LAYERED RELIABILITY ASSESSMENT OF A REALISTIC URBAN MEDIUM VOLTAGE NETWORK UNDER MULTIPLE WEATHER AND LOAD SCENARIOS

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ABSTRACT

This paper investigates the reliability of a 10-kV feeder in a realistic network using the Three-Layer Reliability Technique. Part of a network plan generated by a Network Topology Optimizing Algorithm (NTOA) for a sampled urban region of Helsinki, was more comprehensively assessed in terms of reliability by modifying the three-layer technique for radial/looped networks. The selected feeder was tested in three cases under six weather scenarios that describe load and generation patterns typical in the Nordic countries. Introducing network automation significantly improved reliability and decreased the outage costs. The inclusion of CHP did not add, from the reliability point of view, significant benefits to the tested network over the 40-year project lifespan.

INTRODUCTION

Reliability has emerged as a crucial part of network planning amongst utility companies [1],[2]. As a result, accurate modeling of failure rates of devices and network topology, enabled by detailed databases for the considered area, is imperative in order to properly plan and assess the viability of a new project. Moreover, the inclusion of the direct and indirect influences of weather forms a major role in network planning, acknowledging the local seasonal variation for generation and load profiles as well as the impact of meteorological phenomena on system reliability.

This ongoing study designs a realistic 10-kV distribution network for the sampled area in Helsinki characterized by urban customers. The utilized algorithm [3] calculates the best routes to lay the feeders within the area, provided the location of the primary and secondary substations as well as the topographical features of the targeted area [4]. One of the requirements for this network was that the feeders should have at least one back-up connection from a different primary substation than the main feed in order to improve the system reliability and to better analyze the effect of the reliability from the topology of the 10-kV network.

Given the developed 10-kV distribution network, the three-layer reliability tool is utilized to assess selected substations of a feeder in three different cases. This technique developed in [5], groups adjacent equipment with specific functions into blocks that are thus associated to estimate reliability indices and relevant values in network planning. In this research, this tool is adjusted for backed-up radially-operated distribution networks to appropriately investigate the reliability with regard to the protection philosophy (such as disconnector types and the direction of the power supply). Finland has a high penetration of CHP as a share of total national power production [6]. CHP facilities can be directly connected to the distribution network, thus locally improving the reliability. For instance, in the case of loss of HV connections, the network can operate autonomously as well as providing electricity and heat locally [7]. Accordingly, the connection of a small two-unit combined heat and power (CHP) plant to one of the 10-kV substations was investigated, but given the nature of the test network, it was found to give negligible benefit in terms of reliability indices and outage costs. In addition, this study employs provided statistical data and load profiles in the course of a year by the local utility company for eight substations. This study includes comparison of three cases, subdividing the year into six scenarios that depict weather conditions and load flow patterns intrinsic to this region of the Nordic countries.

This paper is divided into five sections. After the introduction, the methodology describes the network planning algorithm used to generate the tested distribution network and the reliability tool to assess it. The third section describes the generated network and the employed parameters. The fourth section exhibits and explains the results obtained from the reliability analysis and, at last, comes the conclusion.

METHODOLOGY

This study is based on two techniques. The first generated a realistic 10-kV distribution network for the sampled area of Helsinki, considering the topographical features and customer types. The second analyzed the reliability of the planned network and estimated the outage cost during the project time. These techniques are explained in the following sub-sections.

The Network Topology Optimizing Algorithm

The NTOA produces close-to-optimum distribution network plans, taking into account the main driving parameters that affect the topology and topological location of MV feeders and the main protection devices (manual/remote/automatic switches, and circuit breakers). The main driving parameters are investment costs, repair times of existing feeders, geographically relevant fault frequencies, customer dependent interruption costs and running costs, mostly comprising the cost of losses. The NTOA is detailed, *e.g.*, in [3], and can be considered a development of classic branch exchange methodology,

whereby an underlying radial network, that at every iteration is converted to a full network with close-to-optimum reserve connections and switching, is progressively coerced by a smorgasbord of branch exchange routines towards the elusive theoretically optimal network. This brief description unashamedly uses the phrase close-to-optimum. In trying to consider everything, an NTOA cannot do the finest job in any particular respect due to constraints on computation time, and so this paper looks at a particular feeder from a reliability point of view in more detail than an NTOA can afford, with the assumption that the NTOA has treated reliability and the multitude of other considerations in sufficient detail to put the feeder in the right place.

