A Multiobjective Optimization Technique to Develop Protection Systems of Distribution Networks With Distributed Generation

Katiani Pereira, Benvindo R. Pereira Jr., *Member, IEEE*, Javier Contreras, *Fellow, IEEE*, and José R. S. Mantovani, *Member, IEEE*

***Abstract*—This paper presents a new methodology based on multiobjective optimization techniques to perform an optimized, coordinated, and selective allocation of control and protection devices in distribution networks with distributed generation (DG). The proposed mathematical model consists of two objective functions that consider economic issues and the network continuity index. Physical and operational constraints are taken into account, with emphasis on the set of constraints based on practical rules of distribution companies and international technical standards, which require the specification, coordination, and selectivity of the protection devices installed in the network. The possibility of load transfer from neighboring feeders and islanded DG operation is also considered. The proposed model is a mixed integer nonlinear programming, and we use NSGA-II (Nondominated Sorting Genetic Algorithm) to solve it. The proposed methodology is applied in a real 135-bus system found in the literature.**

***Index Terms*—Coordination and selectivity, distributed generation, optimization, protection devices, reliability.**

I. Introduction

Network reliability planning is a challenging task for distribution companies, since this task should seek the best cost-benefit relationship for capital investments in the protection system, ensure power supply with continuity indices to satisfy consumer demands and meet the requirements of regulatory agencies. Optimal allocation of control and protection devices, as well as optimal coordination and selectivity of these devices, is an efficient and safe way to ensure reduction in protection cost and improve system continuity indices, since they allow us to minimize consumer interruptions and/or energy not supplied (ENS) due to faults that occur in the distribution system (DS) [1]–[3].

Distributed generation (DG) is a reality in DS operation, requiring paradigm changes related to the philosophy, coordination and specification of the control and protection devices. Therefore, it is necessary to develop new techniques and mathematical models for the optimal allocation of these devices in DS to ensure safety and reliability, since DG changes the way to plan and operate the network, in normal and contingency conditions [4]–[6]. One of the main benefits associated with DG is the possibility of operation in islanded mode, i.e., in case of a permanent fault in a section of the DS, DG has physical and operational conditions to supply the healthy part of the system load affected by the fault, reducing the number of consumers without energy, consequently, ENS costs [7]–[9].

The presence of DG in the network has a direct influence on the type, specification, and coordination of the protection devices. Since power flow is not unidirectional in some parts of the network, a branch that has a fault can experience short-circuit currents (SCCs) from both sides and various protection devices are needed to interrupt fault currents completely [10], [11]. In some works the loss of coordination between protection devices is discussed, mainly loss of coordination between reclosers and fuses in the presence of DG in the DS, since SCC, besides presenting bidirectional flows, have their magnitude values increased considerably due to the contribution of DG in the fault current generation [12], [13].

In conventional DS reliability procedures, control and protection devices are optimally allocated in the network, assuming that they could be coordinated independently from their location. Nonetheless, this is not possible in many real scenarios and some devices need to be removed to obtain a perfectly coordinated and selective protection system [14], [15]. Some authors consider the coordination of protection devices through qualitative constraints, in other words, these constraints only indicate the possibility of coordination between devices, but do not perform coordination and selectivity between the protection devices [16], [17]. In [18] the verification of the SCC levels in the reclosers allocation is realized, where it is possible to ensure that they will have the possibility of a selective coordination after their installation, but the proposed technique is limited to the coordination of intelligent reclosers.

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TABLE I
COMPARISON WITH CONTRIBUTIONS OF PREVIOUS WORKS

Paper	Considerations			
	1	2	3	4
[4]		x		x
[8]				x
[11]		x		
[12]		x		x
[18]		x		x
[26]	x			
Proposed	x	x	x	x

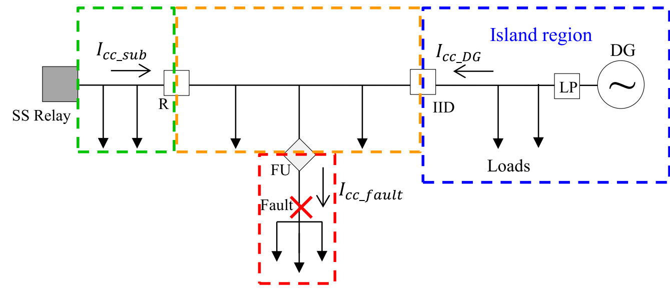

Fig. 1. Fault occurrence in a DS.

This paper presents a new methodology to determine and specify the types of protection and control devices in DS with DG. The methodology is based on multi-objective optimization techniques to carry out the optimized, coordinated and selective allocation of these devices. The model used in the proposed methodology consists of two objective functions, the first one considers the economic aspects and the second one takes into account the network continuity index. In addition to the physical and operational constraints, a set of constraints that ensures the coordination and selectivity of the protection devices installed in the network is added. In this way, the main contributions of this paper are:

1.– Proposal of an optimization technique based on a generic multi-objective mixed integer non-linear programming (MINLP) model, whose difference in relation to other mathematical models is to simultaneously consider the allocation, selectivity, coordination and optimized specification of the control and protection devices in a single mathematical model;
2.– To model the DS as an unbalanced three-phase set of circuits, to find the state of the network and also to calculate all SCC (including DG contribution to SCCs), required to specify and coordinate the control and protection devices;
3.– To propose a new protection philosophy for DS with DG using directional reclosers for circuits with DG. The use of fuses is still allowed as a measure of investment reduction, but only in secondary branches with loads of less importance;
4.– To consider the islanded operation of DG to improve continuity indices in the event of permanent faults.

In Table I a comparison is made between the main contributions mentioned above and the papers presented in literature.

A multi-objective genetic algorithm (MOGA) based on NSGA-II [19] is proposed to solve the multi-objective MINLP model. The computational implementation of the proposed methodology is applied in a real 135-bus system [20]. The efficiency of the mathematical model proposed is checked by comparing the results of two tests: in the first one, the allocation and coordination of the devices is developed in an integrated way, and, in the second one, the optimal allocation of the devices is carried out first and a study of their selectivity and coordination is performed later.

The paper is organized as follows. In Section II, the concepts about islanded operation with DG are presented. In Section III, the proposed mathematical formulation is presented. In Section IV, the MOGA is developed for the problem under study. In Section V, the results and corresponding analysis are shown; and, finally, conclusions are presented in Section VI.

II. Coordination Proposals Considering DG

The presence of DGs in modern DS has a direct impact over the power supply quality indices, and may also offer benefits related to continuity supply indices, provided by the DG capacity of supplying the demand of a specific region, (island). According to [21], islanded systems are autonomous networks consisting of DG and loads, intentionally planned and able to continue operating disconnected from the DS. They occur when part of the network (a subnetwork that has DG) is disconnected due the system protection actuation.

Let us consider a small DS represented in Fig. 1. The protection system of this network has a recloser (R), a fuse (F), an island interconnection device (IID) and DG local protection (LP). In this paper the IID is an automatic directional recloser [7], i.e., the IID acts only for faults outside the island. In addition to a well-planned and coordinated protection system, for islanded operation to be possible it is very important to have good communication between the IID, the local protection, DG and the network operator [9]. After fault repair, in face of the conditions for island reconnection, the IID may have the ability to perform the parallelism and synchronism between the DG and the DS [21], [22].

Thus, considering all requirements for island operation, in case of a fault (temporary or permanent) occurrence in the upstream sections of the IID (Fig. 1), the DG section will be disconnected without the need to turn off DG, i.e., the IID should be open (acting at characteristic 50, Fig. 2), before the generator LP. IID operation shall result in an island that will operate simultaneously with the DS.

