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An adaptive overcurrent protection system applied to distribution systems☆

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ABSTRACT

In this paper, an innovative adaptive directional overcurrent protection system for electric power distribution systems with respect to distributed generation is proposed. The proposed system supervises network topology based on the monitoring functionality of numerical relays. The system detects any changes in the configuration and recalculates the directional overcurrent protection settings by using a microgenetic algorithm. The proposed system was evaluated for several operating scenarios and insertion levels of distributed generation, and then compared with both conventional and adaptive protection systems by means of a traditional genetic algorithm. The results showed that the performance of the proposed system is superior to the other two methods in terms of both speed and selectivity. This shows that this is a promising proposal for the protection of modern electric power distribution systems.

1. Introduction

The supply of electricity is undoubtedly a great worldwide concern given our ever-increasing dependence on electricity. To ensure the quality of the electric power provided by utility companies, electricity regulatory agencies monitor several parameters. One of these parameters is the âæcontinuity of serviceâg, which can be impaired by many kinds of disturbances; fortunately, the electrical systems have protection systems whose function is to ensure the continuity of electricity supply to users. In the case of the electrical power distribution systems (EPDS), the protection task is mainly performed by overcurrent devices which must be programmed to act in a coordinated manner; however, in systems containing numerous protection devices, their coordination becomes difficult. This problem has become increasingly complex due to the increasing prominence of distributed generation (DG), which is a common term that refers to the plant which is directly connected to EPDS and is not centrally planned and dispatched [1].

Despite its many advantages, the insertion of generating units in EPDS can cause several problems, for example, changes in the classical protection schemes and bidirectional power flow. To mitigate these problems, several strategies have been studied, among which the so-called adaptive protection strategy stands out, which can be understood as a protection strategy that aims to automatically adjust the protection functions to the prevailing operating conditions of the system. In practice, this strategy can be implemented in several ways, for example, by using:

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(i) Protection based on communication schemes [2,3]: this enables high performance in terms of the operation speed; however, it calls for massive investments in communication technology.
(ii) Automatic selection of setting groups [4–6]: shows good performance in situations for which the settings have been programmed, however, due to the limited number of setting groups that can be stored in digital relays, only a few operating scenarios can be contemplated.
(iii) Online monitoring and calculation of relay settings [7–9]: comprises one of the most widespread methods, for there are no scenario limitations, but does not guarantee the best possible settings, as it does not usually use optimization methods.
(iv) Optimization methods to perform real-time coordination [10–12] : this derives from iii, with the additional assurance of optimal settings for all possible scenarios; however, it requires high processing because it uses optimization methods, which usually require high computational effort.

In addition to these, several other techniques have been proposed to solve this problem, such as usage of fault current limiters, optimal relay coordination, etc. The state of the art of (iv) was analyzed and it has revealed that, to date: a) the use of optimization methods to perform the coordination of directional overcurrent relays (DOCR) in EPDS in the presence of DG is a relatively incipient line of research; b) the works involving optimization methods present the most efficient solutions; however, one of the disadvantages of the methods used in this category is low processing speed. Nevertheless, developments in processing technology are enabling the production of processors with increasingly better performance; therefore, this drawback will be overcome in time.

The current work fits into this context and proposes an adaptive protection system for primary EPDS in presence of DG which was based on the monitoring of circuit breaker status and active power at monitoring points near DG centers. These signals can be easily obtained from the protection system and can be processed for decision making. A microgenetic algorithm (μGA) was used to perform the optimal coordination of DOCR. This choice was due to its robustness and speed [13], which are essential characteristics for solving the protection problem.

To validate the proposed adaptive protection system, that will be referred to as **APSμg**, a database with several fault cases was simulated using the Simulink/MATLAB® platform. Subsequently, the proposed system was compared with the conventional protection system, that will be referred to as **CPS**, and an adaptive protection system with the traditional genetic algorithm, that will be referred to as **APSga**.

The article is organized as follows: Section 2 has a brief description of the coordination of directional overcurrent relay; In Section 3, we discuss the optimal coordination of DOCR; Section 4 contains the proposal for an adaptive protection system; In Sections 5 and 6, the methodology used, and results obtained are discussed; Finally, Section 7 contains the conclusions.

2. Classical coordination of directional overcurrent relay

The EPDS is the most dynamic part of the power system because it is connected directly to consumers, where several relevant activities occur, due to either power system routine operations or the occurrence of disturbances. The predominant design of the EPDS is radial in structure, with unidirectional power flow and a protection system consisting mainly of DOCR installed at the beginning of the feeders at the substations, in addition to fuses and reclosers. The directional overcurrent protection function is widely used in protection schemes, especially when the relays are arranged into a chain. The coordination between the various devices is well established, as can be seen in the specialized literature [14]. In the specific case of relays, coordination is based on the principle of selectivity, i.e.:

- In order for coordination and selectivity requirements to be met, a parameter called Coordination Time Interval (CTI) must be respected, which corresponds to the minimum operating time interval between two adjacent relays in the chain;
- That means, in the event of a fault, the protection device closest to the fault location (called the primary protection) must operate as fast as possible;
- If the main protection fails, then the device located on the bus upstream of the main protection (called the backup protection) must operate with a certain delay defined as coordination time interval, i.e.:

$$t_{b,l} - t_{p,l} \geq CTI \tag{1}$$

where: CTI is the coordination time interval, and $t_{p,l}$ and $t_{b,l}$ are the operating times of the primary and backup relays, respectively, for a fault in l. Usually, the CTI value is between 0.2 and 0.5 s. In this work, a value of 0.3 s was adopted. The calculation of the operating time of the relay (t_{op}) depends on the protection device used. In this work, the focus is on the time inverse directional overcurrent relay (ANSI number 67/51), whose time operation is inversely proportional to the current. The relationship that describes the characteristics of the inverse time directional overcurrent relay is determined by (2):

$$t_{\text{op}} = TDS \frac{k_1}{\left(\frac{I_f}{I_{\text{pickup}}}\right)^{k_2} - 1} \tag{2}$$

where: TDS is the time-dial setting, I_f is the fault current, I_{pickup} is the pickup current, and k_1 and k_2 are the constants that define the relay operating characteristic. Although relay manufacturers provide several time-overcurrent characteristics, this work focused only on IEC (Normally Reverse - NI, Very Inverse - VI and Extremely Inverse - EI) curves [15]. The TDS has limits according to the relay characteristics used and the position of the relay in the coordination chain:

$$TDS_{i,\min} \le TDS_i \le TDS_{i,\max} \tag{3}$$

where $TDS_{i,\min}$ and $TDS_{i,\max}$ are the minimum and maximum values of the time dial for relay i, respectively. For relays with the IEC curve type, the time dial range is: [0.05; 1.00], with 0.01 steps [16]. The pickup current is the threshold that defines whether the system is in the fault regime. This current varies between a minimum value (usually related to the maximum value of system overload) and a maximum value (usually the minimum short circuit current), according to (4):

$$\alpha I_{\text{load,max}} \le I_{\text{pickup}} \le I_{f,\min} \tag{4}$$

where: $I_{\text{load,max}}$ and $I_{f,\min}$ are the values of the maximum load current and minimum fault current, respectively, and α is the load-growth factor. It is important to highlight that the DOCR receives reduced current levels through the current transformer (CT) so that in practice, the Current Transformer Ratio (CTR) is a parameter that should be considered.

The execution of a relay coordination task is not trivial, and to this day, the usual practice adopted by utility companies, referred to in this paper as âæconventional protectionâg, is to carry out the coordination manually, which makes the process long and tiring as well as subject to errors. On the other hand, when DG is present, the system will tend to behave as an active system. This is certainly a challenge to be faced that calls for new methods and solutions. A first step would be to implement the use of DOCR in order to ensure power system operation along the bidirectional current. However, in the case of topology change, optimal settings for all scenarios would be required.

