The J & P
Transformer Book

J & P Books

The J&P Transformer Book and *The J&P Switchgear Book* were published originally by Johnson & Phillips Ltd, and have for many years been accepted as standard works of reference by electrical engineers concerned with transformers and switchgear. They now appear under the Newnes imprint.

The J & P Transformer Book

Twelfth edition

A PRACTICAL TECHNOLOGY OF THE
POWER TRANSFORMER

Martin J. Heathcote, CEng, FIEE

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Contents

APPENDICES

Foreword

The J & P Transformer Book has been in print for 75 years and during that time it has been a rewarding work of reference for students, young engineers, older engineers who have changed the direction of their careers to become involed with transformers, practising designers and for generations of applications engineers. In the previous eleven editions the publishers endeavoured to revise the work, extend it and to bring it up to date. The fact that *The J & P Transformer Book* is still in demand is a tribute to the publishers and to the authors who have carried the torch to light our way for 75 years. The first edition was prepared by Mr H. Morgan Lacey in 1925, based on a series of pamphlets entitled *Transformer Abstracts* that were first printed in 1922. The book was welcomed as a key reference, giving a guide to British experience at a time of great change in transformer technology. It was reprinted and revised many times during the next three decades.

The ninth edition was produced in 1958 by Mr A. C. Franklin together with his co-author Mr S. A. Stignant. The tenth edition was produced in 1961 by the same authors, and was revised in 1965. Mr Stignant later retired leaving Mr Franklin, as the main author of the eleventh edition, to carry on the work. This edition was published in 1983 with some assistance from Mr D. P. Franklin, who had been appointed as his co-author.

The current twelfth edition has been prepared by Martin J. Heathcote. Unlike the previous authors, Mr Heathcote has experience as both a manufacturer and a purchaser. His most recent appointment was with PowerGen, a successor company to CEGB, where he gained a wide experience in the design and manufacturing techniques adopted by many different transformer manufacturers both in Britain and overseas. His strong relationship with manufacturers and users has allowed him access to a wide range of information that has been included in this edition. In particular he has completely rewritten many sections of the book to bring it up to date and reflect current experience. The latest information on transformer materials has been included, the modern trend to design transformers with the lowest lifetime costs has been addressed, and interface problems with other equipment has been considered in each section. Mr Heathcote's extensive experience in the operation and maintenance phases of transformer life has been included in this edition, together with a more complete analysis of the many specialist types of transformer that are installed on supply systems and in industrial networks.

This edition contains a wealth of new technical information that has been freely made available by transformer manufacturers, the electrical supply industry, learned institutions and industrial associations such as CIGRE. It is intended that the information contained in this twelfth edition of *The J & P Transformer Book* will update the knowledge of the current generation of engineers and will be of as much use to new generations of engineers as the previous editions have been to their predecessors.

Professor Dennis J. Allan FEng
Stafford, 16 March 1998

Preface to the twelfth edition

A brief history of the *J & P Transformer Book* and of its many distinguished previous authors appears elsewhere in this volume. From this it will be seen that most were chief transformer engineers or chief designers for major manufacturers. The effect of this has been twofold. One, all have tended to write from a manufacturer's point of view, and two, all have held very demanding 'day jobs' whilst attempting to bring the benefit of their particular knowledge and experience to the task of revising and updating the efforts of their predecessors. This is a task of great magnitude, and as a result of the many conflicting demands for their time, even the many 'complete revisions' of the *J & P Transformer Book* have not greatly changed the unique character that can be traced back to 1925.

The production of the twelfth edition has been taken as an opportunity to carry out an almost total rewrite, and, as well as making significant changes to the structure, to change the viewpoint significantly towards that of the transformer user.

It is hoped that the book will, nevertheless, still be of value to the young graduate engineer embarking upon a design carreer, as well as to the student and those involved in transformer manufacture in other than a design capacity. To provide more specialist design information than this would require a very much larger volume and would probably have had the effect of discouraging a significant proportion of the prospective readership. For the more advanced designer, there are other sources, the work of CIGRE, many learned society papers, and some textbooks.

Primarily the objective has been to provide a description of the principles of transformer design and construction, testing operation and maintenance, as well as specification and procurement, in sufficient depth to enable those engineers who have involvement with transformers in a system design, installation or maintenance capacity to become 'informed users,' and it is hoped that, in addition, all of that valuable operational guidance contained in earlier editions has been retained and made more relevant by being brought fully into line with current thinking.

Above all, the hope is that the successful formula which has led to the enormous popularity of earlier editions has not been lost and it is hoped that the information contained in this edition will prove even more useful to today's engineers than those editions which have gone before.

M J H

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The author wishes to express grateful thanks to many friends and colleagues who have provided assistance in this major revision of the *J & P Transformer Book*. In particular to my good friend W. J. (Jim) Stevens who has read every word and provided invaluable criticism and comment; to Professor Dennis Allan, FEng, from whom much help and guidance was received; To Dr Colin Tindall of the Department of Electrical and Electronic Engineering, the Queen's University, Belfast, who read my first chapter and helped me to brush up on my somewhat rusty theory; to other friends who have read and commented on specific sections, and to those who have provided written contributions; Aziz Ahmad-Marican, University of Wales, Cardiff, on Petersen coil earthing; Alan Darwin, GEC Alsthom, on transformer noise; Mike Newman, Whiteley Limited, on transformer insulation; Cyril Smith, Bowthorpe EMP Limited, on surge arresters; to Jeremy Price, National Grid Company, for much constructive comment and advice on the sections relating to many specialised transformers including arc furnace transformers, HVDC converter transformers, traction transformers and rectifier transformers. Grateful thanks are also offered to many organisations who freely provided assistance, as well as data, diagrams and photographs which enabled the chapters to be so generously illustrated.

These include:

ABB Power T & D Limited
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Peebles Transformers
South Wales Transformers Limited

Strategy and Solutions
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In addition to these, special thanks must be expressed to National Power Plc for the loan of the original artwork for over 50 illustrations which originally appeared in my chapter on transformers in Volume D of the Third Edition of *Modern Power Station Practice* published by Pergamon Press.

Finally, despite the extensive revision involved in the production of the Twelfth Edition, some of the work of the original authors, H. Morgan Lacey, the late S. A. Stigant, the late A. C. Franklin, and D. P. Franklin, remains; notably much of the sections on transformer testing, transformer protection, magnetising inrush, parallel operation, and third harmonic voltages and currents, and for this due acknowledgement must be given.

1 Transformer theory

1.1 INTRODUCTION

The invention of the power transformer towards the end of the nineteenth century made possible the development of the modern constant voltage AC supply system, with power stations often located many miles from centres of electrical load. Before that, in the early days of public electricity supplies, these were DC systems with the source of generation, of necessity, close to the point of loading.

Pioneers of the electricity supply industry were quick to recognise the benefits of a device which could take the high-current, relatively low-voltage output of an electrical generator and transform this to a voltage level which would enable it to be transmitted in a cable of practical dimensions to consumers who, at that time, might be a mile or more away and could do this with an efficiency which, by the standards of the time, was nothing less than phenomenal.

Today's transmission and distribution systems are, of course, vastly more extensive and greatly dependent on transformers which themselves are very much more efficient than those of a century ago; from the enormous generator transformers such as the one illustrated in *Figure 7.5*, stepping up the output of up to 19 000 A at 23.5 kV, of a large generating unit in the UK, to 400 kV, thereby reducing the current to a more manageable 1200 A or so, to the thousands of small distribution units which operate almost continuously day in day out, with little or no attention, to provide supplies to industrial and domestic consumers.

The main purpose of this book is to examine the current state of transformer technology, primarily from a UK viewpoint, but in the rapidly shrinking and ever more competitive world of technology it is not possible to retain one's place in it without a knowledge of all that is going on on the other side of the globe, so the viewpoint will, hopefully, not be an entirely parochial one.

For a reasonable understanding of the subject it is necessary to make a brief review of transformer theory together with the basic formulae and simple phasor diagrams.

1.2 THE IDEAL TRANSFORMER – VOLTAGE RATIO

A power transformer normally consists of a pair of windings, primary and secondary, linked by a magnetic circuit or core. When an alternating voltage is applied to one of these windings, generally by definition the primary, a current will flow which sets up an alternating m.m.f. and hence an alternating flux in the core. This alternating flux in linking both windings induces an e.m.f. in each of them. In the primary winding this is the 'back-e.m.f.' and, if the transformer were perfect, it would oppose the primary applied voltage to the extent that no current would flow. In reality, the current which flows is the transformer magnetising current. In the secondary winding the induced e.m.f. is the secondary open-circuit voltage. If a load is connected to the secondary winding which permits the flow of secondary current, then this current creates a demagnetising m.m.f. thus destroying the balance between primary applied voltage and back-e.m.f. To restore the balance an increased primary current must be drawn from the supply to provide an exactly equivalent m.m.f. so that equilibrium is once more established when this additional primary current creates ampere-turns balance with those of the secondary. Since there is no difference between the voltage induced in a single turn whether it is part of either the primary or the secondary winding, then the total voltage induced in each of the windings by the common flux must be proportional to the number of turns. Thus the well-known relationship is established that:

$$E_1/E_2 = N_1/N_2 \tag{1.1}$$

and, in view of the need for ampere-turns balance:

$$I_1N_1 = I_2N_2 \tag{1.2}$$

where E, I and N are the induced voltages, the currents and number of turns respectively in the windings identified by the appropriate subscripts. Hence, the voltage is transformed in proportion to the number of turns in the respective windings and the currents are in inverse proportion (and the relationship holds true for both instantaneous and r.m.s. quantities).

The relationship between the induced voltage and the flux is given by reference to Faraday's law which states that its magnitude is proportional to the rate of change of flux linkage, and Lenz's law which states that its polarity is such as to oppose that flux linkage change if current were allowed to flow. This is normally expressed in the form

$$e = -N(\mathrm{d}\phi/\mathrm{d}t)$$

but, for the practical transformer, it can be shown that the voltage induced per turn is

$$E/N = K\Phi_m f \tag{1.3}$$

where K is a constant, Φ_m is the maximum value of total flux in Webers linking that turn and f is the supply frequency in hertz.

The above expression holds good for the voltage induced in either primary or secondary windings, and it is only a matter of inserting the correct value of N for the winding under consideration. *Figure 1.1* shows the simple phasor diagram corresponding to a transformer on no-load (neglecting for the moment the fact that the transformer has reactance) and the symbols have the significance shown on the diagram. Usually in the practical design of a transformer, the small drop in voltage due to the flow of the no-load current in the primary winding is neglected.

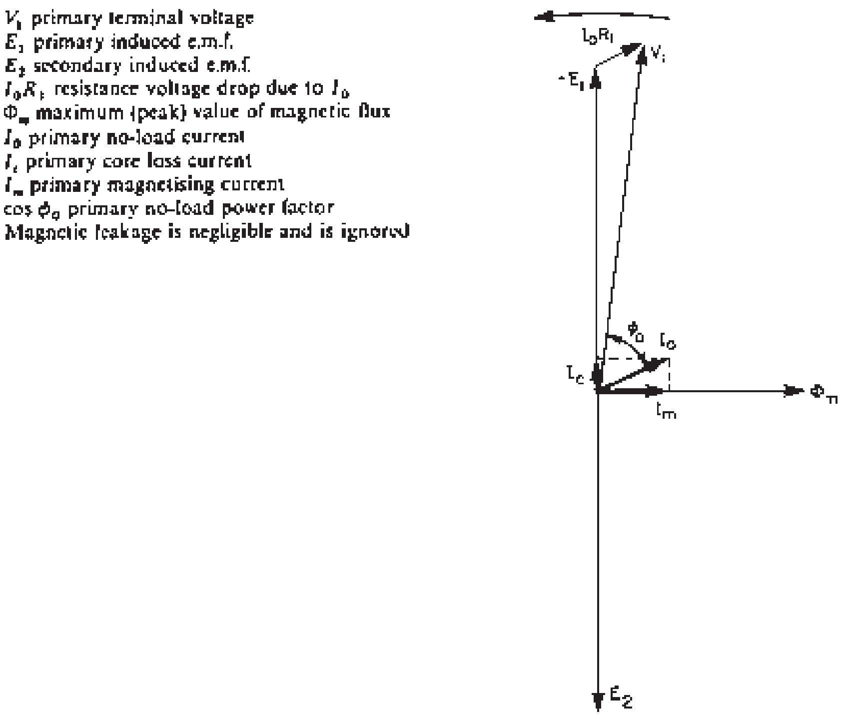


Figure 1.1 Phasor diagram for a single-phase transformer on open circuit. Assumed turns ratio 1:1

If the voltage is sinusoidal, which, of course, is always assumed, K is 4.44 and equation (1.3) becomes

$$E = 4.44 f \Phi N$$

For design calculations the designer is more interested in volts per turn and flux density in the core rather than total flux, so the expression can be rewritten in terms of these quantities thus:

$$E/N = 4.44 B_m A f \times 10^{-6} \tag{1.4}$$

where E/N = volts per turn, which is the same in both windings
B_m = maximum value of flux density in the core, tesla
A = nett cross-sectional area of the core, mm^2
f = frequency of supply, Hz

For practical designs B_m will be set by the core material which the designer selects and the operating conditions for the transformer, A will be selected from a range of cross-sections relating to the standard range of core sizes produced by the manufacturer, whilst f is dictated by the customer's system, so that the volts per turn are simply derived. It is then an easy matter to determine the number of turns in each winding from the specified voltage of the winding.

1.3 LEAKAGE REACTANCE – TRANSFORMER IMPEDANCE

Mention has already been made in the introduction of the fact that the transformation between primary and secondary is not perfect. Firstly, not all of the flux produced by the primary winding links the secondary so the transformer can be said to possess leakage reactance. Early transformer designers saw leakage reactance as a shortcoming of their transformers to be minimised to as great an extent as possible subject to the normal economic constraints. With the growth in size and complexity of power stations and transmission and distribution systems, leakage reactance – or, in practical terms, impedance, since transformer windings also have resistance – gradually came to be recognised as a valuable aid in the limitation of fault currents. The normal method of expressing transformer impedance is as a percentage voltage drop in the transformer at full-load current and this reflects the way in which it is seen by system designers. For example, an impedance of 10% means that the voltage drop at full-load current is 10% of the open-circuit voltage, or, alternatively, neglecting any other impedance in the system, at 10 times full-load current, the voltage drop in the transformer is equal to the total system voltage. Expressed in symbols this is:

$$V_z = \%Z = \frac{I_{FL} Z}{E} \times 100$$

where Z is $\sqrt{(R^2 + X^2)}$, R and X being the transformer resistance and leakage reactance respectively and I_{FL} and E are the full-load current and open-circuit voltage of either primary or secondary windings. Of course, R and X may themselves be expressed as percentage voltage drops, as explained below. The 'natural' value for percentage impedance tends to increase as the rating of the transformer increases with a typical value for a medium-sized power transformer being about 9 or 10%. Occasionally some transformers are deliberately designed to have impedances as high as 22.5%. More will be said about transformer impedance in the following chapter.

1.4 LOSSES IN CORE AND WINDINGS

The transformer also experiences losses. The magnetising current is required to take the core through the alternating cycles of flux at a rate determined by system frequency. In doing so energy is dissipated. This is known variously as the core loss, no-load loss or iron loss. The core loss is present whenever the transformer is energised. On open-circuit the transformer acts as a single winding of high self-inductance, and the open-circuit power factor averages about 0.15 lagging. The flow of load current in the secondary of the transformer and the m.m.f. which this produces are balanced by an equivalent primary load current and its m.m.f., which explains why the iron loss is independent of the load.

The flow of a current in any electrical system, however, also generates loss dependent upon the magnitude of that current and the resistance of the system.

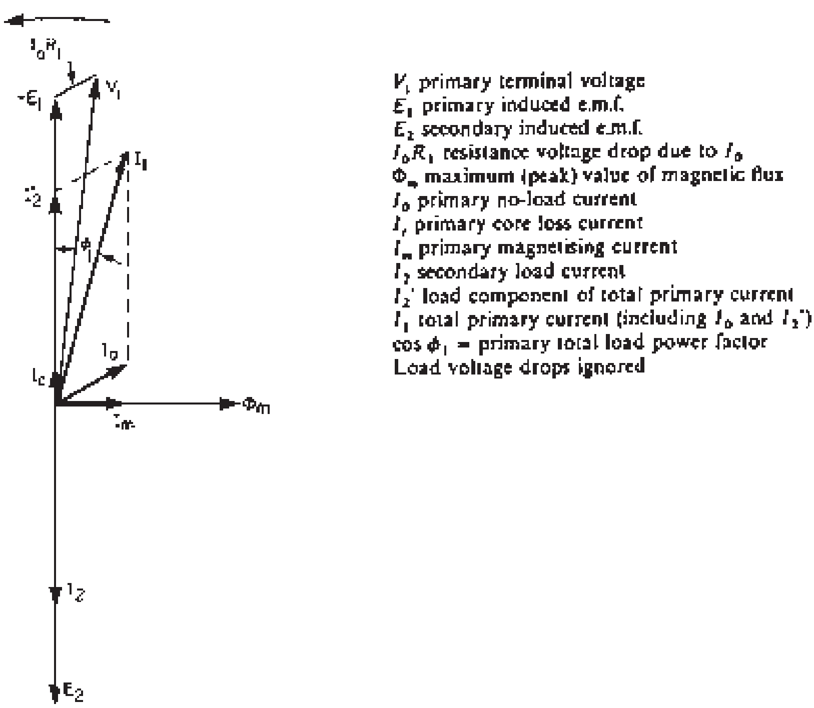


Figure 1.2 Phasor diagram for a single-phase transformer supplying a unity power factor load. Assumed turns ratio 1:1

Transformer windings are no exception and these give rise to the load loss or copper loss of the transformer. Load loss is present only when the transformer is loaded, since the magnitude of the no-load current is so small as to produce negligible resistive loss in the windings. Load loss is proportional to the square of the load current.

Reactive and resistive voltage drops and phasor diagrams

The total current in the primary circuit is the phasor sum of the primary load current and the no-load current. Ignoring for the moment the question of resistance and leakage reactance voltage drops, the condition for a transformer supplying a non-inductive load is shown in phasor form in *Figure 1.2*. Considering now the voltage drops due to resistance and leakage reactance of the transformer windings it should first be pointed out that, however the individual voltage drops are allocated, the sum total effect is apparent at the secondary terminals. The resistance drops in the primary and secondary windings are easily separated and determinable for the respective windings. The

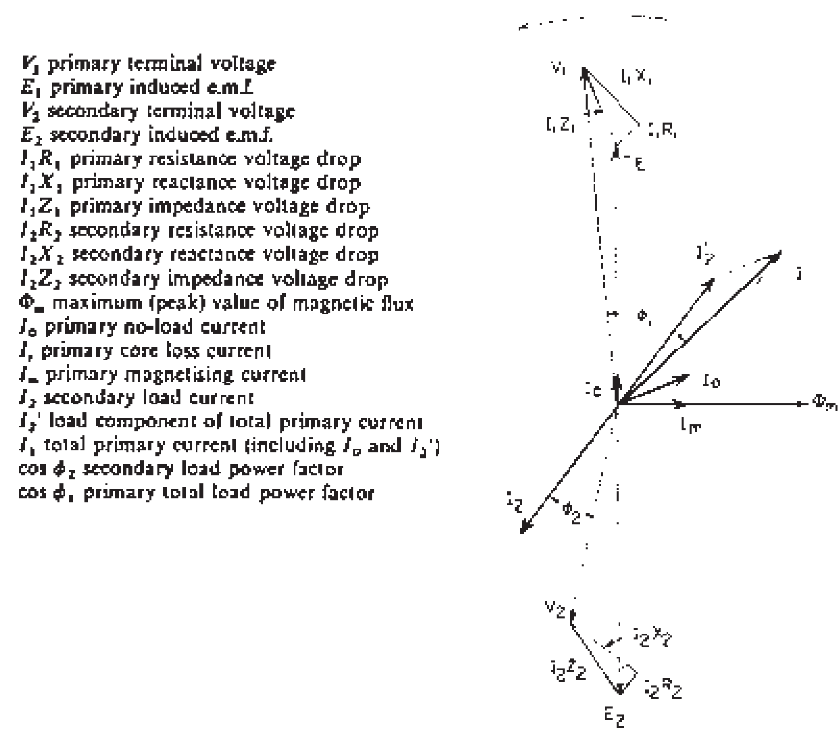


Figure 1.3 Phasor diagram for a single-phase transformer supplying an inductive load of lagging power factor $\cos\phi_2$. Assumed turns ratio 1:1. Voltage drops divided between primary and secondary sides

reactive voltage drop, which is due to the total flux leakage between the two windings, is strictly not separable into two components, as the line of demarcation between the primary and secondary leakage fluxes cannot be defined. It has therefore become a convention to allocate half the leakage flux to each winding, and similarly to dispose of the reactive voltage drops. *Figure 1.3* shows the phasor relationship in a single-phase transformer supplying an inductive load having a lagging power factor of $\cos\phi_2$, the resistance and leakage reactance drops being allocated to their respective windings. In fact the sum total effect is a reduction in the secondary terminal voltage. The resistance and reactance voltage drops allocated to the primary winding appear on the diagram as additions to the e.m.f. induced in the primary windings.

Figure 1.4 shows phasor conditions identical to those in *Figure 1.3*, except that the resistance and reactance drops are all shown as occurring on the secondary side.

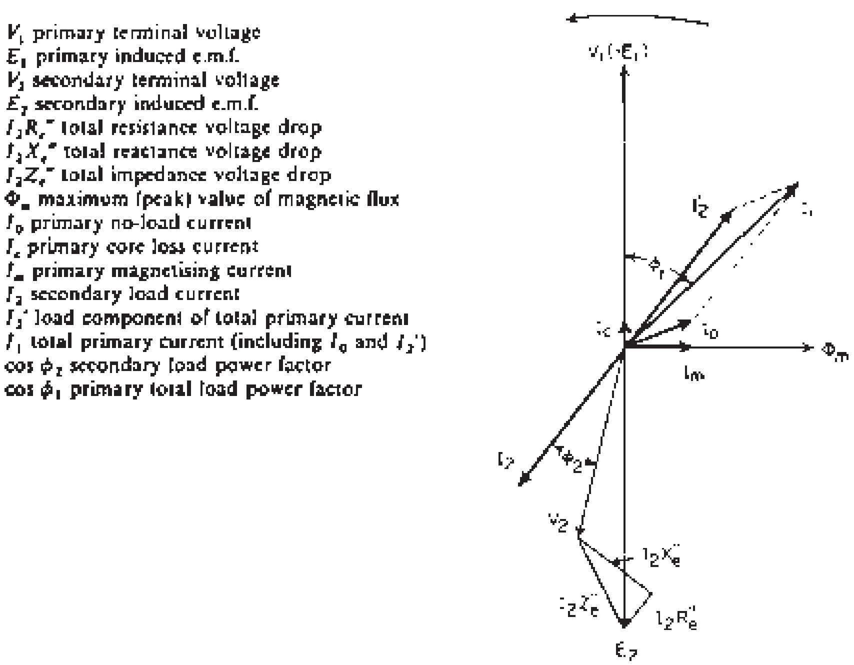


Figure 1.4 Phasor diagram for a single-phase transformer supplying an inductive load of lagging power factor $\cos\phi_2$. Assumed turns ratio 1:1. Voltage drops transferred to secondary side

Of course, the drops due to primary resistance and leakage reactance are converted to terms of the secondary voltage, that is, the primary voltage drops are divided by the ratio of transformation n, in the case of both step-up and step-down transformers. In other words the *percentage* voltage drops considered as occurring in either winding remain the same.

To transfer primary resistance values R_1 or leakage reactance values X_1 to the secondary side, R_1 and X_1 are divided by the square of the ratio of transformation n in the case of both step-up and step-down transformers.

The transference of impedance from one side to another is made as follows:

Let Z_s = total impedance of the secondary circuit including leakage and load characteristics

Z'_s = equivalent value of Z_s when referred to the primary winding

Then $$I'_2 = \frac{N_2}{N_1} I_2 = \frac{N_2}{N_1}\frac{E_2}{Z_s} \text{ and } E_2 = \frac{N_2}{N_1} E_1$$

so $$I'_2 = \left(\frac{N_2}{N_1}\right)^2 \frac{E_1}{Z_s} \tag{1.5}$$

Also, $$V_1 = E_1 + I'_2 Z_1$$

where $$E_1 = I'_2 Z'_s$$

Therefore $$I'_2 = E_1/Z'_s \tag{1.6}$$

Comparing equations (1.5) and (1.6) it will be seen that $Z'_s = Z_s(N_1/N_2)^2$.

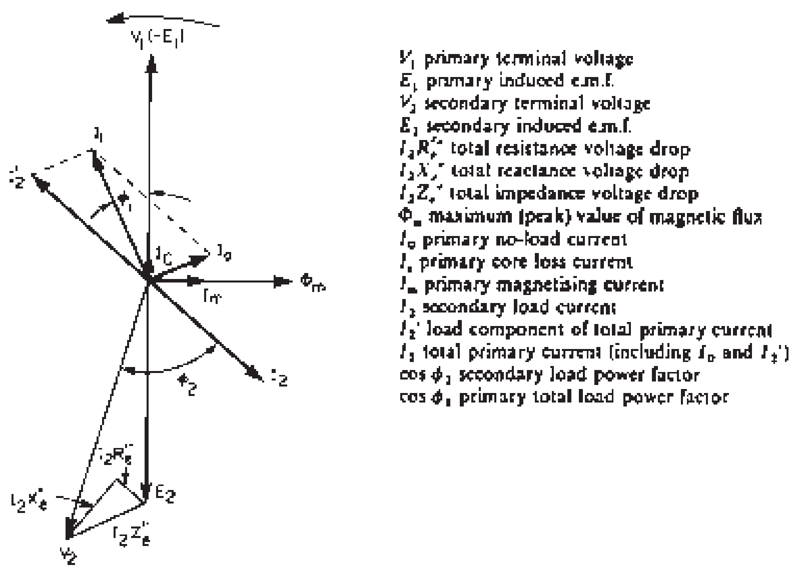


Figure 1.5 Phasor diagram for a single-phase transformer supplying a capacitive load of leading power factor $\cos\phi_2$. Assumed turns ratio 1:1. Voltage drops transferred to secondary side

The equivalent impedance is thus obtained by multiplying the actual impedance of the secondary winding by the square of the ratio of transformation n, i.e. $(N_1/N_2)^2$. This, of course, holds good for secondary winding leakage reactance and secondary winding resistance in addition to the reactance and resistance of the external load.

Figure 1.5 is included as a matter of interest to show that when the load has a sufficient leading power factor, the secondary terminal voltage increases instead of decreasing. This happens when a leading current passes through an inductive reactance.

Preceding diagrams have been drawn for single-phase transformers, but they are strictly applicable to polyphase transformers, so long as the conditions for

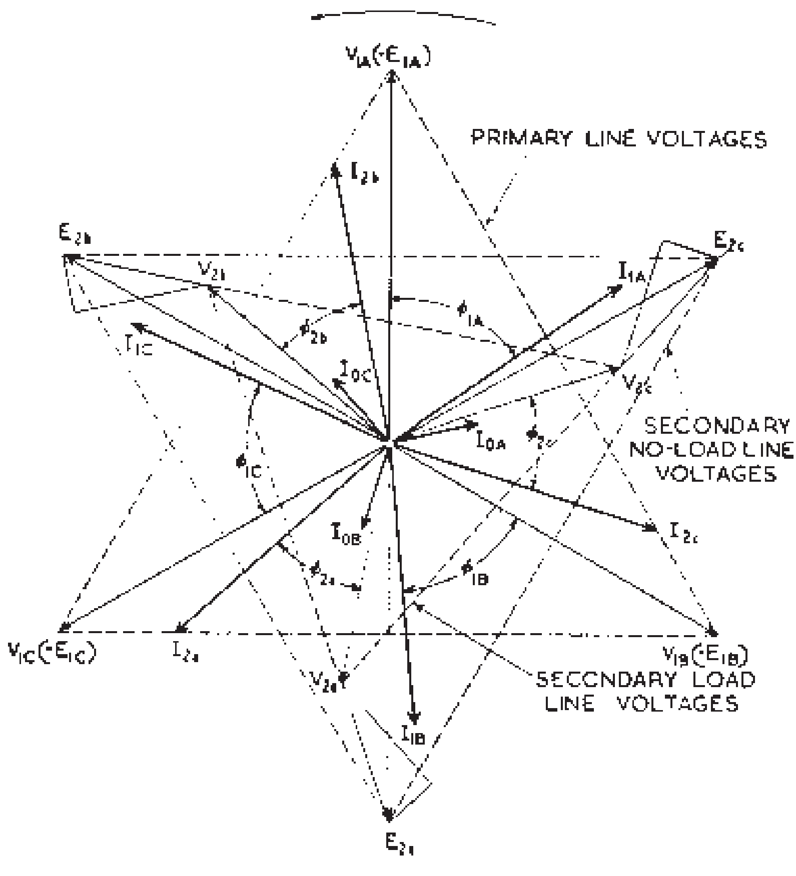


Figure 1.6 Phasor diagram for a three-phase transformer supplying an inductive load of lagging power factor cos ϕ_2. Assumed turns ratio 1:1. Voltage drops transferred to secondary side. Symbols have the same significance as in Figure 1.4 with the addition of A, B and C subscripts to indicate primary phase phasors, and a, b and c subscripts to indicate secondary phase phasors

all the phases are shown. For instance *Figure 1.6* shows the complete phasor diagram for a three-phase star/star-connected transformer, and it will be seen that this diagram is only a threefold repetition of *Figure 1.4*, in which primary and secondary phasors correspond exactly to those in *Figure 1.4*, but the three sets representing the three different phases are spaced 120° apart.

1.5 RATED QUANTITIES

The output of a power transformer is generally expressed in megavolt-amperes (MVA), although for distribution transformers kilovolt-amperes (kVA) is generally more appropriate, and the fundamental expressions for determining these, assuming sine wave functions, are as follows:

Single-phase transformers

Output $= 4.44 f\Phi_m NI$ with the multiplier 10^{-3} for kVA
and 10^{-6} for MVA

Three-phase transformers

Output $= 4.44 f\Phi_m NI \times \sqrt{3}$ with the multiplier 10^{-3} for kVA
and 10^{-6} for MVA

In the expression for single-phase transformers, I is the full-load current in the transformer windings and also in the line; for three-phase transformers, I is the full-load current in each line connected to the transformer. That part of the expression representing the voltage refers to the voltage between line terminals of the transformer. The constant $\sqrt{3}$ is a multiplier for the phase voltage in the case of star-connected windings, and for the phase current in the case of delta-connected windings, and takes account of the angular displacement of the phases.

Alternatively expressed, the rated output is the product of the *rated* secondary (no-load) voltage E_2 and the *rated full-load* output current I_2 although these do not, in fact, occur simultaneously and, in the case of polyphase transformers, by multiplying by the appropriate phase factor and the appropriate constant depending on the magnitude of the units employed. It should be noted that rated primary and secondary voltages do occur simultaneously at no-load.

Single-phase transformers

Output $= E_2 I_2$ with the multiplier 10^{-3} for kVA
and 10^{-6} for MVA

Three-phase transformers

$$\text{Output} = E_2 I_2 \times \sqrt{3} \text{ with the multiplier } 10^{-3} \text{ for kVA}$$
$$\text{and } 10^{-6} \text{ for MVA}$$

The relationships between phase and line currents and voltages for star- and for delta-connected three-phase windings are as follows:

Three-phase star connection

$$\text{phase current} = \text{line current } I = \text{VA}/(E \times \sqrt{3})$$

$$\text{phase voltage} = E/\sqrt{3}$$

Three-phase delta connection

$$\text{phase current} = I/\sqrt{3} = \text{VA}/(E \times \sqrt{3})$$

$$\text{phase voltage} = \text{line voltage} = E$$

$$E \text{ and } I = \text{line voltage and current respectively}$$

1.6 REGULATION

The regulation that occurs at the secondary terminals of a transformer when a load is supplied consists, as previously mentioned, of voltage drops due to the resistance of the windings and voltage drops due to the leakage reactance between the windings. These two voltage drops are in quadrature with one another, the resistance drop being in phase with the load current. The percentage regulation at unity power factor load may be calculated by means of the following expression:

$$\frac{\text{copper loss} \times 100}{\text{output}} + \frac{(\text{percentage reactance})^2}{200}$$

This value is always positive and indicates a voltage drop with load.

The approximate percentage regulation for a current loading of a times rated full-load current and a power factor of $\cos\phi_2$ is given by the following expression:

$$\text{percentage regulation} = a(V_R \cos\phi_2 + V_X \sin\phi_2) + \frac{a^2}{200}(V_X \cos\phi_2 - V_R \sin\phi_2)^2 \tag{1.7}$$

where V_R = percentage resistance voltage at full load

$$= \frac{\text{copper loss} \times 100}{\text{rated kVA}}$$

$$V_X = \text{percentage reactance voltage} = \frac{I_2 X_e''}{V_2} \times 100$$

Equation (1.7) is sufficiently accurate for most practical transformers; however, for transformers having reactance values up to about 4% a further simplification may be made by using the expression:

$$\text{percentage regulation} = a(V_R \cos\phi_2 + V_X \sin\phi_2) \tag{1.8}$$

and for transformers having high reactance values, say 20% or over, it is sometimes necessary to include an additional term as in the following expression:

$$\begin{aligned}\text{percentage regulation} = {} & a(V_R \cos\phi_2 + V_X \sin\phi_2) \\ & + \frac{a^2}{2 \times 10^2}(V_X \cos\phi_2 - V_R \sin\phi_2^2) \\ & + \frac{a^4}{8 \times 10^6}(V_X \cos\phi_2 - V_R \sin\phi_2)^4 \end{aligned} \tag{1.9}$$

At loads of low power factor the regulation becomes of serious consequence if the reactance is at all high on account of its quadrature phase relationship. This question is dealt with more fully in Appendix 4.

Copper loss in the above expressions is measured in kilowatts. The expression for regulation is derived for a simplified equivalent circuit as shown in *Figure 1.7*, that is, a single leakage reactance and a single resistance in series between the input and the output terminals. The values have been represented in the above expressions as secondary winding quantities but they could equally have been expressed in primary winding terms. Since the second term is small it is often sufficiently accurate to take the regulation as equal to the value of the first term only, particularly for values of impedance up to about 4% or power factors of about 0.9 or better.

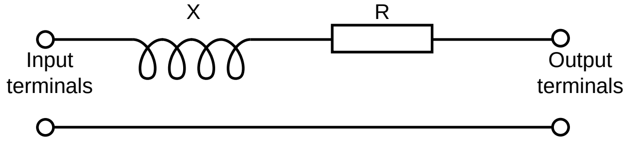


Figure 1.7 Simplified equivalent circuit of leakage impedance of two-winding transformer

V_X may be obtained theoretically by calculation (see Chapter 2) or actually from the tested impedance and losses of the transformer. It should be noted that the per cent resistance used is that value obtained from the transformer losses, since this takes into account eddy-current losses and stray losses within the transformer. This is sometimes termed the AC resistance, as distinct from the value which would be measured by passing direct current through the windings and measuring the voltage drop (see Chapter 5, Testing of transformers).

2 Design fundamentals

2.1 TYPES OF TRANSFORMERS

There are two basic types of transformers categorised by their winding/core configuration: (a) shell type and (b) core type. The difference is best understood by reference to *Figure 2.1*.

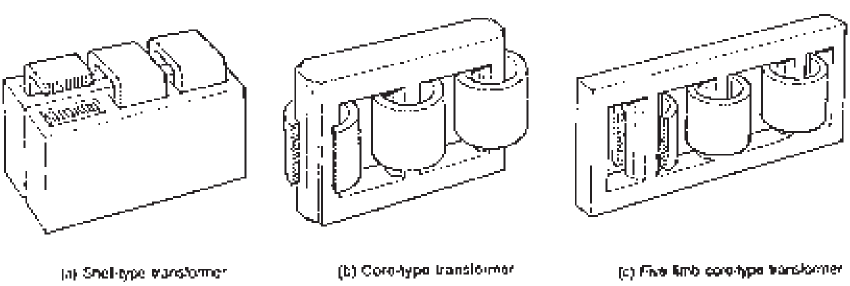


Figure 2.1 Transformer types

In a *shell-type* transformer the flux-return paths of the core are external to and enclose the windings. *Figure 2.1(a)* shows an example of a three-phase shell-type transformer.

While one large power transformer manufacturer in North America was noted for his use of shell-type designs, core-type designs predominate in the UK and throughout most of the world, so that this book will be restricted to the description of core-type transformers except where specifically identified otherwise.

Because of the intrinsically better magnetic shielding provided by the shell-type arrangement this is particularly suitable for supplying power at low voltage and heavy current, as, for example, in the case of arc furnace transformers.

Core-type transformers have their limbs surrounded concentrically by the main windings as shown in *Figure 2.1(b)* which represents a three-phase,

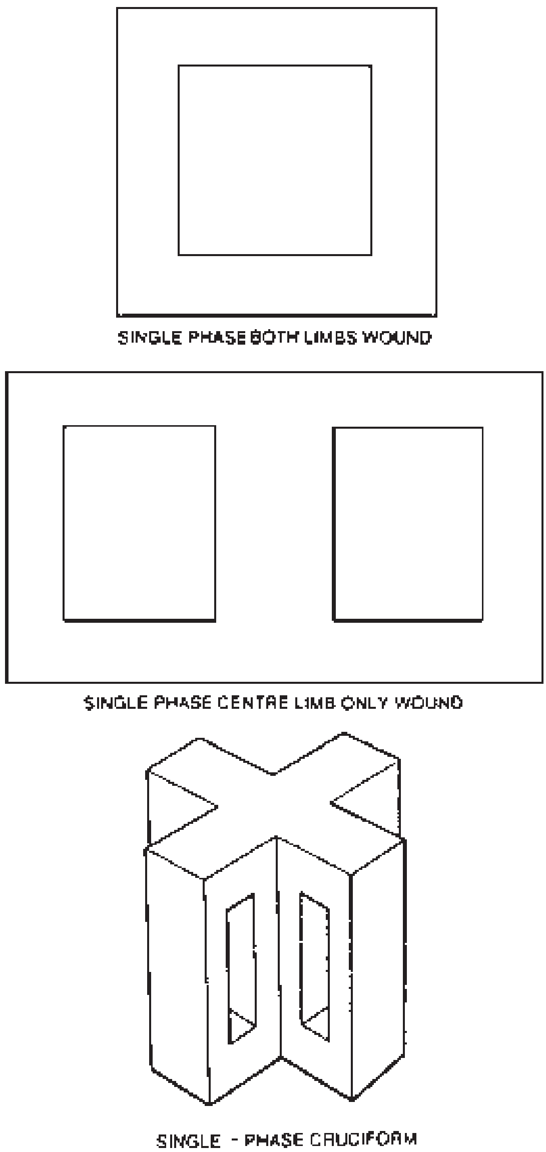


Figure 2.2 Typical core forms for single-phase transformers

three-limb arrangement. With this configuration, having top and bottom yokes equal in cross-section to the wound limbs, no separate flux-return path is necessary, since for a balanced three-phase system of fluxes, these will summate to zero at all times. In the case of a very large transformer which may be subject to height limitations, usually due to transport restrictions, it may be

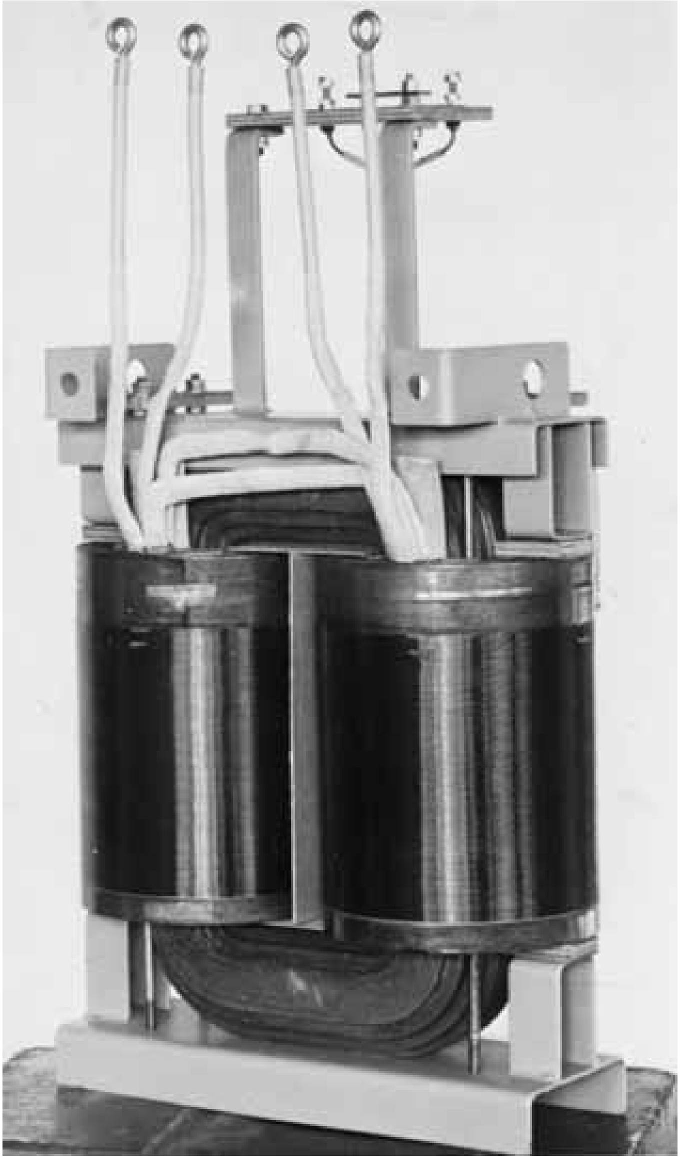


Figure 2.3 Single-phase rural-type transformer with C-type core, rated at 16 kVA 11 000/200–250 V (Allenwest Brentford)

necessary to reduce the depth of the top and bottom yokes. These may be reduced until their cross-sectional area is only 50% of that of the wound limb so that the return flux is split at the top of the limb with half returning in each direction. Clearly in this case return yokes must be provided, so that the arrangement becomes as shown in *Figure 2.1(c)*. The magnetic circuits of these three-phase five-limb core-type transformers behave differently in relation to zero-sequence and third-harmonic fluxes than do the more commonly used three-phase three-limb cores and this aspect will be discussed in greater depth later in this chapter. Of course, it is always necessary to provide a return-flux path in the case of single-phase core-type transformers and various

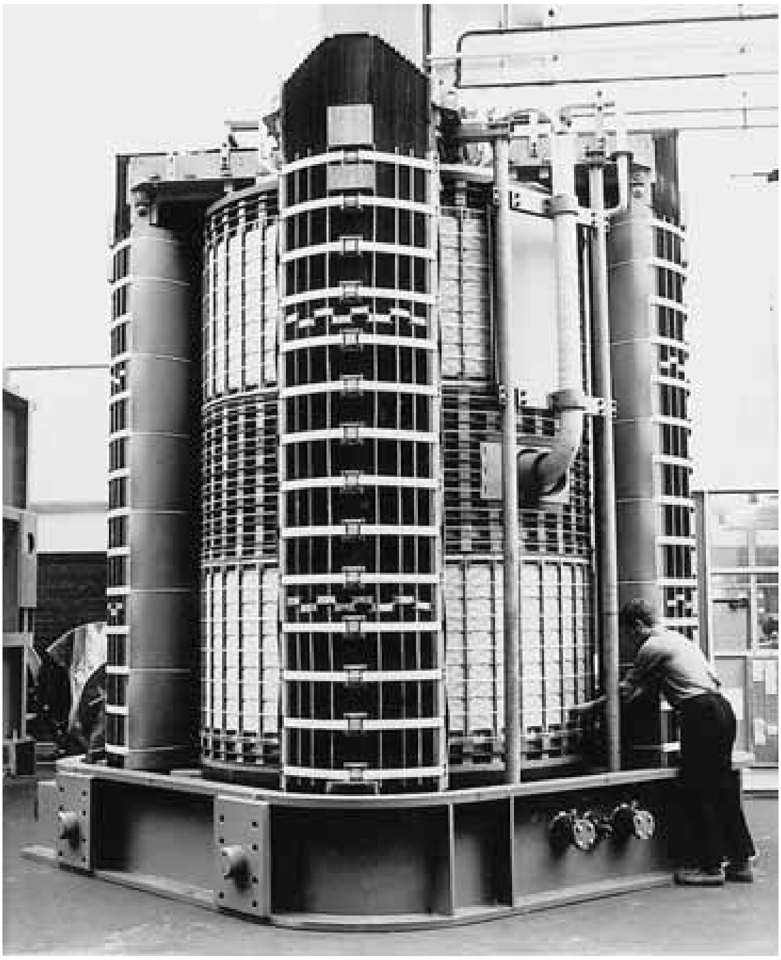


Figure 2.4 Single-phase generator transformer core and winding assembly (cruciform core) 267 MV 432/23.5 kV bank ratio (Peebles Transformers)

configurations are possible according to whether these have one or two wound limbs. *Figure 2.2* shows some of the more common arrangements.

A three-phase transformer has considerable economic advantages over three single-phase units used to provide the same function so that the great majority of power transformers are of three-phase construction. The exceptions occur at each end of the size range.

Single-phase transformers are used at the remote ends of rural distribution systems in the provision of supplies to consumers whose load is not great enough to justify a three-phase supply. These transformers almost invariably have both limbs wound. A typical core and coils assembly of this type is shown in *Figure 2.3*.

Single-phase units are also used for the largest generator transformers. Often the reason for this is to reduce the transport weight and dimensions but there are other factors which influence the argument such as limiting the extent of damage in the event of faults and the economics of providing spare units as well as the ease of moving these around in the event of failures in service. These arguments will be discussed in greater length in the section dealing with generator transformers. In the case of these very large single-phase units the high initial cost justifies a very careful study of all the economic factors affecting each individual design. Such factors include the merits of adopting a one-limb wound or a two-limb wound arrangement. Because the cost of windings usually constitutes a significant proportion of the total cost of these units it is normally more economic to adopt a single-limb wound arrangement. The core and coils of a large single-phase generator transformer are shown in *Figure 2.4*.

The other factor descriptive of the type of transformers which constitute the great majority of power transformers is that they are *double wound*. That is, they have two discrete windings, a low-voltage and a high-voltage winding. This fact is of great importance to the designers of electrical power systems in that it provides a degree of isolation between systems of different voltage level and limits the extent that faults on one system can affect another. More will be said about this in a later chapter.

2.2 PHASE RELATIONSHIPS – PHASOR GROUPS

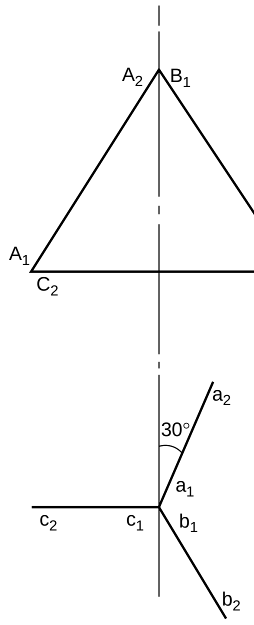
Most electrical systems require an earth, in fact in the UK there is a statutory requirement that all electrical systems should have a connection with earth. This will be discussed further in Section 2 of Chapter 6 which deals in greater detail with the subject of earthing of the neutral. It is convenient, therefore, if the supply winding of the transformer feeding the system can be star connected and thereby provide a neutral for connecting to earth, either solidly or via a fault current-limiting resistor or other such device. It is also desirable that a three-phase system should have a delta to provide a path for third-harmonic currents in order to eliminate or reduce third-harmonic voltages in the waveform, so that considering a step-down transformer, for example, it would be convenient to have the HV winding delta connected and the LV star connected with the neutral earthed.

If a two-winding three-phase transformer has one winding delta connected and the other in star, there will be a phase shift produced by the transformer as can be seen by reference to *Figure 2.5*. In the example shown in the diagram, this phase shift is 30° after 12 o'clock (assuming clockwise rotation) which is referred to as the one o'clock position. The primary delta could also have been made by connecting A_1B_2, B_1C_2 and C_1A_2 which would result in a phase displacement of 30° anticlockwise to the '11 o'clock' position. It has also been assumed that the primary and secondary windings of the transformer have been wound in the same sense, so that the induced voltages appear in the same sense. This produces a transformer with subtractive polarity, since, if the line terminals of a primary and secondary phase are connected together, the voltages will subtract, as can be seen in *Figure 2.5(c)*. If the secondary winding is wound in the opposite sense to the primary, additive polarity will result. The full range of phase relationships available by varying primary and secondary connections can be found in IEC 76, Part 1. There are many circumstances in which it is most important to consider transformer phase relationships, particularly if transformers are to be paralleled or if systems are to be interconnected. This subject will therefore be considered in some detail in Section 4 of Chapter 6 which deals with the requirements for paralleling transformers.