At the same time, the recloser needs to act to eliminate the fault, in two cases:

– In case of a temporary fault, the recloser should act at characteristics 50/50N (phase and ground instantaneous overcurrent), before the fuse burns eliminating the fault and preserving all the network in operation (Fig. 2);

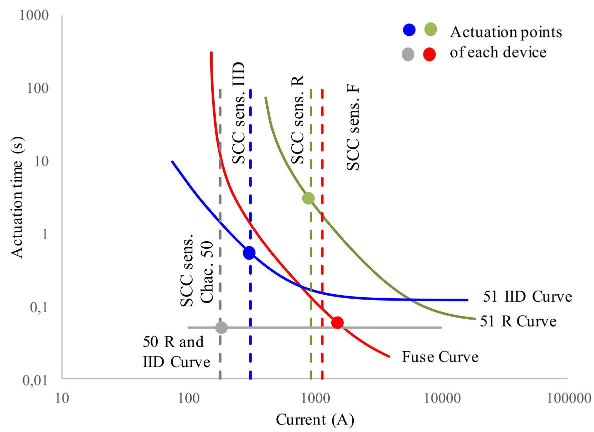

Fig. 2. Devices operating curves.

– In case of a permanent fault, after attempting fault elimination, the recloser will operate at characteristics 51/51N (phase and ground inverse time overcurrent), and the fuse should burn before recloser actuation, eliminating the fault and preserving most of the network in operation (Fig. 2).

For both cases, after fault elimination and with system conditions allowing for synchronism, the island region is reconnected to the system. In order for islanded operation of DG to occur for faults in sections upstream of the IID only, the existence of an efficient coordination between the IID and other protection devices of the network is necessary. In addition of the characteristics 50/50N and 51/51N, the IID must have at least the following protection functions:

– 25 synchronism;
– 67 and 67N phase and ground directional overcurrent (operation hypothesis of IIDs);
– 79 automatic reclosing;
– 27 under-voltage;
– 81/U under-frequency.

Although the parameters of these characteristics do not appear explicitly in the proposed model, they are essential for the correct operation of the IID [23].

III. Mathematical Model

In the mathematical model, the relationships that allow us to carry out the allocation and/or reallocation of fuses, automatic reclosers, automatic sectionalizing switches (ASS), and IIDs are established. The mathematical model formalizes the equations to evaluate quantitatively both objective functions (OFs) and the set of constraints. The proposed model is developed taking into account the following hypotheses:

– All automatic reclosers, automatic sectionalizing switches and substation relays have remote operation;
– There are no fuses in the loop (path) between the IID and the substation;
– IID is an automatic directional recloser, thus it is not sensitized by faults inside the section defined by it;
– The overcurrent relay of the substation must have an automatic reclosing function.

A. Objective Functions

The mathematical model is composed of two OFs:

1) Interruption Cost: This OF, eq. (1), evaluates the interruption costs of energy supply, considering the rates of permanent and temporary faults for each year y of the set of years θ of the planning horizon [4].

$$C_{Interrup} = \sum_{tc\in\{C,\ R,\ I\}} Ce_{tc} \sum_{y\in\theta} \frac{(PI_y + TI_y)}{(1+IRR)^y} \tag{1}$$

where Ce_{tc} is the cost of ENS for each type of consumer tc (commercial, residential and industrial); IRR is the internal rate of return; PI_y and TI_y are the amounts of interrupted energy due to permanent, eq. (2), and temporary, eq. (3), faults, respectively. Eqs. (2) and (3) are related to the concept of ENS [1], [4], [14].

$$PI_y = \sum_{i\in\beta}\sum_{d\in\mu}\sum_{c\in\delta_d} x_{i,d,c}\left(\sum_{h\in\varphi_i}\frac{\lambda_h L_h}{T}\right) \times \left[UI^p_{y,i} + DI_{y,i} - LT_{y,i} - IO_{y,i}\right] \tag{2}$$

$$TI_y = \sum_{i\in\beta}\sum_{\substack{d\in\mu\\ d\neq 2}}\sum_{c\in\delta_d} x_{i,d,c}\left(\sum_{h\in\varphi_i}\frac{\gamma_h L_h}{T}\right) \times \left[UI^t_{y,i} + DI_{y,i} - LT_{y,i} - IO_{y,i}\right] \tag{3}$$

where β is the set of system branches; μ is the set of devices of type d (1 – fuse; 2 – recloser; 3 – ASS; and 4 – IID) available to be allocated/relocated; δ_d is the set of operational ranges c of each protection device of type d; $x_{i,d,c}$ is a binary variable that indicates the allocation at branch i of a device of type d operating at range c; φ_i is the set of branches belonging to the faulted section i (set of branches, buses and pieces of equipment delimited and that can be isolated by the action of protection or sectionalizing devices); L_h, λ_h and γ_h are the lengths and the rates of permanent and temporary faults of each branch h, respectively; T is the total time considered in the planning horizon (in hours); $UI^P_{y,i}$ and $UI^t_{y,i}$ are the amounts of loads interrupted upstream of the section i due to the incidence of permanent and temporary faults, respectively; $DI_{y,i}$ is the loads interrupted downstream of section i due to the incidence of permanent or temporary faults; $LT_{y,i}$ represents the loads of sections downstream of section i that can be transferred between the neighboring feeders in year y, (verification of operational and physical feasibility); and $IO_{y,i}$ represents the loads of sections downstream of section i that have the possibility of an islanded operation in year y due to DG.

$UI^P_{y,i}$ and $UI^t_{y,i}$ solely occur when a faulted section i is delimited in the upstream side by a sectionalizing device. In this case the fault is eliminated by the nearest protection device upstream of section i. Thus eqs. (4a) and (4b) provide the value of the power supply interruption of section j (defined by a protection device) upstream of section i (defined by ASS or IID- since they are not designed to actuate due to faults inside their respective sections) due to the occurrence of permanent and temporary faults, respectively.

$$UI^{p}_{y,i} = \sum_{d\in\{3,4\}} \sum_{c\in\delta_d} x_{i,d,c} \times \left\{ \sum_{j\in\phi_i} \left[\sum_{c\in\delta_1} x_{j,1,c} \left(\sum_{h\in\phi_i} LD_{y,h} \right) TR + \sum_{c\in\delta_2} x_{j,2,c} \left(\sum_{h\in\phi_i} LD_{y,h} \right) Tr \right] \right\} \quad (4a)$$

$$UI^{t}_{y,i} = \sum_{c\in\delta_3} x_{i,3,c} \left\{ \sum_{j\in\phi_i} \sum_{c\in\delta_1} x_{j,1,c} \left(\sum_{h\in\phi_i} LD_{y,h} \right) TR \right\} \quad (4b)$$

where ϕ_i is the set of branches between section i and section j including branches of section j; $LD_{y,h}$ is the load connected at the end of branch h in year y; and TR and Tr are the repair and restoration times, respectively. Eq. (4a) is a general formulation where all combinations of protection devices studied in this paper are contemplated. On the other hand, eq. (4b) is simplified due to the model hypothesis, thus the only possibility for $UI^{t}_{y,i}$ is if a section defined by an ASS has a fuse upstream, since fuse installation in the path between the IID and the substation is not possible and the combinations IID-recloser and ASS-recloser do not provide any cost due to recloser operation. In this case, a repair time (TR) is necessary to verify the reason of the fault, change the fuse and restore the section.

