Appendix D

Appendix D1 – **Short-circuit currents**

In line with the Engineering Recommendation (ER) G74, the transmission licensees (SHE Transmission, SP Transmission and National Grid) have analysed the three-phase-to-earth and single-phase-to-earth short-circuit current in their own transmission area.

The tables in Appendix D (which can be found on the website www.nationalgrid.com/etys) list the results of these analyses. To help you interpret the results, in this section we explain some of the main points relating to our short-circuit calculations, including our assumptions and the terminology we have used.

The listed currents should be regarded as indicative – they provide a general guide only. If you need more detailed information about specific sites, please email transmission.etys@nationalgrid.com.

Although the short-circuit duties at a node may sometimes exceed the rating of the installed switchgear, this does not always overstress the switchgear, for one or more of the following reasons:

- the substation's topology means that the switchgear is not subjected to the full fault current from all of the infeeds connected to that node – this applies to feeder or transformer circuit breakers and mesh circuit breakers under normal operating conditions
- the switchgear is only subjected to excessive fault current when sections of busbar are unselected – this applies to busbar-coupler or section circuit breakers. When this happens the substation can usually be re-switched temporarily or segregated, to reduce the fault level
- the switchgear is being re-certified or modified to remove the overstressing.

Substation running arrangements vary, of course. The running arrangements we have used to determine the short-circuit currents in Appendix D may differ slightly from those presented elsewhere in this document.

Engineering Recommendation G74

International Standard IEC909 –"Short Circuit Current Calculation In Three Phase AC Systems" – was issued in 1988. It was subsequently published as British Standard BS7639.

When IEC909 was issued, there was no standard approach to calculating fault levels within the electricity supply industry. The hand calculation methodology detailed in IEC909 was considered conservative for the UK supply system. It was widely believed that applying it could result in excessive investment, so in 1990 an industry-wide working group set out to define best practice for the calculation of short-circuit currents.

The resulting document, ER G74, defines a computer-based method for calculating short-circuit currents. This is more accurate than the IEC909 methodology, so potential capital investment is more accurately identified. The document has been registered under the Restrictive Trade Practices Act (1976) by the Energy Networks Association (ENA) and the associated Statutory Instrument has been signed to this effect.

Short-circuit current calculation

We use sophisticated computer programs to analyse short-circuit current. Each analysis is based on an initial condition from an AC load flow and is carried out in accordance with ER G74.

Shown below is a summary of our broad calculation methodology.

We make two assumptions that represent the most onerous system conditions:

- when assessing the duties associated with busbars, bus section or bus coupler circuit breakers and elements of mesh infrastructure, we assume that all connected circuits contribute to the fault
- when assessing the duties associated with individual feeder or transformer circuits, we assume that the fault occurs on the circuit side of the circuit-breaker and that the remote ends of the circuit are open.

We calculate short-circuit currents using a full representation of the National Electricity Transmission System (NETS).

Directly connected and large embedded generating units are discretely represented – their electrical parameters are based on data provided by the owner of the generating unit.

Other Network Operators' networks are represented by network equivalents at the interface between the NETS and their own network. For example, a Distribution Network Operator network connected to a 132kV busbar supplied by supergrid transformers (SGTs) will usually be represented by a single network equivalent in the positive phase sequence (PPS) and zero phase sequence (ZPS) networks.

The use of network equivalents allows short-circuit currents in the NETS to be calculated with acceptable accuracy and provides a good indication of the magnitude of the short-circuit currents at interface substations.

However, the short-circuit currents quoted in Appendix D for interface substations are not suitable for specifying short-circuit requirements for new switchgear at the interface substations. These will need to be agreed between the relevant Transmission Licensee and the Network Operator on a site specific basis.

Appendix D2 – **Short-circuit current terminology**

The short-circuit current comprises an AC component with a relatively slow decay rate (see Figure D2.1) and a DC component with a faster decay rate (see Figure D2.2).

These combine into the waveform shown in Figure D2.3, which represents worst-case asymmetry – it's rarely seen in practice.