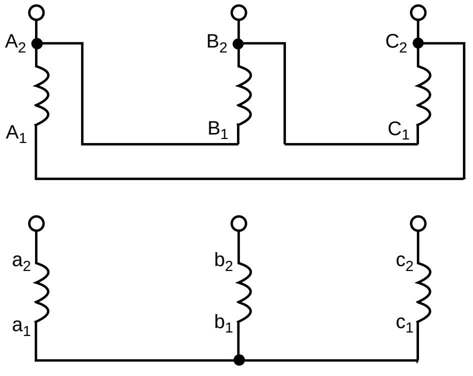
Star/star-connected transformers

One such situation which creates a need for special consideration of transformer connections occurs in the electrical auxiliary system of a power station. When the generator is synchronised to the system and producing power, a small part of its output is generally tapped off the generator terminals to provide a supply for the electrical auxiliaries and this is usually stepped down to a voltage which is less than the generator voltage by means of the *unit transformer*. Such an arrangement is shown in *Figure 2.6*, with a 660 MW generator generating at 23.5 kV stepped up to 400 kV via its *generator transformer* and with a unit transformer providing a supply to the 11 kV unit switchboard. While the unit is being started up, the 11 kV unit board will normally be supplied via the *station transformer* which will take its supply from the 400 kV system, either directly or via an intermediate 132 kV system. At some stage during the loading of the generator, supplies will need to be changed from station to unit source which will involve briefly paralleling these and so, clearly, both supplies must be in phase.

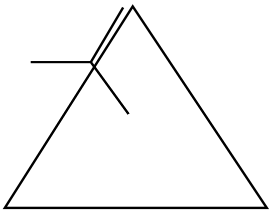
The generator transformer will probably be connected star/delta, with the 23.5 kV phasor at 1 o'clock; that is YNd1. The 23.5/11 kV unit transformer will be connected delta/star, with its 11 kV phasor at the 11 o'clock position; that is Dyn11. This means that the 11 kV system has zero phase shift compared with the 400 kV system. 400 and 132 kV systems are always in phase with each other so that regardless of whether the station transformer is connected



(a)



(b)



(c)

Figure 2.5 Winding connections, phasor and polarity diagram directly to the 400 or to 132 kV, it must produce zero phase displacement and the simplest way of doing this is to utilise a star/star transformer. Such an arrangement ensures that both 400 and 11 kV systems are provided with a neutral for connection to earth, but fails to meet the requirement that the transformer should have one winding connected in delta in order to eliminate

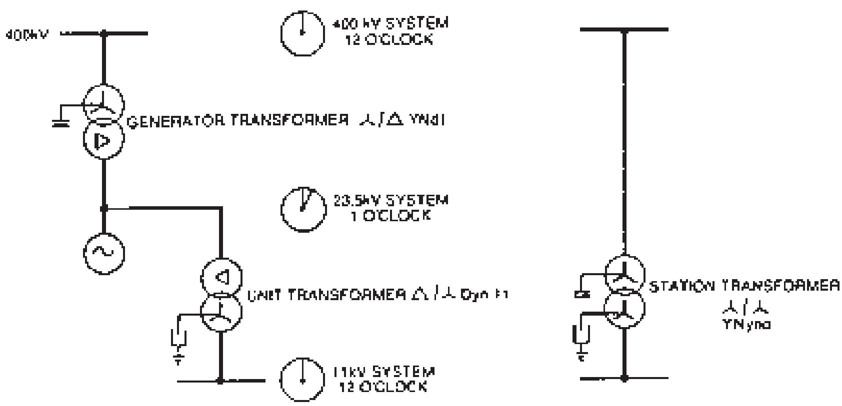


Figure 2.6 Power station auxiliary system

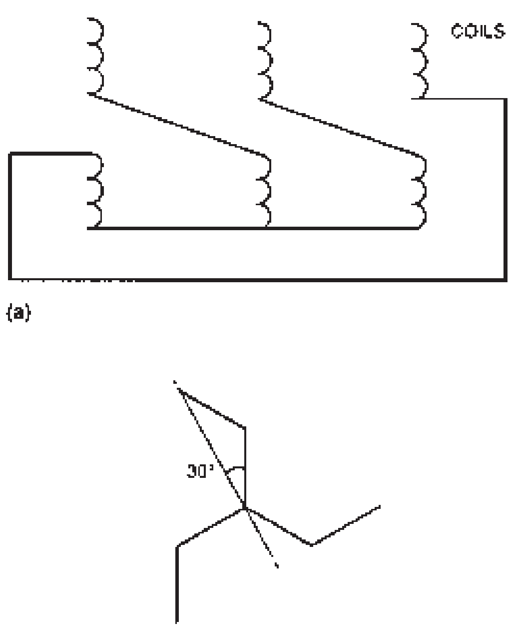


Figure 2.7 Interconnected-star winding arrangement

third-harmonic voltages. It is possible, and it may indeed be necessary, to provide a delta-connected tertiary winding in order to meet this requirement as will be explained later.

The interconnected-star connection

The interconnected-star connection is obtained by subdividing the transformer windings into halves and then interconnecting these between phases. One possible arrangement is shown in *Figure 2.7(a)*, producing a phasor diagram

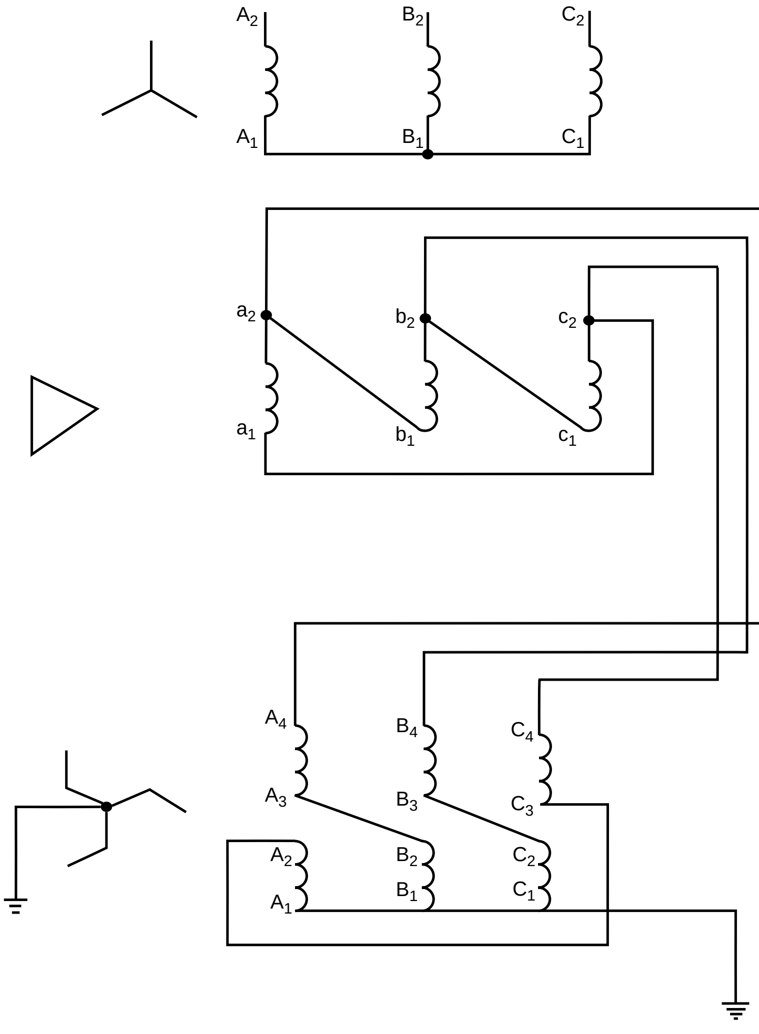


Figure 2.8 Transformer with delta secondary and interconnected-star earthing transformer with neutral connected to earth

of *Figure 2.7(b)*. There is a phase displacement of 30° and, by varying the interconnections and sense of the windings, a number of alternatives can be produced. The interconnected-star arrangement is used to provide a neutral for connection to earth on a system which would not otherwise have one, for example when the low-voltage winding of a step-down transformer is delta connected as shown in *Figure 2.8*. It has the special feature that it has a high impedance to normal balanced three-phase voltages, but a low impedance to the flow of single-phase currents. More will be said about interconnected-star transformers in Section 7 of Chapter 7 and about their use in providing a neutral for connection to earth in Section 2 of Chapter 6.

Autotransformers

It is possible and in some circumstances economically advantageous for a section of the high-voltage winding to be common with the low-voltage winding. Such transformers are known as *autotransformers* and these are almost exclusively used to interconnect very high-voltage systems, for example in the UK the 400 and 132 kV networks are interconnected in this way. Three-phase autotransformers are invariably star/star connected and their use requires that the systems which they interconnect are able to share a common earthing arrangement, usually solid earthing of the common star-point. For very expensive very high-voltage transformers the economic savings resulting from having one winding in common can offset the disadvantages of not isolating the interconnected systems from each other. This will be discussed further in the later section dealing specifically with autotransformers.

2.3 VOLTS PER TURN AND FLUX DENSITY

As explained in Chapter 1, for a given supply frequency the relationship between volts per turn and total flux within the core remains constant. And since for a given core the cross-sectional area of the limb is a constant, this means that the relationship between volts per turn and flux density also remains constant at a given supply frequency. The number of turns in a particular winding will also remain constant. (Except where that winding is provided with tappings, a case which will be considered shortly.) The nominal voltage and frequency of the system to which the transformer is connected and the number of turns in the winding connected to that system thus determines the nominal flux density at which the transformer operates.

The designer of the transformer will wish to ensure that the flux density is as high as possible consistent with avoiding saturation within the core. System frequency is normally controlled within close limits so that if the voltage of the system to which the transformer is connected also stays within close limits of the nominal voltage then the designer can allow the nominal flux density to approach much closer to saturation than if the applied voltage is expected to vary widely.

It is common in the UK for the voltage of a system to be allowed to rise up to 10% above its nominal level, for example at times of light system load. The nominal flux density of the transformers connected to these systems must be such as to ensure a safe margin exists below saturation under these conditions.

2.4 TAPPINGS

Transformers also provide the option of compensating for system regulation, as well as the regulation which they themselves introduce, by the use of tappings which may be varied either on-load, in the case of larger more important transformers, or off-circuit in the case of smaller distribution or auxiliary transformers.

Consider, for example, a transformer used to step down the 132 kV grid system voltage to 33 kV. At times of light system load when the 132 kV system might be operating at 132 kV plus 10%, to provide the nominal voltage of 33 kV on the low-voltage side would require the high-voltage winding to have a tapping for plus 10% volts. At times of high system load when the 132 kV system voltage has fallen to nominal it might be desirable to provide a voltage higher than 33 kV on the low-voltage side to allow for the regulation which will take place on the 33 kV system as well as the regulation internal to the transformer. In order to provide the facility to output a voltage of up to 10% above nominal with nominal voltage applied to the high-voltage winding and allow for up to 5% regulation occurring within the transformer would require that a tapping be provided on the high-voltage winding at about −13%. Thus the volts per turn within the transformer will be:

$$100/87 = 1.15 \text{ approx.}$$

so that the 33 kV system voltage will be boosted overall by the required 15%.

It is important to recognise the difference between the two operations described above. In the former the transformer HV tapping has been varied to keep the volts per turn constant as the voltage applied to the transformer varies. In the latter the HV tapping has been varied to increase the volts per turn in order to boost the output voltage with nominal voltage applied to the transformer. In the former case the transformer is described as having HV tappings for HV voltage variation, in the latter it could be described as having HV tappings for LV voltage variation. The essential difference is that the former implies operation at constant flux density whereas the latter implies variable flux density.

Except in very exceptional circumstances transformers are always designed as if they were intended for operation at constant flux density. In fixing this value of nominal flux density some allowance is made for the variations which may occur in practice. The magnitude of this allowance depends on the application and more will be said on this subject in Chapter 7 when specific types of transformers are described.

2.5 IMPEDANCE

In Chapter 1 it was explained that the leakage reactance of a transformer arises from the fact that all the flux produced by one winding does not link the other winding. As would be expected, then, the magnitude of this leakage flux is a function of the geometry and construction of the transformer. *Figure 2.9* shows a part section of a core-type transformer taken axially through the centre of the wound limb and cutting the primary and secondary windings. The principal dimensions are marked in the figure, as follows:

- l is axial length of windings (assumed the same for primary and secondary)
- a is the radial spacing between windings
- b the radial depth of the winding next to the core
- c the radial depth of the outer winding

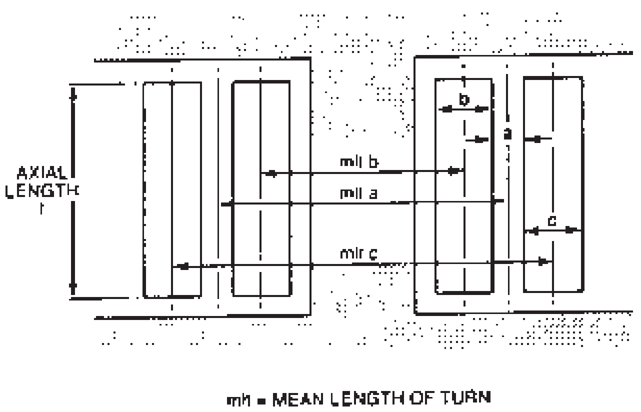


Figure 2.9 Arrangement of windings on single-phase and three-phase cores

If mlt is then the mean length of turn of the winding indicated by the appropriate subscript, mlt_b for the inner winding, mlt_c for the outer winding and mlt_a for a hypothetical winding occupying the space between inner and outer windings, then the leakage reactance in per cent is given by the expression

$$\%X = KF(3a\text{mlt}_a + b\text{mlt}_b + c\text{mlt}_c)/\Phi_m l \qquad (2.1)$$

where K is a constant of value dependent on the system of units used
F is equal to the ampere-turns of primary or secondary winding, i.e., m.m.f. per limb
Φ_m is the maximum value of the total flux in the core

The above equation assumes that both LV and HV windings are the same length, which is rarely the case in practice. It is also possible that a tapped winding may have an axial gap when some of the tappings are not in circuit. It is usual therefore to apply various correction factors to l to take account of these practical aspects. However, these corrections do not change the basic form of the equation.

Equation (2.1) together with (1.1) and (1.2) given in the previous chapter determine the basic parameters which fix the design of the transformer. The m.m.f. is related to the MVA or kVA rating of the transformer and the maximum total flux, Φ_m, is the product of the maximum flux density and core cross-sectional area. Flux density is determined by consideration of the factors identified in the previous section and the choice of core material. The transformer designer can thus select a combination of Φ_m and l to provide the value of reactance required. In practice, of course, as identified in the previous chapter, the transformer winding has resistance as well as reactance so the parameter which can be measured is impedance. In reality for most large power transformers the resistance is so small that there is very little difference between reactance and impedance.

For many years the reactance or impedance of a transformer was considered to be simply an imperfection creating regulation and arising from the unavoidable existence of leakage flux. It is now recognised, however, that transformer impedance is an invaluable tool for the system designer enabling him to determine system fault levels to meet the economic limitations of the switchgear and other connected plant. The transformer designer is now, therefore, no longer seeking to obtain the lowest transformer impedance possible but to meet the limits of minimum and maximum values on impedance specified by the system designer to suit the economics of his system design. (It may, of course, be the case that he would like to see manufacturing tolerances abolished and no variation in impedance with tap position, but generally an acceptable compromise can be reached on these aspects and they will be discussed at greater length later.)

It is worthwhile looking a little more closely at the factors determining impedance and how these affect the economics of the transformer. The relationship must basically be a simple one. Since reactance is a result of leakage flux, low reactance must be obtained by minimising leakage flux and doing this requires as large a core as possible. Conversely, if high reactance can be tolerated a smaller core can be provided. It is easy to see that the overall size of the transformer must be dependent on the size of the core, so that large core means a large and expensive transformer, a small core means a less expensive transformer. Hence, providing a low reactance is expensive, a high reactance is less expensive. Nevertheless within the above extremes there is a band of reactances for a particular size of transformer over which the cost variation is fairly modest.

Looking more closely at equation (2.1) gives an indication of the factors involved in variation within that band. A larger core cross-section, usually referred to as the frame size, and a longer l will reduce reactance and, alternatively, reducing frame size and winding length will increase reactance. Unfortunately, the designer's task is not quite as simple as that since variation of any of the principal parameters affects the others which will then also affect the reactance. For example, increasing Φ_m not only reduces reactance, because of its appearance in the denominator of equation (2.1), but it also reduces the number of turns, as can be seen by referring to equation (1.1), which will thus reduce reactance still further. The value of l can be used to adjust the reactance since it mainly affects the denominator of equation (2.1). Nevertheless, if l is reduced, say, to increase reactance, this shortening of the winding length results in an increase in the radial depth (b and c) of each winding, in order that the same number of turns can be accommodated in the shorter axial length of the winding. This tends to increase the reactance further. Another means of fine tuning the reactance is by variation of the winding radial separation, the value 'a' in equation (2.1). This is more sensitive than changes in b and c since it is multiplied by the factor three, and the designer has more scope to effect changes since the dimension 'a' is purely the dimension of a 'space'. Changes in the value of 'a' also have less of a knock-on effect although they will, of course, affect 'mlt_c'. For a given

Table 2.1 Typical percentage impedances of 50 Hz three-phase transformers

MVA	*Highest voltage for equipment (kV)*						
	12	*36*	*72.5*	*145*	*245*	*300*	*420*
0.315	4.75	5.0	5.5				
0.500	4.75	5.0	5.5				
0.630	4.75	5.0	5.5				
0.800	4.75	5.0	6.0				
1.00	4.75	5.0	6.0	7.0			
1.60	5.0	5.5	6.5	7.0			
2.00	5.5	6.0	6.5	7.0			
2.50	6.5	7.0	7.0	7.5			
3.15	7.0	7.5	7.5	8.0			
6.30	7.5	8.0	8.0	8.5			
8.00	8.5	9.0	9.0	9.0			
10	9.0	9.0	10.0	10.0			
12.5	10.0	10.0	10.0	10.0			
20		10.0	10.0	11.0	13.0		
25		10.0	11.0	11.0	13.0		
30		11.0	11.0	12.0	13.0		
45		11.0	12.0	12.0	14.0	15.0	
60		12.0	12.5	12.5	15.0	15.0	16.0
75					15.0	16.0	17.5
90					16.0	16.0	17.5
100					16.0	17.5	18.0
120					17.5	19.0	20.0
180					19.0	20.0	22.0
240					20.0	21.0	22.0

transformer '*a*' will have a minimum value determined by the voltage class of the windings and the insulation necessary between them. In addition, the designer will not wish to artificially increase '*a*' by more than a small amount since this is wasteful of space within the core window.

It should be noted that since the kVA or MVA factor appears in the numerator of the expression for per cent reactance, the value of reactance tends to increase as the transformer rating increases. This is of little consequence in most transformers, as almost any required reactance can normally be obtained by appropriate adjustment of the physical dimensions, but it does become very significant for large generator transformers, as permissible transport limits of dimensions and weight are reached. It is at this stage that the use of single-phase units may need to be considered.

Table 2.1 lists typical impedance values for a range of transformer ratings which may be found in transmission and distribution systems. It should be recognised that these are typical only and not necessarily optimum values for any rating. Impedances varying considerably from those given may well be encountered in any particular system.

2.6 MULTI-WINDING TRANSFORMERS INCLUDING TERTIARY WINDINGS

It has been assumed thus far that a transformer has only two windings per phase, a low-voltage and a high-voltage winding. In fact, although this is by far the most frequent arrangement, there is no reason why the number of windings should be limited to two. The most common reason for the addition of a third winding to a three-phase transformer is the provision of a delta-connected tertiary winding. Other reasons for doing so could be as follows:

- To limit the fault level on the LV system by subdividing the infeed – that is, double secondary transformers.
- The interconnection of several power systems operating at different supply voltages.
- The regulation of system voltage and of reactive power by means of a synchronous capacitor connected to the terminals of one winding.

Tertiary windings

As indicated in Chapter 1, it is desirable that a three-phase transformer should have one set of three-phase windings connected in delta thus providing a low-impedance path for third-harmonic currents. The presence of a delta-connected winding also allows current to circulate around the delta in the event of unbalance in the loading between phases, so that this unbalance is reduced and not so greatly fed back through the system. Although system designers will aim to avoid the use of star/star-connected transformers, there are occasions when the phase shift produced by a star/delta or delta/star transformer is not acceptable as, for example, in the case of the power station auxiliary system described above. For many years it was standard practice in this situation to provide a delta-connected tertiary winding on the transformer.

Because the B/H curve of the magnetic material forming the transformer core is not linear, if a sinusoidal voltage is being applied for a sinusoidal flux (and hence a sinusoidal secondary voltage), the magnetising current is not sinusoidal. Thus the magnetising current of a transformer having an applied sinusoidal voltage will comprise a fundamental component and various harmonics. The magnitude and composition of these harmonics will depend on the magnetising characteristic of the core material and the value of the peak flux density. It is usual for third harmonics to predominate along with other higher third-order harmonics.

Since the third-order harmonic components in each phase of a three-phase system are in phase, there can be no third-order harmonic voltages between lines. The third-order harmonic component of the magnetising current must thus flow through the neutral of a star-connected winding, where the neutral of the supply and the star-connected winding are both earthed, or around any delta-connected winding. If there is no delta winding on a star/star transformer, or the neutral of the transformer and the supply are not both connected to earth, then line to earth capacitance currents in the supply system lines can supply the necessary harmonic component. If the harmonics cannot flow in any of these paths then the output voltage will contain the harmonic distortion.

Even if the neutral of the supply and the star-connected winding are both earthed, as described above, then although the transformer output waveform will be undistorted, the circulating third-order harmonic currents flowing in the neutral can cause interference with telecommunications circuits and other electronic equipment as well as unacceptable heating in any liquid neutral earthing resistors, so this provides an added reason for the use of a delta-connected tertiary winding.

If the neutral of the star-connected winding is unearthed then, without the use of a delta tertiary, this neutral point can oscillate above and below earth at a voltage equal in magnitude to the third-order harmonic component. Because the use of a delta tertiary prevents this it is sometimes referred to as a stabilising winding.

The number of turns, and hence rated voltage, of any tertiary winding may be selected for any convenient value. Thus the tertiary terminals may be brought out for supplying any substation auxiliary load, dispensing with the need for any separate auxiliary transformer. In the case of large transmission autotransformers, which must of necessity be star/star connected, a common use of the tertiary winding is for connection of system compensation equipment.

Although any auxiliary load may be quite small in relation to the rating of the main transformer, the rating of the tertiary must be such as to carry the maximum circulating current which can flow as a result of the worst system unbalance. Generally this worst unbalance is that condition resulting from a line to earth short-circuit of the secondary winding with the secondary neutral point earthed, see below.

Assuming a one-to-one turns ratio for all windings, the load currents in the primary phases corresponding to a single-phase load on the secondary of a star/star transformer with delta tertiary are typically as shown in *Figure 2.10*. This leads to an ampere-turns rating of the tertiary approximately equal to one-third that of the primary and secondary windings and provides a common method for rating the tertiary in the absence of any more specific rating basis. The full range of possible fault conditions are shown in *Figure 2.11*. The magnitude of the fault current in each case is given by the following expressions. For case (a)

$$I_S = \frac{100I}{IZ_{PT}} \tag{2.2}$$

for case (b) the fault current is

$$I_S = \frac{100I}{2IZ_{PS} + IZ_{TS}} \tag{2.3}$$

for case (c) the fault current is

$$I_S = \frac{100I}{IZ_{PT}} \tag{2.4}$$

and for case (d) the fault current is

$$I_S = \frac{100I}{2IZ_{PS} + IZ_{TS}} \tag{2.5}$$

where I_S = the fault current shown in *Figure 2.11(a), (b)* and *(c)*
I_{SP} = the fault current due to the primary supply in *Figure 2.11(d)*
I_{SS} = the fault current due to the secondary supply in *Figure 2.11(d)*
I = normal full-load current of the transformer
IZ_{PS} = the percentage normal full-load impedance per phase between primary and secondary windings

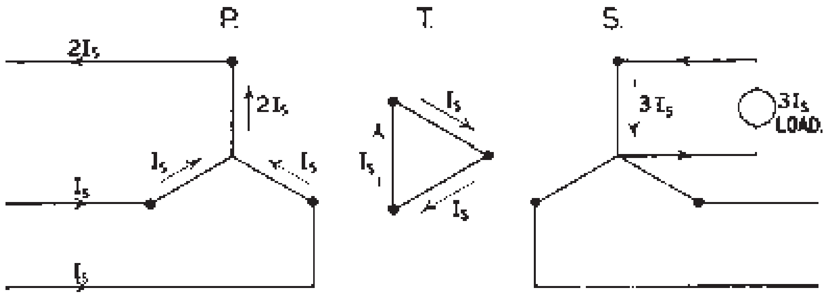


Figure 2.10 Single-phase load to neutral

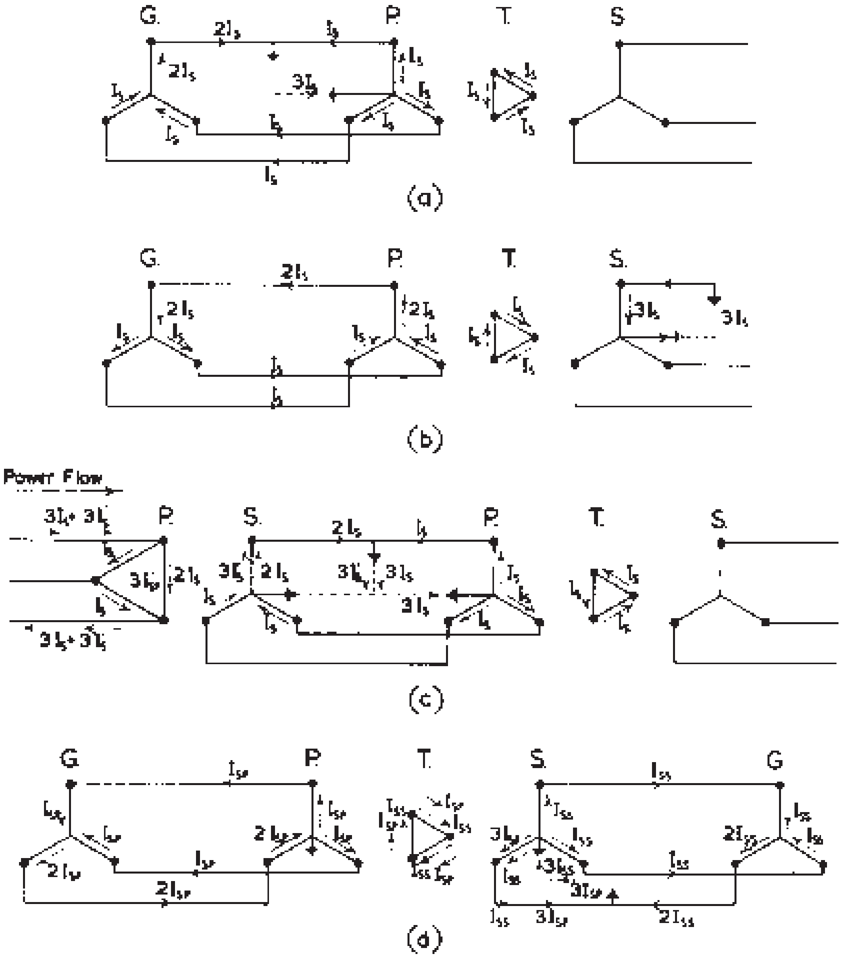


Figure 2.11 Fault currents due to short-circuits to neutral

IZ_{PT} = the percentage normal full-load impedance per phase between primary and tertiary windings

IZ_{TS} = the percentage normal full-load impedance per phase between tertiary and secondary windings

Expressions (2.2) to (2.5) apply strictly to one-to-one turns ratio of all windings, and the true currents in each case can easily be found by taking due account of the respective turns ratios.

It will be appreciated that from the point of view of continuous and short time loads the impedances between tertiary windings and the two main windings are of considerable importance. The tertiary winding must be designed to be strong enough mechanically, to have the requisite thermal capacity, and to have sufficient impedance with respect to the two main windings to be able to withstand the effect of short-circuits across the phases of the main windings and so as not to produce abnormal voltage drops when supplying unbalanced loads continuously.

When specifying a transformer which is to have a tertiary the intending purchaser should ideally provide sufficient information to enable the transformer designer to determine the worst possible external fault currents that may flow in service. This information (which should include the system characteristics and details of the earthing arrangements) together with a knowledge of the impedance values between the various windings, will permit an accurate assessment to be made of the fault currents and of the magnitude of currents that will flow in the tertiary winding. This is far preferable to the purchaser arbitrarily specifying a rating of, say, 33.3%, of that of the main windings, although the reason for use of this rule-of-thumb method of establishing a rating in the absence of any more precise information will be apparent from the example of *Figure 2.10*. A truly satisfactory value of the rating of the tertiary winding can only be derived with a full knowledge of the impedances between windings of the transformer and of the other factors identified above.

As indicated at the start of this section, the above philosophy with regard to the provision of tertiary windings was adopted for many years and developed when the cores of transformers were built from hot-rolled steel. These might have a magnetising current of up to 5% of full-load current. Modern cold-rolled steel cores have a much lower order of magnetising current, possibly as low as 0.5% of full-load current. In these circumstances the effect of any harmonic distortion of the magnetising current is much less significant. It now becomes, therefore, much more a matter of system requirements as to whether a star/star transformer is provided with a delta tertiary or not.

In the case of a star/star-connected transformer with the primary neutral unearthed and with the neutral of the secondary connected to earth, a secondary phase to earth fault may not cause sufficient fault current to flow to cause operation of the protection on account of the high impedance offered to the flow of single-phase currents by this configuration. Generally the presence of a delta tertiary remedies this by permitting the flow of circulating currents which lead to balancing currents in the other two phases. The problem can be illustrated by considering as an example the design of the 60 MVA star/star-connected 132/11 kV station transformer for the CEGB’s Littlebrook ‘D’ Power Station in the mid-1970s. This was one of the first of the CEGB’s power stations to have a station transformer as large as 60 MVA, and there was concern that if this were to follow the usual practice of having a delta-connected tertiary winding, the fault level for single phase to earth faults on the 11 kV system when operating in parallel with the unit transformer might become excessive. Since, at this time, the practice of omitting the tertiaries of star/star-connected 33/11 kV transformers was becoming relatively common, the proposal was made to leave off the tertiary. Discussions were then initiated with transformer manufacturers as to whether there would be a problem of too little fault current in the case of 11 kV earth faults. Manufacturers were able to provide reassurance that this would not be the case and when the transformer was built and tested, this proved to be so. Analysis of problems of this type is best carried out using the concept of zero-sequence impedance and this is described below.

2.7 ZERO-SEQUENCE IMPEDANCE

It is usual in performing system design calculations, particularly those involving unbalanced loadings and for system earth fault conditions, to use the principle of symmetrical components. This system is described in Appendix 5 and ascribes positive, negative and zero-sequence impedance values to the components of the electrical system.

For a three-phase transformer, the positive and negative sequence impedance values are identical to that value described above, but the zero-sequence impedance varies considerably according to the construction of the transformer and the presence, or otherwise, of a delta winding.

The zero-sequence impedance of a star winding will be very high if no delta winding is present. The actual value will depend on whether there is a low reluctance return path for the third-harmonic flux.

For three-limb designs without a delta, where the return-flux path is through the air, the determining feature is usually the tank, and possibly the core support framework, where this flux creates a circulating current around the tank and/or core framework. The impedance of such winding arrangements is likely to be in the order of 75 to 200% of the positive-sequence impedance between primary and secondary windings. For five-limb cores and three-phase banks of single-phase units, the zero-sequence impedance will be the magnetising impedance for the core configuration.

Should a delta winding exist, then the third harmonic flux will create a circulating current around the delta, and the zero-sequence impedance is determined by the leakage field between the star and the delta windings. Again the type of core will influence the magnitude of the impedance because of the effect it has on the leakage field between the windings. Typical values for three-limb transformers having a winding configuration of core/tertiary/star LV/star HV are:

$[Z_0]_{LV}$ approximately equal to 80 to 90% of positive-sequence impedance LV/tertiary

$[Z_0]_{HV}$ approximately equal to 85 to 95% of positive-sequence impedance HV/tertiary

where Z_0 = zero-sequence impedance.

Five-limb transformers have their zero-sequence impedances substantially equal to their positive-sequence impedance between the relative star and delta windings.

2.8 DOUBLE SECONDARY TRANSFORMERS

Another special type of multi-winding transformer is the double secondary transformer. These transformers are sometimes used when it is required to split the number of supplies from an HV feeder to economise on the quantity of HV switchgear and at the same time limit the fault level of the feeds to the LV switchgear. This can be particularly convenient when it is

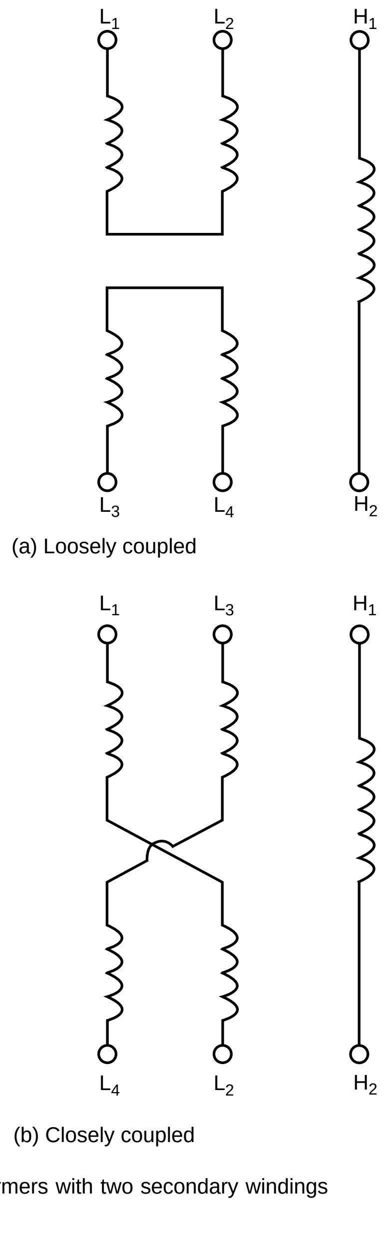


Figure 2.12 Transformers with two secondary windings

required to omit an intermediate level of voltage transformation. For example, a 60 MVA, 132 kV feeder to a distribution network would normally step down to 33 kV. If, in order to meet the requirements of the distribution network, it is required to transform down to 11 kV, this equates to an LV current of about 3000 A and, even if the transformer had an impedance of around 20%, an LV fault level from the single infeed of around 15 kA, both figures which are considerably higher than those for equipment normally used on a distribution network.

The alternative is to provide two separate secondary windings on the 60 MVA transformer, each rated at 30 MVA, with impedances between HV and each LV of, say, 16%. Two sets of LV switchgear are thus required but these can be rated 1500 A and the fault level from the single infeed would be less than 10 kA.

In designing the double secondary transformer it is necessary that both LV windings are disposed symmetrically with respect to the HV winding so that both have identical impedances to the HV. This can be done with either of the arrangements shown in *Figure 2.12*. In both arrangements there is a crossover between the two LV windings half way up the limb. However, in the configuration shown in *Figure 2.12(a)* the inner LV upper half crosses to the outer upper half and the inner lower half crosses to the outer lower half, while in the configuration of *Figure 2.12(b)* upper inner crosses to lower outer and upper outer to lower inner. The LV windings of *Figure 2.12(a)* are

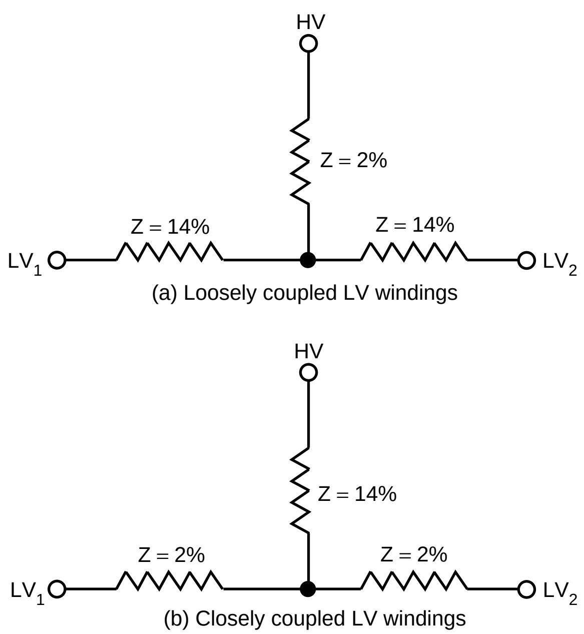


Figure 2.13 Equivalent circuits for loosely coupled and closely coupled double secondary transformers

thus loosely coupled, while those of *Figure 2.12(b)* are closely coupled, so that the leakage reactance LV_1 to LV_2 of *Figure 2.12(a)* is high and that of *Figure 2.12(b)* is low. It is thus possible to produce equivalent circuits for each of these arrangements as shown in *Figures 2.13(a)* and *(b)* in which the transformer is represented by a three-terminal network and typical values of impedance (leakage reactance) are marked on the networks. For both arrangements the HV/LV impedance is 16%, but for the transformer represented by *Figure 2.13(a)* the LV_1 to LV_2 impedance is around 28% while for that represented by *Figure 2.13(b)* it is only 4%. Which of the two arrangements is used depends on the constraints imposed by the LV systems. It should be noted that the same equivalent circuits apply for calculation of regulation, so that for the arrangement shown in *Figure 2.13(a)*, load on LV_1 has little effect on the voltage on LV_2 whereas for *Figure 2.13(b)*, load on LV_1 will considerably reduce the voltage on LV_2.

2.9 GENERAL CASE OF THREE-WINDING TRANSFORMER

The voltage regulation of a winding on a three-winding transformer is expressed with reference to its no-load open-circuit terminal voltage when only one of the other windings is excited and the third winding is on no-load, i.e. the basic voltage for each winding and any combination of loading is the no-load voltage obtained from its turns ratio.

For the case of two output windings W_2 and W_3, and one input winding W_1, shown diagrammatically in *Figure 2.14*, the voltage regulation is usually required for three loading conditions:

W_2 only loaded

W_3 only loaded

W_2 and W_3 both loaded

For each condition two separate values would be calculated, namely, the regulation of each output winding W_2 and W_3 (whether carrying current or not) for constant voltage applied to winding W_1.

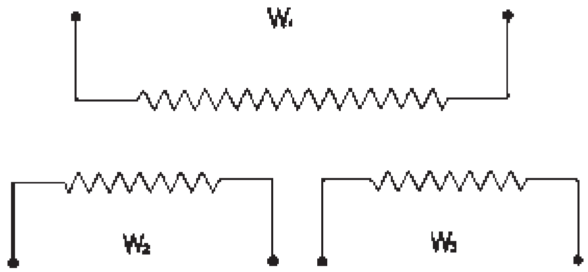


Figure 2.14 Diagram of a three-winding transformer

The voltage regulation between W_2 and W_3 relative to each other, for this simple and frequent case, is implicit in the values (W_1 to W_2) and (W_1 to W_3) and nothing is gained by expressing it separately.

The data required to obtain the voltage regulation are the impedance voltage and load losses derived by testing the three windings in pairs and expressing the results on a basic kVA, which can conveniently be the rated kVA of the lowest rated winding.

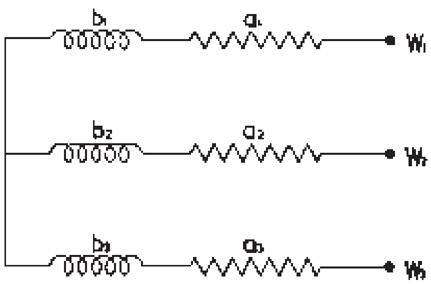


Figure 2.15 Equivalent circuit of a three-winding transformer

From these data an equivalent circuit is derived, as shown in *Figure 2.15*. It should be noted that this circuit is a mathematical conception and is not an indication of the winding arrangement or connections. It should, if possible, be determined from the transformer as built. The equivalent circuit is derived as follows:

let a_{12} and b_{12} be respectively the percentage resistance and reactance voltage referred to the basic kVA and obtained from test, short-circuiting either winding W_1 or W_2 and supplying the other with winding W_3 on open-circuit,

a_{23} and b_{23} similarly apply to a test on the windings W_2 and W_3 with W_1 on open-circuit,

a_{31} and b_{31} similarly apply to a test on the windings W_3 and W_1 with W_2 on open-circuit,

$d =$ the sum $(a_{12} + a_{23} + a_{31})$, and

$g =$ the sum $(b_{12} + b_{23} + b_{31})$

Then the mathematical values to be inserted in the equivalent circuit are:

Arm $W_1: a_1 = d/2 - a_{23} \quad b_1 = g/2 - b_{23}$

Arm $W_2: a_2 = d/2 - a_{31} \quad b_2 = g/2 - b_{31}$

Arm $W_3: a_3 = d/2 - a_{12} \quad b_3 = g/2 - b_{12}$

It should be noted that some of these quantities will be negative or may even be zero, depending on the actual physical relative arrangement of the windings on the core.

For the desired loading conditions the kVA operative in each arm of the network is determined and the regulation of each arm is calculated separately. The regulation with respect to the terminals of any pair of windings is the algebraic sum of the regulations of the corresponding two arms of the equivalent circuit.

The detailed procedure to be followed subsequently for the case of two output windings and one supply winding is as follows:

1. Determine the load kVA in each winding corresponding to the loading being considered.
2. For the output windings, W_2 and W_3, this is the specified loading under consideration; evaluate n_2 and n_3 for windings W_2 and W_3, being the ratio of the actual loading to the basic kVA used in the equivalent circuit.
3. The loading of the input winding W_1 in kVA should be taken as the phasor sum of the outputs from the W_2 and W_3 windings, and the corresponding power factor $\cos\phi$ and quadrature factor $\sin\phi$ deduced from the in-phase and quadrature components.

Where greater accuracy is required, an addition should be made to the phasor sum of the outputs and they should be added to the quadrature component to obtain the effective input kVA to the winding W_1,

$$\begin{aligned}&(\text{the output kVA from winding } W_2)\frac{b_2 n_2}{100}\\&\quad + (\text{the output kVA from winding } W_2)\frac{b_3 n_3}{100}\end{aligned}$$

n for each arm is the ratio of the actual kVA loading of the winding to the basic kVA employed in determining the equivalent circuit.

A more rigorous solution is obtained by adding the corresponding quantities (a, n, output kVA) to the in-phase component of the phasor sums of the outputs, but this has rarely an appreciable effect on the voltage regulation.

Equations (1.7) and (1.8) may now be applied separately to each arm of the equivalent circuit, taking separate values of n for each arm as defined earlier.

To obtain the voltage regulation between the supply winding and either of the loaded windings, add algebraically the separate voltage regulations determined for the two arms, noting that one of these may be negative. A positive value for the sum determined indicates a voltage drop from no-load to the loading considered while a negative value for the sum indicates a voltage rise.

Repeat the calculation described in the preceding paragraph for the other loaded winding. This procedure is applicable to autotransformers if the equivalent circuit is based on the effective impedances measured at the terminals of the autotransformers.

In the case of a supply to two windings and output from one winding, the method can be applied if the division of loading between the two supplies is known.

An example of the calculation of voltage regulation of a three-winding transformer is given in the following.

Assume that:

W_1 is a 66 000 V primary winding.

W_2 is a 33 000 V output winding loaded at 2000 kVA and having a power factor $\cos\phi_2 = 0.8$ lagging.

W_3 is an 11 000 V output winding loaded at 1000 kVA and having a power factor $\cos\phi_3 = 0.6$ lagging.

The following information is available, having been calculated from test data, and is related to a basic loading of 1000 kVA.

$$a_{12} = 0.26 \quad b_{12} = 3.12$$

$$a_{23} = 0.33 \quad b_{23} = 1.59$$

$$a_{12} = 0.32 \quad b_{31} = 5.08$$

whence

$$d = 0.91 \text{ and } g = 9.79$$

Then for

$$W_1,\ a_1 = 0.125 \text{ and } b_1 = +3.305$$

$$W_2,\ a_2 = 0.135 \text{ and } b_2 = -0.185$$

$$W_3,\ a_3 = 0.195 \text{ and } b_3 = +1.775$$

The effective full-load kVA input to winding W_1 is:

(i) With only the output winding W_2 loaded, 2000 kVA at a power factor of 0.8 lagging.

(ii) With only the output winding W_3 loaded, 1000 kVA at a power factor of 0.6 lagging.

(iii) With both the output windings W_2 and W_3 loaded, 2980 kVA at a power factor of 0.74 lagging.

Applying expressions (1.7) or (1.8) separately to each arm of the equivalent circuit, the individual regulations have, in

W_1 under condition (i) where $n_1 = 2.0$, the value of 4.23%

W_1 under condition (ii) where $n_1 = 1.0$, the value of 2.72%

W_1 under condition (iii) where $n_1 = 2.98$, the value of 7.15%

W_2 where $n_2 = 2.0$, the value of -0.02%

W_3 where $n_3 = 1.0$, the value of 1.53%

Summarising these calculations therefore the total transformer voltage regulation has:

(i) With output winding W_2 fully loaded and W_3 unloaded,

at the terminals of winding W_2, the value of $4.23 - 0.02 = 4.21\%$
at the terminals of winding W_3, the value of $4.23 + 0 = 4.23\%$

(ii) With output winding W_2 unloaded and W_3 fully loaded,

at the terminals of winding W_2, the value of $2.72 + 0 = 2.72\%$
at the terminals of winding W_3, the value of $2.72 + 1.53 = 4.25\%$

(iii) With both output windings W_2 and W_3 fully loaded,

at the terminals of winding W_2, the value of $7.15 - 0.02 = 7.13\%$
at the terminals of winding W_3, the value of $7.15 + 1.53 = 8.68\%$

3 Basic materials

3.1 DIELECTRICS

The majority of power transformers in use throughout the world are oil filled using a mineral oil, complying with IEC 296. In the UK the relevant specification is British Standard 148 *Unused mineral insulating oil for transformers and switchgear* which, in its 1984 edition, differs in some respects from IEC 296. More will be said about this later. The oil serves the dual purpose of providing insulation and as a cooling medium to conduct away the losses which are produced in the transformer in the form of heat.

Mineral oil is combustible – it has a fire point of 170°C – and transformer fires do sometimes occur. It is usual, therefore, to locate these out of doors where a fire is more easily dealt with and consequentially the risks are fewer. It is necessary to consider the need for segregation from other plant and incorporate measures to restrict the spread of fire.

Because of the fire hazard associated with mineral oil, it has been the practice to use designs for smaller transformers which do not contain oil. These may be entirely dry, air insulated; or they may contain non-flammable or reduced flammable liquid; they have the advantage that they may be located inside buildings in close proximity to the associated switchgear. More will be said about this type of transformer in Chapter 7.

It is necessary to mention dielectrics thus far in order to distinguish between the principal types of transformers, oil filled and air insulated; this chapter will examine in detail the basic materials which are used to build transformers and mineral oil will be examined in some depth later. It is appropriate to start at the fundamental heart of the transformer, the steel core.

3.2 CORE STEEL

The purpose of a transformer core is to provide a low-reluctance path for the magnetic flux linking primary and secondary windings.

In doing so, the core experiences iron losses due to hysteresis and eddy currents flowing within it which, in turn, show themselves as heating of the core material. In addition, the alternating fluxes generate noise, which, in the case of a large system transformer, for example, can be as invasive in the environment as a jet aircraft or an internal combustion engine at full throttle.

Core losses, though small in relation to the transformer throughput, are present whenever the transformer is energised. Thus they represent a constant and significant energy drain on any electrical system. It has been estimated that some 5% of all electricity generated is dissipated as iron losses in electrical equipment, and in the UK alone in the year 1987/88 the cost of no-load core losses in transformers was estimated at £110 million. At that time around 10^9 units of electricity were estimated to be wasted in core losses in distribution transformers each year, equivalent to seven million barrels of oil to produce it and releasing 35 000 tonnes of sulphur dioxide and four million tonnes of carbon dioxide into the atmosphere. The cost implications identified above were, of course, particularly exacerbated by the significant increase in energy costs initiated by the oil crisis of the early 1970s.

Not surprisingly therefore, considerable research and development resource has been applied to electrical steels and to transformer core design in recent years directed mainly towards the reduction of losses but also to the reduction of noise. As a result a great deal of progress has been made and many changes have taken place since the basic principles of modern power transformer design and construction were laid down in the 1920s and 1930s.

Core loss is made up of two components: the first, the hysteresis loss, is proportional to the frequency and dependent on the area of the hysteresis loop, which, in turn, is a characteristic of the material and a function of the peak flux density; the second is the eddy current loss which is dependent on the square of frequency but is also directly proportional to the square of the thickness of the material. Minimising hysteresis loss thus depends on the development of a material having a minimum area of hysteresis loop, while minimising eddy current loss is achieved by building up the core from a stack of thin laminations and increasing resistivity of the material in order to make it less easy for eddy currents to flow as will be seen by reference to *Figure 3.1*.

