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Energy Regulator Supply Restoration Time

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Abstract: In conventional reliability analysis, the duration of interruptions relied on the input parameter of mean time to repair (MTTR) values in the network components. For certain criteria without network automation, reconfiguration functionalities and/or energy regulator requirements to protect customers from long excessive duration of interruptions, the use of MTTR input seems reasonable. Since modern distribution networks are shifting towards smart grid, some factors must be considered in the reliability assessment process. For networks that apply reconfiguration functionalities and/or network automation, the duration of interruptions experienced by a customer due to faulty network components should be addressed with an automation switch or manual action time that does not exceed the regulator supply restoration time. Hence, this paper introduces a comprehensive methodology of substituting MTTR with maximum action time required to replace/repair a network component and to restore customer duration of interruption with maximum network reconfiguration time based on energy regulator supply requirements. The Monte Carlo simulation (MCS) technique was applied to medium voltage (MV) suburban networks to estimate system-related reliability indices. In this analysis, the purposed method substitutes all MTTR values with time to supply (TTS), which correspond with the UK Guaranteed Standard of Performance (GSP-UK), by the condition of the MTTR value being higher than TTS value. It is nearly impossible for all components to have a quick repairing time, only components on the main feeder were selected for time substitution. Various scenarios were analysed, and the outcomes reflected the applicability of reconfiguration and the replace/repair time of network component. Theoretically, the network reconfiguration (option 1) and component replacement (option 2) with the same amount of repair time should produce exactly the same outputs. However, in simulation, these two options yield different outputs in terms of number and duration of interruptions. Each scenario has its advantages and disadvantages, in which the distribution network operators (DNOs) were selected based on their operating conditions and requirements. The regulator reliability-based network operation is more applicable than power loss-based network operation in counties that employed energy regulator requirements (e.g., GSP-UK) or areas with many factories that required a reliable continuous supply.

Keywords: reliability; network reconfiguration; time to supply; guaranteed standard of performance

1. Introduction

The reliability performance of distribution networks incorporates all possible contingencies associated with all power components in the network, including distribution feeders and protection systems. Reliability performance of the network is mostly related to maintaining the power supply to the customer. Apart from maintaining the voltage level within permissible limits and minimising the feeder losses, network reconfiguration is able to maintain an adequate level of reliability set by the energy regulator [1,2]. In addition, the network operation must adhere to the P2/6 Engineering Recommendation [3] that suggests transfer capacity from alternative sources by certain maximum times based on class of group demands.

In general, the structure of a distribution network reflects a meshed configuration that normally operates radially with the support of another supply point, either a primary substation or a reflection centre. A reflection centre resembles a closed-loop arrangement that guarantees the supply of all connected feeders. With the advent of remote control of switches and circuit breakers, distribution network operators (DNOs) are able to control network reconfiguration easily and further boost system automation. Network reconfiguration also relieves the overloading of the network components. Feeder reconfiguration is performed by opening switches/breakers (normally closed) that are closed to the faulty part of the network and closing switches/breakers (normally open) located at the end of the feeder network [4–7]. Switching is performed in such a way that the network radial is maintained and all loads are energised. A normally open switch/breaker is closed to transfer a load from one feeder to another, while an appropriate switch/breaker is opened to restore the radial structure.

Another conventional method of restoring customer interruption is by repairing or replacing the faulty network component [8–11]. The selection of either repairing or replacing a faulty network component depends on the class of group demand outage, types of network components, network component availability, transportation, geographical area of faulty area, and others. For transformer outage in group of demand type class B [3], supply to customer must be restored by maximum 3 h, which can only be performed via replacement. Outage originated from a faulty fuse is typically below 1 MW (class A [3]) and no definite restoration time in [3]. However, the restoration of faulty fuses must be performed within maximum 3 h based on [1].

In the last decade, various objectives have been used for network reconfiguration. The objective or the aim of network reconfiguration can either be single or multiobjective. The varieties of single objectives are minimisation of power losses or energy losses, total network cost, voltage deviation, benefit/cost ratio and voltage sags. Multiobjectives combine two or more single objectives in a network reconfiguration. Power loss minimisation [12–16] and voltage profile [17–20] are conventionally employed for network reconfiguration with less attention towards network reliability [18,21].

The literature pertaining to reliability-based reconfiguration, though in abundance, is not inclined toward energy regulator requirements, which substantially improves interruption frequency and duration. Although reducing interruption frequency and power loss is interrelated, the objective differs. In reliability, the main purpose is to minimise frequency of customer interruption regardless of load demand (maximum, average or minimum), whereas in power loss, saving maximum load demand (to minimise load loss) is the priority than protecting customers with minimum load. In addressing this challenge, this paper proposes an alternative approach in using new restoration times called time to supply (TTS) for realistic evaluation of distribution reliability performance.

2. Input Parameters

2.1. Suburban MV Network

A typical UK suburban distribution network was considered in the analysis (see Figure 1). The radial type of power distribution network delivers power from the main branch to sub-branches, then splitting out from the sub-branches again. This appears to be the cheapest, but least reliable network configuration. Tables 1 and 2 present the parameters of UK suburban network.