Fig. 1 maps the generated 10-kV network. This distribution network is fed by three different 110-kV substations and the selected feeder for the reliability analysis is mainly fed by one (within the circle) and connected to the same substation by the normally-open (n.o.) point above (orange dot) and to the other two 110-kV substations beyond the other n.o. point (orange dot after substation s4). This area comprises a typical urban area, with important customers such as hospitals, public services and private services. In addition, this network consists of exclusively underground cables (in this specific case, XLPE cables with 240 mm^2 aluminium conductor), which is a requirement at the distribution level within urban areas in Finland.

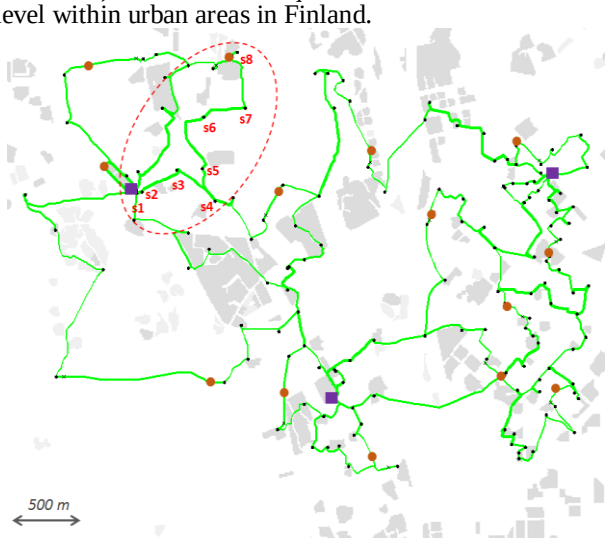

Fig. 1. A 10-kV distribution network generated for a typical urban area of Helsinki. The three purple squares are the primary substations and the other smaller ones are the secondary substations. This paper investigates the right side of the circled feeder isolated by the n.o. switches (the orange dots) and fed mainly by the 110-kV transformer close to substation s1.

Three-layer Reliability Technique

The structure of the three-layer reliability tool was developed in [5]. In this, the three critical zones, *i.e.* layers, were identified to obtain the partial reliability indices to comprehensively assess reliability at different parts of meshed networks. This method is herein adjusted to medium-voltage distribution networks that, in Finland, for instance, consist of backed-up feeders radially operated [8]. A number of technical and topological features must be acknowledged in order to adjust to that.
For this type of networks, based on radially operated backed-up feeders, the structure of the four-block three-layer method still remains the same. However, the form in which these blocks are arranged changes depending on the position of the MV substation. Fig.2 schematizes this new rearrangement. Similarly to [5], block “a” stands for the remote generation (in this case represented by the primary substations and possible proximity to distributed generation); block “b”, for the connecting feeders; block “c”, for the secondary MV-substation; and block “d”, for the local generation, all distinguished by lowercase digits.

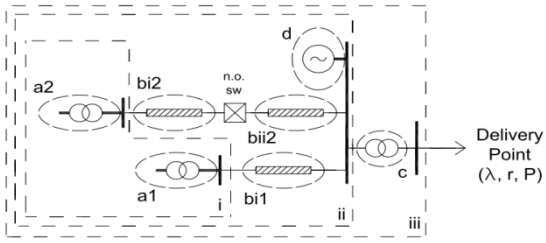

Fig. 2. Schematic of the three-layer reliability technique for distribution networks in this distribution network, being a1 the 110/10-kV transformer and a2 the 110/10-kV transformer upstream to the n.o. switch (sw).

The number of a–b branches to layer ii, for radial and looped distribution networks, can be higher than one. This is determined by the number of back-up connections plus the main trunk of the feeder from the analyzed substation to the main feeding primary substation, denominated by the digit “1”. Block “a1” stands for the delivery point at the secondary of the primary substation that provides the main power supply to the downstream feeder. The reliability indices and other important parameters for the primary substations, in this paper, are obtained from [9]. Block “a2” incorporates the primary station behind the normally-open switch. Blocks “bi1”, “bi2” and “bii2” are the sections of feeder connecting blocks “a” to block “c”. This repeats for a possible third or higher number of a–b branches. This analysis is performed individually substation by substation and the delivery point, in Fig. 2, is located at the 0.4-kV side of the secondary substation.

In this tested network, there are either one or two back-up connections and in the tested feeder there are two back-up connections: one between substation s8 and another on the right of substation s4. Moreover, the ways that blocks “b” are connected from blocks “a” to block “c” vary significantly in comparison to when this same method is applied to meshed subtransmission networks. However, this arrangement does not specifically influence the availability at the secondary substations. Each of the blocks represent an association of adjacent devices and equipment with similar function and are treated as single devices. They are associated in parallel and series and by employing the minimal cuts technique. The partial reliability indices can be obtained at layers i and ii, and the system reliability is therefore estimated by the values simulated to layer iii, which corresponds to the delivery point of this network.