3. Optimal coordination of DOCR

Optimization involves finding the best possible alternative among all feasible possibilities, which can be many or infinite. Thus, solving an optimization problem requires the formulation of the problem under study, which will result in an objective function, also called fitness function, whose value must be maximized or minimized. The problem may require restrictions or links, which may be relationships of equality or inequality. In 1988, [17] proposed the use of optimization methods as a robust alternative to the analytical process for solving relay coordination. Since then, the scientific community has been looking for methods that provide increasingly robust solutions. This topic is discussed as follows: initially, the formulation of the problem will be presented, and then, the µGA will be proposed as the solution for the coordination problem.

3.1. Problem formulation

In this work, the problem of DOCR coordination is treated as an optimization problem, whose objective is to find the shortest operating time of the relays without disobeying the coordination criteria and the physical limits of the relays. Mathematically, the original relations of the coordination problem (1)–(4) can be formulated as an optimization problem:

$$\text{minimize } \sum_{i=1}^{N} t_{i,l} \tag{5}$$

$$\text{subject to } t_{i+1,l} - t_{i,l} \ge CTI \tag{6}$$

$$t_{i,\min} \le t_i \le t_{i,\max} \tag{7}$$

$$TDS_{i,\min} \le TDS_i \le TDS_{i,\max} \tag{8}$$

$$I_{\text{pickup,min}} \le I_{\text{pickup}} \le I_{\text{pickup,max}} \tag{9}$$

$$k_1, k_2 = \begin{cases} RC_1 \\ \vdots \\ RC_N \end{cases} \tag{10}$$

where: $t_{i,l}$ and $t_{i+1,l}$ are the operation time of the relays i and upstream relay i+1, and for a fault located at l, respectively; $t_{i,\min}$ and $t_{i,\max}$ are the minimum and maximum values of the operating times of the relay i, respectively, based on the velocity principle and sensibility; $I_{\text{pickup,min}}$ and $I_{\text{pickup,max}}$ are the minimum and the maximum values of the pickup current, respectively; and, RC_1, âQ, RC_N are constants that define selected time-overcurrent characteristics. The parameter RC refers to the pair k_1 and k_2 from (2). This means that in terms of search space, the curve type may differ for each relay in the chain. From (5)–(10), the problem variables are the pickup current, the time dial and the curve type. At this point it is necessary to make the following assumptions:

- The pickup current is typically used as a sensitivity variable to establish an optimal current value so that it can optimally meet the (4) criteria. However, it is understood that when using the minimum value of the pickup current given by (4), the protection is as sensitive as possible.
- The relay operating characteristic curve depends on the manufacturer and can have up to 13 different curves. Usually, the literature [4,6,17] uses only one shape of curve (most works use NI). However, this may decrease the flexibility of the response because ignoring other solutions may cause many global optima to be neglected.

Thus, in this work, the design variables are the time-dial and the relay characteristic curve, and the pickup current is considered as a constant. The fact of the selected time-overcurrent characteristics (k_1 and k_2) and the TDS are considered as variables, this makes a non-linear and non-convex optimization problem with many possibilities of relay settings, which results in a large search space, so that, it is not possible to use techniques such as linear programming. It is important to highlight that: a) each of the operating times from (5), (6) and (7) are given by (2); b) the first part of (5) relates to the speed criterion of the protection system, that is, the faster the relays of the primary protection zone act, the better the solution will be; c) the second part of (6) aims to ensure coordination between the DOCR.

3.2. Optimal coordination by microgenetic algorithm

The optimization method, called the microgenetic algorithm (μGA), was proposed in 1990 by Krishnakumar [13], which is similar to the traditional genetic algorithm (GA), which emulates the natural process of evolution to find the best solution (chromosome). The process initiates with a random population (npop) representing a set of possible solutions, evolving through successive iterations (or generations). In each generation, a new population is formed, derived from the original one through the genetic operation of crossover (an operation between two chromosomes of a population that results in two new individuals) and mutation (a random change in chromosomes to avoid homogeneity of the population). In each generation, all individuals of the population are evaluated by a survival criterion consisting of the objective function value and a previously established selection mechanism that determines which individuals should survive and participate in the next generation. This process is repeated until a complete population evolution occurs for the optimal solution.

Effectively, what distinguishes a GA from a μGA is the size of the population (GA: 30 to 300 individuals; μGA: 5 to 20 individuals). Furthermore, the periodicity with which the population is restarted, and the use of a mutation operation is optional. In the GA, only the initial population is created, and it determines the diversity. However, in μGA, when the population of size P becomes homogeneous, the best-adapted individual migrates to a new population of size P-1, which is randomly generated. This mechanism is used to compensate the reduced diversity due to small population size, trying to avoid that the algorithm converges to an optimal local [18]. The use of a small population significantly reduces the computational effort, and therefore, the processing time, which is a crucial parameter in solving the protection problem.

In order to guarantee the diversity of the population, another strategy is to apply tournament selection without replacement. This ensures that all chromosomes can be chosen for the tournament, regardless of their suitability, which can only be considered after randomly drawn doubles of the current population [18]. In order to solve the directional overcurrent relay coordination problem via μGA, the following algorithm was developed, as shown in Fig. 1 and detailed below.

Algorithm

- Reading the input data: fault current (I_f), pickup current (I_{pickup}), CTR, total number of relays (N) and all pairs of relays (primary and backup pair - P/B).
- Initialization of the npop: in this work, npop=15 was used.
- Initialization of the generation loop: the objective function value $\left(\sum_{i=1}^{N} t_{i,l}\right)$ of each individual is calculated. The value obtained depends on how suitable the individual is for the solution.
- Execution of the crossover operation: in this, a growth factor of 100% has been adopted. Considering npop=15 after crossover, 16 individuals will be added to the initial population. This will result in npop=31.
- Calculation of the objective functions of the new individuals.
- Execution of the tournament operation: this consists of selecting the most suitable individual from a random selection process applied to the population. In the end, 16 individuals will be eliminated, resulting in npop=15.
- Implementation of the elitism operation: this consists in preserving the individual with less objective function out of the remaining population.
- Analysis of the convergence: in this work, the homogeneity of the objective function was used as a criterion of convergence:

$$\frac{OF_{\min}}{OF_{\max}} \geq 0.95 \tag{11}$$

  where $OF_{\min}$ and $OF_{\max}$ are the minimum and maximum values of the objective function of the final population n in generation m, respectively. If the ratio is greater than or equal to 0.95, the population will be reset with npop-1 individuals and the elite individual. Otherwise, the population will remain unchanged.
- Analysis of the generation counter: in this work, the maximum value of 800 generations ($G_{\max}$=800) was used.

If a solution does not match the restrictions of the problem, a penalty will be added to the objective function.

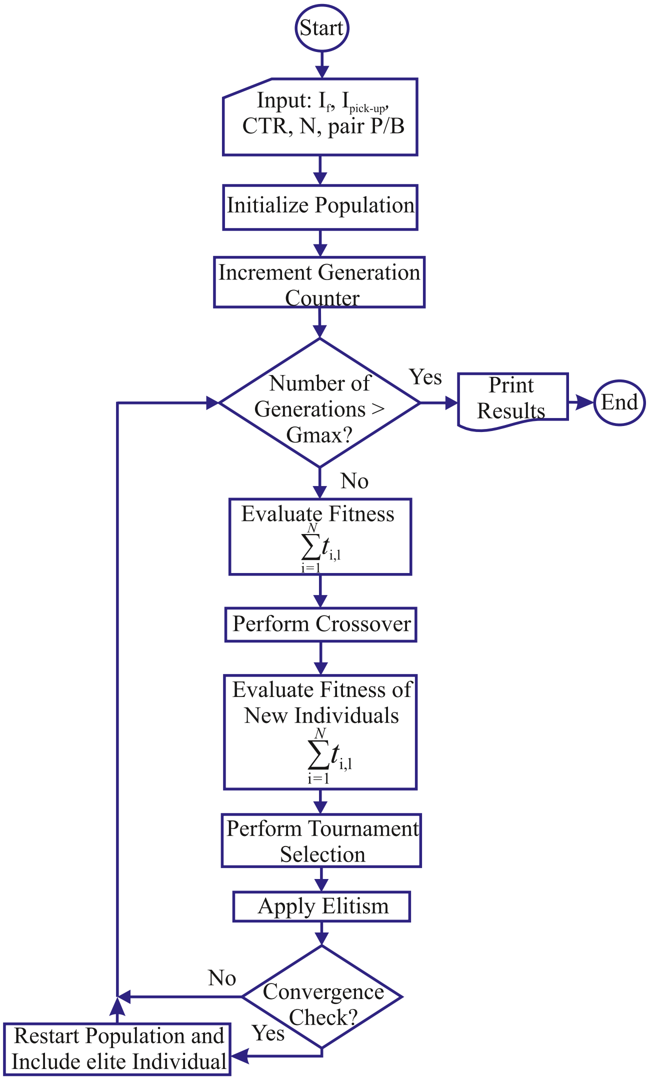

Fig. 1. Coordination of directional overcurrent relays via μGA.

