Reliability Assessment of Microgrids With Local and Mobile Generation, Time-Dependent Profiles, and Intraday Reconfiguration

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***Abstract*—In this paper, the notion of reliability assessment for distribution system applications is revisited to include a number of practices emerging in the smart grid context. The information on the variations in time of generation and demand is taken into account to establish a reference network configuration that considers the definition of an intraday reconfiguration strategy based on conventional load profiles for different categories of demand (residential, industrial, and commercial). After a fault, the service restoration process is aided by the formation of autonomous islanded subsystems (microgrids). During the restoration period, each subsystem is able to serve the local demand in a given portion of the network and to reconnect to the main network through proper synchronization. Dedicated solutions for mobile generation and storage are exploited to reach the nodes needing additional supply. A sequential Monte Carlo method is used to carry out reliability assessment. The use of this method incorporates the effects of interfering near-coincident faults and time-varying load and local generation patterns. The application on a real distribution network is presented, showing the probability distributions of the reliability indicators (power and energy not supplied), as well as the breakdown of these indicators for different demand categories.**

***Index Terms*—Demand profile, intraday reconfiguration, microgrid, mobile generation, reliability, resilience, sequential Monte Carlo (MC), smart grid.**

I. INTRODUCTION

MICROGRIDS are emerging as viable network structures to serve the local demand in the presence of an adequate local energy mix, able to provide voltage and frequency control and grid stability through the available resources during operation [1]. The concepts used to operate a microgrid can be adopted to determine how to manage an intentional island taken as a subsystem of a distribution network to obtain benefits during the restoration process after a fault [2]. In the same way, these concepts may be used to identify subsystems with self-healing capabilities, with the aim of enhancing the distribution system's resilience against extended service interruption events [3]–[5].

The classical reliability analysis of distribution systems is based on the calculation of a number of indicators taking into account the frequency and duration of the interruptions, for example, leading to the determination of the system availability, and the power and energy not supplied (ENS). Reliability indicators may be calculated either *a posteriori* (e.g., at the end of each year) in order to check the compliance with the regulatory limits set up by the relevant authority, or *a priori* (e.g., on the basis of the expected network operation for the next period) in order to be used as objective functions for single- or multi-objective optimization purposes [6]–[8], or within operational planning or expansion planning tools [9]–[12].

In the classical *a priori* reliability analysis, the typical calculations were based on a number of hypotheses, generally considering a given network structure (i.e., the standard network configuration), given power for each customer (based on the contract power), and the absence of a contribution from local generation. Deterministic or probabilistic methods are used. The latter ones are of particular interest as they provide information on the probability distributions of the reliability indices, making it possible to determine the exceeding probability of these indices with respect to specific limits.

Analytical methods or Monte Carlo (MC) methods may be used for a probabilistic reliability analysis [13]. Analytical methods are faster [14]. An effective method that uses the characteristic functions is illustrated in [15]. A limitation of the analytical approach is that it cannot consider common-mode and interfering near-coincident faults. These limitations are not present in MC methods [16], in which the effects of multiple faults can be included, as well as dependencies on external variables and time-changing loads or generation. Different types of MC simulation include nonsequential methods with state sampling or state transition sampling [16], time sequential methods with state duration sampling, and pseudo-sequential MC methods

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with a nonsequential selection of the failure states and a sequential simulation of the sequence of neighboring states [17]. A recent proposal to represent correlated time series within a nonsequential method is discussed in [18].

The penetration of distributed energy resources (DER), including distributed generation (DG), distributed storage (DS), and demand response (DR), has raised interest in reliability assessment with DER, in particular with respect to the possibility of creating islands during the service restoration process, and also as an alternative to construct new network branches [19]–[22]. A general overview of reliability models and methods for distribution systems with renewable energy DG is reported in [23]. An analytical formulation of reliability assessment with remote-controlled switches and islanded microgrids is presented in [24]. An analytical method that considers the DG reliability model, islanding operation, and changes in the protection strategy is described in [25].

A nonsequential MC method is used in [26] to evaluate the reliability of active distribution grids. The application of the pseudo-sequential MC method is discussed in [27]. Examples of using the time-sequential MC method are reported in [28] to calculate the reliability indices for different DG applications without considering islanding, and in [29] with the possibility of forming islands for the generators placed downstream with respect to the fault. A two-step MC simulation is used in [30], where a number of new metrics for reliability assessment with microgrids are also introduced.

A specific case of using DS to improve reliability by considering both the customers' willingness to pay and the DS cost is presented in [31]. In [32] and [33], electric vehicles operating in vehicle-to-grid (V2G) mode are considered as a further possibility of enhancing reliability by exploiting the local supply located in parking lots. Centralized and dispersed contributions of electric vehicles including V2G and vehicle-to-home (V2H) are addressed in [34]. Furthermore, DR has the potential to improve service reliability during contingencies, provided that an appropriate plan for DR procurement is set up [35].

In a smart grid context, the evolution of distribution automation, DER control, computational methods, and data analytics is making it possible to introduce a number of additional features into the classical reliability analysis tools. Thereby, reliability assessment is enriched with innovative contents as follows.

1) The incorporation of DER in the service restoration process, with the creation of intentional islands, provided that the technical properties of the DER are appropriate to ensure suitable control and stability of the microgrid.
2) The provision of supply through mobile generation and storage, to add flexibility to the location of additional supply sources during the service restoration process.
3) The possibility of considering demand profiles for different types of customers, that is, enabling the distinction among the interruptions occurring in different time periods for these customers.
4) Change of network configurations over time, determining the most appropriate intraday configurations according to specific objective functions.

This paper shows how the above-mentioned contents are included in reliability analysis, with the calculation of probabilistic reliability indices. In [36], a time-sequential MC simulation is presented for reliability evaluation of distribution systems with the presence of chronological patterns of specific renewable generation, using an intraday reconfiguration considering two optimal topologies for peak and off-peak hours. This paper is an extended and generalized version of [36]. The specific contributions are as follows.

1) An introduction of a set of conventional load profiles in the reliability analysis, in order to enable the determination of the share of ENS of the different types of consumers (e.g., residential, industrial and commercial), and local generation systems.
2) The execution of a time-sequential MC simulation by considering the starting configuration resulting from the intraday reconfiguration carried out at fixed time intervals on the basis of the conventional load profiles.
3) the formulation of a mathematical model for reliability assessment of a distribution system with renewable generation, possible formation of intentional islands, and use of mobile generation and storage systems.

The next sections of this paper are organized as follows. Section II recalls the reliability assessment methods used with DER and describes the emergent practices recently introduced in the smart grid context, which contribute to reliability assessment with new information. Section III reports the details of the reliability assessment procedure. Section IV shows the results of a case study of a real distribution network. Section V contains concluding remarks.

II. EMERGENT PRACTICES IN THE SMART GRID CONTEXT

A. *Conventional Demand Profiles in Reliability Analysis*

Considering the same duration of the interruptions, the ENS of different types of customers changes when the interruption starts at different times of the day [37]. Indeed, more refined information may be found from a statistical assessment of the duration of the interruptions depending on the starting time of the interruption [38]. Reliability analysis techniques may be detailed by introducing the variation of the load patterns throughout time [39]. Hourly patterns of load and renewable energy sources are used in the analytical approach presented in [40]. The study presented in [41] concludes that the time dependence of the interruption cost should not be ignored, to avoid giving wrong cost signals in the regulation of the quality of supply.

Since the variation in time of the demand that would have been supplied to the loads without the interruption cannot be determined, a conventional rule has to be established to determine the ENS during an interruption, to be considered for different categories of customers. In this way, it is possible to calculate the ENS for each type of customer and to determine the share of the overall ENS among them. For this purpose, different approaches may be considered.

1) Traditional approach, in which the rated power of the loads involved in the interruption is multiplied by the duration

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of the interruption to give the ENS. This approach cannot consider the time at which the interruption occurs.

2) Load profile-based approach, in which conventional predetermined load profiles constructed according to the category of consumers are applied to the duration of the interruption to determine the ENS for each category of consumers.

3) Measure-based approach, in which the active power of the load served at the time step before the occurrence of the fault is assumed as a reference. With these bases, it is possible to determine the ENS by considering a constant power for the duration of the interruption or to apply a combined approach based on the measured power and the load profile.[11] Of course, this approach is applicable only when the measured active power values are available at the time step preceding the interruption. A specific advantage is the possibility of dealing with individual loads and not only a customer category. In the absence of a totally metered system, in the realm of the evolution toward smarter grids, this approach could be applied only to the measured portion of the total load, keeping the other approaches mentioned above for the remaining part of the load.

B. *Intraday Reconfiguration*

The recent trend toward extended automation in distribution networks and microgrids is making the idea of applying intraday reconfiguration more and more appealing. The variability in time of the load and generation patterns makes it possible to formulate suitable strategies to change the optimal network configuration during the day on the basis of a suitably defined objective function. Current literature has addressed the intraday reconfiguration problem under different points of view and time horizons as summarized in [42]. Nevertheless, technical and practical issues limit the number of configuration changes that can be made during the day. Increasing the number of switching operations could result in more transient problems during switching, increased risk of outages, reduction in the expected life of the switches due to their extra stress, and higher cost of repeated switching. Furthermore, intraday reconfiguration leads to higher complexity in tracking the changes of the network configurations during time. A particular issue is the uncertainty whether the new configuration will be significantly better than the previous one, to make the reconfiguration action worthwhile. Resorting to a more extensive action of the centralized remote control of the switches is part of the main benefits of smart grids. However, this extensive action could raise vulnerability issues as indicated in [43].

C. *Exploitation of Dedicated Solutions for Mobile Generation and Storage*

The adoption of mobile generation technologies is one of the solutions that may be used by distribution companies in order to restore supply in a relatively flexible way, provided that efficient solutions for fault location are in place [44]. Depending on the size of the local generator to be used and the voltage level for network connection, the size of the mobile generation system changes. The technologies contain truck-mounted generators, transformers, and protection systems with advanced interfaces to synchronize and control the generators [45]. The current trend is to develop technologies that may be mounted on an ordinary truck, in order to be ready to operate as fast as possible by making the travel time shorter. This aspect is crucial and limits the size of the mobile generation system. In fact, some mobile power stations available today are classified as "exceptional transports," requiring special permits, additional auxiliary vehicles to follow the transport and, if needed, also to close some local roads to enable the transport. All these aspects increase the timing of on-site availability of the mobile generation considerably, strongly affecting the contribution of the mobile generation to reliability.

In addition to mobile generation, mobile storage is of interest for reliability purposes. The technical specifications for a substation-size lithium-ion energy mobile storage system, with rated values of 1 MW and 2 MWh, have been developed by a group of utilities [46]. From the technical point of view, mobile storage can be seen as a version of mobile generation with limited energy capacity.

The availability of mobile emergency power supply with generation and storage resources has to be properly coordinated in order to get the higher benefits from these resources. The solution strategies must also take into account the importance given to the network nodes [47]. The allocation of mobile generation vehicles is carried out in [48] by setting up a cost optimization algorithm that considers the investment costs of additional emergency supply, the customer outage cost, and the operation and maintenance cost of the emergency power supply systems. The prepositioning of truck-mounted mobile emergency generators is proposed in [49] to dispatch these generators to some nodes of the distribution system with the aim of restoring critical loads, by forming multiple microgrids.

III. RELIABILITY ASSESSMENT

A. *Service Restoration Process*

The proposed approach is designed to study real distribution systems, whose structural topologies are meshed, but the redundant branches are open to form radial configurations facilitating network operation and protection schemes. Each distribution network configuration is represented by the state (open/closed) of the connections of each branch terminal to its sending and ending nodes.