Figure D2.1
AC component of the short-circuit current

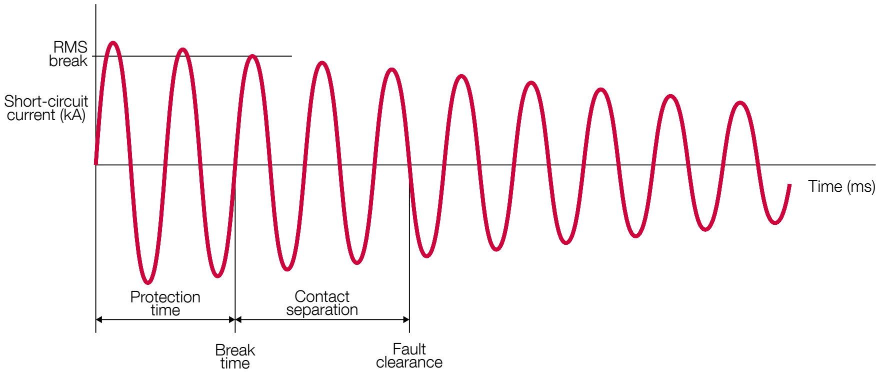
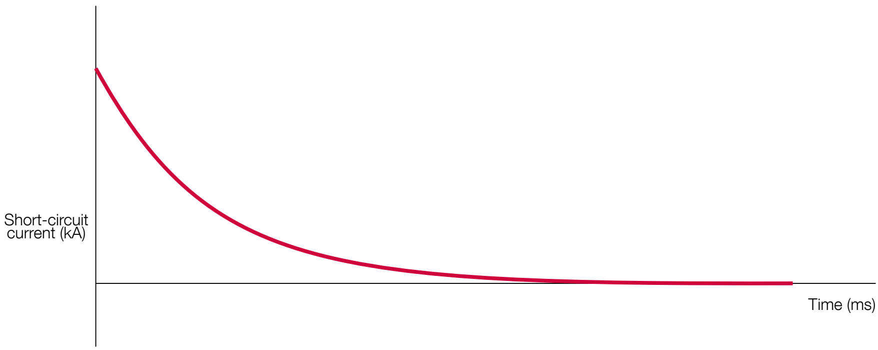


Figure D2.2
DC component of the short-circuit current



X/R ratio

The DC component decays exponentially according to a time constant which is a function of the X/R ratio (the ratio of reactance to resistance in the current paths feeding the fault). High X/R ratios mean that the DC component decays more slowly.

DC component

We use two equivalent system X/R ratios to calculate the DC component of the peak-make and peak-break short-circuit currents. We use an initial X/R ratio to calculate the peak-make current, and a break X/R ratio to calculate the peak-break current. We calculate our initial and break X/R ratios using the equivalent frequency method (IEC 60909-0 (2001-07) Method C). This is because we consider it to be the most appropriate general-purpose method for calculating DC short-circuit currents in the NETS.

We calculate the DC component of short-circuit current on the basis that full asymmetry occurs on the faulted phase for a single-phase-to-earth fault or on one of the phases for a three-phase-to-earth fault.

Making duties

The making duty on a bus section or bus coupler breaker is imposed when they are used to energise an unselected section of busbar that is faulted or earthed for maintenance.

Substation infrastructure (like busbars, supporting structures, flexible connections, conductors, current transformers, wall bushings and disconnectors) must also be able to withstand the making duty.

The making duty on individual circuits is that imposed when they are used to energise a circuit that is faulted or earthed for maintenance. This encompasses the persistent fault condition associated with delayed auto-reclose (DAR) operation.

Breaking duties

The role of bus section or coupler breakers is to break the fault current associated with infeeds from all connected circuits if a fault occurs on an uncommitted section of busbar. Circuit breakers associated with a feeder, a transformer or a mesh corner are needed to break the fault current, on the basis that the circuit breaker which opens last clears the fault.

Circuit breakers associated with faulted circuits are needed to interrupt fault current in order to safeguard system stability, prevent damage to plant and maintain security and quality of supply.

Initial peak current

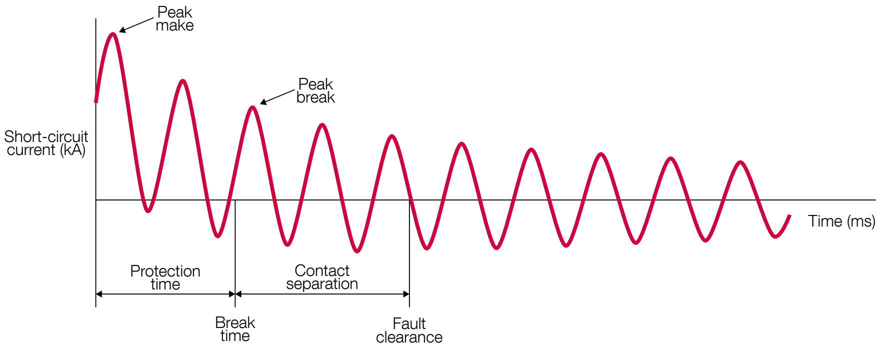
In Figure D2.3, the AC and DC components are decaying; the first peak will be the largest, occurring at about 10ms after the fault occurrence.