Similarly, when this method is applied to distribution networks, there are two types of substations: abc-substations that do not present directly connected generation units and abcd-substations that embody local

generation. At the moment, it is not usual to connect generation directly to MV-networks in urban regions, such as the municipality of Helsinki; nevertheless, this is possible and in some cases it is a viable solution, as for instance, the installation of small CHP units in [7].

Outage Cost Function

This study estimates only the component of the total network cost function attributed to outages. It is:

$$C_{out} = k_l \sum_{c=1}^{4} \sum_{i=1}^{N} \sum_{s=1}^{S} \left[\lambda \cdot P_{ns} \cdot \left(c_p + c_e \cdot r \right) \right]_{c,i,s} \qquad (1)$$

C_{out}	Outage cost for the 40-year period [€]
k_l	Discount factor linearly related to load growth
λ	Equivalent failure rate [occ./subst.a]
P_{ns}	Power not supplied [kW]
c_e	Customer interruption cost energy [€/kWh]
c_p	Customer interruption cost for power [€/kW]
r	Equivalent average repair time [h/occ.]

And the subindices "*c*", "*i*" and "*s*" stand for, respectively, customer category, number of substation and number of hour (regarding the features of each season). Equation (1) is identical to the one introduced in [9]; whereas, the same in this study is calculated at each hour of the year for the eight selected substations.

SIMULATION

Eight 10-kV substations, listed from s1 to s8, in the simulated feeder were sampled to evaluate situations of substations close to the 110-kV substation (s1 and s2), directly connected to three sections of feeder (s4) and far from the 110-kV substations (s8) and their intermediate locations (other substations). The distance between the feeding primary substation and s8 is 2.55 km. In addition to the distance of 1.13 km between s4 and the n.o. switch, the distance from this switch to the closest 110-kV substation afar is 2.40 km. The secondary substations consist of 10-kV single busbars connected in series with a 10/0.4-kV transformer that is connected in series with a 0.4-kV circuit breaker. The 10-kV feeder is connected to the 110-kV substation via a 10-kV circuit breaker.

TABLE I. Failure rate and repair time by equipment

Equipment	λ [occ./a]	r [h/occ.]
10-kV transformer	0.003139	25
10-kV cable [*per* km]	0.035573	20
10-kV busbar	0.003139	25
10-kV circuit breaker	0.003139	10

Table I shows the failure rate λ and repair time r for the considered equipment. The failure rate must be multiplied by both coefficients α (season and weather condition) and β (period of the day) from Tables II and III. These coefficients were obtained based on the fault statistic databases provided by the local utility, considering that UGC are immune to weather. The weather-related faults were exclusively distributed into the adverse scenarios (in which concentrate all storms, winds, icing and weather-related phenomena) and the technical and operational constraints were evenly distributed through the base year.

TABLE II. Coefficient α – season of the year (values in p.u.)

Equip.	sum (norm)	sum (adv)	fall	win (norm)	win (adv)	spring
Transformer	0.724	9.868	0.724	0.724	9.868	0.724
UG cable	1.888		0.832	0.780		0.500
Others	0.724	9.868	0.724	0.724	9.868	0.724

TABLE III. Coefficient β – time of the day (values in p.u.)

Equip.	day (7-18 hs)	night (19-6 hs)
Transformer	0.9090	1.0909
UG cable	1.3333	0.6667
Others	1.0000	1.0000

In order to investigate possible improvements in the reliability analysis, this study considers three cases, divided as "a", "b" and "c". They are:

- Case a: the base case (the feeder depicted in Fig. 1) used as the comparison point, the n.o. switches and the other switches are manual switches (t_{switch} = 45 min), this case also acknowledges failure rate differentiation between night and day as well as between adverse and normal weathers and it does not have distributed generation;
- Case b: the same conditions as in "a", but the n.o. switches and the other switches in the tested feeder are replaced by remote switches (t_{switch} = 10 min);
- Case c: the same conditions as case "a", but all failure rates and loads are averaged over the year, *i.e.*, there is no differentiation between either seasonal and weather scenarios or between daytime (α = β = 1.0).

Fig. 3 exhibits the average load for the eight 10-kV substations by season. Table IV divides the base year into six scenarios, and shows the number of days and average demand for the eight substations in the season.