In this paper, two connecting devices are considered: 1) remote-controlled circuit breaker, with automatic trip in case of fault; and 2) remote-controlled synchronization device (switch), without automatic trip in case of a fault.

The network structure is assumed to be known, without addressing the possible addition of feeder interties as in [50]. Furthermore, the optimal allocation of the switches is not

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[1] The latter way to determine the ENS through the combination of the measured value with the load profile is not straightforward. A discussion on these aspects will be reported in a future contribution.

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addressed in this paper; the reader may refer to [51] for specific details.

Three types of faults are analyzed for calculating the duration of the interruptions as follows.

1) Faults at the local generation units, which may be multiple and may occur inside the restoration period from other faults. The local generating unit is excluded by the action of the local protection device. These faults only affect the availability of the local generation unit.
2) Temporary faults of the system branches with remote-controlled circuit breakers and with automatic trips. There is a single restoration stage as, by definition, the fault is cleared after having reclosed the circuit breaker. When the circuit breaker located in the path from the terminal bus of the faulted branch to the root (substation) opens, all the downward nodes experience a temporary interruption. The local generators with fault ride-through capability remain connected; the other local generation units are switched OFF to avoid their negative impacts on fault currents and protection schemes.
3) Permanent faults of the system branches, indicating fault conditions still exist after the trip and first reclosing of the circuit breaker. For these faults, remote-controlled operations and manual operations of the switches are performed, if necessary, to isolate the fault and restore the operation in the nonfaulted part of the system. The circuit breaker initially opens the circuit, so the downstream feeder is de-energized. Then, the control center of the distribution system activates a remote-controlled operation-based strategy exploring the faulted branch. With this strategy, the fault is located and the faulted branch is isolated. Loads of the feeder located upstream of the faulted branch are resupplied, and for the loads downstream of the feeder, there are two possibilities.
    a) The supply to the loads is restored within the formation of an intentional island.
    b) The loads are subject to a permanent interruption, with the exception of the nodes recovered by the mobile generation, until the reparation of the faulted branch has been completed.

The process after the fault reparation is completed with the restoration of the initial configuration. When the synchronization devices are present in the connection point, the islands can be reconnected to the distribution network without interruption. If there is no synchronization device at the connection point, it is necessary to disconnect the nodes located between the upstream node (able to perform synchronization) and the island boundary. In this case, there is an additional duration of the interruption, given by the time needed to reconnect the island to the grid. A suitable DG unit is needed to be able to sustain the island during and after the island formation, and its interface device must be able to identify the fault currents to avoid the island reconnection to the grid when a fault occurs inside the island.

Many factors affect the probability of the formation of an intentional island as follows.

1) Availability of local generators able to guarantee voltage/frequency control and dynamic response. In this respect, local generators operating in voltage-following mode (i.e., with no voltage control) are not suitable to support the islanding [52]. This may also happen for local generators aiming to provide voltage control when they operate at their reactive power limits.
2) Probability that the generation exceeds the load, providing an adequate supply, also taking into account the determination of the DER capacity under uncertain conditions [53].
3) Probability (1 – PIF) of success in the transition to the island formation, where the probability of island formation (PIF) is an assigned probability of islanding failure. A further possibility could be to run a transient stability simulation for each island formation, to ensure that the new operating point in island conditions is correctly reached [54].

When the service has been restored, the island can be reconnected to the network only when synchronism between the island and the grid is reached at the connection interface.

B. Time-Sequential Monte Carlo Simulation Approach

In classical reliability analysis, the Markov approach is used to establish analytical methods under the hypothesis that the times to failure and the repair times of the system components are exponentially distributed. In this case, the failure rates and the repair rates of these components are constant. However, the exponential distribution cannot be adopted for other variables such as the restoration times, for which various solutions have been adopted in the literature, e.g., lognormal [55], normal [14], and Gamma [56] probability distribution functions (PDFs).

The time-sequential MC simulation is used to calculate the reliability indicators for a distribution system with DG. The procedure contains M repeated simulations, considering for each simulation, a random fault pattern involving the network components and the DG units. The failure rate is specified for each component in the data input.

The overall period of time considered for the observation is denoted by T. Each simulation is based on a fault pattern that is generated by randomly extracting, for each component k, the number of faults $n^{(k)}$ from a Poisson distribution using the failure rate as a parameter.[2] [2] Then, each fault $j = 1, \ldots, n^{(k)}$ involving each component k is randomly located in time period T by extracting a random number from a uniform probability distribution defined in time interval $[0, T]$ and using it to represent the time instant $t_j^{(k)}$ at which the fault occurs.

At the end of the definition of the time instants for each fault, an ordered list is formed, containing all the time instants introduced in ascending order, to represent the time sequence of the fault events occurring in any component. Each fault instant is then associated with its restoration time, selected at random from the probability distribution (e.g., with a Gamma distribution) of the restoration time for the corresponding component. If the component is a branch, the selection includes the determination

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[2] In some references, the negative binomial probability distribution has been considered instead of Poisson to represent the annual number of faults for MV cables [57], [58].

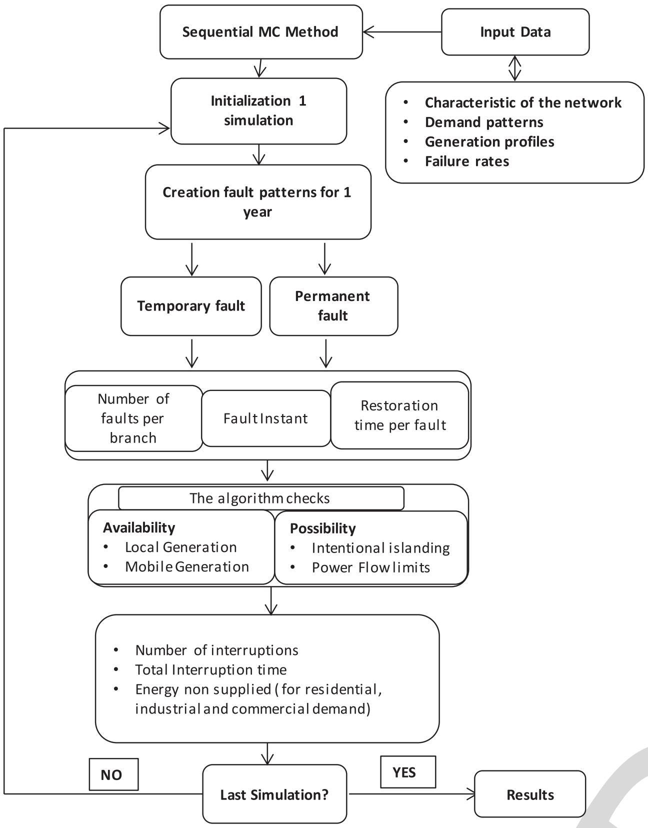

Fig. 1. Time-sequential MC reliability calculation method.

of whether the fault is temporary or permanent, with the related restoration times.

The definition of the fault pattern is followed by the analysis of the individual faults, one at a time, calculating the contribution of each fault to the reliability indicator considered, e.g., ENS. During the analysis, further aspects such as the availability and success of an operation of the components called for performing specific actions (e.g., switching systems associated with DG units that have to operate to guarantee successful island creation) are considered. At the same time, possible multiple or dependent faults are handled during the analysis of the effects of the fault. Finally, the possible occurrence of another fault (set by the definition of the fault time instants) during the restoration process of the fault under analysis is verified. This occurrence is very unlikely, given the relatively fast restoration with respect to the overall time period of observation and the relatively low number of faults but cannot be excluded for practical purposes.

C. Determination of the Duration of the Interruptions

Fig. 1 illustrates the characteristics of the computational procedure. The solution algorithm proceeds sequentially in time with respect to the chronological sequence of the interruption events. The first action is the identification of the circuit breaker serving the faulted feeder. Then, the load points located in other feeders are supplied (with no interruption). For the faulted feeder, the procedure is based on the following steps.

1) Analysis of temporary faults: the first calculation is the extraction of the random restoration time. For the load points located in the feeder with an interruption, the duration of the interruptions is updated by adding the corresponding instant of the restoration time.
2) Analysis of permanent faults: the restoration process with the possibility of islanding formation is carried out. The following steps are considered.
   a) For the faulted feeder, store the location of the load points in a list, and inspect which load point is assigned to an intentional island.
      i) Find the local generators connected to the isolated nodes and check their availabilities at the moment when the fault occurs and for the whole duration of the service restoration process (the local unit could be unavailable due to scheduled maintenance or to failure).
      ii) For the load points assigned to an island, add the island formation time to the interruption duration.
      iii) For the load points not assigned to an island, the interruption duration depends on the random restoration time. Mobile generation can be used to reach the nonsupplied nodes: the interruption duration can be reduced, extracting a random number representing the time to activate the mobile generation.
   b) If an island is formed, the power flow in the microgrid is calculated (e.g., with the backward–forward sweep method), and the constraints on the voltage and current limits verified. In the case of constraint violation, the structure of the intentional island is modified until no violation occurs [29]. All the load points belonging to intentional islands are marked as well as the DG units that control the island operation.
   c) Identification of the synchronization points adjacent to the island that may be located on the island boundary: no further contribution to the interruption duration; or not located on the island boundary: the island reconnection time is added to the interruption duration, due to the operations for restoring the initial configuration after the fault.
   d) Finally, the possibility of using mobile generators to serve the nonsupplied nodes is considered. The number of available mobile generators is randomly selected from 0 to a user-specified maximum number, with a given probability of the various occurrences. Instead of setting up a physical location for the mobile units when they are not used, the time to reach the node to supply is considered as the relevant random variable. The instances of this variable are extracted from a uniform distribution between a minimum and a maximum value.

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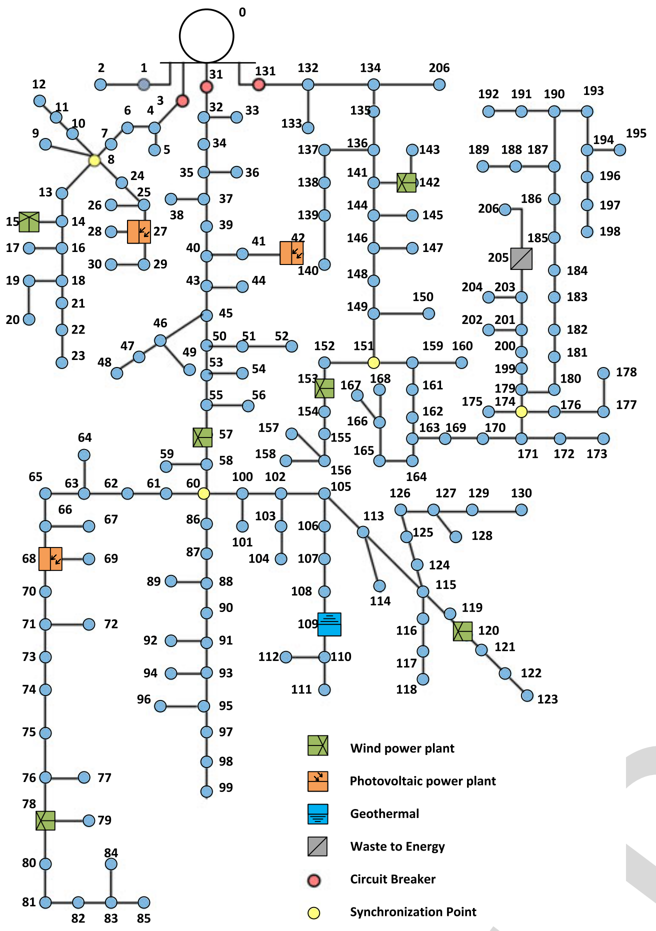

Fig. 2. Scheme of the MV network.

