

Reliability of Distribution Networks with DER including Intentional Islanding

M. H.J. Bollen, Y. Sun, G.W. Ault

Abstract--This paper presents methods for calculating the reliability of distribution systems with distributed energy resources (DER). The impact of intentional islanding of the DER units on the reliability is studied in detail. Different levels of automation are considered, starting from the existing network and continuing with increasing levels of intelligence in the network. The role of the switching devices and of the restoration process is discussed in detail.

Keywords: distributed generation; distributed energy resources (DER); power-system reliability; Monte-Carlo simulation; distribution automation.

I. NOMENCLATURE

DER: Distributed Energy Resources, including both distributed generation and distributed storage.

λ : failure rate per unit length for the distribution feeder

L : length of the distribution feeder.

t_5 : fault isolation time for a fault on the feeder.

t_8 : component repair time for a fault on the feeder.

t_3 : time needed to restart a DER unit after a fault in the grid.

λ_{isla} : failure rate of the DER unit.

r_{isla} : repair time of the DER unit.

F : interruption frequency for a customer.

Q : supply unavailability of a customer.

II. INTRODUCTION

Distributed energy resources (DER, including distributed generation and storage) have a number of well-published advantages [1][2][3][4]. One of the advantages is the ability of the DER to supply loads during a grid failure. The widely used battery-based UPS is an example of a distributed energy storage device aimed at improving supply reliability. Also on-site generating units in large industrial installations are often used for this purpose [5].

The use of DER to improve supply reliability requires additional investment. In addition to a control system enabling

stable island operation (microgrid) additional switchgear is needed as well.

In this paper some of the possible improvements will be quantified in relation to the required changes in the DER unit and in the distribution system.

III. FAULT ISOLATION AND SUPPLY RESTORATION

The presence of DER units does not change a number of fundamental rules on the operation of distribution systems. We may assume that for the foreseeable future switching actions will take place by mechanical switching devices. Three different types of devices have to be distinguished based on their function: circuit breakers are the only devices that can interrupt a short-circuit current; disconnectors are the only devices that can provide safe isolation but they can interrupt a very small current only; load switches can interrupt a current up to the rated current. The prospect for network reliability improvement by DER units depends to a large extent on the presence of appropriate switching devices and the speed with which they can be switched. In short, one may state that circuit breakers reduce the number of interruptions whereas disconnectors can be used to reduce the duration of interruptions.

IV. INTENTIONAL ISLAND OPERATION

DER units close to remote customer locations may improve the supply reliability by limiting the risk of feeder overload. However, the main impact of DER on reliability occurs when island operation is possible for the units together with their local load. The technical aspects of this are discussed in several other publications, e.g. [6][7][8][9]. In this paper the technical issues are put aside and only the potential impact of intentional islanding on reliability is considered.

Different stages may be distinguished in the introduction of DER units for reliability improvement. In the first stage the unit will trip when a fault occurs on the local feeder but is able to restart with its local load in an island. The number of interruptions is not affected, only the duration of the interruptions. In the second stage, the DER rides through a fault on the local feeder. This reduces the number of interruptions and even allows the mitigation of voltage dips. The final stage is what is often referred to as "the intelligent distribution network", in which the DER units pick up any nearby load as well. Failure of a component in the distribution system will lead to a reconfiguration of the network to restore

Part of this work was done within the EU-DEEP integrated project and funded by the European Commission, Svenska Kraftnät and the Swedish Energy Administration. Part of the work is also funded through the 'Future Network Technologies' consortium of the UK research councils funded SuperGen programme.

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the supply to as many customers as possible as fast as possible.

A. Stage 1: Disconnecter-type interface

The first stage towards the intelligent network is where the DER units restart together with their local load after a fault. This reduces the duration of interruptions, but not the number of interruptions. Failures during island operation will even lead to an increase in the interruption frequency. The configuration of the distribution feeder with the DER unit is shown in Figure 1. The figure also shows the switchgear present along the feeder. The number and duration of interruptions is very much influenced by the type and location of the switchgear.