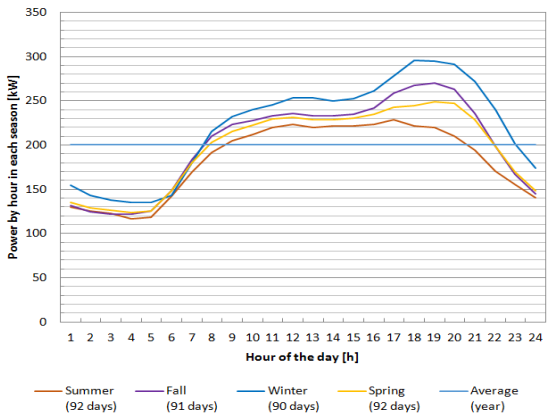

Fig. 3. Average load profile for the eight considered substations by season in the span of a day.

The considered load growth and interest rate for the area are 1 % and 6 %, respectively. The customer interruption costs (CIC) used range from 10.44 to 56.03 euros/kWh for energy and from 0.90 to 5.00 euros/kW for power. These values were provided by the local utility company.

TABLE IV. The six scenarios in the reliability analysis

Scenarios	sum (nor.)	sum (adv.)	fall	win (nor.)	win (adv.)	spring
No. days	87	5	91	94	6	92
P_{dem} [kW]	1 468		1612	1760		1573

RESULTS & DISCUSSION

The results from the reliability analysis are distributed into Tables V, VI and VII and Fig. 4 and 5. Table V shows SAIDI and SAIFI expressed in minutes per substation-season and interruption per substation season respectively. Table VI depicts the energy not supplied (ENS) and the outage costs (C_{out}) in kWh per season and euros per season for the eight substations. In both tables, the row "base year" is the sum of the results in the six scenarios and the row "lifespan" compiles the results projected to the 40-year lifespan, at the given annual interest rate and load growth. Table VII expresses the annual unavailability, in min/year, in the base year.

TABLE V. SAIDI and SAIFI by scenario for the tested cases

	SAIDI			SAIFI		
	"a"	*"b"*	*"c"*	*"a"*	*"b"*	*"c"*
sum (nor.)	5.11	2.53	4.46	0.0753	0.0753	0.0465
sum (adv)	1.61	1.45	0.26	0.0060	0.0060	0.0027
fall	3.68	2.28	4.67	0.0419	0.0419	0.0486
win (nor.)	3.32	2.08	4.31	0.0370	0.0370	0.0448
win (adv)	1.82	1.71	0.31	0.0046	0.0046	0.0033
spring	3.19	2.18	4.72	0.0306	0.0306	0.0491
base year	18.74	12.23	18.72	0.1953	0.1953	0.1950

TABLE VI. C_{out} and ENS by scenario for the tested cases

	C_{out} [base year]			ENS		
	"a"	*"b"*	*"c"*	*"a"*	*"b"*	*"c"*
sum (nor.)	5 044	2 651	4 131	129.62	63.27	109.14
sum (adv)	1 464	1 313	240	39.96	35.76	6.34
fall	3 729	2 360	4 561	101.45	61.99	125.34
win (nor.)	3 640	2 337	4 579	99.58	61.85	126.32
win (adv)	1 877	1 764	332	53.85	50.58	9.14
spring	3 130	2 171	4 545	85.25	57.83	123.70
base year	18 884	12 595	18 388	509.72	331.28	499.98
Lifespan (40 years)	326 236	217 594	317 669	8 806	5 723	8 638

Table VII. Annual unavailability at each substations by case

	s1	s2	s3	s4	s5	s6	s7	s8
"a"	18.73	18.73	18.73	18.73	18.73	18.75	18.75	18.76
"b"	12.22	12.22	12.22	12.22	12.23	12.24	12.25	12.26
"c"	18.72	18.72	18.72	18.72	18.72	18.73	18.73	18.74

Fig. 4 and 5 exhibits the influence of the changes performed in each case in the outage cost. The outage cost reflects indirectly the ENS, to some extent, the SAIDI. The scenarios were grouped as adverse (winter adverse and summer adverse), summing 11 days of the base year, and as normal (the other four scenarios), summing 354 days.

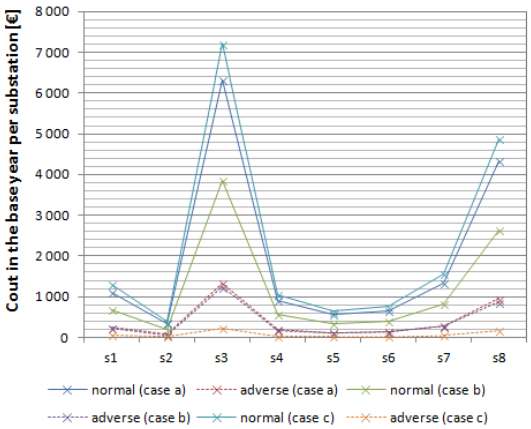

Fig. 4. Outage costs in the base year by substation for the tested cases.

