FAILURE RISK ASSOCIATED WITH DIFFERENT SUBSTATION AND HV NETWORK CONFIGURATIONS

Ricardo PRATA
EDP – Distribuição – Portugal
ricardo.prata@edp.pt

Pedro MS CARVALHO
Instituto Superior Técnico – Portugal
pcarvalho@ist.utl.pt

Luís AFM FERREIRA
Instituto Superior Técnico – Portugal
lmf@ist.utl.pt

CarlosALBERTO SANTOS
EDP – Distribuição – Portugal
carlosalberto.santos@edp.pt

ABSTRACT

To evaluate and validate network planning criteria for HV networks and HV/MV substations, EDPD has developed a risk analysis methodology to calculate power supply failure risk associated with different network and substation typologies. In this paper we present results obtained with the methodology developed for substation topology risks and network topology risks. Maximum equivalent interruption times are shown for different reserve capacities, load/capacity ratios, and line lengths. Our results help assess EDPD's planning criteria and validate its risk matrix based policy.

INTRODUCTION

EDP – Distribuição de Energia, S.A. (EDPD) is the distribution network operator in Continental Portugal. It operates an HV network (mainly 60 kV) of 8,913km long with 352 HV/MV substations (as of 31.12.2009).

In order to evaluate and validate network planning criteria for HV networks and HV/MV substations, EDPD has developed a risk analysis methodology in collaboration with Instituto Superior Técnico, Technical University of Lisbon.

Quality of Service Regulation, enacted by the Portuguese energy sector regulator, classifies the territory in three zones with different quality of service requirements (zones A, B and C). Zone A refers to main cities and has the strictest requirements; zone C refers to rural areas and small towns and has the less strict requirements.

EDPD planning criteria establish that HV/MV substations must guarantee a readly supply of all zone A loads after a HV line or HV/MV transformer fault (N−1 criteria) through alternative HV lines, alternative HV/MV transformers of the same substation, or MV lines connected to neighborhood substations. Concerning zone B and C, the guarantee of supply can rely upon mobile HV/MV substations, which must be deployed within 24h following severe faults.

Furthermore, EDPD has been developing risk policies supported by a risk matrix assessment framework. Thus, reliability risk assessment performed for different substation topologies and HV network configurations constitute an important instrument to quantify risks for assessment with the risk matrix framework.

The risk analysis methodology described hereafter allows EDPD to assess failure risk associated with the HV current planning criteria and to use the risk matrix framework to classify any given HV installation. This methodology complements reliability assessment with a quantitative approach that brings in failure consequences.

SUBSTATION TOPOLOGY RISKS

EDPD operates 352 HV/MV substations of different topologies. In order to assess the failure risk associated with those topologies, a failure mode analysis was performed to identify the components that were more likely to cause an interruption. That analysis was supported on company's experience related with HV/MV substation failures and related causes.

The failure mode analysis has shown that, for HV/MV substations, the power transformer is the most critical component, given the frequency and severity of its faults. The lower failure probability and failure consequences of other substation components (switchgear, busbars, SCADA devices, etc.), allows to simplify the topologies analysis, focusing mainly on the consequences of power transformer failures [1].

The two most frequent topologies in use were analyzed concerning failure risk. These topologies can be described as follows:

- T1. HM/MV substation equipped with a single power transformer directly supplied by a dedicated HV line and connected to a single MV busbar;
- T2. HV/MV substation equipped with two power transformers directly supplied by two HV lines and connected to two independent MV busbars that can be connected through a switch.

Risk analysis took into account several operational aspects, such as different load levels for the substation, different HV line capacities, different backup MV network capacity, and the availability (or unavailability) of a mobile HV/MV substation. The results allowed one to establish planning criteria concerning the operational conditions to use topology T1 and T2. Topology T1 generally involves a smaller initial investment than T2 but has higher associated failure risk

Risk analysis results concerning different operational conditions were presented as an Equivalent Interruption Time (EIT) [2]. Expected EIT and maximum EIT (with 95% guarantee) were computed simulating individual component failure rates and repair times with Poisson processes [3] and evaluating system limiting value unavailability with Markov processes [4-5].
Failure rates and mean times to repair (or to enable) are shown in Table I for the most important backup resources (it is assumed that MV reserve, typically supported by several different neighborhood feeders, is always available).

TABLE I – FAILURE RATES AND ENABLING TIMES CONSIDERED

	Power Transformer	MV network	Mobile Substation
Failure Rate (year $^{-1}$)	0.05	--	0.05
Time to repair or to enable (h)	168	1	24

The periods indicated in Table I are related to (1) the mean time to repair a power transformer; (2) expected time necessary to enable the MV network reserve; and (3) the expected time necessary to deploy a mobile substation, after a transformer fault.

