

## 1 SCOPE

This document sets out the principles and methodologies relating to the calculation of prospective short circuit currents on the Licensee's Distribution and Transmission Systems.

For further clarification on any issues contained within this document, contact the Network Design Group.


## 2 ISSUE RECORD

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Issue Date	Issue No.	Author	Amendment Details
-	1	-	Legacy document
February 2008	2	D E G Carson C Brozio	Original document augmented by extension of scope to detailed analysis methodology, the addition of computer based calculations and problematic scenarios.
		D E G Carson	Update of Table 2 - System Design Limits.
July 2017	3	Russell Bryans	Document review
July 2024	4	Jennifer Miller	Updates from G74/2: <ul style="list-style-type: none"> <li>- Inclusion of additional guidance on the modelling of converter driven plan (Section 11.8)</li> <li>- Additional guidance on the aggregated contribution of HV/LV general load contributions (Section 11.6)</li> </ul> Document review including: <ul style="list-style-type: none"> <li>- Additional detail on 33kV single-phase fault level design limits (Section 9.1)</li> </ul>

## 3 ISSUE AUTHORITY

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## 4 REVIEW

This is a **Controlled** document and shall be reviewed as dictated by business / legislative change but at a period no greater than 5 years from the last issue date.

## 5 DISTRIBUTION

This document is part of the SP Distribution (DOC-00-206), SP Manweb (DOC-00-310) and SP Transmission (DOC-00-311) System Design Virtual Manuals maintained by Document Control but does not have a maintained distribution list. It is also published on the SP Energy Networks website.

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## 7 DEFINITIONS

Please refer to ESDD-01-004 for definitions relating to this document.

## 8 BACKGROUND

When a fault occurs on the transmission or distribution system, the current which flows into the fault will be derived from a combination of three sources:

1. Major generating stations via the transmission and distribution networks (i.e. system derived fault current)
2. Embedded generators connected to the local network
3. Conversion of the mechanical inertia of rotating plant equipment connected to the system into electrical energy.

IEC 60909 is an international standard first published in 1988 which provides guidance on the manual calculation of short circuit currents in a three phase ac system. The standard produces fault current results for an unloaded network, that is the results do not include load current and the pre-fault conditions do not take account of tap positions. To counter some of these assumptions, multipliers are applied to the driving voltage. The calculations from IEC 60909 lead to conservative results and it is possible that this method could result in over investment. Engineering Recommendation G74 was therefore introduced in 1992 as an example of 'Good Industry Practice' for a computer-based derivation of fault currents. In addition to the procedure, G74 also addressed the issue of fault contribution from some types of load as detailed in item 3 above. In the absence of accurate load data, G74 provides guidance on load related fault infeeds. Essentially, this is a variable dependant on the mix of customer type and electrical demand. Engineering Technical Report 120 published in 1995 provides additional guidance on the application of Engineering Recommendation G74. Issue 2 of EREC G74 was published in 2021 and provides new guidance on modelling of fault contributions from converter-driven plant, HVDC terminals and FACTS.

Historically, the network has been designed primarily taking account of system derived prospective fault current. Prior to the Energy Act in 1983, development of embedded generation was not a widespread phenomenon. At this time the predicted system fault levels were 'controllable', non-volatile and essentially only modified by changes in system configuration. As a result, the system was developed to operate with relatively high fault levels. The objective of such a design practice being to produce a strong system conducive to providing a high level of Power Quality, a high fault level or low source impedance gives rise to lower levels of harmonic distortion and/or flicker from distorting and disturbing loads.

### 8.1 Short Circuit Current Terminology

This section provides a high level summary of some of the terminology used in the calculation of short circuit currents, equipment ratings and duties imposed by fault occurrences.

#### 3 phase fault

Balanced three phase faults short circuit all three phase conductors while the network remains balanced electrically. It may or may not involve a connection to earth. A balanced 3 phase fault will not involve any current flowing in the earth conductor even if the fault is connected to earth. At EHV and below, these are often the most severe, and also the most amenable to calculation. For these calculations, equivalent circuits may be used as in ordinary load-flow calculations.

#### Single phase fault

A single phase fault involves a short circuit between one phase conductor and earth. The network becomes electrically unbalanced during these faults and calculation methods make use of symmetrical components to represent the unbalanced network. Depending principally upon transformer winding and earthing arrangements, a single phase to earth fault may result in more current in the faulted phase than would flow in each of the phases for a balanced 3 phase fault at the same location. It is often the case, particularly at 132kV and 275kV that single phase faults are more severe than 3-phase faults.

#### X/R Ratio

The short circuit current is made up of an AC component (with a relatively slow decay rate) and a DC component (with a faster decay rate). These combine into a complex waveform which represents the worst case asymmetry and as such will be infrequently realised in practice.

The DC component decays exponentially according to a time constant which is a function of the X/R ratio. This is 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**

Calculation of the DC component of short-circuit current is based on the worst case scenario that full asymmetry occurs on the faulted phase (for a single phase-to-earth fault) or on any one of the phases (for a three phase-to-earth fault).

The DC component of the peak-make and peak-break short-circuit currents are calculated from two equivalent system X/R ratios. An initial X/R ratio is used to calculate the peak make current, and a break X/R ratio is used to calculate the peak break current. Calculation of the initial and break X/R ratios is undertaken in accordance with IEC 60909. The equivalent frequency method (also known as Method c)) is considered to be the most appropriate general purpose method for calculating DC short-circuit currents (see section 0).

**Circuit Breaker Duty and Capability**

Circuit breakers which may be called on to energise onto faulted equipment or disconnect faulty equipment from the system will have precisely defined capabilities to meet the following equipment duties:

**Make Duty** – The make duty of a circuit breaker is that which is imposed on the circuit breaker in the event that it is closed to energise a faulted or otherwise earthed piece of equipment.

**Break Duty** – The break duty of a circuit breaker is that which is imposed upon the circuit breaker when it is called upon to interrupt fault current.

The duties to which the circuit breakers are exposed to can be demonstrated by considering the fault current waveform immediately following the inception of a fault.

**8.1.1.1 Initial Peak Current**

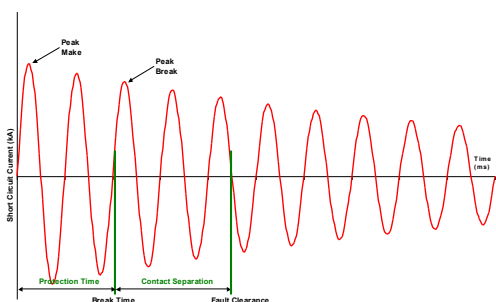


Figure 1: AC Component of Short Circuit Current

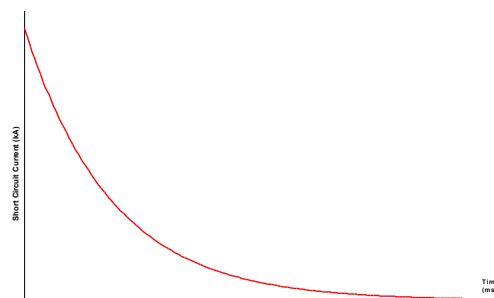


Figure 2: DC Component of Short Circuit

As discussed in section 8.1, the AC component (figure 1) has a relatively long decay rate compared to the DC component (figure 2). The resultant waveform in figure 3 shows both the AC and DC components decaying, with the first peak being the largest and occurring at about 10ms after the fault occurrence. This is the short circuit current that circuit breakers must be able to close onto in the event that they are used to energise a fault; hence this duty is known as the Peak Make. However, this duty can also occur during spontaneous faults. All equipment in the fault current path will be subjected to the Peak Make duty during faults and should therefore be rated for this duty. The Peak Make duty is an instantaneous value.

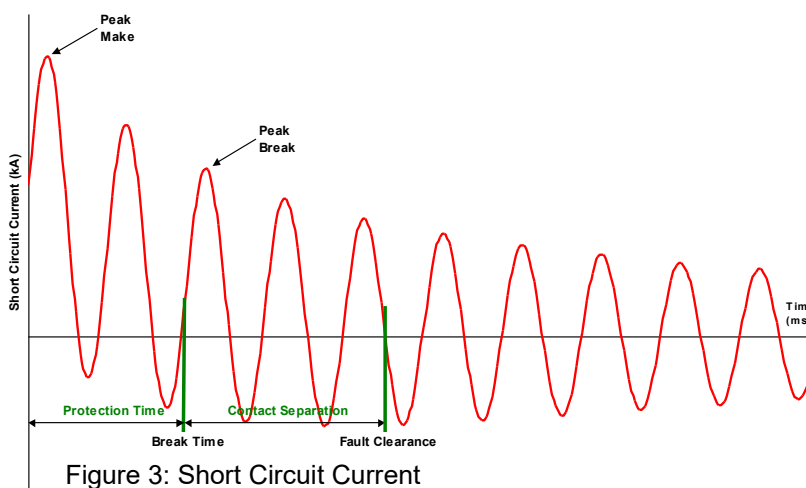


Figure 3: Short Circuit Current

**8.1.1.2 RMS Break Current**

This is the Root Mean Square (RMS) value of the symmetrical AC component of the short circuit current at the time the circuit breaker contacts separate (figure 1), and does not include the effect of the DC component of the short circuit current. This is effectively the nominal rating of the equipment. The RMS break current shall be calculated using the break times set out in Table 1.

<b>Network Voltage (kV)</b>	<b>Break Time (mS)</b>
11kV (incl 6.6kV etc)	90
33kV	90
132kV	70
275kV and 400kV	50

Table 1 - typical break times by system voltage

**8.1.1.3 DC Break Current**

This is the value of the DC component of the short-circuit current at the time the circuit breaker contacts separate (Figure 2).

**8.1.1.4 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 break, hence this duty is known as the Peak Break. This duty will be considerably higher than the RMS Break because, like the Peak Make duty, it is an instantaneous value (therefore multiplied by  $\sqrt{2}$ ) and also includes the DC component.

**8.1.1.5 Break Time**

The RMS Break and Peak Break are, by definition, dependent on the break time. The slower the protection, the later the break time and the more the AC and DC components will have decayed. The assumed value for break time will vary by voltage but will be in the range 50-120ms. It should be noted that a break time of 50ms is the time to the first major peak in the arcing period, rather than the time to arc extinction.