TABLE I
REDUNDANT BRANCHES

Initial and final nodes of the seven redundant branches						
2-69	4-131	8-135	23-148	73-121	85-198	73-121

TABLE II
DG CONNECTED TO THE NETWORK

Generation type	Number of units and rated power (kW)	Annual production (GWh)
Wind	2 × 20	0.15
PV	3 × 200	1.332
Geothermal	1 × 2500	19.99
W2E	1 × 370	1.91

IV. APPLICATION TO A REAL DISTRIBUTION SYSTEM

A. *Description of the System*

1) Network Structure: The medium-voltage (MV) distribution network under analysis is a real network with 207 nodes and 213 branches, located on an island. The network has a weakly meshed structure, but it is operated in a radial way. The number of redundant branches (open for obtaining a radial configuration) is 7. Furthermore, the system is supplied by a single thermal power plant, located at the slack node, composed of eight generator groups, with a total installed power of 20 MW [59]. The island is totally dependent on external sources of energy. The supply system is fed by diesel generators, as well as by oil-based ones.

The scheme of the network, where DG, circuit breakers, and synchronization devices are located,[3] is shown in Fig. 2. The big circle represents the slack node while the small circles represent the other 206 nodes. The network contains different types of loads (residential, industrial, and commercial) and some DG plants supplied by wind, photovoltaic (PV), waste to energy (W2E), and geothermal systems, represented by colored squares. Hourly profiles are used to characterize the different types of loads and generations. The seven redundant branches [42] are indicated in Table I but are not drawn in Fig. 2 for the sake of simplicity.

For the one-year reliability assessment, the DG units have been included in the network to evaluate the benefits of the integration of renewable energy in isolated systems.

2) Generation Profiles: The generation units considered are taken from [59]. The most realistic operation implies full exploitation of the geothermal and W2E sources and the inclusion of some wind and PV power plants. Geothermal and W2E profiles for one year are taken from [59] and [60]. The small geothermal power plant (2.5 MW) is located in the southwest of the island and operates during 8000 h/year (considering a programmed unavailability due to successive maintenance of the generation groups in winter).

Information on DG is reported in Table II. Wind and PV generation profiles are taken from historical data for one year available in [61]. In the case of wind, only data for 9 months are available, and the other 3 months are forecasted using a probabilistic method based on scenario generation from time series data, taken from the approach reported in [62].

3) Demand Profiles: For distribution system studies, a relevant aspect is the characterization of the aggregate demand. The probabilistic model of the aggregate demand is very useful for system operators or aggregators for extracting information about the demand-side behavior in the operation of microgrids.

The time step used to scan the aggregate demand pattern is very important to preserve the information about the consumers' behavior and the related uncertainty. Conventional models of aggregate electrical demand consider an average value for a specific time step (e.g., 30–60 min). In this case, one-hour step is used. The aggregate average load patterns for one day and for the whole network are illustrated in Fig. 3. In the same way, the power generation for a typical summer day is chosen in order to represent the generation profiles in Fig. 4.

4) Intraday Configuration Strategy: An intraday strategy is applied in order to maximize the optimality of the network configuration. In this case, two optimal configurations are used for the whole year, one for peak hours and another for off-peak

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[3] The optimal allocation of the switches is not addressed in this paper. The reader may refer to [51] for specific details.

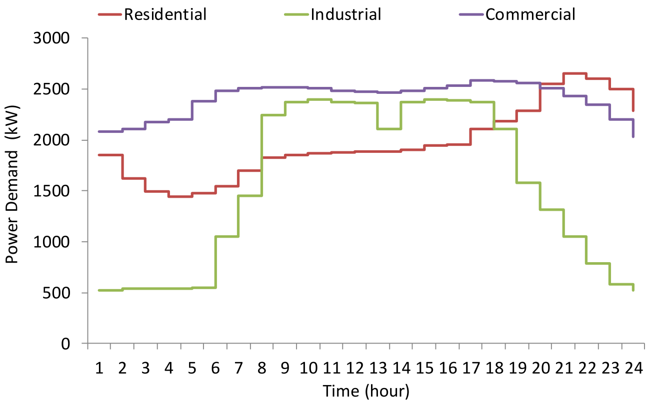

Fig. 3. Average hourly demand profiles.

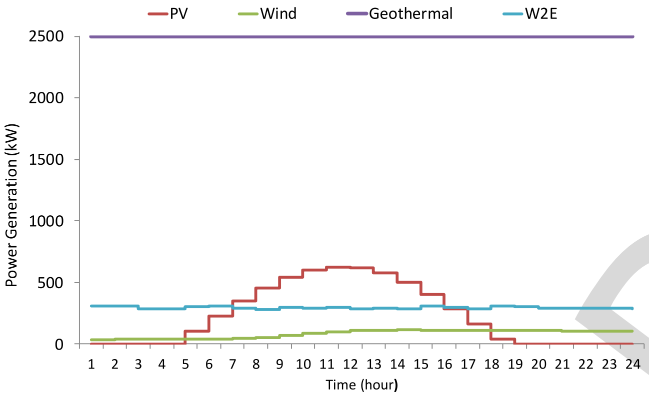

Fig. 4. Average hourly generation profiles for the summer period.

TABLE III
PARAMETERS FOR RESTORATION TIMES

Shape parameter (k)	Scale parameter (θ)	Approx. fault time
5	2	10 s
4	60	3 min
4	450	30 min
4	800	1 h
4	10 000	10 h

hours as shown in [41, Table VII]. These results have been found for the specific case with a relatively low penetration of DG. However, the method used is general, also in case of a more remarkable penetration of DG, in which the distinction between peak hours and off-peak hours becomes less evident.

5) Other Data: For reliability analysis, the whole period of one year with time intervals of one hour is assumed. The failure rate per branch is 0.5 (for temporary faults) and 0.05 (for permanent faults). The duration of faults is assumed to be 10 s for temporary faults, and 3 min, 30 min, 1 h, and 10 h for permanent faults. The fault probability of the generator is 0.1. The parameters of the restoration times for the Gamma distribution (shape and scale factor) are shown in Table III.

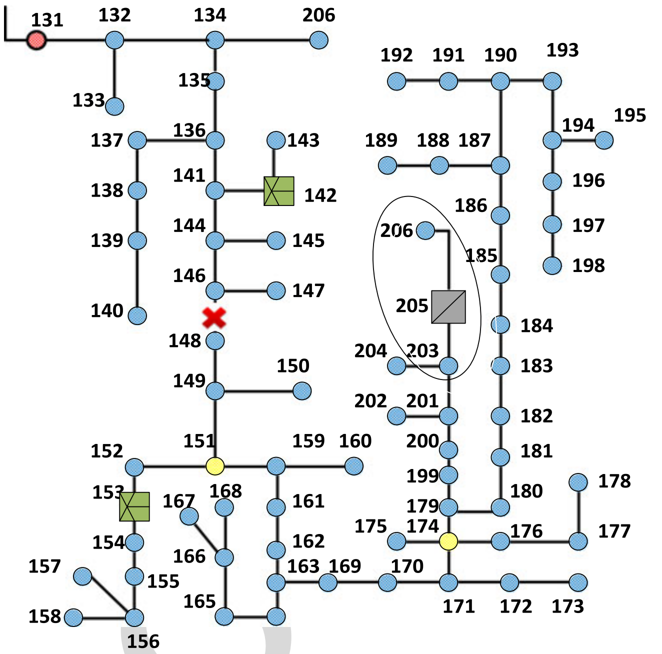

Fig. 5. Island formation during fault in branch 148.

B. Results and Discussion

1) Definition of the Cases and Simulation Framework: The results of the reliability analysis are shown by applying the sequential MC method with 1000 repetitions in the following cases:

1) case I, with neither DG nor mobile generation;
2) case II, with mobile generation and no DG;
3) case III, with DG and no mobile generation;
4) case IV, with DG and mobile generation.

In all the cases, the same random faults are considered in order to provide a sound comparison among the differences in the ENS results.

The simulations have been carried out by using the CPLEX 11 solver in MATLAB [63]. An Intel Xeon E7-4820 computer with four processors at 2 GHz and 128 GB of RAM has been used.

2) Analysis of a Specific Simulation: The details of a specific simulation are provided here in order to illustrate how the algorithm process works. Let us analyze one permanent fault in branch 148 (connecting node 146 to node 148). The time of the fault is selected from a uniform distribution along the year, in this specific situation, occurring during hour 19:00 of the 23rd day of the 9th month.

Initially, the circuit breaker located at node 131 is found and the downstream load (residential load 838.5 kW, industrial load 599.1 kW, and commercial load 867.7 kW) is not supplied. In that instant, the topology is the one shown in Fig. 5, the wind generator at node 153 is producing 12.8 kW, and the W2E power plant is generating 282.8 kW. The number of available mobile generators is 2, acting in the 42nd and 71st min after the fault occurs.

After the algorithm finds the circuit breaker, it verifies the existence of local generation in the isolated feeder with suitable

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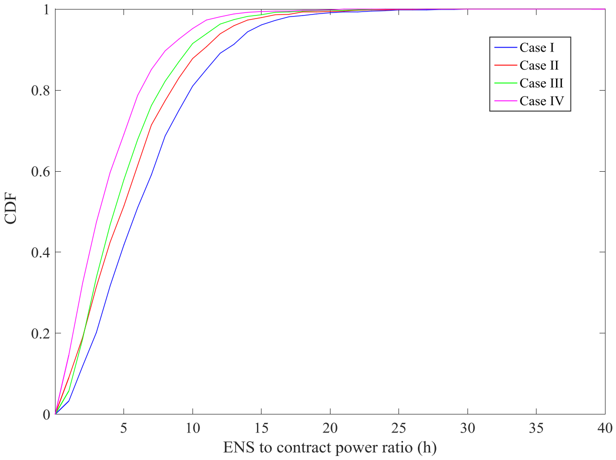

Fig. 6. CDF of the ENS to contract power ratio for residential users.

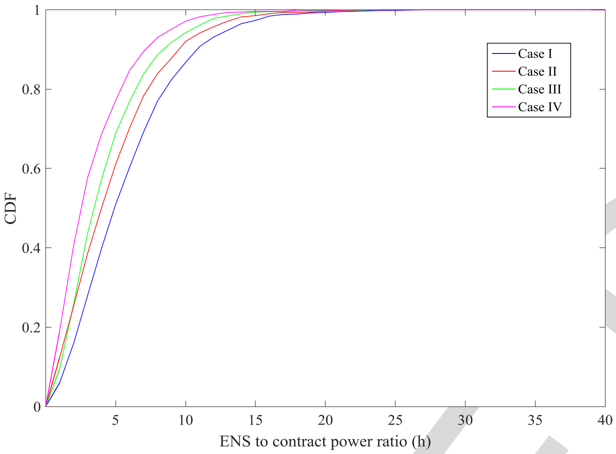

Fig. 7. CDF of the ENS to contract power ratio for industrial users.