The components of core loss can be represented by the expressions:

$$\text{Hysteresis loss, } W_h = k_1 f B_{\max}{}^n \text{ watts/kg} \tag{3.1}$$

$$\text{and Eddy current loss, } W_e = k_2 f^2 t^2 B_{\text{eff}}{}^2/\rho \text{ watts/kg} \tag{3.2}$$

where k_1 and k_2 are constants for the material
f is frequency, Hz

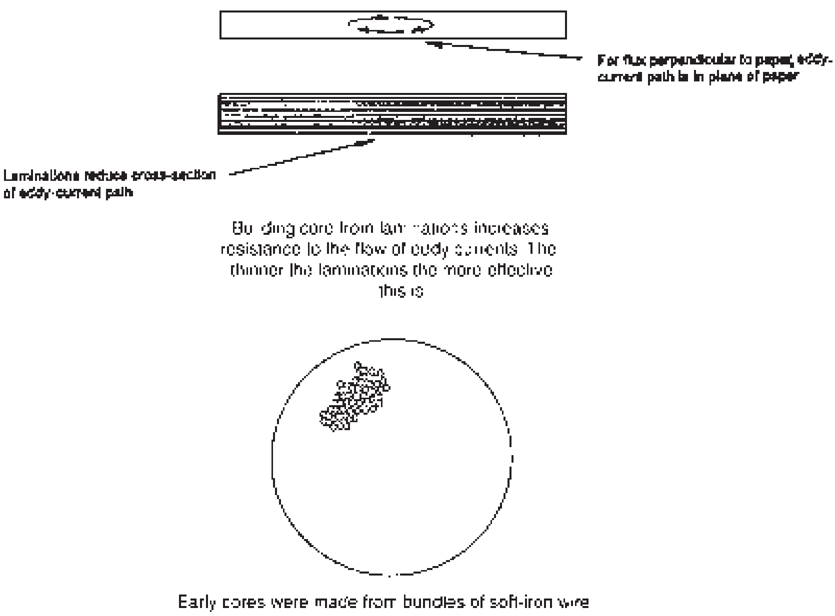


Figure 3.1

t is thickness of the material, mm
ρ is the resistivity of the material
B_{max} is maximum flux density, T
B_{eff} is the flux density corresponding to the r.m.s. value of the applied voltage

n is the 'Steinmetz exponent' which is a function of the material. Originally this was taken as 1.6 but with modern materials and higher flux densities n can vary from 1.6 to 2.5 or higher.

In practice the eddy current term is a complex one and can itself be considered to consist of two components: the first truly varies as the square of frequency times material thickness and flux density as indicated by the expression above. This can be calculated in accordance with classical electromagnetic theory and is referred to as the *classical eddy current loss*; the second is dependent on the structure of the material such as grain size and magnetic domain movement during the magnetising cycle and is known as *anomalous loss* or *residual loss*. Anomalous eddy current loss can account for around half the total loss for any particular steel. It is this anomalous loss which can be greatly reduced by special processing of the core material, so that this forms the basis of most of the modern approaches towards the reduction of core loss. More will be said about this later.

The first transformers manufactured in the 1880s had cores made from high-grade wrought iron and for a time Swedish iron was preferred. However, in about the year 1900 it was recognised that the addition of small amounts of silicon or aluminium to the iron greatly reduced the magnetic losses. Thus began the technology of specialised electrical steel making.

Hot-rolled steel

The addition of silicon reduces hysteresis loss, increases permeability and also increases resistivity, thus reducing eddy current losses. The presence of silicon has the disadvantage that the steel becomes brittle and hard so that, for reasons of workability and ease of core manufacture, the quantity must be limited to about $4\frac{1}{2}$%. The elimination of impurities, including carbon, also has a significant effect in the reduction of losses so that although the first steels containing silicon had specific loss values of around 7 W/kg at 1.5 T, 50 Hz, similar alloys produced in 1990 having high levels of purity have losses less than 2 W/kg at this condition.

As briefly mentioned above, electrical sheet steels have a crystalline structure so that the magnetic properties of the sheet are derived from the magnetic properties of the individual crystals or grains and many of these are dependent on the direction in the crystal in which they are measured.

The crystals of steel can be represented by a cube lattice as shown in *Figure 3.2*. The principal axes of this lattice are designated by x, y, z

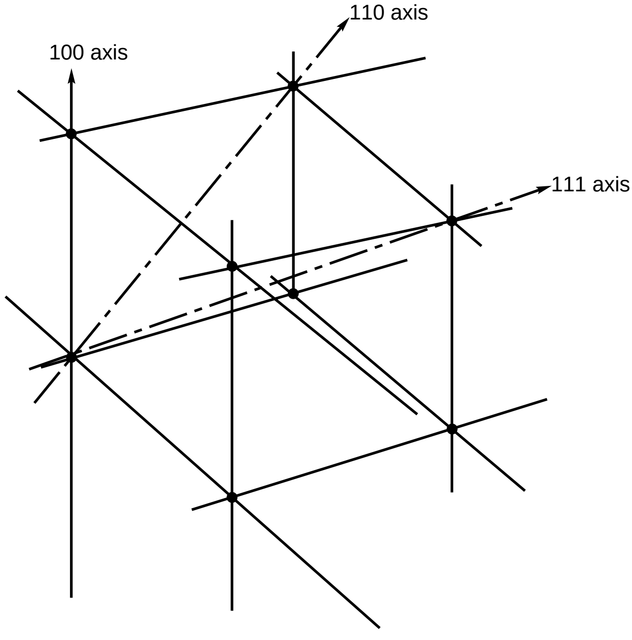


Figure 3.2 100 direction – cube edge – is easiest direction of magnetisation; 110 direction – cube face diagonal – is more difficult; 111 direction – long diagonal – is the most difficult

coordinates enclosed in square brackets, [100], which represents the axis along the cube edge. Planes intersecting the vertices of the cubes are similarly designated by coordinates enclosed in round brackets, (110), representing the plane intersecting diagonally opposite edges.

In the crystal lattice the [100] direction is the easiest direction of magnetisation, the [110] direction is more difficult and the [111] is the most difficult.

Silicon steel laminations of thickness around 0.35 mm used in transformers, in the USA until the 1940s and in the UK until somewhat later, were produced by a hot-rolling process in which the grains are packed together in a random way so that magnetic properties observed in a sheet have similar values independent of the direction in which they are measured. These represent an average of the properties for all directions within the individual crystals. The materials are known as *isotropic*.

Grain-oriented steel

It had been recognised in the early 1920s that the silicon steel crystals were themselves *anisotropic*, but it was not until 1934 that the American N. P. Goss patented an industrial production process, which was chiefly developed by ARMCO in the USA, that commercial use was made of this property. The first commercial quantities were produced in 1939. The material was the first commercial grain-oriented cold-rolled silicon steel. It had a thickness of 0.32 mm with a loss of 1.5 W/kg at 1.5 T, 50 Hz.

The material is cold reduced by a process set out diagramatically in the left-hand half of *Figure 3.3*. This has formed the basis of the production of cold-rolled grain-oriented steels for many years. The initially hot-rolled strip is pickled to remove surface oxides and is then cold rolled to about 0.6 mm thickness from the initial hot band thickness of 2–2.5 mm. The material is given an anneal to recrystallise the cold-worked structure before cold rolling again to the final gauge. Decarburisation down to less than 0.003% carbon is followed by coating with a thin magnesium oxide (MgO) layer. During the next anneal, at 1200°C for 24 hours, purification and secondary recrystallisation occur and the magnesium oxide reacts with the steel surface to form a thin magnesium silicate layer called the glass film or Forsterite layer. Finally, the material is given a flattening anneal, when excess magnesium oxide is removed and a thin phosphate coating is applied which reacts with the magnesium silicate to form a strong, highly insulating coating.

During hot rolling, small particles of manganese sulphide, which has been added to the melt as a grain growth inhibitor, precipitate out as the steel cools. At the same time, some crystals with the Goss texture, that is, having the required orientation, are formed along with many other orientations. After the cold rolling, nuclei with the Goss texture recrystallise during the decarburisation anneal, as the material develops a ‘structure memory’. The grain size, at this stage, is around 0.02 mm diameter, and this increases in the Goss-oriented grains at over 800°C during the high-temperature anneal when the

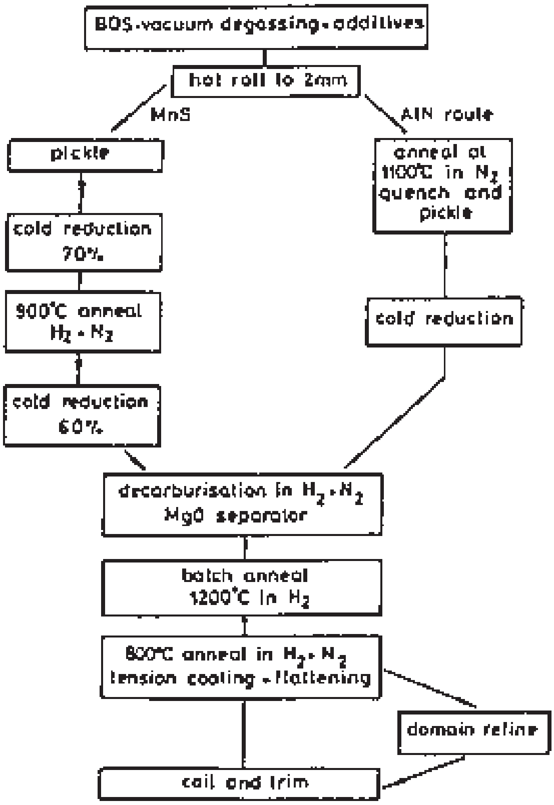


Figure 3.3 Production route of conventional (via MnS route) and high-permeability (via AIN route) grain-oriented silicon iron

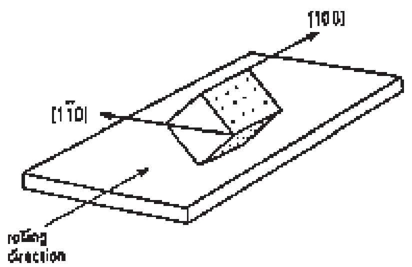


Figure 3.4 Ideal grain alignment in grain oriented steel

manganese sulphide particles retard the growth of other grains. During this secondary recrystallisation process, the Goss grains each consume 10^6–10^7 primary grains and grow through the thickness of the sheet to diameters of 10 mm or more. All grains do not have the ideal Goss orientation but most are within 6° of the ideal [100][110] shown in *Figure 3.4*.

High-permeability steel

Use of cold-rolled grain-oriented steel as described above continued with only steady refinement and improvement in the production process until the late 1960s. However, in 1965 the Japanese Nippon Steel Corporation announced a step-change in the quality of their electrical steel: high-permeability grain-oriented silicon steel. The production process is shown in the right-hand half of *Figure 3.3*. Production is simplified by the elimination of one of the cold-rolling stages because of the introduction of around 0.025% of aluminium to the melt and the resulting use of aluminium nitride as a growth inhibitor. The final product has a better orientation than cold-rolled grain-oriented steel (in this context, generally termed 'conventional' steel), with most grains aligned within 3° of the ideal, but the grain size, average 1 cm diameter, was very large compared to the 0.3 mm average diameter of conventional material. At flux densities of 1.7 T and higher, its permeability was three times higher than that of the best conventional steel, and the stress sensitivity of loss and magnetostriction were lower because of the improved orientation and the presence of a high tensile stress introduced by the so-called stress coating. The stress coating imparts a tensile stress to the material which helps to reduce eddy-current loss which would otherwise be high in a large-grain material. The total loss is further offset by some reduction in hysteresis loss due to the improved coating. However, the low losses of high-permeability steels are mainly due to a reduction of 30–40% in hysteresis brought about by the improved grain orientation. The Nippon Steel Corporation product became commercially available in 1968, and it was later followed by high-permeability materials based MnSe plus Sb (Kawasaki Steel, 1973) and Boron (Allegheny Ludlum Steel Corporation, 1975).

Domain-refined steel

The continued pressure for the reduction of transformer core loss identified above led to further improvements in the production process so that in the early 1980s the Nippon Steel Corporation introduced laser-etched material with losses some 5–8% lower than high-permeability steel. By 1983 they were producing laser-etched steels down to 0.23 mm thick with losses as low as 0.85 W/kg at 1.7 T, 50 Hz.

It has been briefly mentioned above, in defining the quantity 'anomalous eddy-current loss', that this arises in part due to magnetic domain wall movement during the cycles of magnetisation. Messrs Pry and Bean [3.1] as early as 1958 had suggested that in a grain-oriented material anomalous eddy current loss is proportional to the domain wall spacing and inversely proportional to sheet thickness. This is illustrated in *Figure 3.5* which shows an idealised section of grain-oriented material in which 180° magnetic domains stretch infinitely at equal intervals of $2L$. Clearly eddy current loss can be reduced by subdividing the magnetic domains to reduce L.

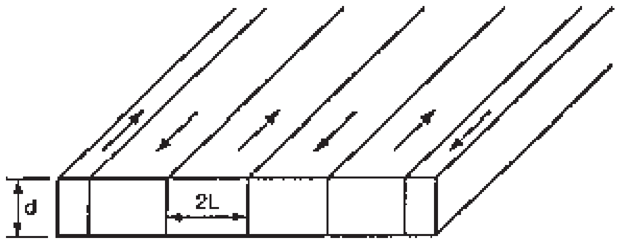


Figure 3.5 Magnetic domains in section. Arrows indicate the direction of magnetisation in magnetic domains

It had been recognised for many years that introduction of strain into sheet steels had the effect of subdividing magnetic domains and thus reducing core loss. This was the basis for the use of the stress coatings for high-permeability steels mentioned above. The coatings imparted a tensile stress into the material on cooling due to their low thermal expansion coefficient. Mechanical scribing of the sheet surface at intervals transverse to the rolling direction also serves as a means of inducing the necessary strain but this is difficult to carry out on a commercial basis and has the disadvantage that the sheet thickness at the point of the scribing is reduced, thus creating a localised increase in the flux density and causing some of the flux to transfer to the adjacent lamination with the consequent result that there is a net increase in loss.

Nippon Steel Corporation's solution to the problem was to employ a non-contact domain-refining process utilising laser irradiation normally referred to as laser etching.

Figure 3.6 shows a diagrammatic arrangement of the process. When the high-power laser beam is trained to the surface of the sheet, the outermost layer of the sheet vaporises and scatters instantaneously. As a result, an impact pressure of several thousand atmospheres is generated to form a local elastic-plastic area in the sheet. Highly dense complex dislocations due to plastic deformation occur leaving a residual strain which produces the required domain refinement. *Figure 3.7* shows domain structures before and after laser irradiation. As the laser irradiation vaporises and scatters the outermost layer of the sheet, an additional coating is necessary in order to make good the surface insulation layer.

An important aspect of the domain refinement process described above is that the residual strains will be removed if the material is subsequently annealed at a temperature above 500°C thus reversing the process. It is important therefore that any processes carried out after laser etching should not take the temperature above 500°C.

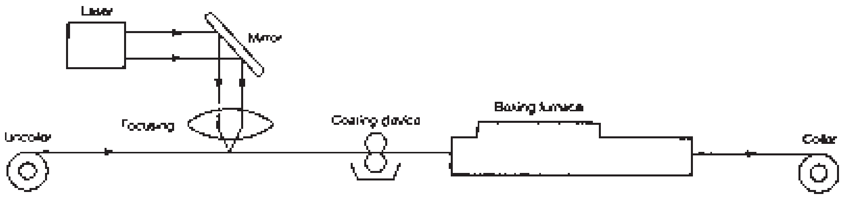


Figure 3.6 Laser etching process

Figure 3.7 Domain structures before and after laser etch

In summary, *Table 3.1* gives a simple reference guide to the methods of reducing losses in sheet steels produced by the conventional rolling process.

Amorphous steels

Amorphous steels have appeared relatively recently and their development stems from a totally different source than the silicon core steels described above. Originally developed by Allied Signal Inc., Metglas Products in the USA, in the early 1970s as an alternative for the steel in vehicle tyre reinforcement, it was not until the mid-1970s that the importance of their magnetic properties was recognised. Although still restricted in their application some 20 years later due to difficulties in production and handling, they offer considerable reduction in losses compared to even the best conventional steels.

Amorphous metals have a non-crystalline atomic structure, there are no axes of symmetry and the constituent atoms are randomly distributed within the bulk of the material. They rely for their structure on a very rapid cooling rate of the molten alloy and the presence of a glass-forming element such as boron. Typically they might contain 80% iron with the remaining 20% boron and silicon.

Various production methods exist but the most popular involve spraying a stream of molten metal alloy to a high-speed rotating copper drum. The molten metal is cooled at a rate of about 10^6°C per second and solidifies to form a continuous thin ribbon. The quenching technique sets up high internal stresses so these must be reduced by annealing between 200 and 280°C to develop good

Table 3.1 Summary of loss reduction processes of conventionally rolled core steels

	Hysteresis loss	*Eddy-current loss*	
		Classical eddy-current loss	*Anomalous eddy-current loss*
Hot-rolled steels 0.35 mm thick	Reduce area of hysteresis loop by addition of silicon reduction of impurities particularly carbon	is function of plate thickness and resistivity. Silicon increases resistivity	depends on grain structure and domain movement
Cold-rolled steels 0.28 mm thick	Alignment of grains within ±6° of rolling direction reduces hysteresis	Thinner sheets leeds to some reduction in eddy current loss	
High permeability steels	Better alignment of grains results in 30–40% reduction in hysteresis		Stress coating reduces eddy-current loss and susceptibility to handling induced loss increases
Domain refined steels			Reduced domain size reduces eddy-current loss

magnetic properties. Earliest quantities of the material were only 2 mm wide and about 0.025–0.05 mm thick. By the mid-1990s a number of organisations had been successful in producing strip up to 200 mm wide.

The original developers of the material, Metglas Products, had towards the end of the 1980s produced a consolidated strip amorphous material named POWERCORE®* strip, designed to be used in laminated cores. The material is produced in the thickness range 0.125–0.25 mm, by bonding several sheets of as-cast ribbon to form a strip which can be handled more easily. The ribbons are effectively bonded over 15–75% of their surface area by a local plastic action combined with a chemical bond of diffused silicon oxide. The weak bond does not allow significant eddy current flow between layers of the composite and the bulk properties are similar to those of single ribbon.

The need for a glass-forming element, which happens to be non-magnetic, gives rise to another of the limitations of amorphous steels, that of low-saturation flux density. POWERCORE® strip has a saturation level of around 1.56 T. Specific loss at 1.35 T, 50 Hz, is just 0.12 W/kg. At 1.5 T, 50 Hz, this is 0.28 W/kg.

Another important property is the magnetising VA. At 1.3 T this is 0.25 VA/kg compared with 0.69 VA/kg for 3% silicon steel. An indication of the effect of the low-saturation flux density can be gained from comparing

* POWERCORE® strip is a registered trademark of Allied Signal Inc., Metglas Products.

these again at 1.5 T. In the case of POWERCORE® strip this has risen to 1.3 VA/kg while for conventional silicon steel it is typically only 0.94 VA/kg.

While the sizes of strip available as POWERCORE® are still unsuitable for the manufacture of large-power transformer cores, in the USA in particular, many hundreds of thousands of distribution transformer cores with an average rating of around 50 kVA have been built using amorphous material. In Europe use of the material has been a far more limited scale, the main impetus being in Holland, Sweden, Switzerland, Germany and Hungary. One possible reason for the slower progress in Europe is that the thin strip material does not lend itself to the European preferred form of core construction, whereas the wound cores, which are the norm for distribution transformers in the USA, are far more suitable for this material. In the UK its use has been almost exclusively by one manufacturer who has built several hundred small distribution transformers. All were manufactured from plain unlaminated ribbon material. This manufacturer has also built a small number of experimental units using the POWERCORE® material, see *Figure 3.8*, but report that the difficulties of cutting and building this into a conventional core can tend to outweigh any benefits gained.

Another of the practical problems associated with amorphous steel is its poor stacking factor which results from a combination of the very large number of layers of ribbon needed to build up the total required iron section and

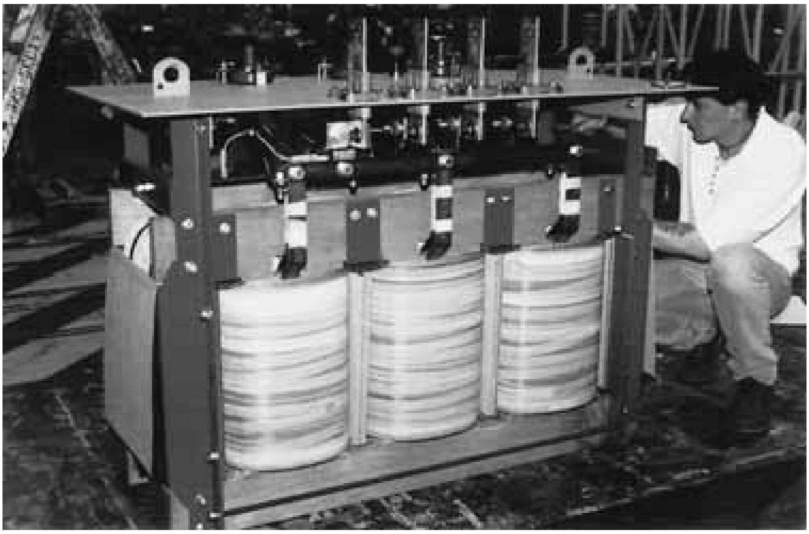


Figure 3.8 Core and windings of 200 kVA, 20/0.4 kV transformer using amorphous steel. Unfortunately very little of the core is visible, but it should be just apparent that this is of the wound construction. It will also be apparent that fairly elaborate clamping was considered necessary and that the physical size, for a 200 kVA transformer, is quite large. (GEC Alsthom)

also the relatively poor flatness associated with this very thin ribbon. Plain ribbon 0.03 mm thick has a stacking factor of only 0.8. POWERCORE® strip 0.13 mm thick can give a figure of 0.9, but both of these are poor compared to the 0.95–0.98 attainable with conventional silicon steel.

Microcrystalline steel

Another approach towards the optimisation of the magnetic and mechanical performance of silicon steel, which has received much attention in Japan, is the production of high-silicon and aluminium–iron alloys by rapid solidification in much the same manner as for amorphous steels. No glass-forming additives are included so a ductile microcrystalline material is produced, often referred to as semicrystalline strip. 6% silicon iron strip has been produced which has proved to be ductile and to have losses fewer than those of commercial grain-oriented 3% silicon iron. A figure of 0.56 W/kg at 1.7 T, 50 Hz, is a typically quoted loss value.

Rapidly quenched microcrystalline materials have the advantage of far higher field permeability than that of amorphous materials so far developed for power applications. *Figure 3.9* indicates typical loss values attainable for the whole range of modern core materials and shows how the non-oriented microcrystalline ribbon fits between amorphous ribbon and grain-oriented steel.

Adoption of improved steels

The cold-rolled grain-oriented steels introduced in the 1940s and 1950s almost completely replaced the earlier hot-rolled steels in transformer manufacture over a relatively short timescale and called for some new thinking in the area of core design. The introduction of high-permeability grain-oriented steels some 30 years later was more gradual and, because of its higher cost, its early use tended to be restricted to applications where the capitalised cost of no-load loss (see Chapter 8) was high. A gradual development in core design and manufacture to optimise the properties of the new material took place but some of these improvements were also beneficial for designs using conventional materials. In 1981 some 12% of the worldwide production of grain-oriented steel was high-permeability grade. By 1995 high-permeability material was the norm. A similar situation occurred with the introduction of laser-etched steel, which for reasons of both availability and cost, remains very much a 'special' material, to be used only where the cost of no-load losses is very high, more than 10 years after its announcement.

The ways in which core design and construction developed to reflect the properties of the available material will be discussed in the next chapter.

Designation of core steels

Specification of magnetic materials including core steels is covered internationally by IEC 404. In the UK this becomes BS 6404, a multi-part

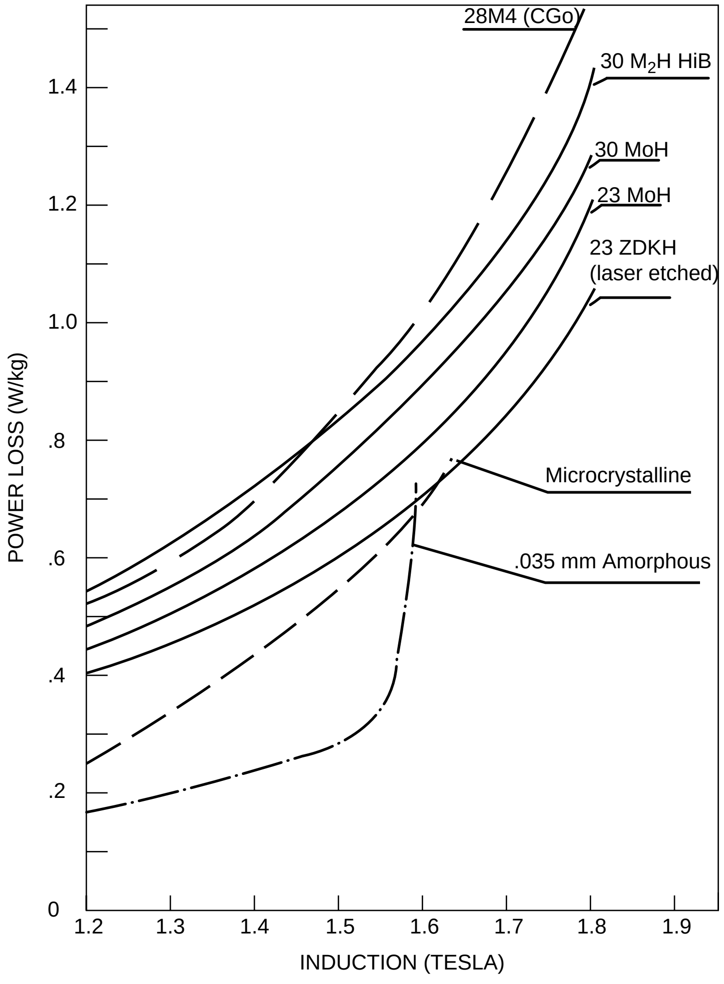


Figure 3.9 Power loss versus induction at 50 Hz for various materials

document, Part 1 of which, *Magnetic materials, classification,* was issued in 1984 and provides the general framework for all the other documents in the series. Part 8 is the one dealing with individual materials of which Section 8.7 *Specification for grain-oriented magnetic steel sheet and strip,* which was issued in 1988, covers the steels used in power transformers.

Until the late 1980s core steels used in power transformers were specified in British Standard 601. BS 601:1973, was a five-part document, Part 2 of which specifically referred to grain-oriented steel greater than 0.25 mm thick. Most cold-rolled grain-oriented steels used up to this time complied with this document which identified particular materials by means of a code, for example 28M4 or 30M5, which were 0.28 and 0.30 mm thick, respectively. The final digit referred to the maximum specific loss value. With the introduction of high-permeability steels this code was arbitrarily extended to cover these materials giving designations as, typically, 30M2H. This is a high-permeability grade 0.30 mm thick with specific loss in the '2' band. Although they continue to be used, designations such as 30M2H no longer have any status in the current British Standard.

Further information

Readers seeking more detailed information relating to core steels may consult an IEE review paper by A. J. Moses [3.2] which contains many references and provides an excellent starting point for any more extensive investigations.

3.3 WINDING CONDUCTORS

Transformer windings are made almost exclusively of copper, or to be precise, high-conductivity copper. Copper has made possible much of the electrical industry as we know it today because, in addition to its excellent mechanical properties, it has the highest conductivity of the commercial metals. Its value in transformers is particularly significant because of the benefits which result from the saving of space and the minimising of load losses.

Load losses

The load loss of a transformer is that proportion of the losses generated by the flow of load current and which varies as the square of the load current. This falls into three categories:

- Resistive loss within the winding conductors and leads.
- Eddy current loss in the winding conductors.
- Eddy current loss in the tanks and structural steelwork.

Resistive loss can be lessened by reducing the number of winding turns, by increasing the cross-sectional area of the turn conductor, or by a combination of both. Reducing the number of turns requires an increase in Φ_m, i.e. an increase in the core cross-section (frame size – see Chapter 4, Section 2), which increases the iron weight and iron loss. So load loss can be traded against iron loss and vice versa. Increased frame size requires reduced winding length to compensate (equation (2.1)) and thus retain the same impedance, although as already explained there will be a reduction in the number of turns (which was the object of the exercise) by way of partial compensation. Reduction of the winding axial length means that the core leg length is reduced, which also offsets the increase in core weight resulting from the increased frame size to some extent. There is thus a band of one or two frame sizes for which loss variation is not too great, so that optimum frame size can be chosen to satisfy other factors, such as ratio of fixed to load losses or transport height.

The paths of eddy currents in winding conductors are complex. The effect of leakage flux within the transformer windings results in the presence of radial and axial flux changes at any given point in space and any moment in time. These induce voltages which cause currents to flow at right angles to the changing fluxes. The magnitude of these currents can be reduced by increasing the resistance of the path through which they flow, and this can be effected by reducing the total cross-sectional area of the winding conductor or by subdividing this conductor into a large number of strands insulated from each other. (In the same way as laminating the core steel reduces eddy-current losses in the core.) The former alternative increases the overall winding resistance and thereby the resistive losses. Conversely, if the overall conductor cross-section is increased with the object of reducing resistive losses, one of the results is to increase the eddy current losses. This can only be offset by a reduction in strand cross-section and an increase in the total number of strands. It is costly to wind a large number of conductors in parallel and so a manufacturer will wish to limit the total number of strands in parallel. Also, the extra insulation resulting from the increased number of strands results in a poorer winding space factor.

Compact size is important for any item of electrical plant. In transformer windings this is particularly so. The size of the windings is the determining factor in the size of the transformer. As explained above the windings must have a sufficiently large cross-section to limit the load losses to an acceptable level, not only because of the cost of these losses to the user but also because the heat generated must be removed by the provision of cooling ducts. If the losses are increased more space must be provided for ducts. This leads to yet larger windings and thus a larger core is needed to enclose them. Increasing the size of the core increases the no-load loss but, along with the increase in the size of the windings, also means that a very much larger tank is required which, in turn, results in an increased oil quantity and so the whole process escalates. Conversely, any savings in the size of windings are repaid many times over by reductions in the size of the transformer and resultant further savings elsewhere. As the material which most economically meets the above criteria and which is universally commercially available, high-conductivity copper is the automatic choice for transformer windings.

Eddy-current losses in tanks and internal structural steelwork such as core frames only constitute a small proportion of the total load losses. These are also a result of leakage flux and their control is mainly a matter of controlling the leakage flux. More will be said about this in Chapter 4.

During the 1960s, at a time when copper prices rose sharply, attempts were made to explore the possibilities offered by the use of the then very much cheaper aluminium in many types of electrical equipment. Indeed, about this time, the use of aluminium in cables became widespread and has tended to remain that way ever since. However, although some quite large transformers were built using aluminium for windings, mainly at the instigation of the aluminium producers, the exercise largely served to demonstrate many of the disadvantages of this material in large-power transformers.

Aluminium has some advantages for certain transformer applications, notably for foil windings which are intended to be resin encapsulated, where its coefficient of thermal expansion matches much more closely the expansion of the resin than does that of copper. This leads to less of a tendency for resin cracking to occur under load cycling. These properties of aluminium will be discussed when these applications are described.

Copper is in plentiful supply, being mined in many places throughout the world, but it also has the great advantage of being readily recycled. It is easily separated from other scrap and can be reused and re-refined economically, thus preventing unnecessary depletion of the earth's natural resources.

There are an enormous range of electrical applications for which high-conductivity copper is used, and there are a number of different coppers which may be specified, but for the majority of applications the choice will be either electrolytic tough pitch copper (Cu-ETP-2) or the higher grade Cu-ETP-1.

The former is tough pitch (oxygen-bearing) high-conductivity copper which has been electrolytically refined to reduce the impurity levels to total less than 0.03%. In the UK it is designated Cu-ETP-2, as cast, and C101 for the wrought material. This copper is readily available in a variety of forms and can be worked both hot and cold. It is not liable to cracking during hot working because the levels of lead and bismuth which cause such cracking are subject to defined limits.

The latter, Cu-ETP-1, as cast, and C100 when wrought, is now available for use by manufacturers with advantage in modern high-speed rod breakdown and wire-drawing machines with in-line annealing. It makes excellent feedstock for many wire-enamelling processes where copper with a consistently low annealing temperature is needed to ensure a good reproducible quality of wire.

Production of high-conductivity copper

As indicated above, copper is extracted and refined in many places throughout the world. *Figure 3.10* illustrates these. The output from a refinery is in a variety of forms depending on the type of semi-finished wrought material to be made. Cathodes are the product of electrolytic refining of copper. They must be remelted before being usable and may then be cast into different 'refinery shapes'. The shapes are *billets* for extrusions, *cakes* for rolling into flat plate, *wirebars* for rolling into rod and *wire rod* for wire drawing. Sizes of cathodes vary depending on the refinery. Typically they may be plates of 1200×900 mm in size weighing 100–300 kg.

Billets are usually about 200 mm in diameter and no more than 750 mm in length to fit the extrusion chamber. Extrusions are usually subsequently drawn to the required finished sizes by one or more passes through the mill drawblocks.

Figure 3.10 Map showing location of copper extraction sites
(Copper Development Association)

Cakes (or slabs) are used when flat plate, sheet, strip and foil are required. They are nowadays mostly cast continuously. Copper is commonly hot rolled from 150 mm down to about 9 mm and then cold rolled thereafter.

Wirebars were previously the usual starting point for hot rolling of rod. They were generally cast horizontally and therefore had a concentration of oxide at and near the upper surface. It is now possible to continuously cast them vertically with a flying saw to cut them to length but they are now almost obsolete, however.

Wire rod is the term used to describe coils of copper of 6–35 mm diameter (typically 9 mm) which provide the starting stock for wire drawing. At one time these were limited to about 100 kg in weight, the weight of the wirebars from which they were rolled. Flash-butt welding end to end was then necessary before they could be fed into continuous wire-drawing machines.

It is now general practice to melt cathodes continuously in a shaft furnace and feed the molten copper at a carefully controlled oxygen content into a continuously formed mould which produces a feedstock led directly into a multistand hot-rolling mill. The output from this may be in coils of several tonnes weight each. For subsequent wire drawing these go to high-speed rod breakdown machines which carry out interstage anneals by resistance heating the wire at speed in-line. This has superseded the previous batch annealing techniques and shows considerable economies but does require a consistently high quality of copper.

Electrical and thermal properties

Besides being a good conductor of electricity, copper is, of course, an excellent conductor of heat. The standard by which other conductors are judged is the International Annealed Copper Standard on which scale copper was given the arbitrary value of 100% in 1913. A list of some of its more important properties, particularly to transformer designers, is given in *Table 3.2*.

High-conductivity copper alloys

There are many alloys of copper and high-conductivity copper all of which have their specific uses in different types of electrical equipment. The approximate effect of impurities and some added elements on conductivity is shown in *Figure 3.11*. Most of the elements shown have some solubility in copper. Those which are insoluble tend to have little effect on conductivity and are often added to improve properties such as machinability of high-conductivity copper.

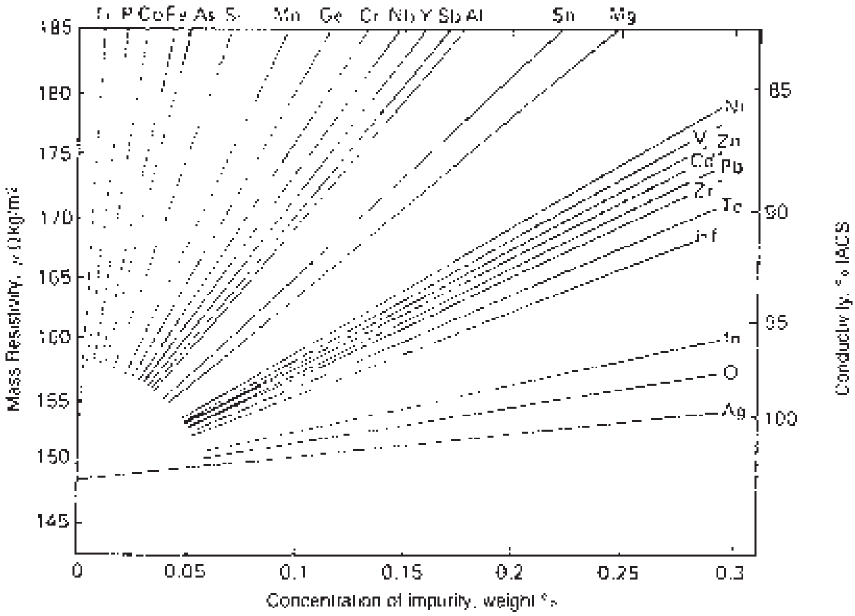


Figure 3.11 Approximate effect of impurity elements on the electrical resistivity of copper (Copper Development Association)

By far the most important alloy of copper to transformer designers is silver-bearing copper. The addition of silver to pure copper raises its softening temperature considerably with very little effect on electrical conductivity. A minimum of 0.01% of silver is normally used, which also improves the other mechanical properties, especially creep resistance, to provide transformer winding copper with the necessary mechanical strength to withstand the forces arising in service due to external faults and short-circuits. The disadvantage of this material can be the added difficulty introduced into the winding process due to its increased hardness, so its use tends to be restricted to those very

Table 3.2 Properties of high-conductivity copper and copper alloys of interest to transformer designers (Copper Development Association)

Description	*Designation*		*Approximate composition %*	*Typical electrical properties*			*Physical properties*			*Mechanical properties*		
	ISO/CEN	*Wrought*		*Conductivity*		*Mass* resistivity* $\Omega\ gm^{-2}$	*Specific heat at 20°C*	*Density gm/cm³*	*Thermal conductivity at 20°C*	*Tensile strength N/mm²*	*0.1% proof stress N/mm²*	*Creep strength*
	Cast and wrought	*BS 1432*		MS/m	% IACS							
Electrolytic tough pitch high-conductivity copper	Cu-ETP-2	C101	99.90 Cu + Ag min	58	100	0.15328	0.386 J/g°C	8.92	3.94 Wcm/cm² °C	a 220 h 385	a 60 h 325	
Silver-bearing copper	Cu-Ag		99.90 Cu + Ag 0.01–0.25%									Preferred material where high creep strength required
Oxygen-free high-conductivity copper	Cu-OF	C103	99.95 Cu + Ag min	58	100	0.15328				a 220 h 385	a 60 h 325	
Copper-cadmium	Cu-Cd	C108	0.5–1.2 cd	46	80					a 280 h 700	a 60 h 460	

a – annealed
h – hard
* – mandatory maximum

large units for which high mechanical strength is demanded. More will be said about this aspect in the following chapter.

Copper winding wires

Almost all of the copper used in transformer windings is in the form of rectangular-section wire or strip complying with British Standard 1432:1987 *Copper for electrical purposes: high conductivity copper rectangular conductors with drawn or rolled edges*. In addition to specifying the required characteristics of the copper including degree of purity, edge radii, resistivity and dimensional tolerances, the standard gives in Appendix B a table of recommended dimensions. Wire of circular cross-section cannot be wound into windings having as good a space factor as can rectangular-section wire, nor does it produce a winding with as high a mechanical stability. Circular-section wire is therefore generally restricted to small medium-voltage distribution transformer sizes for which it is used in plain enamel covered form. Special types of winding must be used for these circular conductors and these are described in Section 8 of Chapter 7.

Much of the foregoing data relating to copper, including that in *Table 3.2*, are taken from the booklet *High Conductivity Coppers* [3.3] published by the Copper Development Association to which the reader is referred for further information

3.4 INSULATION

It is hardly necessary to emphasise the importance of a reliable insulation system to the modern power transformer. Internal insulation failures are invariably the most serious and costly of transformer problems. High short-circuit power levels on today's electrical networks ensure that the breakdown of transformer insulation will almost always result in major damage to the transformer. However, consequential losses such as the non-availability of a large generating unit can often be far more costly and wide reaching than the damage to the transformer itself.

The ever growing demands placed on electricity supplies has led to increasing unit sizes and ever higher transmission voltages. Transformer ratings and voltages have been required to increase consistently to keep pace with this so that they have been nudging the physical limits of size and transport weight since the 1950s. That transformer rated voltages and MVA throughputs have continued to increase since this time without exceeding these physical limits has largely been due to better use being made of the intrinsic value of the insulation. A vital aspect is the transformer life, and this is almost wholly dependent up the design and condition of the insulation. It must be adequate for a lifespan of 40 years or more and this probably explains the increasingly demanding testing regime of impulse testing, switching surges and partial discharge measurement. At the other end of the scale, distribution transformers have become more compact and manufacturers' prices ever more competitive. Many of the savings achieved have been as a result of improvements and innovation in insulating materials and the production of special insulation components. *Figure 3.12* shows some of the insulation items which have been developed specifically for the distribution transformer industry in recent years.

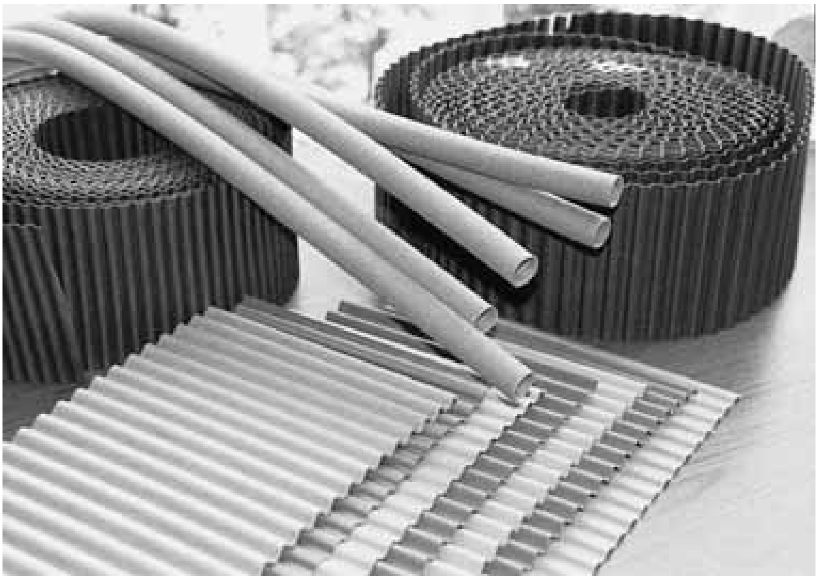


Figure 3.12 Insulation items (Whiteley Limited)

As indicated at the start of this chapter, today's transformers are almost entirely oil filled, but early transformers used asbestos, cotton and low-grade pressboard in air. The introduction of shellac insulated paper at the turn of the century represented a tremendous step forward. It soon became the case, however, that air and shellac-impregnated paper could not match the thermal capabilities of the newly developed oil-filled transformers. These utilised kraft paper and pressboard insulation systems supplemented from about 1915 by insulating cylinders formed from phenol-formaldehyde resin impregnated kraft paper, or Bakelised paper, to give it its proprietary name. Usually referred to as s.r.b.p. (synthetic resin-bonded paper), this material continued to be widely used in most transformers until the 1960s and still finds many uses in transformers, usually in locations having lower electrical stress but where high mechanical strength is important.

Kraft paper

Paper is among the cheapest and best electrical insulation material known. Electrical papers must meet certain physical and chemical standards; in addition they must meet specifications for electrical properties. Electrical properties are, in general, dependent on the physical and chemical properties of the paper. The important electrical properties are:

- high dielectric strength;
- dielectric constant – in oil-filled transformers as close as possible a match to that of oil;
- low power factor (dielectric loss);
- freedom from conducting particles.

The dielectric constant for kraft paper is about 4.4 and for transformer oil the figure is approximately 2.2. In a system of insulation consisting of different materials in series, these share the stress in inverse proportion to their dielectric constants, so that, for example, in the high-to-low barrier system of a transformer, the stress in the oil will be twice that in the paper (or pressboard). The transformer designer would like to see the dielectric constant of the paper nearer to that of the oil so the paper and oil more nearly share the stress.

Kraft paper is, by definition, made entirely from unbleached softwood pulp manufactured by the sulphate process; unbleached because residual bleaching agents might hazard its electrical properties. This process is essentially one which results in a slightly alkaline residue, pH 7–9, as distinct from the less costly sulphite process commonly used for production of newsprint, for example, which produces an acid pulp. Acidic content leads to rapid degradation of the long-chain cellulose molecules and consequent loss of mechanical strength which would be unacceptable for electrical purposes – more on this aspect shortly. The timber is initially ground to a fine shredded texture at the location of its production in Scandinavia, Russia or Canada using carborundum or similar abrasive grinding wheels. The chemical sulphate process then removes most of the other constituents of the wood, e.g. lignin, carbohydrates, waxes, etc., to leave only the cellulose fibres. The fibres are dispersed in water which is drained to leave a wood-pulp mat. At this stage the dried mat may be transported to the mill of the specialist paper manufacturer.

The processes used by the manufacturer of the insulation material may differ one from another, and even within the mill of a particular manufacturer treatments will vary according to the particular properties required from the finished product. The following outline of the type of processes used by one UK producer of specialist high-quality presspaper gives some indication of what might be involved. Presspaper by definition undergoes some compression during manufacture which increases its density, improves surface finish and increases mechanical strength. Presspaper production is a continuous process in which the paper is formed on a rotating fine mesh drum and involves building the paper sheet from a number of individual layers. Other simpler processes may produce discrete sheets of paper on horizontal screen beds without any subsequent forming or rolling processes, but, as would be expected, the more sophisticated the manufacturing process, the more reliable and consistent the properties of the resulting product.

The process commences by repulping the bales of dry mat using copious quantities of water, one purpose of which is to remove all residual traces of the chemicals used in the pulp extraction stage. The individual fibres are crushed and refined in the wet state in order to expose as much surface area as possible. Paper or pressboard strength is primarily determined by bonding forces between fibres, whereas the fibres themselves are stressed far below their breaking point. These physiochemical bonding forces which are known as 'hydrogen bonding' occur between the cellulose molecules themselves and are influenced primarily by the type and extent of this refining.

Fibres thus refined are then mixed with more water and subjected to intensive cleaning in multi-stage centrifugal separators which remove any which may not have been totally broken down or which may have formed into small knots. These can be returned to pass through the refining cycle once more. The centrifuges also remove any foreign matter such as metallic particles which could have been introduced by the refining process. The cellulose/water mixture is then routed to a wide rotating cylindrical screen. While the water flows through the screen, the cellulose fibres are filtered out and form a paper layer. An endless band of felt removes the paper web from the screen and conveys it to the forming rolls. The felt layer permits further water removal and allows up to five or six other paper plies to be amalgamated with the first before passing through the forming rolls. These then continue to extract water and form the paper to the required thickness, density and moisture content by means of heat and pressure as it progresses through the rolls. Options are available at this stage of the process to impart various special properties, for example the CLUPAK* process which enhances the extensibility of the paper, or impregnation with 'stabilisers' such as nitrogen containing chemicals like dicyandiamide which provide improved thermal performance. More will be said about both of these later. Final finish and density may be achieved by means of a calendering process in which the paper, at a controlled high moisture content, is passed through heavily loaded steel rollers followed by drying by means of heat in the absence of pressure.

The cohesion of the fibres to one another when the mat is dried is almost exclusively a property of cellulose fibres. Cellulose is a high-polymer carbohydrate chain consisting of glucose units with a polymerisation level of approximately 2000. *Figure 3.13* shows its chemical structure.

Hemi-cellulose molecules are the second major components of the purified wood pulp. These are carbohydrates with a polymerisation level of less than 200. In a limited quantity, they facilitate the hydrogen bonding process, but the mechanical strength is reduced if their quantity exceeds about 10%. Hemi-cellulose molecules also have the disadvantage that they 'hold on' to water and make the paper more difficult to dry out.

* CLUPAK Inc.'s trademark for its extensible paper manufacturing process.

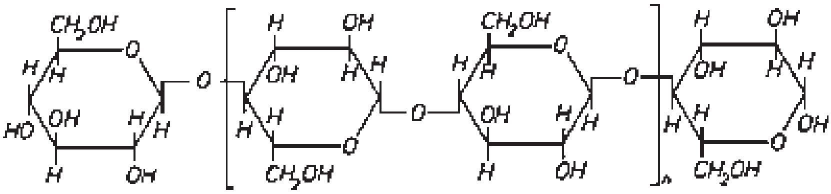


Figure 3.13 Chemical formula for cellulose

Softwood cellulose is the most suitable for electrical insulation because its fibre length of 1–4 mm gives it the highest mechanical strength. Nevertheless small quantities of pulp from harder woods may be added and, as in the case of alloying metals, the properties of the resulting blend are usually superior to those of either of the individual constituents.

Cotton cellulose

Cotton fibres are an alternative source of very pure cellulose which has been used in the UK for many years to produce the so-called 'rag' papers with the aim of combining superior electrical strength and mechanical properties to those of pure kraft paper. Cotton has longer fibres than those of wood pulp but the intrinsic bond strength is not so good. Cotton is a 'smoother' fibre than wood so that it is necessary to put in more work in the crushing and refining stage to produce the side branches which will provide the necessary bonding sites to give the required mechanical strength. This alone would make the material more expensive even without the additional cost of the raw material in itself.

When first used in the manufacture of electrical paper in the 1930s the source of cotton fibres was the waste and offcuts from cotton cloth which went into the manufacture of clothing and this to an extent kept the cost competitive with pure kraft paper. In recent years this source has ceased to be an acceptable one since such cloths will often contain a proportion of synthetic fibres and other materials so that the constitution of offcuts cannot be relied upon as being pure and uncontaminated. Alternative sources have therefore had to be found. Cotton linters are those cuts taken from the cotton plant after the long staple fibres have been cut and taken for spinning into yarn for the manufacture of cloth. First-grade linters are those taken immediately after the staple. These are of a length and quality which still renders them suitable for high-quality insulation material. They may provide the 'furnish' or feedstock for a paper-making process of the type described, either alone or in conjunction with new cotton waste threads.

Cotton fibre may also be combined with kraft wood pulp to produce a material which optimises the advantages of both constituents giving a paper which has good electrical and mechanical properties as well as maximum oil absorption capability. This latter requirement can be of great importance in paper used for high to low wraps or wraps between layers of round-wire distribution transformer high-voltage windings where total penetration of impregnating oil may be difficult even under high vacuum.