The calculation of the power supply interruptions to consumers downstream of the faulted section due to the incidence of permanent and temporary faults is provided by eq. (5), where set ω_i is composed of all branches k downstream of the faulted section i, including the branches of section i.

$$DI_{y,i} = \left(\sum_{h\in\omega_i} LD_{y,h} \right) TR \quad (5)$$

Eq. (6) provides the ENS amount restored by transferring load from neighboring feeders. If there is a set of feeders Ω_i downstream of the faulted section i it is possible to feed the loads existing in this area, reallocating loads for this set of feeders. To model the relocation of loads in the faulted sections, binary variable $y_{k,e}$ defines whether neighboring feeder e has sufficient power reserve to feed section load k.

$$LT_{y,i} = \sum_{\substack{k\in\omega_i \\ k\neq i}} \sum_{d\in\{2,3\}} \sum_{c\in\delta_d} x_{k,d,c} \sum_{e\in\Omega_i} y_{k,e} \times \left(\sum_{h\in\varphi_k} LD_{y,h} \right) (TR - Tr) \quad (6)$$

where set ω_i is composed of all branches k of the distribution network downstream of section i.

In eq. (7) the amount of energy restored is described. In this equation the possibility of distributed generator g to supply power to section k downstream of the faulted section i is modeled.

$$IO_{y,i} = \sum_{\substack{k\in\omega_i \\ k\neq i}} \sum_{c\in\delta_d} x_{k,4,c} \sum_{g\in G_i} s_{k,g} \left(\sum_{h\in\varphi_k} LD_{y,h} \right) TR \quad (7)$$

where binary variable $s_{k,g}$ defines whether generator g can supply all loads downstream of branch k.

2) Equipment Cost: Control and protection devices are mainly installed in the DS during the network planning phase. However, due to load growth and changes in topology, distribution companies (DISCOs) often want to increase the security and reliability of the network to ensure the indices required by regulatory agencies. This is achieved through the installation of new protection devices and/or the reallocation of existing ones, thus the mathematical model proposed in this paper is developed for DS in the planning stage or already in operation [1], [4]. We use a binary variable, $x^{base}_{i,d,c}$, which allows us to check if there is a device of type d with operation range c installed in branch i.

Eq. (8) takes into account the acquisition, installation/uninstallation and maintenance costs of the control and protection devices.

$$C_{Equip} = C_{acqui} + C_{inst/uni} + \sum_{y\in\theta} \frac{C_{main_y}}{(1+IRR)^y} \quad (8)$$

where C_{Equip} represents the total costs; C_{aqui} acquisition; ($C_{inst/uni}$) installation and uninstallation; and C_{main_y} maintenance. The values of C_{aqui}, $C_{ins/uni}$, C_{main_y} are given by:

$$C_{acqui} = \sum_{d\in\mu} \sum_{c\in\delta_d} Acqu_{d,c} Z_{d,c} \left(\sum_{i\in\beta} \left(x_{i,d,c} - x^{base}_{i,d,c} \right) \right) \quad (9)$$

$$C_{ins/uni} = \sum_{d\in\mu} \sum_{c\in\delta_d} \sum_{i\in\beta} \left(x_{i,d,c} \left(x_{i,d,c} - x^{base}_{i,d,c} \right) Ins_d \right) + x^{base}_{i,d,c} \left(x^{base}_{i,d,c} - x_{i,d,c} \right) Uni_d \quad (10)$$

$$C_{main_y} = \sum_{d\in\mu} \sum_{c\in\delta_d} \sum_{i\in\beta} \left(x_{i,d,c} Main_d \right) \quad (11)$$

In eq. (9), the amount of devices that must be installed is subtracted from the quantity of devices of the same type and the operational capacity already existing in the system; $Acqu_{d,c}$, represents the device acquisition costs of type d with operational capacity c; and binary variable $Z_{d,c}$ has a value of 1 if the result of the sum in parenthesis $(x_{i,d,c} - x^{base}_{i,d,c})$ is greater than 0, otherwise its value is 0, ensuring that only the acquisition costs of the new devices will be added in the evaluation. In eq. (10), the installation and uninstallation costs are calculated, where Ins_d and Uni_d represent the installation and uninstallation costs of a device of type d with operational capacity c, respectively. In eq. (11) the annual maintenance costs of the devices are calculated, where $Main_d$ represents the maintenance cost of a device of type d.

B. Coordination and Selectivity Constraints

The coordination and selectivity constraints are modeled to maintain the adequate time intervals between the operational characteristic curves of the devices, taking into account SCCs between phases and single-phase (N). The coordination constraints are related to the operational times of the instantaneous characteristics of phase (50) and ground (50N) of the reclosers, and the selectivity constraints are related to the operational times in the inverse-time characteristics to phase (51) and ground (51N) of overcurrent protection devices [23], [24]. The selectivity between the devices is evaluated considering the maximum SCC, and the coordination using the minimum SCC. In the constraints, set U_i is the set of branches that are in the loop between branch i and the substation, and branch j represents the location of a protection device upstream and in series with the device allocated in the branch i.

1) Adjuster of Characteristic 50: The constraints that define the adjusters of characteristic 50 (defined time) of the reclosers use discrete time values, which are limited to a pre-established range according to eqs. (12) and (13).

$$t_{\min}^{D50} \leq (x_{i,d,c}) t_{i,d,c}^{D50} \leq t_{\max}^{D50} \qquad \forall\, i \in \beta,\ d = \{2,4\},\ c \in \delta_d \tag{12}$$

$$t_{\min}^{D50N} \leq (x_{i,d,c}) t_{i,d,c}^{D50N} \leq t_{\max}^{D50N} \qquad \forall\, i \in \beta,\ d = \{2,4\},\ c \in \delta_d \tag{13}$$

where $t_{i,d,c}^{D50}$ and $t_{i,d,c}^{D50N}$ are the adjusters of reclosers of type d installed in section i for characteristics 50 and 50N, respectively; and $t_{\max}^{D50}$, $t_{\max}^{D50N}$, $t_{\min}^{D50}$, and $t_{\min}^{D50N}$ are the maximum and minimum values to the adjusters of the 50 and 50N characteristics, respectively.

2) Time Dial Adjuster of Characteristic 51: The time dial adjusters of characteristic 51 for the reclosers and overcurrent relays are also defined in a range of discrete values according to eqs. (14) and (15).

$$t_{\min}^{D51} \leq (x_{i,d,c}) t_{i,d,c}^{D51} \leq t_{\max}^{D51} \qquad \forall\, i \in \beta,\ d = \{2,4\},\ c \in \delta_d \tag{14}$$

$$t_{\min}^{D51N} \leq (x_{i,d,c}) t_{i,d,c}^{D51N} \leq t_{\max}^{D51N} \qquad \forall\, i \in \beta,\ d = \{2,4\},\ c \in \delta_d \tag{15}$$

where $t_{i,d,c}^{D51}$ and $t_{i,d,c}^{D51N}$ are the time dial adjusters of the characteristics of phase (51) and ground (51N) of the recloser or overcurrent relay in section i, respectively; and $t_{\max}^{D51}$, $t_{\max}^{D51N}$, $t_{\min}^{D51}$ and $t_{\min}^{D51N}$ are the maximum and minimum time values of the adjuster characteristics 51 and 51N, respectively.