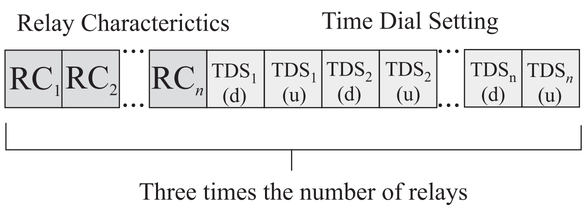

Fig. 2. Codification.

A decimal codification was adopted, in which the chromosome has a dimension equal to three times the number of relays to be coordinated (Fig. 2), being:

- the 1st part of the chromosome (genes equal to the number of relays) representing the relay characteristic, which can vary between 1 and 3, representing IEC relay characteristics addressed [15];
- the 2nd part of the chromosome (genes equal to twice the number of relays) representing the time-dial, TDS, which can vary from 0.05 to 1 for the IEC curve types [16]. In decimal coding, each chromosome ranges from 0 to 9, so that for every two genes, the first represents the units, and the second represents the tens.

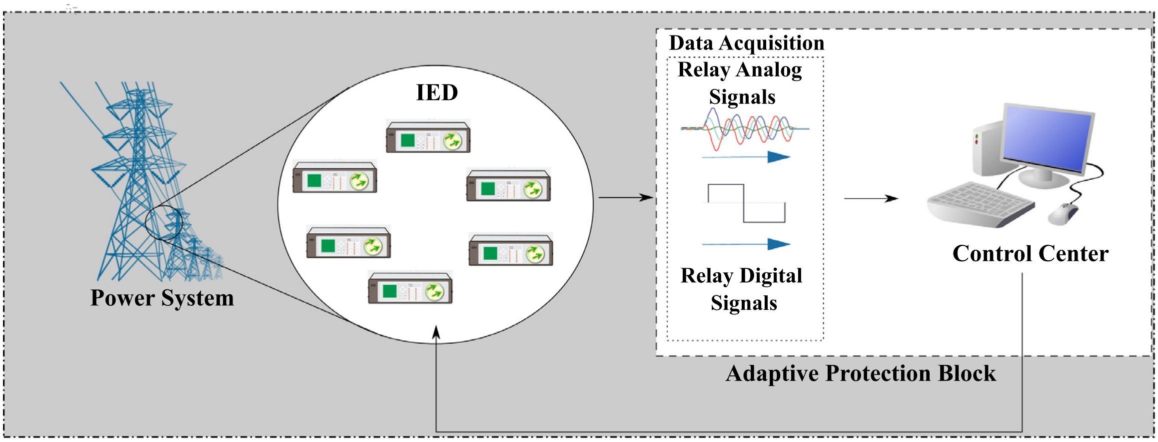

Fig. 3. Architecture of the adaptive protection system.

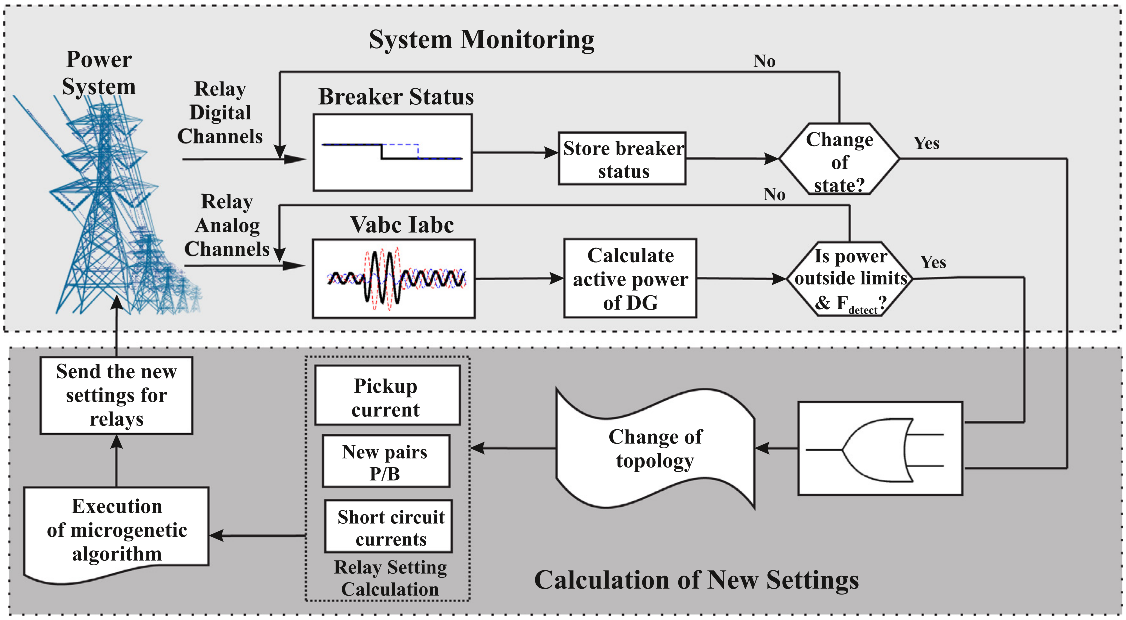

Fig. 4. Adaptive protection system flowchart.

4. Adaptive protection system

Basically, adaptive protection is a protection strategy that seeks to adjust protection settings to all possible conditions to which the power system may be subjected, ensuring that the correct operation is performed, notwithstanding the system topology. Among the various types of architecture already proposed [19], a decentralized type, composed of several independent control centers and dividing the relay into sectors, was selected. Fig. 3 shows one of the units of the decentralized architecture.

The idea is to concentrate a small number of DOCR to improve the processing per group and consequently, the overall processing of the adaptive protection system. However, the number may differ depending on the total number of relays in the system. The ideal would be that the relay chain should be in the same center. In case the primary and backup relay pairs are in different centers, the simulation priority is at the center of the primary relay. After processing, primary relay unit sends the calculated settings to backup relay unit, which will use the data to process the backup relay settings.

Regarding the operation mode, the proposed system (APSμg) is an online type, in which the optimal values are recalculated automatically for each configuration change in real-time. The APSμg is summarized in the flow chart of Fig. 4 and described below.

Briefly, the APSμg continuously monitors the electrical system by reading the digital and analog channels, which are the status of the circuit breakers and the signals of voltage and current in the region monitored by the relays. Changes in

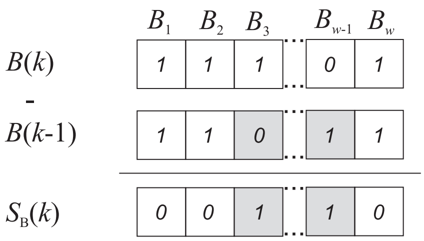

Fig. 5. Circuit breaker status change computation example.

these variables are understood as topological changes in the electric system. In this case, the protection system automatically recalculates the new directional overcurrent relay settings of the monitored system using the µGA and sends it to the system relays.