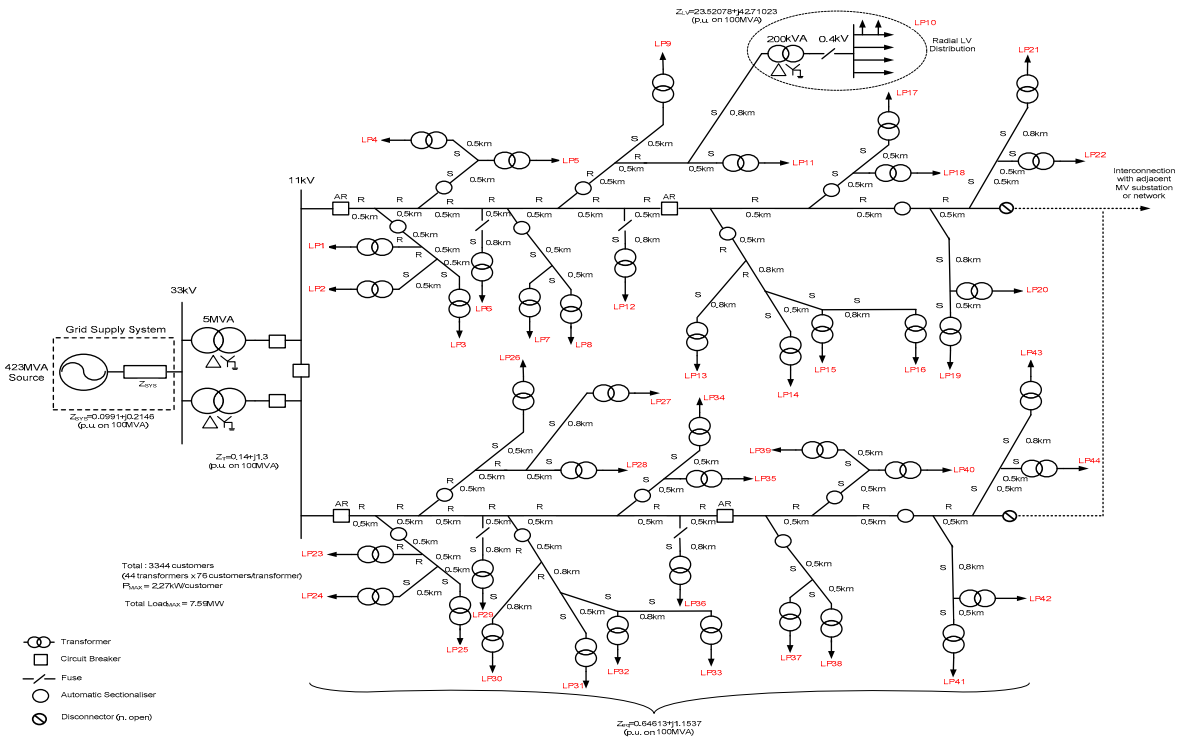


Figure 1. Typical distribution network configuration supplying suburban residential load [22–27].

Table 1. Parameters of Typical 11, 0.4, and 0.23 kV Feeders [22,28–30].

Operating Voltage (kV)	Feeder Type	Id.	Cross Section (mm^2)	Resistance/km (p.u. on 100 MVA)	Reactance/km (p.u. on 100 MVA)
11	Overhead Lines or Mixed	R	150	0.11259	0.18363
		S	100	0.14658	0.26189
0.4		D	95	0.32	0.075
		E	50	0.443	0.076
		H	95	0.32	0.085
0.23		L	35	0.851	0.041

Table 2. Parameters of Typical MV/LV Transformers [22,28,30–32].

Operating Voltage (kV)	Vector Group	Rating (MVA)	Resistance (p.u. on 100 MVA)	Reactance (p.u. on 100 MVA)	Tap Range Min	Tap Range Max	Tap Step
33/11	Dyn11	5	0.14	1.3	0.85	1.045	0.0143
11/0.4	Dyn11	0.2	7.5	22.5	0.95	1.05	0.025

2.2. Mean Fault Rates and Mean Time to Repair (MTTR)

Mean fault rates and MTTR are the two basic inputs required for system reliability assessments. In the literature, the reported values of these two input data vary in wide ranges (based on the characteristics and location of network, types and features of power components, as well as their operating conditions). Table 3 presents the statistics of mean fault rates and mean repair times obtained from two main sources: UK-related values reported in [33] and from other sources [34–41].

Table 3. Mean Fault Rates and MTTR of Power Components.