3) Selectivity Between Fuses: Selectivity between fuses is ensured when the protective fuse interruption time is no higher than 75% of the fusion time of the protected fuse, for the biggest SCC of both protection zones [25], eq. (16):

$$(x_{i,1,c}) \left[t_{i,1,c}^{MI} \left(I_i^{SC\max} \right) \right] \leq (x_{j,1,c}) \left[0.75 t_{j,1,c}^{MF} \left(I_{j-i}^{SC\max} \right) \right] \qquad \forall\, i \in \beta,\ j \in U_i, c \in \delta_1 \tag{16}$$

where I_i^{SCmax} is the maximum phase or ground SCCs in branch i; I_{j-i}^{SCmax} is the maximum SCC of branch i which also flows through branch j; $t_{j,1,c}^{MI}$ is the maximum interruption time of the fuse installed in branch i; and $t_{j,1,c}^{MF}$ is the minimum fusing time of the fuse installed in branch j.

4) Recloser – Fuse Coordination: The coordination among reclosers and fuses must ensure that the recloser first acts on its instantaneous characteristic, guaranteeing that the fuse is not acting. Thus, it should be considered that, for any minimum SCC, the recloser acts before the fusing time of the fuse [25], see eqs. (17) and (18).

$$(x_{j,d,c}) \left[k_{coord}^{50-MF} \cdot t_{j,d,c}^{50} \left(I_{j-i}^{SC\min P} \right) t_{j,d,c}^{D50} \right] \leq (x_{i,1,c}) \left[t_{i,1,c}^{MF} \left(I_i^{SC\min P} \right) \right] \forall\, i \in \beta,\ j \in U_i, d \in \{2,4\}, c \in \delta_d \tag{17}$$

$$(x_{j,d,c}) \left[k_{coord}^{50-MF} \cdot t_{j,d,c}^{50N} \left(I_{j-i}^{SC\min G} \right) t_{j,d,c}^{D50N} \right] \leq (x_{i,1,c}) \left[t_{i,1,c}^{MF} \left(I_i^{SC\min G} \right) \right] \forall\, i \in \beta,\ j \in U_i, d \in \{2,4\}, c \in \delta_d \tag{18}$$

where I_i^{SCminP} and I_i^{SCminG} are the minimum phase and ground SCCs in branch i, respectively; I_{j-i}^{SCminP} and I_{j-i}^{SCminG} are the minimum phase and ground SCC, respectively, which also flows through branch j; and k_{coord}^{50-MF} is the coordination factor of the instantaneous characteristic considering the minimum fusing time of the fuse.

5) Recloser – Fuse Selectivity: This set of constraints is related to the recloser inverse time characteristic and the maximum fuse interruption curve, where it must be ensured that the operating time of the fuse plus a safety time should be lower than the operation time of the overcurrent relay or recloser [25], see eqs. (19) and (20).

$$(x_{i,1,c}) \left[t_{i,1,c}^{MI} \left(I_i^{SC\max P} \right) + t_{coord}^{51-MI} \right] \leq (x_{j,d,c}) \left[t_{j,d,c}^{51} \left(I_{j-i}^{SC\max P} \right) t_{j,d,c}^{D51} \right] \forall\, i \in \beta,\ j \in U_i, d \in \{2,4\}, c \in \delta_d \tag{19}$$

$$(x_{i,1,c}) \left[t_{i,1,c}^{MI} \left(I_i^{SC\max G} \right) + t_{coord}^{51-MI} \right] \leq (x_{j,d,c}) \left[t_{j,d,c}^{51N} \left(I_{j-i}^{SC\max G} \right) t_{j,d,c}^{D51N} \right] \forall\, i \in \beta,\ j \in U_i, d \in \{2,4\}, c \in \delta_d \tag{20}$$

where I_i^{SCmaxP} and I_i^{SCmaxG} are the maximum phase and ground SCCs in branch i, respectively; I_{j-i}^{SCmaxP} and I_{j-i}^{SCmaxG} are the maximum phase and ground SCC of branch i passing through branch j, respectively; and t_{coord}^{51-MI} is the coordination time of the recloser inverse characteristic with the maximum interruption curve of the fuse.

6) Coordination Between Reclosers: In the coordination between reclosers it must be ensured that for any minimum SCC the main device must operate before the rearguard device [25], according to eqs. (21) and (22).

$$(x_{i,d,c}) \left[t_{i,d,c}^{50} \left(I_i^{SC\min P} \right) t_{i,d,c}^{D50} + t_{coord}^{50-50} \right] \leq (x_{j,d,c}) \left[t_{j,d,c}^{50} \left(I_{j-i}^{SC\min P} \right) t_{j,d,c}^{D50} \right] \forall\, i \in \beta,\ j \in U_i, d \in \{2,4\}, c \in \delta_d \tag{21}$$

$$(x_{i,d,c})\left[t_{i,d,c}^{50N}\left(I_i^{SC\min G}\right)t_{i,d,c}^{D50N}+t_{coord}^{50-50}\right] \leq (x_{j,d,c})\left[t_{j,d,c}^{50N}\left(I_{j-i}^{SC\min G}\right)t_{j,d,c}^{D50N}\right]\forall\, i\in\beta,\ j\in U_i,\quad d\in\{2,4\}, c\in\delta_d \tag{22}$$

where t_{coord}^{50-50} is the coordination factor of the instantaneous characteristic between two reclosers.

7) Selectivity Between Reclosers: In the selectivity between reclosers, it must be ensured that the actuation time of the main device plus a coordination time must be smaller than the actuation time of the rearguard device [25] for phase and ground coordination, see eqs. (23) and (24).

$$(x_{i,d,c})\left[t_{i,d,c}^{51}\left(I_i^{SC\max P}\right)t_{i,d,c}^{D51}+t_{coord}^{51-51}\right] \leq (x_{j,d,c})\left[t_{j,d,c}^{51}\left(I_{j-i}^{SC\max P}\right)t_{j,d,c}^{D51}\right]\forall\, i\in\beta,\ j\in U_i,\quad d\in\{2,4\}, c\in\delta_d \tag{23}$$

$$(x_{i,d,c})\left[t_{i,d,c}^{51N}\left(I_i^{SC\max G}\right)t_{i,d,c}^{D51N}+t_{coord}^{51-51}\right] \leq (x_{j,d,c})\left[t_{j,d,c}^{51N}\left(I_{j-i}^{SC\max G}\right)t_{j,d,c}^{D51N}\right]\forall\, i\in\beta,\ j\in U_i,\quad d\in\{2,4\}, c\in\delta_d \tag{24}$$

where t_{coord}^{51-51} is the coordination time of characteristic 51 between reclosers.

Several parameter values of the protection devices used in the constraints of the proposed model, eqs. (12)–(24), can be found in detail in [25]. An illustrative example of how these equations work is shown in the Appendix.

IV. Solution Techniques and Auxiliary Tools

A. Solution Techniques

The problem proposed in (1)–(24) is of a complex nature, non-convex, difficult to solve through exact classical optimization techniques. Among the techniques reported in literature to solve this kind of problem, the MOGA, based on the improved version of the NSGA-II [19], is used in this paper. The MOGA is able to minimize the objective functions at the same time, finding the trade-off (Pareto Frontier) between them without adding elements which could, in some way, prioritize any of them in the decision making process. The unique characteristics of MOGA such as, coding, mutation, and recombination are described below, while details about the selection operator and dominance criteria can be found in detail in [19].

1) Codification and Initial Population: To explore the problem characteristics and extract the maximum potential of the MOGA, an integer decimal code is used, which makes possible to represent the different types of protective devices in a simple and efficient way. Each individual is represented by a vector with n positions, where n is the number of system branches and the integer numbers in each position of the vector (gene) represent the allocation (or not) of the devices. In this way, the proposed coding allows the methodology developed in this paper to be applied in the design of any distribution network, provided the network topology is known.

The initial population is generated pseudo-randomly, since practical hypotheses taken into account in the model formulation of the problem are considered.