**Fault Withstand Capability**

Substation infrastructure such as busbars, supporting structures, flexible connections, current transformers, and terminations must be capable of withstanding the mechanical forces associated with the passage of fault current.

## 9 PHILOSOPHY / POLICY

Health & Safety requirements dictate that all equipment is fit for the duty it is required to perform. In the Electricity at Work Regulations, Regulation 5 states that 'No electrical equipment shall be put into use where its strength and capability may be exceeded in such a way as may give rise to danger.' In order to comply with this requirement with respect to plant fault capability, the maximum prospective fault current must be constrained or controlled such that no item of equipment on the system shall be overstressed due to its fault interruption or making duties being greater than its assigned rating.

### 9.1 Design Limits

System fault levels shall be constrained within the design limits for each voltage level which are summarised in Table 2. Any modification, extension or addition to the system shall take account of the resultant changes to the prospective fault currents and ensure that these design limits detailed are not breached.

System Voltage	Three Phase Symmetrical Short Circuit Current		Single Phase Short Circuit Current	
	MVA	kA	MVA	kA
400kV	34,500	50	38,000	55
275kV	15,000	31.5	19,000	40
132kV	4,570	20	5,700	25
33kV (Scotland)	1,000	17.5	240 *	4.2 *
33kV (Manweb legacy) <sup>1</sup>	750	13.1	750	13.1
33kV (Manweb) <sup>2</sup>	1,000	17.5	240 *	4.2 *
11kV	250	13.1	250	13.1
6.6kV	150	13.1	150	13.1
6.3kV	143	13.1	143	13.1

Table 2 - Design Fault Level Limits

These limits, particularly at the lower voltage levels, relate to sites which form part of the general transmission or distribution system. Where an individual customer connection is solely derived from the LV side of a GSP or Primary transformer, i.e. the point of common coupling is at the higher voltage level, then it is permissible for the fault level to exceed the design limits, provided the connection is engineered accordingly. Such circumstances may be inevitable where customer installations consist of significant generation or motor load.

Due to the potential impact on third party installations in the lower voltage systems, revision to the design limits for 33kV and 11kV and application of a Local Fault Level Design Limit requires to be carefully considered and will only be sanctioned after due process. For the higher voltage grid and supergrid networks which are within SPEN control, future review and revision to the design limits for the 400kV, 275kV and 132kV systems may be possible.

1 - The legacy 33kV network and design fault level in Manweb historically has been based on 750MVA equipment. Where all equipment within the local system has the capability to operate to the Company limit of 1,000MVA, taking due account of directly connected customer installations, that system can be assigned the higher design limit.

2 - The migrational target for the Manweb 33kV system is the Company limit of 1,000MVA. Therefore, new networks or incremental modifications which have a material impact on existing networks, may be assigned the design limit of 1,000MVA provided the comments in item 1 are addressed.

\* The 33 kV system is resistance earthed (via earthing transformers on the transformer 33kV tails and earthing resistors). The single-phase earth-fault current is usually designed to be 1 p.u. on the transformer rating. For example in a Scottish 33kV system, the design single-phase earth fault current in a GSP with two units of 120 MVA transformers would be  $2 \times 120 \text{MVA} / (\sqrt{3} \times 33 \text{kV}) = 4.2 \text{kA}$ . For Manweb network with four units of 60 MVA grid transformers in a BSP group, the design single-phase earth fault current would be  $4 \times 60 \text{MVA} / (\sqrt{3} \times 33 \text{kV}) = 4.2 \text{kA}$ .

## 10 IMPACT OF INCREASING FAULT LEVELS

There are a number of obvious areas where the rise in fault levels have an impact on the design or operation of the system.

- Health and Safety – the implications of having the prospective fault current exceeding the plant capability with respect to the safety of employees, members of the public and the equipment.
- Power Quality / Security of Supply – having to reconfigure the system to alleviate the over-stressing condition and discharge the H&S obligations may expose customers to single circuit risk or reductions in the perceived power quality.
- Asset Replacement Programme and Budget – significant capex may have to be committed in future to addressing over-stressed switchgear and is anticipated to increase with time in proportion to incremental load growth.
- New Business – when load or generation connections cannot easily be facilitated due to fault level considerations, the company is exposed to added pressures due to the consequential additional cost of the reinforcement works.

In addition to these more obvious results of rising fault levels there are associated areas of concern. For example, the transformer procurement process, particularly with respect to Grid Supply Point transformers, may prove to be more problematic in future.

In determining the appropriate impedance for a GSP transformer, two issues must be considered, fault level and voltage step change. The impedance of the transformers must be high enough to constrain the fault level to within design limits, and low enough to prevent excessive voltage step. Clearly these are conflicting requirements which produce an acceptable impedance envelope (across the tap range) which will, in turn, satisfy both conditions. ENA ACE Report 62 provides guidance on the calculation of the acceptable reactance variation for large supply transformers. With embedded generation connections increasing fault levels, this envelope is compressing such that, for some sites, the normal manufacturing tolerances will be wider than the acceptable envelope, and therefore without additional mitigating measures, one or other of the conditions will be breached.

### 10.1 Impact on Customers' Systems

It is also essential to consider the impact of over-stressing equipment within customer installations. Customer installations will have declared maximum fault levels for their point of connection to the transmission or distribution system and in the first instance it must be assumed that the customer's installation is rated and constructed accordingly. Any increase in system fault levels for the point of connection may result in the customer's installation being exposed to unidentified over-stressing.

While over-stressing on our system can be identified and managed and is effectively within our own control, the same condition does not apply to the customer. Over-stressing of the customers equipment, whether from normal or temporary conditions, is entirely beyond their control and awareness. It is not acceptable for the fault level conditions on the SPEN Networks to impose such over-stressing conditions on these customers.

## 11 CALCULATION OF FAULT LEVELS

### 11.1 Fault Level Calculation Fundamentals

The management of prospective fault level conditions in terms of circuit breaker make and break duties requires an assessment of the fault current contributions from all potential sources. This section addresses the procedures for the development of network and load models to enable the assessment of the interaction of the various sources of fault current contributions.

The methodology described in IEC 60909 allows for the calculation of short circuit currents using sequence components. The methodology makes certain assumptions about the nature of the fault for the purposes of defining the network impedance conditions.

1. For the duration of the short circuit there is no change in the type of short circuit involved, that is a three phase short circuit remains three phase and a line-to-earth short circuit remains line-to-earth fault for the duration of the fault.
2. For the duration of the short circuit, there are no other changes in the network.
3. The impedance of the transformers is referred to the tap-changer in nominal position. This is admissible because an impedance correction factor  $K_T$  for network transformers is introduced.
4. Arc Resistances are not taken into account.
5. All line capacitances and shunt admittances and non-rotating loads, except those of the zero-sequence system, are neglected.

### 11.2 Simple Fault Level Calculations

The method of calculating system fault levels are covered in detail in many text books and it is not the intention of this document to reproduce that material. However, some practical guidance may be of assistance.

The basis of fault level calculations can be either:-

- (a) Ohms at a chosen Standard Voltage
- (b) Percentage impedance drop at a chosen standard MVA base
- (c) Per unit method (an adaptation of (b))

Many planners prefer option (b) and the most convenient and normal standard base is 100MVA.



### 11.3 Network Reduction

In order to determine the prospective fault current at any point on the system, the process, in simple terms, is as follows:-

1. Prepare a single line diagram of the system indicating all generators, transformers, lines etc. and the point at which the fault level is required.
2. Indicate the reactance of all items to 100 MVA base. For generators, transformers etc. reactance is normally given as a percentage at normal rating (MVA), i.e.

$$X\% \text{ to } 100\text{MVA} = \frac{\% \text{ to rated MVA} \times 100}{\text{normal rating (MVA)}} \quad \dots(1)$$

3. Reduce the system to a single reactance between all generators or grid infeeds and the fault point by standard series/parallel and star/delta transformations and calculate the fault MVA from the formula: -

$$\text{Fault MVA} = \frac{10,000}{\text{Reactance (\% to 100 MVA)}} \quad \dots(2)$$

Note: For lines and cables; reactance is normally given in ohms, and

$$X\% \text{ to } 100 \text{ MVA} = \frac{\text{Ohms} \times 10^4}{(\text{kV})^2} \quad \text{where kV is the line kV.} \quad \dots(3)$$

$$\text{Conversely, the ohmic value is given by} \quad \frac{X\% \times (\text{kV})^2}{(10)^4} \quad \dots(4)$$

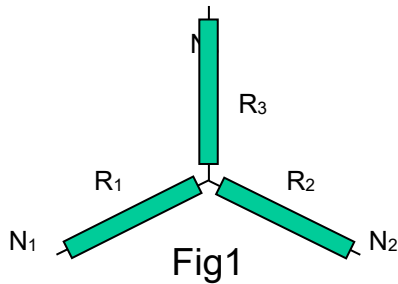
For convenience, tables of resistance and reactance (% to 100 MVA) for standard lines and cables are given in Annex 1.

In the above formulae it is tacitly assumed that resistance can be ignored and in fact where R is less than 30% of X the error in doing so is less than 5%.

Where greater accuracy is required computer methods should be employed.

**11.4 Delta/Star and Star/Delta Transformations**

The configuration of an impedance network can be changed from delta (mesh) to star and vice-versa by the following transformations:-



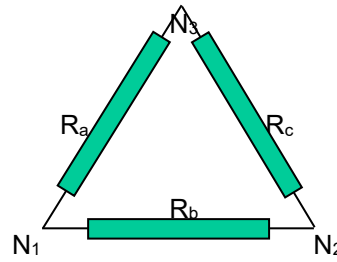
**Fig1**  
**Delta - Star**

$$R_1 = \frac{R_a R_b}{R_a + R_b + R_c} \quad \dots(5)$$

$$R_2 = \frac{R_b R_c}{R_a + R_b + R_c} \quad \dots(6)$$

$$R_3 = \frac{R_a R_c}{R_a + R_b + R_c} \quad \dots(7)$$

( $R_a, R_b, R_c$  from fig2)



**Fig2**  
**Star - Delta**

$$R_a = \frac{R_1 R_2 + R_2 R_3 + R_3 R_1}{R_2} \quad \dots(8)$$

$$R_b = \frac{R_1 R_2 + R_2 R_3 + R_3 R_1}{R_3} \quad \dots(9)$$

$$R_c = \frac{R_1 R_2 + R_2 R_3 + R_3 R_1}{R_1} \quad \dots(10)$$

( $R_1, R_2, R_3$  from fig1)

Examples of 3 phase calculations are provided in section 0.