Power Component	Voltage Level (kV)	Mean Fault Rate λ_{mean} (Faults/Year)		MTTR μ_{mean} (Hours/Fault)	
		[33]	[34–41]	[33]	[34–41]
Overhead Lines	<11	0.168	0.21	5.7	-
	11	0.091	0.1	9.5	-
	33	0.034	0.1	20.5	55
Cables	<11	0.159	0.19	6.9	85
	11	0.051	0.05	56.2	48
	33	0.034	0.05	201.6	128
Transformers	11/0.4	0.002	0.014	75	120
	33/0.4	0.01	0.014	205.5	120
	33/11	0.01	0.009	205.5	125
Buses	0.4	-	0.005	-	24
	11	-	0.005	-	120
	>11	-	0.08	-	140
Circuit Breakers	0.4	-	0.005	-	36
	11	0.0033	0.005	120.9	48
	33	0.0041	-	140	52
Fuses	<11	0.0004	-	35.3	-

2.3. Fault Types

The classification of customer interruption into short interruption (SI) and long interruption (LI) is impossible without, for instance, modelling the applied protection systems. One simple way to make a clear distinction between short and long supply interruptions of customers is by defining a uniform distribution and linking it to the system reliability assessment procedure. For that purpose, past recordings collected from 14 UK DNOs between 2005 and 2009 [42] were analysed, in which 54% of supply interruption events were caused by temporary faults (i.e., SI), and 46% were due to permanent faults (i.e., LI).

2.4. Guaranteed Standard of Performance

The energy regulator has specified certain requirements for the duration and the number of interruptions in order to protect domestic (i.e., residential) and non-domestic customers (i.e., customers without special contract or agreement with the DNOs regarding LI) from excessive LI events. References depicted in [1] and [28] refer to the main UK statutory instrument, specifying the permissible supply restoration times for up to 5000 customers and more than 5000 customers, respectively. This is illustrated in Table 4 (normal system operating conditions), along with the corresponding compensations that DNOs pay directly to the customers (and not to the regulator), if the supply is not restored within the specified time [1] and [28].

Table 4. The UK Guaranteed Standard of Performance (GSP-UK).

Supply Restoration Time		Compensation Paid to:	
No. of Customers Interrupted	**Maximum Supply Restoration Time**	**Domestic Customers**	**Non-Domestic Customers**
<5000	18 h	£54	£108
	After each succeeding 12 h	£27	
≥5000	24 h	£54	£108
	After each succeeding 12 h	£27	
	Maximum	£216	
Multiple Interruptions		Compensation (all customers)	
Four or more interruptions (≥4), each lasting at least three hours (≥3 h)		£54	

3. Reliability Methodologies

Probabilistic reliability assessment procedures seem to suit the analysis of system reliability performance, particularly in terms of their ability to model stochastic and inherently unpredictable variations of input parameters and data (e.g., fault rates and repair times) with their assumed probability distributions. The approaches of the probabilistic reliability assessment model provide a wide range of variations of practically all input parameters and data in one or a few simulation/calculation setups, without repeating the calculation after an input data is modified.

Although the probabilistic reliability assessment procedures are more difficult to implement (particularly in complex large-scale systems), they provide accurate and detailed outputs. The most frequently used probabilistic reliability assessment approach is the Monte Carlo simulation (MCS) [43–47]. Aside from network modelling, conventional MCS analysis requires statistical information on fault rates and MTTR of faulted power components as input data. Network models and fault rates of power components are used to establish customers experiencing interruptions (and the frequency), whereas MTTR of faulted components and network protection, reconfiguration, switching and alternative supply functionalities are used to estimate the duration of corresponding supply interruptions. The outputs of MCS analysis are reliability indices that reflect probability distributions with the corresponding mean values.

3.1. Monte Carlo Simulation (MCS) Procedures

In any power system reliability procedures, MTTR is used to define the restoration times of network components that directly have an impact on the duration of interruption. In some cases, where network automation is unavailable (network reconfiguration) or in the absence of regulatory supply requirements (in some nations) on distribution networks, it is indeed realistic to use MTTR values. Nevertheless, in a country that applies regulatory supply requirements, the function of MTTR as input data may result in significant overestimation of reliability performance. Thus, DNOs should consider a new method to assess the duration of interruption by correlating with regulatory supply requirement time. Accordingly, this section presents a new methodology (see Figure 2) of assessing duration of interruption realistically, based on GSP-UK restoration times.