Single transformer HV/MV Substations

For single transformer HV/MV substations, the consequences of a power transformer failure must be mitigated enabling the MV reserve and, in some cases, deploying a mobile substation. Therefore, EIT was computed as a function of the MV reserve capacity for different mobile substation capacities (capacities are refered to the installed substation capacity). Fig. 1 presents results for the expected EIT and maximum EIT with a 95% guarantee (collored area). Mobile substation capacity is shown in a parameterized form for 50% and full capacity.

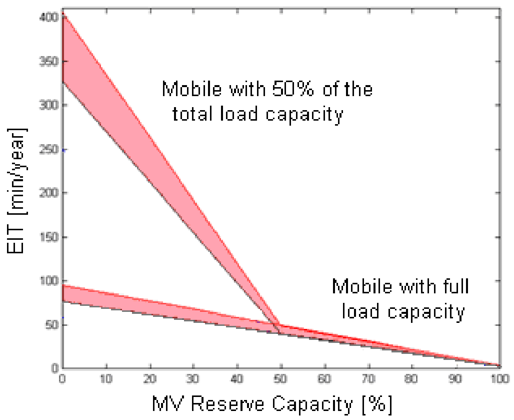

FIGURE 1 – EXPECTED AND MAXIMUM EIT FOR SINGLE TRANSFORMER SUBSTATIONS

Depending on the MV reserve capacity, and assuming that the mobile substation guarantees full load capacity (as expected in most cases), expected EIT may range from 5 min to 75 min.
If one considers that the HV/MV substation is connected to a HV line with a failure rate of 0.03 year^{-1} and a mean time to repair (MTTR) of 130 min, then IET becomes also a function of the HV line length, as shown in Fig. 2. Line lengths are shown in a parameterized form.

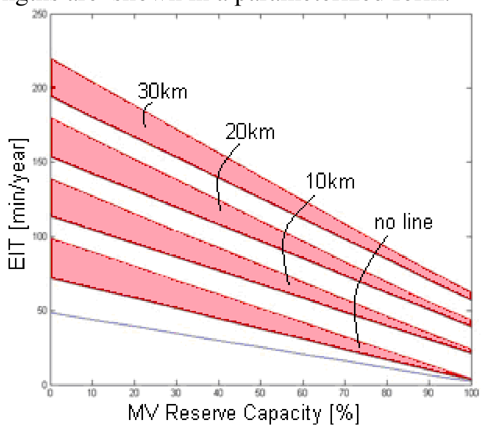

FIGURE 2 – EXPECTED AND MAXIMUM EIT FOR A SINGLE TRANSFORMER SUBSTATION CONNECTED THROUGH A SINGLE HV LINE

Double transformer HV/MV Substations

Double transformer HV/MV substations are usually equipped with two MV busbars that can be connected by a switch. EIT depends on the capacity of each transformer when compared to the total load supplied by the substation. Therefore, EIT was computed as a function of the load/capacity ratio, where "capacity" refers to a single power transformer. As before, EIT also depends on MV reserve capacity. Fig. 3 presents results for the expected and maximum EIT with a 95% guarantee for different MV reserve capacities.

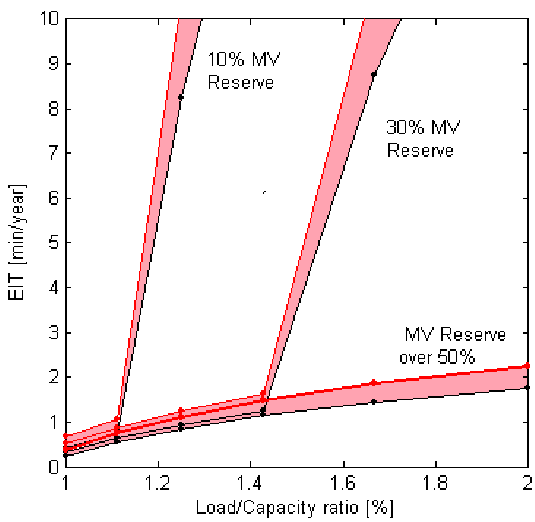

FIGURE 3 – EXPECTED AND MAXIMUM EIT FOR DOUBLE TRANSFORMER SUBSTATIONS

For a substation loaded at 62.5% of the installed capacity

(Load/Capacity ratio of 1.25), EIT may range from less than one minute to about 10 minutes, depending on the MV reserve capacity – admitting that MT reserve is never inferior to 10% of the substation capacity.

The methodology developed to assess risk failure associated with substation topologies, when applied to the HV/MV substations operated by EDPD, allows one to conclude that the annual expected EIT associated with substation failures is less than 10 min.