Other fibres such as manila hemp and jute may also be used to provide papers with specific properties developed to meet particular electrical purposes, for example in capacitors and cable insulation. British Standard 5626:1979 *Cellulosic papers for electrical purposes*, which is based on IEC 554, lists the principal paper types and properties. Presspapers are covered by British Standard 5937:1980 *Pressboard and presspaper for electrical purposes*. This is based on IEC 641 and will be mentioned further in relation to pressboard.

Papers for special applications

The foregoing paragraphs should have conveyed the message that there are many different types of electrical papers all of which have particular properties which have been specifically developed to meet certain requirements of particular applications. Before leaving the subject of paper insulation it is worthwhile looking a little more closely at four special types of paper whose properties have been developed to meet particular needs of the transformer industry. These are:

- Crêped paper.
- Highly extensible paper.
- Thermally upgraded paper.
- ‘Diamond dotted’ presspaper.

Crêped paper was probably the earliest of the special paper types. It is made with an irregular close ‘gathering’ or crimp which increases its thickness and greatly increases its extensibility in the machine direction. It is normally produced cut into strips around 25 mm wide and is ideal where hand applied covering is required on connections in leads or on electrostatic stress control rings which are to be placed between end sections within windings. Its extensibility enables it to be shaped to conform to irregular contours or to form bends which may be necessary, for example, in joining and forming tapping leads. *Figure 3.14* shows an arrangement of leads to an on-load tapchanger which makes extensive use of crêped paper for this purpose.

A disadvantage of crêped paper is its tendency to lose elasticity with time so that after some years in service taping of joints may not be as tight as when it was first applied. A better alternative in many situations is highly extensible paper. CLUPAK extensible presspaper is one such material. Manufacture of the basic presspaper is as described above and the elastic property is added at a stage in the roll-forming process in which the action of the rolls in conjunction with heat and moisture is to axially compress the fibres in the machine direction. As a result the paper retains its smooth finish but attains greatly enhanced burst, stretch and cross-machine tear properties while retaining its tensile strength and electrical performance. The high mechanical strength and resilience of the paper makes it ideally suited to machine

Figure 3.14 Transformer leads wrapped with crêpe paper (Peebles Transformers)

application for such items as electrostatic stress control rings identified above or as an overall wrapping on continuously transposed conductors (CTC) (see Chapter 4). CTC used in large power transformer windings often has a large cross-section making it stiff and exceedingly difficult to bend to the required radius of the winding. As a result the conductor can be subjected to very severe handling at the winding stage. In addition, the actual process of winding this large-section conductor around the winding mandrel imposes severe stress on the paper covering, creating wrinkling and distortion which can intrude into radial cooling ducts. The toughness and resilience of the extensible press-paper makes it better able than conventional paper to withstand the rough use which it receives during the winding process and the elasticity ensures that any tendency to wrinkling is minimised.

As explained above, thermally upgraded paper is treated by the addition of stabilisers during manufacture to provide better temperature stability and reduced thermal degradation. The subject of ageing of insulation will be dealt with at some length later (Section 5 of Chapter 4). At present it is sufficient to say that degradation is temperature dependent and is brought about by the breakdown of the long-chain cellulose molecules. The permitted temperature rise for power transformers is based on reaching an average hot spot temperature in operation which will ensure an acceptable life for the insulation. This is usually between about 110 and 120°C. However, within this range of temperatures insulation degradation is greatly increased by the presence of oxygen and moisture, both of which are present to some extent in most oil-filled transformers and particularly in distribution transformers whose breathing arrangements are often basic and for which maintenance can frequently be minimal. It is in these situations that thermally upgraded paper can be beneficial in retarding the ageing of paper insulation; not by permitting higher operating temperatures, but by reducing the rate of degradation at the operating temperatures normally reached.

Figure 3.15 shows diamond dotted presspaper being used in the construction of a distribution transformer. Mention has already been made of the fact that s.r.b.p. – synthetic resin-bonded paper – tubes were widely used in transformers for their good insulation properties combined with high mechanical strength. These are made by winding kraft paper which has been coated with thermosetting resin on one side onto a mandrel and then curing the resin to produce a hard tube. The reason that their use has become more selective is that the large ratio of resin to paper which is necessary to obtain the required mechanical strength makes these very difficult to impregnate with transformer oil. In the presence of electrical stress in service any voids resulting from

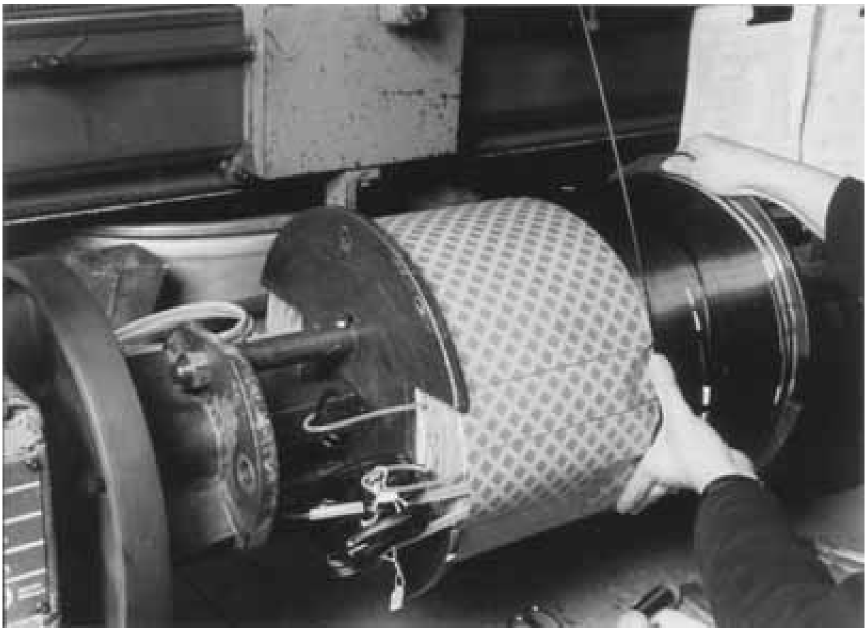


Figure 3.15 (a) Diamond dotted presspaper being used in the production of a distribution transformer winding (Merlin Gerin Transformers)

less than perfect impregnation can become a source of partial discharge which can result ultimately in electrical breakdown. Kraft papers are used for s.r.b.p. cylinders because thin papers of the necessary width are only available from the large flat wire machines in Sweden and these machines cannot handle cotton fibres. If they could a cotton paper would improve the drying and impregnation properties of s.r.b.p. cylinders. The diamond dotted presspaper shown in *Figure 3.15* represents a more acceptable method of achieving high mechanical strength without the associated difficulty of impregnation. The presspaper is pre-coated with two-stage resin in a diamond pattern which can be allowed to dry following the coating stage. The resin dots create a large bonding surface while ensuring that the paper can be effectively dried and oil impregnation efficiently carried out. When the winding is heated for drying purposes, the adhesive dots melt and cure so creating permanent bonding sites which will be unaffected by subsequent heating cycles in service but which give the structure its high mechanical strength. Although the diamond adhesive pattern can be applied to any type of paper, in practice it is still desirable to use a base paper which has good drying and impregnation properties such as the wood/cotton fibre blend identified above, particularly if used in foil-type low-voltage windings (see Section 8, Chapter 7) which can be notoriously difficult to dry out and oil impregnate.

Pressboard

At its most simple, pressboard represents nothing more than thick insulation paper made by laying up a number of layers of paper at the wet stage of manufacture. *Figure 3.16* shows a diagrammatic arrangement of the manufacturing process. Of necessity this must become a batch process rather than the continuous one used for paper, otherwise the process is very similar to that used for paper. As many thin layers as are necessary to provide the required thickness are wet laminated without a bonding agent. Pressboard can, however, be split into two basic categories:

- That built up purely from paper layers in the wet state without any bonding agent, as described above.
- That built up, usually to a greater thickness, by bonding individual boards using a suitable adhesive.

Each category is covered by a British Standard: the former by BS 5937:1980 *Pressboard and presspaper for electrical purposes*, based on IEC 641, and the latter by BS 5354:1993 *Laminated pressboard for electrical purposes*, based on IEC 763. As in the case of paper insulation, there are a number of variants around the theme and all the main types of material are listed in the British Standards. Raw materials may be the same as for presspaper, that is, all woodpulp, all cotton, or a blend of wood and cotton fibres.

Pressboard in the first of the above categories is available in thicknesses up to 8 mm and is generally used at thicknesses of around 2–3 mm for

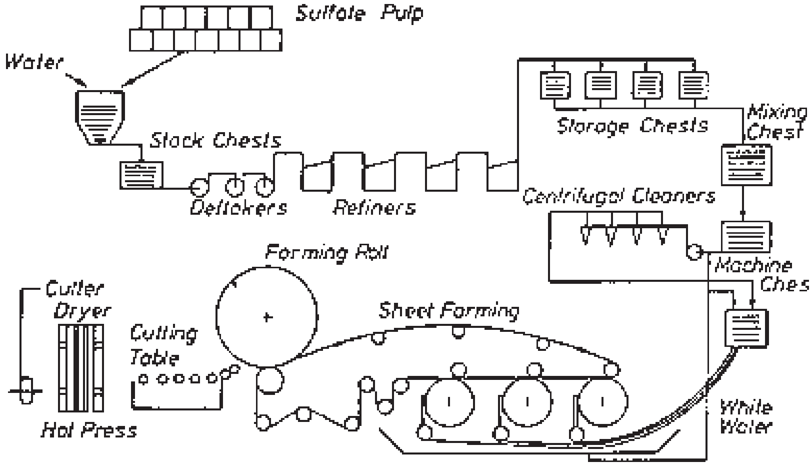


Figure 3.16 Manufacturing process for precompressed transformer board. (H Weidmann AG)

interwinding wraps and end insulation and 4.5–6 mm for strips. The material is usually produced in three subcategories.

The first is known as calendered pressboard and undergoes an initial pressing operation at about 55% water content. Drying by means of heat without pressure then follows to take the moisture level to about 5%. The pressboard thus produced has a density of about 0.90–1.00. Further compression is then applied under heavy calenders to take the density to between 1.15 and 1.30.

The second category is mouldable pressboard which receives little or no pressing after the forming process. This is dried using heat only to a moisture content of about 5% and has a density of about 0.90. The result is a soft pressboard with good oil absorption capabilities which is capable of being shaped to some degree to meet the physical requirements of particular applications.

The third material is precompressed pressboard. Dehydration, compression and drying are performed in hot presses direct from the wet stage. This has the effect of bonding the fibres to produce a strong, stable, stress-free material of density about 1.25 which will retain its shape and dimensions throughout the stages of transformer manufacture and the thermal cycling in oil under service conditions to a far better degree than the two boards previously described. Because of this high-stability precompressed material is now the preferred pressboard of most transformer manufacturers for most applications.

Laminated pressboard starts at around 10 mm thickness and is available in thicknesses up to 50 mm or more. The material before lamination may be of any of the categories of unlaminated material described above but generally precompressed pressboard is preferred. This board is used for winding support platforms, winding end support blocks and distance pieces as well as cleats for securing and supporting leads.

Pre-formed sections

The electrical stress between co-axial cylindrical windings of a high-voltage transformer is purely radial and the insulation in this region can simply consist of a series of cylindrical pressboard barriers and annular oil spaces as shown in *Figure 3.17(a)*. Pressboard can be rolled to form the cylinders and the axial joint in these may be in the form of an overlap or a scarfed arrangement as shown in *Figure 3.17(b)*. The winding ends create much more of a problem since the pressboard barriers cannot be extended far enough beyond the winding ends to provide adequate tracking distance without unduly increasing the length of the core limb. The interwinding insulation must thus be bent around the end of the winding as shown in *Figure 3.18*. For many years the way of achieving this was to make the interwinding wraps of paper or alternatively provide a tube with soft unbonded ends. The ends of the tubes or paper wraps were then ‘petalled’ by tearing them axially at intervals of about 80 mm and folding over the ‘petals’. The tears on successive layers were carefully arranged to be staggered so as to avoid the formation of direct breakdown paths through the petalling.

This process had a number of disadvantages. Firstly, it was very laborious and added greatly to manufacturing costs. Secondly, when axial compression was applied to the windings to take up shrinkage, the profile of the petalling could become displaced so as to less accurately assume the required shape and also in some circumstances create partial blockage of oil ducts. The solution is to produce shaped end rings using the process for mouldable pressboard as described above. Since this requires little pressure at the forming stage it is not necessary to manufacture elaborate and expensive moulds and the resulting shapes being fairly low density and soft in character are easily oil impregnated. A variety of moulded shapes are possible, for example shaped insulation to protect high-voltage leads. Some of the possibilities are shown in *Figure 3.19* and a typical high-voltage winding end insulation arrangement based on the use of shaped end rings is shown in *Figure 3.20*. As winding end insulation, moulded end rings have the added advantage over petalling that they can be formed to a profile which will more closely follow the lines of equipotential in the area, thus eliminating tracking stress and more closely approximating to an ideal insulation structure as can be seen from *Figure 3.20*.

Other insulation materials

Before leaving this section dealing with insulation it is necessary to briefly mention other insulation materials. Paper and pressboard must account for by far the greatest part of insulation material used in power transformers; however, there are small quantities of other materials used on certain occasions. The most common material after paper and presspaper is wood. This is almost exclusively beech for its high density, strength and stability. It must be kiln dried to a moisture content of about 10% for forming, to be further dried at the time that the transformer is dried out. In small distribution transformers the use of wood for core frames can eliminate problems of electrical

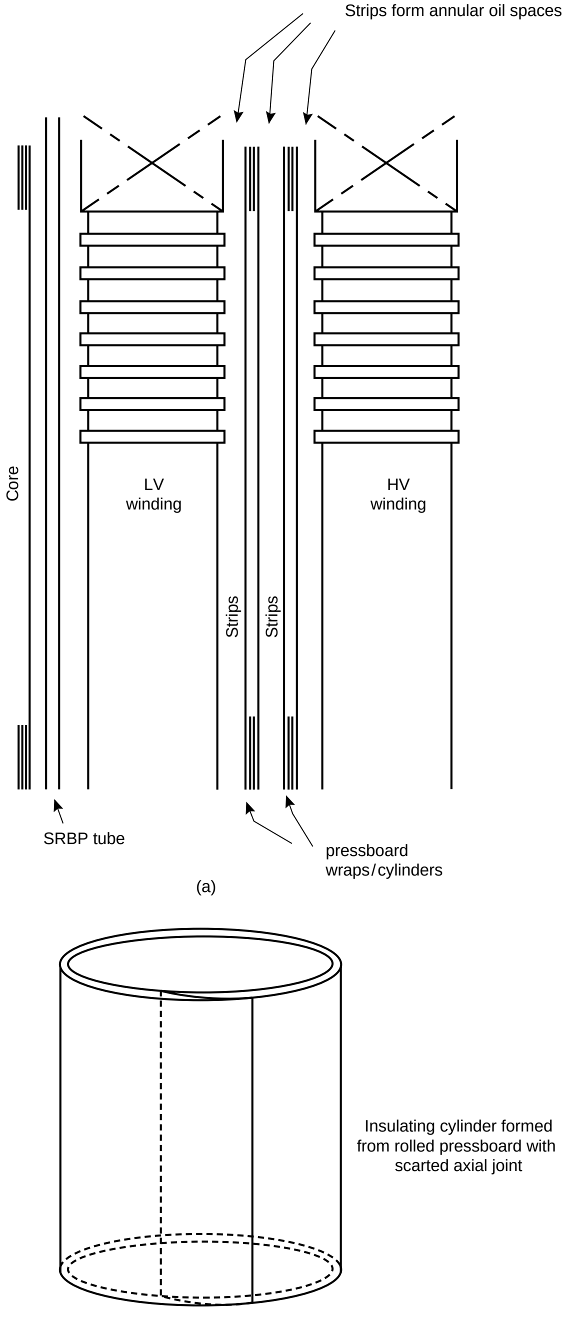

Strips form annular oil spaces
Core
LV
winding
HV
winding
Strips
Strips
SRBP tube
pressboard
wraps/cylinders
(a)
Insulating cylinder formed
from rolled pressboard with
scarted axial joint
(b)

Figure 3.17

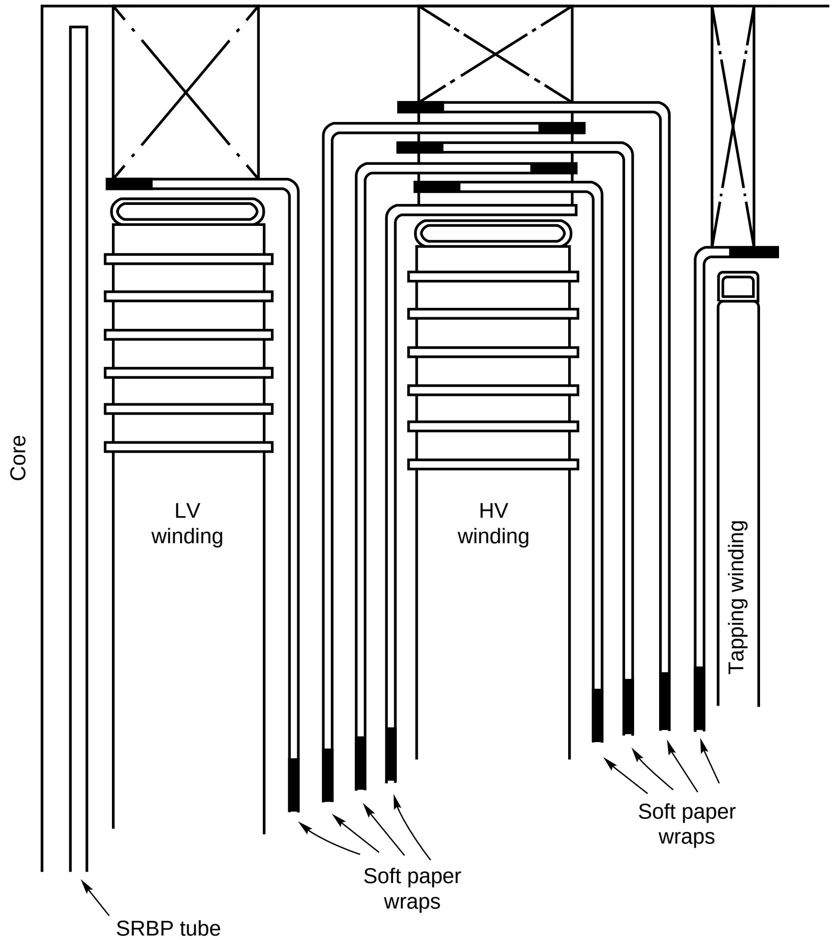
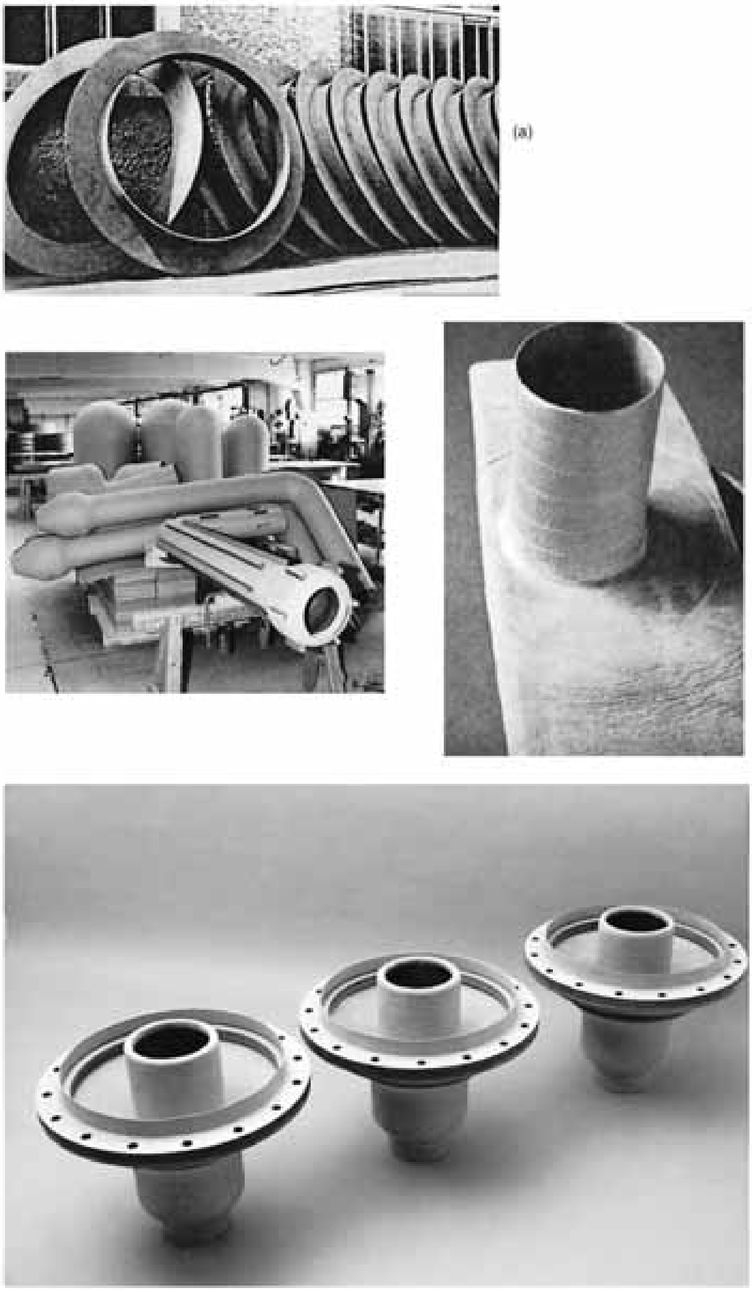


Figure 3.18 Winding end insulation shown in section to show ends of soft paper wraps ‘petalled’ and bent over through 90° so as to follow lines of equipotential (strips forming oil spaces between paper wraps have been omitted for clarity)

clearances to leads. For large transformers wood can be used economically for lead support frames and cleats. Also in large transformers wood can provide an alternative to pressboard for winding end support slabs. In this case in order to provide the necessary strength in all directions the wood must be built up from laminations with the grain rotated in a series of steps throughout 90° several times throughout its thickness.

Paper and pressboard are excellent insulation materials when used in transformer oil. If, in order to eliminate any perceived fire hazard, it is required to install a transformer that does not contain oil, one possible option is to revert to the early systems in which air is the main dielectric. Paper and pressboard are



(a) (b) (c) (d)

Figure 3.19 Moulded pressboard sections. (a) Shaped end rings photographed in the 1930s, but of a type still widely used at the present time. (b), (c), (d) More sophisticated sections produced in recent years (H. Weidmann AG)

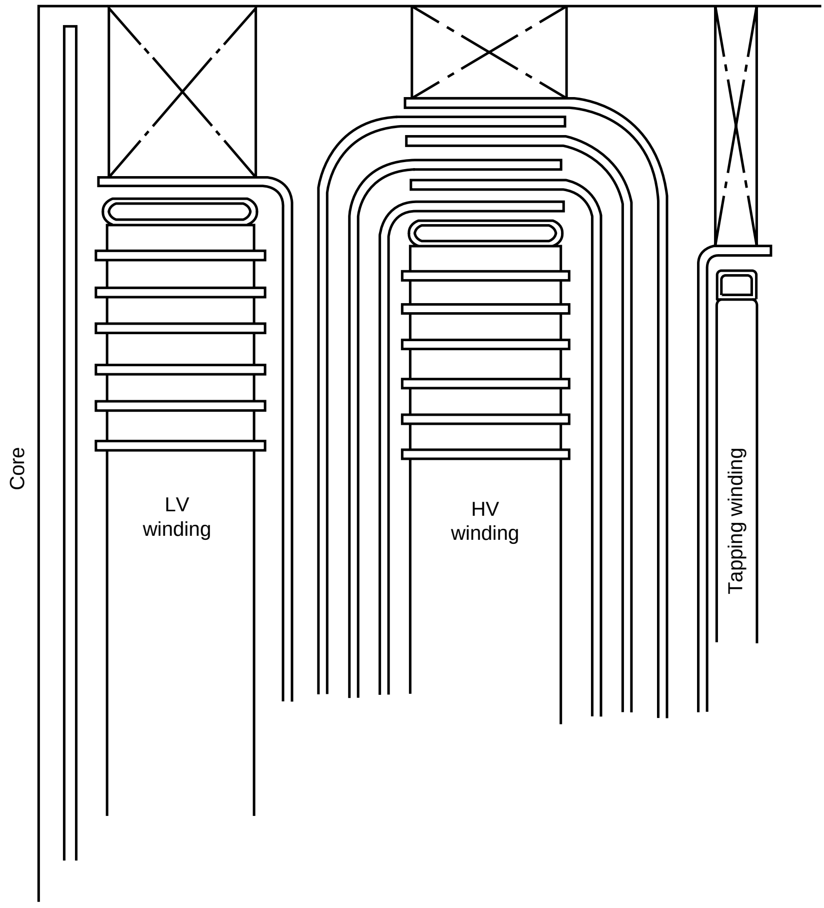


Figure 3.20 Winding end insulation associated with a similar winding configuration to that shown in Figure 3.18 but the use of moulded sections allows these to follow more closely the lines of equipotential

not good dielectrics in the absence of oil. Without the very efficient cooling qualities of oil, transformers must run hotter in order to be economic and paper and pressboard cannot withstand the higher temperatures involved. One material which can is an organic polymer or aromatic polyamide produced by Du Pont of Switzerland and known by their tradename of NOMEX.* This material can be made into a range of papers and boards in a similar way to cellulose fibres but which remain stable at operating temperatures of up to 220°C. In addition, although the material will absorb some moisture dependent upon the relative humidity of its environment, moisture does not detract from its dielectric strength to anything like the extent as is the case with

* Du Pont's registered trademark for its aramid paper.

cellulose-based insulation. Until the mid-1970s PCB-based liquid dielectrics were strongly favoured where a high degree of fire resistance was required (see following section). As PCBs became unacceptable around this time due to their adverse environmental effects, the search for alternatives was strongly pursued in a number of directions. In many quarters the benefits of transformers without any liquid dielectric were clearly recognised and this led to the manufacture and installation of significant numbers of so-called 'dry-type' transformers complying with the requirements of the former Class C of British Standard 2757 (IEC 85) *Classification of insulating materials for electrical machinery and apparatus on the basis of thermal stability in service* which permits a temperature rise of up to 210°C. By the 1990s this class of transformers has been largely eclipsed by cast resin-insulated types so that the use of NOMEX based insulation has become less widespread. Dry-type transformers and those containing alternative dielectrics will be described in greater detail in Section 8 of Chapter 7.

3.5 TRANSFORMER OIL

For both the designer and the user of an oil-filled transformer it can be of value to have some understanding of the composition and the properties of the transformer oil and an appreciation of the ways in which these enable it to perform its dual functions of providing cooling and insulation within the transformer. Such an understanding can greatly assist in obtaining optimum performance from the transformer throughout its operating life.

That is the main purpose of this section. To increase awareness of the role of insulating oil, which can often be taken somewhat for granted and to help those having dealings with oil-filled transformers to recognise the important part which the oil plays in the achievement of satisfactory operation.

Since this is intended to be an electrical engineering textbook it is not the intention to go too deeply into the chemistry of insulating oils. It has already proved necessary to look a little at the chemistry of cellulose in order to understand something about the properties of paper insulation. It is even more the case that some understanding of the chemistry of transformer oil can be of value to transformer designers and users. In fact, it is not possible for engineers to get the best from any material, particularly one as complex as insulating oil, without some understanding of its chemistry.

Much of today's industrial technology involves an appreciation of many aspects of science. Electrical power engineers often find that they have a need to call upon the knowledge of physicists, chemists and materials scientists, but each of these specialists brings their own viewpoint to the solution of a problem, often without appreciating the true nature of the problem faced by the user of the equipment, and it is left to the engineer to understand and interpret the advice of these specialists to obtain an optimum and economic solution.

This is particularly true with insulating oil. So much so that many engineers with years of experience do not have a full understanding of the subject, and many chemists with a very detailed knowledge of the chemistry, cannot translate this knowledge into practical advice of use to the operator of the plant.

The statement has already been made that transformer oil has a dual role. It is appropriate to look a little more closely at each of these aspects.

Oil as a coolant

In discussion of the other basic materials, iron and copper, mention has already been made of the energy losses which their use entails. These, of course, manifest themselves in the form of heat. This results in a rise in temperature of the system, be it core and windings, core frames, tank, or other ancillary parts. These will reach an equilibrium when the heat is being taken away as fast as it is being produced. For the great majority of transformers, this limiting temperature is set by the use of paper insulation, which, if it is to have an acceptable working life, must be limited to somewhere in the region of 100°C. Efficient cooling is therefore essential, and for all but the smallest transformers, this is best provided by a liquid.

For most transformers mineral oil is the most efficient medium for absorbing heat from the core and the windings and transmitting it, sometimes aided by forced circulation, to the naturally or artificially cooled outer surfaces of the transformer. The heat capacity, or specific heat, and the thermal conductivity of the oil have an important influence on the rate of heat transfer.

Oil as an insulator

In most electrical equipment there are a number of different parts at different electrical potentials and there is a need to insulate these from each other. If this equipment is to be made as economically as possible the separation between these different parts must be reduced as much as possible, which means that the equipment must be able to operate at as high an electrical stress as possible. In addition, transformers are often required to operate for short periods above their rated voltage or to withstand system transients due to switching or to lightning surges.

The oil is also required to make an important contribution to the efficiency of the solid insulation by penetrating into and filling the spaces between layers of wound insulation and by impregnating, after they have been dried and de-aerated by exposure to vacuum, paper and other cellulose-based insulation material.

As an indication of the importance that is placed on electrical strength, it should be noted that for a long time, since the early days of oil-filled transformers, a test of electrical strength was the sole indicator of its electrical quality. Even today, when there are many more sophisticated tests, the electrical withstand test is still regarded as the most simple and convenient test for carrying out in the field.

Viscosity and pour point

Heat can be dissipated in three ways, by radiation, by conduction, and by convection, and each of these contributes to cooling the core and conductors of an oil-filled transformer, but convection is by far the most important element. This convection relies upon the 'natural circulation' produced by gravity due to the difference in density between the hotter and the cooler fluid. The ease with which this convection flow can be induced clearly is very dependent on the *viscosity* of the fluid and it is therefore important for a transformer oil to have a low viscosity. Sometimes the convection is forced or assisted by means of pumps, but it is still desirable that the need for this assistance is minimised by the use of an oil which itself offers the minimum resistance and maximum convective assistance to the flow.

Additionally, low viscosity will assist in the penetration of oil into narrow ducts and assist in the circulation through windings to prevent local overheating which would result from poorer flow rates in the less accessible areas.

Initial impregnation is also greatly accelerated by the use of oil which is thin enough to penetrate into multi-layers of paper insulation found in areas of high stress in extra high-voltage transformers.

Mineral oils, like most other fluids, increase in viscosity as their temperature is reduced until they become semi-solid, at which stage their cooling efficiency is virtually nil. The *pour point* of a fluid is the lowest temperature at which the fluid is capable of any observable flow. For many transformers used in cold climates the oil must not approach this semi-solid condition at the lowest temperatures likely to be experienced and so the oil must have a low pour point.

Even at temperatures which, though low, are well above this pour point, the viscosity of the oil must be such that the flow is not significantly impeded. Specifications for transformer oil thus frequently specify a maximum viscosity at a temperature well below the normal ambient.

Volatility and flash point

Normally transformers are expected to have a life of at least 30 years. It is desirable not to have to constantly think of making good evaporation losses during this lifetime, nor is it acceptable that the composition of the oil should change due to loss of its more volatile elements. Low *volatility* is therefore a desirable feature.

It will be recognised that fire and explosion are to some extent potential risks whenever petroleum oils are used in electrical equipment. It is therefore necessary that the temperature of the oil in service should be very much lower than the *flash point*. On the other hand it is possible for oil to become contaminated by more volatile products which even when present in quite small quantities may constitute an explosion hazard when the oil is heated in normal service.

Such contamination has been known to occur due to removing oil from a transformer in service and transferring it to drums or tankers which had previously contained a volatile solvent.

Certain types of electrical fault can also give rise to comparatively volatile lower molecular weight hydrocarbons or to inflammable gases due to breakdown of the heavier constituent molecules of the transformer oil.

Chemical stability

All petroleum oils are subject to attack by oxygen in the atmosphere. Transformer oil is no exception although the extent to which this takes place depends on many factors.

The subject of *oxidation*, the reasons why it is important to prevent this, and the ways in which this can be achieved will be discussed at some length later in this section. Selectivity in the types of oil, or more precisely, the constituents of the oil that is used, and control of the factors which affect oxidation are the most effective strategies. Three factors are most evident: temperature, availability of oxygen, and the presence of catalysts.

Oils consisting of high molecular weight hydrocarbon molecules can suffer degradation due to *decomposition* of these molecules into lighter more volatile fractions. This process is also accelerated by temperature. It is desirable that it should not occur at all within the normal operating temperatures reached by the plant, but it cannot be prevented at the higher temperatures generated by fault conditions. This aspect will be discussed at some length in Section 7 of Chapter 6.

Selection of oils – the refining process

So far the main properties which are required from an electrical oil have been identified. There are other less important properties which, if it were possible, it would be desirable to influence. These will be discussed when oil specifications are examined in detail. If the properties that have been identified above could be closely controlled, this would go a long way to producing an electrical oil which would meet most of the needs of the practical engineer.

Types of oil

Petroleum oils have been used in electrical equipment since the latter part of the last century. Sebastian de Ferranti, who might be considered to have been the father of the transformer, recognised their benefits as long ago as 1891. Their performance has been improved a little since then, both as a result of better refining techniques and in the way in which they are selected and used. They still represent a very important component of much electrical power plant.

Firstly, it is appropriate to look a little at the sources and production of oil.

All types of mineral oils are obtained from crude petroleum, which is said to have been formed from buried and decayed vegetable matter or by the action of water on metal carbides. It is defined by the American Society for Testing and Materials in ASTM. D288 as follows:

A naturally occurring mixture, consisting predominantly of hydrocarbons which is removed from the earth in liquid state or is capable of being removed. Crude petroleum is commonly accompanied by varying quantities of extraneous substances such as water, inorganic matter and gas. The removal of such extraneous substances alone does not change the status of the mixture as crude petroleum. If such removal appreciably affects the composition of the oil mixture then the resulting product is no longer crude petroleum.

Crude petroleum is now extracted from the earth in many parts of the world and its quality and composition vary within quite small geographical areas. It is a complex mixture of molecules made up of carbon and hydrogen and a small proportion of sulphur and nitrogen.

There are three main groups of hydrocarbon molecules. These are *paraffins*, *naphthenes* and *aromatics*. Each has a characteristic molecular structure, and no two crudes are exactly alike in the relative proportions of the hydrocarbon types or in the proportions and properties of the products to which they give rise.

Figure 3.21 shows the typical molecular structure of the three types of hydrocarbon, and includes some of the simplest members of the groups. The simplest paraffin is methane, CH_4, a gas, but there is almost no limit to the length of the straight chain of carbon atoms, or to the variety of paraffins with branched chains, the isoparaffins, with side chains attached to individual carbon atoms in the main chain. Normal butane, C_4H_{10}, is shown as a straight chain paraffin, while isobutane, also C_4H_{10}, has a single branch, and both occur in petroleum gas, but some idea of the complexity of the mixtures of compounds that petroleum represents can be gauged from the fact that there are more than 300 000 possible isoparaffins all with the basic formula $C_{20}H_{42}$, and many billions with the formula $C_{40}H_{82}$.

The naphthenes have ring structures, and those shown in *Figure 3.21* have six-membered rings, i.e. rings with six carbon atoms though, it will be noted, the three-ring compound has 14, not 18, carbon atoms. Naphthenes with five- or seven-membered rings also occur in petroleum but six-membered are the most common. The aromatics, too, have six-membered ring structures, but with the important difference that some of the carbon atoms are joined by double bonds, shown in the figure as double lines. This has the effect of making the aromatics ‘unsaturated’ and, in general, more reactive. Aromatics fall into two groups, those with single rings, or monoaromatics, and those with two or more rings, or polyaromatics, sometimes termed PACs. In petroleum-based transformer and switch oils the aromatics vary in proportion, but are generally present in much smaller amounts than either the naphthenes or the paraffins.

Many classifications have been proposed for the various types of crudes, but the most generally accepted is that based on the main constituent of the distillation residue and consists of four descriptions: paraffinic, asphaltic,

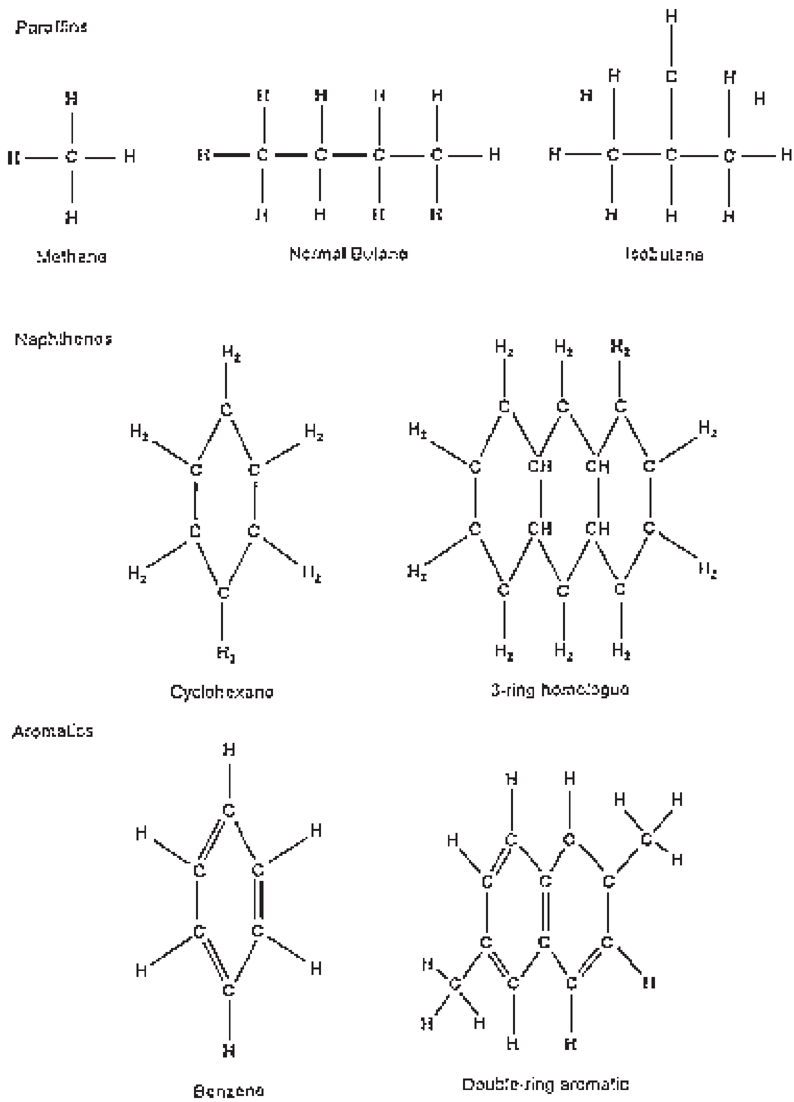


Figure 3.21 Molecular structures of hydrocarbons

mixed or intermediate, and naphthenic. The world's known supply of crude oil is made up of very approximately 7% paraffinic, 18% asphaltic (including 5% naphthenic) and 75% mixed or intermediate.

In the UK for at least 60 years, insulating oils have been manufactured almost exclusively from naphthenic or intermediate crudes, at one time from Russia and more recently from Venezuela, Peru, Nigeria and the Gulf Coast of the USA.

Refining of petroleum

Crude oil is subjected to a series of physical and chemical treatments to produce the refined product. A typical refinery is custom designed to deal with a particular type of crude oil and to produce a selected range of products. The development of cracking, reforming and hydrofining processes in recent years has revolutionised the petroleum industry, and has resulted in the production of finished products which are ‘tailor made’ and which bear no relation to the crude oil feedstock composition. Thus, the classification given to the crude oil may no longer have the same significance in relation to the end product.

In a typical refinery which produces a full range of products the crude oil is distilled at atmospheric pressure to remove the low boiling point products, and these are then used as fuels and solvents after suitable further refining. The residue may then be distilled under vacuum to give stocks for the production of electrical and lubricating oils. The residue from this vacuum distillation can then be used for the production of fuels, asphalts and bitumens depending on the quality of the feedstock and the product(s) required.

The vacuum unit distillate is refined by one or more of a number of processes such as selective solvent extraction, sulphuric acid extraction, earth filtration, hydrogenation, redistillation, filtration, and dehydration. The most economical technique is used, subject to the processes available at the refinery, which will produce a product to the required quality level. The aims of the refining processes are to remove or reduce waxes, sulphur, nitrogen, and oxygen-containing compounds and aromatic hydrocarbons.

Alternative viscosity grades are obtained by suitable blending of the distillate fractions collected or by redistillation in the case of a single fraction.

In principle, solvent refining relies upon the selective solubility of such materials as wax, sulphur and nitrogen compounds and aromatic hydrocarbons in the selected solvents; sulphuric acid chemically combines with sulphur compounds and aromatic hydrocarbons; earth filtration removes residual polar contaminants; and hydrogenation reduces sulphur, nitrogen and aromatic hydrocarbon compounds.

Earth filtration is nowadays regarded as rather environmentally unfriendly in view of the large quantity of contaminated filtration medium which it produces and which it is required to dispose of. For this reason the process is now less frequently used but it is still without equal in the production of the highest quality electrical oils.

Hydrogenation is the most recent and versatile refining treatment and the reactions are controlled by temperature, pressure, catalyst, time and other factors. Light hydrogenation, usually referred to as ‘hydrofinishing’ or ‘hydropolishing’, may be used following one or more of the other processes to remove sulphur and nitrogen by converting the compounds to hydrocarbons. Severe hydrogenation, also called ‘hydrofining’, is used to reduce the total unsaturated ring compounds; for example, aromatic to naphthene and paraffin hydrocarbons, when those compounds containing the highest number of rings react first.

In producing electrical oils particular attention is paid to producing the required electrical properties, oxidation stability and, where appropriate, gas absorbing properties. (Good gas absorption is a requirement particularly called for in oil for power cables.) This necessitates low sulphur and nitrogen content, but an optimum aromatic content. *Figure 3.22* shows the effects of refining treatment on the principal properties of insulating oil.

A little more about the classification of oils

Mention has already been made of the extent and complexity of the array of hydrocarbons which go to make up a particular crude oil. Such complexity makes it difficult to describe and classify oil from a particular source. One way of getting round this, the Brandes system, which uses infrared spectroscopy, is to express hydrocarbon content in terms of the total carbon in the individual types of hydrocarbon irrespective of whether it is present as an individual compound or as a substituent group attached to a type of hydrocarbon. Thus, it is possible to express percentage carbon in paraffin chains $\%C_P$, percentage carbon in aromatic rings $\%C_A$, and percentage carbon in naphthene rings $\%C_N$.

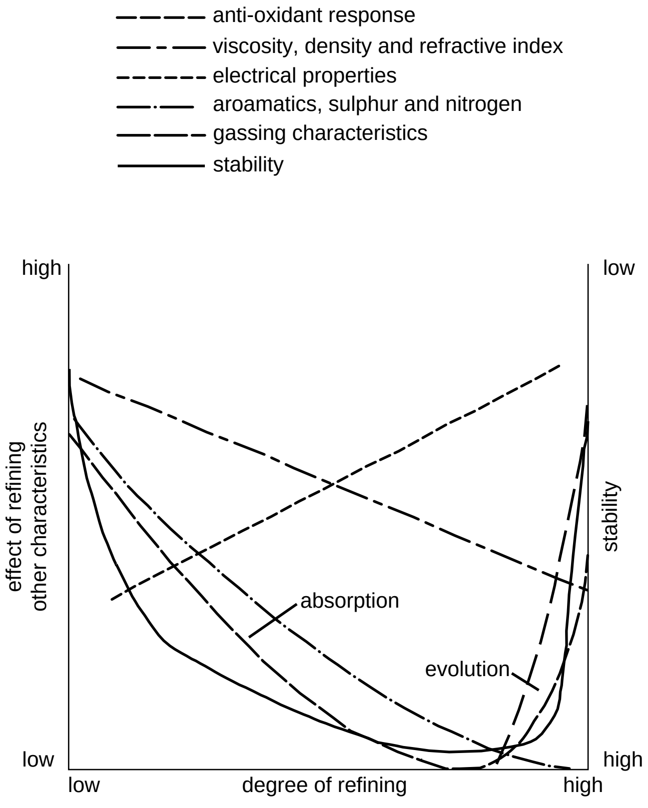


Figure 3.22 Effect of refining on properties of oil

It is of interest, using this classification, to look at a number of crudes which have been traditionally classified as either naphthenic or paraffinic. These are listed in *Table 3.3*.

Table 3.3 Typical analyses of crude oils classified as naphthenic and paraffinic showing actual proportions of aromatics, naphthenes and paraffins present

Classification of crude oil	*%C_A*	*%C_P*	*%C_N*
	9	54	37
	10	54	36
	10	44	46
Naphthenic	12	49	39
	14	46	40
	5	43	52
	9	47	44
	8	71	21
	16	56	28
Paraffinic	17	63	20
	20	60	20
	4	62	34
	19	56	25

It will be noted that in no fewer than four of the so-called naphthenic oils, the percentages of carbon atoms in paraffinic structures are markedly higher than in naphthenic structures, and in two others the proportions of the two types are very similar. Among the paraffinic oils, the paraffinic structures predominated, but the %C_P values for two of them were almost identical to those of the naphthenic oils. The essential difference between the two types of oil seems, therefore, less one of differing %C_P/%C_N relationships or structural constitution but the fact that the paraffinics contain wax whereas the normally selected naphthenic crudes contain little or none. The significance of this fact will be explained later.

Specification of insulating oil

Towards the beginning of this section certain properties for insulating oil were identified as being very important. These are:

- Low viscosity.
- Low pour point.
- High flash point.
- Excellent chemical stability.
- High electrical strength.

There are also some other properties which might be less important, but for which it would nonetheless be desirable to have some say in their determination. These include:

- High specific heat.
- High thermal conductivity.
- Good impulse strength.
- High or low permittivity, depending on intended use.
- High or low gas absorbing, depending on intended use.
- Low solvent power.
- Low density.
- Good arc quenching properties.
- Non-toxic.

And, of course, in addition to all of the above it is required that the insulating oil be cheap and easily available!

It is clear that no single liquid possesses all of these properties and that some of the requirements are conflicting. Compromise, therefore, will be necessary and the design of the equipment will have to take into account the shortcomings of the oil.

It is appropriate to look at how these properties are specified and at the tests made for them according to British Standard 148:1984. This document is now very similar to IEC Publication 296:1982, but it continues the UK practice of specifying water content on delivery and also anticipates the IEC document in introducing a new oxidation test and gassing tendency test. These differences are not important for the purposes of this chapter.

BS 148:1984 also included for the first time a specification for oxidation-inhibited oil, although little use is made of such material in the UK. Its use is widespread, however, in most other parts of the world and so the subject of oxidation-inhibited oils will be considered at some length later in this section. However, for clarity, in the present context only *uninhibited* oil will be considered.

The following characteristics are laid down in BS 148:1984 for uninhibited oils:

Characteristic	*Limit*		
	Class I	*Class II*	*Class III*
Viscosity			
mm^2/s at 40°C(max.)	16.5	11.0	3.5
−15°C(max.)	800		
−30°C(max.)		1800	
−40°C(max.)		150	
Flash point (closed) (min.)	140°C	130°C	95°C
Pour point (max.)	−30°C	−45°C	−60°C
Density	0.895 g/cm^3		

Acidity (neutralisation value) (max.)	0.03 mgKOH/g
Corrosive sulphur	Shall be non-corrosive
Water content (max.)	
bulk delivery	30 ppm
drum delivery	40 ppm
Anti-oxidant additives	Not detectable
Acidity after oxidation (max.)	1.5 mgKOH/g
Sludge value, % by mass (max.)	1.0
Electric strength (breakdown) (min.)	30 kV
DDF (max.)	0.005
Gassing tendency at 50 Hz after 120 min (max.)	5 mm^3/min

Physical properties of transformer oil

In the foregoing specification the properties concerned with the physical nature of the oil are viscosity, closed flash point, pour point and density. The first three of these are properties which were identified as falling within the 'important' category. The reason for specifying closed, as opposed to open, flash point is that the former is more precise and more meaningful than the latter. The fire point is normally approximately 10°C higher than the closed flash point. The reason for the three classes, I, II and III, is concerned with the use of insulating oil in switchgear as well as the provision of oils for use in very cold climates. This aspect will be discussed in a little more detail shortly.

Viscosity

Viscosity is measured in glass tube viscometers, which can be closely standardised and also allow the use of the centistoke or mm^2/s, which is based on the absolute definition of viscosity. In the specification, the temperatures of measurement indicated for viscosity are −15°C, for Class I oil, and 40°C. For Class II and Class III oils the low-temperature points are respectively −45 and −60°C. *Figure 3.23* shows the extent to which the three grades of oil complying with the requirements of IEC 296 vary in viscosity with temperature.