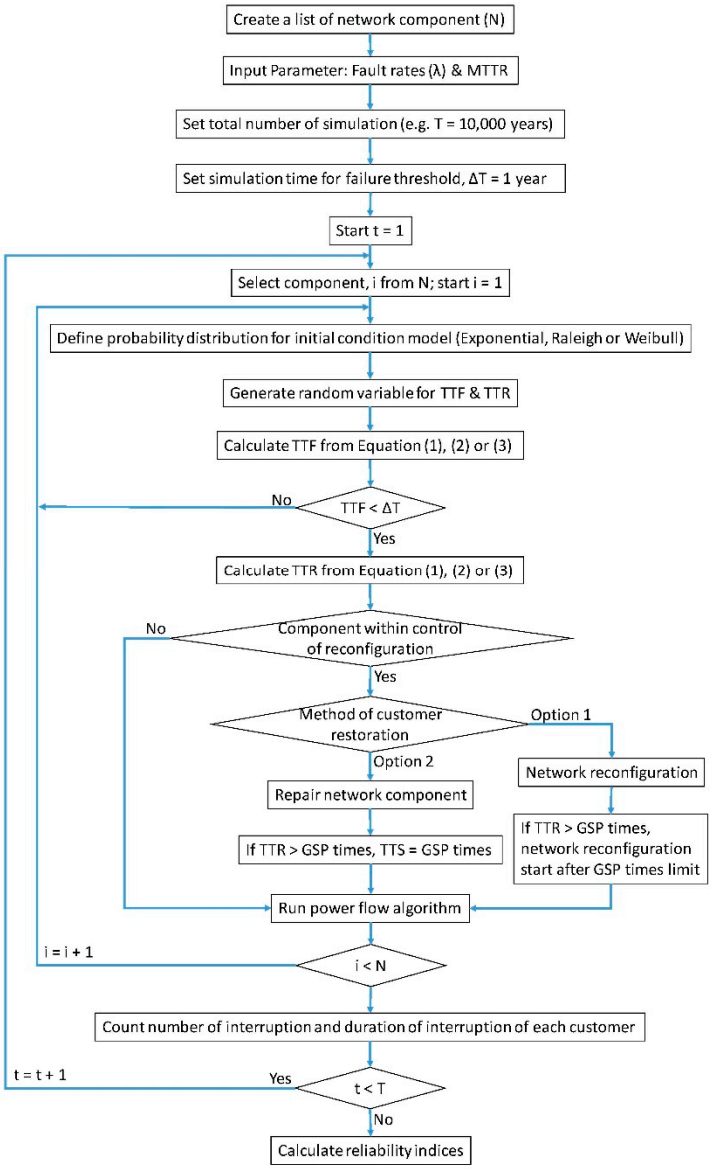


Figure 2. Monte Carlo simulation (MCS) procedures.

Based on the methods in MCS, a random variable (generated by a random generator) is assigned to an inverse cumulative distribution function to convert fault rates and MTTR (see Table 3) into system states, time to fail (TTF) and time to repair (TTR). The system states of the network component can be modelled with a series of distribution functions: Exponential, Weibull and Rayleigh. The parameters of distribution function are available in [48–50]

$$\text{Exponential}: \ \text{TTF/TTR} \ = \ inverse\{1 - \exp(-\lambda t)\}, \tag{1}$$

$$\text{Weibull}: \ \text{TTF/TTR} \ = \ inverse\left\{1 - \exp(-t/\delta)^{\beta}\right\}, \tag{2}$$

$$\text{Rayleigh}: \ \text{TTF/TTR} \ = \ inverse\left\{1 - \exp\left(-0.5(t/\delta)^{2}\right)\right\}. \tag{3}$$

Generally, the proposed method substitutes MTTR values of intended network component with new time to supply (TTS) of GSP-UK values only if MTTR value > TTS value. Literally, the TTS value indicates a fast time response (compared to the MTTR value) either by replacing with a new component or quick repairing the existing component. Since it is nearly impossible to have a fast response time to all network components and cause under-utilisation of network automation (network

reconfiguration), only components on the main feeder (carrying a high current that may affect many customers) are selected to replace MTTR values with TTR values (option 2). To compare the practicality of option 2 with complete network automation, option 1, network reconfiguration, was generated. In option 1, the network component fault/interruption time adheres to the exact values of MTTR, while the customer restoration time is shorted by the GSP-UK duration limit via network reconfiguration. In other word, customers experience outages through the normal path of electrical supply and the duration of outage experienced by the same customer is shortened by rerouting the electrical supply through the network reconfiguration until the faulty component is repaired/replaced.

3.2. Considered Scenarios

In Table 5, scenario SC-1 is a base case that quantifies the benefits of network reconfiguration and repair/replace network component with TTS value. Scenario SC-2 represents the existing network reconfigurations and functionalities (option 1) in accordance with GSP requirements. This means that the network should have switching functionalities to transfer to an alternative supply and for reconfiguration, since, otherwise, many customers would face excessively long supply interruptions (determined by MTTR network components). Next, scenario SC-3 (option 2) has the same purpose in scenario SC-2, but without any transfer to an alternative supply and reconfiguration, as it only substitutes the MTTR of each power component into TTS in accordance with GSP. Scenario SC-3 determines the variance between network reconfiguration and the replacement time of MTTR in adherence to GSP. The purpose of scenario SC-4 is to list the benefits of minimising time window of fault via network reconfiguration. Finally, scenario SC-5 embeds "smart grid", wherein automatic remote-controlled switching may be implemented in future for a suburban distribution network.

Table 5. Description of the Analysed Scenarios.

Description of Scenarios
Scenario SC-1: No reconfiguration and repair/replace network component in accordance with GSP (time to supply—TTS) in the network
Scenario SC-2: All long interruption (LI) (including transfer to alternative supplies and reconfiguration) up to maximum 18 h (in accordance to GSP)—OPTION 1
SC-2A: Reconfiguration at random hours up to 18 h
SC-2B: Reconfiguration at exactly maximum 18 h
Scenario SC-3: Replacement of all LI repair time with TTS (within the control of reconfiguration, as in scenario SC-2) up to maximum 18 h (in accordance GSP)—OPTION 2
SC-3A: Replacement of all LI repair time with random hours up to 18 h
SC-3B: Replacement of all LI repair time with exactly 18 h
Scenario SC-4: All LIs (including transfer to alternative supplies and reconfiguration) up to maximum 3 h
SC-4A: Reconfiguration at random hours up to 3 h
SC-4B: Reconfiguration at exactly 3 h
Scenario SC-5: Time for transfer to alternative supply and reconfiguration are exactly 3 min

4. Reliability Performance Results

Table 6 presents the values of reliability indices; System Average Interruption Frequency Index (SAIFI), Momentary Average Interruption Frequency Index (MAIFI), System Average Interruption Duration Index (SAIDI), Customer Average Interruption Duration Index (CAIDI) and Energy Not Supplied (ENS) calculated using the MCS technique with a total simulation of 10,000 years for suburban distribution network. MATLAB (R2018a, MathWorks, Natick, MA, US) is used to implement MCS and PSSE software (33, Siemens, Schenectady, NY, US) to model the analysed network and solve the power flows.