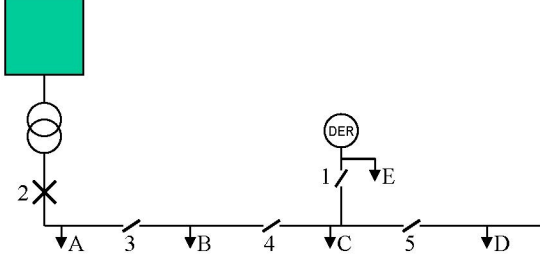


Figure 1. Distribution feeder and DER unit with disconnecter-type interface.

Once a fault occurs anywhere on the feeder, circuit breaker 2 opens to clear the fault. This results in de-energizing the whole feeder including the DER unit with its local load (customer E). Instead of waiting for fault location, isolation and repair, disconnecter 1 is opened and the DER unit is restarted together with its local load or part of its local load.

The interruption duration for customer E has now been reduced from several hours or days to several minutes. This scheme is only advantageous when the interruption costs are low for interruptions shorter than the restart time of the unit. Two examples are shown in Figure 2 of interruption costs for interruptions of different duration. For the solid curve the costs only increase significantly for interruptions much longer than the restart time of the DER unit. The increase in number of interruptions is more than compensated by the large reduction in costs per interruption. This kind of cost-duration curve is found for domestic customers and for commercial customers for which the important loads are equipped with UPS. Hospitals mostly also fall into this category.

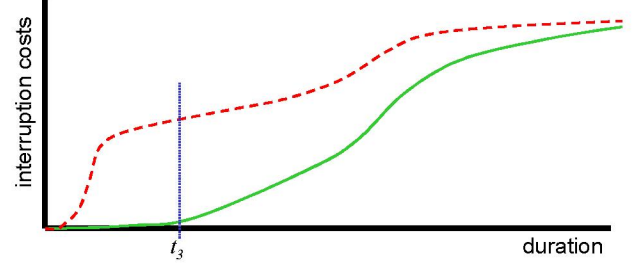


Figure 2. Two examples of distribution costs versus duration of the interruption, with t_3 the restart time of the DER unit.

B. Stage 2: breaker-type interface

The next step towards the intelligent distribution network is to install a circuit breaker at the interface of the DER and local load group as shown in Figure 3. This gives the possibility of removing the DER with its local load from the grid before the fault is removed from the system. It is no longer required to trip the DER unit and restart for island operation. This kind of configuration has been used for many years in large industrial installations, like steel or chemical plants, where the process is very sensitive to voltage disturbances and where down time is very expensive.

Future applications may initially include commercial load with high interruption costs and unreliable supply, but a large-scale integration of DER units may result in such a scheme becoming widespread.

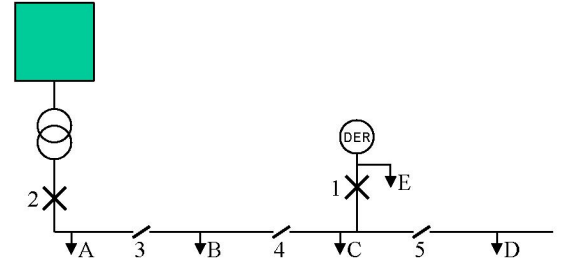


Figure 3. Distribution feeder and DER unit with breaker-type interface.

In this scheme the fault clearing takes place by the feeder breaker (2) and the DER breaker (1). The latter may trip on undervoltage or on overcurrent, depending on the protection scheme. It is most likely that a scheme is chosen in which the DER breaker opens faster than the feeder breaker. This reduces the strain on the unit and its control system, at the expense of a larger number of unnecessary trips. DER unit dynamics and control are crucial in maintaining operation during such an event.

The DER customer E no longer experiences an interruption, only a voltage dip with a duration determined by the opening speed of the breaker. With existing technology, opening times of 50 ms are easily achievable. An additional advantage of this scheme is that it also enables the mitigation of voltage dips due to faults external to the local feeder.

C. Island operation of multiple customers

One further stage towards the intelligent distribution network is the dynamic creation of power islands with the DER unit, its local load and additional loads on the feeder. The interruption duration experienced by the customers again depends on the presence of circuit breakers and disconnectors in the network. An interruption-free transition is only possible when circuit breakers are present at a sufficient number of locations in the network. The choice of an appropriate protection scheme becomes very important as the risk of failure during island operation becomes larger when more customers are supplied from the microgrid.