With increases in temperature, the viscosity of oil falls, at a rate dependent upon its particular chemical composition. An unacceptably high viscosity at low temperatures is guarded against by the specification of a maximum viscosity limit at the lower temperature, −15°C in the case of Class I oil and correspondingly lower for Classes II and III. The document does not lay down a lower limit for viscosity because the specification of a minimum for closed flash point prevents the use of the lowest viscosity fraction of the oils. Similarly, because the specification stipulates a maximum value for viscosity, the

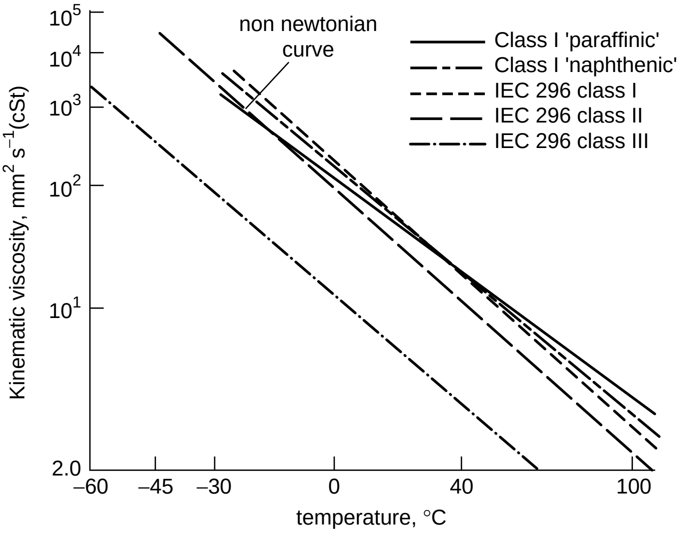


Figure 3.23 Variation of viscosity with temperature for IEC 296 oils

closed flash point of transformer oil cannot be very much above the minimum requirement stated. It is left to the oil refiner's skills and experience to give due regard to all these points in selecting the base oil for the manufacture of the transformer oil so that the best compromise can be obtained. One of the important requirements of the oil used in switchgear is that it must assist in the quenching of the arc formed by the opening of a circuit breaker. This necessitates that the oil must quickly flow into the gap left by the separating circuit breaker contacts, which demands that it must have low viscosity and which is the other main reason for the specification of Class II and III oils. For these low viscosity is more important than high flash point which explains why it is necessary to relax the requirement in respect of this parameter.

Closed flash point

The reason for wishing to fix the closed flash point is, as mentioned above, to ensure that some of the coolant is not lost over the years. Loss would be greatest in the case of distribution transformers without conservators. These present the largest oil surface area to the atmosphere. They are, of course, the transformers which it would be most preferable to install and forget, but if they experience loss of oil there could be a danger of getting into the situation where ultimately windings are uncovered.

The closed flash point of oil is measured by means of the Pensky-Martens apparatus. It gives a guide to the temperature of the oil at which the combustible vapour in a confined space above it accumulates sufficiently to 'flash' upon exposure to a flame or other equivalent source of ignition.

Pour point

The value of $-30^\circ C$ for the maximum pour point of Class I oil is used in many specifications, since this represents a likely minimum ambient temperature in which electrical plant might be called upon to operate. The inclusion of Classes II and III oils with pour points of -45 and $-60^\circ C$ respectively is specifically to allow for oils for use in very cold climates.

Density

The reason for wishing to place a limit on density is because at very low temperatures the increase in density might be such that ice, if present, would float on the top of the oil. The density limit of 0.895 g/cm^3 (max.) at $20^\circ C$ ensures that the temperature must fall to about $-20^\circ C$ before the density of oil, of the maximum permitted density at $20^\circ C$, would exceed that of ice. Clearly, if there is to be ice, it is preferable for it to form at the bottom of the tank, out of harm's way.

Chemical properties of transformer oil

Some description has been given of the chemical composition of oil, and mention has been made of the need for chemical stability, that is, resistance to oxidation and decomposition. The former requirement is covered in the BS 148 specification by the specifying of limiting values for sludge formation and acidity, which, as will be shown later, are closely linked to oxidation.

In Section 7 of Chapter 6 the subject of decomposition of transformer oil will be discussed at some length and it will be seen that the decomposition process is much the same for all types of electrical oils. This is probably the reason why BS 148 does not address this aspect of chemical stability.

In fact, the other chemical properties that BS 148 seeks to define are those which ensure freedom from small amounts of undesirable compounds, demonstrated by low initial acidity and freedom from corrosive sulphur.

Resistance to oxidation

Sludge deposition and increase in acidity are both linked to the oxidation process. Earlier specifications did not recognise this, neither did they recognise the harmful effects of high acidity. BS 148:1923 included an oxidation test with a limit to the amount of sludge produced. However, new oil was allowed an acidity equivalent to 2.0 mgKOH/g, a figure which is *four times higher* than the level at which oil would now be discarded.

The current BS 148 oxidation test is carried out by maintaining a sample of 25 g of the oil in the presence of metallic copper – copper is a powerful catalyst for oxidation – at $100^\circ C$ while oxygen is bubbled through the sample for 164 hours. The oil is then cooled in the dark for one hour, diluted with normal heptane and allowed to stand for 24 hours, during which time the more highly oxidised products are precipitated as sludge, which is separated and weighed. The remaining solution of *n*-heptane is used for the measurement of acidity development. The combined two values effectively define the oxidation stability of the oil.

Acidity as supplied

The initial acidity, or acidity as supplied, as distinct from acidity after the oxidation test, is considered by some no longer to be a test of quality since, in the course of normal refining, it is possible to reduce the acidity to a negligible level. It does, however, represent a test of quality to the extent that it demonstrates freedom from contamination. The specification recognises that it is difficult to obtain complete freedom, but nevertheless sets a very low level of 0.03 mgKOH/g. The acidic materials which may contaminate the oil are not capable of precise definition but may range from the so-called naphthenic acids, which are present in unrefined petroleum, to organic acids which are formed by oxidation during the refining process.

At this point it may be appropriate to consider the method used for quantitative estimation of acidity. Most of the standards covering electrical oils express acidity in milligrams of potassium hydroxide required to neutralise one gram of oil (mgKOH/g). The method of establishing this is by titration of the oil with a standard solution of the alkali in the presence of a suitable solvent for acids. Such a method is described in BS 2000: Part 1, the point of neutralisation being shown by the colour change of an added indicator, this being an organic material of a type which experiences a colour change on becoming alkaline.

Test for corrosive sulphur

The test for corrosive sulphur, sometimes known as deleterious sulphur and copper discoloration, was made more severe with the issue of BS 148:1972. It involves immersing a strip of polished copper in oil at a temperature of 140°C and in an atmosphere of nitrogen for 19 hours, after which the copper is examined. An oil is failed if the copper strip, or part of it, is dark grey, dark brown or black. A pass does not necessarily mean that the oil is free from sulphur compounds but simply that these are not of an active nature. In fact, with modern transformer oils trouble in service due to sulphur attack on copper is, nowadays, very rare indeed.

Water content

Although this does not truly represent a chemical property, it is convenient to include the test for water content with the chemical tests.

Water is soluble in transformer oil only to a limited extent. The solubility ranges from about 30 to 80 ppm at 20°C, with the higher levels of solubility being associated with the higher aromatic content oils. The solubility is higher at higher temperatures.

The presence of free water will reduce the electrical strength of oil. While it remains dissolved, the water has little detrimental effect on the oil, but it is the case that paper insulation has a very great affinity for water, its equilibrium level in contact with oil being such that the quantity contained in the paper is very much greater than that in the oil. The main objective, therefore, in striving to obtain low moisture-in-oil contents is in order to limit the quantity of water in the paper insulation. The subject of water in oil will be discussed at some length later in this section.

Traditionally the test for free water has been the crackle test. A small quantity of the oil is heated quickly in a shallow cup over a silent flame. The object is to heat up the water to well above its normal boiling point before it can dissolve in the hotter oil. As the water droplets instantaneously expand to become vapour they produce an audible crackle.

The 1972 issue of BS 148 introduced the Karl Fischer method detailed in BS 2511 for the first time. The test is a complex one but it is claimed to have a repeatability to approximately 2 ppm. In the 1984 issue this is retained but the acceptable levels are reduced slightly.

Electrical properties of transformer oil

Electrical strength

The *electrical strength test* included in all BS specifications prior to BS 148:1972 is very much seen as the fundamental test of the oil as an insulant. It is not surprising to learn that it was, in fact, one of the earliest tests devised on transformer oil. It is nevertheless not truly a test of the electrical quality of the oil so much as an assessment of its condition. In first-class condition the oil will withstand an electrical stress very much higher than that demanded by the standard. However, very small traces of certain impurities, namely moisture and fibre, particularly in combination, will greatly reduce the withstand strength of the oil.

As originally devised, the electrical strength test involved the application of the test voltage to a sample of oil contained in the test cell across a pair of spherical electrodes 4 mm apart. The sample was required to withstand the specified voltage for one minute, any transient discharges which did not develop into an arc being ignored. A pass required two out of three samples to resist breakdown for one minute.

The issue of BS 148:1972 replaced the above test by one which measures *breakdown voltage* and this is retained in the 1984 issue. In this test oil is subjected to a steadily increasing alternating voltage until breakdown occurs. The breakdown voltage is the voltage reached at the time that the first spark between the electrodes occurs whether it be transient or total. The test is carried out six times on the same cell filling, and the electric strength of the oil is the average of the six breakdown values obtained. The electrodes have a spacing of 2.5 mm. The electrodes of either copper, brass, bronze or stainless steel are either spherical and 12.5–13 mm in diameter or spherical surfaced and of dimensions shown in *Figure 3.24*.

The first application of the voltage is made as quickly as possible after the cell has been filled, provided that there are no air bubbles in the oil, and no later than 10 minutes after filling. After each breakdown, the oil is gently stirred between the electrodes with a clean, dry, glass rod, care being taken to avoid as far as possible the production of air bubbles. For the five remaining tests the voltage is reapplied one minute after the disappearance of any air bubbles that may have been formed. If observation of the disappearance of air bubbles is not possible it is necessary to wait five minutes before a new breakdown test is commenced.

The minima for breakdown voltage in the 1972 and 1984 issues of BS 148 are lower than those of earlier issues. This does not, of course, represent a lowering of standards, but simply reflects the new method of carrying out the test – and especially the fact that the gap between the electrodes has been reduced from 4 to 2.5 mm.

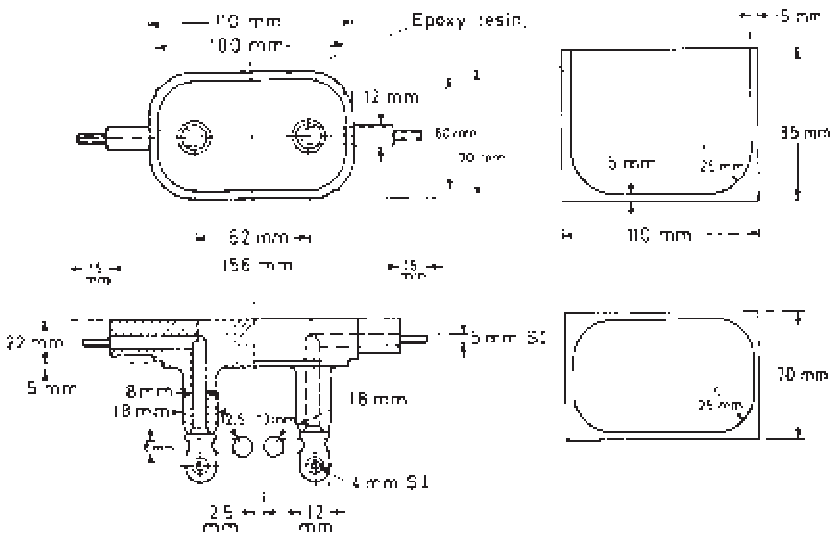
The 'old' test method has not been completely abandoned. Since it is less searching where high breakdown strengths are not expected it is still accepted as a method for testing used oil and is included as such in BS 5370:1979 *Code of Practice for Maintenance of Insulating Oil.*

DDF and resistivity

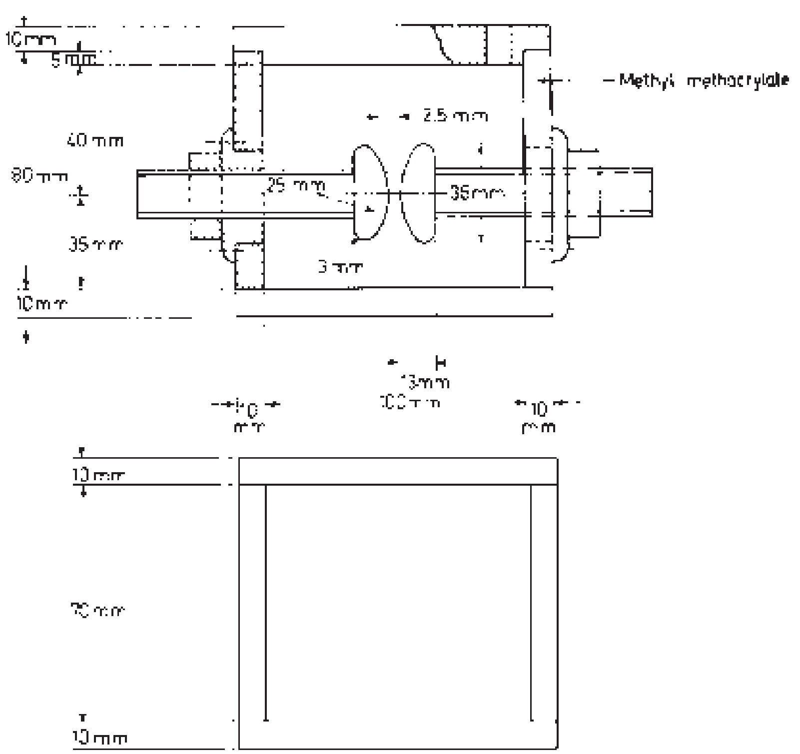
Dielectric dissipation factor, DDF, which used to be known as loss angle or tan δ, and resistivity are more fundamental electrical properties than electrical strength and are of most interest to designers of EHV transformers.

Only DDF is considered as mandatory by BS 148:1984; however, reference to resistivity remains in BS 5730:1979 as an indication of electrical quality especially for used oils. This latter document is discussed further in Section 7 of Chapter 6. For DDF measurement a specially designed test cell or capacitor is filled with the oil under test which displaces air as the capacitor dielectric. The cell is connected in the circuit of a suitable AC bridge where its dielectric losses are directly compared with those of a low-loss reference capacitor.

The cell employed should be robust and have low loss; it must be easy to clean, reassemble and fill, without significantly changing the relative position of the electrodes. *Figure 3.25* shows two possible arrangements. The upper one is recommended by CIGRE (Conference Internationale des Grandes Réseaux Electriques), and consists of a three-terminal cell which is now widely used. An alternating current bridge (40–62 Hz) is used, which should be capable of measuring loss angle or tan δ down to 1×10^{-4} for normal applications, but preferably down to 1×10^{-5}, with a resolution of 1×10^{-5} in a capacitance of 100 pF. The voltage applied during the measurement must be sinusoidal. Measurement is made at a stress of 0.5–1.0 kV/mm at 90°C, and is started when the inner electrode attains a temperature within plus or minus 0.5°C of the desired test temperature.

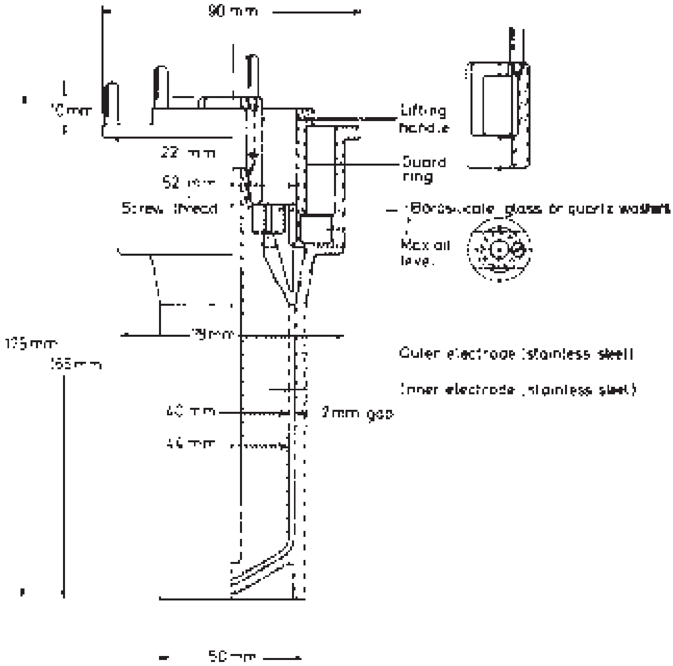


(a)

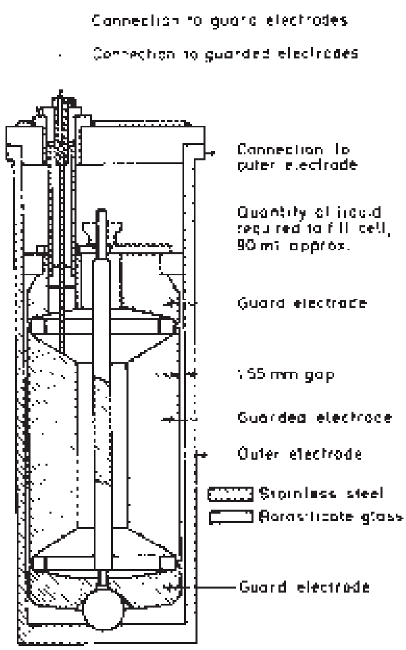


(b) Test cell with spherical surfaced electrodes

Figure 3.24 Oil test cells



(a) DDF test cell recommended by CIGRE.
(Quantity of liquid required to fill cell, 45 ml approx.)



(b) A three-terminal DDF test cell

Figure 3.25 DDF test cells

For DC resistivity measurement, the current flowing between the electrodes is measured when a specified voltage, normally 550 V, is applied to the cell. The current is noted after the voltage has been applied for one minute. The electrodes should be short-circuited for five minutes between the DDF and resistivity measurements. Average resistivity values are calculated from readings taken after direct and reverse polarity. For measurement, an instrument capable of detecting 10^{-11} amps is required.

More closely standardised methods for both DDF and resistivity have also been published as BS 5737:1979 which aim to provide greater precision.

Additives and inhibited oil

In the oil industry in recent years, particularly for oils used for lubrication, enormous advances, providing spectacular improvements in performance, have been made by the use of oil additives, that is, very small quantities of substances not naturally present in oil which modify the performance or properties of the oil. Similar results are possible in the field of electrical oils, although the transformer industry, particularly in the UK, has been cautious and reluctant to accept this. This caution has mainly been concerned with how long the beneficial effects are likely to last. After all, even with the benefits of the most modern additives it is not yet possible to leave the oil in a motor car engine for 30 years! There has also been some suspicion on the part of users that, by the use of additives, oil companies might seek to off-load onto the transformer industry oils which have been under-refined or are not entirely suitable for the electrical industry.

Reasons for additives

Before discussion of the additives themselves and the properties which it might be desirable to gain from them, it is logical to consider the undesirable properties of oils and what can be done to minimise the problems which these cause without resorting to additives.

It has already been highlighted that electrical oil is subject to oxidation and that this leads to sludge formation. Perhaps 30 or more years ago, when a transformer was taken out of service, either due to old age or because of premature failure, it was often the case that the complete core and coils were covered by heavy, dark brown, sludge deposits. These deposits partially block ducts, reducing the oil circulation. They reduce the heat transfer efficiency between the coils and the core steel and the oil. This, in turn, causes copper and iron temperatures to rise, which, of course, further increases oxidation and sludge formation, and so the problem becomes an accelerating one. Excessive temperatures lead to more rapid degradation of insulation and the transformer may fail prematurely.

As already indicated, another result of oxidation is the increase in acidity of the oil. At one time this acidity was seen as less of a problem than that of sludge formation, and, indeed, that is probably the case. It is now recognised, however, that increased acidity of the oil is very detrimental to the well-being of the transformer and therefore something to be avoided. The acids are organic and nothing like as corrosive as, say, sulphuric acid, but they can cause corrosion and accelerate the degradation of solid insulation.

There is, however, a great deal which can be done to reduce oxidation without the use of additives.

Firstly, by reducing the degree of contact between the oil and air. There are good reasons for not wishing to seal off the oil completely from the external air and these will be identified later. However, in all but the smallest distribution transformers it is economic to provide a conservator. Not only does this reduce the area of contact between the oil and air, but it also ensures that the oil which is in contact with air is at a lower temperature than the bulk oil.

Temperature is, of course, an important factor. Each 7°C increase in temperature above normal ambients doubles the rate of oxidation.

Then there are, as has been mentioned, the effects of catalysts. It is unfortunate that copper is a strong catalyst in the oxidation process. Iron is a catalyst also, but not quite so strongly. There is little that can be done about the copper in the windings, although being insulated does restrict the access to the oil thereby reducing the effect. Bare copper, such as is frequently used for lower voltage leads and connections, can be tinned, since tin does not have a catalytic action. The internal surfaces of steel tanks and steel core frames can be painted with oil-resistant paint.

There is also an effect which is sometimes referred to as auto-catalytic action. Some of the products of oxidation themselves have the effect of accelerating further oxidation. This is particularly the case when some aromatic compounds are oxidised. Hence, oils with increased aromatic content over a certain optimum quantity of about 5–10% are more prone to oxidation. The curve, *Figure 3.26,* shows the effect of varying aromatic content on oxidation.

By the use of these measures alone there has been a significant reduction in the extent to which oxidation has shown itself to be a problem over the last 30 or so years. Offset against this is the fact that since the 1970s there has been a tendency to increase operating temperatures, and measures to reduce the degree of contact between the oil and catalytic copper and iron have been reduced as a cost-saving measure, particularly in many distribution transformers. It is possible that once again users will begin to experience the re-emergence of oxidation as a serious problem in many transformers.

Use of additives

In the UK it has been the practice not to allow additives in electrical oil. Elsewhere additives have been used in transformer oils for many years with the specific purpose of inhibiting oxidation. In fact, oils thus treated were referred to as *inhibited oils*.

Inhibition of oxidation is achieved by the inclusion of oxidation inhibitors, metal passivators and deactivators. The latter react with metals to prevent the metal catalysis mechanism, while oxidation inhibitors react with the initiation

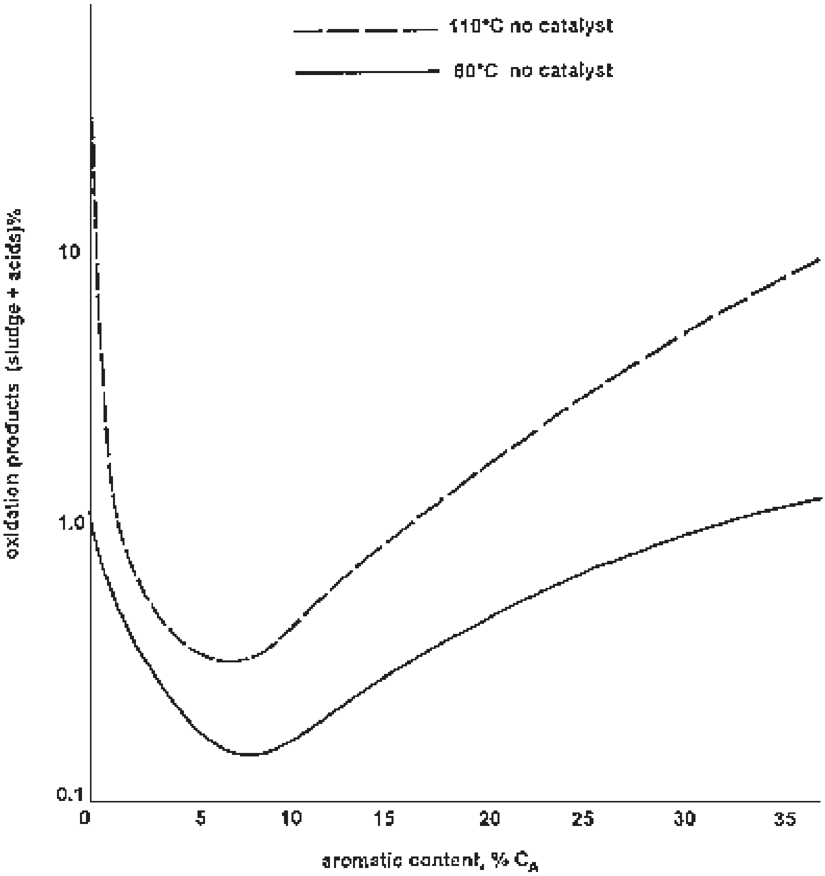


Figure 3.26 Effect of aromatic content on oxidation of insulating oils

products, free radicals or peroxides to terminate or break the oxidation reactions. Some naturally occurring oil compounds, principally those containing sulphur, act as oxidation inhibitors in this way. As a result of research into the oxidation process it became clear that certain organo-metallic compounds of copper, when dissolved in the oil were even more active catalysts than the oil itself. Certain compounds were then developed which deactivate or 'passivate' the copper surfaces essentially preventing solution of copper in the oil, and even inhibiting the catalytic effects of any existing copper in solution.

Most transformer engineers are now familiar with inhibited oils but their use is still frowned upon in the UK. In addition to the natural suspicions on the part of the users, this is probably due to the quality of the uninhibited oils which have been available for many years, coupled with the increased care with which they are maintained, resulting in such long life in most transformers that users have been reluctant to meet the higher first cost that inhibited oil involves.

The 1972 edition of BS 148 stated: ‘the oil shall be pure hydrocarbon mineral oil . . . without additives. By arrangement between seller and buyer the oil may contain an oxidation inhibitor or other additive, in which case the oil, before inclusion of the additive, shall comply with the BS. Oils complying with the requirements of this standard are considered to be compatible with one another and can be mixed in any proportion; this does not necessarily apply to inhibited oils.’ The insertion of this clause had two objectives:

- To allay fears about the use of under-refined or unsuitable base oils, as mentioned previously.
- To ensure as far as possible that oils, after possible loss of inhibitor in service, would not be prone to unduly rapid deterioration, as might be the case if the base oils were not of the best modern type.

However, oxidation-inhibited oils tend to be popular in most of Europe as well as in the USA, and as already discussed, BS 148:1984 has a section covering inhibited oils and includes, as an appendix, an oxidation test for inhibited oil which is likely to form part of any future edition of the IEC specification. The reason for its inclusion in the BS specification, however, is regarded by most UK users of transformer oil as solely for the purposes of European harmonisation.

Of course, the technical possibilities of inhibited oils are most important in applications where the operating temperature of the oil may be higher than average, such as could be the case in tropical locations, but due regard must still be paid to the effect of such temperatures on cellulose insulation.

Pour point depressants

The only other additives in common use in transformer oil are as pour point depressants. Their use is more recent than oxidation inhibitors, dating back to about the 1970s. It will be recalled that BS 148 requires that oil should be fluid down to a temperature of $-30°C$. This level of performance is available from naphthenic oil so there was little need to seek any measures to obtain an improvement. However, it seemed, in the early 1970s, that the world’s supply of naphthenic crudes might be very close to running out. (This has since proved to be far from the case.) In addition, there were other economic reasons for wishing to produce electrical oils based on paraffinic crudes. These oils do not exhibit the low pour points shown by the naphthenic based oils due to the tendency of the waxy paraffinic constituents to solidify at relatively high temperatures. Although as already mentioned de-waxing is possible and can form part of the refining process, this is costly and therefore defeating the objective of the use of paraffinic crudes.

Pour point depressants work by preventing the wax particles precipitating out at low temperatures conglomerating and forming a matrix and impeding the flow of the oil.

It is interesting to note that initially naphthenic oils were thought not to contain many paraffinic hydrocarbons, but, as indicated in *Table 3.3*, it is now known that this is not the case and that many naphthenic oils have as high a %C_P as do the paraffinics. What appears to be the case is that the paraffinic hydrocarbons in these oils are of a ‘non-waxy’ type.

Miscibility of oils

It is important to look briefly at miscibility of oils. This is unlikely to be a problem in the UK with only a small number of suppliers of exclusively uninhibited oils, all of which can and frequently are mixed. It is also the case that most users in the field will recognise the wisdom of avoiding the mixing of different types and grades of oil, but in many parts of the world it might be more difficult to achieve such an ideal in practice and a greater awareness is therefore necessary. Before giving the following guidance it is necessary to remind the reader that wherever possible the oil supplier should be consulted and the above comments are not intended to contradict any guidance which the oil supplier might provide.

Firstly, most manufacturers of oils claim that mixing of paraffinic and naphthenic is permissible, even assuming the paraffinic oil might contain additives in the form of pour point depressants, and they have evidence, from field trials, in support of this.

It should be recognised, of course, that it is the refiners of the paraffinic oils who have an interest in getting into the market, who are keen to allow mixing of oils, and it is usually they who, therefore, carry out the field trials. The problems can arise when a manufacturer of naphthenic oil is asked to remove the oil from a transformer to which paraffinic has been added. He, arguably justifiably, may not wish his bulk stock to become contaminated with additives over which he has no control even though he is simply taking it for re-refining.

The problems are similar with inhibited oil. If the inhibited oil complied with BS 148:1972, or a similar standard which required that the quality of the oil before addition of inhibitors was as good as the uninhibited oil, then mixing simply dilutes the inhibitors, which, by definition, are not necessary anyway, and so the mixture is acceptable. The difficulty is when a manufacturer is asked to recover oil which has an unknown composition. Such action should not therefore be viewed as routine, but preferably one to be undertaken only in an emergency.

Mixing of different refiners’ brands of inhibited oil demands very much greater caution. The compatibility of different additives is not known and much more likely to cause problems. BS 148:1984 advises that if mixing of inhibited oils is contemplated ‘a check should be made to ensure that the mixture complies with the requirements of this standard’. To carry out such a check properly would be a time-consuming exercise and would hardly be justified simply for the purposes of topping-up existing equipment with oil from an inappropriate source.

Water in oil

Theory of processes

Water, of course, is not an additive. In fact, it would be convenient if it were not present at all, but a discussion of water probably follows naturally from a discussion of additives, in that it is the other major non-hydrocarbon which is always present in the oil.

The point has already been made that the presence of some water in the oil, provided it remains in solution, does not greatly affect the electrical strength of the oil. However, water in paper insulation does significantly reduce its electrical insulation properties.

Oil in contact with air of higher humidity will absorb moisture and carry it across to the paper insulation. This action is also reversible, of course, which is the principle that is employed when aiming to dry out the insulation of a transformer in service, but it can be a time-consuming process to reverse an action which may have been occurring for many years. The water distributes itself between the air, oil and paper so that the relative saturation is the same in each medium when equilibrium is reached. The solubility of water in oil varies with the type of oil from approximately 30 to 80 ppm at 20°C, with the higher levels being associated with the higher aromatic oils. Water solubility also increases with ageing (oxidation) of the oil.

The effect of temperature on solubility is very marked. *Figure 3.27* shows a typical relationship. From the curve it can be seen that an oil which might be fully saturated with 40 ppm of water at 20°C will hold around 400 ppm at 80°C. This demonstrates why it is important to record the temperature of the oil when drawing a sample for assessment purposes. A water content of 50 ppm in a sample drawn from a newly filled unit at 20°C would give cause for concern, but the same figure in a sample taken from an old unit at 80°C would be very good indeed because it would represent a much lower level of saturation, as can be seen from *Figure 3.28*.

It has already been identified that the water distributes itself between air, oil and paper in accordance with the relative saturation level in each medium. Paper, however, has a much greater capacity for water than does oil. Its saturation level can be 5% or more by weight depending on the temperature and the acidity of the oil. A large 600 MVA generator transformer could contain 10 tonnes of cellulose insulation and with a water content at, say, 2% would contain as much as 200 litres of water in the insulation. This explains why attempting to dry out the insulation on site by circulating and drying the oil is such a slow and laborious process. More will be said about the subject of drying out on site in Section 4 of Chapter 5.

For some years it has been known that the presence of moisture in the solid insulation accelerates the ageing process. It is only relatively recently, however, that the extent to which this is the case has been clearly recognised, probably as a result of the research effort which has been put into the subject following many premature failures of large extra high-voltage transformers.

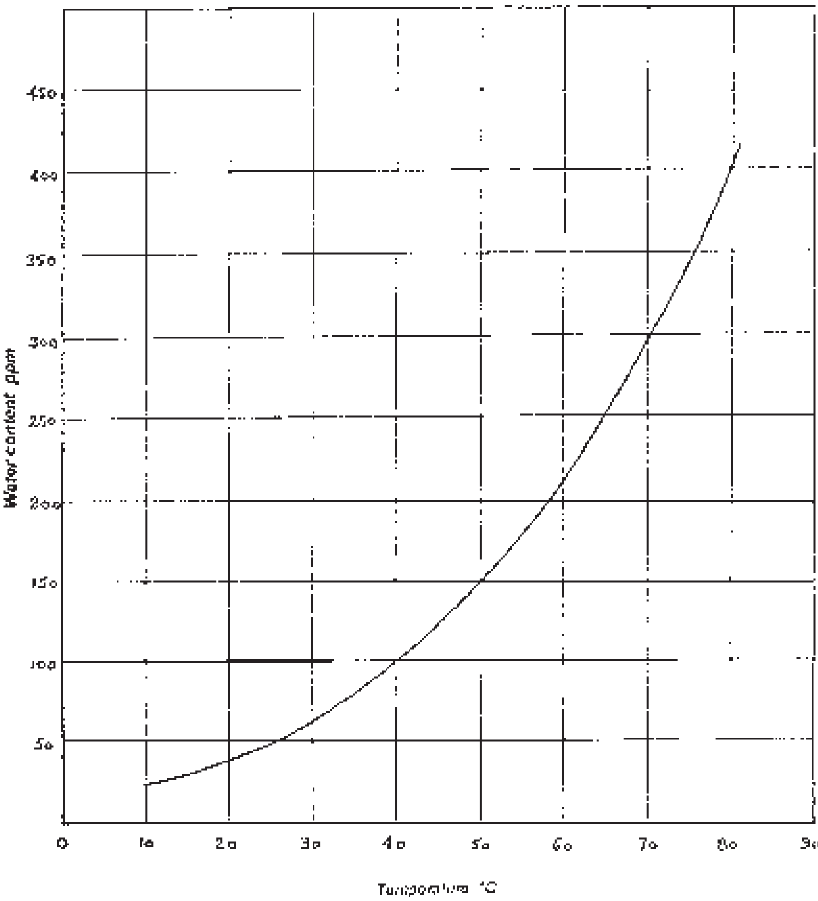


Figure 3.27 Water content of transformer oil at saturation as a function of temperature

The life of paper insulation at 120°C is reduced by a factor of 10 by increasing the moisture level from 0.1 to 1%. The latter figure, which was considered a reasonably acceptable moisture level a few years ago, represents no more than about 20% of the saturation level for the paper. Thus it can be clearly seen that it is desirable to maintain the level of water in oil as far as possible below its saturation level and that a figure of around 30–40 ppm of water in oil at 80°C is a reasonable target.

Transformer breathing systems

Because of the high thermal expansion of transformer oil, it is necessary, for all but the smallest transformers, to provide a mechanism to accommodate this expansion.

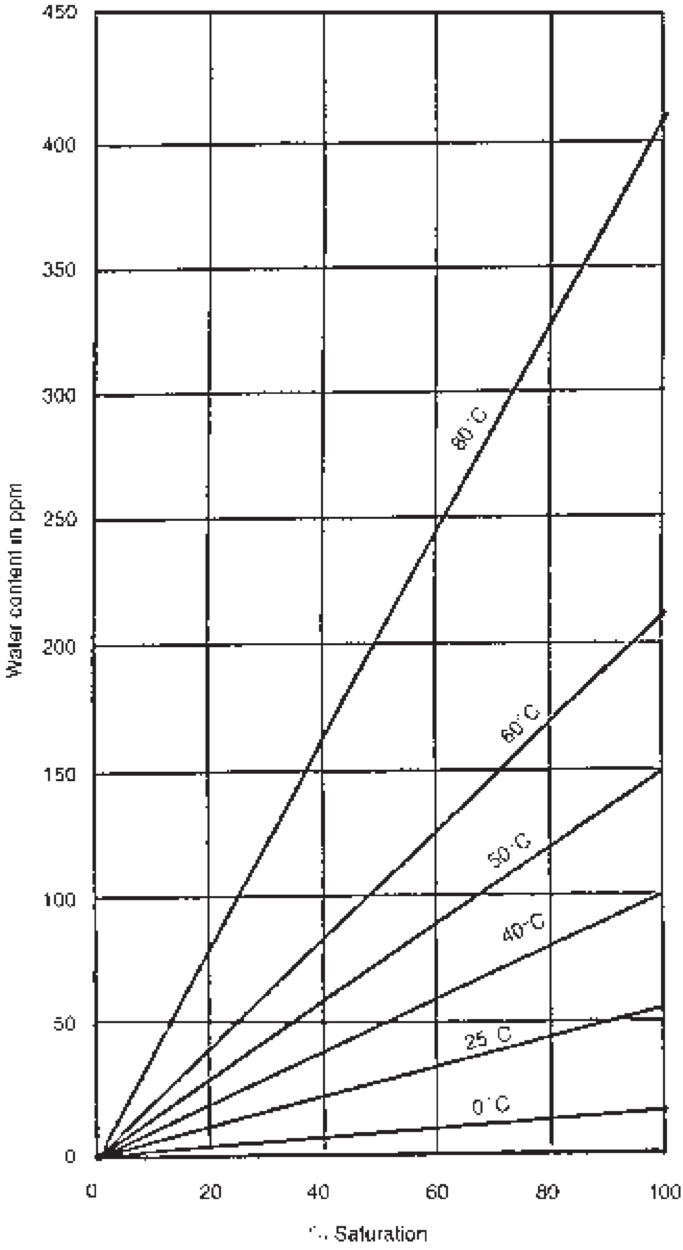


Figure 3.28 Water content of transformer oil (in equilibrium with moist air for several temperatures) as a function of saturation level for several temperatures

Mention has already been made that there would be merit in excluding air from transformer oil. This would greatly reduce the oxidation problem. Indeed there are some users who do this, particularly in tropical climates with prolonged periods of high humidity. They specify that the transformer be provided with a membrane or diaphragm system which allows for expansion and contraction of the oil without actually allowing this to come into contact with the external air. Such users generally also experience high ambient temperatures which aggravate the oxidation problem.

The disadvantage of the sealed system, though, is that water is a product of the degradation process of both oil and insulation. By sealing the transformer this water is being sealed inside the transformer unless a procedure of periodic routine dry-outs is adopted. If a free-breathing system is provided and the air space above the oil is kept dry by the use of a dehydrating breather, then these degradation products will be able to migrate to the atmosphere as they are produced and, of course, their continuous removal in this way is far easier than allowing them to accumulate for periodic removal by oil processing.

An improvement over the type of dehydrating breather which uses a chemical desiccant is the refrigeration breather which relies on the Peltier effect to provide freeze drying for the air in the conservator over the oil. In fact, this air will circulate, via reverse convection, through the refrigeration device, whether the transformer is breathing or not, so that this air, and hence the oil and the insulation, are being continually dried in service. Because of their cost, refrigeration breathers can only be justified for large EHV transformers, but they probably represent the optimum available system. Refrigeration breathers are used on all transformers connected to the UK 400 and 275 kV grid systems.

Oil preservation equipment will be considered further in Chapter 4. Maintenance of transformer oil in service is discussed in Section 7 of Chapter 6.

Other dielectric liquids

There are some locations where the flammable nature of mineral oil prevents the installation of transformers filled with it. From the early 1930s askarels, synthetic liquids based on polychlorobiphenyls (PCBs), have been used to meet such restrictions on the use of transformer oil. However, due to the non-biodegradable nature of PCBs, which cause them to remain in the environment and ultimately to enter the food chain, plus their close association with a more hazardous material, dioxin, production of these liquids has now ceased in many countries and their use is being phased out.

Alternative insulants such as silicone liquids and synthetic ester fluids possessing high flash points, good thermal conductivities and low viscosities at low temperatures are now in worldwide use. This combination of properties renders them acceptable to the designers and manufacturers of fire-resistant transformers and there has been an increasing market for this type as the use of askarel is diminishing. Generally these transformers have been built to conventional designs developed for mineral oil or askarel with very little modification. The liquids themselves are capable of satisfactory operation at temperatures above that appropriate for mineral oil, but there are problems if attempts are made to take advantage of this. Firstly, and most significantly, it is necessary to find an alternative to paper insulation, and secondly, high operating temperature tends to equate to high current density which results in high load losses increasing operating costs and offsetting any savings made in initial cost.

A number of specialist organisations exist who have developed the skills for draining askarel-filled transformers, refilling them with alternative liquids and safely disposing of the askarels. The process is, however, fraught with difficulties as legislation is introduced in many countries requiring that fluids containing progressively lower and lower levels of PCBs be considered as and handled as PCBs. It is very difficult as well as costly to remove all traces of PCB from a transformer. This persists in insulation, in interstices between conductors and between core plates so that some time after retrofilling the PCB level in the retrofill fluid will rise to an unacceptable level. The result is that retrofilling is tending to become a far less viable option, and those considering the problem of what to do with a PCB-filled transformer are strongly encouraged to scrap it in a safe manner and replace it.

Silicone liquid

Silicone liquid, a Dow Corning product, is frequently employed in transformers where there is a desire to avoid fire hazard. Silicone liquids are synthetic materials, the most well known being polydimethylsiloxane, characterised by thermal stability and chemical inertness. They have found a wide range of practical applications and have an acceptable health record over many years' use in medical, cosmetic and similar applications.

Silicone liquid has a very high flash point and in a tank below 350°C will not burn even when its surface is subjected to a flame. If made to burn it gives off very much less heat than organic liquids, having a low heat of combustion and the unique property of forming a layer of silica on the surface which greatly restricts the availability of air to its surface.

Distribution transformers using silicone liquid have been in operation for several years and there are now several thousand in service. The ratings of these transformers lie mainly in the 250 kVA–3 MVA, 11–36 kV working range, but units up to 9 MVA at 66 kV have been manufactured.

Synthetic ester fluid

Complex esters or hindered esters are already widely accepted in the fields of high-temperature lubrication and hydraulics, particularly in gas turbine applications and as heat transfer fluids generally. In this respect they have largely replaced petroleum and many synthetic oils which have proved unstable or toxic.

A similar ester has been developed to meet high-voltage insulation fluid specifications and is finding increasing application as a dielectric fluid in transformers and tapchangers.

Midel 7131 transformer fluid developed in the UK by Micanite and Insulators Limited, is a synthetic ester which has a very high flash point of 310°C and an auto-ignition temperature of 435°C. Synthetic esters also possess excellent lubrication properties, which enable the fluid to be used with forced cooled (i.e. pumped) units of all types.

Midel 7131 is manufactured from compounds which can be largely vegetable in origin and it has proved to be of very low toxicity; in certain cases it has been shown to be many times less toxic than highly refined petroleum oil, and being completely biodegradable is harmless to marine life.

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3.2 Moses, A. J. (1990) 'Electrical steels: past, present and future developments'. *Proc. IEE*, **137**, 233–245.

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4 Transformer construction

Introduction

Power transformer construction follows similar principles for units rated from a few kVA up to the largest sizes manufactured, but as the unit size increases a greater degree of sophistication becomes justified. Many manufacturers subdivide their construction activities into ‘distribution’ and ‘large power’, although exactly where each one makes this division varies widely. Usually the dividing line depends on the weight of the major components and the type and size of handling facilities which are required in the factory. Manufacturers of distribution transformers rated up to between 1 and 2 MVA often utilise roller conveyors and runway beams for the majority of their handling. Large-power transformers require heavy lifting facilities such as large overhead cranes. Those manufacturers who produce the largest sizes may further subdivide their operations into ‘medium power’ and ‘large power’ sections. Since the largest transformers require very heavy lifting facilities – up to 400 tonnes capacity including lifting beams and slings is not uncommon – it is usual to restrict the use of these very expensive facilities exclusively to the largest units so that the medium construction factory may only possess lifting facilities of up to, say, 30 tonnes capacity.

These subdivided construction arrangements often coincide with divisions of design departments so that design practices are frequently confined within the same boundaries.

In the following descriptions of transformer design and constructional methods, the aim will generally be to describe the most developed ‘state of the art’ even though in some instances, for example for distribution transformers, more simplified arrangements might be appropriate. In Chapter 7, which describes specialised aspects of transformers for particular purposes, aspects in which practices might differ from the norm will be highlighted.

A note on standards

The practices of transformer design and construction adopted in the UK have evolved in an environment created by British Standard 171 *Power Transformers*. With the move towards acceptance of international standards, the governing document for power transformers throughout most of the world has become IEC 76, which is now very similar to BS 171. IEC 76 was for some time a five-part document but was reduced to four parts with the issue of the second edition in 1993, by the incorporation of Part 4 into Part 1. However, at the time of writing, January 1996, IEC 76 Part 3, which refers to insulation levels and dielectric tests, has not been officially adopted in the UK since there is still some small area of disagreement with the international body. The ruling document for insulation levels and dielectrics tests in the UK remains therefore BS 171-3:1987, which differs in some respects from IEC 76-3. The CENELEC Harmonisation Document covering power transformers is HD 398 and it is hoped that with the issue of HD 398-3 in the near future, which will include amendments to IEC 76-3, the UK will come into line. In general, throughout this book where reference is made to standards the aim will be to follow the practices recommended in the IEC documents. However there are practices, particularly with regard to insulation design and dielectric testing which have grown up because that was the requirement of BS 171. These practices are continuing and are likely to continue for many years, although they might no longer strictly be a requirement of the governing standard. Because they remain current practice in the UK, it is these practices which this chapter describes and, except where specifically indicated to the contrary, throughout this chapter the transformer standard referred to will be BS 171.

4.1 CORE CONSTRUCTION

Design features

Chapter 3 has described the almost constant developments which have taken place over the years to reduce the specific losses of core material. In parallel with these developments manufacturers have striven constantly to improve their core designs in order to better exploit the properties of the improved materials and also to further reduce or, if possible, eliminate losses arising from aspects of the core design. Superficially a core built 30 years ago might resemble one produced at the present time but, in reality, there are likely to be many subtle but significant differences.

Core laminations are built up to form a limb or leg having as near as possible a circular cross-section (*Figure 4.1*) in order to obtain optimum use of space within the cylindrical windings. The stepped cross-section approximates to a circular shape depending only on how many different widths of strip a

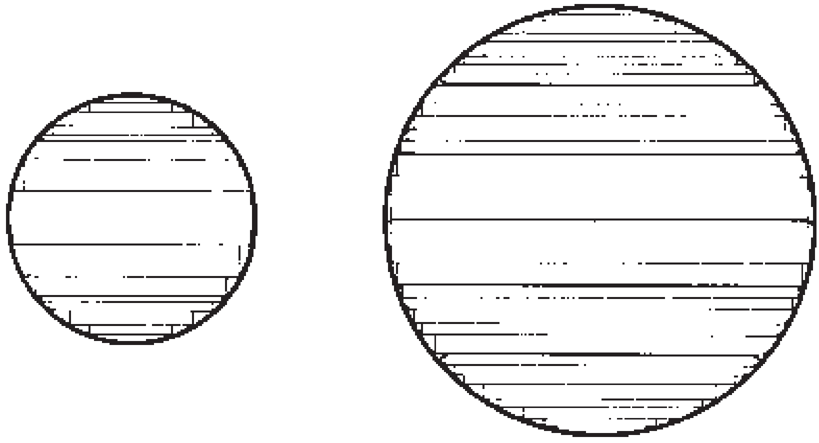


Figure 4.1 Core sections. Seven step, taped (left); and 14 step, banded (right)

manufacturer is prepared to cut and build. For smaller cores of distribution transformers this could be as few as seven. For a larger generator transformer, for example, this might be 11 or more. Theoretically, these fill from just over 93% to over 95%, respectively, of the available core circle. In reality the actual utilisation is probably slightly less than this since the manufacturer aims to standardise on a range of plate widths to cover all sizes of cores, or he may buy in material already cut to width, in which case he will be restricted to the standard range of widths provided by the core steel manufacturer, usually varying in 10 mm steps. In either circumstance it will be unlikely that the widths required to give the ideal cross-section for every size of core will be available.