Table 6. Scenario SC-1 to SC-5.

Scenario	Indices	Probabilistic (Mean Values)
SC-1	SAIFI	0.4929
	MAIFI	0.5527
	SAIDI	33.7625
	CAIDI	68.4914
	ENS	3539.4823
SC-2A	SAIFI	0.4787
	MAIFI	0.5481
	SAIDI	6.5735
	CAIDI	13.7321
	ENS	669.5330
SC-2B	SAIFI	0.4682
	MAIFI	0.5580
	SAIDI	8.4968
	CAIDI	18.1494
	ENS	842.8723
SC-3A	SAIFI	0.4847
	MAIFI	0.5597
	SAIDI	6.1732
	CAIDI	12.7374
	ENS	625.1351
SC-3B	SAIFI	0.4854
	MAIFI	0.5581
	SAIDI	8.1339
	CAIDI	17.6588
	ENS	831.2357
SC-4A	SAIFI	0.4733
	MAIFI	0.5569
	SAIDI	4.0005
	CAIDI	8.4526
	ENS	397.6056
SC-4B	SAIFI	0.4734
	MAIFI	0.5569
	SAIDI	4.3145
	CAIDI	9.1138
	ENS	430.6348
SC-5	SAIFI	0.1514
	MAIFI	0.8785
	SAIDI	3.3554
	CAIDI	22.1576
	ENS	346.5313

5. Discussion

The results of scenarios SC-1, SC-2A/2B, and SC-3A/3B suggest that network reconfiguration and repair/replace with TTS can successfully reduce long supply interruptions. Figure 3d illustrates that the MCS outputs displayed a greater reduction in hours, from 68.4914 to 13.7321/18.1494, for scenarios SC-1 and SC-2B/3B, respectively.

In scenarios SC-2A/2B and SC-3A/3B, although the methods (options 1 and 2) of restoration supply differed, both scenarios shared almost similar values. In detail, Figure 3d shows that the line graph of scenario SC-2B is up to 175.5 h, while that for scenario SC-3B is up to 190.5 h. This signifies that for scenario SC-2B, two separate durations of interruptions occurred, and they overlapped with the reconfiguration duration time causing the tail of scenario SC-2B to be smaller than scenario SC-3B.

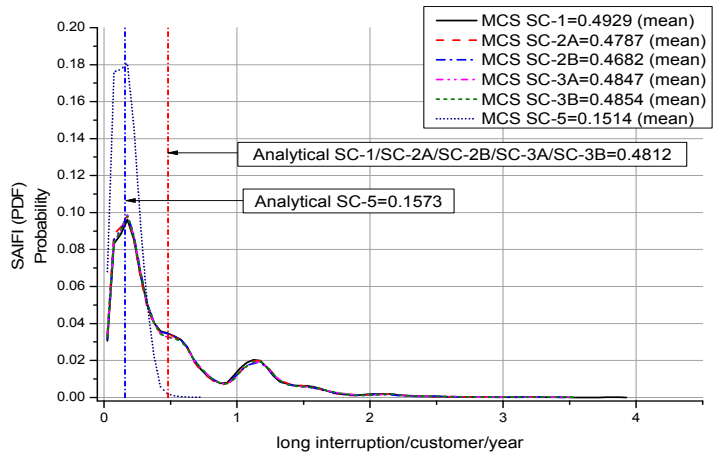
Between scenarios SC-2A and SC-2B, or SC-3A and SC-3B, huge variances were noted in the values based on Figure 3d (CAIDI index). This is because the repair time in scenario SC-2B/3B was always exactly 18 h, while in scenario SC-2A/3A, although the repair time window was up to 18 h, it was not always exactly 18 h. This led the values of CAIDI in Figure 3d for scenario SC-2A/3A to be lower than scenario SC-2B/3B. As long as the duration of interruption is within the permissible limit (scenario SC-2A/3A), the values are acceptable.

There are possibilities that the values for scenarios SC-2A and SC-2B, or SC-3A and SC-3B share almost similar values. In scenario SC-2A/3A, the time window of repair time/reconfiguration is bigger (up to 18 h), with multiple choices for selecting the hour for repair time or reconfiguration time. For a smaller window of reconfiguration/repair time, as in scenarios SC-4A (repair time up to 3 h) and SC-4B (repair time exactly 3 h), the values of CAIDI for both scenarios in Figure 4d were almost identical.