V. RELIABILITY CALCULATIONS

A. No DER

Consider a feeder with a length A and a DER unit connected at a distance xA from the main busbar. The failure rate λ is uniform over the feeder. The reliability indices for the DER customer (at E) are calculated from the frequency and unavailability for each group of faults, as shown in Table I, where t_8 is the repair time of the faulted component and t_5 is the time needed to locate and isolate the fault.

TABLE I
RELIABILITY CALCULATION FOR THE NO-DER CASE.

Event	Frequency	Duration	Unavailability
Fault between main substation and DER unit.	$\lambda x \Lambda$	t_8	$\lambda x \Lambda t_8$
Fault between DER unit and end of feeder.	$\lambda(1-x)\Lambda$	t_5	$\lambda(1-x)\Lambda t_5$

The resulting number of interruptions per year (interruption frequency) and unavailability are equal to

$$F = \lambda \Lambda \quad (1)$$

$$Q = \lambda \Lambda \{x t_8 + (1-x) t_5\} \quad (2)$$

B. DER with disconnector-type interface

The same calculation method as before results in the following interruption frequency:

$$F = \lambda \Lambda + x \lambda \Lambda \lambda_{isla} t_8 + (1-x) \lambda \Lambda \lambda_{isla} t_5 \quad (3)$$

where it has been assumed that the restart time t_3 is much smaller than the fault-isolation time t_5 or the repair time t_8 . The first term in (3) is due to faults on the feeder; the second term is due to DER failures and feeder outages due to faults between the main substation and the DER; the third term is related to faults between the DER and the end of the feeder.

The contribution of failures during island operation dominates the failure frequency when the expected time to failure of the DER unit becomes too small. The expected time to failure shall be significantly less than the isolation time for units near the start of the feeder and significantly less than the repair time for units near the end of the feeder.

This does not immediately imply more severe demands on the unit's reliability when it is connected towards the end of the feeder. The base-case reliability is much worse towards the

end of the feeder so that the customer may accept a lower reliability.

The unavailability of the supply for the DER customer is

$$Q = \lambda \Lambda t_3 + x \lambda \Lambda Q_{isla} t_5 + (1-x) \lambda \Lambda Q_{isla} t_8 \quad (4)$$

where $Q_{isla} = \lambda_{isla} r_{isla}$ is the unavailability of the DER unit.

The restart time t_3 is much shorter than the isolation time t_5 or the repair time t_8 (minutes versus hours and days). The result is that the latter two terms will dominate already for relatively low values of the unavailability. The contribution of failures during island operation increases for customers further along the feeder because the duration of island operation increases.

C. DER with breaker-type interface

The resulting interruption frequency and unavailability for this case reads as:

$$F = \lambda \Lambda \{x \lambda_{isla} t_8 + (1-x) \lambda_{isla} t_5 + \lambda_{isla} r_{isla}\} \quad (5)$$

$$Q = x \lambda \Lambda Q_{isla} t_8 + (1-x) \lambda \Lambda Q_{isla} t_5 \quad (6)$$

All interruptions for this case are due to the failures during island operation. The expressions are similar to the ones for disconnector-type interface, with the difference that only grid outages together with DER outages contribute to the unreliability.

D. Comparative study

A comparison has been made for the reliability between the three above-mentioned cases: no-DER or DER without islanding capability; DER with disconnector-type interface; DER with breaker-type interface. The following component data have been used: $\lambda=0.5$ faults per km per year; $A=20$ km; $t_3=10$ minutes; $t_5=5$ hours; $t_8=48$ hours; $\lambda_{isla}=0.05$ failures per hour; $r_{isla}=1$ hour.

The results are shown in Figure 4. The impact of failures during island operation on interruption frequency and unavailability is high. Note that the unavailability of the DER unit during island operation is only 5%. The unavailability of the supply is improved for all locations, but the difference between disconnector-type interface and breaker-type interface is small.