4.1. System monitoring

The process of monitoring the system involves reading the analogue and digital channels of power system equipment for protection, control, and measurement. Therefore, in this work, the analogue and digital channels of digital relays will be taken as input signals for the adaptive protection system, as shown in Fig. 4. This fact makes the work feasible because digital relays can capture voltage and current waveforms online. Digital signal monitoring provides the status of the circuit-breakers, which is done by applying the following equation:

$$S_B(k) = B(k) - B(k-1) \tag{12}$$

where $S_B(k)$ is the variation of the status of all circuit-breakers in the power system; $B(k)$ and $B(k\text{-}1)$ are the breaker status values at the current and previous instants, respectively. If the result is different from 0 (zero), the APSµg shows that there have been changes in the system topology calling for a recalculation of the protection settings [20].

An example of this process is shown in Fig. 5, in which the status of circuit breakers B_1 to B_w are monitored continuously. At a given instant k, circuit breakers B_3 and B_{w-1} change, resulting in the subtraction of a value equal to 1 (one). If the result of the subtraction of the status of circuit breakers results in a value of 1 (one), the adaptive protection system indicates that there have been changes in the system topology and must recalculate the protection settings.

Analogue signal monitoring, i.e., voltage and current signal monitoring (from which the active power value is calculated and the range of variation, ΔP, is found) can indicate the mode of operation of the power system (normal or abnormal), as well as indicate changes in system state, according to (13):

$$q \le \Delta P \le x \tag{13}$$

where q and x are the limits that define normal operation of the system. In case of a violation of the limits, the APSµg process determines that there has been a change in system operation and will recalculate the protection setting. Since the measurement is the power variation, the established normal values range from 0 to 10% of the initial measured active power. In fault situations, ΔP would be out of bounds, and the APSµg would interpret that as a change in topology. To prevent this from occurring, the analogue signal monitoring module only sends the change detection signal when ΔP is outside limits and the relay has not detected a fault, i.e., the F_{detect} flag is equal to 0 (zero), as shown in Fig. 4. New settings are calculated by µGA, which requires, as input values, the pickup currents, the primary and backup relay pairs and the short-circuit current. These values should be recalculated at every change that occurs in the system operation.

4.2. Calculation of new settings

In the addition to the detection of topology change, it is necessary to make appropriate arrangements to ensure that the protection system can adapt to this new reconfiguration. After detecting the topology change, the APSµg performs three essential calculation steps: pickup current, new P/B pairs, and short-circuit current. These data are essential because they serve as inputs for the execution of the µGA. Subsequently, the APSµg sends the new protection settings to the digital relays that the system is monitoring. Each step is performed as follows:

Pickup current calculation: the pickup current uses a load growth factor of 1.5, i.e., the scenario of the system operating below 50% overload is not considered faulty. One of the simplest ways to obtain the pickup current is by calculating the RMS current obtained from the analogue relay channels as follows:

$$i_{\mathrm{RMS}} = \sqrt{\frac{1}{S}\sum_{j=1}^{S} i_a^2} \tag{14}$$

where: i_{RMS} is the RMS current for a given portion of the EPDS and i_a is the current of the sample a of the signal for a set of S samples. From the RMS current, the pickup current can be calculated through (4), considering only the minimum

Table 1
Short circuit currents per scenario.

$I_{cc3\phi}$	Branch	Phase A	Phase B	Phase C	$I_{cc1\phi}$	Branch	Phase A	Phase B	Phase C
Scenario 1	800	850.5	597.2	684.1	Scenario 1	800	850.8	604.3	683.8
	832	286.4	256.8	254.8		832	257.7	228.2	227.1
	834	310.7	277.5	277.6		834	285.3	252.6	253.3
	836	387.9	414.3	345.5		836	399.7	334.6	353.2
	842	400.5	342.0	355.8		842	411.0	342.9	358.8
Scenario 2	800	846.2	597.0	679.8	Scenario 2	800	833.5	820.6	679.9
	832	285.4	256.7	253.1		832	243.6	216.3	210.2
	834	309.8	277.6	275.8		834	269.9	240.1	234.6
	836	301.8	403.3	326.1		836	257.4	233.7	239.2
	842	309.2	277.5	275.3		842	265.0	235.6	227.2
Scenario 3	800	839.0	597.8	671.8	Scenario 3	800	838.5	598.1	671.9
	832	283.6	256.7	249.8		832	238.5	366.8	225.4
	834	269.7	245.2	237.5		834	220.1	197.5	188.7
	836	263.6	387.1	326.0		836	212.5	193.1	191.3
	842	269.3	245.3	237.1		842	217.0	206.1	181.1

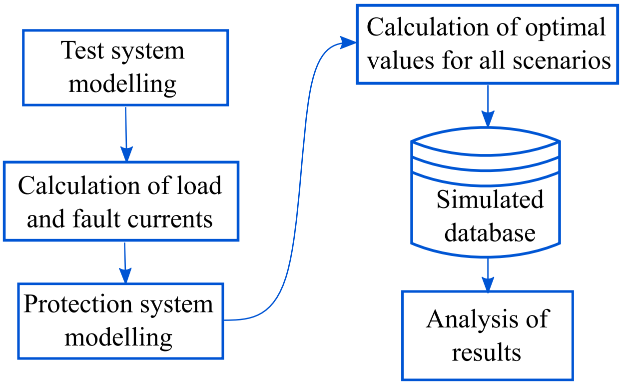

Fig. 6. Methodology.

value of inequality, with $\alpha = 1.5$. It should be noted that to obtain this current, the current signal from the electrical power system must go through pre-processing such as a low pass filter, analogue to digital conversion, and so on. For this case, the current signal is digitized at a sampling rate of 960 Hz. Further details about signal processing are presented in Section 5.3.

Calculation of primary and backup relay pairs: this procedure involves the definition of the bus level concept [21]: i) the level of a bus connected directly to the substation is set to 0 (zero); ii) the level of one bus attached directly to another of level b is defined as b+1. Thus, the buses are connected in levels, and primary and backup relay pairs are defined in a database. The APSμg also checks the status of circuit breakers connected to the bus. If the previous level circuit breaker is disconnected, then the next level relays will be disabled, thereby generating a new database.

Calculation of short-circuit currents: this step is carried out via Thévenin's analysis, since the method of symmetrical components is not well suited for EPDS, given their unbalanced nature [22]. At this stage, the currents were calculated using Simulink/MATLAB® software. For each scenario, the currents for the overcurrent relay design were calculated, namely 800–802, 832–858, 834–842, 834–860, 836–840. In Simulink/MATLAB®, phase and ground currents were simulated and saved in two matrices, one of three-phase and one of single-phase. The results are shown below (Table 1).

Execution of the μGA: the execution will be done according to what has already been discussed in Section 3.2.

Send the new settings for relays: here the APSμg sends the new settings to the relays. It is common knowledge that digital relays can be configured online, and with the advent of smart grids and the SCADA system, it is expected that soon this task will become increasingly simple.

5. Validation methodology

The methodology presented in Fig. 6 was developed to test and validate the APSμg, and it was all programmed in the Simulink/MATLAB® platform:

Each step of the flowchart will be described in Sections 5.1–5.5. The main idea was to generate a database with several cases, varying the types and locations of faults as well as the quantity of DG. This database was used to measure the performance of the APSμg against the APSga and the CPS.