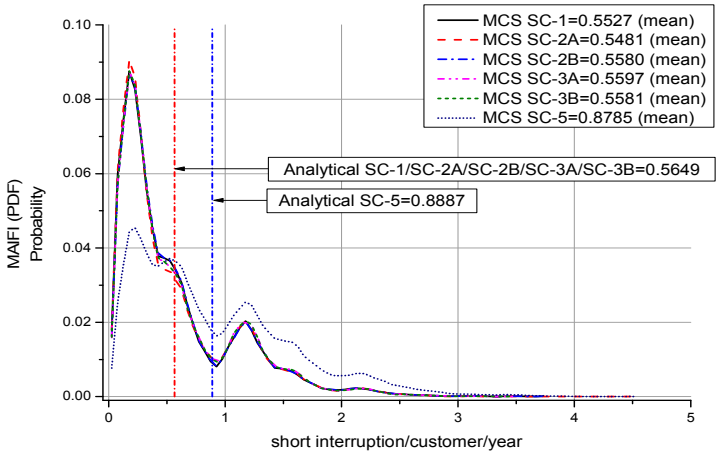
In Figure 3a, the MCS mean value of SAIFI scenario SC-2B was slightly lower than SC-3B because in scenario SC-2B (see Figure 5), the frequency of interruptions was lower than that in scenario SC-3B (see Figure 6). In Figure 5, customers only experienced single interruption, while double interruptions are shown in Figure 6. Thus, scenario SC-3B exhibited higher values of average duration of interruption than those recorded for scenario SC-2B.

Figures 5 and 6 portray the tail graphs of scenarios SC-2B and SC-3B for better understanding. In Figures 5 and 6, the same customers experienced LIs with varied average duration of interruption. In Figure 5, no second duration of interruption was noted, while in Figure 6, the customer experienced a second interruption within a 3 h duration. Thus, as displayed in Figure 6, the duration of interruption was 21 h, which is longer than that in Figure 5, 18 h.

As for scenario SC-5, when "smart grid" automatic switching was applied to the network reconfiguration, the CAIDI values (i.e., average duration of LIs) increased after all faults were addressed within 18 h, to turn into Sis, due to less than 3 min of automatic switching. In detail, the shorter duration of LI no longer contributes to the average values, causing the average values of CAIDI of scenario SC-5 to be higher. This also indicates that automatic switching reduced the number of LIs but increased the average duration of interruptions and the number of SIs.



(**a**)



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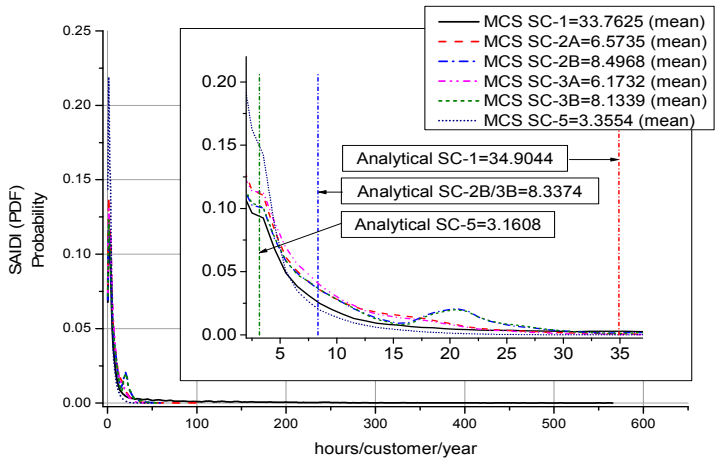
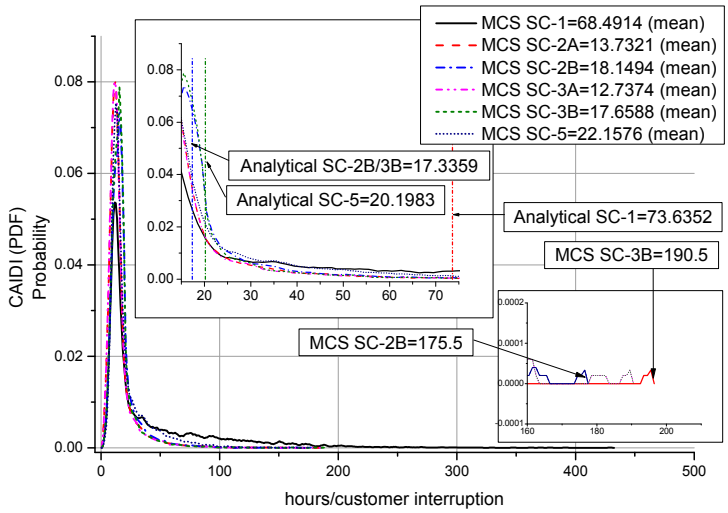


(**c**)