Transformer manufacturers will normally produce a standard range of core cross-sections – they often refer to these as *frame sizes* – with each identified by the width in millimetres of the widest plate. These might start at 200 mm for cores of small auxiliary transformers and progress in 25 mm steps up to about 1 m, the full width of the available roll, for the largest generator transformers. This cylindrical wound limb forms the common feature of all transformer cores. The form of the complete core will, however, vary according to the type of transformer. Alternative arrangements are shown in *Figure 4.2*; of these, by far the most common arrangement is the three-phase, three-limb core. Since, at all times the phasor sum of the three fluxes produced by a balanced three-phase system of voltages is zero, no return limb is necessary in a three-phase core and both the limbs and yokes can have equal cross-section. This is only true for three-phase cores, and for single-phase transformers return limbs must be provided. Various options are available for these return limbs, some of which are shown in *Figure 4.2*; all have advantages and disadvantages and some of these will be discussed in greater depth

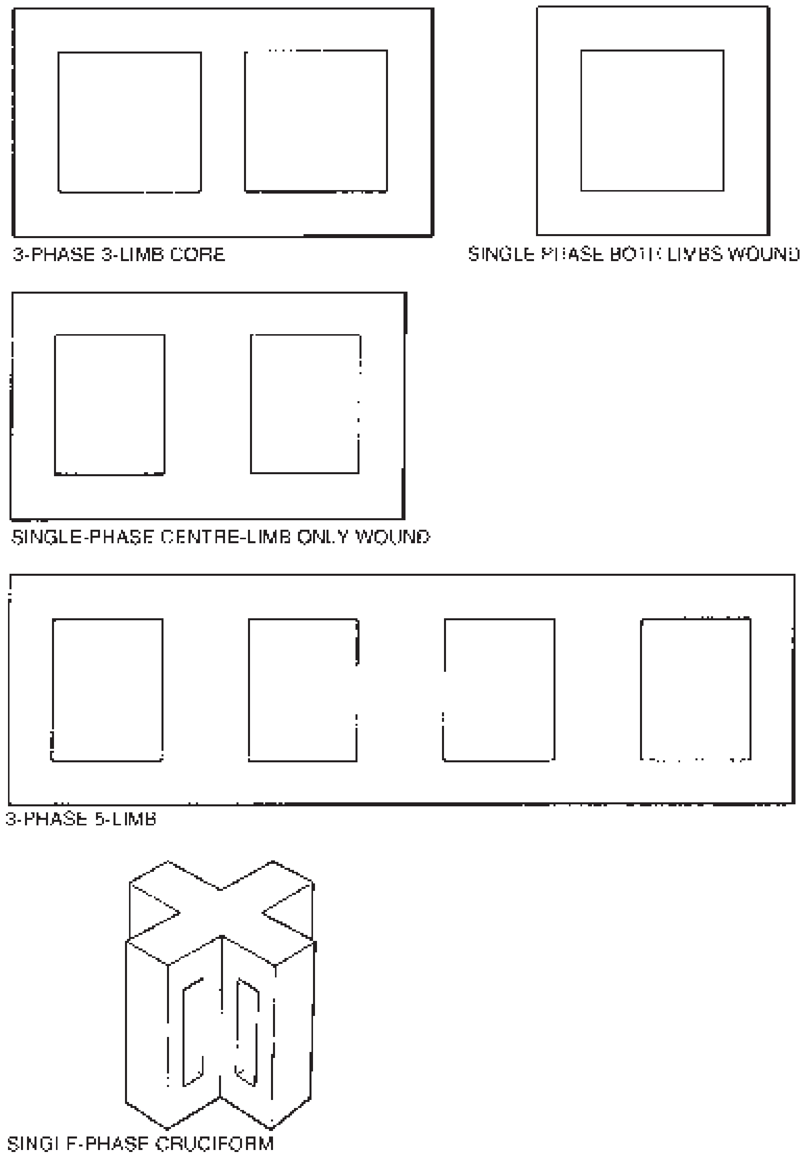


Figure 4.2 Typical core forms for single- and three-phase transformers

in Section 1 of Chapter 7, which deals with generator transformers. Generator transformers represent the only occasion where single-phase units are used on three-phase systems although in some countries they are used for large interbus transformers or autotransformers. The main reason for the use of single-phase units is from transport considerations, since the largest generator transformers can be too large to ship as three-phase units. The use of single phase units also has advantages where very high reliability is required as, for example, in the case of large generator transformers. This aspect will be considered in greater depth in Section 1 of Chapter 7 which deals with generator transformers. *Figure 4.2* also shows a three-phase, five-limb core which is another arrangement used mainly for large three-phase generator transformers and interbus transformers in order to reduce transport height. This configuration enables the yoke depth to be reduced by providing a return flux path external to the wound limbs. In the limit the yokes could be half that which would be required for a three-phase, three-limb arrangement so the saving in height can be considerable. The 'cost' is in the provision of the return limbs which add significantly to the size of the core and to the iron losses. Of course, if transport height considerations permit, the yoke depth need not be reduced to half the limb width. If the yokes are provided with a cross-section greater than half that of the limbs the flux density in the yokes will be reduced. This will result in a reduction in specific core loss in the yokes which is greater than the proportional increase in yoke weight compared to that of a half-section yoke, hence a reduction in total core loss is obtained. This will be economic if the capitalised cost of the iron loss saved (see Section 2 of Chapter 8) is greater than the cost of the extra material. The only other occasion on which a three-phase, five-limb core might be necessary is when it is required to provide a value of zero-sequence impedance of similar magnitude to the positive sequence impedance as explained in Chapter 2.

The first requirement for core manufacture is the production of the individual laminations. Most manufacturers now buy in the core material already cut to standard widths by the steel producer so it is necessary only for them to cut this to length. Production of the laminations is one of the areas in which core manufacture has changed significantly in recent years. As explained in Section 2 of Chapter 3, the specific loss of core steel is very dependent on the nature and level of stress within the material. It is therefore necessary to minimise the degree of working and handling during manufacture. Cutting of the laminations is, of course, unavoidable but this operation inevitably produces edge burrs. Edge burrs lead to electrical contact between plates and the creation of eddy-current paths. Until the end of the 1980s British Standard 601 *Steel Sheet and Strip for Magnetic Circuits of Electrical Apparatus* laid down acceptable limits for these burrs which generally meant that they had to be removed by a burr-grinding process. Burr grinding tends to damage the plate insulation and this damage needs to be made good by an additional insulation application. Each of these operations involves handling and burr grinding in particular raises stress levels, so an additional anneal is required. Modern cutting tools enable the operation to be carried out with the production of the very minimum of edge burr. This is to some extent also assisted by the properties of the modern material itself. Typically burrs produced by 'traditional' tools of high-quality tool steel on cold-rolled grain-oriented material of the 1970s might be up to

0.05 mm in height as permitted by BS 601. These could be reduced by a burr-grinding operation to 0.025 mm. With HiB steel and carbide-steel tools, burrs less than 0.02 mm are produced so that all of the burr-grinding, additional insulating and annealing processes can now be omitted.

It is perhaps appropriate at this stage to look a little further into the subject of plate insulation. The quality of this insulation was defined in BS 601, Part 2, which stated that 80% of a specified number of insulation resistance measurements made on a sample of the core plate should be greater than 2 Ω and 5% should be greater than 5 Ω. As indicated in Section 2 of Chapter 3 the purpose of this insulation is to prevent the circulation of eddy currents within the core. Preventing these currents from flowing does not, however, prevent the induced voltages from being developed. The induced voltage is proportional to the plate width and it was generally considered that plate insulation complying with the requirements of BS 601 was acceptable for plates of up to about 640 mm wide. For cores of a size which would require a plate width greater than this there are the options of subdividing the cross-section so that each part individually meets the 640 mm maximum requirement or, alternatively, additional insulation could be provided. It is often necessary to subdivide large cores anyway in order to provide cooling ducts, so that this option could normally be selected without economic penalty. It should be noted that some manufacturers had long considered that the BS 601 requirement to achieve 2 Ω was a rather modest one. When they intended to apply additional insulation anyway there was no pressing need for change to the British Standard and the issue only came to the fore when this additional coating was dropped. At about this time BS 601, Part 2 was superseded by BS 6404 : Section 8.7 : 1988 *Specification for grain-oriented magnetic steel sheet and strip,* which stated that the insulation resistance of the coating should be agreed between the supplier and the purchaser. Manufacturers were thus able to take the opportunity to apply their own specifications for the material and these generally called for a higher resistance value. There also remained the question as to what was required of the remaining 20% of the readings. These could, in theory, be zero and dependent on the coating process control they could be located in a single area of the steel strip. Reputable transformer manufacturers in this situation issued their own individual specifications usually stipulating that the physical location of the 20% low-resistance value readings occurred randomly throughout the samples, i.e. it was not acceptable that all of these should be located in the same area of the sample. As indicated in Section 2 of Chapter 3 many of the modern steels are provided with a high-quality insulation coating which is part of the means of reducing the specific loss. With these steels it is not normally necessary to provide additional coating regardless of the size of the core and the resistance measurements obtained are invariably considerably better than the minimum requirements of the old BS 601.

One of the disadvantages of grain-oriented core steels is that any factor which requires the flux to deviate from the grain direction will increase the core loss and this becomes increasingly so in the case of the HiB range of core steels. Such factors include any holes through the core as shown in *Figure 4.3* as well as the turning of the flux which is necessary at the top and bottom corners of the core limbs. This latter effect is noticeable in that a tall, slim core will have a lower loss than a short, squat core of the same weight and flux density since the former arrangement requires less deviation of the flux as illustrated in *Figure 4.4*. The relationship between the core loss of a fully assembled core and the product of core weight multiplied by specific loss is known as the *building factor* for the core. The building factor is generally about 1.15 for a well-designed core of grain-oriented steel. Expressed in terms of building factor the tall core discussed above has a better (i.e. lower) building factor than the squat core. In order to limit the extent to which the flux path cuts across of the grain direction at the intersection of limbs and yokes corners of laminations are cut on a 45° mitre. The core plates at these mitred corners must be overlapped so that the flux can transfer to the adjacent face rather than cross the air gap which is directly in its path (*Figure 4.5*). These mitred corners were, of course, not necessary for cores of hot-rolled (i.e. non-oriented) steel. It was also normally accepted practice for cores of hot-rolled steel for the laminations to be clamped together to form the complete core by means of steel bolts passing through both limbs and yokes. With the advent of grain-oriented steel it was recognised that distortion of the flux by bolt holes through the limbs was undesirable and that the loss of effective cross-section was also leading to an unnecessary increase in the diameter of the core limb. Designers therefore moved towards elimination of core bolts replacing these on the limbs by bands of either steel (with an insulated break) or glass fibre. In the former case the insulated break was inserted in the steel band to prevent current flow in the band itself and additionally it was insulated from the core to prevent shorting out individual laminations at their edges. Core bolts had always needed to be effectively insulated where they passed through the core limbs and yokes for the same reasons. The top and bottom yokes of cores continued to be bolted, however, since the main structural strength of the transformer is provided by the yokes together with their heavy steel yoke frames. *Figure 4.6* shows a three-phase core of cold-rolled grain-oriented steel with banded limbs and bolted yokes.

In the latter part of the 1970s increasing economic pressures to reduce losses, and in particular the core loss since it is present whenever the transformer is energised, led designers and manufacturers towards the adoption of totally boltless cores. The punching of holes through core plates has the additional disadvantage that it conflicts with the requirement to minimise the working of the core steel, mentioned above, thus increasing the loss in the material. Both these factors together with the marginal reduction in core weight afforded by a boltless core, were all factors favouring the elimination of bolt holes.

With modern steels having a very high degree of grain orientation the loss penalty for deviation of the flux from the grain direction is even more significant so that manufacturers are at even greater pains to design cores entirely without bolts through either limbs or yokes. On a large core this calls for

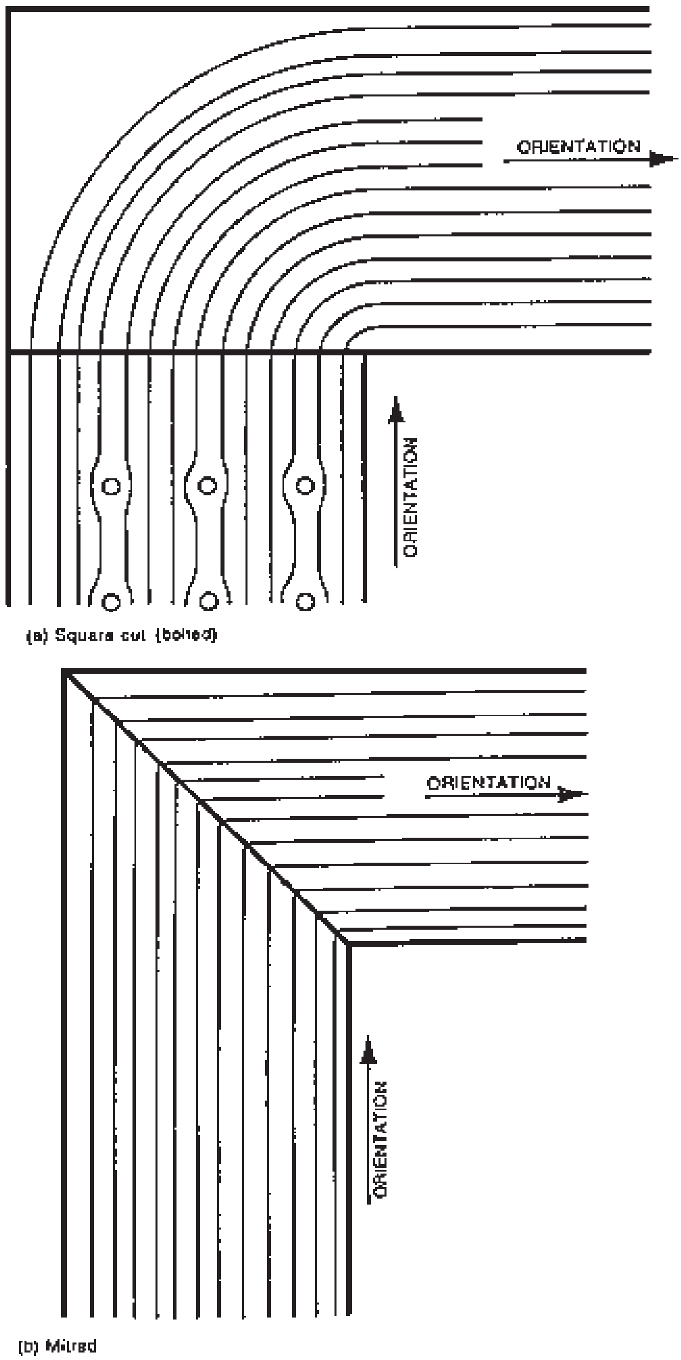
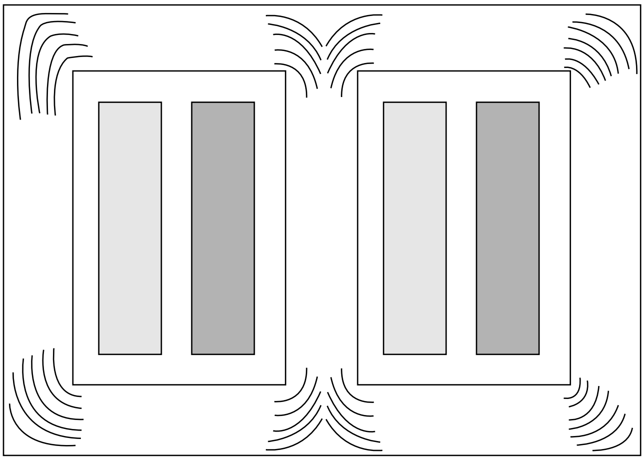
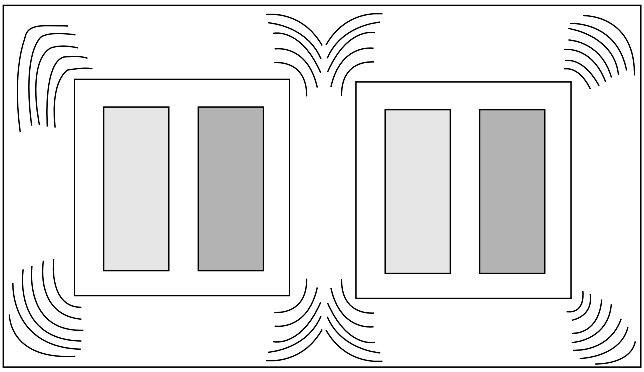


Figure 4.3 Effect of holes and corners on core flux



(a) Flux paths in tall slim single-phase core



(a) Flux paths in squat core

Figure 4.4 Cross flux at corners forms greater portion of total flux path in short squat core than in tall slim core

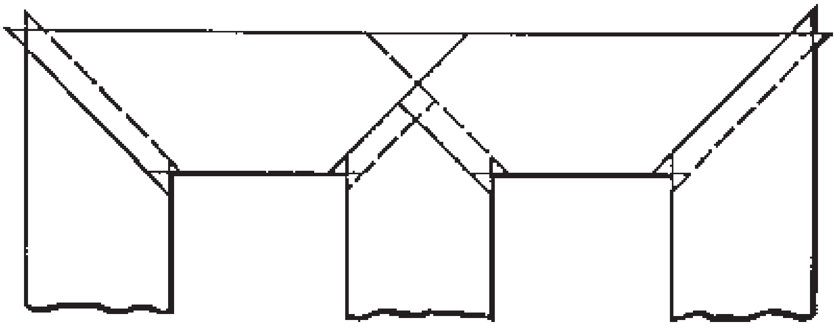


Figure 4.5 45° mitre overlap construction

Figure 4.6 Three-phase mitred core of a 150 MVA 132/66 kV 50 Hz transformer showing the banding of the core limb laminations (Bonar Long Ltd.)

a high degree of design sophistication to ensure that the necessary structural strength is not sacrificed. *Figure 4.7* shows a large modern core having totally boltless construction.

Core building

The core is built horizontally by stacking laminations, usually two or three per lay, on a jig or stillage. The lay-down sequence must take account of the need to alternate the lengths of plates to provide the necessary overlaps at the mitred corners as shown in *Figure 4.5*. *Figure 4.8* shows a large core being built in the manufacturer's works. The clamping frames for top and bottom yokes will be incorporated into the stillage but this must also provide support and rigidity for the limbs until the core has been lifted into the vertical position for the fitting of the windings. Without clamping bolts the limbs have little rigidity until the windings have been fitted so the stillage must incorporate means of providing this. The windings when assembled onto the limbs will not only provide this rigidity, in some designs the hard synthetic resin-bonded paper (s.r.b.p.) tube onto which the inner winding is wound provides the clamping for the leg laminations. With this form of construction the leg is clamped with temporary steel bands which are stripped away progressively as the winding is lowered onto the leg at the assembly stage. Fitting of the windings requires that the top yoke be removed and the question can be asked as to why it is

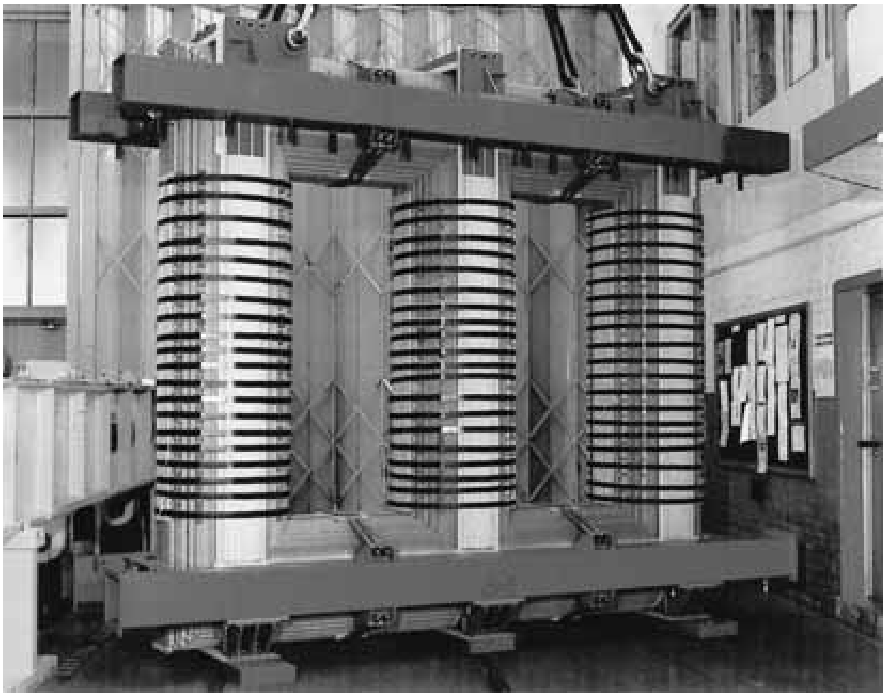


Figure 4.7 Three phase three limb boltless core. Three flitch plates (tie bars) are used each side of each limb and are visible at the top of each limb below the upper frame. The temporary steel bands clamping the limbs will be cut off as the winding assemblies are lowered onto the limbs (GEC Alsthom)

necessary to build it in place initially. The answer is that some manufacturers have tried the process of core building without the top yokes and have found that the disadvantages outweigh the saving in time and cost of assembly. If the finished core is to have the lowest possible loss then the joints between limbs and yokes must be fitted within very close tolerances. Building the core to the accuracy necessary to achieve this without the top yoke in place is very difficult. Once the windings have been fitted the top yoke can be replaced, suitably interlaced into the projecting ends of the leg laminations, followed by the top core frames. Once these have been fitted, together with any tie bars linking top and bottom yokes, axial clamping can be applied to the windings to compress them to their correct length. These principles will apply to the cores of all the core-type transformers shown in *Figure 4.2*.

Step-lapped joints

The arrangement of the limb to yoke mitred joint shown in *Figure 4.5* uses a simple overlap arrangement consisting of only two plate configurations.

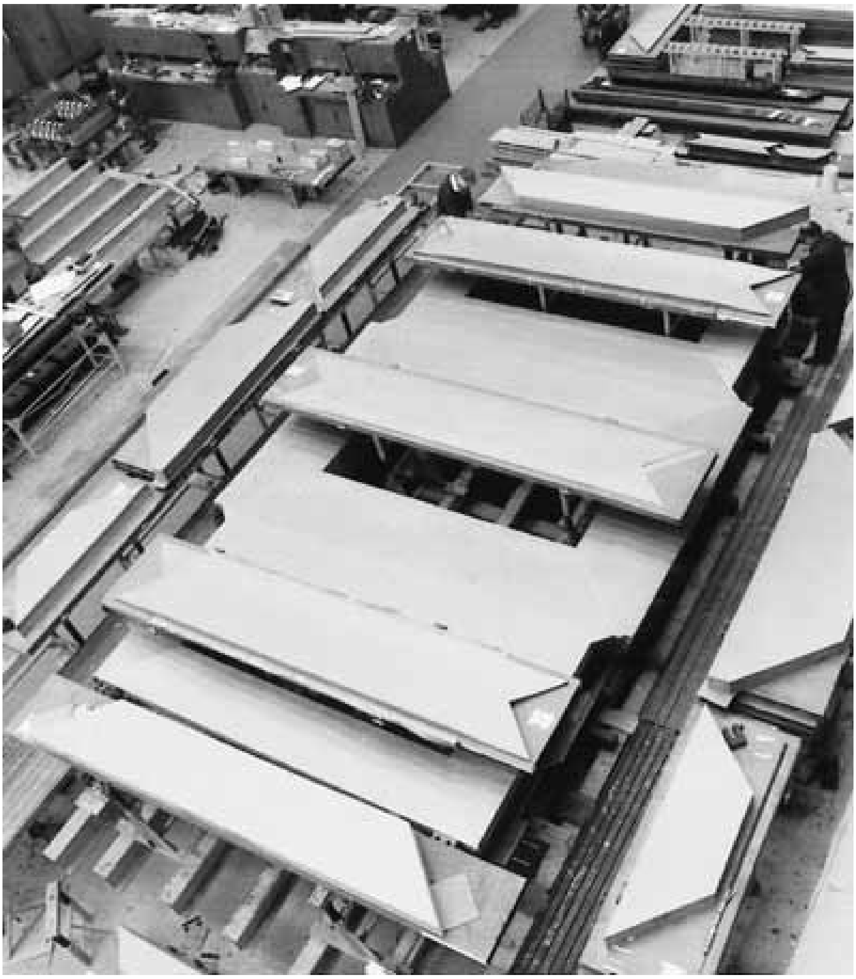


Figure 4.8 Four limb (single-phase with two limbs wound) core with 60/40% yokes and return limbs in course of building. (GEC Alsthom)

Because much of the loss associated with a modern transformer cores arises from the yoke to limb joints manufacturers have given considerable thought to the best method of making these joints. One arrangement which has been used extensively, particularly in distribution transformers, is the *step-lapped* joint. In a step-lapped joint perhaps as many as five different plate lengths are used so that the mitre can have a five-step overlap as shown in *Figure 4.9* rather than the simple overlap shown in *Figure 4.5*. This arrangement which allows the flux transfer to be gradual through the joint ensures a smoother transfer of the flux and thus provides a lower corner loss. The disadvantages

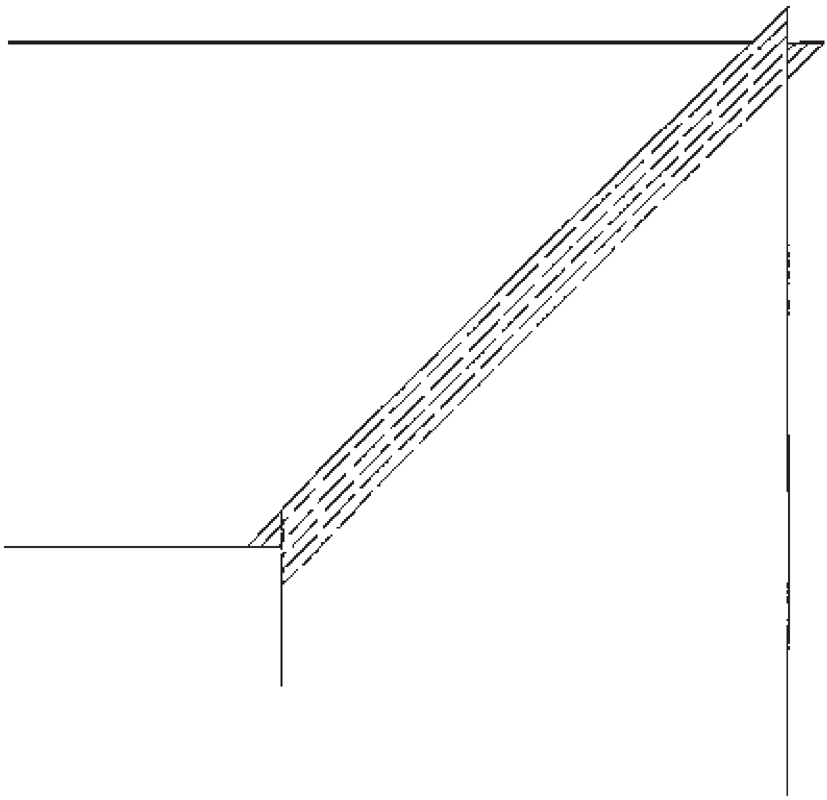


Figure 4.9 Five-step step-lapped mitred core joint

are that more lengths of plate must be cut, which will increase costs, and the replacing of the top yoke after installation of the windings becomes a more complex process requiring greater care and thus further increased labour costs. On a distribution transformer core the smaller, stiffer laminations are probably easier to replace than would be the case on a larger core, which is possibly the reason why this form of construction has found wider application in distribution transformers. It is also the case that the corner joints represent a larger proportion of the total core in the case of a small distribution transformer than they do in a larger power transformer core, making such an improvement more worthwhile. (Of course, the other side of the coin is that it must be easier to cut and build a small core, having a yoke length of, say, 1 metre, to a degree of tolerance which results in joint gaps of, say, 0.5 mm, than it is for a large core having a yoke length of, say, 4 metres.) An additional factor is that the very competitive state of the world distribution transformer market probably means than any savings which can be made, however small, will be keenly sought after.

Core earthing

Before concluding the description of core construction, mention should be made of the subject of core earthing. Any conducting metal parts of a transformer, unless solidly bonded to earth, will acquire a potential in operation which depends on their location relative to the electric field within which they lie. In theory, the designer could insulate them from earthed metal but, in practice, it is easier and more convenient to bond them to earth. However, in adopting this alternative, there are two important requirements:

- The bonding must ensure good electrical contact and remain secure throughout the transformer life.
- No conducting loops must be formed, otherwise circulating currents will result, creating increased losses and/or localised overheating.

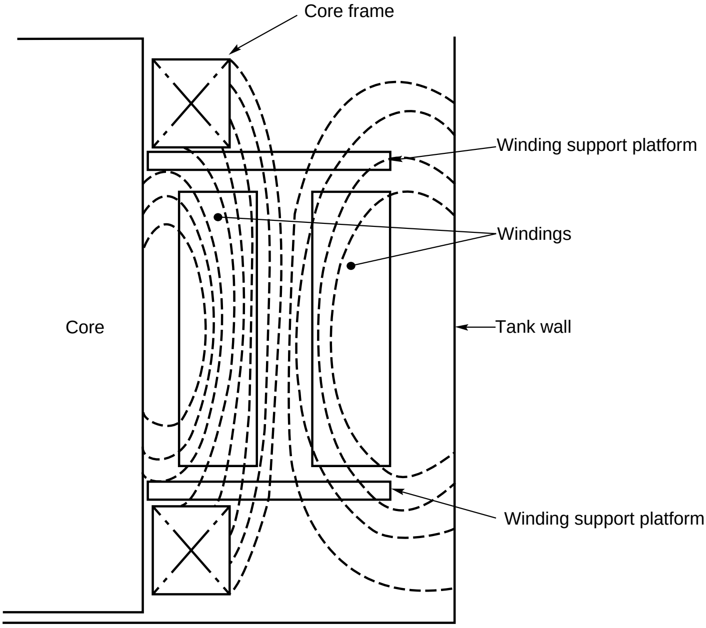
Metalwork which becomes inadequately bonded, possibly due to shrinkage or vibration, creates arcing which will cause breakdown of insulation and oil and will produce gases which may lead to Buchholz relay operation, where fitted, or cause confusion of routine gas-in-oil monitoring results (see Section 7 of Chapter 6) by masking other more serious internal faults, and can thus be very troublesome in service.

The core and its framework represent the largest bulk of metalwork requiring to be bonded to earth. On large, important transformers, connections to core and frames can be individually brought outside the tank via 3.3 kV bushings and then connected to earth externally. This enables the earth connection to be readily accessed at the time of initial installation on site (see Section 4 of Chapter 5) and during subsequent maintenance without lowering the oil level for removal of inspection covers so that core insulation resistance checks can be carried out.

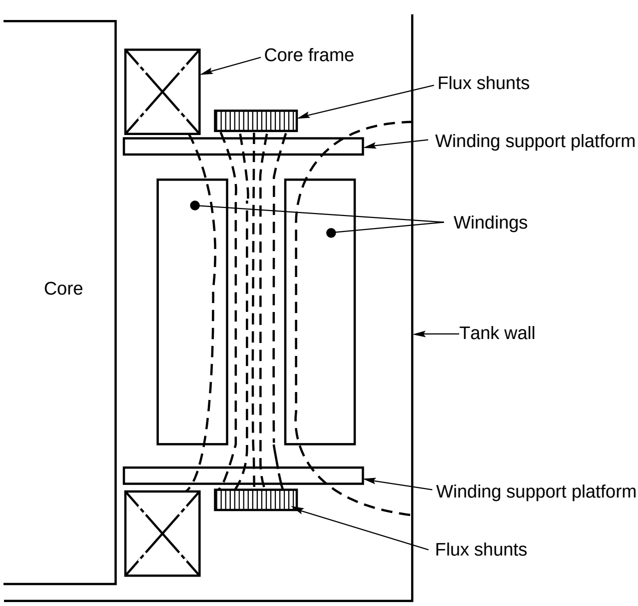
In order to comply with the above requirement to avoid circulating currents, the core and frames will need to be effectively insulated from the tank and from each other, nevertheless it is necessary for the core to be very positively located within the tank particularly so as to avoid movement and possible damage during transport. It is usual to incorporate location brackets within the base of the tank in order to meet this requirement. Because of the large weight of the core and windings these locating devices and the insulation between them and the core and frames will need to be physically very substantial, although the relevant test voltage may be modest. More will be said about this in Chapter 5 which deals with testing.

Leakage flux and magnetic shielding

The purpose of the transformer core is to provide a low-reluctance path for the flux linking primary and secondary windings. It is the case, however, that a proportion of the flux produced by the primary ampere-turns will not be constrained to the core thus linking the secondary winding and vice versa.



(a)



(b)

Figure 4.10 (a) Winding leakage flux paths – no shunts;
(b) Winding leakage flux paths modified by the installation of flux shunts

It is this leakage flux, of course, which gives rise to the transformer leakage reactance. As explained in the previous chapter leakage flux also has the effect of creating eddy-current losses within the windings. Control of winding eddy-current losses will be discussed more fully in the section relating to winding design; however, if the leakage flux can be diverted so as to avoid its passing through the winding conductors and also made to run along the axis of the winding rather than have a large radial component as indicated in *Figure 4.10*, this will contribute considerably to the reduction of winding eddy-current losses. The flux shunts will themselves experience losses, of course, but if these are arranged to operate at modest flux density and made of similar laminations as used for the core, then the magnitude of the losses in the shunts will be very much less than those saved in the windings. Requirements regarding earthing and prevention of circulating currents will, of course, be the same as for the core and frames. On very high-current transformers, say where the current is greater than about 1000 A, it is also the case that fluxes generated by the main leads can give rise to eddy-current losses in the tank adjacent to these. In this situation a reduction in the magnitude of the losses can be obtained by the provision of flux shunts, or shields, to prevent their flowing in the tank. This arrangement, shown in *Figure 4.11*, will also prevent an excessive temperature rise in the tank which could occur if it were allowed to carry the stray flux.

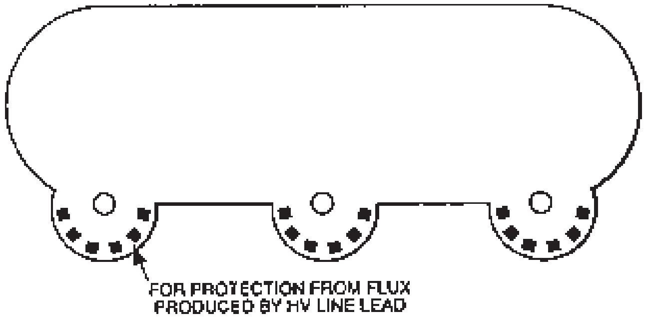


Figure 4.11 Flux shields for main leads

4.2 TRANSFORMER WINDINGS

In describing the basic principles of a two-winding transformer, it has been assumed that the windings comprise a discrete primary and secondary, each being a cylinder concentric with the wound limb of the core which provides the low-reluctance path for the interlinking flux. Whether of single-phase or three-phase construction, the core provides a return flux path and must, therefore, enclose the winding, as shown in *Figure 4.12*. As well as dictating the overall size of the transformer, the size of the two concentric windings thus dictate the size of the window that the core must provide, and hence fix the dimensions of the core which, for a given grade of core steel and flux density, will determine the iron losses. The designer must aim for as compact a winding arrangement as possible. Militating against this are the needs to provide space for cooling ducts and insulation, and also to obtain as large a copper cross-section as possible in order to minimise load losses.

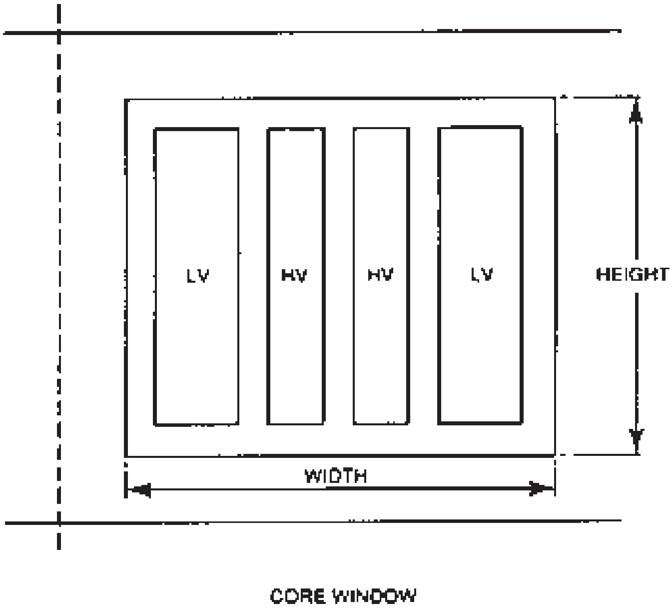


Figure 4.12 Arrangement of windings within core window

The following section describes how the best compromise between these conflicting objectives is achieved in practice. Firstly, it is necessary to look more closely at the subject of load losses. By definition the load loss of a transformer is that proportion of the losses generated by the flow of load current and which varies as the square of the load. There are three categories of load loss which occur in transformers:

- Resistive losses, often referred to as I^2R losses.
- Eddy-current losses in the windings due to the alternating leakage fluxes cutting the windings.

- So-called stray losses in leads, core framework and tank due to the action of load-dependent, stray, alternating fluxes.

More will be said about the third of these later. At the moment it is appropriate to examine the losses which occur in windings. These are by far the most significant proportion.

Resistive losses, as the term implies, are due to the fact that the windings cannot be manufactured without electrical resistance and therefore cannot be eliminated by the transformer designer. There are, however, ways normally open to the designer whereby they can be reduced. These are as follows:

- Use of the lowest resistivity material. This, of course, normally means high-conductivity copper.
- Use of the lowest practicable number of winding turns.
- Increasing the cross-sectional area of the turn conductor.

Minimising the number of winding turns means that a core providing the highest practicable total flux must be used. This implies highest acceptable flux density and the largest practicable core cross-section. The penalty of this option is the increase in core size (frame size) which, in turn, increases iron weight and hence iron loss. Load loss can thus be traded against iron loss and vice versa. Increased frame size, of course, increases the denominator in the expression for per cent reactance (equation (2.1), Chapter 2) so that l, the axial length of the winding, must be reduced in order to compensate and maintain the same impedance, although there will be a reduction in F, the winding ampere-turns by way of partial compensation (since a reduction in the number of turns was the object of the exercise). Reduction in the winding axial length means that the core leg length is reduced, which also offsets the increase in core weight resulting from the increased frame size to some extent. There is thus a band of one or two frame sizes for which the loss variation is not too great, so that the optimum frame size can be chosen to satisfy other factors, such as ratio of fixed to load losses or transport height (since this must be closely related to the height of the core).

The penalty for increasing the cross-section of the turn conductor is an increase in winding eddy-current loss (in addition to the increase in the size of the core window and hence overall size of the core). Eddy-current loss arises because of the leakage flux cutting the winding conductors. This induces voltages which cause currents to flow at right angles to the load current and the flux. The larger the cross-section of the turn the lower will be the resistance to the eddy-current flow and hence the larger the eddy currents. The only way of increasing resistance to the eddy currents without reducing the turn cross-section is to subdivide the turn conductor into a number of smaller strands or subconductors individually insulated from each other (*Figure 4.13*) and transposing these along the length of the winding. The practical aspects of transposition will be described below in the section dealing with winding construction. In reality, although the winder will prefer to use a reasonably small strand size in order that he can bend these more easily around the mandrel in producing his winding, in general the greater the number of strands in parallel the more costly it becomes to make the winding, so a manufacturer will wish to limit the number of these to the minimum commensurate with an acceptable level of eddy-current loss – more on this later. In addition the extra interstrand insulation resulting on the increased number of strands will result in a poorer winding space factor providing yet another incentive to minimise the number of strands.

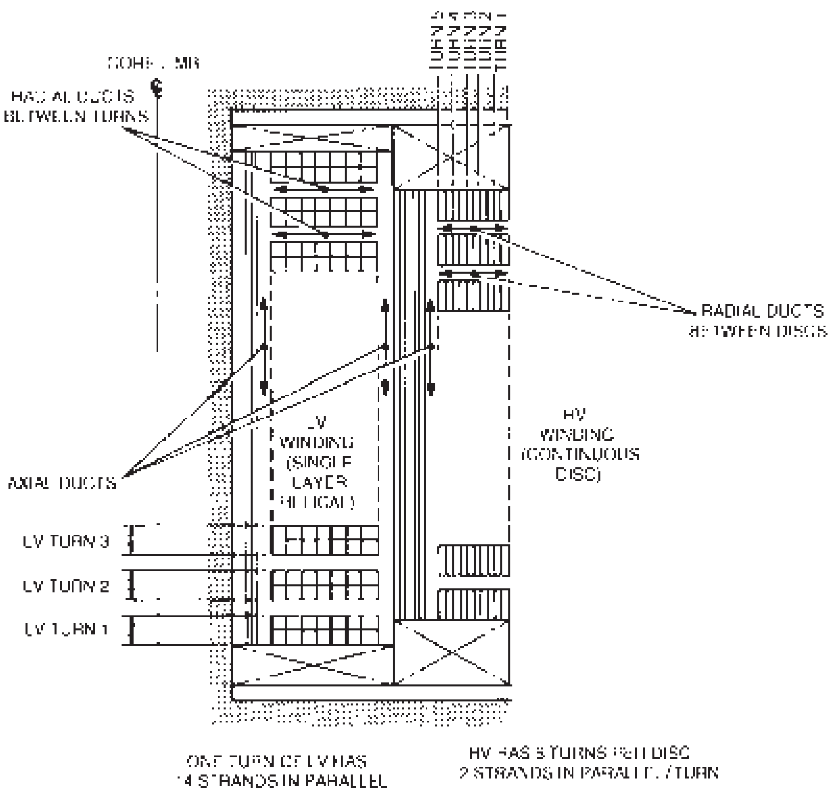
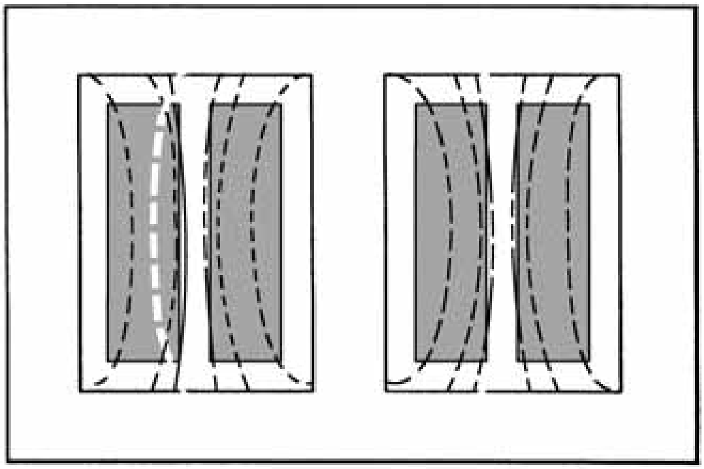
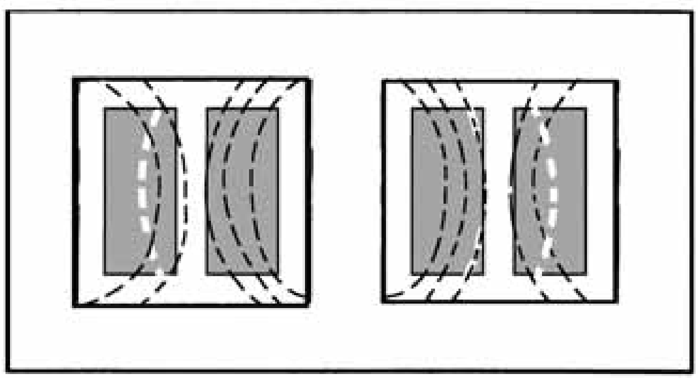


Figure 4.13 Section of LV and HV windings showing radial and axial cooling ducts

As explained above, eddy currents in winding conductors are the result of leakage flux, so a reduction in leakage flux results in smaller eddy currents. It will therefore be evident that in a transformer having a low leakage reactance, winding eddy currents are less of a problem than one with high reactance. Physically this can be interpreted by examination of equation (2.1), Chapter 2, which shows that a low leakage reactance is associated with a long or large



(a) Leakage flux paths in tall single-phase core



(b) Leakage flux in squat core

Figure 4.14 Leakage flux paths in tall and squat windings

winding axial length, l, that is, a tall, slim design will have less leakage flux than a short, squat design and will therefore tend to have less winding eddy currents (*Figure 4.14*). It will also be apparent that with a tall, slim arrangement the leakage flux is largely axial and it can be shown that when this is the case, it is only necessary to subdivide the conductor in the direction perpendicular to the leakage flux, that is, in the radial dimension. With the short, squat winding arrangement the flux will also have a significant radial component, particularly near to the ends of the windings, so that the conductor must be subdivided additionally in the axial dimension. (In theory this would only be necessary near the ends of the windings, but it is not generally feasible to change the number of conductors mid-winding.) Another method of controlling winding eddy currents, mentioned in the previous section, is the use of flux shunts to modify the leakage flux patterns with the aim of ensuring that these do not pass through windings and where they do so their path will be predominantly axial (*Figure 4.10*). Such measures will only tend to be economic in the larger high-impedance transformers where winding eddy currents prove particularly problematical. In practice, manufacturers find it is economic to limit eddy-current loss to about 25% of that of the resistive loss, although the degree of sophistication necessary to achieve this will vary greatly according to the circumstances and in low-impedance designs the level might easily be considerably less than this without resort to any special features.

Winding construction

Chapter 3 briefly considered the requirements for copper as used in transformer windings and explained why this material is used almost exclusively. Before discussing the details of transformer windings further it is necessary to look a little more closely at winding conductors.

Mention has already been made in the previous chapter that winding conductors for all transformers larger than a few kVA are rectangular in section (*Figure 4.13*). Individual strands must be insulated from each other within a winding conductor and, of course, each conductor must be insulated from its neighbour. This is achieved by wrapping the strands helically with paper strip, and at least two layers are used, so that the outer layer overlaps the butt joints in the layer below. The edges of the copper strip are radiused in order to assist in paper covering. This also ensures that, where strands are required to cross each other at an angle, there will be less ‘scissor action’ tending to cut into the insulation. Where conditions demand it, many layers of conductor insulation can be applied and the limit to this is determined by the need to maintain a covered cross-section which can be built into a stable winding. This demands that, particularly when they have to have a thick covering of insulation, winding conductors should have a fairly flat section, so that each can be stably wound on top of the conductor below. In practice this usually means that the axial dimension of the strand should be at least twice, and preferable two and a half times, the radial dimension. Conditions may occasionally require that a conductor be wound on edge. This can be necessary in a tapping winding. Such an arrangement can be acceptable if made with care, provided that the winding has only a single layer.

Low-voltage windings

Although the precise details of the winding arrangements will vary according to the rating of the transformer, the general principles remain the same throughout most of the range of power transformers. When describing these windings it is therefore convenient to consider specific cases and it is, hopefully, also of help to the reader to visualise some practical situations.

Generally the low-voltage winding of a transformer is designed to approximately match the current rating of the available low-voltage (LV) switchgear so that, regardless of the voltage class of the transformer, it is likely to have an LV current rating of up to about 2400 A. Occasionally this might extend to 3000 A and, as an instance of this, the majority of the UK power stations having 500 and 660 MW generating units installed have station transformers with a nominal rating of 60 MVA and rated low-voltage windings of 11 kV, 3000 A. This current rating matched the maximum 11 kV air-break circuit-breakers which were available at the time of the construction of these stations. For the low-voltage winding of most transformers, therefore, this is the order of the current involved. (There are transformers outside this range, of course; for an 800 MVA generator transformer, the LV current is of the order of 19 000 A.)

The voltage ratio is such that the current in the high-voltage (HV) winding is an order of magnitude lower than this, say, up to about 300 A. In most oil-filled transformers utilising copper conductors, the current density is between 2 and 4 A/mm^2, so the conductor section on the LV winding is of the order of, say, 50 mm $\times$ 20 mm and that on the HV winding, say, 12 mm $\times$ 8 mm. As explained in Chapter 1, the volts per turn in the transformer is dependent on the cross-sectional area of the core or core frame size. The frame size used depends on the rating of the transformer but, since, as the rating increases the voltage class also tends to increase, the volts per turn usually gives an LV winding with a hundred or so turns and an HV winding with a thousand or more. In practice, the actual conductor sizes and the number of turns used depend on a good many factors and may therefore differ widely from the above values. They are quoted as an indication of the differing problems in designing LV and HV windings. In the former, a small number of turns of a large-section conductor are required; in the latter, a more manageable cross-section is involved, but a very much larger number of turns. It is these factors which determine the types of windings used.

The LV winding is usually positioned nearest to the core, unless the transformer has a tertiary winding (which would normally be of similar or lower voltage) in which case the tertiary will occupy this position:

- The LV winding (usually) has the lower test voltage and hence is more easily insulated from the earthed core.
- Any tappings on the transformer are most likely to be on the HV winding, so that the LV windings will only have leads at the start and finish and these can be easily accommodated at the top and bottom of the leg.

The LV winding is normally wound on a robust tube of insulation material and this is almost invariably of synthetic resin-bonded paper (s.r.b.p.). This material has high mechanical strength and is capable of withstanding the high loading that it experiences during the winding of the large copper-section coils used for the LV windings. Electrically it will probably have sufficient dielectric strength to withstand the relatively modest test voltage applied to the LV winding without any additional insulation. (See Section 4 of Chapter 3 regarding dielectric strength of s.r.b.p. tubes when used in oil-filled transformers.)

The hundred or so turns of the LV winding are wound in a simple helix, using the s.r.b.p. tube as a former, so that the total number of turns occupy the total winding axial length, although occasionally, for example, where the winding is to be connected in interstar, the turns might be arranged in two helical layers so that the two sets of winding ends are accessible at the top and bottom of the leg. As explained in Chapter 2, winding length is dictated by the impedance required, so that the need to accommodate the total turns within this length will then dictate the dimensions of the individual turn.