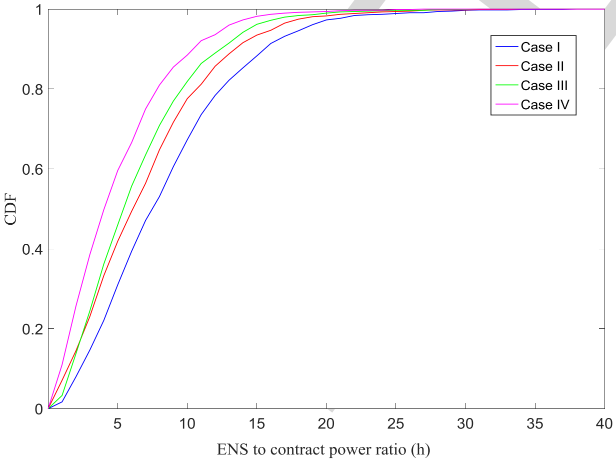

Fig. 8. CDF of the ENS to contract power ratio for commercial users.

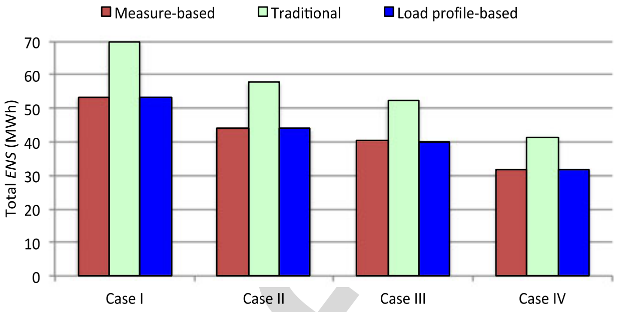

Fig. 9. Average values of the total ENS in the four cases.

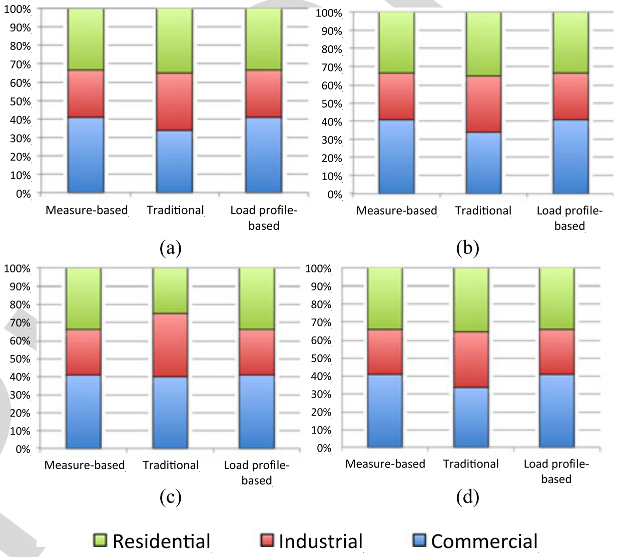

Fig. 10. ENS share for residential, industrial and commercial users with different approaches to ENS calculation and DG and mobile generation penetration. (a) Case I, (b) case II, (c) case III, and (d) case IV.

characteristics to create an intentional island and looks for the synchronization point in order to isolate part of the network until the fault is restored.

There are two synchronization points at nodes 151 and 174. The wind generator at node 153 can only supply 12.8 kW of the demand (21.86 kW) at that node. On the other hand, the W2E power plant checks whether it can create an island supplying the loads near its location (node 205) with its own power. Therefore, there is an island formation among nodes 201, 203, 204, 205, and 206, located downstream from the synchronization point at node 174. In this specific situation, the synchronization point is not located on the island boundary. Finally, the existence of two available mobile generators covers the demand of nodes 148 and 149 until the fault is restored.

3) Comparison Criterion and Overall Results: Considering all the simulations for one year, for the sake of comparison, the faults are the same for all the cases. The maximum and minimum number of faults are 149 and 84, respectively. ENS values have been calculated for residential, industrial, and commercial users. However, the total energy consumption in one year for the three types of users is different. Considering the conventional load profiles established for the different types of users, the energy consumption in one year (without interruptions) is 17 275 MWh for residential users, 13 346 MWh for industrial users, and 21 073 MWh for commercial users. Thereby, considering only the ENS values to compare the results for the different users is not appropriate. The energy consumption is taken as the

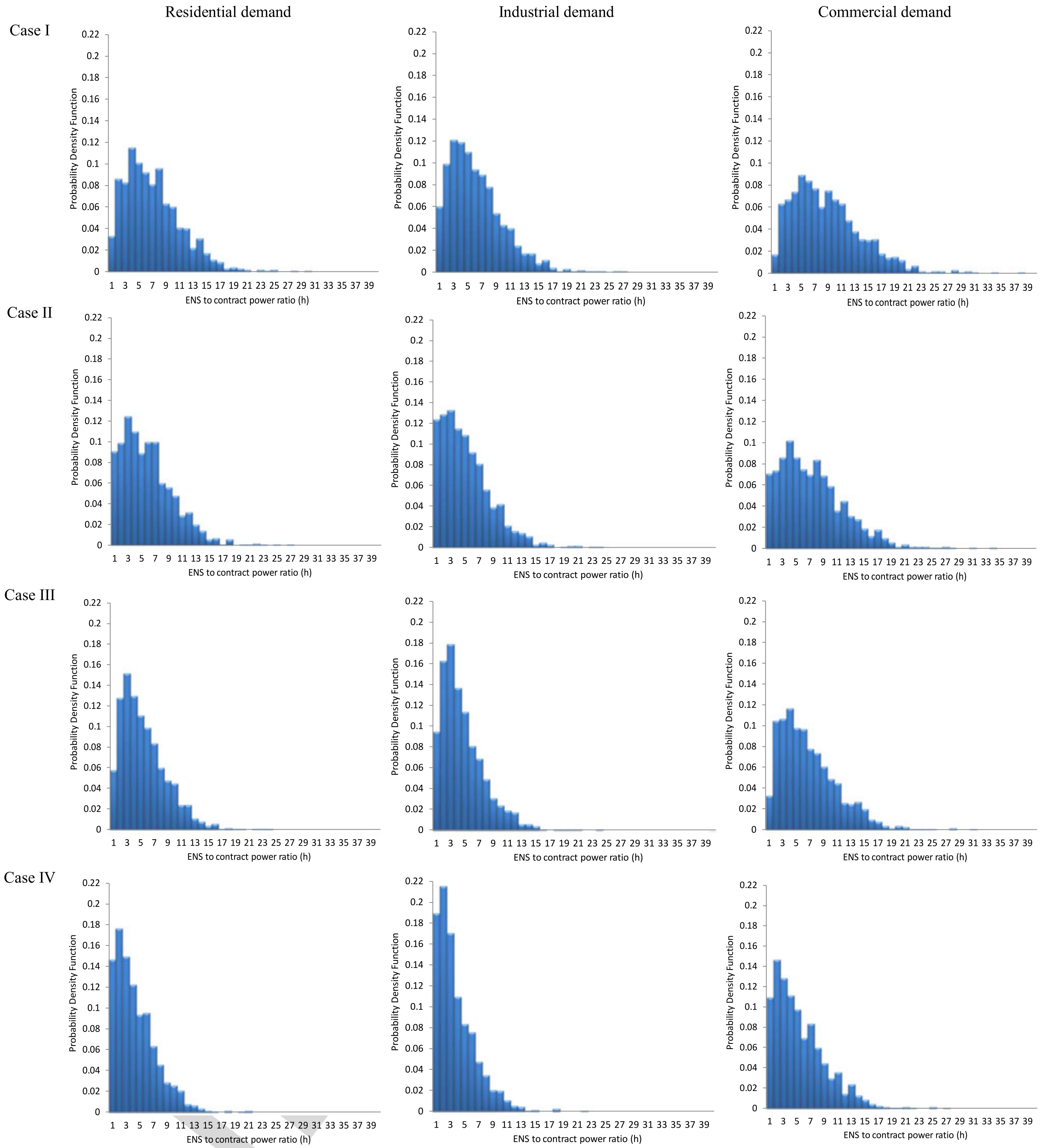

Fig. 11. Probability density functions (PDFs) of the ENS to energy consumption ratio.

conventional reference to calculate the ratio between the total ENS and the contract power for each type of user. This ratio is the relevant variable used for the sake of comparison.

The cumulative distribution functions (CDFs) of the ENS to contract power ratio are presented in Figs. 6–8, in the four cases. Comparing the three figures, it is more likely to have a higher ENS to contract power ratio for the commercial users, compared to the other ones, as its CDF is shifted to the right-hand side. On the other hand, it is more frequent to have a lower ENS to contract power ratio, first, for the industrial users, then, for the residential users, and finally, for the commercial users as shown in Figs. 6–11. Moreover, as expected, there is a higher probability to have a lower ENS in case IV, which includes DG and availability for mobile generation. Cases II and III are similar, case III being slightly better to reduce the overall ENS. Finally, case I is the worst one in terms of continuity of supply.

As observed, the CDF is close to 1 in the worst situation when the ratio is 28 h for industrial users, 31 h for residential users, and 39 h for commercial users. This can also be seen in Fig. 9. Moreover, this figure also illustrates the different total ENS values corresponding to the different methods. The traditional approach provides higher ENS, as expected, while the results obtained from the measure-based and load profile-based approaches are very similar. In particular, the load profile-based approach leads to slightly lower values than the measure-based approach whilst being more accurate in determining the total ENS.

Fig. 10 illustrates the ENS share among the different users for each case. The ENS share for the commercial users is similar to the measure-based and load profile-based approaches for all the cases. In the traditional approach, the ENS share is equivalent among the three types of users, except for case III, in which the proportion is 40% commercial, 35% industrial, and 25% residential, the ENS share of the residential users being the lowest of all the cases. In the load profile-based and measure-based approaches, the ENS share remains approximately constant among all the users for the four cases (41% commercial, 25% industrial, and 34% residential). Finally, as explained before, the higher percentage of the ENS share corresponds to the commercial users.

Fig. 11 displays the PDFs of the ENS to contract power ratio. It shows that the commercial demand contribution to the ENS to contract power ratio is also higher than for the residential and industrial users as it is further shifted to the right for the four cases. The highest probability is 0.21 in case IV for the industrial users, which corresponds to an ENS to contract power ratio of 2 h. This means that the highest probability of having the lowest ratio is for the industrial users. In fact, the probability of having a lower ratio is seen in case IV, in which the PDFs are concentrated on the lowest ratios for all types of users. In all the cases, the distribution is asymmetrical and right-skewed.

V. CONCLUSION

This paper has presented an extended framework for the reliability evaluation of active distribution systems for a period of time. This framework includes the possibility of creating intentional islands in case a fault occurs and shows how the introduction of DG, intraday network reconfiguration strategy, and mobile generation improve reliability by reducing the ENS.

The effectiveness of the proposed approach has been shown in the application to a real MV network. Numerical results have been presented in different cases, with and without DG and mobile generation, and with different ways to calculate the ENS, based on conventional load profiles or measured values of the demand at given time steps. This is in line with the current developments aimed at providing practical implementations of the smart grid paradigm. One of the advantages that DG can provide to electric utilities and customers is the possibility of improving the continuity of supply by implementing safe intentional islands in the event of an upstream supply outage. The possibility of creating islands during the service restoration process may be constrained by regulatory issues as the DG owner would have to take care of the loads served by another entity under normal operating conditions. The analyses carried out in this paper consider that such a limitation is not in place.

Based on the framework presented, it is possible to carry out many types of parametric analyses by changing the amount of DG and mobile generation in the network, assessing the effects on reliability in such a way to provide useful information for distribution system planning.