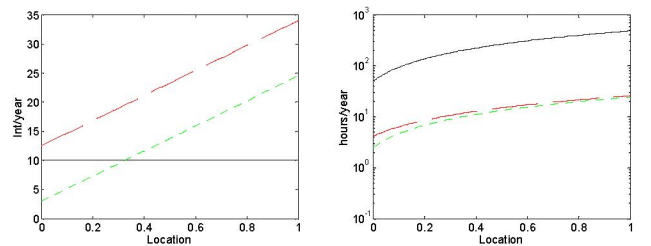


Figure 4. Interruption frequency (left) and unavailability (right) for customer supplied from DER unit; no islanding (solid line); disconnector-type (dashed); breaker-type (dotted).

The interruption frequency is up to three times as high for the disconnector-type interface as for the no-DER case and up to twice as high for the breaker-type interface. These solutions are only suitable when the interruption costs are most heavily

influenced by unavailability and not interruption frequency.

The calculations have been repeated for a more reliable DER unit ($\lambda_{isla}=0.005$ hours; expected time to failure equal to 200 hours), resulting in the plots shown in Figure 5. Note the difference in vertical axis for the interruption frequency. The interruption frequency shows a small increase for the disconnector-type interface and a significant decrease for the breaker-type interface, compared to the no-DER case. The unavailability has been reduced to less than 5 hours per year for any interface switch type.

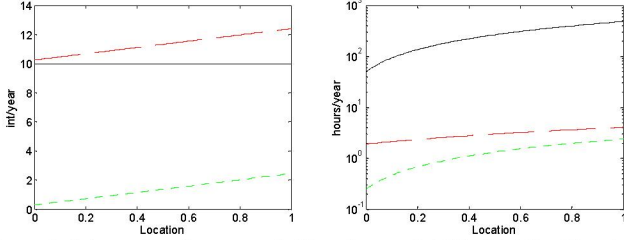


Figure 5, Interruption frequency (left) and unavailability (right) with reduced failure rate DER unit.

The impact of the DER failure rate on frequency of interruption and unavailability is shown in Figure 6 for a DER customer at 80% of the feeder length. The horizontal scale gives the expected time to failure of the DER unit (the inverse of the failure rate). For high DER reliability the interruption frequency and unavailability become close to zero for the breaker-type interface.

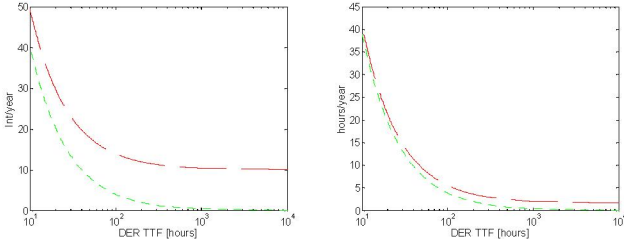


Figure 6, Interruption frequency (left) and unavailability (right) as a function of the DER unit's reliability.

To compare interruption frequency and unavailability for individual customers, the interruption costs as a function of interruption duration should be known. To generalize the results, the interruption frequency is translated to an "equivalent unavailability" by assuming that it takes a certain number of hours after the end of an interruption to restart the production process or any other activity. The longer this "process-restart time" the more important the interruption frequency becomes towards the perceived reliability. The process unavailability has been calculated for zero and for 10-hour process restart time, resulting in the plots shown in Figure 7.

The difference between breaker-type and disconnector-type interface is small for low DER reliability, especially for short process-restart time. Note that a short process-restart time corresponds to low costs associated with short interruptions.

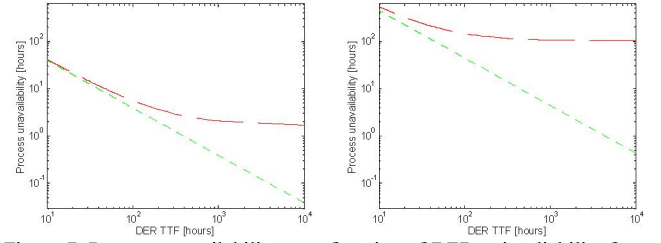


Figure 7, Process unavailability, as a function of DER unit reliability for zero process-restart time (left) and for a 10-hour restart time (right).