Between the winding base tube and the winding conductor, axial insulation board (pressboard) strips are placed so as to form axial ducts for the flow of cooling oil. These strips are usually of a dovetail cross-section (*Figure 4.15*) so that spacers between winding turns can be threaded onto them during the course of the winding. Axial strips are usually a minimum of 8 mm thick and the radial spacers 4 mm. The radial cooling ducts formed by the spacers are

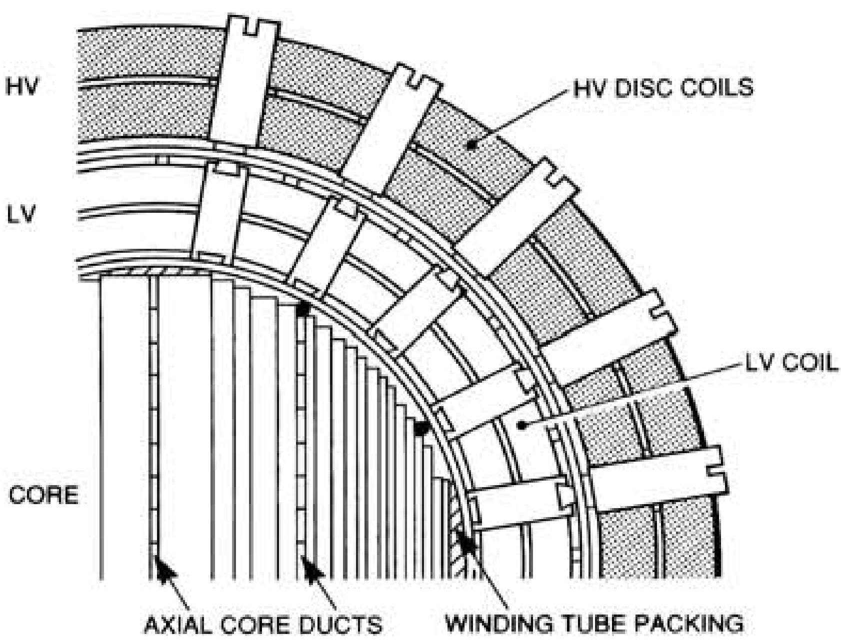


Figure 4.15 Transverse section of core and windings, showing axial cooling ducts above and below windings and dovetailed spacers which form radial ducts

arranged to occur between each turn or every two turns, or even, on occasions, subdividing each turn into half-turns.

Transpositions

It has already been explained that the winding conductor of an LV winding having a large copper cross-section is subdivided into a number of subconductors, or strands, to reduce eddy-current loss and transposing these throughout the length of the winding. Transposition is necessary because of the difference in the magnitude of the leakage flux throughout the radial depth of the winding. If the strands were not transposed, those experiencing the higher leakage flux would be subjected to higher induced voltages and these voltages would cause circulating currents to flow via the ends of the winding where strands are of necessity commoned to make the external connections. Transposition ensures that as nearly as possible each strand experiences the same overall leakage flux. There are various methods of forming conductor transpositions, but typically these might be arranged as shown in *Figure 4.16*. If the winding conductor is subdivided into, say, eight subconductors in the radial dimension, then eight transpositions equally spaced axially are needed over the winding length. Each of these is carried out by moving the inner conductor sideways from below the other seven, which then each move radially inwards by an amount equal to their thickness, and finally the displaced inner conductor would be bent outwards to the outer radial level and then moved to the outside of the stack.

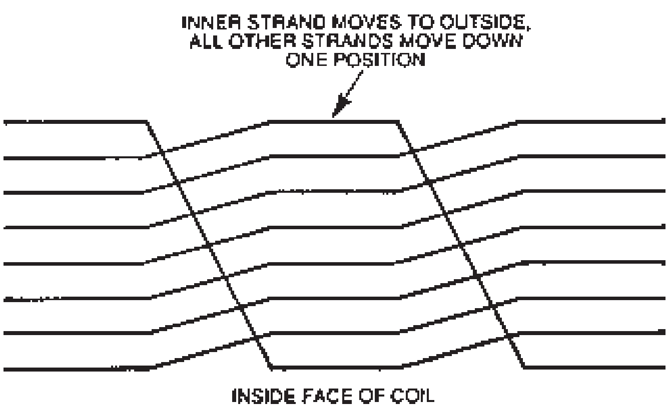


Figure 4.16 Developed section of an eight-strand conductor showing transposition of strands

Continuously transposed strip

Even with an arrangement of transpositions of the type described above and using many subconductors, eddy currents in very high-current windings

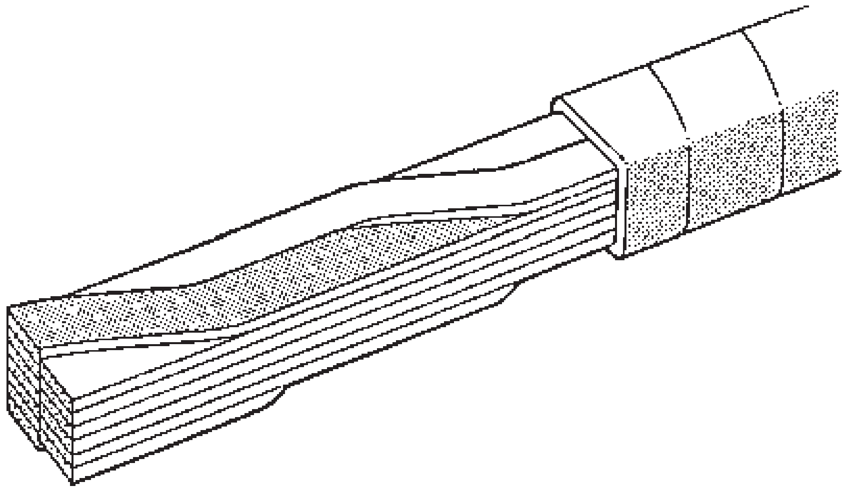


Figure 4.17 Continuously transposed conductor

(perhaps of 2000 A or greater) cannot be easily limited in magnitude to, say, 25% of the resistance losses as suggested above. In addition, transpositions of the type described above take up a significant amount of space within the winding. As a result, in the early 1950s, manufacturers introduced a type of continuously transposed conductor. This enables a far greater number of transpositions to be carried out. In fact, as the name suggests, these occur almost continuously in the conductor itself before it is formed into the winding. Although the 'continuous' transpositions result in some loss of space within the conductor group, this amounts to less space within the winding than that required for conventional transpositions, so that there is a net improvement in space factor as well as improved uniformity of ampere-conductor distribution. *Figure 4.17* shows how the continuously transposed conductor is made up. It has an odd number of strands in flat formation insulated from each other by enamel only and these are in two stacks side by side axially on the finished winding. Transpositions are effected by the top strip of one stack moving over to the adjacent stack as the bottom strip moves over in the opposite direction. The conductor is moved sideways approximately every 50 mm along its length. In addition to the enamel covering on the individual strands, there is a single vertical paper separator placed between the stacks and the completed conductor is wrapped overall with at least two helical layers of paper in the same manner as a rectangular section conductor. Manufacture of the continuously transposed conductor involves considerable mechanical manipulation of the strands in order to form the transpositions and was made possible by the development of enamels which are sufficiently tough and resilient to withstand this. The introduction of continuously transposed strip has been particularly beneficial to the design of large transformers, which must be capable of carrying large currents, but its use is not without some disadvantages of which the following are most significant:

- A single continuously transposed conductor stack which might be up to, say, 12 strands high, and two stacks wide wrapped overall with paper, tends to behave something like a cart spring in that it becomes very difficult to wind round the cylindrical former. This problem can be limited by the use of such strip only for large-diameter windings. It is usual to restrict its use to those windings which have a minimum radius of about 30 times the overall radial depth of the covered conductor.
- When the covered conductor, which has significant depth in the radial dimension, is bent into a circle, the paper covering tends to wrinkle and bulge. This feature has been termed ‘bagging’. The bagging, or bulging, paper covering can restrict oil flow in the cooling ducts. The problem can be controlled by restricting the bending radius, as described above, and also by the use of an outer layer of paper covering which has a degree of ‘stretch’ which will contain the bagging such as the highly extensible paper described in Chapter 3. Alternatively some allowance can be made by slightly increasing the size of the ducts.
- Joints in continuously transposed strip become very cumbersome because of the large number of strands involved. Most responsible manufacturers (and their customers) will insist that a winding is made from one length of conductor without any joints. This does not, however, eliminate the requirement for joints to the external connections. It is often found that these can best be made using crimped connectors but these have limitations and very careful control is necessary in making the individual crimps.
- A high degree of quality control of the manufacture is necessary to ensure that defects in the enamel insulation of the individual strands or metallic particle inclusions do not cause strand-to-strand faults.

High-voltage windings

Mention has already been made of the fact that the high-voltage (HV) winding might have 10 times as many turns as the low-voltage (LV) winding, although the conductor cross-sectional area is considerably less. It is desirable that both windings should be approximately the same axial length subject to the differing end insulation requirements, see below, and, assuming the LV winding occupied a single layer wound in a simple helix, the HV winding would require 10 such layers. A multilayer helical winding of this type would be somewhat lacking in mechanical strength, however, as well as tending to have a high voltage between winding layers. (In a 10-layer winding, this would be one-tenth of the phase voltage.) HV windings are therefore usually wound as ‘disc windings’. In a disc winding, the turns are wound radially outwards one on top of the other starting at the surface of the former. If a pair of adjacent discs are wound in this way the crossover between discs is made at the inside of the discs, both ‘finishes’ appearing at the outer surfaces of the respective discs. The required number of disc pairs can be wound in this way and then connected together at their ends to form a complete winding. Such an arrangement requires a large number of joints between the pairs of discs (usually individual discs are called *sections*) and so has been largely superseded by the *continuous disc winding*. This has the same configuration when completed as a sectional disc winding but is wound in such a way as to avoid the need for it to be wound in separate disc pairs. When the ‘finish’ of a disc appears at the outside radius, it is taken down to the mandrel surface using a tapered curved former. From the surface of the mandrel, a second disc is then built up by winding outwards exactly as the first. When this second complete disc has been formed, the tension is taken off the winding conductor, the taper former removed and the turns laid loosely over the surface of the mandrel. These turns are then reassembled in the reverse order so that the ‘start’ is the crossover from the adjacent disc and the ‘finish’ is in the centre at the mandrel surface. The next disc can then be built upwards in the normal way. A section of continuous disc winding is shown in *Figure 4.18*.

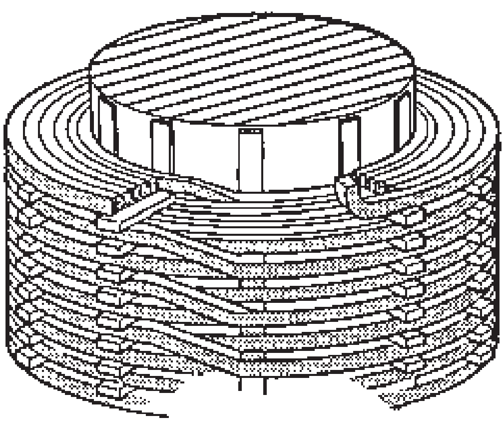


Figure 4.18 Arrangement of continuous disc winding

The operation as described above has been the method of producing continuous disc windings since they were first introduced in about the 1950s. While it may sound a somewhat complex procedure to describe, a skilled winder makes the process appear simple and has no difficulty in producing good quality windings in this way. There are, however, disadvantages of this method of winding. The most significant of these is associated with the tightening of those discs which must be reversed. After reassembling the individual turns of these discs to return the winding conductor to the surface of the mandrel, a procedure which requires that the turns are slack enough to fit inside each other, the winder must then retighten the disc to ensure that the winding is sufficiently stable to withstand any shocks due to faults or short-circuits in service. This tightening procedure involves anchoring the drum from which the conductor is being taken and driving the winding lathe forward. This can result in up to a metre or so of conductor being drawn from the inside of the disc and as this slack is taken up the conductor is dragged across the dovetail strips over which the disc winding is being wound. To ensure that the conductor will slide easily the surface of the strips is usually waxed, but it is not unknown for this to ‘snag’ on a strip damaging the conductor covering. And, of course this damage is in a location, on the inside face of the disc, which makes it very difficult to see.

The other disadvantage is minor by comparison and concerns only the labour cost of making a continuous disc winding. The process of laying out the disc turns along the surface of the mandrel and reassembling them in reverse order requires skill in manipulation and it is the case that a second pair of hands can be beneficial. In fact when labour costs were very much lower than at present it was standard practice for a winder engaged in producing a continuous disc winding to have the services of a labourer throughout the task. Nowadays such practices are considered to be too costly but nevertheless in many organisations the winder will seek the assistance of a colleague for the more difficult part of the process, which also has cost implications.

Both of the above problems associated with the manufacture of continuous disc windings have been overcome by the introduction of the vertical winding

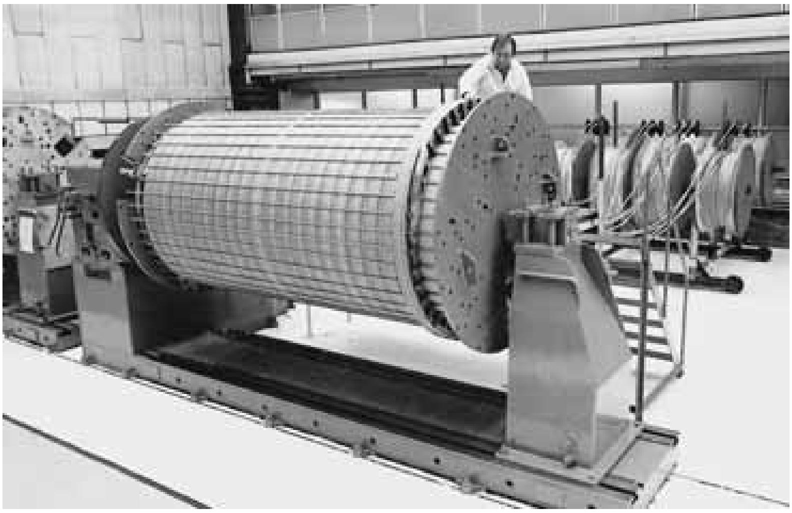


Figure 4.19 Winding in progress – horizontal lathe (Peebles Transformers)

machine which has been used by some manufacturers for many years but whose use became more widespread in the 1980s. From the earliest days of transformer manufacture it has been the practice to wind conductors around horizontal mandrels of the type shown in *Figure 4.19*. *Figure 4.20* shows a modern vertical axis machine which has replaced some of the horizontal axis types in the winding shops of some of the more advanced manufacturers of large high-voltage transformers. On these machines production of continuous disc windings is a much more straightforward and reliable procedure. Using such a machine, the first disc is wound near to the lower end of the mandrel building up the disc from the mandrel surface, outwards, in the normal manner. Then the next disc is wound above this, starting from the outer diameter, proceeding inwards in a conical fashion, over a series of stepped packing pieces of the type shown in *Figure 4.21*. When this 'cone' has been completed, taking the conductor down to the mandrel surface, the packing pieces are removed allowing the cone to 'collapse' downwards to become a disc. This procedure requires only a very small amount of slackness to provide sufficient clearance to allow collapse of the cone, so the tightening process is far less hazardous than on a horizontal machine and furthermore the process can easily be carried out single handed. Vertical machines allow the production of windings of considerably superior quality to those produced using the horizontal type but their installation requires considerably greater capital outlay compared with the cost of procuring and installing a horizontal axis machine.

The HV winding requires space for cooling-oil flow in the same way as described for the LV winding and these are again provided by using dovetail strips over the base cylinder against the inner face of the discs and radial spacers interlocking with these in the same way as described for the LV. Radial cooling ducts may be formed either between disc pairs or between individual discs.

Before concluding the description of the various types of high-voltage winding it is necessary to describe the special type of layer winding sometimes used for very high-voltage transformers and known as a shielded layer winding. Despite the disadvantage of multilayer high-voltage windings identified above namely that of high voltages between layers and particularly at the ends of layers; electrically this winding arrangement has a significant advantage when used as a star-connected high-voltage winding having a solidly earthed star point and employing non-uniform insulation. This can be seen by reference to *Figure 4.22*. If the turns of the winding are arranged between a pair of inner and outer 'shields', one connected to the line terminal and the other to earth, the distribution of electromagnetic voltage within the winding will be the same as the distribution of capacitance voltage if the outer and inner shields are regarded as poles of a capacitor, so that the insulation required to insulate for the electromagnetic voltage appearing on any turn will be the same as that required to insulate for a capacitative voltage distribution. This provides the winding with a high capability for withstanding steep-fronted

Figure 4.20 Winding in progress – vertical lathe (Peebles Transformers)

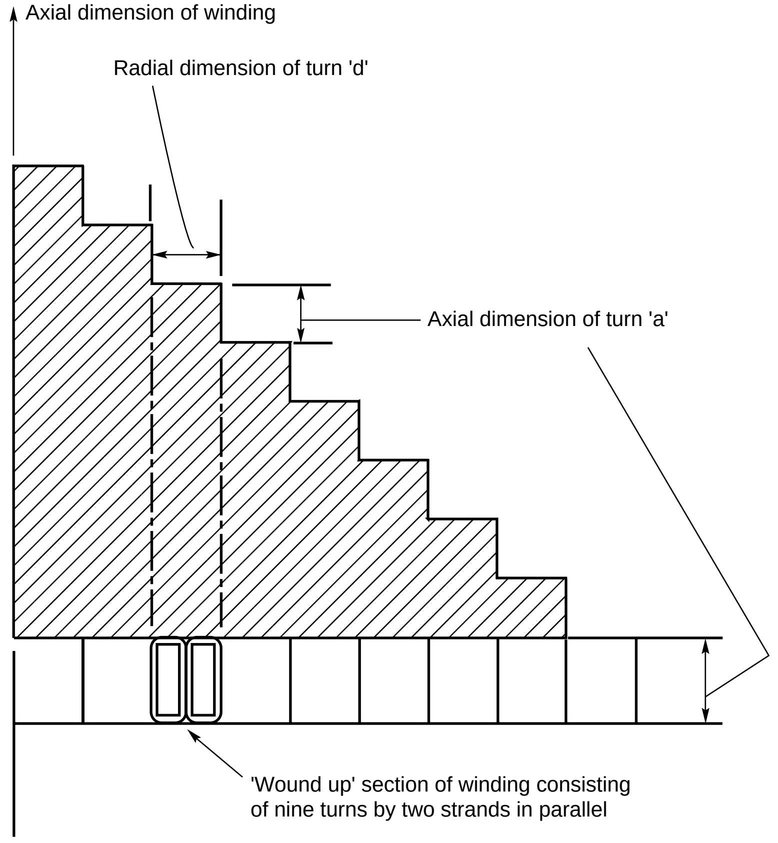


Figure 4.21 Typical stepped wedge used in the production of a continuous disc winding on a vertical axis lathe

waves such as those resulting from a lightning strike on the line close to the transformer. (The next section of this chapter deals in detail with this subject.) *Figure 4.22(a)* shows the ideal arrangement for a shielded layer winding. *Figure 4.22(b)* shows how such a winding might typically be manufactured in practice. As will be apparent from *Figure 4.22(b)*, this type of winding has very poor mechanical strength, particularly in the axial direction, making it difficult to withstand axial clamping forces (see Section 7 of this chapter). There is also a problem associated with the design of the shields. These must be made of very thin conducting sheet, otherwise they attract a high level of stray loss and additionally the line-end shield, being heavily insulated, is difficult to cool, so there can be a problem of local overheating. The shields must have an electrical connection to the respective ends of the winding and making these to flimsy metallic sheets in such a manner that they will withstand a lifetime of high 100 Hz vibration is not easy. These difficulties and in particular the complex insulation structure required make this type

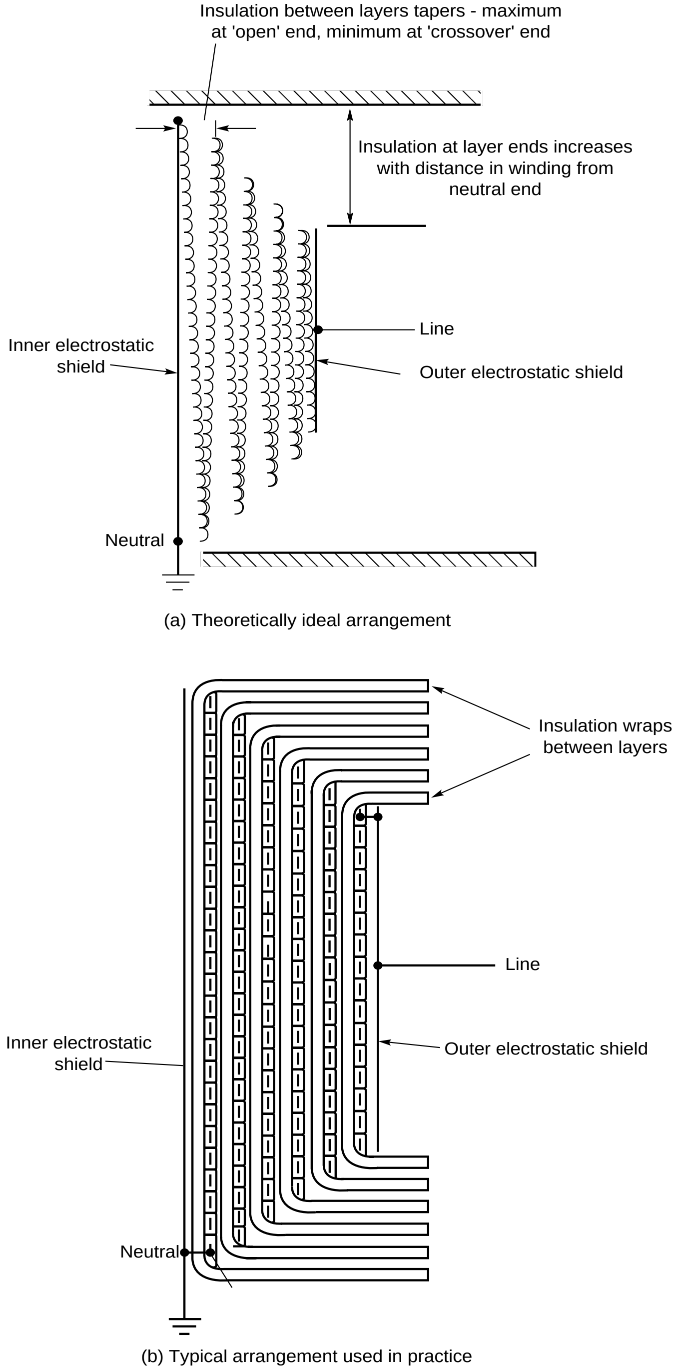


Figure 4.22 Shielded layer windings

of winding very costly to manufacture. Consequently designers have concentrated on improving the response of disc windings to steep-fronted waves. This work has been largely successful in recent years, so that shielded layer-type windings are now rarely used.

Tapping windings

Thus far it has been assumed that power transformers have simply a primary and secondary winding. However, practically all of them have some form of tapping arrangement to allow both for variations of the applied voltage and for their own internal regulation. In the case of distribution and small auxiliary transformers these tappings will probably allow for $\pm 5\%$ variation, adjustable only off-circuit. On larger transformers tappings of $\pm 10\%$ or more might be provided, selectable by means of on-load tapchangers. More will be said later about the subject of tappings and tapchangers. However, it is convenient at this stage to describe the tap windings themselves.

Most power transformers have the tappings in the HV winding for two reasons. Firstly, it is convenient to assume that the purpose of the tappings is to compensate for variations in the applied voltage which, for most transformers, except generator transformers, will be to the HV winding. (Generator transformers are a special case and will be discussed more fully in Chapter 7.) As the applied voltage increases, more tapping turns are added to the HV winding by the tapchanger so that the volts per turn remain constant, as does the LV winding output voltage. If the applied voltage is reduced, tapping turns are removed from the HV winding again keeping the volts per turn constant and so retaining constant LV voltage. From the transformer design point of view, the important aspect of this is that, since the volts per turn remains constant, so does the flux density. Hence the design flux density can be set at a reasonably high economic level without the danger of the transformer being driven into saturation due to supply voltage excursions (see also Chapter 2).

The second reason for locating tappings on the HV side is that this winding carries the lower current so that the physical size of tapping leads is less and the tapchanger itself carries less current.

Since the tappings are part of the HV winding, frequently these can be arranged simply by bringing out the tapping leads at the appropriate point of the winding. This must, of course, coincide with the outer turn of a disc, but this can usually be arranged without undue difficulty.

In larger transformers, the tappings must be accommodated in a separate tapping winding since the leaving of gaps in one of the main windings would upset the electromagnetic balance of the transformer to an unacceptable degree so that out-of-balance forces in the event of an external fault close to the transformer could not be withstood. The separate tapping winding is usually made the outermost winding so that leads can be easily taken away to the tapchanger. The form of the winding varies greatly and each of the arrangements have their respective advantages and disadvantages.

Before describing separate tapping windings further it should be noted that it is always significantly more costly to place the taps in a separate layer because of the additional interlayer insulation that is required. It is always preferable therefore to accommodate the taps in the body of the HV if this is at all possible.

One common arrangement for a separate tapping winding is the multi-start or interleaved helical winding. This is shown diagramatically in *Figure 4.23*. These windings usually occupy two layers but may occasionally have four layers. The arrangement is best described by using a practical example.

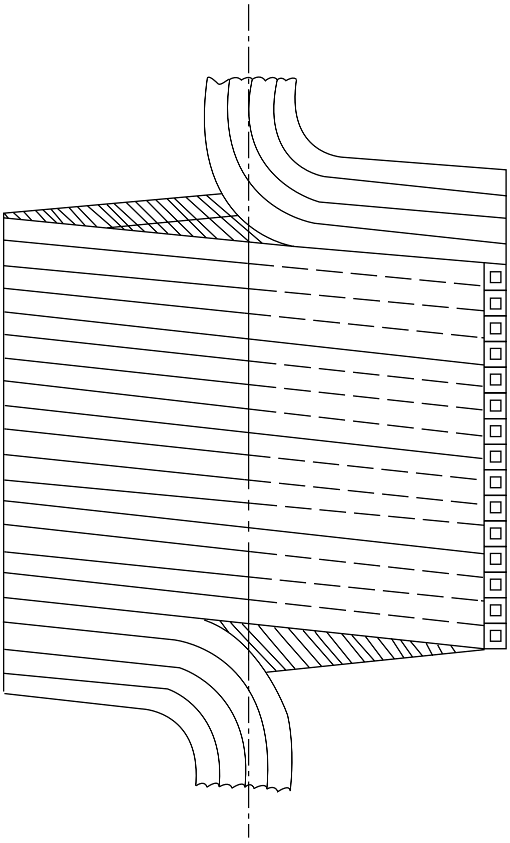


Figure 4.23 Interleaved helical tapping winding having four taps in parallel of five turns per tap

Consider a transformer with a 275 kV star-connected HV winding having a tapping range of plus 10 to minus 20% in 18 steps of 1.67% per step. It has already been suggested that a typical HV winding might have about 1000 turns total. In general, transformers for higher voltages, particularly at the lower end of the MVA rating range, tend to be on smaller frames in relation to their class so that the number of turns tends to be higher than the average. In this example, and being very specific, assume that the HV winding has 1230 turns on principal tap, so that each tap would require:

$$\frac{1.67}{100} \times 1230 = 20.54 \text{ turns}$$

This means that the tapping winding must provide approximately $20\frac{1}{2}$ turns per tap. Of course, half turns are not possible so this would be accommodated by alternating 20 and 21 turn tapping steps. (In practice the designer would need to be satisfied that his design complied with the requirements of IEC 76, Part 1, as regards tolerance on voltage ratio for all tap positions. This might necessitate the adjustment of the number of turns in a particular tap by the odd one either way compared with an arrangement which simply alternated 20 and 21 turn tapping steps.) One layer of the tapping winding would thus be wound with nine (i.e. half the total number of taps) sets of conductors in parallel in a large pitch helix so that, say, 20 turns took up the full axial length of the layer. There would then be an appropriate quantity of interlayer insulation, say duct-wrap-duct, the ducts being formed by the inclusion of pressboard strips, followed by a further layer having nine sets of 21 turns in parallel. The winding of the layers would be in opposite senses, so that, if the inner layer had the starts at the top of the leg and finishes at the bottom, the outer layer would have starts at the bottom and finishes at the top, thus enabling series connections, as well as tapping leads, to be taken from the top and bottom of the leg. (As stated earlier, the voltage induced in all turns of the transformer will be in the same direction regardless of whether these turns are part of the LV, HV or tapping windings. In order that these induced voltages can be added together, all turns are wound in the same direction. This difference in sense of the windings, therefore, depends upon whether the start is at the top of the leg or at the bottom, or, since most windings are actually wound on horizontal mandrels, whether the start is at the left or the right. In the case of buck/boost tapping arrangements – see Section 7 of this chapter – the winding output voltage is in some cases reduced by putting in-circuit tappings in a subtractive sense, i.e. ‘buck’, and in other cases increased by putting in-circuit tappings in an additive sense, i.e. ‘boost’. The windings themselves are, however, still wound in the same direction.)

The helical interleaved tap winding arrangement has two advantages:

- By distributing each tapping along the total length of the leg a high level of magnetic balance is obtained whether the taps are in or out.
- Helical windings with a small number of turns are cheap and simple to manufacture.

It unfortunately also has disadvantages, the first of which is concerned with electrical stress distribution and is best illustrated by reference to *Figure 4.24*.

Manufacturers design transformers in order to meet a specified test condition so it is the electrical stress during the induced overvoltage test which must be

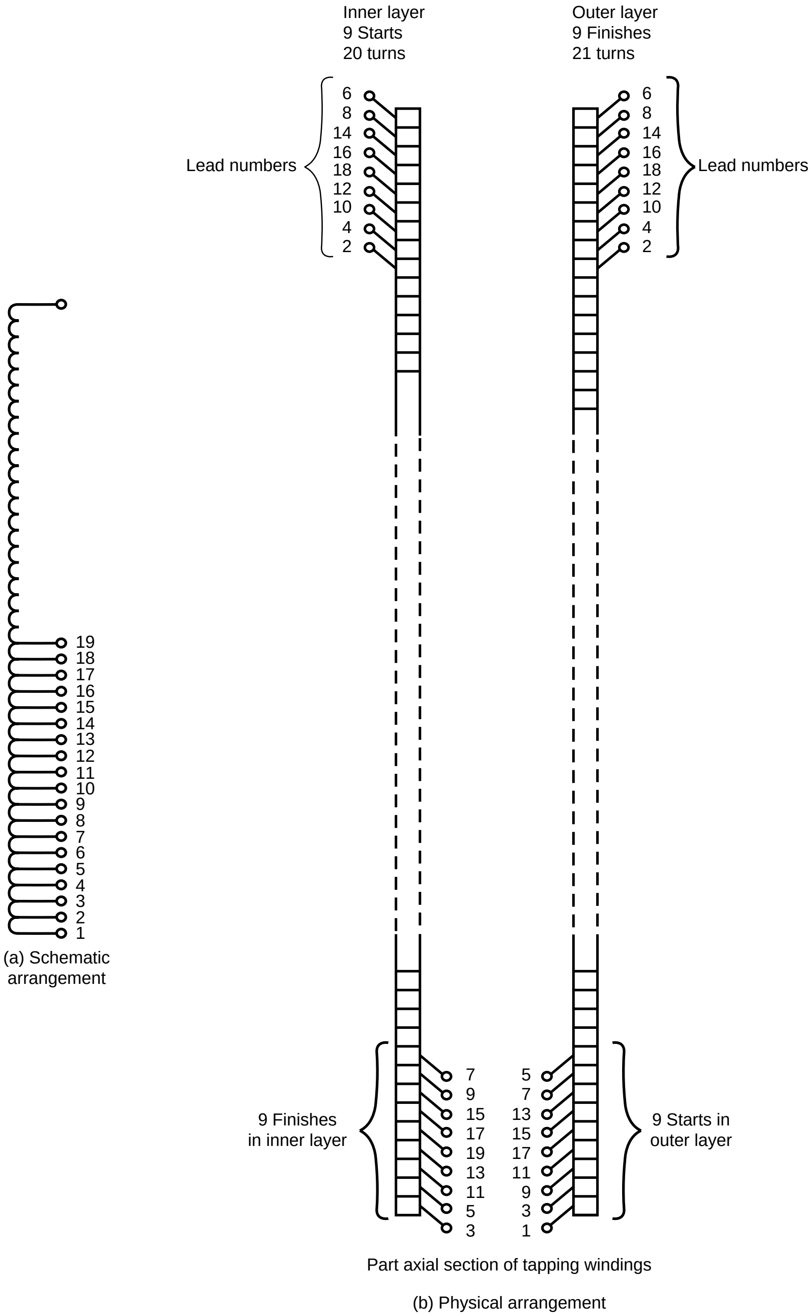


Figure 4.24 Arrangement of two-layer helical interleaved tapping winding

considered. A transformer having an HV voltage of 275 kV will be subjected to an induced overvoltage test at 460 kV (see *Table 5.1* in Section 2 of Chapter 5) and it is permitted in IEC 76 to induce this test voltage on the maximum plus tap, i.e. plus 10% in this example, so that 460 kV must be induced in 110% of the winding turns.

Figure 4.24(b) shows a part section of the tapping layers. It will be apparent from this that it is not advisable to allocate the tapping sections in numerical order, otherwise in the outer layer at the end of the first turn, tapping 1 will be immediately adjacent tapping 17 and in the inner layer, tapping 2 will be adjacent tapping 18. The diagram shows one possible way of distributing the taps so as to reduce the voltage differences between turns which are physically close together. In this arrangement the start of tapping 17 is separated from the start of tapping 1 by the width of three turns. The test voltage appearing between the start of tapping 1 and the start of tapping 17 is that voltage which is induced in 16 tapping steps, which is

$$16 \times \frac{1.67}{100} \times \frac{460}{110} \times 100 = 111.74 \text{ kV, approx.}$$

The width of three turns depends on the total length available for the tapping layer. On a fairly small 275 kV transformer this could be as little as 2 m. In layer one 9×20 turns must be accommodated in this 2 m length, so three turns occupy

$$3 \times \frac{2000}{9 \times 20} = 33.33 \text{ mm}$$

and the axial creepage stress is thus

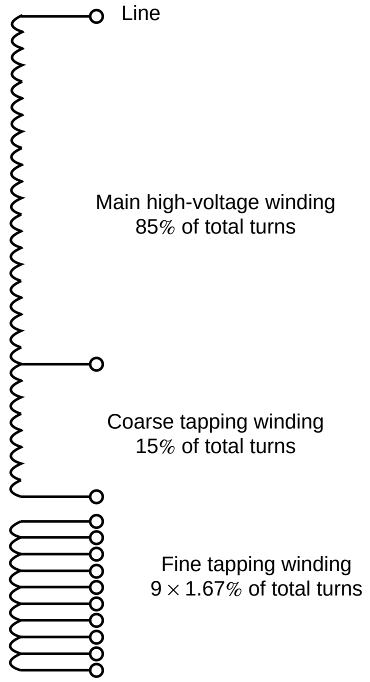
$$\frac{111.74}{33.33} = 3.35 \text{ kV/mm}$$

which is unacceptably high.

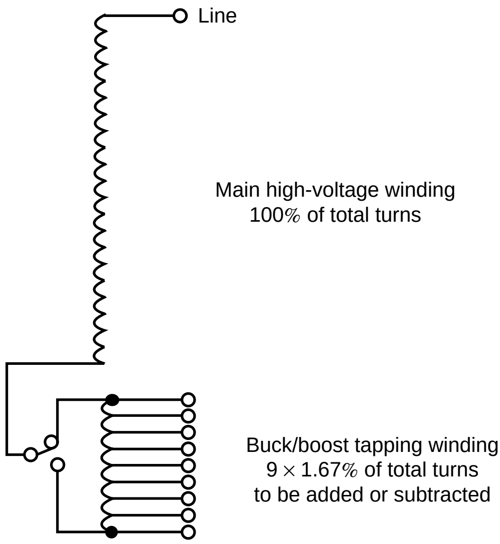
The situation could be greatly improved by opting for four layers of taps rather than two, arranged so that no more than half the tapping-range volts appeared in the same layer.

While the numbers quoted above do not relate to an actual transformer they do illustrate the problem, also showing that design problems frequently arise in very high-voltage transformers at the lower end of the MVA rating band applicable to the voltage class in question.

Another way of resolving this problem would be to use either a coarse/fine or a buck/boost tapping arrangement. These require a more sophisticated tapchanger (see Section 7 of this chapter) but allow the tap winding to be simplified. They can be explained by reference to *Figure 4.25*. With a coarse/fine arrangement (*Figure 4.25(a)*) the tapping winding is arranged in two groups. One, the coarse group, contains sufficient turns to cover about half of the total tapping range and is switched in and out in a single operation, the other, the fine group, is arranged to have steps equivalent to the size of



(a) Coarse/fine arrangement to provide a tapping range of ±15% in 18 steps of 1.67% per step



(b) Buck/boost tapping arrangement to provide a tapping range of ±15% in 18 steps of 1.67% per step

Figure 4.25

tapping step required and is added and subtracted sequentially either with or without the coarse group in circuit. Physically, the coarse group would occupy a third helical layer and no more than half tapping-range volts would appear in one layer. With the buck/boost arrangement, the tapchanger is arranged to put taps in and out with such a polarity as to either add or subtract to or from the voltage developed in the main HV winding. Again, with this arrangement the taps could be contained in two helical layers so that these did not contain more than half tapping-range volts.

The second disadvantage of the helical tapping arrangement concerns its mechanical strength. Under short-circuit conditions (see Section 6 of this chapter) an outer winding experiences an outward bursting force. Such a winding consisting of a small number of turns wound in a helix does not offer much resistance to this outward bursting force and requires that the ends be very securely restrained to ensure that the winding does not simply unwind itself under the influence of such a force. The 20/21 turns in the example quoted above can probably be adequately secured; however, as the transformer gets larger (and the magnitude of the forces increases also) the frame size will be larger, the volts per turn increased and the turns per tap proportionally reduced, so the problem becomes more significant.

The most common alternative to the use of interleaved helical tapping windings is to use disc windings. These at least have the advantage that they can be accommodated in a single layer. The number of turns in an individual tapping section must ideally be equal to an even number of discs, usually a single disc pair. Tapping leads are thus connected between disc pairs so the disc pairs may be joined at this point also, that is, it is just as convenient to make up the winding from sectional disc pairs as to use a continuous disc. This former method of manufacture is therefore often preferred. Another advantage of using a disc winding is that the discs can be arranged in the normal tapping sequence so that the full volts across the tapping range is separated by the full axial length of the tap winding.

A third possibility for the tapping winding is to utilise a configuration as for the disc-wound taps described above but nevertheless to wind each tap section as a helix. This arrangement might be appropriate at the lower end of the size range for which a separate tapping winding is necessary so that the radial bursting forces under short-circuit are not too great. In the example quoted above, a figure of around 20 turns per tap would lend itself ideally to a disc arrangement having 10 turns per disc, that is, 20 turns per disc pair. The example quoted was, however, quite a high-voltage transformer. Often the number of turns per tap will be very much less, possibly as few as six or seven. Such a small number does not lend itself so well to a pair of discs and hence a helical arrangement must be considered, which raises the problem of accommodating the necessary number of turns in a single layer. It is here that it might be necessary to wind the conductor on edge. As previously stated, this can be done provided the winding is single layer and of a reasonably large diameter. In fact this might produce a stiffer winding, more able to withstand the radial bursting forces than one in which the conductor was laid flat.

4.3 DISPOSITION OF WINDINGS

Mention has already been made of the fact that the LV winding is placed next to the core because it has the lower insulation level. It is now necessary to look in further detail at the subject of insulation and insulation levels and to examine the effects of these on the disposition of the windings.

Transformer windings may either be *fully insulated* or they can have *graded insulation*. In IEC 76-3 these are termed *uniform insulation* and *non-uniform insulation* respectively. In a fully or uniform insulated winding, the entire winding is insulated to the same level, dictated by the voltage to which the entire winding is to be raised on test.

Graded or non-uniform insulation allows a more economical approach to be made to the design of the insulation structure of a very high-voltage (EHV) winding. With this system, recognition is made of the fact that such windings will be star connected and that the star point will be solidly earthed. The insulation of the earthy end of the winding thus need only be designed for a very nominal level.

Before the adoption of IEC 76 in the UK, BS 171 required that all windings up to 66 kV working level should he uniformly insulated. Above this, which in the UK means 132, 275 and 400 kV, non-uniform insulation was the norm. Although IEC 76-3 allows for either system to be used at all voltage levels, the UK practice has been continued partly for reasons of custom and practice and also because in many instances new equipment being procured must operate in parallel with equipment designed to earlier standards. In addition the systems themselves have been designed for this standard of equipment. Since most transformers having two EHV windings, that is, each winding at 132 kV or higher, tend to be autotransformers, this means that most double-wound transformers will have, at most, only one winding with graded insulation and many will have both windings fully insulated.

Figure 4.26(a) shows the arrangement of a transformer in which both windings are fully insulated. This might be a primary substation transformer, 33/11 kV and perhaps around 20 MVA. The LV winding must withstand an applied voltage test which will raise the entire winding to 28 kV above earth. The winding insulation must therefore withstand this voltage between all parts and earthed metalwork, including the core. Along the length of the winding this test voltage appears across the dovetail strips plus the thickness of the s.r.b.p. tube. At the ends, these strips and the tube are subjected to surface creepage stress, so that the end-insulation distance to the top and bottom yokes must be somewhat greater.

The 33 kV winding is tested at 70 kV above earth. The radial separation between LV and HV must be large enough to withstand this with, say, a single pressboard wrap and spacing strips inside and outside (*Figure 4.26*). The end

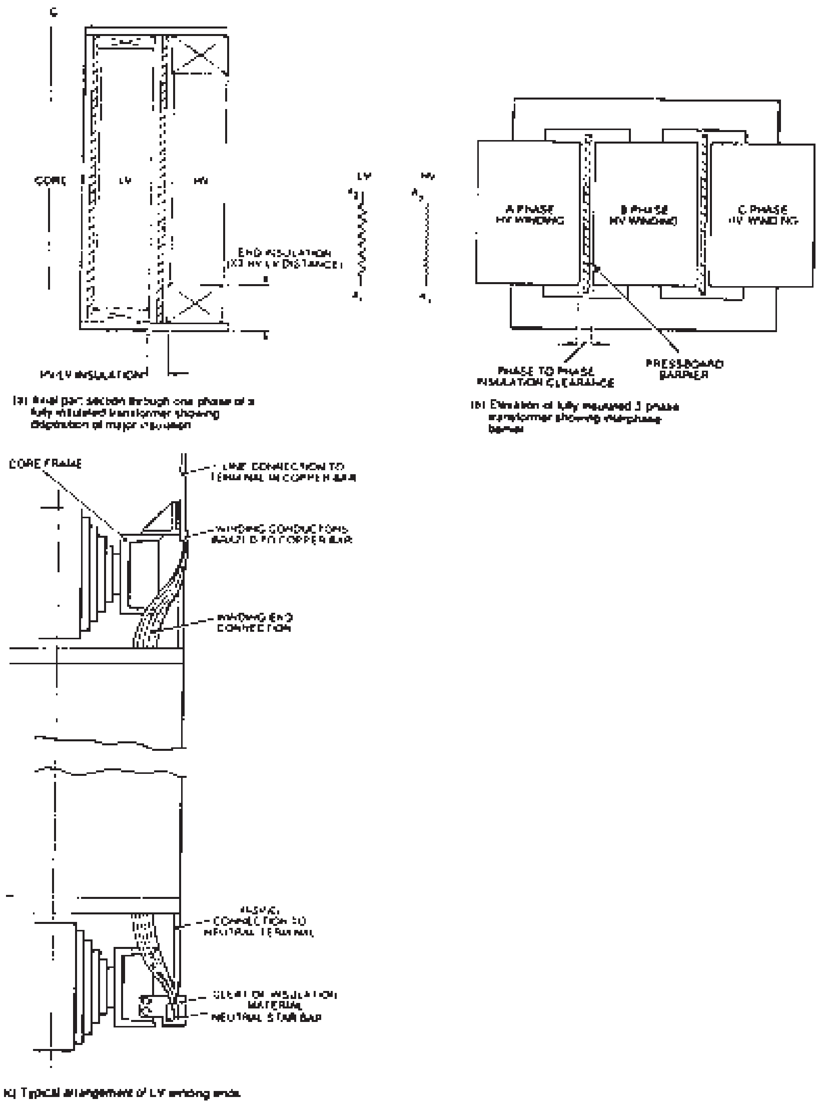


Figure 4.26 Arrangements of windings and leads for transformer having uniform insulation

insulation will be subjected to creepage stress and so the distance to the yoke must be somewhat greater than the HV/LV distance. Between the transformer limbs, the HV windings of adjacent phases come into close proximity.

To withstand the 70 kV test voltage between phases, it is necessary to have a clearance similar to that between HV and LV windings with, say, a single pressboard barrier in the middle of this distance, as shown in *Figure 4.26(b)*.

The LV winding leads are taken out at the top and bottom of the leg, which means that they must of necessity pass close to the core framework. Since they are at relatively low voltage, it is probable that the necessary clearance can be obtained by bending these away from the core as close to the winding as possible and by suitably shaping the core frame (*Figure 4.26(c)*).

The HV winding leads also emerge from the top and bottom of the leg but these are taken on the opposite side of the coils from the LV leads. Being at a greater distance from the core frame than those of the LV winding, as well as having the relatively modest test voltage of 70 kV, these require a little more insulation than those of the LV winding.

It is usually convenient to group the tapping sections in the centre of the HV windings. This means that when all the taps are not in circuit, any effective 'gap' in the winding is at the centre, so that the winding remains electromagnetically balanced. More will be said about this aspect below. The tapping leads are thus taken from the face of the HV winding, usually on the same side of the transformer as the LV leads.

Figure 4.27 shows the arrangement of a transformer in which the LV winding is fully insulated and the HV winding has non-uniform (graded) insulation. This could be a bulk supply point transformer, say, 132/33 kV, star/delta connected, possibly 60 MVA, belonging to a Regional Electricity Company (REC). Some RECs take some of their bulk supplies at 11 kV, in which case the transformer could be 132/11 kV, star/star connected, and might well have a tertiary winding. This too could be 11 kV although it is possible that it might be 415 V in order to fulfil the dual purpose of acting as

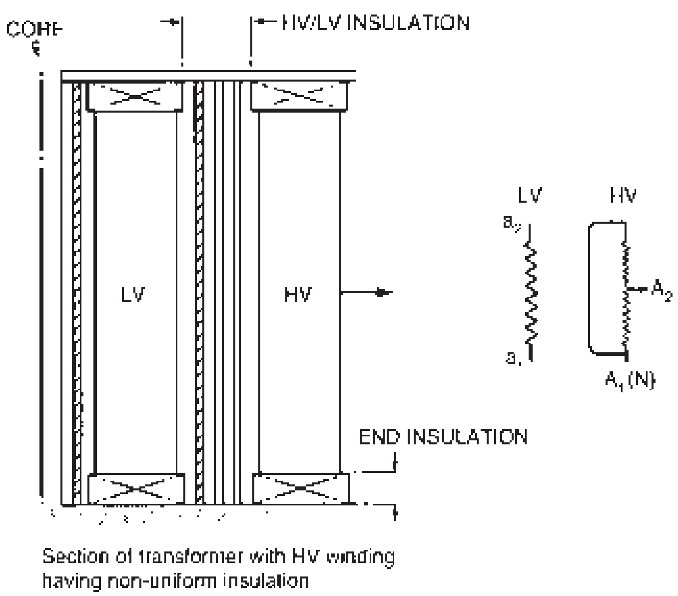


Figure 4.27

a stabilising winding and providing local auxiliary supplies for the substation. Whichever the voltage class, it would be placed nearest to the core. If 11 kV the test levels would be the same as the 11 kV LV winding and that of the LV winding of the 33/11 kV transformer described above. If 415 V, the test levels would be very modest and the insulation provided would probably be dictated by physical considerations rather than electrical. In either case the tertiary and LV insulations would be similar to that of the 33/11 kV transformer. The LV winding would be placed over the tertiary and the tertiary to LV gap would require radial and end insulation similar to that between LV and core for the star/delta design. The 132 kV HV winding is placed outside the LV winding and it is here that advantage is taken of the non-uniform insulation.

For 132 kV class non-uniform insulation, when it is intended that the neutral shall be solidly connected to earth, the applied voltage test may be as low as 38 kV above earth. (More will be said about the subject of dielectric test levels in Chapter 5.) When the overpotential test is carried out, at least 230 kV is induced between the line terminal and earth. Consequently the neutral end needs insulating only to a level similar to that of the LV winding, but the line end must be insulated for a very much higher voltage. It is logical, therefore, to locate the line end as far as possible from the core and for this reason it is arranged to emerge from a point halfway up the leg. The HV thus has two half-windings in parallel, with the neutrals at the top and bottom and the line ends brought together at the centre. If, with such an arrangement, the HV taps are at the starred neutral end of the winding, the neutral point can thus be conveniently made within the tapchanger and the voltage for which the tapchanger must be insulated is as low as possible. Unfortunately it is not possible to locate these tapping coils in the body of the HV winding since, being at the neutral end, when these were not in circuit there would be a large difference in length between the HV and LV windings. This would greatly increase leakage flux, stray losses and variation of impedance with tap position as well as creating large unbalanced forces on short-circuit. It is therefore necessary to locate the taps in a separate winding placed outside the HV winding. This winding is shorter than the HV and LV windings and split into upper and lower halves, with an unwound area in the middle through which the HV line lead can emerge.