2) Genetic Operators: Recombination: Four types of recombination are used, which are performed randomly for each pair of selected individuals for recombination: 1 - single crossing point, 2 - two crossing points, 3 - one crossing point with gene inversion 4 - one crossing point with inversion of genes of the other individual [26].

Mutation: A single mutation is used. If the selected gene (vector position) has a value different from 0, then the gene value is replaced with 0, otherwise a nonzero value between 1, 2, 3 and 4 is randomly chosen to replace the 0 value. The rates of recombination and mutation are adaptively altered during the iterations of NSGA-II, as proposed in [15].

B. Auxiliary Tools

Some auxiliary tools are used to evaluate the solution proposals, through OFs and constraints, provided by NSGA-II. The first one is an algorithm for the three-phase power flow calculation for unbalanced systems [27], considering the contribution of DG. The power flow algorithm is used to obtain load currents to specify the nominal current values of the control and protection devices and the pre-fault voltages, which are used to calculate the SCC.

The SCCs are calculated using the algorithm proposed in [28], considering the loads modeled as constant impedances. In the SCC calculations, it is considered that DG is connected through coupling transformers, and this set (DG + transformer) is modeled as described in [29]. Eq. (25) allows us to find the equivalent impedance of the generator connection reflected at the medium voltage bus of the distribution network.

$$Z_s = K_s(t_r^2 Z_G + Z_{THV}) \tag{25}$$

where K_s is a correction factor; Z_G is the sub-transient impedance of the generator, $Z_G = R_G + jx_d''$; Z_{THV} is the impedance of the transformer that connects DG to the system reflected in the medium-voltage side; t_r is the nominal transformer ratio $t_r = U_n/U_{rG}$, where U_n is the nominal voltage at the medium- voltage side; and U_{rG} is the nominal voltage at the low-voltage side.

The types of faults simulated and used in this work are: single-phase-ground with and without ground fault impedance; two-phase (between phases B and C); and three-phase without contact impedance, obtaining the maximum and minimum phase and ground SCCs. The maximum and minimum phase and ground SCCs, and the data of the protection devices to be allocated, are the necessary data to run the computational program implemented from the proposed methodology.

V. Tests and Results

A. Test System and Data

The proposed methodology is implemented in C++, and and is applied in the unbalanced three-phase 135-bus system of Fig. 3, operating at a nominal voltage of 13.8 kV and with 7,065 MVA of load. The complete data of this system can be found in [20] and [30]. The test was carried out using a personal computer with a Intel(R) Core(TM) i7-7700, 3.60 GHz and 16Gb of RAM.

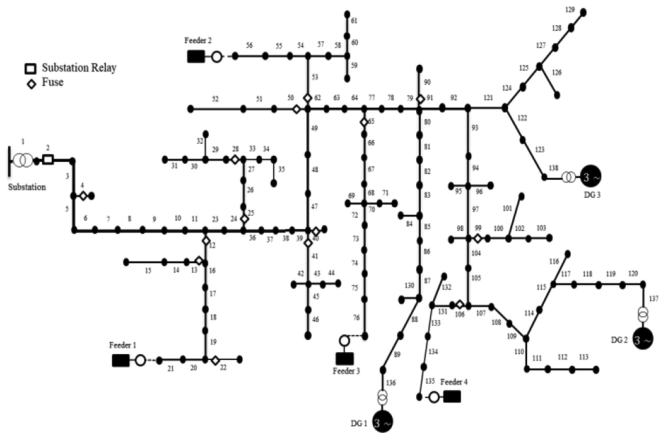

Fig. 3. 135-bus real-life distribution system.

TABLE II
COSTS OF PROTECTION DEVICES AVAILABLE TO BE INSTALLED

Devices	Current rate (A)	Acquisition Costs ($)	Install./Uninst. Costs ($)	Maint. Costs ($)
Fuse	0 - 6	300	100	50
	6 - 10	400		
	10 - 15	500		
	15 - 25	600		
	25 - 40	700		
	40 - 65	800		
	65 - 100	900		
	100 - 140	1000		
	140 - 200	1100		
Automatic recloser	0 - 50	15000	2000	1000
	50 - 100	19000		
	100 - 300	22000		
	300 - 500	27000		
	500 - 1000	30000		
Automatic sectionalizing switch	0 - 50	3500	800	350
	50 - 100	4000		
	100 - 300	4500		
	300 - 500	5000		
	500 - 1000	5500		
IID	0 - 50	20000	2500	1500
	50 - 100	25000		
	100 - 300	30000		
	300 - 500	35000		
	500 - 1000	40000		

The initial system has 4 switches (normally open) that allow the load to transfer to neighboring feeders 1, 2, 3 and 4. The load transfer capacity between the feeder under study (started at bus substation) and the neighboring feeders 1 and 3 is 800 kVA; and to feeders 2 and 4 is 500 kVA. In addition to sectionalizing switches the system has 14 fuses and one overcurrent relay at the substation. The planning horizon considered is 5 years, in which a 5% of load growth per year and a 5% of IRR are assumed. The demand consumption at each bus was divided as the following percentages: 50% residential, 30% commercial and 20% industrial. This kind of consumption was selected to run the tests in an easy and practical way, however, the algorithm is able to consider a specific kind of consumption for each

TABLE III
COMPARISON OF RESULTS BETWEEN TESTS 1 AND 2

		Test 1	Test 2	Best OF for test 2 after coordination is achieved
Best OF ($)		67025.5	64769.3	69513.6
Interruption Cost ($)		51142.8	47077.3	54558.2
Equipment Cost ($)		15882.7	17691.9	14955.4
Devices Allocated	Fuse	9	13	8
	Reclose	1	1	1
	ASS	1	1	1
	IID	0	0	0
Violated restrictions		0	5	0

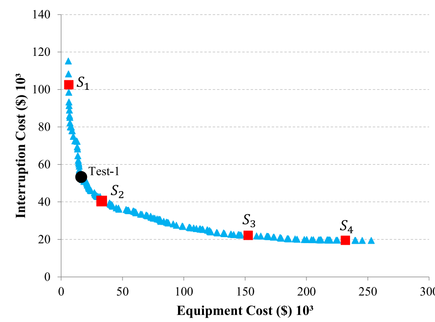

Fig. 4. Pareto curve found by NSGA-II.

system bus. The 3 DG units installed are synchronous generators operating with voltage control and the data for each of them is presented in [30] where the values of short-circuit impedance of the generators are based on [31]. Data about DG connection transformers (eq. 25) can be found in detail in [30].

In the specification of control and protection devices, the operational current values calculated for the last year of the planning horizon in their respective installation points, are used. For the maximum and minimum phase-to-phase SCC and maximum and minimum phase-to-ground SCC, the three-phase SCC, the two-phase SCC, the single-phase SCC with a contact impedance of 0.0, and the single-phase SCC with a contact impedances of 40 ohms are used, respectively.

ENS cost is $1.5/kWh for residential consumers, $30/kWh for commercial consumers and $4.64/kWh for industrial consumers. The average repair time is TR $=$ 4 hours, and average restoration time $Tr = 0.08$ hours. Rates of permanent and temporary faults are $\lambda = 0.072$ fault/km/year and $\gamma = 0.98$ fault/km/year, respectively being 8760 hours/year [14]. In addition, it is also considered that 25% of the faults that occur in the system are phase-to-phase faults while 75% are phase- to-ground faults. The costs of acquisition, installation/uninstallation, and maintenance of the devices available to be installed in the DS are presented in Table II and are based on [4].