For examples of the use of Symmetrical Components for Asymmetrical Faults, see section 0.

### Example of 3 Phase Symmetrical Fault Calculation

#### Example

A primary (33/11kV) two-transformer substation is supplied at 33kV through two 0.3 sq.in. 3-core solid type 33kV copper cables, each of 4.85 km route length, from a grid supply point. The fault level at the GSP 33kV busbars is 750MVA. The impedance of each of the 15/21MVA (ON/OFB) 33/11kV transformers at the remote end of each 33kV cable is 15% on 15 MVA. The impedance of the 11kV cables connecting the transformers to the 11kV switchboard is considered negligible. What is the fault level at the 11kV switchboard?

#### Source Infeed

Fault level at 33kV busbars at grid supply point = 750MVA

Equivalent reactance of infeed (resistance can be neglected) =  $\frac{100}{750} \times 100$   
= 13.3% / 100MVA

#### 33kV Cable

From Annex 1, Table 7, % Reactance of cable =  $0.84 \times 4.85 = 4.07\%$  / 100MVA

The resistance of the cable can be neglected as it is negligible in comparison with the reactance of the system.

#### 33/11kV Transformers

Reactance of each transformer on 100 MVA base =  $\frac{15\%}{15} \times 100 = 100\%$

Transformer resistance is only about 5% of the impedance value and can be neglected.

#### One Circuit comprising of One Cable and One Transformer

	Reactance (%)
Cable	4.07
Transformer	100.00
Total	104.07

#### Two Circuits in parallel, each comprising of One Cable and One Transformer

Reactance (%)  
52.04

#### Total Impedance

	Reactance (%)
Up to 33kV busbars	13.3
Cables and transformers	52.0
Total	65.3

Hence the fault level at the 11kV switchboard is  $\frac{100 \times 100}{65.3}$  i.e. 153MVA

### Asymmetrical Faults - Symmetrical Components

The evaluation of asymmetrical fault currents is often necessary when investigating the performance of protective equipment, and for this purpose the method of symmetrical components is most often used.

A complete description of the theory of symmetrical components is outside the scope of this manual, but the principal formulae can be summarised as follows:-

#### Principal Symbols Used:

$E_{ph}$	=	Phase-neutral voltage (volts)
$Z_1, Z_2, Z_0$	=	Positive, negative and zero phase sequence impedances of system up to a fault (ohms)
$I_1, I_2, I_0$	=	Positive, negative and zero phase sequence components of fault current
$I_F$	=	(amps)

For a phase-phase fault,

$$I_1 = I_2 = \frac{E_{ph}}{Z_1 + Z_2} \quad \dots(11)$$

$$I_F = 3I_1 = \frac{3E_{ph}}{Z_1 + Z_2} \quad \dots(12)$$

For a single phase to earth fault,

$$I_1 = I_2 = I_0 = \frac{E_{ph}}{Z_1 + Z_2 + Z_0} \quad \dots(13)$$

$$I_F = I_1 + I_2 + I_0 = \frac{3E_{ph}}{Z_1 + Z_2 + Z_0} \quad \dots(14)$$

In most earth faults the term  $Z_0$  includes the resistance of the earth path and that of the neutral earthing resistor if present. If the total earth path and neutral resistance is  $R_n$ , the term to be included in  $Z_0$  is  $3R_n$ .

In all static plant (transformers, regulators, lines, etc.) the positive and negative sequence impedances are equal, but the zero sequence impedances are not always equal to the other sequence impedances.

Simple problems involving symmetrical components can be solved by hand calculation and computer applications are available for more complex systems.

For fuller treatment of symmetrical components the following standard works may be helpful:-

"Fault Calculations" by Lackey

"Circuit Analysis of A.C. Power Systems" by Edith Clarke.

**Short Circuit Ratings for Belted and Screened 11kV Cables**

When a cable is subjected to high short circuit currents any resultant damage may be due to:-

- (a) High temperatures set up in the conductors or sheath which are a function of the magnitude and duration of the current.
- (b) High electro-magnetic forces which are a function of the magnitude, but independent of the duration of the current.

Short circuit currents in accordance with (a) are given by:-

$$I\sqrt{t} = K A_c \text{ amperes (sec)}^{1/2}$$

where I = short circuit current in amperes

t = duration of short circuit in seconds.

K = constant varying with conductor material and temperature range of the short circuit

A<sub>c</sub> = area of conductor in mm<sup>2</sup> for 11kV belted cables

The effect of (b) is more difficult to calculate but safe non-bursting limits of current have been obtained by experiment. For belted and screened armoured cables the conductor temperature should be a maximum of 160°C.

If the lead sheath temperature rises above 250°C sheath bursting can take place, especially in cables which are unarmoured.

**11.4.1.1 Application of Criteria**

- (a) The criterion for all steel wire armoured, lead sheathed cables up to 400mm<sup>2</sup> (0.6 in.<sup>2</sup>) Al or 0.4 in.<sup>2</sup> Cu. is joint damage, hence:

$$I\sqrt{t} = 119 A_c \text{ amperes (sec)}^{1/2} \text{ for Copper cables}$$

and  $I\sqrt{t} = 79.3 A_c \text{ amperes (secs)}^* \text{ for Aluminium cables}$

- (b) The criterion for all unarmoured and tape armoured cables and for steel wire armoured cables above the sizes given in (b) is sheath damage, hence:

$$I_s \sqrt{t} = 29.6 A_s \text{ amperes (sec)}^{1/2}$$

where I<sub>s</sub> = sheath current in amperes

A<sub>s</sub> = cross sectional area of sheath in mm<sup>2</sup>

In an armoured cable the sheath current is obtained from the following expression:-

$$I_s = I_T \times \frac{R_s}{R_s + R_A}$$

Where I<sub>T</sub> = total current flowing in sheath and armour  
 R<sub>A</sub> = armour resistance per unit length  
 R<sub>S</sub> = sheath resistance per unit length

**11.4.1.2 Safeguards Against Damage**

The use of the above criteria will prevent the following potential causes of damage arising:-

- (a) dielectric charring by heated conductors
- (b) melting of solder in joints
- (c) crushing of dielectric by mechanical forces

Table 3 provides values of short circuit ratings at 11kV and 6.6kV for various durations of fault and sizes of conductor. It also provides safe non-bursting limits of short circuit current.

Conductor C.S.A.		Safe Non-bursting Limit			Rating for Time Period of											
C.S.A. in <sup>2</sup> (Cu)	C.S.A. mm <sup>2</sup> (Al)	MVA at 6.6kV	MVA at 11kV	I (kA)	0.1 Sec.			0.25 Sec.			0.5 Sec.			1.00 Sec.		
					MVA at 6.6kV	MVA at 11kV	I (kA)	MVA at 6.6kV	MVA at 11kV	I (kA)	MVA at 6.6kV	MVA at 11kV	I (A)	MVA at 6.6kV	MVA at 11kV	I (kA)
0.0225		-	-	-	62.3	104	5.45	39.3	65.5	3.44	27.8	46.4	2.44	19.7	32.8	1.72
0.04(0.06A1)		-	-	-	110	184	9.68	70	116	6.12	49.5	82.5	4.33	35.0	58.3	3.06
0.06(0.1A1)		386	648	34.00	166	277	14.53	105	175	9.18	74.2	123	6.49	52.4	87.4	4.59
0.10(0.15A1)		423	705	37.00	276	461	24.20	175	291	15.30	123	206	10.82	87.4	145	7.65
0.15(0.25 Al)		446	743	39.00	415	692	36.30	263	438	23.00	185	309	16.23	131	219	11.50
0.2(0.3A1)		480	800	42.00	553	922	48.40	350	583	30.60	247	411	21.60	175	291	15.30
0.25		491	819	43.00	692	1,153	60.50	437	729	38.25	309	515	17.05	218	364	19.13
0.30		514	857	45.00	830	1,383	72.60	525	874	45.90	371	618	32.46	263	438	23.00
	95	352	587	30.80	-	310	16.30	-	280	14.70	.	194	10.20	.	139	7.30
	185	401	668	35.10	-	604	31.70	-	533	28.00	-	381	20.00	-	266	14.00
	300	451	752	39.50	-	990	52.00	-	886	46.50	-	629	33.00	-	440	23.10

Table 3: Short Circuit Ratings of PILC SWA Screened or Belted 11kV Cables

Imperial Cables:-  $I_C \sqrt{t} = 76,500 A_c$  where  $A_c$  is the conductor area (Copper or Copper equivalent Aluminium) in square inches

Metric Cables  $I_C \sqrt{t} = 79.3 A_c$  where  $A_c$  is the conductor area (Al only) in square millimetres

### 11.5 Engineering Recommendation G74

G74 describes a procedure to meet the requirements of IEC 60909 *Short-circuit currents in three-phase a.c. systems*. The requirements of EREC G74 are not intended to be applied to hand calculation of short circuit currents but describe a method which can be realised with a computer network analysis package. G74 Issue 2 (G74/2) was published in 2021 and includes new guidance on converter-driven plant, HVDC terminals and flexible alternating current transmission systems (FACTS).

The principles underpinning EREC G74 are:

- Pre-fault conditions must be established from the network configuration, plant parameters, load and boundary conditions specified by the user; where available measured values should be used. Users must ensure that a credible system operating arrangement giving rise to maximum short circuit levels is used to establish the pre-fault network conditions.
- To represent network conditions as accurately as possible, an AC load flow is to be used to determine the pre-fault voltage profile, motor and generator internal voltages and transformer tap settings. These initial conditions are to be used in the subsequent short-circuit current calculations.
- Short circuit current contributions from all rotating plant must be included in the calculation. Where rotating plant can be individually identified, it must be modelled either as an individual item or part of an equivalent group in the system representation. Rotating plant forming part of the general load must be represented by a suitable equivalent.
- EREC G74 Issue 2 also provided new guidance where short circuit current contributions from all generators and loads, which are connected to the electrical grid through a static converter should be modelled by a current vs voltage relationship with a limit for maximum current injection.

### 11.6 G74 Asynchronous (Induction) LV Motor Infeeds/General Load Contributions

In order to model the fault infeed associated with asynchronous motors that are not individually identifiable but form part of the general load, fault level studies are carried out with equivalent machines connected to all Grid Supply points or 33 kV busbars.