This is the short-circuit current that circuit breakers must be able to close onto if they are used to energise a fault. This duty is known as the peak make – a name that is slightly misleading because this peak also occurs during spontaneous faults.

All equipment in the fault current path will be subjected to the peak-make duty during faults so should be rated to withstand this current. The peak-make duty is an instantaneous value.

Appendix D2 –
Short-circuit current terminology

Figure D2.3
Combined AC and DC components of short-circuit current



RMS break current
This is the RMS value of the AC component of the short-circuit current when the circuit breaker contacts separate (see Figure D2.1). It does not include the effect of the DC component of the short-circuit current.

DC break current
This is the value of the DC component of the short-circuit current when the circuit-breaker contacts separate (see Figure D2.2).

Peak break
As both the AC and DC components are decaying, the first peak after contact separation will be the largest during the arcing period. This is the highest instantaneous short-circuit current that the circuit breaker has to extinguish.

This duty will be considerably higher than the RMS break. Like the peak-make duty, it is an instantaneous value (so it is multiplied by the square-root of 2) and includes the DC component too.

Choice of break time
The RMS break and peak break will of course depend on the break time. The slower the protection, the later the break time and the more the AC and DC components will have decayed.

For the purposes of *ETYS*, we have applied a uniform break time of 50ms at all sites. For most of our circuit breakers, this is a fair or pessimistic assumption. In this context the break time of 50ms is the time to the first major peak in the arcing period, rather than the time to arc extinction.

Appendix D3 – Data requirements

Generator infeed data
All generating units of directly connected large power stations are individually modelled, as are the associated generator transformers.

Units are represented in terms of their sub-transient and transient reactances (submitted under the provision of Grid Code), as well as the DC stator resistances and negative-phase sequence (NPS) reactances. Neither reactance is submitted under the Grid Code but we derive or assume the stator resistance value from historic records. The NPS reactance is calculated as the average of the relevant PPS sub-transient reactance ((Xd" + Xq")/2).

We carry out fault-level studies for planning purposes under maximum plant conditions (where all large power stations are included, whether contributory or not) to simulate the most onerous possible scenario for a future generation pattern.

Auxiliary system infeed data
The induction motor fault infeed from the station board is modelled at the busbar associated with the station transformer connection. Where there is not enough information available, we have assumed that auxiliary gas turbines are connected to the station boards as well as to the main generating units in order to simulate the most onerous system conditions. Where the X/R ratio has not been provided, we have assumed a value of 10.

Where the information is available, the fault infeed from the unit board, due to induction motors and auxiliary gas turbines, is modelled as an adjustment to the main generator sub-transient reactance.

A more detailed model of the power station system may have to be used to assess fault levels when station and unit boards are interconnected.

GSP infeed data
Infeed data for induction motors and synchronous machines at grid supply points (GSPs) is submitted by users under the Grid Code. Infeeds from induction motors and synchronous machines are modelled as equivalent lumped impedances at the GSP.

Where detailed information is not available, we have assumed 1 MVA of fault infeed per MVA of substation demand, with an X/R ratio of 2.76, for all induction motors. This approach reflects the requirements of ER G74.

Where more detailed fault level studies are needed at 132kV or below, the associated system should be modelled in detail, down to individual bulk supply points (BSPs). Induction motor infeeds should then be modelled at these BSP busbars.

LV system modelling
Where there are interconnections between GSPs, they take the form of PPS impedances between those GSPs. The ZPS networks take the form of minimum ZPS values modelled as shunts at the GSP busbars.

Where there are no interconnections to other GSPs, they take the form of equivalent LV susceptances modelled as shunts at the GSP busbar. The ZPS networks are modelled as shunt minimum ZPS values at the GSP busbars.

The values of PPS impedances between GSPs' shunt LV susceptances and shunt ZPS minimum impedances are as submitted by the users under the Grid Code.

Appendix D4 – **Fault level results**

The fault level of a system provides a good indication of the strength of the network. It must be calculated accurately to make sure that all electrical components are rated to withstand the fault current.

We have created a spreadsheet that provides fault-level information for Great Britain's most onerous system conditions – winter peak demand. You can view it online at www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/Electricity-Ten-Year-Statement/

The fault levels calculated and presented in the spreadsheet are based on the **Gone Green** scenario. They cover SHE Transmission, SP Transmission and National Grid each year from 2017/18 to 2026/27,