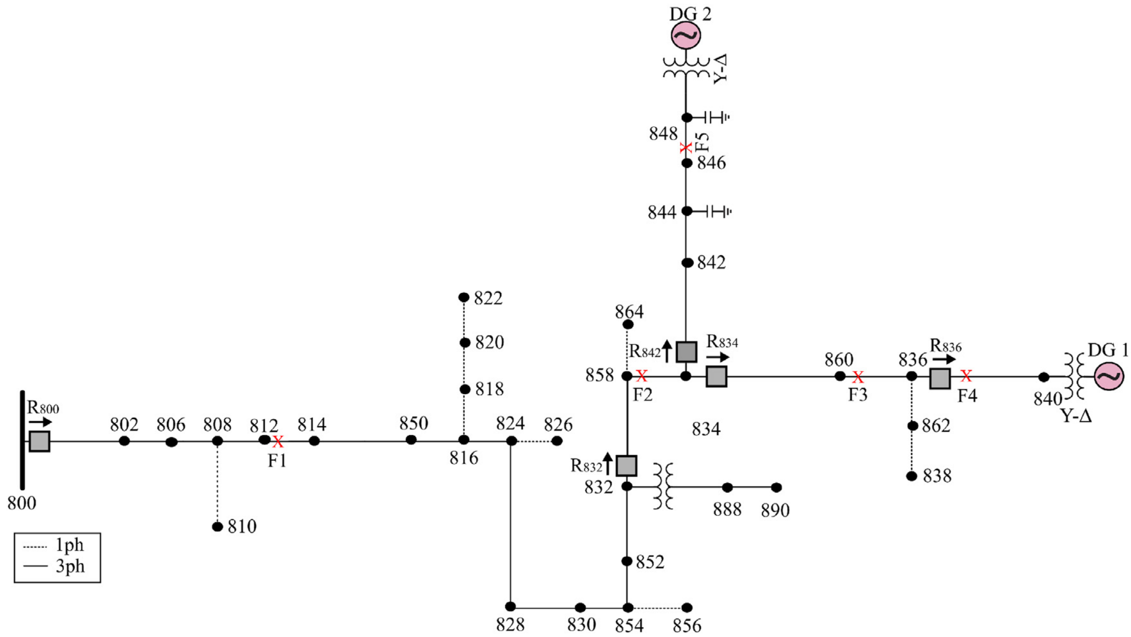

Fig. 7. IEEE 34 node test system (modified).

Table 2
RTC ratio.

Node	800	832	834	836	842
CTR	8:1	8:1	8:1	5:1	5:1

Table 3
Parameters of distributed generators.

Distributed Generators			
S = 210 kVA	f = 60 Hz	V_b=13800 V	
X_d = 1.305 pu	X_d' = 0.296 pu	X_d"= 0.252 pu	X_q = 0.474 pu
X_q" = 0.243 pu	X_l = 0.18 pu	T_d'=1.01 s	T_d"= 0.053 s
T_{q0}" = 0.1 s	H = 3.2 s		

5.1. Test system

The selected system was the IEEE 34 node test system, which has been widely used by the scientific community for EPDS studies [23]. This is a primary distribution system of 24.9 kV modified to fit the purposes of this study (Fig. 7) as follows: insertion of two DG of 200 kVA at nodes 840 and 848; insertion of relays at nodes 800, 832, 834, 836 and 842; the presence of voltage regulators was not considered. The transformation ratios of adopted CT are arranged in Table 2. The DG are modelled as synchronous machine. The DG are equal-sized, rated at 200 kVA, 13.8 kV, and they are connected to the system through a Delta-Wye 210 kVA transformer. The parameters of the generators are presented in Table 3.

It is worth mentioning that, what was taken into consideration for relay allocation was the design usually done in EPDS, which inserts a relay into the substation (R_{800}). It has been considered to insert relays to protect the DG sections (R_{842} and R_{836}) and two additional relays along the feeder to provide a backup of the relays protecting the DG sections to ensure coordination and disconnect the smallest possible feeder sections, ensuring selectivity.

5.2. Computation of load and fault currents

The calculation of these variables was done considering all the operating scenarios contemplated in the study. The short-circuit study considered the simulation of three-phase and single-phase faults in the feeder section where the DOCR are installed (close-in faults). As already mentioned, the resulting data of this module constitute entries of the μGA.

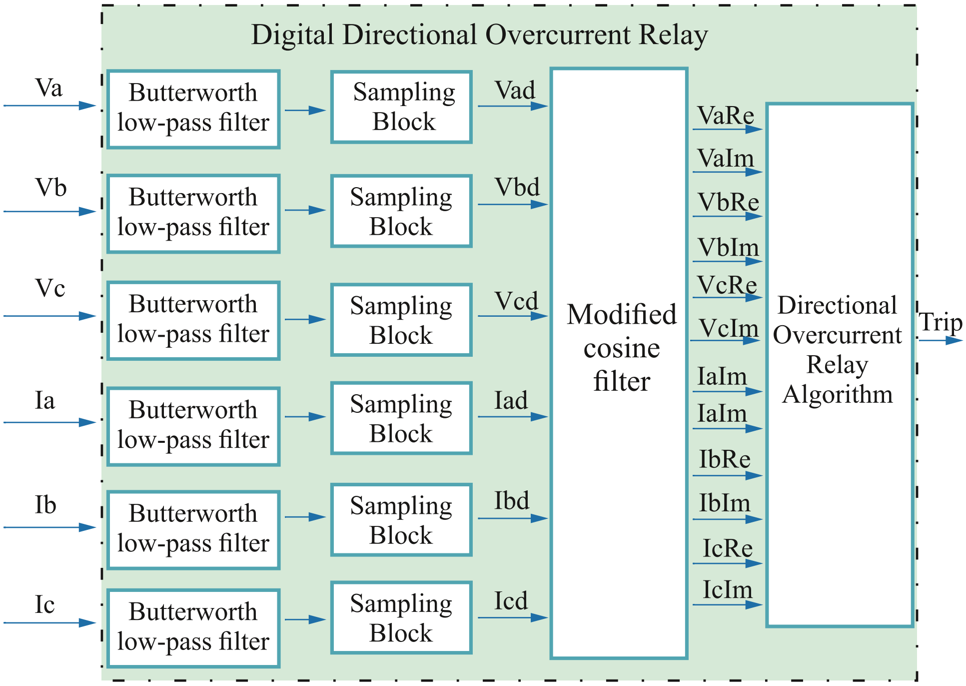

Fig. 8. Directional overcurrent relay architecture.

Table 4
Simulated database.

Simulation set	Description	Number of cases
Fault type	AG, BG, CG, AB, BC, CA, ABG, BCG, ACG, ABC, ABCG	11
Fault resistance	0 Ω, 1 Ω, 5 Ω and 10 Ω	4
Fault location	F1, F2, F3, F4 and F5	5
Scenario	1 (DG1 and DG2 connected), 2 (only DG2 connected), 3 (DG1 and DG2 disconnected)	3
Protection System	CPS, APSμg, APSga	3

5.3. Relay modeling

The modelling step of the digital relay was implemented according to the classical architecture of digital relays [14], in which methods and values usually adopted were used, such as: use of a Butterworth low-pass filter of order 2, with a cut-off frequency of 180 Hz; conversion of analogue signals to digital format with a sampling frequency of 960 Hz (16 samples per cycle); estimation of voltage and current phasors using the modified cosine method; and inverse time DOCR emulator module. This has input voltage and current values. The output is the trip signal for the circuit breaker. The digital relay was modelled in a Simulink/MATLAB® environment using a block diagram of the software itself, and the DOCR emulator and Phasor Estimation block were developed using a Simulink/MATLAB® S-Function. The relay architecture is shown in Fig. 8.

5.4. Simulated database

The database presented in Table 4 was designed to show that the settings provided by the μGA can perform the coordination of the test system for each topology change. In the end, 1980 cases were evaluated. To validate the proposed system (APSμg), a comparison was made with the APSga and the CPS. For this, the execution of the μGA module of Fig. 4 was modified by the GA module, depending on the coordination method used.