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Reliability Assessment of Microgrids With Local and Mobile Generation, Time-Dependent Profiles, and Intraday Reconfiguration

Pilar Meneses de Quevedo, *Member, IEEE*, Javier Contreras, *Fellow, IEEE*, Andrea Mazza, *Member, IEEE*,
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***Abstract*—In this paper, the notion of reliability assessment for distribution system applications is revisited to include a number of practices emerging in the smart grid context. The information on the variations in time of generation and demand is taken into account to establish a reference network configuration that considers the definition of an intraday reconfiguration strategy based on conventional load profiles for different categories of demand (residential, industrial, and commercial). After a fault, the service restoration process is aided by the formation of autonomous islanded subsystems (microgrids). During the restoration period, each subsystem is able to serve the local demand in a given portion of the network and to reconnect to the main network through proper synchronization. Dedicated solutions for mobile generation and storage are exploited to reach the nodes needing additional supply. A sequential Monte Carlo method is used to carry out reliability assessment. The use of this method incorporates the effects of interfering near-coincident faults and time-varying load and local generation patterns. The application on a real distribution network is presented, showing the probability distributions of the reliability indicators (power and energy not supplied), as well as the breakdown of these indicators for different demand categories.**

***Index Terms*—Demand profile, intraday reconfiguration, microgrid, mobile generation, reliability, resilience, sequential Monte Carlo (MC), smart grid.**

I. Introduction

MICROGRIDS are emerging as viable network structures to serve the local demand in the presence of an adequate local energy mix, able to provide voltage and frequency control and grid stability through the available resources during operation [1]. The concepts used to operate a microgrid can be adopted to determine how to manage an intentional island taken as a subsystem of a distribution network to obtain benefits during the restoration process after a fault [2]. In the same way, these concepts may be used to identify subsystems with self-healing capabilities, with the aim of enhancing the distribution system's resilience against extended service interruption events [3]–[5].

The classical reliability analysis of distribution systems is based on the calculation of a number of indicators taking into account the frequency and duration of the interruptions, for example, leading to the determination of the system availability, and the power and energy not supplied (ENS). Reliability indicators may be calculated either *a posteriori* (e.g., at the end of each year) in order to check the compliance with the regulatory limits set up by the relevant authority, or *a priori* (e.g., on the basis of the expected network operation for the next period) in order to be used as objective functions for single- or multi-objective optimization purposes [6]–[8], or within operational planning or expansion planning tools [9]–[12].

In the classical *a priori* reliability analysis, the typical calculations were based on a number of hypotheses, generally considering a given network structure (i.e., the standard network configuration), given power for each customer (based on the contract power), and the absence of a contribution from local generation. Deterministic or probabilistic methods are used. The latter ones are of particular interest as they provide information on the probability distributions of the reliability indices, making it possible to determine the exceeding probability of these indices with respect to specific limits.

Analytical methods or Monte Carlo (MC) methods may be used for a probabilistic reliability analysis [13]. Analytical methods are faster [14]. An effective method that uses the characteristic functions is illustrated in [15]. A limitation of the analytical approach is that it cannot consider common-mode and interfering near-coincident faults. These limitations are not present in MC methods [16], in which the effects of multiple faults can be included, as well as dependencies on external variables and time-changing loads or generation. Different types of MC simulation include nonsequential methods with state sampling or state transition sampling [16], time sequential methods with state duration sampling, and pseudo-sequential MC methods

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with a nonsequential selection of the failure states and a sequential simulation of the sequence of neighboring states [17]. A recent proposal to represent correlated time series within a nonsequential method is discussed in [18].

The penetration of distributed energy resources (DER), including distributed generation (DG), distributed storage (DS), and demand response (DR), has raised interest in reliability assessment with DER, in particular with respect to the possibility of creating islands during the service restoration process, and also as an alternative to construct new network branches [19]–[22]. A general overview of reliability models and methods for distribution systems with renewable energy DG is reported in [23]. An analytical formulation of reliability assessment with remote-controlled switches and islanded microgrids is presented in [24]. An analytical method that considers the DG reliability model, islanding operation, and changes in the protection strategy is described in [25].

A nonsequential MC method is used in [26] to evaluate the reliability of active distribution grids. The application of the pseudo-sequential MC method is discussed in [27]. Examples of using the time-sequential MC method are reported in [28] to calculate the reliability indices for different DG applications without considering islanding, and in [29] with the possibility of forming islands for the generators placed downstream with respect to the fault. A two-step MC simulation is used in [30], where a number of new metrics for reliability assessment with microgrids are also introduced.

A specific case of using DS to improve reliability by considering both the customers' willingness to pay and the DS cost is presented in [31]. In [32] and [33], electric vehicles operating in vehicle-to-grid (V2G) mode are considered as a further possibility of enhancing reliability by exploiting the local supply located in parking lots. Centralized and dispersed contributions of electric vehicles including V2G and vehicle-to-home (V2H) are addressed in [34]. Furthermore, DR has the potential to improve service reliability during contingencies, provided that an appropriate plan for DR procurement is set up [35].

In a smart grid context, the evolution of distribution automation, DER control, computational methods, and data analytics is making it possible to introduce a number of additional features into the classical reliability analysis tools. Thereby, reliability assessment is enriched with innovative contents as follows.

1) The incorporation of DER in the service restoration process, with the creation of intentional islands, provided that the technical properties of the DER are appropriate to ensure suitable control and stability of the microgrid.
2) The provision of supply through mobile generation and storage, to add flexibility to the location of additional supply sources during the service restoration process.
3) The possibility of considering demand profiles for different types of customers, that is, enabling the distinction among the interruptions occurring in different time periods for these customers.
4) Change of network configurations over time, determining the most appropriate intraday configurations according to specific objective functions.

This paper shows how the above-mentioned contents are included in reliability analysis, with the calculation of probabilistic reliability indices. In [36], a time-sequential MC simulation is presented for reliability evaluation of distribution systems with the presence of chronological patterns of specific renewable generation, using an intraday reconfiguration considering two optimal topologies for peak and off-peak hours. This paper is an extended and generalized version of [36]. The specific contributions are as follows.

1) An introduction of a set of conventional load profiles in the reliability analysis, in order to enable the determination of the share of ENS of the different types of consumers (e.g., residential, industrial and commercial), and local generation systems.
2) The execution of a time-sequential MC simulation by considering the starting configuration resulting from the intraday reconfiguration carried out at fixed time intervals on the basis of the conventional load profiles.
3) The formulation of a mathematical model for reliability assessment of a distribution system with renewable generation, possible formation of intentional islands, and use of mobile generation and storage systems.

The next sections of this paper are organized as follows. Section II recalls the reliability assessment methods used with DER and describes the emergent practices recently introduced in the smart grid context, which contribute to reliability assessment with new information. Section III reports the details of the reliability assessment procedure. Section IV shows the results of a case study of a real distribution network. Section V contains concluding remarks.

II. EMERGENT PRACTICES IN THE SMART GRID CONTEXT

A. *Conventional Demand Profiles in Reliability Analysis*

Considering the same duration of the interruptions, the ENS of different types of customers changes when the interruption starts at different times of the day [37]. Indeed, more refined information may be found from a statistical assessment of the duration of the interruptions depending on the starting time of the interruption [38]. Reliability analysis techniques may be detailed by introducing the variation of the load patterns throughout time [39]. Hourly patterns of load and renewable energy sources are used in the analytical approach presented in [40]. The study presented in [41] concludes that the time dependence of the interruption cost should not be ignored, to avoid giving wrong cost signals in the regulation of the quality of supply.

Since the variation in time of the demand that would have been supplied to the loads without the interruption cannot be determined, a conventional rule has to be established to determine the ENS during an interruption, to be considered for different categories of customers. In this way, it is possible to calculate the ENS for each type of customer and to determine the share of the overall ENS among them. For this purpose, different approaches may be considered.

1) Traditional approach, in which the rated power of the loads involved in the interruption is multiplied by the duration

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of the interruption to give the ENS. This approach cannot consider the time at which the interruption occurs.

2) Load profile-based approach, in which conventional predetermined load profiles constructed according to the category of consumers are applied to the duration of the interruption to determine the ENS for each category of consumers.

3) Measure-based approach, in which the active power of the load served at the time step before the occurrence of the fault is assumed as a reference. With these bases, it is possible to determine the ENS by considering a constant power for the duration of the interruption or to apply a combined approach based on the measured power and the load profile.[1] Of course, this approach is applicable only when the measured active power values are available at the time step preceding the interruption. A specific advantage is the possibility of dealing with individual loads and not only a customer category. In the absence of a totally metered system, in the realm of the evolution toward smarter grids, this approach could be applied only to the measured portion of the total load, keeping the other approaches mentioned above for the remaining part of the load.

B. *Intraday Reconfiguration*

The recent trend toward extended automation in distribution networks and microgrids is making the idea of applying intraday reconfiguration more and more appealing. The variability in time of the load and generation patterns makes it possible to formulate suitable strategies to change the optimal network configuration during the day on the basis of a suitably defined objective function. Current literature has addressed the intraday reconfiguration problem under different points of view and time horizons as summarized in [42]. Nevertheless, technical and practical issues limit the number of configuration changes that can be made during the day. Increasing the number of switching operations could result in more transient problems during switching, increased risk of outages, reduction in the expected life of the switches due to their extra stress, and higher cost of repeated switching. Furthermore, intraday reconfiguration leads to higher complexity in tracking the changes of the network configurations during time. A particular issue is the uncertainty whether the new configuration will be significantly better than the previous one, to make the reconfiguration action worthwhile. Resorting to a more extensive action of the centralized remote control of the switches is part of the main benefits of smart grids. However, this extensive action could raise vulnerability issues as indicated in [43].

C. *Exploitation of Dedicated Solutions for Mobile Generation and Storage*

The adoption of mobile generation technologies is one of the solutions that may be used by distribution companies in order to restore supply in a relatively flexible way, provided that efficient solutions for fault location are in place [44]. Depending on the size of the local generator to be used and the voltage level for network connection, the size of the mobile generation system changes. The technologies contain truck-mounted generators, transformers, and protection systems with advanced interfaces to synchronize and control the generators [45]. The current trend is to develop technologies that may be mounted on an ordinary truck, in order to be ready to operate as fast as possible by making the travel time shorter. This aspect is crucial and limits the size of the mobile generation system. In fact, some mobile power stations available today are classified as "exceptional transports," requiring special permits, additional auxiliary vehicles to follow the transport and, if needed, also to close some local roads to enable the transport. All these aspects increase the timing of on-site availability of the mobile generation considerably, strongly affecting the contribution of the mobile generation to reliability.

In addition to mobile generation, mobile storage is of interest for reliability purposes. The technical specifications for a substation-size lithium-ion energy mobile storage system, with rated values of 1 MW and 2 MWh, have been developed by a group of utilities [46]. From the technical point of view, mobile storage can be seen as a version of mobile generation with limited energy capacity.

The availability of mobile emergency power supply with generation and storage resources has to be properly coordinated in order to get the higher benefits from these resources. The solution strategies must also take into account the importance given to the network nodes [47]. The allocation of mobile generation vehicles is carried out in [48] by setting up a cost optimization algorithm that considers the investment costs of additional emergency supply, the customer outage cost, and the operation and maintenance cost of the emergency power supply systems. The prepositioning of truck-mounted mobile emergency generators is proposed in [49] to dispatch these generators to some nodes of the distribution system with the aim of restoring critical loads, by forming multiple microgrids.

III. RELIABILITY ASSESSMENT

A. *Service Restoration Process*

The proposed approach is designed to study real distribution systems, whose structural topologies are meshed, but the redundant branches are open to form radial configurations facilitating network operation and protection schemes. Each distribution network configuration is represented by the state (open/closed) of the connections of each branch terminal to its sending and ending nodes.