Section 7.2.4 of EREC G74/2 makes the following recommendations regarding the magnitude of initial fault infeed from the equivalent machines.

Location of aggregated contribution	Fault contribution	Aggregated peak demand connected at
Short circuit contribution at the EHV busbar of a primary substation	1.0 MVA per MVA	demand connected at LV
	2.6 MVA per MVA	demand directly connected at HV
Short circuit contribution to the HV supply network	1.1 MVA per MVA	demand connected at LV

The aggregate peak demand excludes battery energy storage system import load for G99 connections to the HV network as such systems are covered by requirements for Converter-Driven Plant.

An equivalent X/R ratio of 2.76 can be assumed for an equivalent motor connected at 33 kV or 11 kV unless more specific details are available.

For Peak Make conditions, the generators are assumed to have positive and negative phase sequence components but no zero sequence component due to the winding configuration of distribution transformers.

The fault current from asynchronous motors decays very rapidly and will not contribute to the fault clearing (break) duty of switchgear apart from the negative sequence component which is assumed to remain constant for the duration of the fault.

### 11.7 HV Generator AC Decrements

For generation connected directly to the transmission system, the effect of the AC decrement has been taken into account when determining the break duty values. The effect of the AC decrement is to reduce the positive sequence contributions from HV generators to transient levels.

### 11.8 Converter-Driven Plant (Static and Rotating)

#### Generators and Load with Fully Rated Converter

Generally, the short-circuit contribution of a converter-driven plant should be modelled by a current vs voltage relationship. This can be modelled by a linear function with a limit for the maximum current injection. This applies to all generators and loads, which are connected to the electric grid through a static converter, for example:

- Battery Energy Storage Schemes (BESS)
- Wind turbine generators with a fully rated converter
- Photovoltaic modules with an inverter
- Variable speed drives with an active grid-side converter

#### Doubly-fed Induction Machines

Doubly-fed Induction Machines contribute to both the rotating plant and converter driven plant components of short-circuit currents. Initially, after a fault has been inserted, the DFIG reacts similarly to an induction machine because of the magnetic flux in the rotor which dominates its contribution to a short-circuit current. Consequently, the DFIG short-circuit is modelled by an equivalent subtransient reactance and resistance as provided by the manufacturer.

However, very quickly after a fault insertion (e.g. in transient time frames), the controller of a DFIG takes over and regulates its current contribution to the fault. Therefore, in transient timeframes, a DFIG response is similar to the response of a generator with Fully Rated Converter.

#### HVDC Terminals and FACTS

Voltage Source Converter (VSC) type HVDC terminals, STATCOMs which are equipped with VSCs can contribute to the short-circuit current of an AC network. This can be modelled by a current vs voltage relationship with a limit for the maximum current injection, i.e. the same as converter-driven plant.

### 11.9 Detailed Fault Level Calculation by Power System Analysis Software

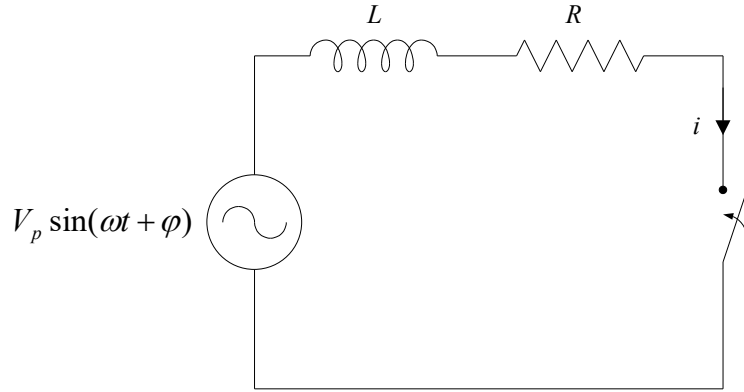
Power system fault current transients consist of a constant AC component, a decaying AC component and a decaying DC component. Generally, the transient fault current can be calculated accurately by applying a time-domain transient analysis program. For large-scale fault current calculations, this is not feasible and this section aims to outline the theoretical background to calculating various characteristics of a fault current transient, based on steady-state analysis. This is used as a basis to formulate procedures to implement these calculations in power system analysis software.



**Background Theory**

**11.9.1.1 Fault Current in a Simple RL Circuit**

Consider the simple series RL circuit shown in figure 1.



**Figure 1.** Simple series RL circuit.

After the switch is closed at  $t = 0$ :

$$V_p \sin(\omega t + \varphi) = Ri + L \frac{di}{dt} \quad \dots(15)$$

The general solution for eq. 15 is:

$$i(t) = \frac{V_p}{\sqrt{R^2 + \omega^2 L^2}} \sin \left[ \omega t + \varphi - \tan^{-1} \left( \frac{\omega L}{R} \right) \right] + Ae^{-\frac{Rt}{L}} \quad \dots(16)$$

The fault current has a constant AC component, plus a decaying DC component with a magnitude that depends on the initial conditions. At  $t=0$ , the instant at which the fault starts,  $i = 0$ . Setting  $i = 0$  and  $t = 0$  and solving eq. 16 for  $A$  then yields:

$$A = \frac{-V_p}{\sqrt{R^2 + \omega^2 L^2}} \sin \left[ \varphi - \tan^{-1} \left( \frac{\omega L}{R} \right) \right] \quad \dots(17)$$

Writing the peak AC current in terms of the RMS fault current,  $I_{RMS}$ :

$$\frac{V_p}{\sqrt{R^2 + \omega^2 L^2}} = \sqrt{2} I_{RMS} \quad \dots(18)$$

Then, with  $X = \omega L$ :

$$i(t) = \sqrt{2} I_{RMS} \sin \left( \omega t + \varphi - \tan^{-1} \frac{X}{R} \right) - \sqrt{2} I_{RMS} \sin \left( \varphi - \tan^{-1} \frac{X}{R} \right) e^{-\frac{\omega R t}{X}} \quad \dots(19)$$

If the source in the above example is a synchronous machine, instead of a constant AC source, the amplitude of the AC component will no longer be constant. This is because the internal voltage of the machine, which is a function of the rotor flux linkages, is not constant. Initially, the AC component decays rapidly as the flux linking the sub-transient circuits decays. This is followed by a relatively slow decay of flux linking the transient circuits. The decay from sub-transient to transient current, with a time constant of  $\tau''$ , can be included in eq. 19, resulting in:

$$i(t) = \sqrt{2} \left[ I' + (I'' - I') e^{-\frac{t}{\tau''}} \right] \sin \left( \omega t + \varphi - \tan^{-1} \frac{X}{R} \right) - \sqrt{2} I'' \sin \left( \varphi - \tan^{-1} \frac{X}{R} \right) e^{-\frac{\omega R t}{X}}, \quad \dots(20)$$

where  $I''$  is the RMS sub-transient current and  $I'$  is the RMS transient current. For the purpose of fault current calculations, it will be assumed that sub-transient current components decay to a negligible value within 120 ms, which gives  $\tau'' \approx 40$  ms. Note that the time constant of the DC component is not affected by the decay of the AC fault current component.

#### 11.9.1.2 Peak Make Current

The highest peak current that a circuit breaker will see is the first peak of the fault current transient. As the worst-case peak occurs about 10 ms after fault inception, the circuit breaker will never be required to break this current, due to protection system and mechanical delays. Therefore, the worst-case peak is known as the peak make current,  $i_p$ . The highest DC component occurs when:

$$\varphi - \tan^{-1} \frac{X}{R} = \frac{-\pi}{2} \quad \dots(21)$$

For this case, the peak value of the AC component occurs at  $t = 10$  ms. However, this is not the condition under which the worst-case peak make current occurs. Due to the decay of the DC component, the worst-case value of the total fault current transient tends to occur when  $\varphi = 0$  and at a time just before 10 ms. The highest possible peak value of eq. 19 is difficult to determine analytically and the following empirical formula is recommended in IEC 60909 and Engineering Recommendation G74 to calculate the worst-case peak make current:

$$i_p = \sqrt{2} I'' \left[ 1.02 + 0.98 e^{\frac{-3R}{X}} \right] \quad \dots(22)$$

For practical X/R ratios, eq. 22 tends to over-estimate the peak value slightly (by about 0.2% to 0.5%).

#### 11.9.1.3 Break current

When breaking a fault current, the breaker contacts will start moving apart at about 50 ms to 90 ms after fault inception, depending on the speed of the protection and the breaker operating time. At the break time ( $t_B$ ) the RMS AC component of the fault current, the RMS break current ( $I_B$ ), is given by:

$$I_B = I' + (I'' - I') e^{\frac{-t_B}{0.04}} \quad \dots(23)$$

Eq. 23 is based on the assumption that  $\tau'' = 40$  ms. For a system frequency of 50 Hz, the DC current component at the break time is given by:

$$i_{DC} = \sqrt{2} I'' e^{\frac{-100 \pi R t_B}{X}} \quad \dots(24)$$

Combining the AC and DC components, the peak break current ( $i_B$ ) is given by:

$$i_B = \sqrt{2} \left[ I' + (I'' - I') e^{\frac{-t_B}{0.04}} + I'' e^{\frac{-100 \pi R t_B}{X}} \right] \quad \dots(25)$$