VI. MONTE-CARLO SIMULATION

The type of reliability calculations used above is only possible for simple systems. For larger systems automatic methods should be used as described in many publications on power-system reliability. A Monte-Carlo simulation appears the most appropriate method to study the impact of DER on the reliability as this method allows for the highest flexibility in the models. An important reason for using Monte-Carlo simulation is the large impact of the restoration process on the reliability indices (as shown by the prominent role of the switching and repair times in the above equations). Analytical methods are only valid under rather strict limitations for the distribution functions of the various durations in the restoration process. Furthermore, a Monte Carlo simulation is able to produce a distribution of possible results rather than the expected value alone. This and the unknown complexity of the process when starting the research, led to the choice of a sequential event-based Monte-Carlo simulation technique [10][11].

A random-number generator is used to generate events (faults; fault isolation; DER unit failure; repair) in the distribution system. The constant failure rate assumption for lines mean that the time to failure has an exponential distribution. Weibull distributions are used for all stochastic isolation and repair durations of lines and generator. The period of interest (a period of one year has been used in this study) is repeated many times to get statistically relevant results. Calculations are performed for the breaker-type interface as in Figure 3.

Island operation of DER units is expected to be allowed in the future. When managed properly, it will have a positive effect on system reliability. In order to operate in island mode, DG units have to be able to satisfy the islanded load. Considered cases during islanding are:

- DG supplies only load E;
- DG supplies loads C and E;
- DG supplies loads C, D and E.

In terms of generator size, a) is the smallest and c) the largest. Some of the results for case c) are shown in Figure 8 through Figure 10.

The following component data have been used in the simulations:

- Failure rate: 2/yr for element A; 4/yr for element B, C and D and for the DER unit.

- Expected isolation time: 5 hours
- Expected repair time: 30 hr for element A and C; 20 hr for element B and D and for the DER unit.

The repair and isolation time distributions consisted of two Weibull distributions with a ratio of 10 between their expected values and 10% belonging to the long-duration component.

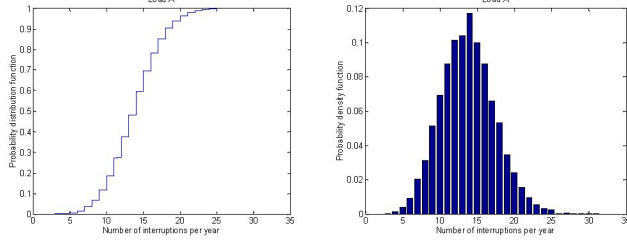


Figure 8, Probability distribution function and probability density function of interruption frequency for load A (DER supplies C, D, and E).

Figure 8 shows the probability distribution and density functions of the number of interruptions for load A. As A, B, C and D are behind the same circuit breaker, the number of interruptions is very similar. The number of interruptions shows a strong year-to-year variation with a 95%-confidence interval ranging from 8 to 22.

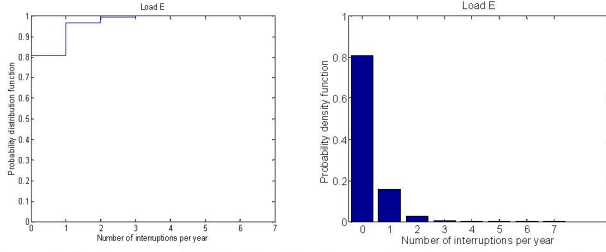


Figure 9, Probability distribution function and Probability density function of interruption frequency for load E (DER supplies C, D, and E).

The DER load (load E) only experiences interruptions due to overlapping grid and generator failures. The probability distribution and density functions are shown in Figure 9. The load has an 80% probability of not suffering any interruption during a given year. This should be compared with 14 interruptions per year in case no DER unit is present.