In this paper, two connecting devices are considered: 1) remote-controlled circuit breaker, with automatic trip in case of fault; and 2) remote-controlled synchronization device (switch), without automatic trip in case of a fault.

The network structure is assumed to be known, without addressing the possible addition of feeder interties as in [50]. Furthermore, the optimal allocation of the switches is not

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[1] The latter way to determine the ENS through the combination of the measured value with the load profile is not straightforward. A discussion on these aspects will be reported in a future contribution.

addressed in this paper; the reader may refer to [51] for specific details.

Three types of faults are analyzed for calculating the duration of the interruptions as follows.

1) Faults at the local generation units, which may be multiple and may occur inside the restoration period from other faults. The local generating unit is excluded by the action of the local protection device. These faults only affect the availability of the local generation unit.
2) Temporary faults of the system branches with remote-controlled circuit breakers and with automatic trips. There is a single restoration stage as, by definition, the fault is cleared after having reclosed the circuit breaker. When the circuit breaker located in the path from the terminal bus of the faulted branch to the root (substation) opens, all the downward nodes experience a temporary interruption. The local generators with fault ride-through capability remain connected; the other local generation units are switched OFF to avoid their negative impacts on fault currents and protection schemes.
3) Permanent faults of the system branches, indicating fault conditions still exist after the trip and first reclosing of the circuit breaker. For these faults, remote-controlled operations and manual operations of the switches are performed, if necessary, to isolate the fault and restore the operation in the nonfaulted part of the system. The circuit breaker initially opens the circuit, so the downstream feeder is de-energized. Then, the control center of the distribution system activates a remote-controlled operation-based strategy exploring the faulted branch. With this strategy, the fault is located and the faulted branch is isolated. Loads of the feeder located upstream of the faulted branch are resupplied, and for the loads downstream of the feeder, there are two possibilities.
    a) The supply to the loads is restored within the formation of an intentional island.
    b) The loads are subject to a permanent interruption, with the exception of the nodes recovered by the mobile generation, until the reparation of the faulted branch has been completed.

The process after the fault reparation is completed with the restoration of the initial configuration. When the synchronization devices are present in the connection point, the islands can be reconnected to the distribution network without interruption. If there is no synchronization device at the connection point, it is necessary to disconnect the nodes located between the upstream node (able to perform synchronization) and the island boundary. In this case, there is an additional duration of the interruption, given by the time needed to reconnect the island to the grid. A suitable DG unit is needed to be able to sustain the island during and after the island formation, and its interface device must be able to identify the fault currents to avoid the island reconnection to the grid when a fault occurs inside the island.

Many factors affect the probability of the formation of an intentional island as follows.

1) Availability of local generators able to guarantee voltage/frequency control and dynamic response. In this respect, local generators operating in voltage-following mode (i.e., with no voltage control) are not suitable to support the islanding [52]. This may also happen for local generators aiming to provide voltage control when they operate at their reactive power limits.
2) Probability that the generation exceeds the load, providing an adequate supply, also taking into account the determination of the DER capacity under uncertain conditions [53].
3) Probability (1 – PIF) of success in the transition to the island formation, where the probability of island formation (PIF) is an assigned probability of islanding failure. A further possibility could be to run a transient stability simulation for each island formation, to ensure that the new operating point in island conditions is correctly reached [54].

When the service has been restored, the island can be reconnected to the network only when synchronism between the island and the grid is reached at the connection interface.

B. Time-Sequential Monte Carlo Simulation Approach

In classical reliability analysis, the Markov approach is used to establish analytical methods under the hypothesis that the times to failure and the repair times of the system components are exponentially distributed. In this case, the failure rates and the repair rates of these components are constant. However, the exponential distribution cannot be adopted for other variables such as the restoration times, for which various solutions have been adopted in the literature, e.g., lognormal [55], normal [14], and Gamma [56] probability distribution functions (PDFs).

The time-sequential MC simulation is used to calculate the reliability indicators for a distribution system with DG. The procedure contains *M* repeated simulations, considering for each simulation, a random fault pattern involving the network components and the DG units. The failure rate is specified for each component in the data input.

The overall period of time considered for the observation is denoted by *T*. Each simulation is based on a fault pattern that is generated by randomly extracting, for each component *k*, the number of faults $n^{(k)}$ from a Poisson distribution using the failure rate as a parameter.[2] Then, each fault $j = 1, \ldots, n^{(k)}$ involving each component *k* is randomly located in time period *T* by extracting a random number from a uniform probability distribution defined in time interval [0, *T*] and using it to represent the time instant $t_j^{(k)}$ at which the fault occurs.

At the end of the definition of the time instants for each fault, an ordered list is formed, containing all the time instants introduced in ascending order, to represent the time sequence of the fault events occurring in any component. Each fault instant is then associated with its restoration time, selected at random from the probability distribution (e.g., with a Gamma distribution) of the restoration time for the corresponding component. If the component is a branch, the selection includes the determination

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[2] In some references, the negative binomial probability distribution has been considered instead of Poisson to represent the annual number of faults for MV cables [57], [58].

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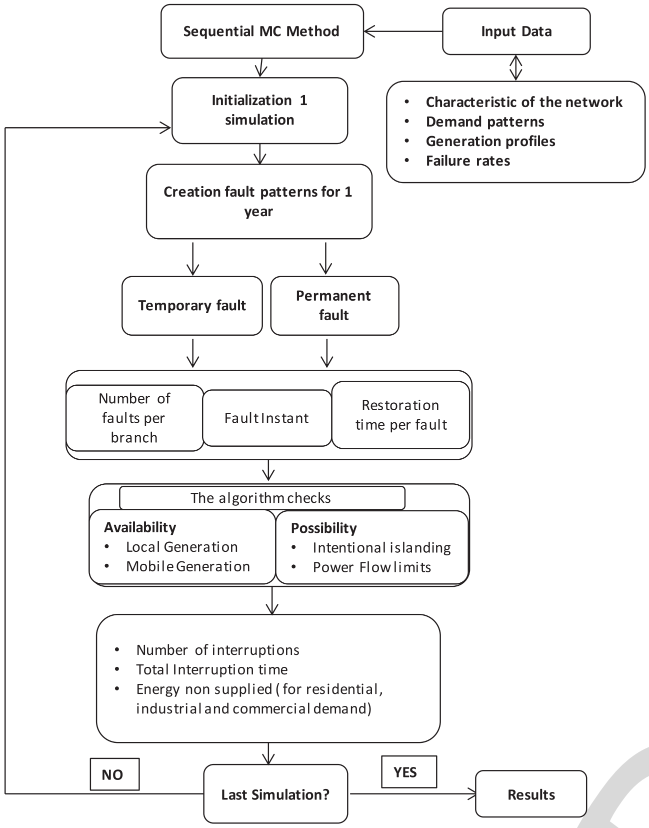

Fig. 1. Time-sequential MC reliability calculation method.

of whether the fault is temporary or permanent, with the related restoration times.

The definition of the fault pattern is followed by the analysis of the individual faults, one at a time, calculating the contribution of each fault to the reliability indicator considered, e.g., ENS. During the analysis, further aspects such as the availability and success of an operation of the components called for performing specific actions (e.g., switching systems associated with DG units that have to operate to guarantee successful island creation) are considered. At the same time, possible multiple or dependent faults are handled during the analysis of the effects of the fault. Finally, the possible occurrence of another fault (set by the definition of the fault time instants) during the restoration process of the fault under analysis is verified. This occurrence is very unlikely, given the relatively fast restoration with respect to the overall time period of observation and the relatively low number of faults but cannot be excluded for practical purposes.

C. Determination of the Duration of the Interruptions

Fig. 1 illustrates the characteristics of the computational procedure. The solution algorithm proceeds sequentially in time with respect to the chronological sequence of the interruption events. The first action is the identification of the circuit breaker serving the faulted feeder. Then, the load points located in other feeders are supplied (with no interruption). For the faulted feeder, the procedure is based on the following steps.

1) Analysis of temporary faults: the first calculation is the extraction of the random restoration time. For the load points located in the feeder with an interruption, the duration of the interruptions is updated by adding the corresponding instant of the restoration time.
2) Analysis of permanent faults: the restoration process with the possibility of islanding formation is carried out. The following steps are considered.
    a) For the faulted feeder, store the location of the load points in a list, and inspect which load point is assigned to an intentional island.
        i) Find the local generators connected to the isolated nodes and check their availabilities at the moment when the fault occurs and for the whole duration of the service restoration process (the local unit could be unavailable due to scheduled maintenance or to failure).
        ii) For the load points assigned to an island, add the island formation time to the interruption duration.
        iii) For the load points not assigned to an island, the interruption duration depends on the random restoration time. Mobile generation can be used to reach the nonsupplied nodes: the interruption duration can be reduced, extracting a random number representing the time to activate the mobile generation.
    b) If an island is formed, the power flow in the microgrid is calculated (e.g., with the backward–forward sweep method), and the constraints on the voltage and current limits verified. In the case of constraint violation, the structure of the intentional island is modified until no violation occurs [29]. All the load points belonging to intentional islands are marked as well as the DG units that control the island operation.
    c) Identification of the synchronization points adjacent to the island that may be located on the island boundary: no further contribution to the interruption duration; or not located on the island boundary: the island reconnection time is added to the interruption duration, due to the operations for restoring the initial configuration after the fault.
    d) Finally, the possibility of using mobile generators to serve the nonsupplied nodes is considered. The number of available mobile generators is randomly selected from 0 to a user-specified maximum number, with a given probability of the various occurrences. Instead of setting up a physical location for the mobile units when they are not used, the time to reach the node to supply is considered as the relevant random variable. The instances of this variable are extracted from a uniform distribution between a minimum and a maximum value.

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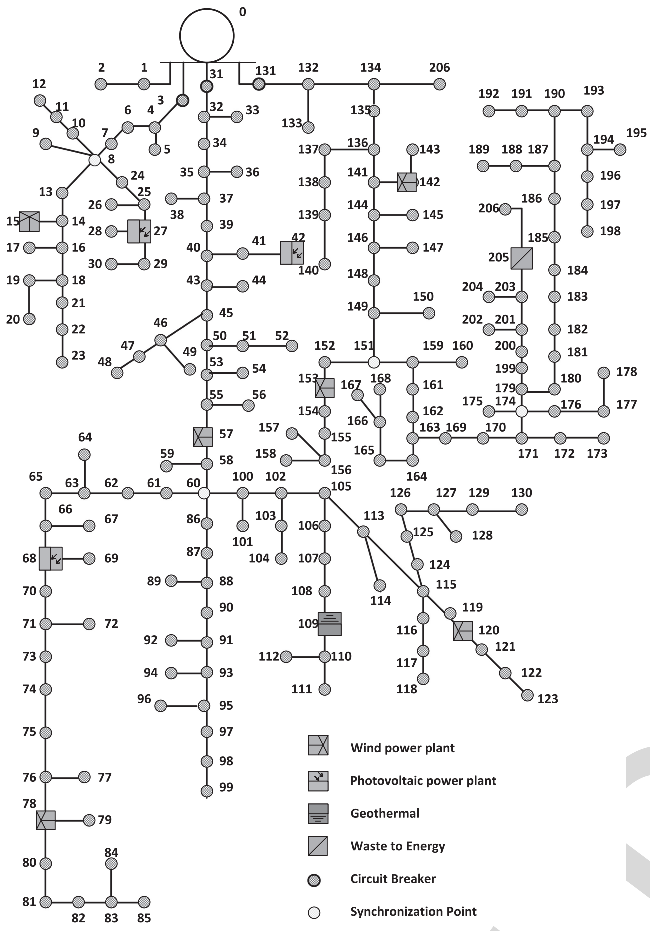

Fig. 2. Scheme of the MV network.

