
- When there are no tie-lines the number of operations, closing tie-lines is zero i.e., $NOPP = 0$, thus, there is no operation cost $COPP = 0$.
- When the DSO restore the services using tie-lines, the cost of the distribution system is EENS's cost plus the cost of tie-lines operation.

The operation of tie-lines can be done using telecontrol or sending the crew to change the sectionalizes status, each options imply different cost. The algorithm must calculate in every contingency whether it is profitable to expend money doing the network reconfiguration versus the reduction in the *EENS* cost. For example, in scenario 2 (con2) the cost of operating tie-lines is £3,740.08 /year and this operation reduces *EENS*'s to zero, and total cost is reduced from £161,073.79 to £3,740.08 /year, it is

98% cost reduction. In some other contingencies, e.g. contingency 8, tie-lines do not improve the performance of the network because the tie-lines cannot restore the service. Considering the 18 contingency scenarios, the systems total reliability cost is reduced from £652,788.11 to £190,529.45/year, representing a 71% cost reduction.

The algorithm proposed and tested not only provides the optimal investment decisions to improve network reliability using tie-lines but a real-time operation tool. The DSO can utilize this algorithm in real time operation to define the best set of operations to reduce the impact of contingency in the post-failure network.

In the above simulations, the four tie-lines positions in the network are a parameter, i.e., a given decision. Next, the optimal investment and operation model results are presented by extending the operation model described before. In this model the algorithm finds simultaneously both stages decisions: investment stage and operation stage. Therefore, whether tie-lines are available or not is a decision along with the optimal operation for every contingency (see Table V). There are six scenarios where the investment cost of every tie-line $\lambda_{i,j}$ varies from zero to 20,000 £/year, which for the sake of simplicity is the same for all the tie-lines candidates. The operation cost $\theta_{i,j} = 500$ £/opp is the same in all scenarios. When the price is lower than 5,000 £/year the DSO decides to build four tie-lines, however when the price is higher than 20,000 it is profitable to invest in only one tie-line.

Table VI shows the $DSCost$ improvement for a number of optimal investment and the operation decisions for several tie-line investment $\lambda_{i,j}$ and operation $\theta_{i,j}$ prices. The

DSO's cost improvement is calculated in Eq. (18), where $DSOCost(no\ tie-line) = 652{,}788.11$.

$$\frac{DSOCost(no\_tie-line) - DSOCost(\lambda_{i,j};\theta_{i,j})}{DSOCost(no\_tie-line)} \times 100 \qquad (18)$$

The first row shows the savings when the investment price is zero, therefore, the DSO decides to deploy all four lines with no cost getting the same results presented in the Table VI. The operation decisions are subject to the investment decision, for example, when the price is $\lambda_{i,j} = £2{,}000/year$, all four tie-lines are built and then in every contingency the best configuration is found considering the four tie-lines, For example, the optimal network configuration for contingency 7 (closing Bus10-Bus7) is illustrated in Fig. 2.

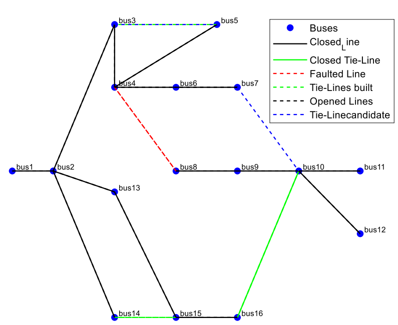

Fig. 2. Optimal network configuration in Contingency 7.

TABLE VI. RELIABILITY COST REDUCTION DEPENDING ON OPERATION AND INVESTMENT COSTS

	$\boldsymbol{\theta_{i,j} = 500}$	$\boldsymbol{\theta_{i,j} = 1{,}000}$	$\boldsymbol{\theta_{i,j} = 1{,}500}$	$\boldsymbol{\theta_{i,j} = 2{,}000}$
$\boldsymbol{\lambda_{i,j} = 0}$	70.81%	65.05%	60.17%	55.99%
$\boldsymbol{\lambda_{i,j} = 2{,}000}$	69.59%	63.98%	59.25%	55.07%
$\boldsymbol{\lambda_{i,j} = 5{,}000}$	67.75%	62.60%	57.87%	54.06%
$\boldsymbol{\lambda_{i,j} = 7{,}500}$	66.49%	61.45%	57.01%	53.29%
$\boldsymbol{\lambda_{i,j} = 10{,}000}$	65.57%	60.60%	56.34%	52.62%
$\boldsymbol{\lambda_{i,j} = 20{,}000}$	63.65%	59.07%	54.81%	51.08%

The reliability-cost reduction depends on the investment cost $\lambda_{i,j}$ (building a tie-line) and the operation cost $\theta_{i,j}$. The operation and investment cost depends on the sectionalizing technology (manual or using telecontrol). Depending on the technology, therefore the cost, the reliability-cost reduction ranges from 70.81% to 51.08%.

IV. CONCLUSION

The proposed reliability-based algorithm finds the best investment and operation to reconfigure the distribution network after a failure is cleared. A two-stage mix-integer linear model is developed to optimize the reliability cost considering all network technical constraints. The results show that the benefit of tie-lines is strongly related to the branch's position, the demand location, and the failure rate of branches. In the example considered here a reduction in the operation cost range from 71% to 51% depending on the operation and investment cost. With the sensitivity analysis performed, DSOs can decide whether is profitable to automatize the operation of tie-lines which leads to higher investment prices and lower operation cost; on the contrary, in the case of no automation, the lower investment cost is lower and the operation cost is higher. The proposed algorithm helps DSOs not only to take the most convenient investment decision, but to reconfigure the post-failure network in real time. Since the algorithm considers all networks' constraints, the optimal configuration is always a feasible solution.

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