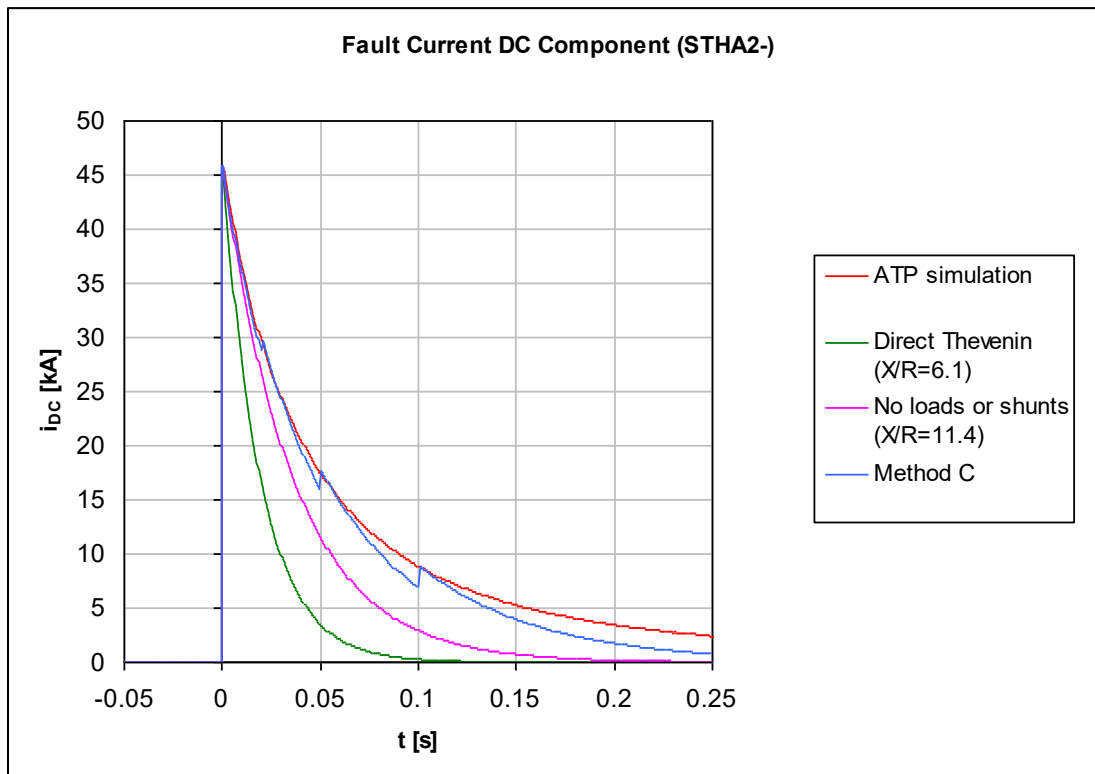
**Practical Fault Current Calculation**

For large-scale fault studies, it is not desirable to carry out detailed transient analysis to obtain fault currents. Instead, IEC 60909 and EREC G74 outline methods to obtain the worst-case AC and DC fault current components accurately, using conventional steady-state fault analysis programs. Conventional fault analysis programs can be used to determine  $I''$  and  $I'$ . This is achieved by using the applicable generator impedances in the fault study and by correctly representing any fault infeeds from motors in the sub-transient and transient system models. If an equivalent  $X/R$  ratio can now be found,  $i_p$ ,  $I_B$ ,  $i_{DC}$  and  $i_B$  discussed above can be determined.

**11.9.1.4 X/R Ratio**

To accurately determine the decay of the DC fault current component, the  $X/R$  ratio of the system under consideration has to be known. This is not a problem for a simple system like the one shown in figure 1. However, in a complex, meshed network, there are several sources contributing to the total fault current via a number of branches with different  $X/R$  ratios. The problem is thus to determine an equivalent  $X/R$  ratio to represent the entire system. A number of methods that can be used to determine an equivalent  $X/R$  ratio will be briefly described below, at the hand of a practical example.

A transient simulation was run to determine the fault current for a three-phase fault at Strathaven 275kV. The DC component of the fault current was isolated by subtracting the AC component, giving the result shown by the red curve in figure 2.



**Figure 2.** DC fault current components for a fault at Strathaven 275kV.

This is an accurate calculation, which correctly accounts for DC current contributions from across the network.

**(a) Direct X/R Calculation**

The most obvious method of obtaining an equivalent  $X/R$  ratio is to simply determine the Thevenin equivalent of the network. Using the  $R$  and  $X$  values from the Thevenin impedance, an  $X/R$  ratio of 6.09 is found. The DC component of the fault current is then given by:

$$i_{DC}(t) = \sqrt{2}I''e^{\frac{-100\pi}{6.09}t} \quad \dots(26)$$

From figure 2 it is clear that  $i_{DC}$  of eq. 26 decays much faster than the actual DC component, leading to the conclusion that a direct  $X/R$  calculation is inaccurate and will underestimate the  $X/R$  ratio.

**(b) X/R Calculation with Shunt Impedances Removed**

The calculation in (a) above included impedances representing the system loads as well as line charging susceptances and other shunts. During a three-phase fault, none of these shunt impedances carry any fault current and should therefore not affect the  $X/R$  ratio – thus, only the series impedances in the fault current paths should be taken into consideration. By removing all load impedances and line charging from the network, and then calculating the  $X/R$  ratio, a value of 11.37 is found. Figure 2 shows that this is a reasonable approximation during the first 10 or 20 ms of the fault, after which  $i_{DC}$  again decays faster than the accurately calculated DC component. Therefore, this method of calculation will give acceptable results for peak make current calculations, but not for determining break current DC components.

**(c) Method c)**

The so-called ‘Method c)’ described in IEC 60909 aims to improve the DC current calculation by using a variable  $X/R$  ratio. A different  $X/R$  ratio is used for different time periods following the inception of the fault. Method c), also known as the ‘equivalent frequency method’, works by scaling all reactances in the network to an equivalent frequency,  $f_c$ . The network is thus treated as if the system frequency is  $f_c$  and not 50 Hz. The ratio  $X_c/R_c$  is now calculated and scaled back to obtain the  $X/R$  ratio:

$$\frac{X}{R} = \frac{50}{f_c} \cdot \frac{X_c}{R_c} \quad \dots(27)$$

Table 4 shows values of  $f_c$  that are to be used for a range of time windows following the start of the fault.

Table 4 - Equivalent frequencies for Method c).

<b>Time window [ms]</b>	<b><math>f_c</math> [Hz]</b>
$t < 10$	20.00
$10 \leq t < 20$	13.50
$20 \leq t < 50$	7.50
$50 \leq t < 100$	4.60
$100 \leq t < 250$	2.75

It is not the intention to explore the basis for Method c) here. However, to demonstrate how Method c) works, consider the simple network shown in figure 3.

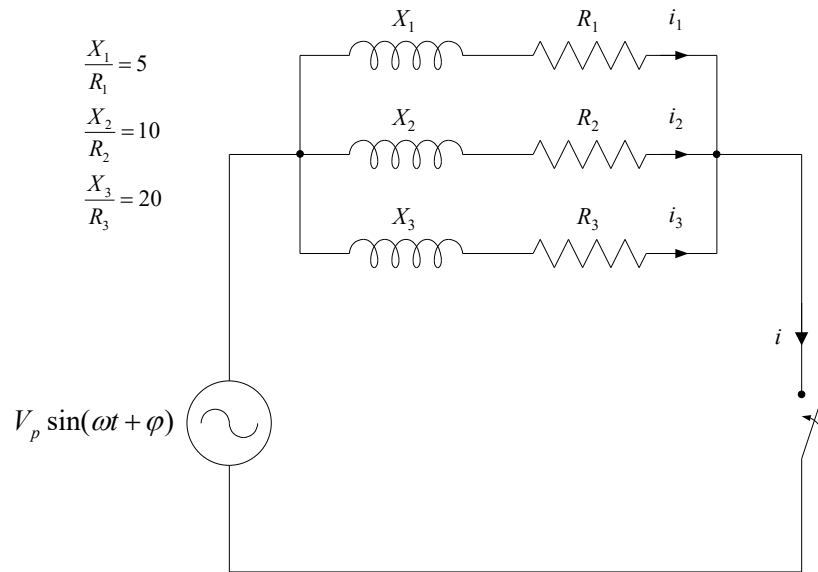


Figure 3. Network to illustrate Method c)

This network has three parallel branches with similar impedance magnitudes, but widely differing X/R ratios.

Figure 4 shows the DC component contributed to the fault current via each branch ( $i_1$ ,  $i_2$  and  $i_3$ ) and the total DC component of the fault current.

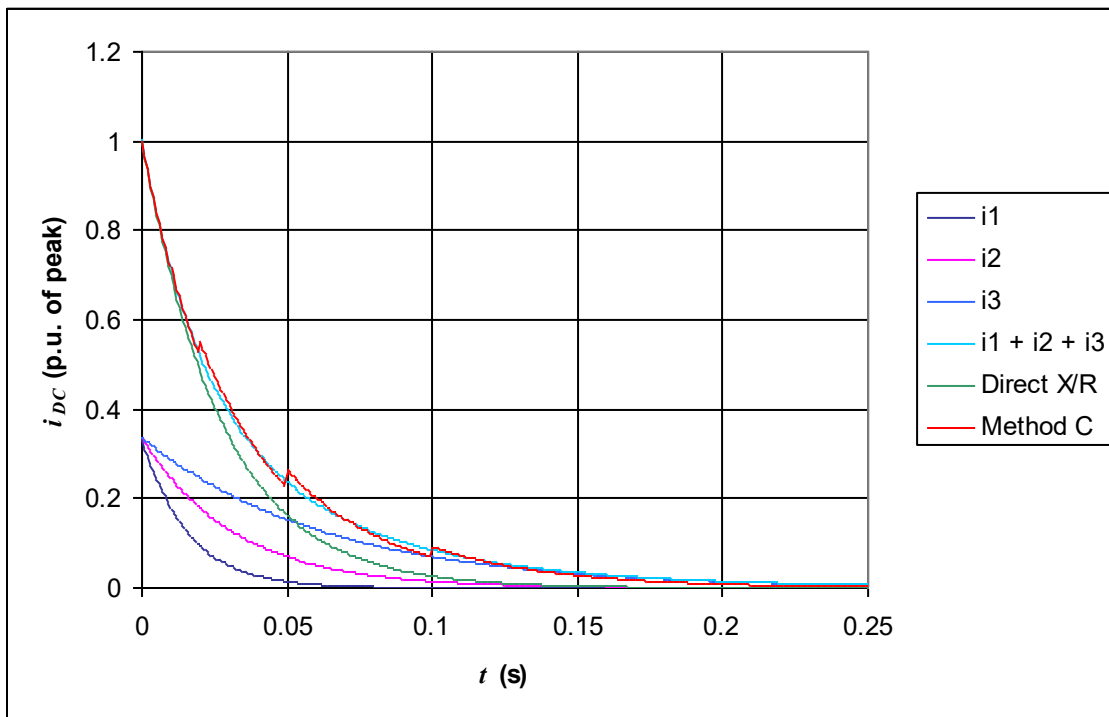


Figure 4. DC fault current components for the network shown in figure 3.

