A METHODOLOGY FOR RANKING LOCATIONS ACCORDING TO THE LIKELIHOOD AND CONSEQUENCE OF EXTREME EVENTS

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ABSTRACT

The present paper describes a methodology for evaluating major system risk on distribution networks, developed for and used by a distribution network operator (DNO) located in the North of England. Its purpose is to assess and rank each primary load point across the network as regards both the probability of extreme events occurring, and their consequence, expressed as a single major system risk index (MSR).

This methodology was applied to around 150 separate load points, and the 40 with the highest MSR were further investigated to identify a range of possible mitigation strategies in each case. The paper concludes by evaluating the benefits of such a methodology to support long term network planning across a whole DNO, and by suggesting ways in which its applicability could be extended.

INTRODUCTION

Faults in electrical distribution circuits are not uncommon, but in most cases their impact is not great. At lower voltages (in the UK, 20 kV and below), some customers may be disconnected, but generally the number will be small (typically 1000 or fewer), and the duration of the disconnection a few hours at most. At higher voltages (33 kV or above in the UK), there will usually be some redundancy, so the loss of a single circuit will not cause customer disconnection.

The loss of two or more circuits at higher voltages will have more serious consequences. Several thousand customers may lose supply, and depending on the cause of the underlying faults, it may take many hours to restore supply to some or all of them. Fortunately, events of this magnitude are comparatively infrequent.

The most extreme events are those that occur at the highest voltages, typically on transmission networks, where possibly millions of customers may be disconnected, perhaps as a consequence of cascading circuit failures in a strongly interconnected network. These events are extremely rare, and are sometimes categorised as high impact low probability (HILP) events.

Perhaps because of their high profile, such HILP events have been well-researched. The normal methodology for evaluating multiple failures is Markov Analysis [1], but in the case of cascading failures the individual faults are no longer truly independent [2], and so more bespoke methods such as analytical simulation must be employed [3]. A study based on the Portuguese transmission network looks at multiple failures that can arise, not just from cascading, but from widespread events such as severe weather or forest fires [4]. A summary paper looking at common mode failure (CMF) also looks primarily at transmission networks [5].

Double Failures

The present paper looks rather at the sub-transmission level, from the grid supply points on the boundary of transmission and distribution networks (typically 275/132 kV) down through bulk supply points (132/33 kV) to primary substations (33/11 kV). It is concerned in particular with major system risk (MSR), which can be defined as an event involving the outage of two or more circuits, in which a substantial number of customers are disconnected for several hours.

Co-incident outages of two or more circuits can occur in a number of ways. In [6], genuine CMF events such as the collapse of a tower carrying two circuits are distinguished from 'simultaneous S-dependent' events where one outage leads directly to another, as in cascading, and also from 'simultaneous S-independent' events where a second circuit fails coincidentally during the outage of a first circuit, whether that first outage is planned (for example as part of annual maintenance) or unplanned (for example, a repair that has taken a long time to complete). In the present paper, as in previous papers on network risk by the present authors [7, 8], all these forms of co-incident outages are combined as 'double failures' (DF). A significant result is that historically up to 20% of circuit failure events at these high voltages were double failures, resulting in customer disconnection [9]. Thus the likelihood of such events is higher than would be expected as a result of analysis which assumes independence.

In the UK, the national network design standard P2/6 [10] distinguishes sharply between single (n-1) outages and multiple (n-2) outages. At the voltage levels under consideration, with demand groups between 12 MW and 100 MW, (n-1) constitutes a secured event, as a result of which customer supply should be restored within a specified short time to the majority of customers. However, (n-2) is regarded as an unsecured event, with no restoration time specified. The incentive for the distribution network operator (DNO) to restore supply following a (n-2) event comes rather from their statutory duty to operate the network effectively, from possible financial penalties based on the number of customer interruptions (CI) and customer minutes lost (CML), and from concern for reputation. It is with such (n-2) events that the present paper is concerned.

The likelihood of an (n-2) event depends on a number of factors, in particular asset condition, but also climate and asset utilisation [11, 12]. The consequence of the event depends on several factors, and may also depend on the nature of the customers and their own outage costs [13]. Multiplying the event probability by its severity gives a measure of risk [4, 7]. It is then possible to assess reliability by ranking different assets, or groups of assets, according to this measure of risk [14, 15]. Such ranking can be used not only for reliability but for other areas of concern, including personal safety and network security [15].

Following an effective ranking exercise, the highest ranked assets or groups of assets can be investigated in greater detail, with a view to identifying possible risk mitigation strategies. That is the approach adopted in the present paper.