5.5. Calculation of optimal values for all scenarios

The three operating scenarios were constructed based on DG quantities with the CPS designed to preserve the topology of scenario 1. The configuration of the CPS is an important consideration and it is noteworthy that it is used as a metric for comparison with adaptive protection system. For a typical system, the CPS is usually designed for only one operating scenario because it is fixed and predetermined. According to the literature, normally the curve type C1 (NI) is chosen, and the time dial values are computed from it [14], resulting in the settings in Table 5. The aim was for the APSμg to provide the

Table 5
Optimal values.

Scenario	Setting	Coordination Method	RC_{800}	TDS_{800}	RC_{832}	TDS_{832}	RC_{834}	TDS_{834}	RC_{836}	TDS_{836}	RC_{842}	TDS_{842}	OF
1	Phase	µGA	EI	0.12	NI	0.15	MI	0.12	EI	0.05	EI	0.05	2.1049
		GA	EI	0.12	NI	0.15	MI	0.12	EI	0.05	EI	0.05	2.1049
		CP	NI	0.19	NI	0.16	NI	0.12	NI	0.05	NI	0.05	–
	Ground	µGA	VI	0.56	EI	0.80	NI	0.12	EI	0.05	EI	0.05	1.8340
		GA	EI	0.94	VI	0.43	NI	0.12	EI	0.11	EI	0.05	1.7750
		CP	NI	0.33	NI	0.25	NI	0.16	NI	0.05	NI	0.05	–
2	Phase	µGA	EI	0.12	VI	0.13	VI	0.35	EI	0.05	EI	0.05	1.7260
		GA	EI	0.12	VI	0.13	VI	0.35	EI	0.11	EI	0.05	1.7300
	Ground	µGA	VI	0.60	VI	0.45	NI	0.18	EI	0.05	EI	0.05	1.7657
		GA	VI	0.59	EI	0.91	NI	0.18	EI	0.05	EI	0.05	1.7362
3	Phase	µGA	VI	0.20	VI	0.17	VI	0.31	EI	0.05	EI	0.05	1.8182
		GA	EI	0.11	VI	0.12	EI	0.52	EI	0.05	EI	0.05	1.6972
	Ground	µGA	VI	0.64	VI	0.52	VI	0.81	EI	0.05	EI	0.05	1.6979
		GA	VI	0.81	VI	0.67	NI	0.18	EI	0.05	EI	0.05	1.7887

optimal relay settings for each operating scenario. It was necessary to calculate the optimal relay settings for all operating scenarios in the case of the µGA and of the GA. For the CPS, the relay settings were calculated for only one situation (scenario), according to the philosophy of the CPS, which was projected for scenario 1. All these calculated values are shown in Table 5. For an AMD PRO A10-8770E R7 processor, 10 COMPUTE COLORS 4C + 6G 2.8 GHz 8GB RAM, the execution time of the GA was 8.736222 s, and the µGA was 1.499842 s. All processing was performed using the Simulink/MATLAB® platform, which has the disadvantage of slow execution speed.

6. Results

In this section, the obtained results will be presented and discussed. It is expected that each scenario change in an EPDS with DG will result in changes of protection settings, and those call for the application of the adaptive protection concept. The validation of the APSµg was made by relating it to the APSga and the CPS. Given the large number of simulated cases (1980), only a few are discussed in Sections 6.1 to 6.3. However, statistical analyses contemplating all cases are discussed in Section 6.4.

6.1. Scenario 1 (DG1 and DG2 connected)

In this scenario, two DG were connected, totaling a DG insertion of 400 kVA. Since DG are modeled as a synchronous machine, they will make a significant contribution at the moment of fault. These are not disconnected at the time instant the fault occurred, but adaptive protection is proposed as a strategy to keep these systems connected to the system without causing significant damage. It is expected that the CPS operates correctly; however, the APSµg should present better results, since one expects it to compute the optimal settings. Faults were applied to all locations (Table 4). For analysis, the case of an ABG fault applied on F4 at 1.0 s with a 10 Ω fault resistance was selected. Fig. 9 shows the results.

Nevertheless, one should notice that this relay (R_{836}) will not operate as a back-up to any other relays. As expected, no misoperation occurred as only the R_{836} operated. Thus, for all cases, the fault was cleared, following the requirements of selectivity and speed. The CPS time was 0.127 s (Fig. 9 (b)), while the APSga time was 0.050 s (Fig. 9 (d)) and the APSµg time was 0.030 s (Fig. 9 (f)), i.e., a difference of 0.84 cycles for the APSga and 6.3 cycles for the CPS, which is a significant value in terms of protection. A fact to be considered in all cases is that as unit 51 of the relay is generally used as backup protection, their operating times are naturally slower than an instantaneous directional overcurrent protection (ANSI 50/67).

6.2. Scenario 2 (only DG2 connected)

In this scenario, DG1 was disconnected, so that the DG insertion was only 200 kVA. For analysis, the case of a CA fault applied on F1 at 1.0 s and a fault resistance of 5 Ω was selected. The results obtained are shown in Fig. 10. The relays of the three protection systems operated correctly, with the CPS operating on 1.0 s and both the APSga and the APSµg on 0.59 s, which means a significant difference of 24.6 cycles, which demonstrates the superiority of using optimised adaptive protection settings. However, in terms of processing speed, the µGA is faster than the GA, so in terms of speed gain it would be preferable to use the APSµg.