It is clear that the lower the  $X/R$  ratio of a branch, the quicker its portion of the DC fault current decays. This is not taken into account when using the  $X/R$  ratio of the parallel combination of the three branches to estimate the DC component, as also shown in figure 4. The DC current contributions via the highest  $X/R$  branches have the longest time constant and hence the relative contribution of these components to the total DC current will become higher with time. Method c) takes this into account by increasing the relative effect of high  $X/R$  branches as a function of time, i.e. the  $X/R$  ratio increases with time. In figure 4 it can be seen that the Method c) DC component is remarkably close to the accurately calculated DC current.

Returning to the Strathaven fault current example of figure 2, note that Method c) also gives very good results for a large practical, interconnected network. Note that line charging and loads were removed from the network before calculating the  $X/R$  ratio.

#### 11.9.1.5 $X/R$ Ratio for Unbalanced Faults

The  $X/R$  ratio for unbalanced faults is not the same as the  $X/R$  ratio for balanced faults. In fact,  $X/R$  ratios for unbalanced faults are found by interconnecting the sequence networks in the same manner as for the corresponding unbalanced fault current calculation. Thus, for single-phase (line-to-ground) faults:

$$\left. \frac{X}{R} \right|_{L-G} = \frac{X_0 + X_1 + X_2}{R_0 + R_1 + R_2} \quad \dots(28)$$

For line-to-line faults:

$$\left. \frac{X}{R} \right|_{L-L} = \frac{X_1 + X_2}{R_1 + R_2} \quad \dots(29)$$

and for line-line-ground faults

$$\left. \frac{X}{R} \right|_{L-L-G} = \frac{\text{Im}(Z_{eq})}{\text{Re}(Z_{eq})} \quad \dots(30)$$

where

$$Z_{eq} = (R_1 + jX_1) + \frac{(R_0 + jX_0)(R_2 + jX_2)}{(R_0 + jX_0) + (R_2 + jX_2)} \quad \dots(31)$$

In most cases, positive and negative sequence impedances are equal, or very similar, so that the line-line  $X/R$  ratio is equal (or very close to) the  $X/R$  ratio for balanced three-phase faults. Depending on the network, however, the line-to-ground and line-line-ground  $X/R$  ratios could differ significantly from the balanced  $X/R$  ratio. If method c) is applied, the  $X/R$  ratio is calculated at the equivalent frequency, according to eq. 28 – 31, before scaling back according to eq. 27.

#### 11.9.1.6 Practical X/R calculation

From the above discussion it is clear that Method c) gives the best approximation to the DC fault current component, based only on steady-state calculations. Depending on the fault calculation software that is used, it may be very difficult to apply Method c). In this case, a simple X/R ratio calculation will suffice for peak make current calculations, provided that loads and shunt impedances have been removed from the positive and negative sequence networks. From figure 2 it can be seen that the error is relatively small. IEC 60909 recommends that a safety factor of 1.15 should be applied in this case, but G74 states that this can be ignored, unless a significant number of branches in the network have an X/R ratio below 3.3. In the British transmission network, branches with an X/R ratio below 10 are rare and therefore the safety factor of 1.15 can be ignored for transmission system fault studies.

To calculate the DC component after more than 10 ms have expired, only Method c) should be used. It is clear from the results presented above that large errors will be made if the Thevenin impedance X/R ratio is used.

#### Calculation Procedures

In the event of incomplete or missing generator or motor base data, the machine is commonly modelled only by its equivalent reactance. This leads to satisfactory results when calculating  $I'$  or  $I''$ . However, because  $R = 0$ , the X/R ratio tends to infinity. This is not a problem if the machine is remote from the fault, but close to a fault this tends to increase the X/R ratio. This leads to an over-estimation of the DC fault current component. Therefore, care should be taken to include realistic resistances for motors and generators where possible. For most circuit breakers, the RMS break current rating is known. For circuit breakers rated to IEC 62271-100, the peak make current rating is given as 2.5 times the rated breaking current.

#### 11.9.1.7 Simplified X/R Ratio for Peak Make Current Calculations

1. To calculate the X/R ratio for three-phase and single-phase peak make current calculations, set classical fault current calculation assumptions. Note that:

- (a) Transformer tap ratios should NOT be set to unity
- (b) Charging must be set to zero
- (c) Shunts (including loads) must be set to zero in the positive and negative sequence, but NOT in the zero-sequence network.

2. Carry out the fault current calculation. Note that this calculation is only performed to obtain an X/R ratio – the calculated fault currents will NOT be correct.

3. For three-phase faults, determine X/R from the positive sequence Thevenin impedance:

$$\left. \frac{X}{R} \right|_{3\text{-PH}} = \frac{X_1}{R_1} \quad \dots(32)$$

4. For single-phase faults, determine X/R from all three sequence Thevenin impedances:

$$\left. \frac{X}{R} \right|_{L-G} = \frac{X_0 + X_1 + X_2}{R_0 + R_1 + R_2} \quad \dots(33)$$

**11.9.1.8 X/R Ratio using Method c)**

1. Select equivalent frequency  $f_c$ . For peak make calculations this will always be 20.0 Hz. For break current calculations,  $f_c$  depends on the break time  $t_B$ , as shown in Table 4.
2. Scale all network reactances to the equivalent frequency  $f_c$ . I.e. all inductive reactances and capacitive susceptances are multiplied by  $f_c/50$ , while keeping all resistances constant. Note that positive, negative and zero-sequence impedances must be adjusted, although line charging and shunt components can be ignored in the positive and negative sequence. Once frequency scaling has been applied, there is no need carry out a load-flow, despite the mismatches caused by changing the network impedances.
3. Set classical fault current calculation assumptions. Note that:
  - (a) Transformer tap ratios should NOT be set to unity
  - (b) Charging must be set to zero
  - (c) Shunts must be set to zero in the positive and negative sequence, but NOT in the zero-sequence network.
4. Carry out the fault current calculation. Note that this calculation is only performed to obtain an X/R ratio – the calculated fault currents will NOT be correct.
5. For three-phase faults, determine the scaled X/R ratio from the positive sequence Thevenin impedance:

$$\left. \frac{X_c}{R_c} \right|_{3\text{-PH}} = \frac{X_1}{R_1} \quad \dots(34)$$

6. For single-phase faults, determine the scaled X/R ratio from all three sequence Thevenin:

$$\left. \frac{X_c}{R_c} \right|_{L-G} = \frac{X_0 + X_1 + X_2}{R_0 + R_1 + R_2} \quad \dots(35)$$

7. Finally, scale the X/R ratios back to 50 Hz (eq. 27):

$$\left. \frac{X}{R} \right|_{3\text{-PH}} = \frac{50}{f_c} \cdot \left. \frac{X_c}{R_c} \right|_{3\text{-PH}} \quad \dots(36)$$

and

$$\left. \frac{X}{R} \right|_{L-G} = \frac{50}{f_c} \cdot \left. \frac{X_c}{R_c} \right|_{L-G} \quad \dots(37)$$

**11.9.1.9 Peak make current (3-phase and single phase faults)**

1. Without applying any flat conditions, calculate the sub-transient RMS fault current,  $I''$ . A network to which flat conditions have been applied, or that has been scaled to an equivalent frequency, should NOT be used for this purpose.
2. Use the appropriate X/R ratio (see 11.9.1.7 and 11.9.1.8 above) to calculate the peak make current using eq. 22.



#### 11.9.1.10 RMS break current

1. Without applying flat conditions, calculate the transient RMS fault current  $I'$ . All generators should be represented by their transient reactance and no contribution from equivalent or large induction machines should be included.
2. If  $t_B > 120$  ms it can be assumed that all sub-transient AC current components have decayed to a negligible magnitude and therefore  $I_B = I'$ .
3. If  $t_B < 120$  ms, the sub-transient AC component has to be included in the RMS break current. Therefore,  $I_B$  should be calculated using eq. 23. Note that,  $I''$  as calculated in 11.9.1.9 is also required.

#### 11.9.1.11 DC Break and Peak Break Currents

1. The DC current component at  $t_B$  should only be calculated with an  $X/R$  ratio obtained by applying Method c) (see 11.9.1.8 above).
2. Using the sub-transient RMS fault current,  $I''$ , as calculated in 11.9.1.9 above, the DC break current is calculated using eq. 24.
3. Finally, the peak break current is given by (see eq. 23 - 25):

$$i_B = \sqrt{2}I_B(t_B) + i_{DC}(t_B) \quad \dots(38)$$

#### 11.9.1.12 Modelling of 11kV Network G74 Infeed on the IPSA Modelling Platform

As described in section 0, in order to model the fault infeed associated with asynchronous motors that are not individually identifiable but form part of the general load, fault level studies for the 132kV and 33kV networks are carried out with equivalent synchronous motors normally drawing no load connected to the system.

However, for fault level modelling of the 11kV system using the IPSA analytical software where equivalent synchronous motors are not modelled, in order to represent the prospective fault current infeed from rotating plant the following approach may be required.

**Break Duty** - Engineering Recommendation G74 recommends allowing an initial (time=0) rotating plant contribution for a fault at the 33kV bus bar of 1MVA per MVA of LV load with a decay constant of 40ms. Therefore the maximum initial contribution at 33kV is 100% of the demand value with a decay to 10.55% of the demand value at t=90ms. Due account of the transformer impedance has to be taken when considering the fault current infeed at the 11kV busbar which results in the fault infeed to the 33kV busbar. Typically this would require an infeed from the 11kV busbar equivalent to 10.65% of the demand value. Therefore, for an 11kV fault at t=90ms, the allowance for fault current contribution from rotating plant will be *approximately* 10.65% of the demand value.

**Make Duty** - Given the possible timing variations between onset of fault conditions and circuit breaker closure, as well as the credible scenario of closure onto an earthed system, it is recommended that full account be taken of the G74 infeed when considering make duty, i.e. the maximum initial contribution at 33kV is 100% of the demand value with no allowance for decay. In common with the Break Duty methodology described above, due account of the transformer impedance has to be taken when considering the fault current infeed at the 11kV busbar.