MAJOR SYSTEM RISK

The analysis in the present paper was initially applied to the extra high voltage (EHV) networks of Northern Powergrid, a DNO with 3.8 million customers in the North of England. Their objective was to assess the level of major system risk (MSR) at the most critical load points, to rank that risk, and to explore ways of mitigating it. The first stage was to define precisely what constituted MSR.

MSR Definition

Earlier work carried out by and for Northern Powergrid defined MSR as “risks due to loss of functionality of the distribution system that threaten the continuity of the business” [16]. The specific event whose probability and consequence are calculated for the MSR index in the present paper, as described below, was the (n-2) loss of high voltage infeed to a substation, where that loss could not be restored for at least 18 hours. The period of 18 hours was chosen as the threshold after which compensation payments must be made to customers, although this is due to reduce to 12 hours, which could modify the definition in future, which would increase the likelihood of MSR events. This definition excludes a range of more serious, if less likely, HILP events, including:

- Common mode events including severe weather, malicious attack, or communications failure which ou. affects more than one substation at a time.
- Cascading of failures, where the loss of one substation leads to abnormal loads which might then cause protection to disconnect other substations.
- Loss of infeed at a time when neighbouring substations are unavailable for reconnecting customers, due to maintenance, repair or construction projects.
- The failure of all infeed to a single substation with 3 or more infeed circuits.
- The total loss of the lower voltage outfeed from a substation. This can be more serious than loss of infeed, as the low voltage busbars are then not available for possible customer feeder transfer.

Probability of (n-2) Failure

The annual probability λ^* of a co-incidental MSR event as defined is a function of the underlying annual circuit failure rate λ (including all assets, asset condition where appropriate, and averaging the two circuits), the average repair time T in hours, and the probability p that neither fault can be restored within 18 hours from the second circuit failure, as shown in (1):

$$\lambda^* = \frac{\lambda^2 Tp}{8766} \qquad (1)$$

The value of p is itself a function of T, and the relationship between them was established by Monte Carlo simulation, as shown in Figure 1. While equation (1) underestimates λ^* by effectively assuming independence of circuit failures, it overestimates λ^* by using mean repair time T, when in practice repairs can often be completed more quickly than average following a MSR event. It has been assumed that these two effects will tend to cancel each other out, and that any residual error will be systematic and therefore will not affect rankings unduly.

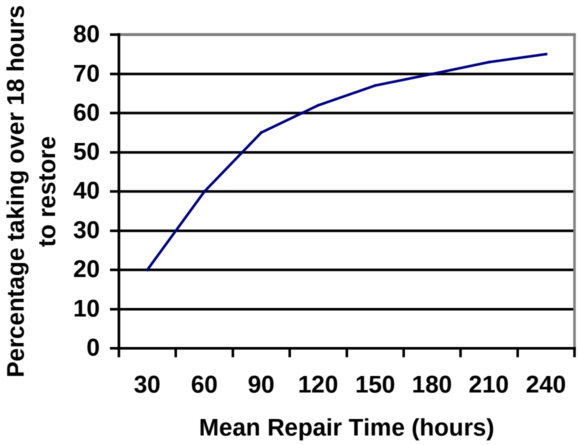

Figure 1 – Percentage of double faults lasting over 18 hours

Consequences of (n-2) failure

The consequences of a MSR event could include some or all of safety, environment, loss of reputation, regulatory infringement, direct repair costs, indirect loss of asset life, and regulator financial penalties [9]. In the present paper, the financial penalty imposed as a consequence of customer minutes lost (CML) is used as the sole measure of consequence. This cost can be expressed as a product of 5 distinct factors, as in (2):

$$CML = (\lambda^*)(NC)(TR)(f)(UCML) \qquad (2)$$

Where λ* is the double failure probability defined in (1), NC is the number of customers disconnected, TR is the average customer restoration time, UCML is the unit regulatory penalty per customer minute lost, and f is a factor to allow for adjustment due to exacerbating consequences such as safety, environmental or reputation.

TR can be estimated with the help of historical data [10]. It will be a weighted average for those customers who can be restored automatically (typically in under 3 minutes), those restored by tele-control (15 minutes), those restored by manual switching (1-2 hours), and those who have to wait until one of the two EHV faults can be restored or repaired, assumed to be over 18 hours for a MSR event. The CML for this last group of customers dwarfs that for the other 3 groups, so TR is calculated as in (3):

$$TR = (MT)(PNR) \tag{3}$$

Where PNR is the proportion of customers who cannot be restored by reconfiguration (an average is taken of peak and non-peak times of day), and MT is the mean time from second circuit outage to the restoration of one or other of the two EHV outages. MT is itself a function of the mean repair time T, estimated by Monte Carlo simulation. For values of T over 40 hours, which accounts for all substations under consideration, the product of p and MT was found to be close to a constant value of 0.48 multiplied by T. Substituting this expression, and UCML at £10 per hour, into a combination of (1), (2) and (3) gives:

$$CML = (k)(\lambda^2)(NC)(PNR)(T^2)(f) \tag{4}$$

where k is a constant, evaluated at 0.000548. Equation (4) can be used directly to calculate the expected annual CML penalty due to MSR at any location. As an example, at one substation, λ was assessed at 0.333 (each supply circuit failing once in 3 years), NC was 30 000, PNR was 0.49, T was 144 hours, and f was l.0. The likelihood of the particular class of event under consideration, namely a coincidental two circuit failure which cannot be restored in under 18 hours, is shown by (1) to be extremely low, around once in 800 years. However, the CML cost per event is high, at around £15 M. The product of the two is an expected cost of £18.6k per year. This low figure arises from the extremely low probability of the particular HILP event as defined.

CONSTRUCTING A RANKING

Equation (4) enables the expected financial value of CML to be calculated as the product of 5 variables and a constant. However, for ease of use by engineers within the DNO, (4) was transformed by taking logarithms, and then scaling appropriately. This gives two practical advantages. The first is that excessively large or small numbers can be changed to more manageable values (integers between 0 and 30). The second is that components of risk can be added instead of being multiplied, which is easier to understand and to manipulate. Equation (4) then transforms to (5):

$$\begin{aligned} MSR &= (10)(\log CML) + 17.6 = (20.\log \lambda + 28) \\ &+ (10.\log NC - 29) + (10.\log PNR + 20) \\ &+ (20.\log T - 34) + (10 \log f) \end{aligned} \tag{5}$$

In (5), MSR is the major system risk index, which will be used to rank load points on a single scale, calculated by summing 5 distinct elements. Applying this to the example substation, the first 4 components are 18 (for λ=0.333), 16 (for NC=30000), 17 (for PNR=0.49) and 9 (for T=144hrs). The fifth component is 0, for f=1.0. In practice, this component was used to allow the expert judgment of network control engineers to add or subtract 5 (corresponding to a multiplicative factor of 3 or one third) to the total of the other 4 components.

Application

Within Northern Powergrid, this methodology was applied to Grid Supply Points (primary voltage 400 or 275 kV), Supply Points (132 kV) and Primary Substations (66 or 33 kV). A subset was chosen in each category based on prior assessment of expected risk, and the subset was then ranked. Table 1 shows the calculation and ranking of the 6 supply points in the southern area of Northern Powergrid, with the highest MSR index, including the previous example 'B'.

Name	λ	NC	PNR	T	f	MSR
A	17	19	15	6	+5	62
B	18	16	17	9	0	60
C	20	18	8	9	+5	60
D	19	12	14	9	+5	59
E	20	18	10	11	0	59
F	13	18	15	6	+5	57

Table 1 – Ranking of 6 Supply Points

Once the ranking is complete within each class and region, it can be seen not only which are the substations with the highest MSR, but also what contributes to that high value. So, while 'C' and 'E' have the highest failure probabilities, 'A' has the largest number of customers and 'B' has the highest proportion of customers who cannot be restored by lower voltage reconfiguration. 'E' has the longest repair time (typically as a result of a high ratio of underground cable to overhead line), while 4 of the 6 have had their MSR index boosted by the expert judgment of a panel of 6 Network Control Engineers who considered that these locations would experience higher levels of MSR in practice for a variety of operational reasons.

Mitigation Options

While it is beyond the scope of the present paper to give full details of the mitigation options considered, an example can indicate how the ranking was used. In the case of 'B', a higher than average proportion of customers cannot be restored at that supply point's secondary voltage. Further investigation shows that this is because the downstream network is an island at 33 kV surrounded by a network at 66 kV. One possible mitigation could be the installation of a 66/33 kV transformer for use in such an emergency. This could have the effect of reducing PNR at 'B' from 17 to 0, and the total MSR index from 60 to 43. Another possible mitigation could be to develop more interconnection at a lower voltage still (here 11 kV) to circumvent the island. Mitigation could also come as a result of asset renewal, if that were due anyway, which would decrease the contribution of λ to the MSR index, typically by 3 points. It should be noted, however, that it is often difficult to justify significant capital works for (n-2) scenarios.

CONCLUSIONS

A methodology has been developed to define and assess the major system risk (MSR) at any load point on a distribution network. By calculating a single MSR index, load points can be ranked according to risk, and those with the highest ranking can then be investigated in more detail, to identify possible mitigation options.

Further developments of this methodology could include extending it to more likely events, or to events with more serious consequences. These could include loss of outfeed, multiple events that affect more than one substation at once, and cascading failures. Another development could be the identification (perhaps for higher frequency routine maintenance) of those interconnector circuits which would be most relied upon in the event of MSR to reconnect a large proportion of customers more quickly.

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