HV NETWORK TOPOLOGY RISKS

Two different HV network topologies, embodying different strategies concerning HV/MV connection, were analyzed. Topologies can be described as follows:

T1. HV/MV substation equipped with two transformers, each transformer connected by a dedicated HV line with a rated capacity similar to the capacity of the corresponding transformer;

T2. HV/MV substation with two transformers connected to a HV busbar that is fed through two HV lines.

Three different outage situations were considered:

a) The MV network reserve guarantees the supply of 50% or more of the load and the mobile substation guarantees the rest;
b) The MV network reserve guarantees less that 50% of the load and the mobile substation guarantees the supply of 50% ;
c) Transformer and line capacities are high enough for neither being necessary to deploy a mobile substation nor being necessary to use MV reserve

Throughout the analysis we considered a HV line failure rate of 0.05 $year^{-1}$ and a MTTR of 3 hours. All the remaining parameters did not change. EIT is calculated for different loading situations. Results are presented for different load/capacity ratios, where load is defined as the substation peak load and capacity is defined as the transformer individual rated capacity.

Situation a)

If the MV reserve is higher than 50% of the substation peak load, the simulation results show that:

- If the HV line rated-capacity equals the transformer rated capacity, then both topologies show similar results concerning risk failure (dashed lines in Fig. 4);
- For topology T2, substation availability shows higher sensitivity to line capacity than to transformer capacity;
- Topology T2 shows better results than topology T1 if the line rated-capacity is higher than the transformers capacity.

Fig. 4 shows EIT results for topologies T1 and T2, for three different line capacities and a line length of 10km. Black lines indicate EIT expected values and red lines maximum values with 95 % guarantee. The intercection points between dashed and solid lines identify the load levels for which risk is identical between topologies We assume that, for T1, the line capacity is at least as high as the transformer capacity, whilst for T2 we set different values for the line capacity as parameterized in the figure.

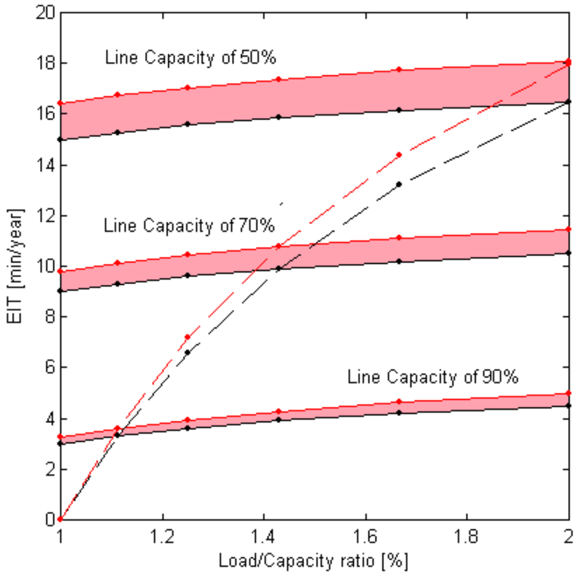

FIGURE 4 – EIT FOR TOPOLOGY T2 AND DIFFERENT 10 KM LINE CAPACITIES (SOLID LINES) AND TOPOLOGY T1 (DASHED LINES)

Situation b)

If the MV reserve is lower than 50%, when a fault occurs in a transformer, part of the load would have to be supplied by a mobile substation. The deployment of a mobile substation is also necessary if a fault occurs in a HV line as the other line and the reserve capacity together are insufficient to supply the total load.

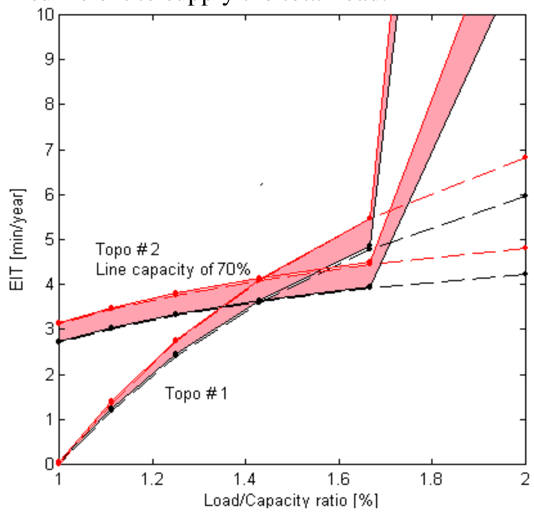

FIGURE 5 – EIT FOR BOTH TOPOLOGIES WITH 3 KM LINES 40 % MT RESERVE AND MOBILE SUBSTATION DEPLOYMENT

Under these circumstances, simulation results indicate that, if transformers capacity is lower than lines capacity, then T2 shows better results than T1. Fig. 5 compares EIT results between topologies, considering HV lines capacity of 70% and MV reserve of 40%. Dashed lines show EIT evolution should MV reserve increase to 50%. Notice that T2 is better that T1 for transformer capacities lower than 70% (i.e., ratios higher that 1/0.7≈1.43) and that risk increases a lot for capacities lower than 60% (i.e., ratios higher that 1.67) as with a MV reserve of 40% the mobile substations becomes necessary.