For the maximum and minimum time limits of the dial adjusters of characteristics 50 and 51 of the reclosers, the following values are used: $t^{50}_{\min} = t^{50N}_{\min} = 1.0\ s$, $t^{51}_{\min} = t^{51N}_{\min} = 0.5\ s$ and $t^{50}_{\max} = t^{50N}_{\max} = t^{51}_{\max} = t^{51N}_{\max} = 10\ s$ [32]. For the coordi nation and selectivity constraints, the following coordination values are

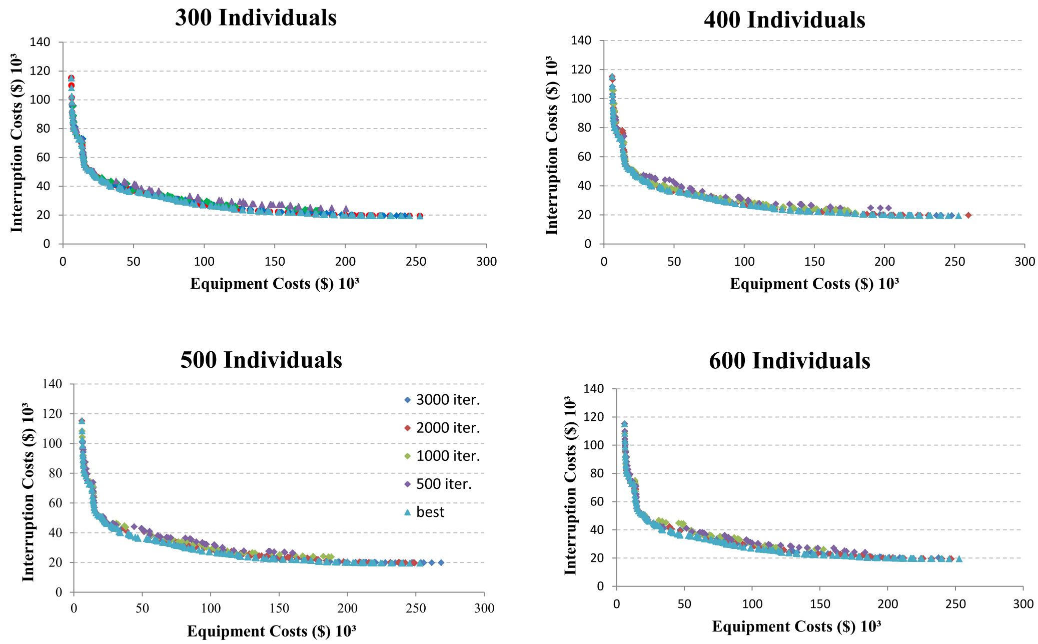

Fig. 5. Pareto frontier evolution changing the number of iterations.

used: $t_{coord}^{51-MI} = t_{coord}^{51-51} = 0.2\,s, t_{coord}^{50-50} = 0.05\,s$ and $k_{coord}^{50-MF} = 1.35$ [32]. In this paper we consider the extremely inverse operational curve to facilitate the coordination with the fuse curve and characteristic 51 of the relays and reclosers.

B. Model Efficiency

The validation of the proposed model is performed using a simple genetic algorithm (GA) proposed in [26]. The validation consists of the following procedure: Test 1: Solve problem (1)–(24), where OFs and coordination and selectivity constraints are evaluated in the same model; Test 2: The second test is performed in 3 steps: In the first one, the equipment is optimally allocated in the system in order to minimize interruption and equipment costs, eqs. (1)–(11); in the second one, with the equipment already allocated optimally, the coordination and selectivity of the protection devices, eqs. (12)–(24), are evaluated; and finally, the devices that cannot be coordinated are removed from the network and the OF is recalculated [14], [15], [17].

The OF considered in these two tests is the sum of functions (1) and (8) with the same weight (importance), as presented in eq. (26).

$$OF = C_{Interrup} + C_{Equip} \tag{26}$$

In both tests, a population of 500 individuals and a maximum amount of 3000 iterations are used. For each test, 15 samples of solutions are analyzed. The average values for the simulations are $70,193.10 and $67,499.60 for tests 1 and 2, respectively, with respective standard deviations of 1.2% and 0.8%. The average time to carry out the simulation is approximately 9 min for both cases, highlighting that the inclusion of the coordination and selectivity constraints does not worsen the methodology execution time.

In Table III the best values of the OFs for the two tests as well as the values of interruption costs, equipment costs, number of devices allocated, and number of coordination and selectivity constraints violated are shown. The worst values found by the algorithm for tests 1 and 2 are 3.2% and 3.3% higher than the best ones for each case.

As can be seen in Table III, the solution found by test 2 has a lower value than the one of test 1 (which is a more restricted model) since it considers that the allocated devices must operate in coordination and selectively. However, when the coordination and selectivity constraints of the 11 fuses are evaluated, after the optimized allocation, it is not possible to obtain the coordination of 4 fuses and it is necessary to remove them from the network in order to obtain protection system coordination. After removal of these 4 fuses and re-evaluation of the OF, the real values of the interruption costs are obtained, resulting in a OF value higher than the value found in test 1, according to the last column of Table III.

In this way, it is possible to conclude that the mathematical model proposed in this paper in which the allocation, coordination and selectivity of the control and protection devices are performed simultaneously, provides better results when compared to the results obtained in the allocation and coordination carried out in separate processes, validating the contribution of coordination and selectivity constraints to the DS protection planning problem.

C. Results Obtained Using the MOGA

The results found by the MOGA representing the trade-off between OFs are presented in Fig. 4. This curve is obtained using the following parameters: a population of 500 individuals and a maximum of 2000 iterations and presents 140 non-dominated solutions.

These parameters have been chosen after a careful test selection to find the limit parameter values which are able to cause changes in the Pareto frontier, as we can observe in Fig. 5.

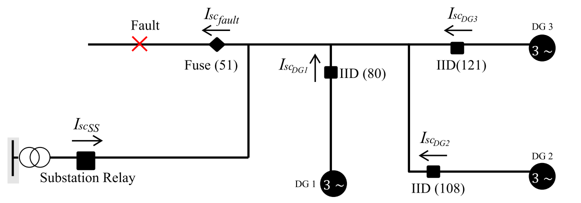

Fig. 6. Coordination scheme with multiple sources.

TABLE IV
EXAMPLES OF PARETO CURVE SOLUTIONS

Solutions		S_1	S_2	S_3	S_4
Interruption Cost ($)		101299.0	41340.3	22409.2	19948.8
Equipment Cost ($)		6327.8	38283.3	154059.0	237270.0
Devices Allocated	fuse	3	10	8	3
	recloser	1	1	1	3
	ASS	0	4	7	12
	IID	0	0	3	3

Therefore, these sets of parameter values are able to find the best results for the proposed problem. It can also be observed that, despite the parameters' variation presented in Fig. 5, the solutions are very close to the best one found by the algorithm. The processing time to find the solutions presented in Fig. 6 was approximately 15 min, a very acceptable time for a planning problem.

To verify the trade-off between the objectives, solutions S1, S2, S3 and S4, identified in Fig. 5, are detailed in Table IV. A simple economic analysis that can help the decision maker is to verify the benefit achieved in the reduction in the interruption costs compared to the increase in the investment costs made in the protection system. For example, comparing S1 and S2 solutions, solution S2 has a value of $31,955.50 higher than solution S1 for equipment costs, however, when comparing ENS costs, solution S2 shows a reduction of $59,958.70 when compared to the value presented by solution S1.