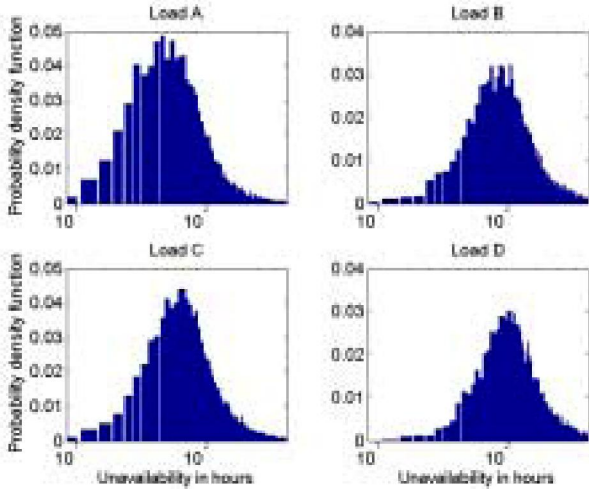


Figure 10, Probability density function for unavailability of load A, B, C, D (DER supplies C, D, and E).

Figure 10, shows the probability density function for the unavailability of loads A, B, C, and D. The most frequent

unavailability is different for each load.

Some numerical results of the study are shown in Table II: the system indices for the test system in Figure 3. The three cases correspond to different penetrations of DG integration. SAIFI and CAIDI are obtained as the average failure frequency and unavailability, respectively, over all customers. Not considering the microgrid capabilities of customer E would have resulted in a SAIFI of about 14.

The increasing DER size leads to a slight increase in SAIFI but a significant decrease in CAIDI.

TABLE II.

RESULTS OF MONTE-CARLO SIMULATION: SYSTEM INDICES.

System Indices	Case a	Case b	Case c
SAIFI	10.91	10.98	11.05
CAIDI (hours/year)	187.74	158.96	135.67
Average interruption frequency for each customer	A 13.68 B 13.62 C 13.54 D 13.44 E 0.25	A 13.73 B 13.66 C 13.80 D 13.50 E 0.24	A 13.76 B 13.70 C 13.82 D 13.74 E 0.24
Average unavailability for each customer (hours/year)	A 123.14 B 197.22 C 271.43 D 344.38 E 2.52	A 119.79 B 193.50 C 140.18 D 339.01 E 2.30	A 120.95 B 196.18 C 142.17 D 216.86 E 2.18

The impact of the increasing DER size on customer C is shown in Figure 11. The difference between cases b and c is small as the load is in both cases included in the microgrid. The difference between cases a and b is significant however.

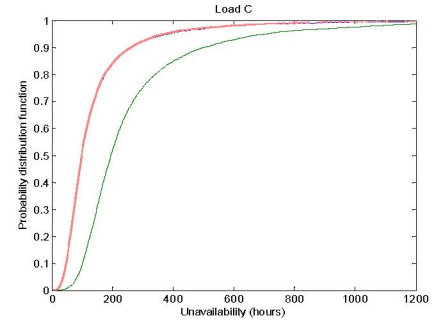


Figure 11, probability distribution function of unavailability of load C for cases a (green), b (red) and c (blue).

VII. CUSTOMER AND NETWORK INDICES

Appropriate use of DER units enables an improvement in reliability as experienced by individual customers. The impact on the reliability indices for the network operator depends on their definition. A distinction has to be made between individual customers using DER units to improve their reliability and network operators using DER units to improve the reliability of groups of customers. The former case is similar to the installation of a UPS by one customer. This improves the perceived reliability for this customer, but should not be taken into consideration for the network reliability indices. According to the same reasoning, failures during

island operation are not counted towards the network-performance indices. However when the network operator is in charge of the DER unit, the improvement in reliability should be incorporated in the reliability indices and failures during island operation should also be counted towards reliability indices.

VIII. CONCLUSIONS

Accurate reliability calculations for distribution systems with distributed energy resources require accurate modeling of the switchgear and the restoration process. Simple mathematical calculations applied to test networks give insight in the various parameters that influence the reliability. For a more detailed quantitative study, Monte-Carlo simulation is a suitable tool.

In this paper rather simple network configurations have been studied. For assessing the advantages of DER in actual cases as part of an investment decision, it is important to include a realistic network model and, especially, realistic failure rates and restoration times. Obtaining those data may not be straightforward however.

In this paper we did not consider any load-shedding schemes or variations in generator capacity. It has been assumed that the DER capacity is in all cases sufficient to supply the essential parts of the load.

Improving the supply reliability with the help of DER units requires a control system guaranteeing secure microgrid operation and appropriate switchgear to disconnect from and connect to the grid. These are not straightforward issues either.

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X. BIOGRAPHY



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