Situation c)

If transformer and line capacities are high enough, a single fault will not require enabling MV reserve capacity or deploying a mobile substation. The differences related to the topologies's results, under these assumptions, are due to the possible simultaneous fault of a line and a transformer. Simulation indicated that:

- Both topologies have very low EIT, even though topology T2 always performs better. For example, for HV lines of 10km long, expected EIT is of 0.50 min for T2 and of 0.67min for T1;
- EIT increases with line length for both topologies, but increases with a higher rate for topology T1. For 50km, EIT for topology T1 roughly doubles T2 (0.86 vs 1.73 min), see Fig. 6.

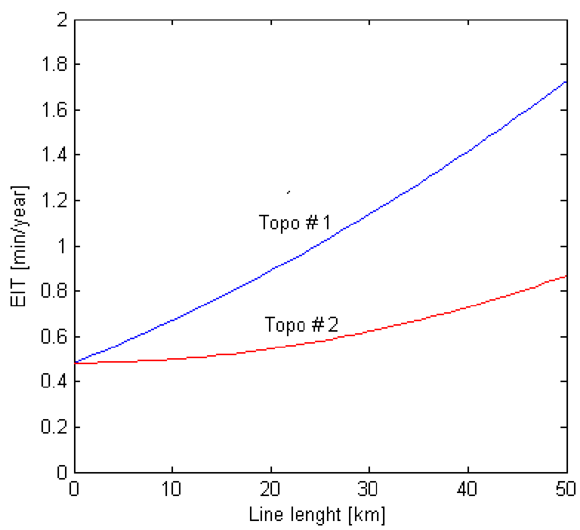

FIGURE 6 – EIT VS. LINE LENGTH WITH NO MV RESERVE AND NO MOBILE SUBSTATION

FINAL CONSIDERATIONS

Previous results can be used to support the evaluation of the criticality (including impact severity) of different substations and networks topologies. Such evaluation can be mapped into a risk matrix, as shown in Table 2.

Impact severity is measured considering hazards effects on people security, environment, public opinion repercussion, quality of service and economical results. Risk is assessed calculating probability and effects associated with any given event, and mapping it on the resulting quadrant of the matrix. These quadrants are aggregated in three levels – high (H), moderate (M) and low (L), as indicated through the characters depicted in each quadrant.

TABLE 2 – EDPD'S RISK MATRIX

EDP Distribuição - Corporative Risk Management					
Impact Severity	Frequency				
	Average Period between Events (years)				
	Very High (f ≤ 0,5)	High (1 ≥ f > 0,5)	Medium (2 ≥ P > 1)	Low (5 ≥ f > 2)	Vey Low (5 ≥ f)
	5	4	3	2	1
5 very critical	H1	H2	H4	M5	M1
4 critical	H3	H5	M6	M2	L10
3 high effect	H6	M7	M3	L9	L6
2 medium effect	M8	M4	L8	L5	L3
1 low effect	L11	L7	L4	L2	L1

HV lines and HV/MV substations faults may have effects that can be measured with two criteria – quality of service and public opinion repercussion. Failure risk results presented in this paper allow calculating expected frequency and quality of service impact associated with a fault. Furthermore, given the expected and maximum power failure duration associated with a fault it is also possible to estimate public opinion repercussion. Impact severity is defined as the maximum severity associated with all specifyed hazard effects.

These methodologies are flexible enough to allow EDPD to assess failure risk associated with specific installations or with generic topologies used in HV lines or HM/MV substations. This allows verifying that EDPD's planning criteria and company's risk policy are coherent.

REFERENCES

[1] R Billinton and R N Allan, *Reliability Evaluation of Engineering Systems: Concepts and Techniques*, Plenum Press, 2nd Edition, 1992.*Reliability*

[2] *IEEE Trial-Use Guide for Electric Power Distribution Reliability Indexes*, IEEE Std. 1366-1998, 1998.

[3] A Leon-Garcia, *Probability and Random Processes for Electrical Engineering*, Addison Wesley, 1993.

[4] *Assessment of Composite Generation and Transmission Systems*, IEEE Tutorial Course, course text 90EH0311-1-PWR

[5] R. E. Brown et al., "Distribution System Reliability Assessment Using Hierarchical Markov Modeling," *IEEE Trans. Power Delivery*, Vol. 11, No. 4, 1996, pp. 1929-1934.