Therefore, the investment in the protection system is compensated by the benefit of the interruption costs reduction. Performing the same comparison between solutions S2 and S3, an increase of $11,5775.70 in the investment costs of S3 with respect to S2 is not exceeded by the reduction of interruption costs, which is only $18,931.10 lower than the value found for solution S2. In this case, the increase in investment costs is not compensated by the reduction in interruption costs. Thus, it can be concluded that solution S2 is more attractive than solutions S1 and S3 from an economic point of view. However, in order to adopt a final solution, other aspects related to the company's image and eventual regulatory fines by non-compliance of the continuity and reliability indices need to be taken into account. Considering that a company is looking for a system with greater reliability, solutions S3 and S4 are more attractive. These two solutions allow for the installation of 3 IID devices. Solution S4 presents an investment of $83,211.00 higher than that presented by S3 to reduce interruption costs by only $2,460.40. In this sense, solution S3 becomes the best option for the DISCO and the pieces of equipment that must be allocated or reallocated for this solution are: installation of 3 fuses (65K) (branches 15, 98 and 101); relocation of 5 fuses within the network (branches 42, 45, 51, 95 and 192); installation of 7 ASS (branches 12, 26, 36, 53, 66, 79 and 106); and installation of 3 IIDs (branches 80, 108 and 121). The ASS installed in branches 12, 53, 66 and 106 can enable, in the occurrence of permanent faults upstream of their installation points, a load transfer of 2.077 MVA to neighbor feeders. The 3 IIDs installed in branches 80, 108 and 121 allow for the disconnection of the DG section in the occurrence of permanent faults upstream of its installation point, maintaining 1.609 MVA supplied through the DG units. In order to verify DG participation in the occurrence of faults in the DS, a particular case of coordination and selectivity is presented between some protection devices presented in solution S3. If a fault occurs in the section delimited by the fuse installed in branch 51, (fuse 51) the SCC of branch 51 is the sum of the SCCs supplied by all sources, i.e., by the substation and the 3 generators. Thus, the SCC sensitizes the substation relay and each one of the IIDs (IID (80), IID (121) and IID (108)) are different from the SCC that sensitizes the fuse, as can be seen in Fig. 6

In the event of temporary faults, the coordination constraint ensures that the fuse performance must be slower than the actuation of the substation relay and the three IIDs for the minimum phase and ground SCCs. In this case, solution S3 sets to 0.05s the actuation time of the substation relay and the IIDs (80, 108 and 121), according to characteristic 50. The operation of fuse 51 (65 k) occurs only in 0.0761s for minimum-phase SCC (1317.4 A), and in 11.11s for minimum-ground SCC (180.59 A)

When considering permanent faults, the selectivity must ensure that the fuse isolates its faulted section to the maximum SCC. The selectivity between fuse 51 and the four SCC sources, for their respective maximum phase-to-ground SCCs, can be verified in Fig. 7.

The maximum ground SCC that sensitizes fuse 51 is 1,527 A, which operates in 0.057 s. The constraints considered in the model have a safety margin that increases this time by 0.2 s, therefore the performance of all rearguard devices must be greater than 0.257 s. In Fig. 7 it is possible to visualize the actuation times of each device, as well as the SCC that sensitizes each protection device in the selectivity constraint curves of the fuse with respect to each one of the reclosers. In Fig. 7(a) the SCC sensitizing the substation relay is 912 A, resulting in an actuation time of 2.998 s, however, in Fig. 7(c), for example, the SCC sensitizing the IID (121) is 155 A, which has an actuation time of 0.379 s, these times are clearly higher than the safety actuation time of fuse 51. The same occurs in Figs. 7(b) and 7(d). The same coordination and selectivity between these devices is obtained for phase-to-phase SCC and for all the devices installed in the network.

The results presented in Figs. 6 and 7 validate the need for mathematical models and methodologies that consider in detail the physical problems of the protection operation of distribution systems with DG. In the presented case, it is possible to see the real contribution of each DG to the analyzed SCC, as well as the operational details of each protection device involved in the fault, thus validating the contribution and efficiency of the model and methodology proposed in this paper.

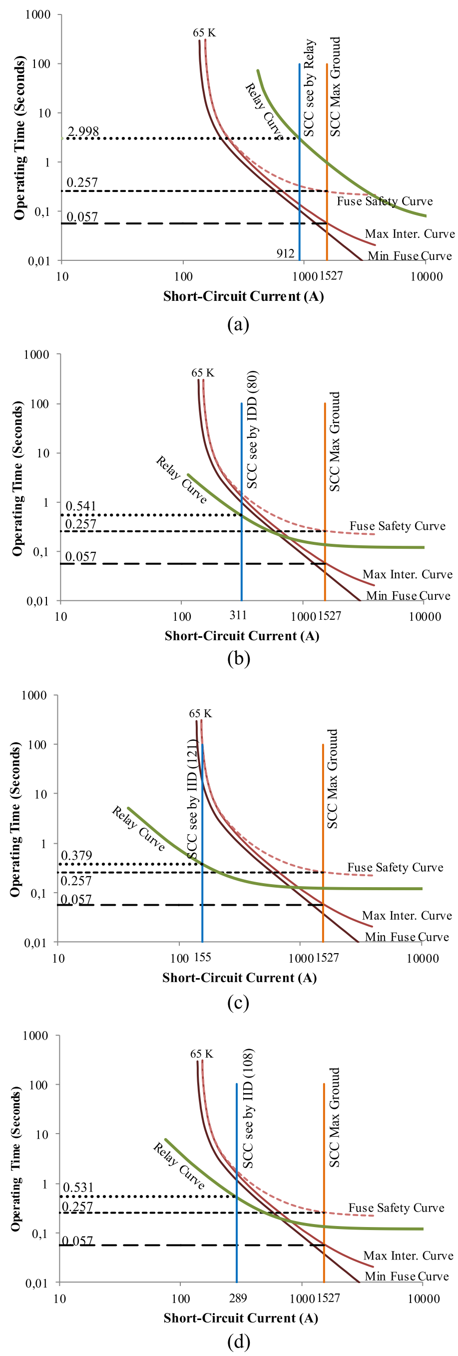

Fig. 7. Selectivity between fuse (51) and 4 sources. (a) Selectivity between fuse and substation relay. (b) Selectivity between the fuse and the IID (80). (c) Selectivity between the fuse and the IID (121). (d) Selectivity between the fuse and the IID (108).

VI. Conclusion

The proposed optimization model that takes into account simultaneously the specification, allocation, coordination and selectivity of the control and protection devices in electrical DS allows us to obtain technically and economically viable solutions. The results presented prove the efficiency of the proposed mathematical model. It is a realistic and complex model that considers, through its parameters, the influence of the loads and DG on the calculations of the load currents and SCC and consequently in the specification, allocation, coordination and selectivity of the control and protection devices. It is verified in the results presented that all sources contribute to the SCC and the devices installed in the system are sensitized by different currents. Thus, these currents must be considered in the coordination and selectivity constraints in order to keep a correct system operation and the power supply to the consumers with adequate continuity indices in normal conditions in the event of permanent and temporary faults.

Other DG models, such as inverter-based DGs, can be used in the proposed methodology. Inverter-based DGs have limited SCC, due to relay adjustments, and these limits can be easily included in the algorithm for SCC calculation presented in [28]. Once the SCC considering the DG limits is known, the proposed mathematical model can be solved without any change.

The presented results also prove the multiobjective nature of the problem, and the proposed MOGA is able to find a set of solutions that represent a tradeoff between two objective functions, one based on economic issues and the other one on network continuity. This set of solutions can be of great interest for DISCOs to find the best protection planning proposal.