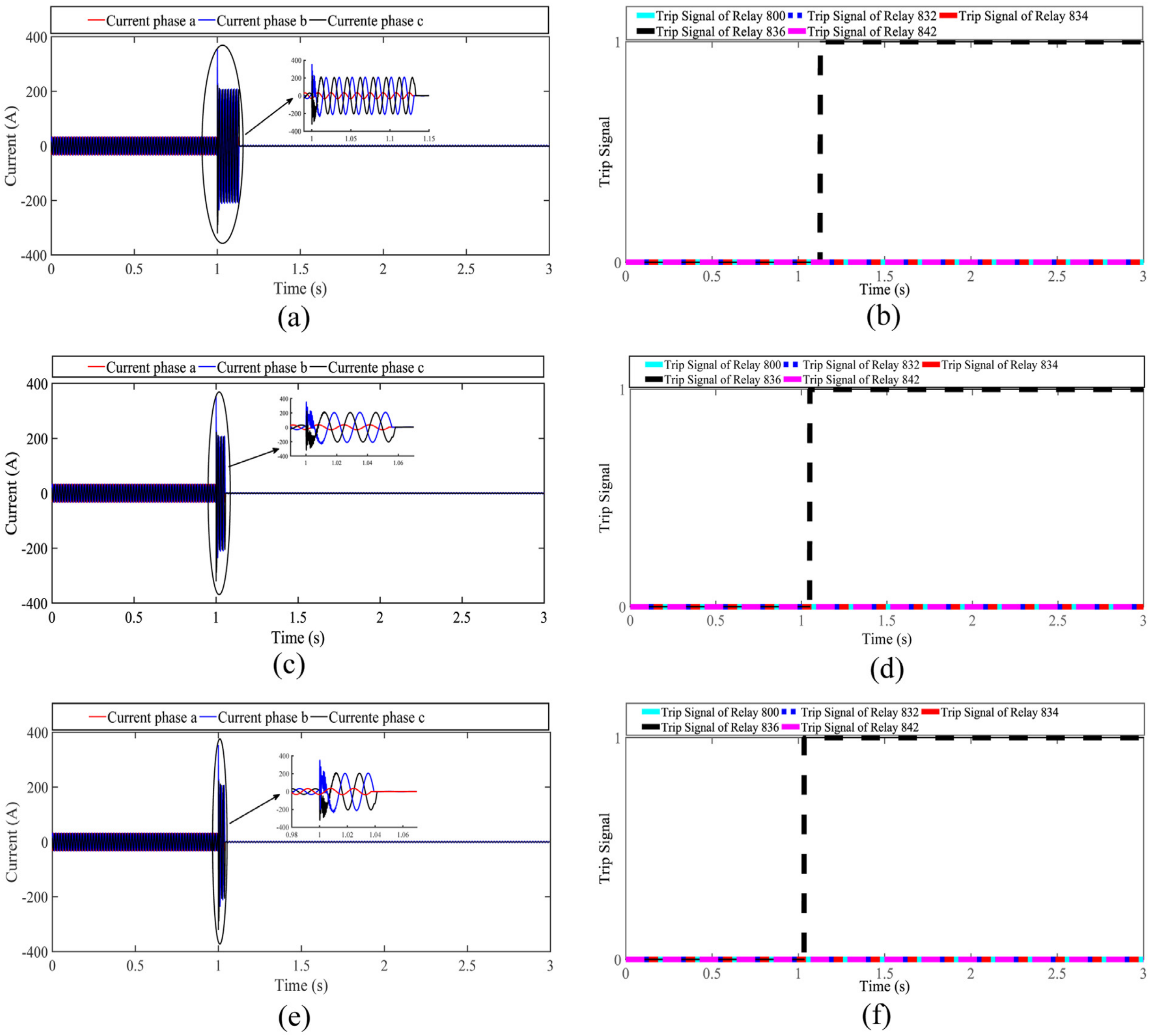

Fig. 9. (a) Current signals on branch 836–840 (CPS); (b) Trip signal of relays (CPS); (c) Current signals on branch 836–840 (APSga); (d) Trip signal of relays (APSga); (e) Current signals on branch 836–840 (APSμg); (f) Trip signal of relays (APSμg).

6.3. Scenario 3 (DG1 and DG2 disconnected)

In this scenario, the two DG were disconnected, resulting in a case of the CPS miscoordination, due to a BG fault applied on F2 with 10 Ω fault resistance. Results are shown in Fig. 11. Again, the APSμg operated correctly, clearing the fault in 0.787 s (Fig. 11 (f)), but the APSga obtained a better result, operating in 0.56 s (Fig. 11 (d)). In the case of the CPS, relay 832 operated correctly at 1.074 s, but exceeded the coordination interval, which caused loss of DOCR grading of backup relay 800 at 1.082 s (Fig. 11).

As a result, parts of the system were disconnected incorrectly. This shows that the CPS does not have the ability to protect an EPDS with DG inclusion, making the system susceptible to unnecessary shutdowns, affecting system continuity. Therefore, it is essential to include new strategies to protect the EPDS, corroborating the importance of this line of research.

6.4. Statistical analysis

In order to obtain a better understanding of the results, scenarios 1, 2 and 3 were compared (Fig. 12). For this, a statistical analysis was carried out considering the operation speed as the evaluation criterion. To evaluate this approach, we used a MATLAB® boxplot function of all 1980 cases from Table 4. This type of graph allows the visual representation of the

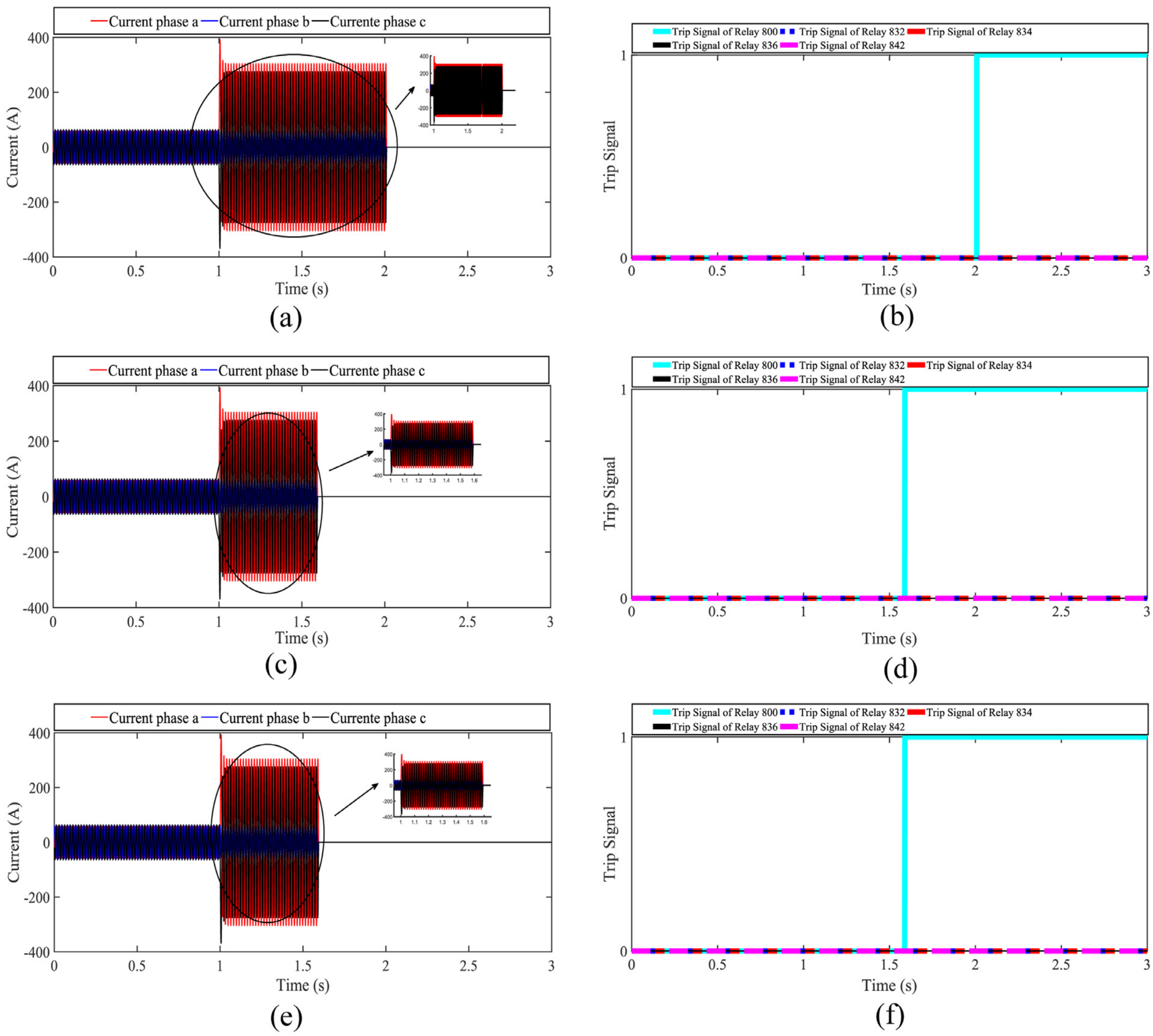

Fig. 10. (a) Current signals on branch 800–814 (CPS); (b) Trip signal of relays (CPS); (c) Current signals on branch 800–814 (APSga); (d) Trip signal of relays (APSga); (e) Current signals on branch 800–814 (APSμg); (f) Trip signal of relays (APSμg).

distribution of a set of data by means of five indices in each box: the central mark shows the median, and the bottom and top edges of the box indicate the 25th and 75th percentiles, respectively. The whiskers reach to the most extreme data points that are not considered outliers, and the outliers are plotted individually using the: “+” symbol [24].

- The CPS has a mean operation time of 0.631 s. A total of 75% of the cases have an operating time of less than 0.871 s, and in 25% of the cases, the relays operate for less than 0.183 s.
- The APSga has a mean operation time of 0.311 s. A total of 75% of the cases have an operating time of less than 0.576 s, and in 25% of the cases, the relays operate for less than 0.0725 s.
- The APSμg has a mean operation time of 0.346 s. A total of 75% of the cases have an operating time of less than 0.603 s, and in 25% of the cases, the relays operate for less than 0.0725 s.