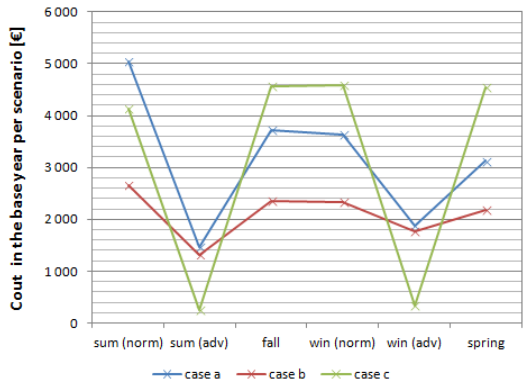

Fig. 5. Outage costs in the base year for the three cases (sum of the eight substations) in the six scenarios.

In Tables V and VI, comparing case "a" with the base case "c", the total SAIDI, ENS and C_{out} in the base year are approximately the same. Possibly, if the considered failure rates had been chosen differently, these total values would have diverted more than in the tables. The differentiation of weather conditions is, notwithstanding, important, particularly in the case of equipment susceptible to meteorological phenomena, such as overhead lines and air-insulated switchgear. On the other hand, for case "c", these values averaged by day are equally distributed, while for the other cases, the adverse scenarios, summing only eleven days, consist of a considerable percentage of these three parameters. The ENS and C_{out} values for cases "a" and "b" are higher during summer scenarios due to the effect of higher cable failure rates. This does not coincide with the yearly load peaks that in Nordic countries that occur during the coldest days of winter, when a significant percentage of the load is related to indoor heating. When changing the switches in the feeder from manual to remote switch, case "b" exhibits significantly smaller results and therefore longer availability. This occurs in the situations in which switching the power supply from the main feed to the back-up connection, in case of failure, instead of t_{switch} = 45 min, it decreases to 10 min. The switching time constants are an average estimation from the local utility company.

The connection of CHP to the MV network was investigated, but immediately revealed a conundrum for the type of network we are considering (a fully looped radially operated underground cable network). For the CHP to be of benefit, the faulted section(s) of line would have to be quickly isolated. If such fast switching would be implemented in such a network, the normally open points of the network would also be closable in the same time frame, which would mean that the benefit of CHP on reliability would be negligible. The conversion of the LV networks behind secondary substations to microgrids tends to remove the need for backup connections in MV networks, but this has been investigated in [4].

From Fig. 2, block "c", in this case, the 10-kV substation introduces the highest influence on the availability to the delivery point, since it is the only parallel path between the source and load in layers ii and iii. The equipment in the MV substations incorporates low repair times, thus average outage time, in comparison to EHV and HV substations, where transformer repair times can last over a week. For this reason, the effect of block "c" is low enough so that block "b" (feeder connections) can play a stronger role in the system reliability indices. In addition, blocks "a" and "b", represented by their sub-blocks (a1, a2, bi2, bi2 and bii2), support higher availability because in case of an N-1 contingency, these blocks provide alternative paths, after switching time, for power flowing from the source to the delivery point.

Table VII shows the unavailability by substation for the three cases. Because it is a backed-up feeder, the availability (similarly unavailability) is nearly the same for all substations. However, this assessment tool includes second, third and fourth-order failures in addition to the single failures leading to a small difference between these results related to the position in relation to the main primary substation.

CONCLUSION

The feeder chosen for this reliability assessment from the 10-kV network generated by the employed NTOA depicts a realistic situation of a typical urban area in Finland. The investigation of improvement in reliability and outage costs was clearly represented by the three tested cases divided into six scenarios. Introducing network automation positively influenced the reliability indices and outage costs.

Reducing the switching time decreased the outage costs and decreased the unavailability experienced by the sampled 10-kV substations. Moreover, the inclusion of CHP directly connected to the MV network did not provide plausible benefits from the perspective of reliability. Under the improbable circumstances of both the main supply and the back-up connections or the main primary substation being out of service, the islanded-mode operation of the 10-kV feeder requires deeper analysis.

The present research showed that it is important to model equipment with different behaviour both in the timespan of a year and a day. This can be helpful in mobilizing operational teams to promptly operate during certain periods, particularly in urban areas where traffic jam and important customers, such as hospitals, might influence the repair time and therefore the outage costs.

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