Figure 3. *Cont.*



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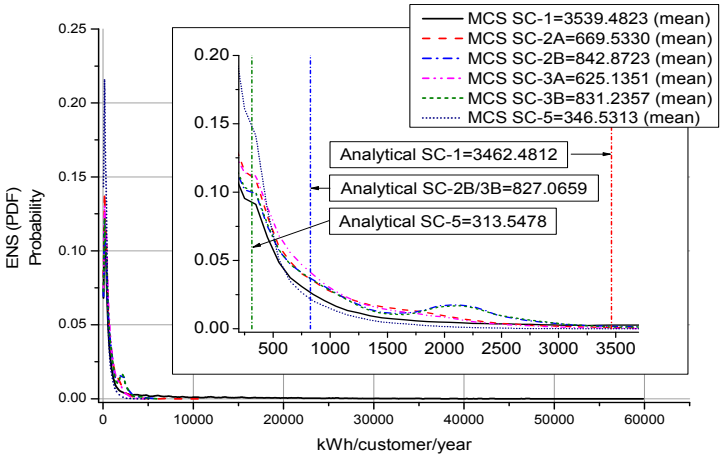
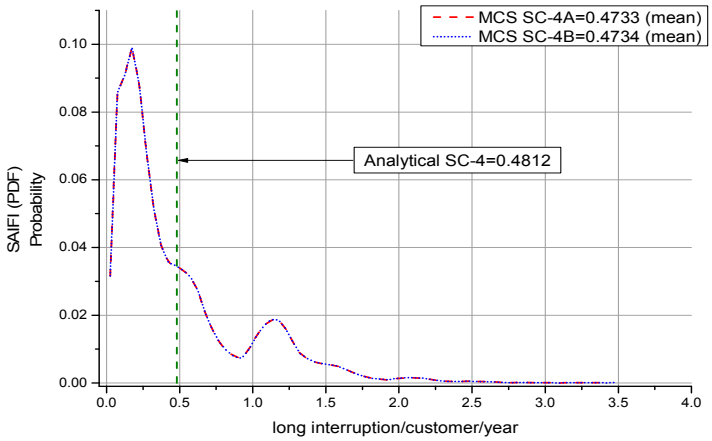


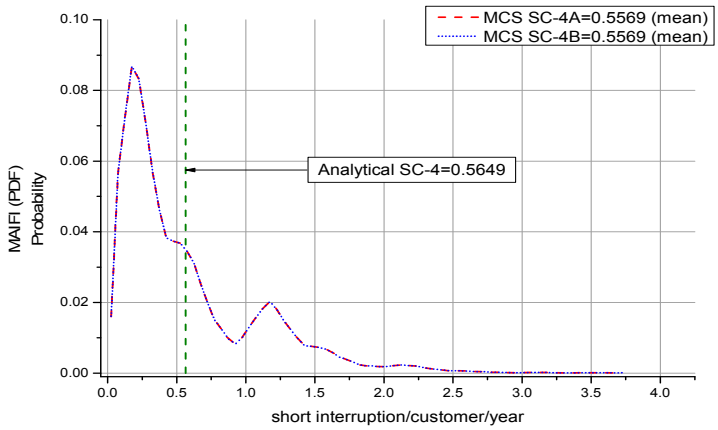
(**e**)

Figure 3. Indices for scenario SC-1, SC-2A/2B, SC-3A/3B and SC-5. (**a**) SAIFI index; (**b**) MAIFI index; (**c**) SAIDI index; (**d**) CAIDI index; and (**e**) ENS index.



(**a**)

Figure 4. *Cont.*



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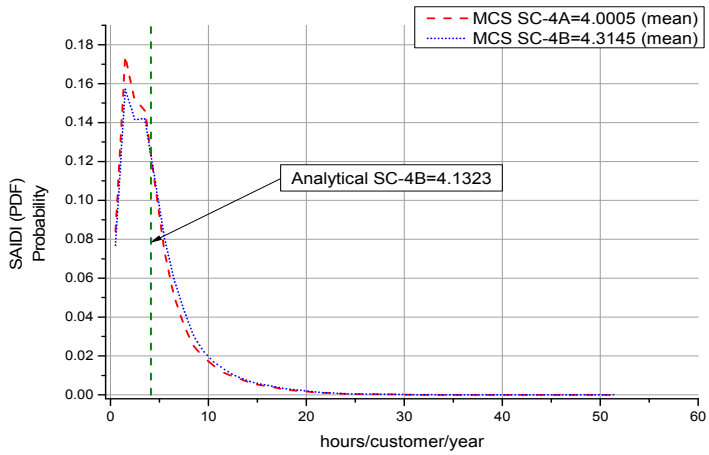

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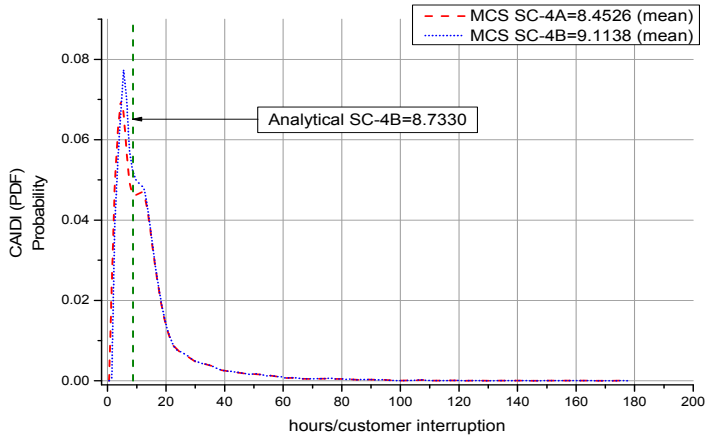