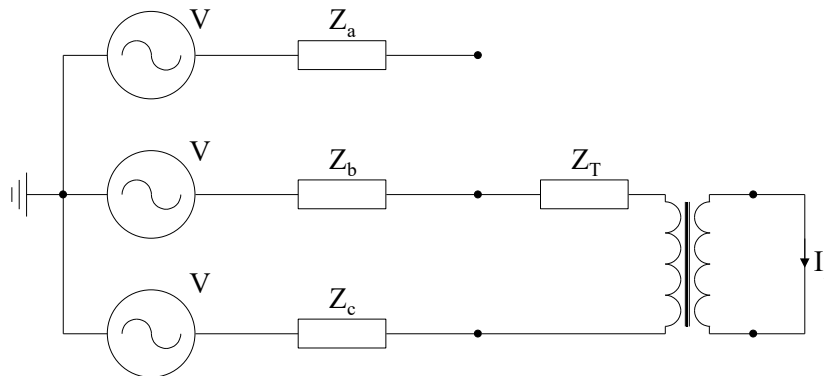
Due cognisance should be taken of site minimum infeed to assess circuit breaker duty. This aspect is covered in more detail in Design Manual Section 9b "Design for System Fault Levels and Equipment Capabilities" (ESDD-02-014)

**Fault Current Calculation for Traction Supplies**

This section outlines the calculation of fault currents for single-phase traction supplies. Differences between the booster transformer (BT) and autotransformer (AT) systems are also briefly considered.

**11.9.1.13 Basic calculation**

Traction supply transformer HV windings are connected phase-to-phase, which means that a fault on the LV (25kV) side of the transformer can be treated as a line-to-line fault with a fault impedance equal to that of the traction transformer plus any additional impedance in the 25kV network.



For a line-line fault, the positive and negative sequence networks are connected in series with the fault impedance to find the positive and negative sequence fault currents:

$$I_1 = -I_2 = \frac{V}{Z_1 + Z_2 + Z_T} \quad \dots(39)$$

$$I_0 = 0 \quad \dots(40)$$

Assuming that the transformer is connected between phases *b* and *c* as shown above, the fault current is:

$$\begin{aligned} I_f &= a^2 I_1 + a I_2 + I_0 \\ &= (a^2 - a) I_1 \\ &= -j\sqrt{3} I_1 \end{aligned} \quad \dots(41)$$

and therefore:

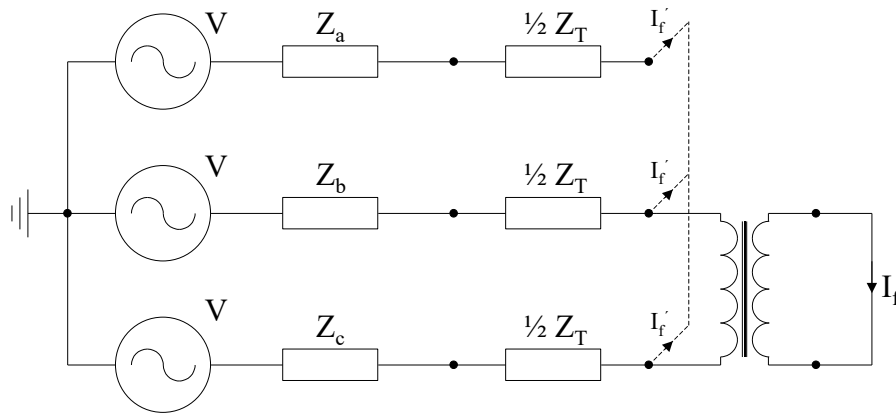
$$|I_f| = \sqrt{3} \left| \frac{V}{Z_1 + Z_2 + Z_T} \right| \quad \dots(42)$$

For peak make current or DC component calculation, the equivalent *X/R* ratio needs to be calculated. This is found from the *X/R* ratio of the series connection of the sequence impedances and the traction transformer impedance:

$$\frac{X}{R} = \frac{X_1 + X_2 + X_T}{R_1 + R_2 + R_T} \quad \dots(43)$$

**11.9.1.14 Alternative calculation method**

This section shows how the fault current can be calculated from an 'equivalent' positive phase sequence representation. To calculate the fault current with a computer program, the representation shown below may be simpler to apply than the calculation discussed in the previous section.



Finding  $I_f$  as a line-line fault, as in (39) above:

$$I_1 = -I_2 = \frac{V}{(Z_1 + \frac{1}{2}Z_T) + (Z_2 + \frac{1}{2}Z_T)} \quad \dots(44)$$

$$= \frac{V}{Z_1 + Z_2 + Z_T}$$

If it is assumed that  $Z_1 = Z_2$ :

$$I_1 = -I_2 = \frac{V}{2Z_1 + Z_T} \quad \dots(45)$$

Now, consider the three-phase short-circuit current,  $I_f'$ :

$$I_f' = I_1' = \frac{V}{Z_1 + \frac{1}{2}Z_T} = 2I_1 \quad \dots(46)$$

or

$$I_1 = \frac{1}{2}I_f' \quad \dots(47)$$

I.e. if it assumed that the network positive and negative phase-sequence impedances are equal, the positive phase sequence current can be found from a simple three-phase fault current calculation, provided that only half the traction transformer (and network) impedance is represented in the study network. Finally, the fault current,  $I_f$ , can be found:

$$|I_f| = \sqrt{3}|I_1| = \frac{\sqrt{3}}{2}|I_f'| \quad \dots(48)$$

If the assumption that  $Z_1 = Z_2$  is valid, the equivalent  $X/R$  ratio can also be found from the 'equivalent' positive sequence representation:

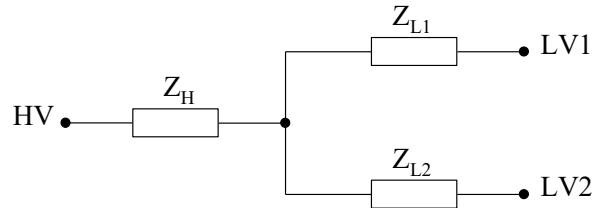
$$\frac{X}{R} = \frac{X_1 + \frac{1}{2}X_T}{R_1 + \frac{1}{2}R_T}$$

$$= \frac{2X_1 + X_T}{2R_1 + R_T} \quad \dots(49)$$

$$= \frac{X_1 + X_2 + X_T}{R_1 + R_2 + R_T}$$

**11.9.1.15 AT feeder transformer model**

A model of an AT transformer is shown below. From short-circuit measurements,  $Z_1$ ,  $Z_2$  and  $Z_{12}$  are usually available. These impedances are determined by respectively short-circuiting LV winding 1, LV winding 2 or both LV windings.



Writing the test impedances ( $Z_1$ ,  $Z_2$  and  $Z_{12}$ ) in terms of the model parameters:

$$\begin{aligned} Z_{12} &= Z_H + Z_{L1} \parallel Z_{L2} \\ &= Z_H + \frac{Z_{L1} Z_{L2}}{Z_{L1} + Z_{L2}} \end{aligned} \quad \dots(50)$$

$$Z_1 = Z_H + Z_{L1} \quad \dots(51)$$

$$Z_2 = Z_H + Z_{L2} \quad \dots(52)$$

To find  $Z_H$ , (50), (51) and (52) can be written in terms of  $Z_H$ ,  $Z_1$ ,  $Z_2$  and  $Z_{12}$ :

$$Z_H^2 - 2Z_{12}Z_H + (Z_{12}Z_1 + Z_{12}Z_2 - Z_1Z_2) = 0 \quad \dots(53)$$

From (53), two solutions for  $Z_H$  can be found. The following example shows how the model parameters are found and how to apply these to a fault calculation.

Typical test impedances, derived from a transformer test certificate for a 400kV / 26.25-0-26.25kV AT transformer, are (referred to HV):

$$\begin{aligned} Z_{12} &= 5.139 + j329.71 \Omega \\ Z_1 &= 10.336 + j651.98 \Omega \\ Z_2 &= 10.401 + j656.16 \Omega \end{aligned} \quad \dots(54)$$

Solving for  $Z_H$ ,  $Z_{L1}$  and  $Z_{L2}$  yields the following two solutions:

	Solution 1	Solution 2
$Z_H$	$-0.090 + j5.357 \Omega$	$10.368 + j654.06 \Omega$
$Z_{L1}$	$10.426 + j646.62 \Omega$	$-0.032 - j2.083 \Omega$
$Z_{L2}$	$10.491 + j650.80 \Omega$	$0.033 + j2.097 \Omega$

Here, the values from solution 1 should be used because it is expected that  $Z_{L1} \approx Z_{L2}$ . Also, solution 2 would lead to an unreasonably low leakage impedance between the two secondary windings. Note that the bulk of the leakage impedance is attributed to the LV winding, which is important when estimating the HV and LV fault currents when both LV windings are short-circuited, as discussed below.

For fault calculations on either LV winding,  $Z_T = Z_1$  or  $Z_T = Z_2$  should be used. For the example case,  $Z_T$  values on a 100 MVA base are:

$$\begin{aligned} Z_T = Z_1 = Z_H + Z_{L1} &= 0.65 + j40.75 \% \\ Z_T = Z_2 = Z_H + Z_{L2} &= 0.65 + j41.01 \% \end{aligned}$$

#### 11.9.1.16 BT and AT systems

Fault calculations for the BT system are straightforward. Care should be taken to use the correct base current to calculate the LV fault current in kA (for a 25kV secondary voltage on a 100 MVA base, the base current is 2.31 kA). Fault currents are typically just below 6 kA.

Matters are slightly more complicated for AT systems or for a BT system fed from an AT transformer. At present, BT systems are commonly fed by AT transformers, using only one secondary winding. AT systems generally have a maximum fault level of 12 kA, so for a BT system fed by an AT transformer, the maximum fault current is usually limited by a series reactor.

Note that the rated AT transformer secondary voltage is unlikely to be 25kV, a rated voltage of 26.25kV seems to be the preferred value. In this case, a base current of 2.2 kA should be used. A typical value of  $Z_T$  for an AT transformer (for a short-circuit on one LV winding) is  $0.6 + j40.9$  % on 100 MVA. The series reactor impedance is in the order of  $0.19 + j26.0$  % on 100 MVA. Take care to consider off-nominal transformer tap ratios when referring the reactor impedance between the HV and LV windings.

Detailed fault calculations on an AT system have to be carried out jointly with Network Rail, as the current distribution in the AT system is not straightforward to determine. However, if the AT electrical system is ignored, a terminal fault on either of the LV windings is treated exactly like the BT case. Two other possibilities require some consideration: (a) a terminal short-circuit on *both* LV windings, or (b) a short-circuit across the series connection of the two windings (i.e. between the catenary terminal and the AT feeder terminal).