From the results, the APSμg and the APSga present a very good performance in all scenarios evaluated, since they operated correctly and quickly for all cases. In addition, as expected, it is noted that the results obtained through the APSga are better than those obtained using the APSμg, although these are relatively close. This is because the GA works with larger numbers of populations and generations, but its convergence takes a processing time about five times greater than the μGA, depending on the processor utilization and parameters of both algorithms (Section 5.5). However, both are dramatically better than conventional protection. Thus, if processing speed is a crucial factor, the use of a method with faster processing speed may be justifiable, although the results may be worse due to their intrinsic characteristics [25].

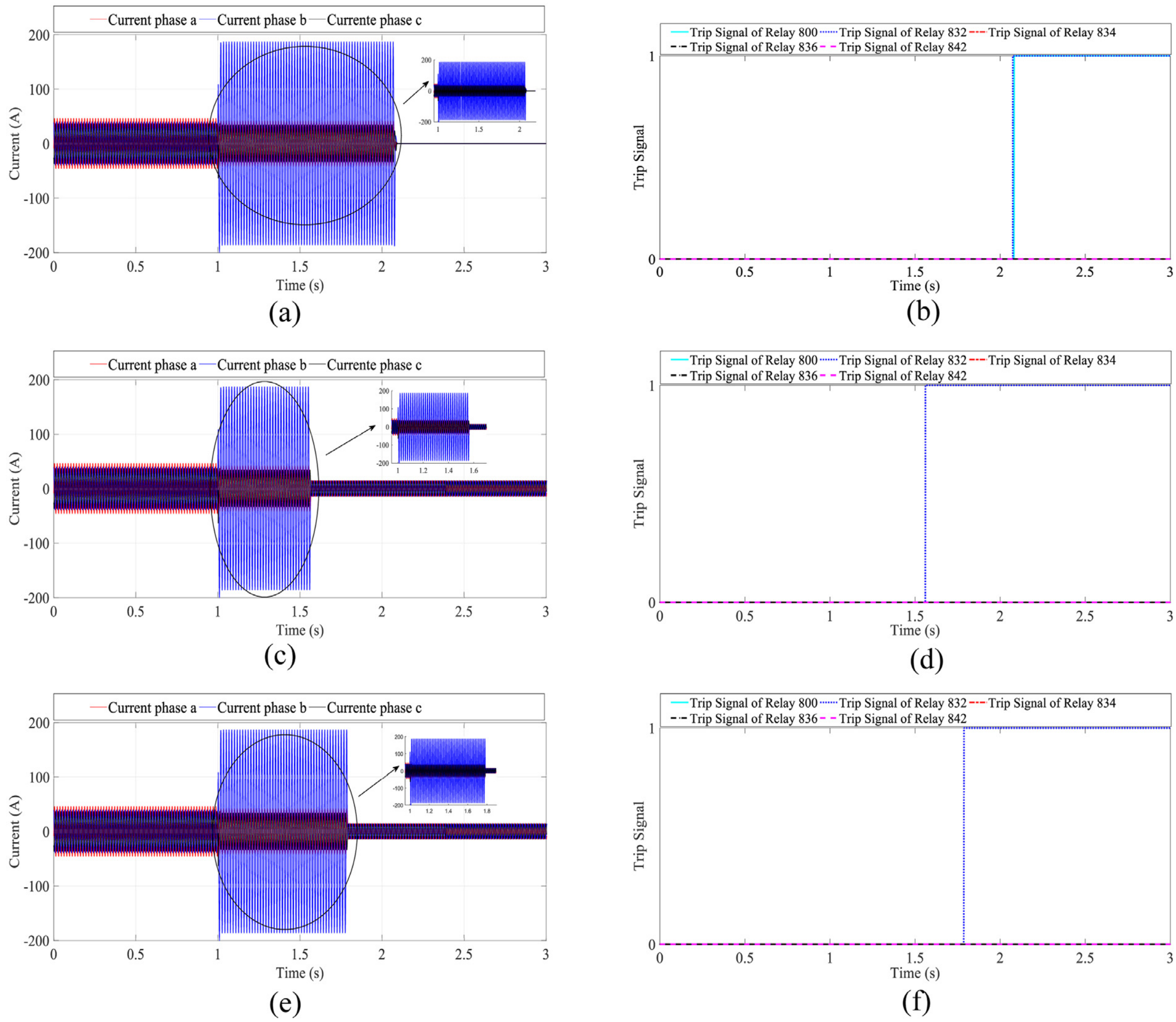

Fig. 11. (a) Current signals on branch 832–834 (CPS); (b) Trip signal of relays (CPS); (c) Current signals on branch 832–834 (APSga); (d) Trip signal of relays (APSga); (e) Current signals on branch 832–834 (APSμg); (f) Trip signal of relays (APSμg).

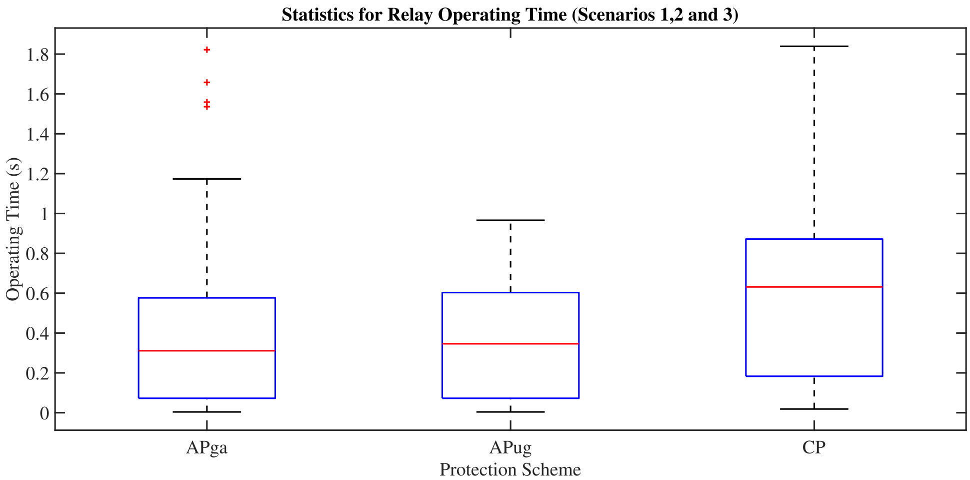

Fig. 12. Statistical analysis.

7. Conclusion

In this work, an adaptive directional overcurrent protection system for electric power distributed systems with the presence of distributed generation was proposed. The system was based on a microgenetic algorithm aimed at both protecting the electrical system, and perform the protection optimally. The proposed system continuously monitors the status of circuit breakers and the active power of distributed generation detecting any changes in these variables, and then the system recalculates the new settings for the relays. The proposed system was compared with both conventional protection system and adaptive protection system by means of a traditional genetic algorithm.

To validate the proposed system, a methodology for the construction of operating scenarios was developed. 1980 cases were simulated, and in the end, it was found that even in scenarios for which the conventional protection was designed, the adaptive protection presented superior performance. Although the traditional genetic algorithm presented a slightly better performance than the proposed method, the algorithm has a slower execution time. The good performance of the proposed system was undoubtedly due to the use of the microgenetic algorithm, which was well-suited to the problem, enabling higher speed.

From the obtained results, we can conclude that: i) the proposed system uses data easily obtained by real relays such as current, voltage, and state of the circuit breaker; ii) signal monitoring is done relatively simply, thus saving processing time; iii) the use of optimization ensures that the results obtained are the best possible; iv) the use of active power gives a good metric of the system situation, and can even be adapted in future work to do islanding detection as well as assist in the detection of faults for distributed generation with an inverter interface; v) the proposed system presents promising results, and its modularity means it can be increased and improved.

Thus, the new protection system can produce fast and satisfactory results in terms of the quality of the protection settings using easily obtainable inputs, thereby keeping the system protected and highly efficient. This improves the operation and performance of the system.

Declaration of Competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

CRediT authorship contribution statement

Jamile P. Nascimento: Conceptualization, Methodology, Software. **Núbia S.D. Brito:** Supervision, Writing - review & editing. **Benemar A. Souza:** Supervision, Writing - review & editing.

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