IV. APPLICATION TO A REAL DISTRIBUTION SYSTEM

A. Description of the System

1) Network Structure: The medium-voltage (MV) distribution network under analysis is a real network with 207 nodes and 213 branches, located on an island. The network has a weakly meshed structure, but it is operated in a radial way. The number of redundant branches (open for obtaining a radial configuration) is 7. Furthermore, the system is supplied by a single thermal power plant, located at the slack node, composed of eight generator groups, with a total installed power of 20 MW [59]. The island is totally dependent on external sources of energy. The supply system is fed by diesel generators, as well as by oil-based ones.

The scheme of the network, where DG, circuit breakers, and synchronization devices are located,[3] is shown in Fig. 2. The big circle represents the slack node while the small circles represent the other 206 nodes. The network contains different types of loads (residential, industrial, and commercial) and some DG plants supplied by wind, photovoltaic (PV), waste to energy (W2E), and geothermal systems, represented by colored squares. Hourly profiles are used to characterize the different types of loads and generations. The seven redundant branches [42] are indicated in Table I but are not drawn in Fig. 2 for the sake of simplicity.

TABLE I
REDUNDANT BRANCHES

Initial and final nodes of the seven redundant branches						
2-69	4-131	8-135	23-148	73-121	85-198	73-121

TABLE II
DG CONNECTED TO THE NETWORK

Generation type	Number of units and rated power (kW)	Annual production (GWh)
Wind	2 × 20	0.15
PV	3 × 200	1.332
Geothermal	1 × 2500	19.99
W2E	1 × 370	1.91

For the one-year reliability assessment, the DG units have been included in the network to evaluate the benefits of the integration of renewable energy in isolated systems.

2) Generation Profiles: The generation units considered are taken from [59]. The most realistic operation implies full exploitation of the geothermal and W2E sources and the inclusion of some wind and PV power plants. Geothermal and W2E profiles for one year are taken from [59] and [60]. The small geothermal power plant (2.5 MW) is located in the southwest of the island and operates during 8000 h/year (considering a programmed unavailability due to successive maintenance of the generation groups in winter).

Information on DG is reported in Table II. Wind and PV generation profiles are taken from historical data for one year available in [61]. In the case of wind, only data for 9 months are available, and the other 3 months are forecasted using a probabilistic method based on scenario generation from time series data, taken from the approach reported in [62].

3) Demand Profiles: For distribution system studies, a relevant aspect is the characterization of the aggregate demand. The probabilistic model of the aggregate demand is very useful for system operators or aggregators for extracting information about the demand-side behavior in the operation of microgrids.

The time step used to scan the aggregate demand pattern is very important to preserve the information about the consumers' behavior and the related uncertainty. Conventional models of aggregate electrical demand consider an average value for a specific time step (e.g., 30–60 min). In this case, one-hour step is used. The aggregate average load patterns for one day and for the whole network are illustrated in Fig. 3. In the same way, the power generation for a typical summer day is chosen in order to represent the generation profiles in Fig. 4.

4) Intraday Configuration Strategy: An intraday strategy is applied in order to maximize the optimality of the network configuration. In this case, two optimal configurations are used for the whole year, one for peak hours and another for off-peak

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[3] The optimal allocation of the switches is not addressed in this paper. The reader may refer to [51] for specific details.

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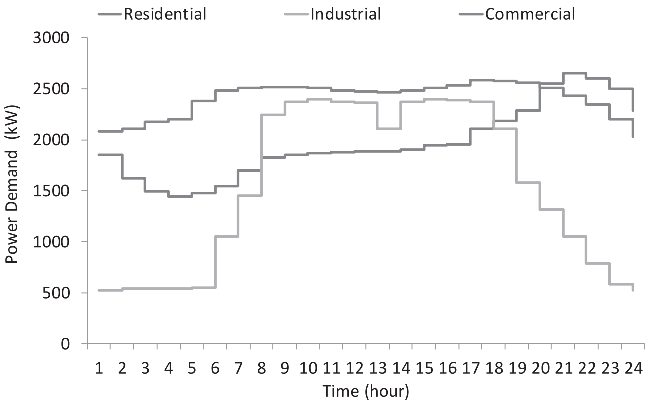


Fig. 3. Average hourly demand profiles.

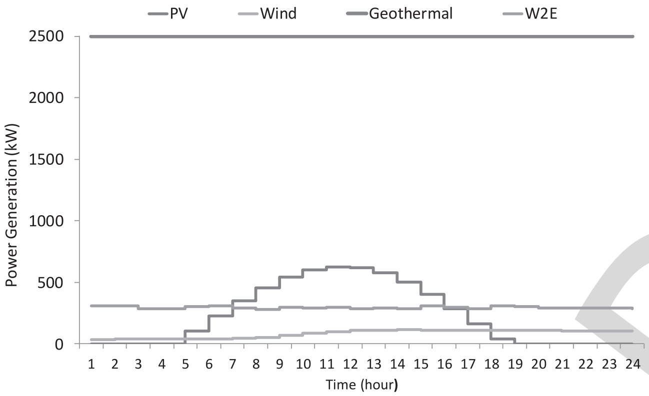


Fig. 4. Average hourly generation profiles for the summer period.

TABLE III
PARAMETERS FOR RESTORATION TIMES

Shape parameter (k)	Scale parameter (θ)	Approx. fault time
5	2	10 s
4	60	3 min
4	450	30 min
4	800	1 h
4	10 000	10 h

hours as shown in [41, Table VII]. These results have been found for the specific case with a relatively low penetration of DG. However, the method used is general, also in case of a more remarkable penetration of DG, in which the distinction between peak hours and off-peak hours becomes less evident.

5) Other Data: For reliability analysis, the whole period of one year with time intervals of one hour is assumed. The failure rate per branch is 0.5 (for temporary faults) and 0.05 (for permanent faults). The duration of faults is assumed to be 10 s for temporary faults, and 3 min, 30 min, 1 h, and 10 h for permanent faults. The fault probability of the generator is 0.1. The parameters of the restoration times for the Gamma distribution (shape and scale factor) are shown in Table III.

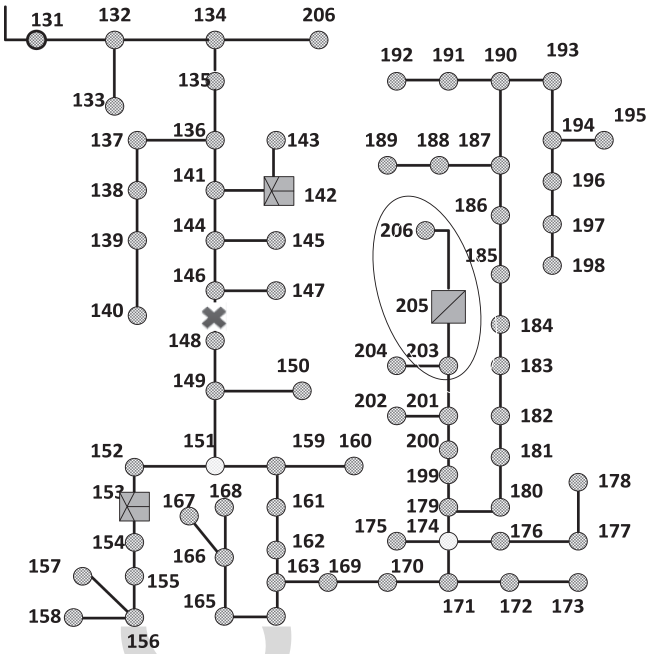


Fig. 5. Island formation during fault in branch 148.

B. Results and Discussion

1) Definition of the Cases and Simulation Framework: The results of the reliability analysis are shown by applying the sequential MC method with 1000 repetitions in the following cases:

1) case I, with neither DG nor mobile generation;
2) case II, with mobile generation and no DG;
3) case III, with DG and no mobile generation;
4) case IV, with DG and mobile generation.

In all the cases, the same random faults are considered in order to provide a sound comparison among the differences in the ENS results.

The simulations have been carried out by using the CPLEX 11 solver in MATLAB [63]. An Intel Xeon E7-4820 computer with four processors at 2 GHz and 128 GB of RAM has been used.

2) Analysis of a Specific Simulation: The details of a specific simulation are provided here in order to illustrate how the algorithm process works. Let us analyze one permanent fault in branch 148 (connecting node 146 to node 148). The time of the fault is selected from a uniform distribution along the year, in this specific situation, occurring during hour 19:00 of the 23rd day of the 9th month.

Initially, the circuit breaker located at node 131 is found and the downstream load (residential load 838.5 kW, industrial load 599.1 kW, and commercial load 867.7 kW) is not supplied. In that instant, the topology is the one shown in Fig. 5, the wind generator at node 153 is producing 12.8 kW, and the W2E power plant is generating 282.8 kW. The number of available mobile generators is 2, acting in the 42nd and 71st min after the fault occurs.

After the algorithm finds the circuit breaker, it verifies the existence of local generation in the isolated feeder with suitable

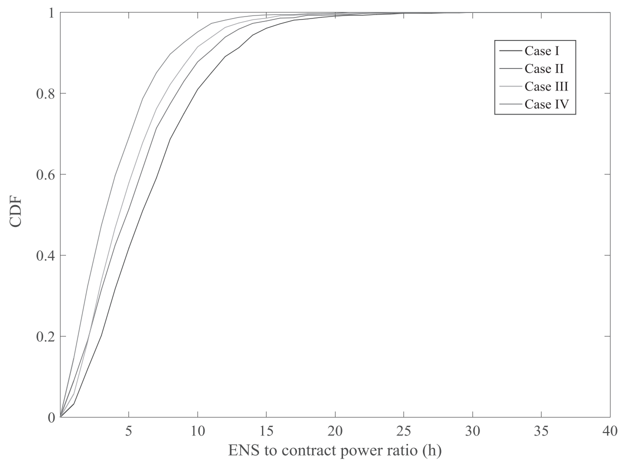


Fig. 6. CDF of the ENS to contract power ratio for residential users.

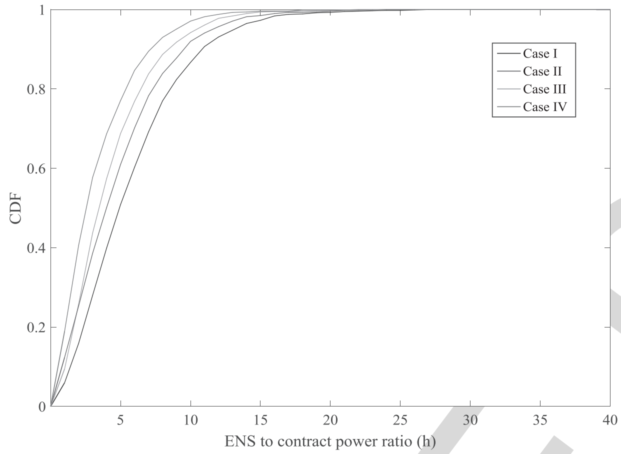


Fig. 7. CDF of the ENS to contract power ratio for industrial users.