- (a) The fault current in the LV windings should be very close to the BT value. This assumes that the LV windings are identical and that the bulk of the leakage impedance can be attributed to the LV windings (see above). However, the HV current will be twice BT value.
- (b) The series connection of the two windings leads to a doubling of the applied voltage, but also doubles the LV leakage impedance. Therefore, the LV fault current will be very close to the BT value. As for (a) above, the HV current doubles to maintain the VA balance between the windings.

**ANNEX 1 - ELECTRICAL CONSTANTS FOR STANDARD HV CONDUCTORS**

**Standard H.V. Overhead Lines**

Table 5 provides the electrical constants, per phase, per kilometre of circuit for 33kV and 11kV overhead lines built to the Company's standard specifications, i.e. horizontal formation with spacing of 3'6" (1.07m) for 33kV and 2'6" (0.76m) for 11kV and lower voltage circuits.

The percentage figures for 11kV line construction working at a lower voltage may be obtained from the 11kV figures by multiplying by the square of (11 divided by the actual voltage in kV) e.g. for an overhead line operating at 6.6kV the percentage value would be the appropriate 11kV figure multiplied by :

$$\left[ \frac{11}{6.6} \right]^2 \quad \text{i.e. by 2.78}$$

The ohmic values would of course, be the same, irrespective of the value of the working voltage.

Table 5 - Hard Drawn Copper Conductors

Voltage (kV)	Conductor Size		Ohms per kilometre			Percentage on 100 MVA per kilometre		
	in <sup>2</sup>	Stranding (in.)	Resistance	Reactance	Impedance	Resistance	Reactance	Impedance
33	.2	7/.193	.140	.340	.372	1.29	3.12	3.42
	.15	7/.166	.180	.350	.394	1.65	3.21	3.62
	.1	7/.136	.270	.360	.460	2.48	3.31	4.22
	.075	7/.116	.370	.370	.525	3.40	3.40	4.82
	.05	1/.252	.530	.380	.655	4.87	3.49	6.01
11	.2	7/.193	.142	.328	.350	11.7	27.1	28.9
	.15	7/.166	.180	.328	.372	14.9	27.1	30.7
	.1	7/.136	.274	.340	.437	22.6	28.1	36.1
	.075	7/.116	.372	.340	.504	30.7	28.1	41.7
	.05	1/.252	.536	.360	.650	44.3	29.8	53.7
	.025	3/.104	1.080	.383	1.150	89.3	31.6	95.0

Reference S Butterworth "Electrical Characteristics of Overhead Lines".

Any error introduced by using the above figures for overhead lines with non-standard spacings will be small. An increase of 100% in the equivalent spacing causes only an increase in reactance of approximately 10% and therefore minor variations in conductor spacings are not considered to be significant.

Table 6 - Steel Cored Aluminium & Hard Drawn Aluminium Conductors

Voltage (kV)	Conductor Size			Cond. Type	Ohms, per km			Percentage on 100 MVA per km		
	in <sup>2</sup> (Cu.e q)	mm <sup>2</sup> (Al.e q)	Stranding (in. or mm)		R	X	Z	R	X	Z
33kV	.2		30/.118 7/.118	S.C.A	.137	.314	.344	1.27	2.89	3.16
	.175		30/.110 7/.110	S.C.A	.159	.320	.356	1.47	2.95	3.29
	.15		30/.102 7/.102	S.C.A	.185	.324	.373	1.70	2.98	3.44
	.1		6/.186 7/.062	S.C.A	.275	.370	.460	2.53	3.42	4.25
	.075		6/.161 1/.161	S.C.A	.366	.385	.532	3.37	3.56	4.90
	0.5		6/.132 1/.132	S.C.A	.544	.392	.672	5.02	3.62	6.19
		150	30/2.59 7/2.59	S.C.A	.185	.324	.373	1.70	2.98	3.44
		400	37/3.78	Alum.	.069	.317	.322	.0635	2.91	2.96
11kV	.2		30/.118 7/.118	S.C.A	.137	.297	.330	11.3	24.5	27.0
	.15		30/.102 7/.102	S.C.A	.185	.304	.357	15.3	25.2	29.4
	.1		6/.186 7/.062	S.C.A	.275	.352	.447	22.8	29.1	37.3
	.075		6/.161 1/.161	S.C.A	.366	.366	.520	30.2	30.2	42.5
	.05		6/.132 1/.132	S.C.A	.544	.373	.660	44.8	30.9	54.5
		25	6/2.34 1/2.34	S.C.A	1.100	.382	1.162	90.5	31.6	96.0
		50	6/3.35 1/3.35	S.C.A	.544	.373	.660	44.8	30.9	54.5
		100	6/4.72 7/1.57	S.C.A	.275	.352	.447	22.8	29.1	37.3
		150	30/2.59 7/2.59	S.C.A	1.85	.304	.357	15.3	25.2	29.4
		400	37/3.78	Alum.	0.69	.317	.322	5.7	26.2	26.8

Reference S Butterworth "Electrical Characteristics of Overhead Lines" other characteristics obtained by calculation.

**Standard HV Underground Cables**

Resistance, Reactance per Kilometre and Percentage on 100 MVA Base

Table 7 - Copper Cables

Voltage (kV)	Conductor Size		Ohms/km			Percentage on 100 MVA Base/km		
	in <sup>2</sup> (Cu)	mm <sup>2</sup> (Al)	R	X	Z	R	X	Z
33kV 3C (Screened)	.06		.4635	.1310	.4216	4.26	1.20	4.42
	.1		.2755	.1126	.2976	2.53	1.03	2.73
	.15		.1882	.1050	.2155	1.73	0.96	1.98
	.2		.1377	.1006	.1705	1.26	0.98	1.57
	.25		.1128	.0973	.1490	1.04	0.89	1.37
	.3		.0920	.0941	.1316	0.84	0.86	1.21
	.5		.0558	.0897	.1056	0.51	0.82	0.97
	.75 Trefoil	300	.073	.0941	.119	0.67	0.86	1.09
22kV 3C (Belted)	0.06		.4635	.1145	.4774	9.58	2.37	9.86
	.1		.2755	.1052	.2949	5.69	2.17	6.09
	.15		.1882	.0981	.2122	3.89	2.03	4.38
	.2		.1377	.0940	.1667	2.84	1.94	3.44
	.25		.1128	.0909	.1449	2.33	1.88	2.99
	.3		.0920	.0879	.1272	1.90	1.82	2.63
11kV (Belted)	.75 Trefoil					.765	2.12	2.25
	.0225		1.256	.1137	1.261	103.80	9.40	104.21
	.06		.4635	.0962	.4733	38.31	7.95	39.12
	.1		.2755	.0897	.2897	22.77	7.41	23.94
	.15		.1882	.0842	.2062	15.55	6.96	17.04
	.2		.1416	.0820	.1636	11.70	6.78	13.52
	.25		.1128	.0798	.1382	9.32	6.60	11.42
	.3		.0920	.0776	.1204	7.60	6.41	9.95
	.5		.0558	.0744	.0930	4.61	6.15	7.69
.6 Trefoil		.045	.092	.1024	3.72	7.60	8.46	
6.6kV (Belted)	.75 Trefoil		.037	.089	.0964	3.06	7.36	7.97
	.0225		1.257	.1040	1.261	288.6	23.88	289.5
	.06		.4635	.0886	.4719	106.4	20.34	108.3
	.1		.2755	.0831	.2878	63.24	19.08	66.06
	.15		.1882	.0787	.2040	43.21	18.08	46.83
	.2		.1416	.0765	.1610	32.51	17.56	36.96
	.25		.1127	.0755	.1357	25.88	17.32	31.14
	.3		.0920	.0744	.1183	21.11	17.07	27.16
.5		.0558	.0711	.0904	12.81	16.32	20.75	
.75 Trefoil		.037	.089	.0964	8.49	20.43	22.13	

Resistance values are at 20°C - See Note (Table 8).



Table 8 - Aluminium Cables

Voltage (kV)	Conductor Size		Ohms/km			Percentage on 100 MVA Base/km		
	in <sup>2</sup> (Cu)	mm <sup>2</sup> (Al)	R	X	Z	R	X	Z
33kV (Screened)	.1		.4517	.1126	.466	4.15	1.03	4.27
	.15		.3084	.1050	.326	2.83	0.96	2.99
	.02		.2322	.1006	.253	2.13	0.92	2.32
	.25		.1849	.0973	.209	1.70	0.89	1.92
	.3		.1505	.0941	.177	1.38	0.86	1.63
		300	.1200	.0940	.152	1.10	0.86	1.40
	0.5		.0914	.0897	.128	0.84	0.82	1.18
11kV (Belted)	0.1		.4517	.0897	.4605	37.33	7.41	38.06
		95	.321	.087	.332	26.5	7.19	27.4
	0.15		.3084	.0842	.3197	25.49	6.96	26.42
	0.2		.2322	.0820	.2462	19.19	6.78	20.35
	0.25		.1849	.0798	.2013	15.28	6.60	16.64
		185	.165	.080	.183	13.6	6.61	15.1
	0.3		.1506	.0776	.1690	12.45	6.42	14.00
		300	.100	.076	.126	8.3	6.32	10.4
11kV used at 6.6kV (Belted)	0.1		.4517	.0897	.4605	103.70	20.59	105.72
		95	.321	.087	.332	73.69	19.97	76.35
	0.15		.3084	.0842	.3197	70.80	19.33	73.39
	0.2		.2322	.0820	.2462	53.31	18.82	56.52
	0.25		.1849	.0798	.2013	42.45	18.32	46.21
		185	.165	.080	.1833	37.88	18.37	42.10
	0.3		.1506	.0776	.1690	34.57	17.81	38.80
		300	.100	.076	.126	22.95	17.45	28.83
	0.5		.0914	.0744	.1178	20.98	17.08	27.04

The resistance values are for a conductor temperature of 20°C.

For a temperature of T°C above 20°C, the above resistance values should be multiplied by the factor  $1 + 0.0039T$ .

The reactance of a screened cable at 6.6kV, 11kV or 22kV can be derived by multiplying the value for the equivalent belted cable by the factor 1.07 for imperial sizes and 1.14 for metric.

The R, X and Z values for a cable operating at 20kV can be obtained by multiplying the equivalent 22kV values by the factor 1.21.