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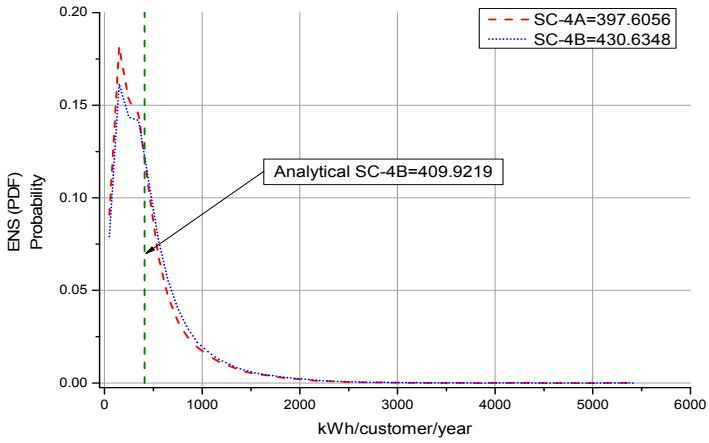

(**e**)

Figure 4. Indices for scenario SC-4A/4B; (**a**) SAIFI index; (**b**) MAIFI index; (**c**) SAIDI index; (**d**) CAIDI index; and (**e**) ENS index.

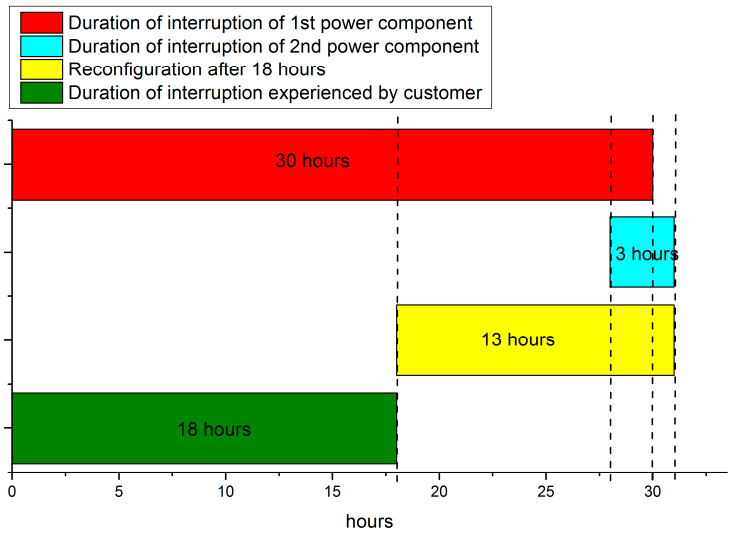

Figure 5. Example of scenario SC-2B tail graph.

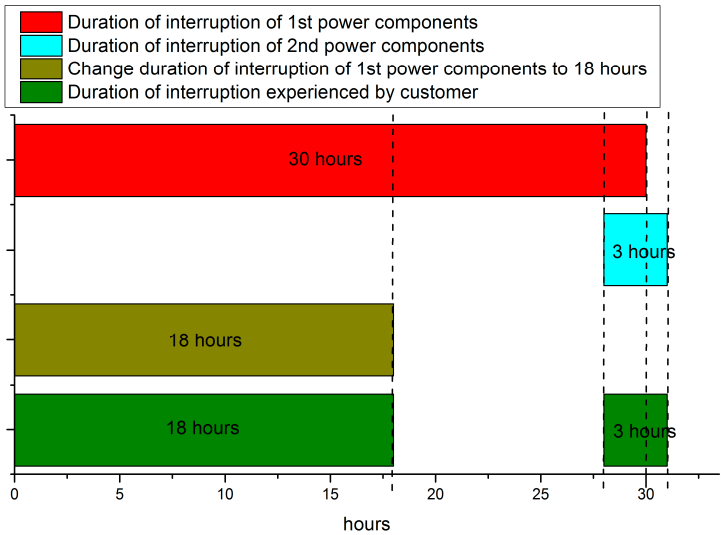

Figure 6. Example of scenario SC-3B tail graph.

6. Conclusions

This paper presents the reliability performance under various reconfigurations and replacement repair times based on regulator supply requirements. Each presented scenario has its own pros and cons. It is possible and realistic to change the mode of operation from a power loss-based to a regulator reliability-based network reconfiguration or repair/replace network component by adhering to GSP requirements on the existing network, so as to meet the target set by the energy regulator. In option 1 (network reconfiguration), the selection of restoration time (either 3 min, or 3 or 18 h) was unrestricted by human activity and weather, as DNOs may operate switches/breakers manually or automatically, rerouting the electrical supply. As for option 2 (repair/replace network component with TTS value), it is practical to completely clear the fault within 18 h, but optional (either feasible or otherwise) for 3 h or below 3 h. The 3 h replacement/repairing of network component depends on the definition, by including or excluding travelling time, locating fault area, weather condition, and others. Hence, several scenarios bring about extra flexibility to DNOs. DNOs may choose the most appropriate methods/options or scenario in accordance with their operation conditions and the requirements of the network system so as to meet their own reliability target, as well as the target fixed by the energy regulator.

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