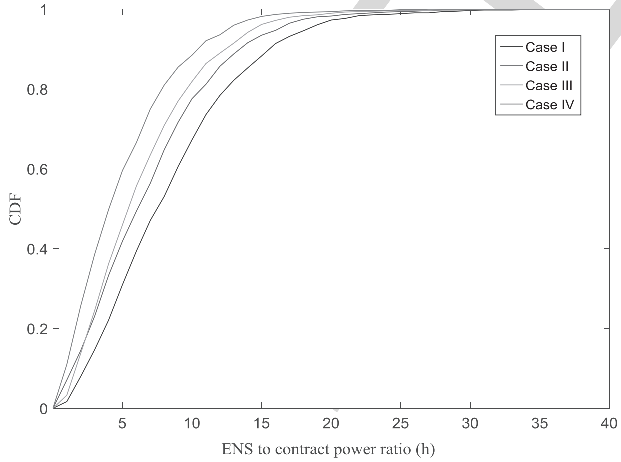


Fig. 8. CDF of the ENS to contract power ratio for commercial users.

characteristics to create an intentional island and looks for the synchronization point in order to isolate part of the network until the fault is restored.

There are two synchronization points at nodes 151 and 174. The wind generator at node 153 can only supply 12.8 kW of the demand (21.86 kW) at that node. On the other hand, the W2E power plant checks whether it can create an island supplying the loads near its location (node 205) with its own power. Therefore, there is an island formation among nodes 201, 203, 204, 205, and 206, located downstream from the synchronization point at node 174. In this specific situation, the synchronization point is not located on the island boundary. Finally, the existence of two available mobile generators covers the demand of nodes 148 and 149 until the fault is restored.

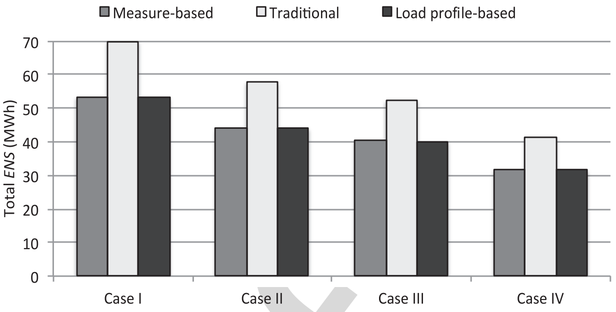
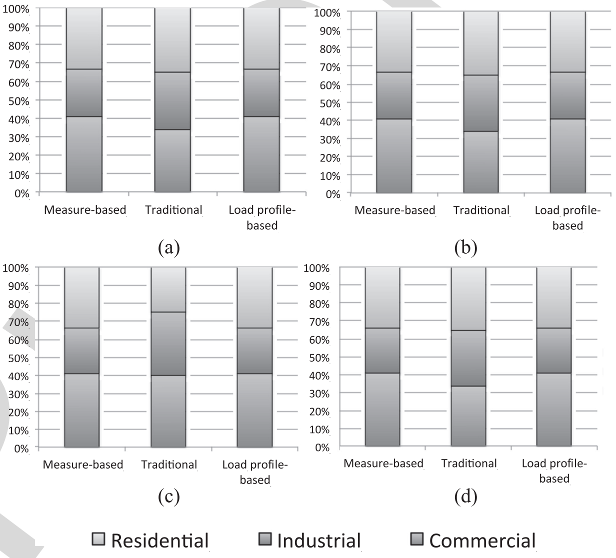


Fig. 9. Average values of the total ENS in the four cases.



(a)

(b)

(c)

(d)

Fig. 10. ENS share for residential, industrial and commercial users with different approaches to ENS calculation and DG and mobile generation penetration. (a) Case I, (b) case II, (c) case III, and (d) case IV.

3) Comparison Criterion and Overall Results: Considering all the simulations for one year, for the sake of comparison, the faults are the same for all the cases. The maximum and minimum number of faults are 149 and 84, respectively. ENS values have been calculated for residential, industrial, and commercial users. However, the total energy consumption in one year for the three types of users is different. Considering the conventional load profiles established for the different types of users, the energy consumption in one year (without interruptions) is 17 275 MWh for residential users, 13 346 MWh for industrial users, and 21 073 MWh for commercial users. Thereby, considering only the ENS values to compare the results for the different users is not appropriate. The energy consumption is taken as the

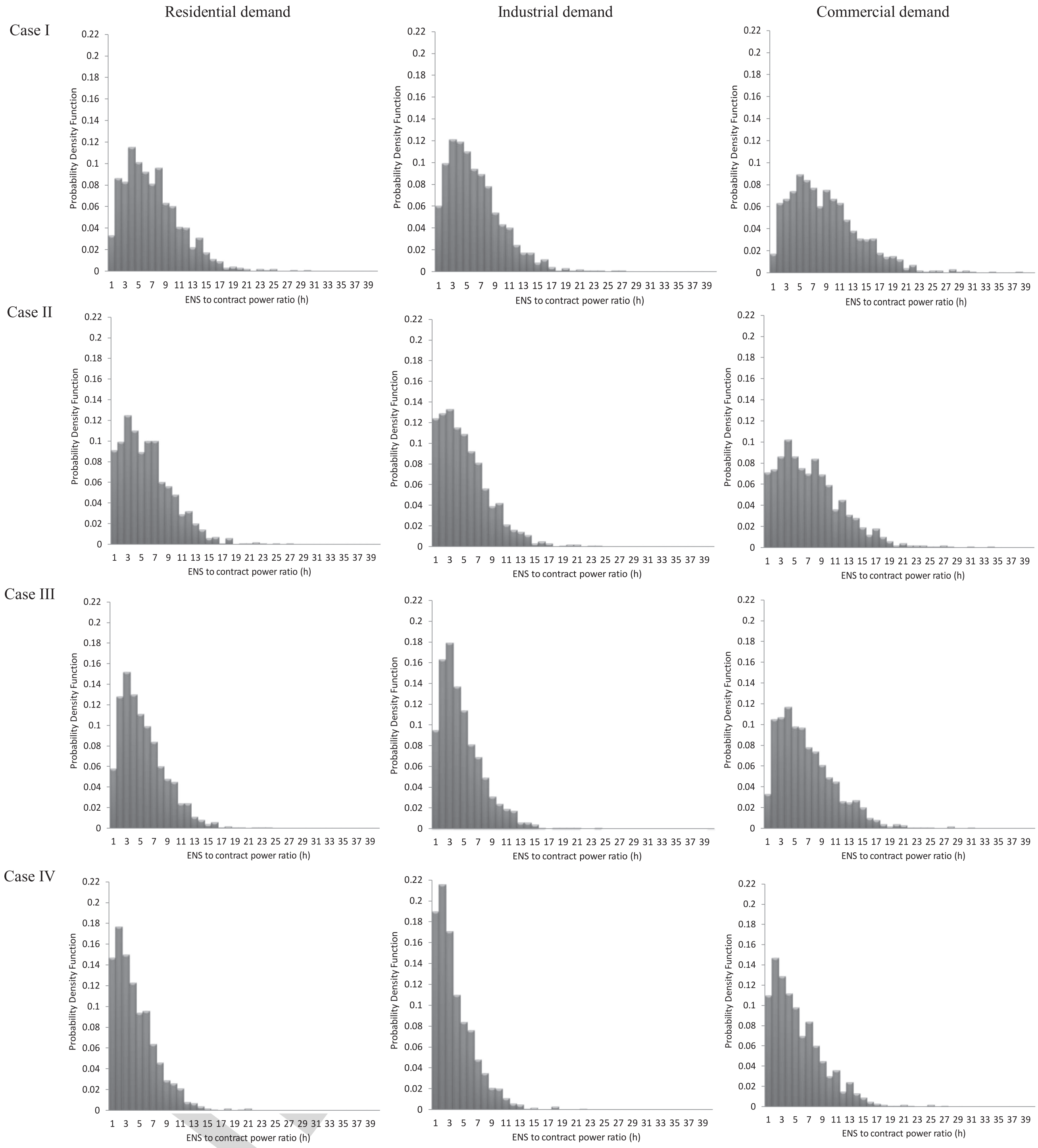


Fig. 11. Probability density functions (PDFs) of the ENS to energy consumption ratio.

conventional reference to calculate the ratio between the total ENS and the contract power for each type of user. This ratio is the relevant variable used for the sake of comparison.

The cumulative distribution functions (CDFs) of the ENS to contract power ratio are presented in Figs. 6–8, in the four cases. Comparing the three figures, it is more likely to have a higher ENS to contract power ratio for the commercial users, compared to the other ones, as its CDF is shifted to the right-hand side. On the other hand, it is more frequent to have a lower ENS to contract power ratio, first, for the industrial users, then, for the residential users, and finally, for the commercial users as shown in Figs. 6–11. Moreover, as expected, there is a higher probability to have a lower ENS in case IV, which includes DG and availability for mobile generation. Cases II and III are similar, case III being slightly better to reduce the overall ENS. Finally, case I is the worst one in terms of continuity of supply.

As observed, the CDF is close to 1 in the worst situation when the ratio is 28 h for industrial users, 31 h for residential users, and 39 h for commercial users. This can also be seen in Fig. 9. Moreover, this figure also illustrates the different total ENS values corresponding to the different methods. The traditional approach provides higher ENS, as expected, while the results obtained from the measure-based and load profile-based approaches are very similar. In particular, the load profile-based approach leads to slightly lower values than the measure-based approach whilst being more accurate in determining the total ENS.

Fig. 10 illustrates the ENS share among the different users for each case. The ENS share for the commercial users is similar to the measure-based and load profile-based approaches for all the cases. In the traditional approach, the ENS share is equivalent among the three types of users, except for case III, in which the proportion is 40% commercial, 35% industrial, and 25% residential, the ENS share of the residential users being the lowest of all the cases. In the load profile-based and measure-based approaches, the ENS share remains approximately constant among all the users for the four cases (41% commercial, 25% industrial, and 34% residential). Finally, as explained before, the higher percentage of the ENS share corresponds to the commercial users.

Fig. 11 displays the PDFs of the ENS to contract power ratio. It shows that the commercial demand contribution to the ENS to contract power ratio is also higher than for the residential and industrial users as it is further shifted to the right for the four cases. The highest probability is 0.21 in case IV for the industrial users, which corresponds to an ENS to contract power ratio of 2 h. This means that the highest probability of having the lowest ratio is for the industrial users. In fact, the probability of having a lower ratio is seen in case IV, in which the PDFs are concentrated on the lowest ratios for all types of users. In all the cases, the distribution is asymmetrical and right-skewed.

V. CONCLUSION

This paper has presented an extended framework for the reliability evaluation of active distribution systems for a period of time. This framework includes the possibility of creating intentional islands in case a fault occurs and shows how the introduction of DG, intraday network reconfiguration strategy, and mobile generation improve reliability by reducing the ENS.

The effectiveness of the proposed approach has been shown in the application to a real MV network. Numerical results have been presented in different cases, with and without DG and mobile generation, and with different ways to calculate the ENS, based on conventional load profiles or measured values of the demand at given time steps. This is in line with the current developments aimed at providing practical implementations of the smart grid paradigm. One of the advantages that DG can provide to electric utilities and customers is the possibility of improving the continuity of supply by implementing safe intentional islands in the event of an upstream supply outage. The possibility of creating islands during the service restoration process may be constrained by regulatory issues as the DG owner would have to take care of the loads served by another entity under normal operating conditions. The analyses carried out in this paper consider that such a limitation is not in place.

Based on the framework presented, it is possible to carry out many types of parametric analyses by changing the amount of DG and mobile generation in the network, assessing the effects on reliability in such a way to provide useful information for distribution system planning.

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