TABLE V
Power of Loads and Permanent and Temporary Fault Rates of Sections

Section	Power (kVA)	Failure rate	
		Temporary	Permanent
SS Relay	457.5	$1.957\ 10^{-4}$	$1.438\ 10^{-5}$
R-Fuse-IID	5721.8	$7.596\ 10^{-4}$	$5.580\ 10^{-5}$
Fuse	187.5	$3.020\ 10^{-5}$	$2.219\ 10^{-6}$
IID	698.0	$5.761\ 10^{-5}$	$4.232\ 10^{-6}$

TABLE VI
Interruption Costs Due to Sections Under Fault

Section under Fault	Interruption costs ($)			
	Upstream	Downstream.	Load Transfer	Island Operation
SS Relay	0.00	2,1602.18	0.00	2,134.29
R-Fuse-IID	0.00	7,8407.83	0.00	8,283.06
Fuse	0.00	88.474	0.00	0.00
IID	106.37	628.23	0.00	0.00

Appendix

The model presented in Section III is verified using the system shown in Fig. 1. Information about SCC of this system is detailed in [30]. The three-phase power of system sections, as well as their respective failure rates are shown in Table V. All other data are the same presented in Section V.

The acquisition, installation and maintenance costs total $108,438.00. Energy interruption costs occur due to permanent faults only, since the temporary faults are eliminated by the recloser and substation relay. The energy interruption costs due to faults in each section are presented in Table VI. The total cost of ENS is $90,415.75.

For the solution to be feasible, perfect coordination and selectivity of the protection system is necessary, i.e., constraints (12), (13), (14), (15), (17), (18), (19), (20), (21), (22), (23) and (24) must be satisfied. Constraints (12), (13), (14) e (15) define the time adjusters of characteristics 50 and 51. In this case, $t_{i,d,c}^{D50}$

TABLE VII
ACTING TIME AND MINIMUM AND MAXIMUM SCC THAT SENSITIZE EACH DEVICE PROTECTION OF THE SYSTEM – FAULT IN THE FUSE SECTION

Condition /SCC (A)	Current through device (A) / Acting time (s)			
	Fuse	IID	Recloser	SS Relay
Mininum of phase / 783.2	785.8 / 0.138	215.16 / 0.05	768.24 / 0.05	778.45 / 0.10
Mininum of ground / 165.65	167.81 / 8.105	65.88 / 0.05	317.89 / 0.05	333.52 / 0.10
Maximum of phase / 1352.63	1385.4 / 0.065	326.46 / 0.481	1164.75 / 2.38	1175.66/ 3.53
Maximum of ground / 1025.59	1151.38 / 0.085	311.61 / 0.515	931.94 / 2.58	934.44 / 5.81

and $t_{i,d,c}^{D50N}$ are adjusted to 1.0 s and $t_{i,d,c}^{D51}$ e $t_{i,d,c}^{D51N}$ to 0.5 s:

$$1.0 \leq t_{i,d,c}^{D50} \leq 10 \tag{27}$$

$$1.0 \leq t_{i,d,c}^{D50N} \leq 10 \tag{28}$$

$$0.5 \leq t_{i,d,c}^{D51} \leq 10 \tag{29}$$

$$0.5 \leq t_{i,d,c}^{D51N} \leq 10 \tag{30}$$

The next constraints to be met are those related to the coordination and selectivity between the devices installed in the network, i.e., the coordination and selectivity between the fuse - recloser, between the fuse - IID and between the substation relay - recloser. Thus, the following constraints should be taken into account:

– Constraints (17) and (18)

Fuse – Recloser

$$1.35\, t_{j,d,c}^{50N}\left(I_{j-i}^{SC\min G}\right) \leq t_{i,1,c}^{MF}\left(I_i^{SC\min G}\right) \tag{31}$$

$$1.35\, t_{j,d,c}^{50}\left(I_{j-i}^{SC\min P}\right) \leq t_{i,1,c}^{MF}\left(I_i^{SC\min P}\right) \tag{32}$$

Table VII shows the recloser ($t_{j,d,c}^{50}$) and fuse ($t_{i,1,c}^{MF}$) acting times to the minimum SCC to phase and ground that sensitize each device, resulting in:

$$0.0675\, s \leq 8.105\, s \tag{33}$$

$$0.0675\, s \leq 0.138\, s \tag{34}$$

Fuse – IID

IID is also adjusted to act in 0.05 s in characteristics 50 and 50N, resulting in the same fuse-recloser relationship equations.

– Constraints (19) and (20)

Fuse – Recloser

$$t_{i,1,c}^{MF}\left(I_i^{SC\max G}\right) + 0.2 \leq 0.5\, t_{j,d,c}^{51N}\left(I_{j-i}^{SC\max G}\right) \tag{35}$$

$$t_{i,1,c}^{MF}\left(I_i^{SC\max P}\right) + 0.2 \leq 0.5\, t_{j,d,c}^{51}\left(I_{j-i}^{SC\max P}\right) \tag{36}$$

Using the acting time of each device presented in Table VII, we have:

$$0.085 \leq 1.29 \tag{37}$$

$$0.065 \leq 1.19 \tag{38}$$

TABLE VIII
ACTING TIME AND MINIMUM AND MAXIMUM SCC THAT SENSITIZE EACH DEVICE PROTECTION OF THE SYSTEM – FAULT IN THE RECLOSER SECTION

Condition /SCC (A)	Current through device (A) / Acting time (s)		
	IID	Recloser	SSR
Mininum of phase / 790.3	161.70 / 0.05	628.40 / 0.05	635.36 / 0.10
Mininum of ground / 175.25	63.67 / 0.05	320.97 / 0.05	336.56 / 0.10
Maximum of phase / 1451.63	328.93 / 0.445	1240.04 / 1.45	1260.64/ 2.75
Maximum of ground / 1112.56	314.29 / 0.514	1011.29 / 2.45	1013.45 / 4.51

Fuse – IID

$$0.085 \leq 0.2405 \tag{39}$$

$$0.065 \leq 0.2575 \tag{40}$$

– Constraints (21) and (22) – *Substation Relay – Recloser*

$$t_{i,d,c}^{50N}\left(I_{j-i}^{SC\min G}\right) + 0.05 \leq t_{j,d,c}^{50N}\left(I_j^{SC\min G}\right) \tag{41}$$

$$t_{i,d,c}^{50}\left(I_{j-i}^{SC\min P}\right) + 0.05 \leq t_{j,d,c}^{50}\left(I_j^{SC\min P}\right) \tag{42}$$

With the values of Table VIII, we have:

$$0.1 \leq 0.1 \tag{43}$$

$$0.1 \leq 0.1 \tag{44}$$

In this case we consider that the IID acts before the DG local protection.

– Constraints (23) and (24) – Substation Relay – Recloser

$$0.5\, t_{i,d,c}^{51N}\left(I_{j-i}^{SC\max G}\right) + 0.2 \leq 0.5\, t_{j,d,c}^{51N}\left(I_j^{SC\max G}\right) \tag{45}$$

$$0.5\, t_{i,d,c}^{51}\left(I_{j-i}^{SC\max P}\right) + 0.2 \leq 0.5\, t_{j,d,c}^{51}\left(I_j^{SC\max P}\right) \tag{46}$$

With the values of Table VIII, we have:

$$1.425 \leq 2.255 \tag{47}$$

$$0.925 \leq 1.35 \tag{48}$$

with the IID acting before DG local protection.

It can be seen from the times shown in Table VII that constraints (21), (22), (23) and (24) continue to be satisfied when considering the SCC in the fuse section.

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