The centre of the HV winding must be insulated from the LV winding by an amount capable of withstanding the full HV overpotential test voltage. This requires a radial distance somewhat greater than that in the 33/11 kV transformer and the distance is taken up by a series of pressboard wraps interspersed by strips to allow oil circulation and penetration. Alternatively, it is possible that the innermost wrap could be replaced by an s.r.b.p. tube which would then provide the base on which to wind the HV winding. The disadvantage of this alternative is that the HV to LV gap is a highly stressed area for which s.r.b.p. insulation is not favoured (see Chapter 3) so that, while it might be convenient to wind the HV onto a hard tube, the use of such an arrangement would require a reduced high to low design stress and a greater high to low gap. High to low gap, a, appears in the numerator of the expression for percent reactance (equation (2.1) of Chapter 2) multiplied by a factor three. If this is increased then winding axial length, l, must be increased in order to avoid an increase in reactance, thus making the transformer larger. The designer's objective is normally, therefore, to use as low a high to low as possible and it is probably more economic to wind the HV over a removable mandrel so that it can be assembled onto the LV on completion thus avoiding the use of a hard tube.

The voltage appearing on test between the line end of the HV winding and the neutral-end taps is similar to that between HV and LV windings so it is necessary to place a similar series of wraps between the HV and tapping windings. These wraps must be broken to allow the central HV line lead to emerge; an arrangement of petalling (see Chapter 3) or formed collars may be used to allow this to take place without reducing the insulation strength (*Figure 4.28*).

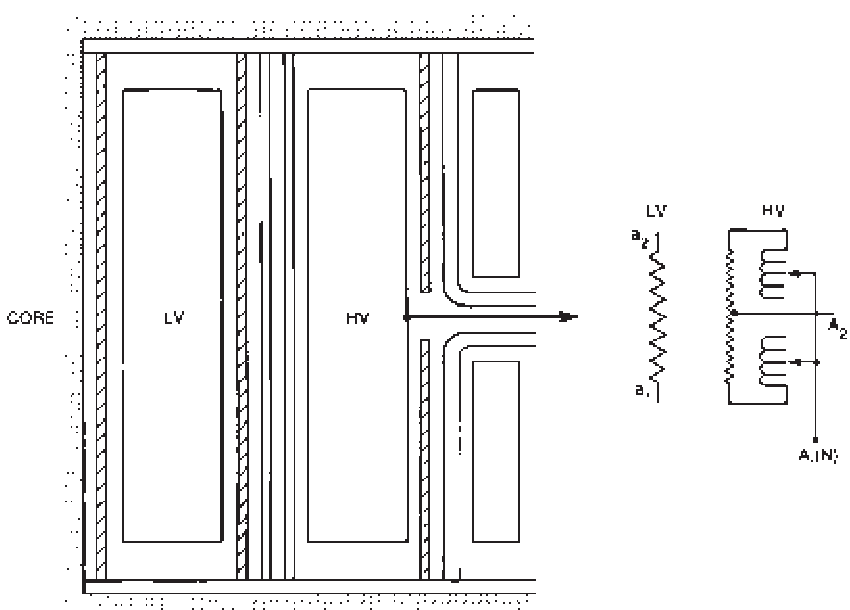


Figure 4.28 Arrangement of HV line lead with outer HV tapping winding and non-uniform insulation

Although the system of non-uniform insulation lends itself well to the form of construction described above, which is widely used in the UK for transformers of 132 kV and over, there are disadvantages and there are also circumstances when this cannot be used. The main disadvantage is seen when the transformer rating is such that the HV current is small. An example will make this clear. Although it is rare to require to transform down from 400 kV at ratings as low as 60 MVA, it has on occasions occurred, for example to provide station supplies for a power station connected to the 400 kV system where there is no 132 kV available. In this case the HV line current is 86.6 A. With two half HV windings in parallel the current in each half winding is 43.3 A. A typical current density for such a winding might be, say, 3 A/mm^2 so that at this current density the required conductor cross-section is 14.4 mm^2. This could be provided by a conductor of, say, 3 × 5 mm which is very small indeed and could not easily be built into a stable winding, particularly when it is recognised that possibly one millimetre radial thickness of paper covering might be applied to this for this voltage class. It would therefore be necessary to use a much lower current density than would normally be economic in order to meet the physical constraints of the winding.

This problem can be eased by utilising a single HV winding instead of two half-windings in parallel as indicated in *Figure 4.29*. This would immediately result in a doubling of the conductor strand size so that this might typically become 3 × 10 mm which is a much more practicable proposition. Of course, the benefit of the central line lead is now no longer available and the winding end must be insulated for the full test voltage for the line end.

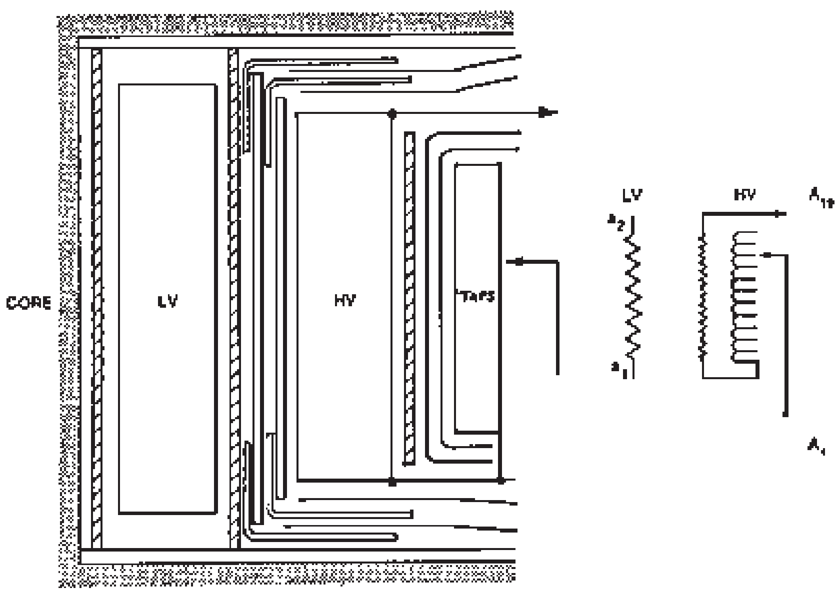


Figure 4.29 Typical arrangement of windings and HV line lead for uniform insulation

Non-uniform insulation cannot be used if the neutral is to be earthed via an impedance, as is often the case outside the UK, nor is it acceptable for a delta-connected HV which would be unlikely to be used in the UK at a voltage of 132 kV and above, but is used occasionally in other countries, so again there is no merit in having the line lead at the centre of the leg. Hence the arrangement shown in *Figure 4.29* would be necessary. If a delta connection is used, any HV tappings must be in the middle of the winding and in order to meet the uniform insulation requirement, the tapchanger must be insulated to the full HV test level. Such a configuration will clearly be more costly than one with non-uniform insulation, but this simply demonstrates the benefit of a solidly earthed neutral as far as the transformer is concerned. No doubt proponents of systems having impedance earthing of the neutral would wish to identify benefits to the system of using this arrangement.

4.4 IMPULSE STRENGTH

The previous section dealt with the disposition of the windings as determined by the need to meet the power frequency tests, or electromagnetic voltage distributions which are applied to the windings, but it also briefly mentioned the need to withstand the effect of steep-fronted waves. When testing a power transformer such waves are simulated by an impulse test, which is applied to the HV line terminals in addition to the dielectric testing at 50 Hz. Impulse testing arose out of the need to demonstrate the ability to withstand such waves, generated by lightning strikes, usually to the high-voltage system to which the transformer is connected. These waves have a much greater magnitude than the power frequency test voltage but a very much shorter duration.

While considering the construction of transformer windings it is necessary to understand something of the different effect which these steep-fronted waves have on them compared with power frequency voltages and to examine the influence which this has on winding design. Section 5 of Chapter 6, which deals with all types of transients in transformers, will go more deeply into the theory and examine the response of windings to lightning impulses in greater detail.

For simulation purposes a standard impulse wave is defined in BS 171 as having a wavefront time of 1.2 μs and a time to decay to half peak of 50 μs. (More accurate definition of these times will be found in Chapter 5 which deals with transformer testing.) When struck by such a steep wavefront, a transformer does not behave as an electromagnetic impedance, as it would to power frequency voltages, but as a string of capacitors as shown in *Figure 4.30*. When the front of the impulse wave initially impinges on the winding, the capacitances C_s to the succeeding turn and the capacitance of each turn to earth C_g predominate, so that the reactance and resistance values can be ignored. It will be shown in Section 5 of Chapter 6 that when a high voltage is applied to such a string, the distribution of this voltage is given by the expression:

$$e_x = \frac{E \sinh \dfrac{\alpha x}{L}}{\sinh \alpha}$$

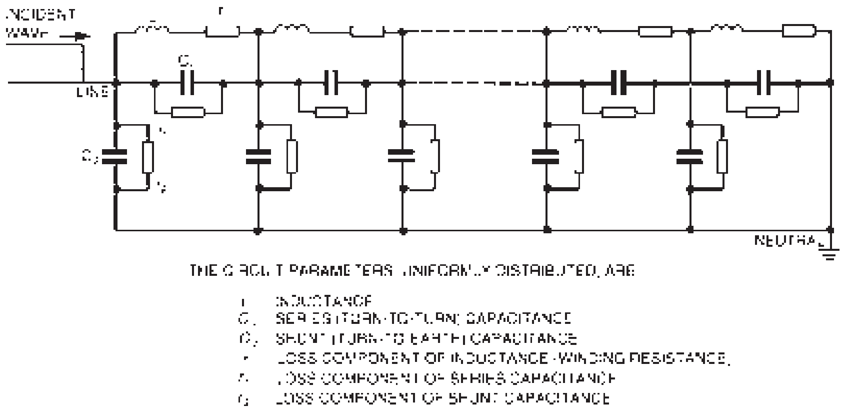


Figure 4.30 Equivalent circuit of transformer for simplified uniform winding

where E = magnitude of the incident wavefront
L = winding length
$\alpha = \sqrt{(C_g/C_s)}$

which represents a curve of the form shown in *Figure 4.31*. The initial slope of this curve, which represents the voltage gradient at the point of application, is proportional to C_g/C_s. In a winding in which no special measures had been taken to reduce this voltage gradient, this would be many times that which would appear under power frequency conditions. If additional insulation were placed between the winding turns, this would increase the spacing between them and thus reduce the series capacitance C_s. C_g would be effectively unchanged, so the ratio C_g/C_s would increase and the voltage gradient become greater still. The most effective method of controlling the increased stress at the line end is clearly to increase the series capacitance of the winding, since reducing the capacitance to earth, which can be partially

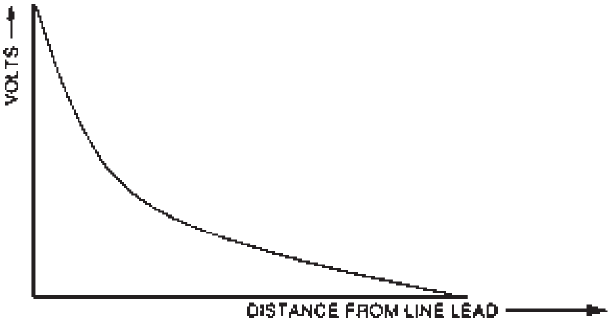


Figure 4.31 Distribution of impulse voltage within winding

achieved by the use of electrostatic shields, is nevertheless not very practicable.* *Figure 4.32* shows several methods by which series capacitance can be increased. The first, *Figure 4.32(a)*, uses an electrostatic shield connected to the line end and inserted between the two HV discs nearest to the line end. The second, *Figure 4.32(b)*, winds in a dummy strand connected to the line lead but terminating in the first disc. Both of these arrangements effectively bring more of the winding turns nearer to the line end. The electrostatic shield was probably the first such device to be used and is possibly still the most widely favoured. The shield itself is usually made by wrapping a pressboard ring of the appropriate diameter with thin metal foil (thin to ensure minimum stray loss – see description of shield for shielded layer winding earlier in this chapter) and then covering this with paper insulation of about the same radial thickness as the winding conductor. It is necessary to make a connection to the foil in order to tie this to the line lead and this represents the greatest weakness of this device, since, as indicated in the description of the shielded layer winding, making a high-integrity connection to a thin foil is not a simple matter.

As the travelling wave progresses further into the winding, the original voltage distribution is modified due to the progressive effect of individual winding elements and their capacitances, self- and mutual inductances and resistance. The voltage is also transferred to the other windings by capacitance and inductive coupling. *Figure 4.33(a)* shows a series of voltage distributions typical of a conventional disc winding having an HV line lead connection at one end. It can be seen that, as time elapses, the voltage distribution changes progressively – the travelling wave being reflected from the opposite end of the winding back towards the line end, and so on. These reflections interact with the incoming wave and a complex series of oscillations occur and reoccur until the surge energy is dissipated by progressive attenuation and the final distribution (*Figure 4.33(b)*) is reached.

Thus it is that, although the highest voltage gradients usually occur at or near to the line-end connection coincident with the initial arrival of the impulse wave, these progress along the winding successively stressing other parts and, while these stresses might be a little less than those occurring at the line end they are still likely to be considerably greater than those present under normal steady-state conditions. In many instances, therefore, stress control measures limited to the line end will be insufficient to provide the necessary dielectric strength and some form of interleaving is required (*Figure 4.32(c)*). This usually involves winding two or more strands in parallel and then reconnecting the ends of every second or fourth disc after winding to give the interleaving arrangement required. It has the advantage over the first two methods that it does not waste any space, since every turn remains active. However, the

* A short, squat winding tends to have a lower capacitance to ground than a tall slim winding, so such an arrangement would have a better intrinsic impulse strength. There are, however, so many other constraints tending to dictate winding geometry that designers are seldom able to use this as a practical means of obtaining the required impulse strength.

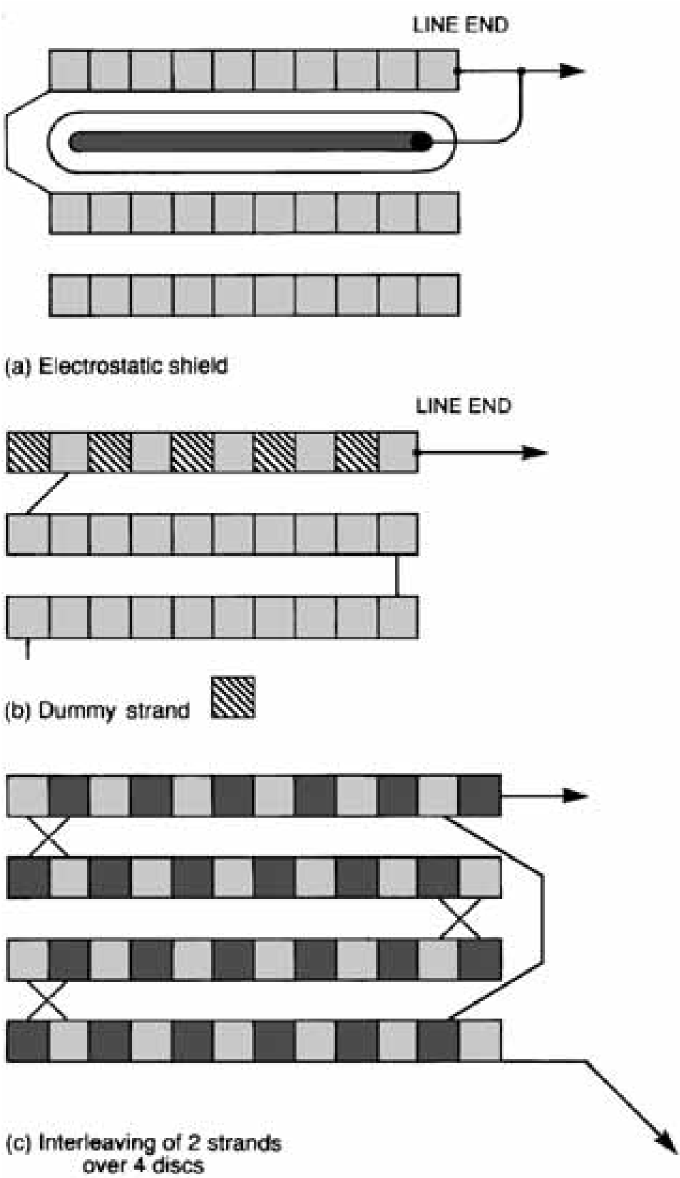


Figure 4.32 Types of winding stress control

cost of winding is greatly increased because of the large number of joints. It is possible by adjustment of the degree of interleaving, to achieve a nearly linear distribution of impulse voltage throughout the winding, although because of the high cost of interleaving, the designer aims to minimise this and, where possible, to restrict it to the end sections of the winding.

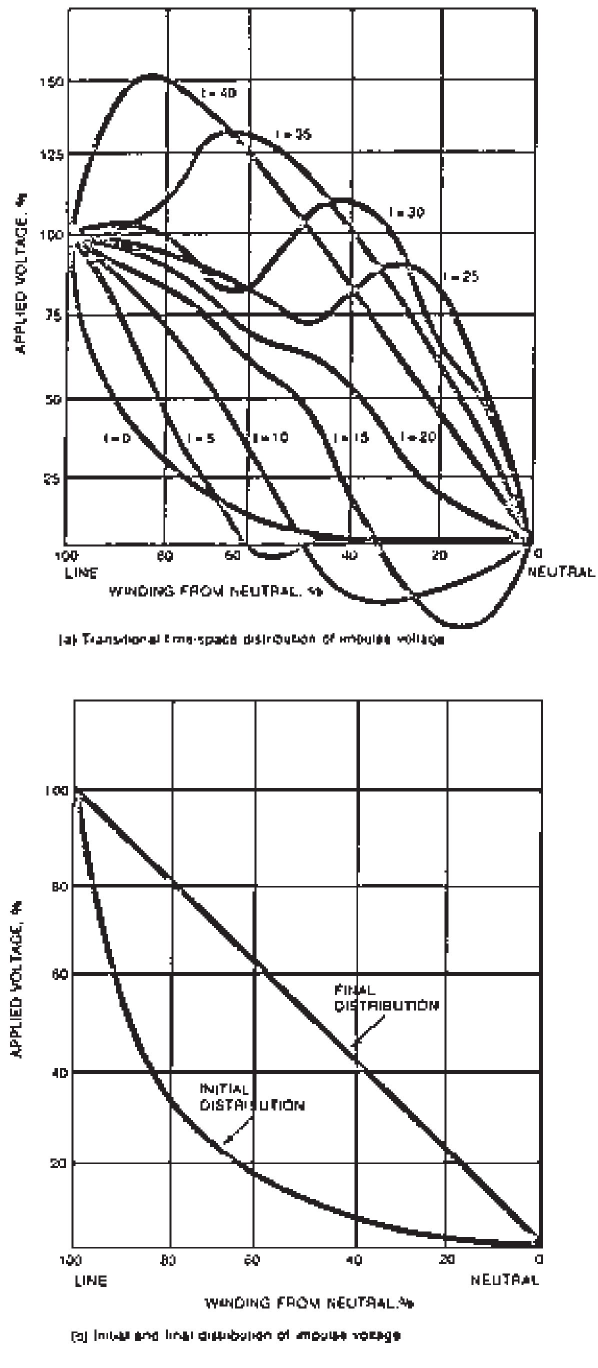


Figure 4.33 Voltage distribution through windings

After the line-end sections, the next most critical area will usually be at the neutral end of the winding, since the oscillations resulting from interactions between the incident wave and the reflection from the neutral will lead to the greatest voltage swings in this area (*Figure 4.33*). If some of the tapping winding is not in circuit, which happens whenever the transformer is on other than maximum tap, the tapping winding will then have an overhang which can experience a high voltage at its remote end. The magnitude of the impulse voltage appearing both across the neutral end sections and within the tapping winding overhang will be similar and will be at a minimum when the initial distribution is linear, as can be seen from *Figure 4.34*. It is often necessary, therefore, to use a section of interleaving at the neutral end to match that of the line-end sections. The magnitude of impulse voltage seen by the tapping winding due to overhang effects is likely to be dependent on the size of tapping range (although it will also be influenced by the type of tapping arrangement, for example, buck/boost or linear, and physical disposition of this with respect to the HV winding and earth), so this must be borne in mind when deciding the size of tapping range required.

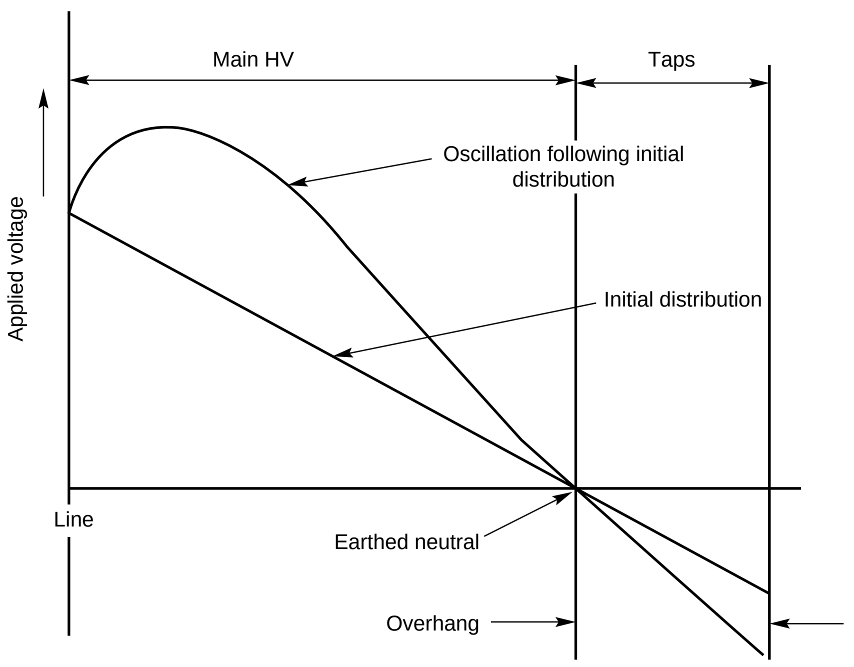


Figure 4.34 Impulse voltage distribution in tapping winding overhang – tapchanger selected on minimum tap

The need for an interleaved HV winding arrangement, as opposed to, say, a simpler line-end shield, is often determined by the rating of the transformer as well as the voltage class and impulse test level required. The lower the MVA rating of the unit the smaller the core frame size, which in turn leads to a lower volts per turn for the transformer and a greater total number of turns. A disc winding with a high total number of turns must have a large number of turns per disc, perhaps as many as 15 or 16, in order to accommodate these within the available winding length, compared with a more normal figure of, say, eight or nine. As a result, the maximum volts appearing between adjacent discs might be as high as 32 times the volts per turn compared with say, only 18 times in a more ‘normal’ winding. This large difference in power frequency voltage between adjacent sections, i.e. discs, can become even more marked for the impulse voltage distribution, thus necessitating the more elaborate stress-control arrangement.

For very high-voltage windings the impulse voltage stress can be too high to be satisfactorily controlled even when using an interleaved arrangement. It is in this situation that it may be necessary to use a shielded-layer winding as described earlier in the chapter. When the steep-fronted impulse wave impinges on the line end of this type of winding, the inner and outer shields behave as line and earth plates of a capacitor charged to the peak magnitude of the impulse voltage. The winding layers between these plates then act as a succession of intermediate capacitors leading to a nearly linear voltage distribution between the shields. (This is similar to the action of the intermediate foils in a condenser bushing which is described in Section 8 of this chapter.) With such a near linear distribution, the passage of the impulse wave through the winding is not oscillatory and the insulation structure required to meet the impulse voltage is the same as that required to withstand the power frequency stress. Electrically, therefore, the arrangement is ideal. The disadvantage, as explained earlier, is the winding’s poor mechanical strength so that a disc winding is used whenever the designer is confident that the impulse stress can be satisfactorily controlled by static shield, dummy strand, or by interleaving.

Chopped waves

For many years it has been the practice to protect transformers of all voltages connected to overhead lines and therefore exposed to lightning overvoltages, by means of surge diverters or coordinating gaps. More will be said about the devices themselves in Section 6 of Chapter 6. Although such devices undoubtedly protect the windings by limiting the magnitude of the wavefronts and the energy transferred to them, operation of these does itself impose a very steep rate of change of voltage onto the line terminal which can result in severe inter-turn and inter-section stress within the windings. The most modern surge arresters are designed to attenuate steep-fronted waves in a ‘softer’ manner than the majority of those used hitherto, but the cost of protecting every transformer connected to an overhead line in this way would be prohibitive. By far the most practicable and universal form of protection used in the UK is the rod gap, or coordinating gap. *Figure 4.35* shows a simple arrangement as used on the 11 kV HV bushings of a 11/0.415 kV rural distribution transformer. A

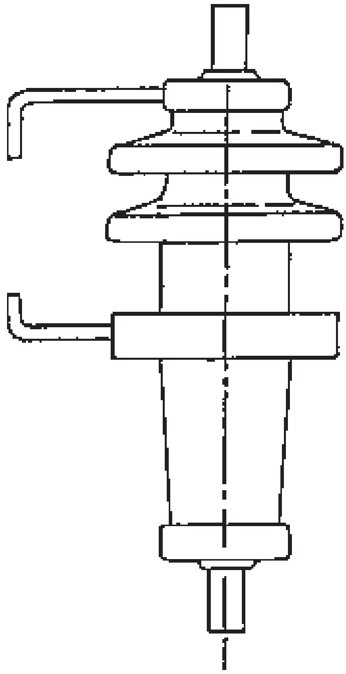


Figure 4.35 Arrangement of rod gap on 11 kV bushing

more elaborate device as used at 275 and 400 kV is shown in *Figure 6.81*. The coordinating gap is designed to trigger at a voltage just below that to which the winding may be safely exposed. If it is set too low it will operate too frequently. Set too high it will fail to provide the protection required. Because of the severe dV/dt imposed on the transformer windings by the triggering of a rod gap it has been the practice to test for this condition by means of chopped-wave tests when carrying out impulse tests in the works. *Figure 4.36* shows a typical chopped impulse wave as applied during these tests.

For many years the chopping was carried out by installing a rod gap across the impulse generator output. In order to ensure that this gap flashed over as close as possible to the nominal impulse test level, it was the practice in the UK electricity supply industry to specify that the impulse voltage for the chopped-wave test should be increased by a further 15% over the normal full-wave test level. Specification requires that the gap should flash over between 2 and 6 μs from the start of the wave and since the nominal time to peak is 1.2 μs, this means that the peak has normally passed before flashover and the winding has been exposed to 115% of the nominal test voltage. Designers were thus required to design the windings to withstand this 115% as a full-wave withstand. It is now possible to use triggered gaps whose instant of flashover can be very precisely set, so the need to specify that the test be carried out at 115% volts no longer arises and IEC 76, Part 3, which deals

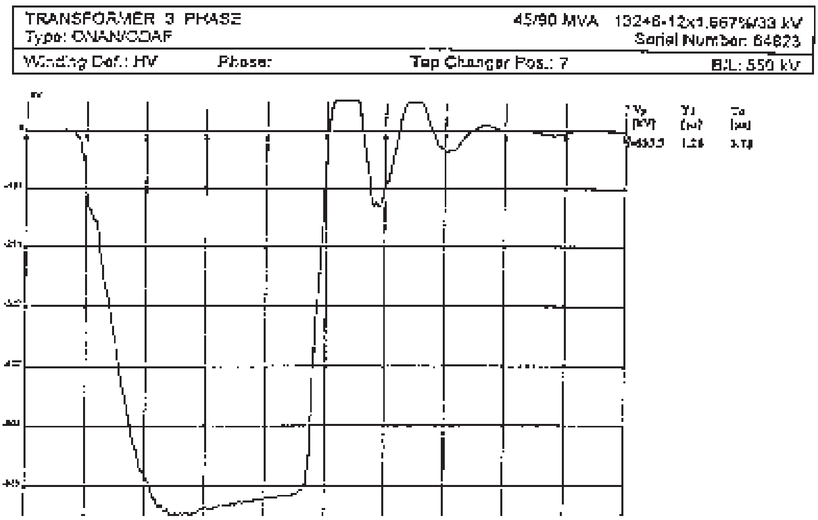


Figure 4.36 Chopped-wave impulse test record for 132/33 kV transformer

with dielectric testing of transformers, now specifies that the chopped-wave tests should be carried out at 100% volts. As far as withstanding the rapidly collapsing voltage wave is concerned, this will, of course, be better dispersed through the winding with a high series capacitance, so that the winding design will follow the same principles as for the full-wave withstand.

4.5 THERMAL CONSIDERATIONS

When the resistive and other losses are generated in transformer windings heat is produced. This heat must be transferred into and taken away by the transformer oil. The winding copper retains its mechanical strength up to several hundred degrees Celsius. Transformer oil does not significantly degrade below about 140°C, but paper insulation deteriorates with greatly increasing severity if its temperature rises above about 90°C. The cooling oil flow must, therefore, ensure that the insulation temperature is kept below this figure as far as possible.

The maximum temperature at which no degradation of paper insulation occurs is about 80°C. It is usually neither economic nor practical, however, to limit the insulation temperature to this level at all times. Insulation life would greatly exceed transformer design life and, since ambient temperatures and applied loads vary, a maximum temperature of 80°C would mean that on many occasions the insulation would be much cooler than this. Thus, apart from premature failure due to a fault, the critical factor in determining the life expectancy of a transformer is the working temperature of the insulation or, more precisely, the temperature of the hottest part of the insulation or *hot spot*. The designer's problem is to decide the temperature that the hot spot should be allowed to reach. Various researchers have considered this problem and all of them tend to agree that the rate of deterioration or ageing of paper insulation rapidly increases with increasing temperature. In 1930, Montsinger [4.1] reported on some of the materials which were then in common use and concluded that the rate of ageing would be doubled for every 8°C increase between 90 and 110°C. Other investigators of the subject found that rates of doubling varied for increases between 5 and 10°C for the various materials used in transformer insulation, and a value of 6°C is now generally taken as a representative average for present-day insulation materials.

It is important to recognise that there is no 'correct' temperature for operation of insulation, nor is there a great deal of agreement between transformer designers as to the precise hot-spot temperature that should be accepted in normal operation. In fact it is now recognised that factors such as moisture content, acidity and oxygen content of the oil, all of which tend to be dependent upon the breathing system and its maintenance, have a very significant bearing on insulation life. Nevertheless BS 171 (IEC 76) and other international standards set down limits for permissible temperature rise which are dictated by considerations of service life and aim at a minimum figure of about 30 years for the transformer. These documents are based on the premise that this will be achieved with an *average* hot-spot temperature of 98°C.

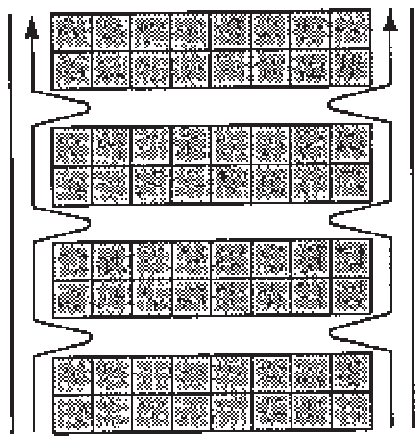
It must also be recognised that the *specified* temperature rise can only be that value which can be measured, and that there will usually be, within the transformer, a hot spot which is hotter than the temperature which can be measured and which will really determine the life of the transformer.

Study of the permitted temperature rises given in BS 171 and IEC 76 shows that a number of different values are permitted and that these are dependent on the method of oil circulation. The reason for this is that the likely difference between the value for temperature rise, which can be measured, and the hot spot, which cannot be measured, tends to vary according to the method of oil circulation. Those methods listed in BS 171 are:

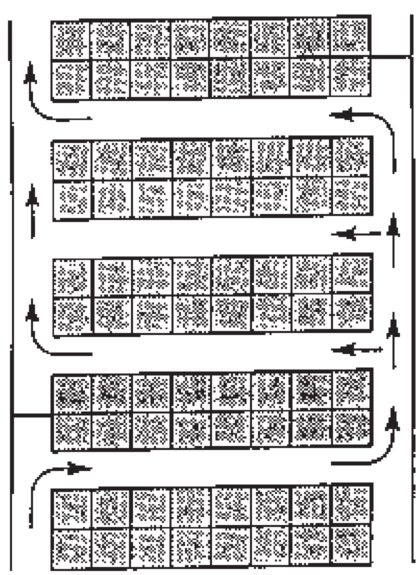
- Natural.
- Forced, but not directed.
- Forced and directed.

Natural circulation utilises the thermal head produced by the heating of the oil which rises through the windings as it is heated and falls as it is cooled in passing through the radiators.

With *forced circulation*, oil is pumped from the radiators and delivered to the bottom of the windings to pass through the vertical axial ducts formed by the strips laid 'above' and 'below' the conductors. In referring to axial ducts within the windings, the expressions 'above' and 'below' mean 'further from the core' and 'nearer to the core' respectively. Radial ducts are those which connect these. In a non-directed design, flow through the radial, horizontal, ducts which connect the axial ducts above and below is dependent entirely on thermal and turbulence effects and the rate of flow through these is very much less than in the axial ducts (*Figure 4.37(a)*). With a forced and directed circulation, oil is fed to a manifold at the bottom of the windings and thence in appropriate proportions to the individual main windings. *Oil flow washers* are inserted at intervals in the winding which alternately close off the outer



(a) Non-directed flow



(b) Directed flow

Figure 4.37 Directed and non-directed oil flow and then the inner axial ducts so that the oil in its passage through the winding must weave its way through the horizontal ducts thus ensuring a significant oil flow rate in all parts of the winding. This arrangement is illustrated in *Figure 4.37(b)*. The rate of heat transfer is very much a function of the rate of oil flow so that the directed oil flow arrangement will result in a lower winding to oil differential temperature or *gradient*. Typical values of gradient will be discussed shortly.

The designer generally aims to achieve a 'balanced' design, in which both top oil temperature rise and temperature rise by resistance for LV and HV windings approach reasonably close to the specified maxima by control of the winding gradient. If the gradient is 'too high' it will be necessary to limit the top oil temperature rise to ensure that the permitted temperature rise by resistance is not exceeded. Given that the oil flow arrangement used will itself be dictated by some other factors, the designer's main method of doing this will be by adjustment of the number of horizontal cooling ducts employed in the winding design.

The *average* temperature rise of the winding is measured by its change in resistance compared with that measured at a known ambient temperature. There are many reasons why the temperature rise in some parts of the winding will differ significantly from this average, however, and, while some of the differences can be accurately estimated, there are others which are less easily predicted. For example, some of the winding at the bottom of the leg is in cool oil and that at the top of the leg will be surrounded by the hottest oil. It is a relatively simple matter to measure these two values by placing a thermometer in the oil at the top of the tank near to the outlet to the coolers and another at the bottom of the tank. The average oil temperature will be halfway between these two values and the *average* gradient of the windings is the difference between average oil temperature rise and average winding temperature rise, that is, the temperature rise determined from the change of winding resistance. The temperature of the hottest part of the winding is thus the sum of the following:

- Ambient temperature.
- Top oil temperature rise.
- Average gradient (calculable as indicated above).
- A temperature equal to the difference between maximum and average gradient of the windings (hot-spot factor).

It will be seen that this is the same as the sum of:

- Ambient temperature.
- Temperature rise by resistance.
- Half the temperature difference between inlet oil from cooler and outlet oil to cooler.

- Difference between maximum and average gradient of the windings, as above.

This latter sum is, on occasions, a more convenient expression for hot-spot temperature. In both cases it is the last of these quantities which cannot be accurately determined. One of reasons why there will be a difference between maximum gradient and average gradient will be appreciated by reference to *Figure 4.38* which represents a group of conductors surrounded by vertical and horizontal cooling ducts. The four conductors at the corners are cooled directly on two faces, while the remainder are cooled on a single face only. Furthermore, unless the oil flow is forced and directed, not only will the heat transfer be poorer on the horizontal surfaces, due to the poorer oil flow rate, but this oil could well be hotter than the general mass of oil in the vertical ducts. In addition, due to the varying pattern of leakage flux, eddy-current losses can vary in different parts of the winding. Fortunately copper is as good a conductor of heat as it is of electricity so that these differences can be to a large extent evened out. However, in estimating the hot-spot temperature this difference between average and maximum winding gradient cannot be neglected. For many years this was taken to be approximately 10% of the average gradient, that is, the maximum gradient was considered to be 1.1 times the average. It is now suggested that this might have been somewhat optimistic and the 1991 issue of IEC 354, *Guide to Loading of Power Transformers*, concludes that a value of 1.1 is reasonable for small transformers but that a figure of up to 1.3 is more appropriate for medium and large transformers. More will be said on this aspect in Section 8 of Chapter 6.

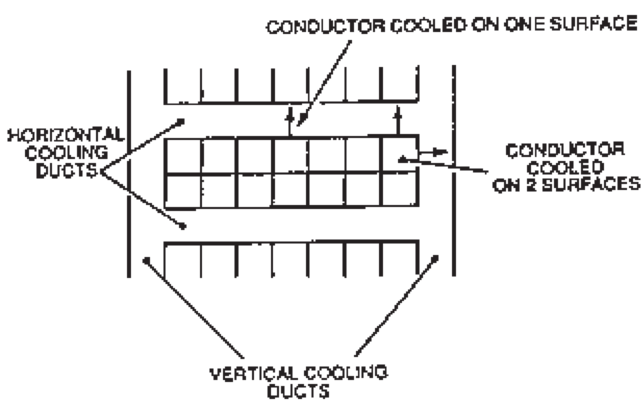


Figure 4.38 Winding hot spots

BS 171, Part 2 and IEC 76, Part 2 deal with temperature rise. In these documents the type of cooling for a particular transformer is identified by means of a code of up to four letters. These are as follows:

The first letter refers to the type of internal cooling medium in contact with the windings. This may be:

O mineral oil or synthetic insulating liquid with a fire point $\leq$300°C
K insulating liquid with fire point >300°C
L insulating liquid with no measurable fire point.

The second letter refers to the circulation mechanism for the internal cooling medium from the options described above:

N *natural* thermosiphon flow through cooling equipment and windings
F *forced* circulation through cooling equipment, thermosiphon through windings
D forced circulation through cooling equipment, *directed* from the cooling equipment into at least the main windings.

Frequently, tapping windings which might contain only 20% of the total ampere-turns and thus have far fewer losses to dissipate than the main windings, will be excluded from the directed flow arrangements and cooled only by natural circulation.

The third letter refers to the external cooling medium, thus:

A air
W water.

The fourth letter refers to the circulation mechanism for the external cooling medium:

N natural
F forced circulation (fans, pumps).

A transformer may be specified to have alternative cooling methods, for example ONAN/ODAF, which is a popular dual rating arrangement in the UK. The transformer has a totally self-cooled or ONAN rating, usually to cover base load conditions and a forced cooled ODAF rating achieved by means of pumps and fans to provide for the condition of peak load. A ratio of one to two between the ONAN and ODAF ratings is common.

For normal ambient conditions, which are defined in BS 171, Part 2, as air never below −25°C and never hotter than +40°C, not exceeding +30°C average during the hottest month and not exceeding +20°C yearly average, or water never exceeding 25°C at the inlet to oil/water coolers, permitted temperature rises are as follows:

Temperature rise of top oil	60 K
Average winding temperature rise by resistance	
• for transformers identified as ON.. or OF..	65 K
• for transformers identified as OD..	70 K

No tolerances are permitted on the above values.

In all except the smallest transformers cooling of the oil will be by some external means, tubes or radiators mounted on the side of the tank, external banks of separate radiators or even oil/water heat exchangers. If the oil is required to circulate through these coolers by natural thermosiphon, that is, ON.. type cooling is employed, then a fairly large thermal head will be required to provide the required circulation, possibly of the order of 25 K. If the oil is pumped through the coolers, that is, OF.. or OD.. type cooling is employed, then the difference between inlet and outlet oil temperatures might be, typically, 10–15 K. Thus temperatures within designs of each type of transformer, using the second of the two alternative derivations identified above, might typically be:

Type of cooling	ODAF	ONAN
(a) Ambient (BS 171)	30	30
(b) Temperature rise by resistance (BS 171)	70	65
(c) Half (outlet–inlet) oil	8	12
(d) Maximum gradient–average gradient, typical value	4	5
Hot spot temperature	112	112

The differences between maximum and average gradient are estimates simply for the purpose of illustration. The value has been taken to be less for the ODAF design on the basis that there are likely to be fewer inequalities in oil flow rates. The fact that the hot-spot temperature is the same in both cases is coincidence.

For each of the above arrangements the permitted top oil rise according to BS 171 is 60 °C, so the mean oil rises could be $(60 - 8) = 52°C$ and $(60 - 12) = 48°C$ respectively for the ODAF and ONAN designs. Since temperature rise by resistance is mean oil temperature rise plus gradient, it would thus be acceptable for the winding gradient for the ODAF design to be up to 18°C and for the ONAN design this could be up to 17°C. This is, of course, assuming 'balanced' designs as defined above. It should be remembered that, if one of the windings is tapped, the transformer is required to deliver full rating on the maximum minus tapping and that the BS 171 temperature rise limits must be met on this tapping.

It must be stressed that in the examples given above, items (c) and (d) cannot be covered by specification, they are typical values only and actual values will differ between manufacturers and so, therefore, will the value of hot-spot temperature. It will be noted also that the hot-spot temperatures derived significantly exceed the figure of 98°C quoted above as being the temperature which corresponds to normal ageing. It will also be seen that the figure used for ambient temperature is not the maximum permitted by BS 171, which allows for this to reach 40°C, giving a hot-spot temperature of 122°C in this case. Such temperatures are permissible because the maximum ambient temperature occurs only occasionally and for a short time.

When a transformer is operated at a hot-spot temperature above that which produces normal ageing due to increase in either ambient temperature or loading, then insulation life is used up at an increased rate. This must then be offset by a period with a hot-spot temperature below that for normal ageing, so that the total use of life over this period equates to the norm. This is best illustrated by an example; if two hours are spent at a temperature which produces twice the normal rate of ageing then four hours of life are used in this period. For the balance of those four hours (i.e. $4 - 2 = 2$) the hot-spot must be such as to use up no life, i.e. below 80°C, so that in total four hours life are used up. This principle forms the basis of IEC 354. The subject will be discussed at greater length in Section 8 of Chapter 6. The system works well in practice since very few transformers are operated continuously at rated load. Most transformers associated with the public electricity supply network are subjected to cyclic daily loading patterns having peaks in the morning and afternoon. Many industrial units have periods of light loading during the night and at weekends, and ambient temperatures are subject to wide seasonal variations. In addition, in many temperate countries such as the UK a significant portion of the system load is heating load which is greater in the winter months when ambient temperatures are lower, thus reducing the tendency for actual hot-spot temperatures to reach the highest theoretical levels.

Core, leads and internal structural steelwork

Although the cooling of the transformer windings represents the most important thermal aspect of the transformer design, it must not be overlooked that considerable quantities of heat are generated in other parts. The core is the most significant of these. There is no specified maximum for the temperature rise of the core in any of the international standards. One of the reasons for this is, of course, the practical aspect of enforcement. The hottest part of the core is not likely to be in a particularly accessible location. In a three-phase three-limb core, for example, it is probably somewhere in the middle of the leg to yoke joint of the centre limb. Its temperature could only be measured by means of thermocouple or resistance thermometer, even this exercise would be difficult and the accuracy of the result would be greatly dependent on the manufacturer placing the measuring device in exactly the right location. BS 171 resolves this difficulty by stating that the temperature rise of the core or of electrical connections or structural parts shall not reach temperatures which will cause damage to adjacent parts or undue ageing of the oil. This approach is logical since, in the case of all of these items, temperatures are unlikely to reach such a value as to damage core steel or structural metalwork or even the copper of leads. It is principally the material in contact with them, insulation, or oil, which is most at risk of damage. Hence ‘damage to adjacent parts’ usually means overheating of insulation and this can be detected during a temperature rise test if oil samples are taken for dissolved gas analysis. More will be said about this in Chapter 5, which deals with testing.

Cooling of the core will usually be by natural circulation even in transformers having forced cooling of the windings. The heat to be removed will depend on grade of iron and flux density but direct heat transfer from the core surface to the surrounding oil is usually all that is necessary up to leg widths (frame sizes) of about 600 mm. Since the ratio of surface area to volume is inversely proportional to the diameter of the core, at frame sizes above this the need to provide cooling becomes an increasingly important consideration.

Because the concern is primarily that of overheating of insulation, some users do specify that the maximum temperature rise for the surface of the core should not exceed the maximum temperature permitted for windings. Some users might also agree to a localised hot-spot of 130°C on the surface of very large cores in an area well removed from insulation, on the basis that oil will not be significantly degraded on coming into contact with this temperature provided the area of contact is not too extensive and recognising that cooling of these large cores is particularly problematical. Enforcement of such restrictions, of course, remains difficult.

Cooling of the oil

In discussion of the typical internal temperatures identified above, little has been said about the cooling of the oil, which having taken the heat from the windings and other internal parts, must be provided with means of dissipating this to the atmosphere. In a small transformer, say up to a few kVA, this can be accomplished at the tank surface. As a transformer gets larger, the tank surface will increase as the square of the linear dimension whereas the volume, which is related to rating and thus its capacity for generating losses, will increase in proportion to the cube of this, so the point is soon reached at which the available tank surface is inadequate and other provision must be made to increase the dissipation, either tubes or fins attached to the tank, or radiators consisting of a series of pressed steel 'passes'. While the transformer remains small enough for fins or tubes to be used, heat loss is by both radiation and convection. The radiation loss is dependent on the size of the envelope enclosing the transformer, convection loss is related to the total surface area. The effectiveness of a surface in radiating energy is also dependent on its emissivity, which is a function of its finish. Highly polished light-coloured surfaces being less effective than dull black surfaces. In practical terms, however, investigators soon established that most painted surfaces have emissivities near to unity regardless of the colour of the paint.

It is possible to apply the laws of thermodynamics and heat transfer to the tank and radiators so as to relate the temperature rise to the radiating and convecting surfaces and, indeed, in the 1920s and 1930s when much of the basic ground work on transformer cooling was carried out, this was done by a combination of experiment and theory. Nowadays manufacturers have refined their databases empirically so as to closely relate the cooling surface required to the watts to be dissipated for a given mean oil rise. For the larger sizes of transformer, say, above a few MVA, the amount of convection surface required becomes so large that the radiating surface is negligible by proportion and can thus be neglected. Then it is simply a matter of dividing the total heat to be dissipated by the total cooling surface to give a value of watts per square centimetre, which can then be tabulated against mean oil rise for a given ambient. As an approximate indication of the order of total convection surface required when heat is lost mainly by convection, for a mean oil rise of 50 K in an ambient of 20°C, about 0.03 watts/cm^2 can be dissipated.

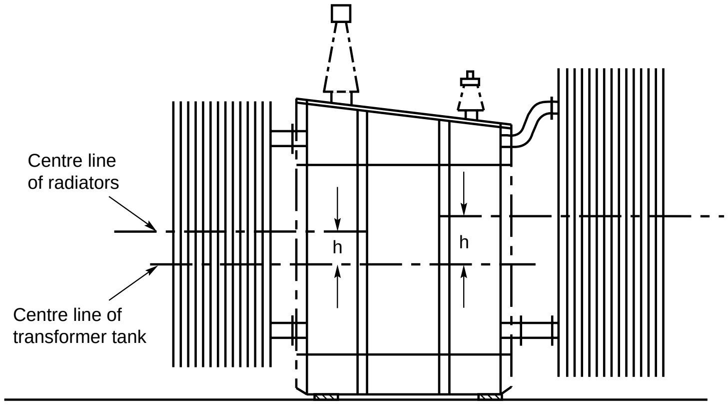
An example can be used to translate this figure into practical terms. Consider a 10 MVA ONAN transformer having total losses on minimum tapping of 70 kW. Let us assume it has a tank 3.5 m long × 3.5 m high × 1.5 m wide.

$$\begin{aligned}
\text{Total cooling surface required at 0.03 watts/cm}^2 &= \frac{70\,000}{0.03} \\
&= 233\ \text{m}^2 \\
\text{Tank surface (sides plus cover)} &= 2(3.5 \times 3.5) + 2(1.5 \times 3.5) + 1.5 \times 3.5 \\
&= 40.25\ \text{m}^2 \\
\text{Hence, net surface of radiators} &= 233 - 40.25 \\
&= 193\ \text{m}^2
\end{aligned}$$

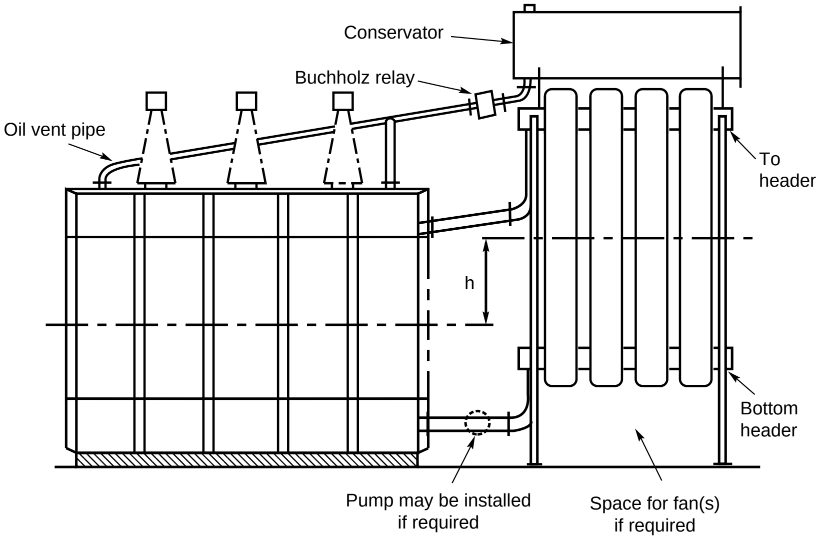
Suppose pressed steel radiators are used 3 m long × 0.25 m wide, these will have a convection surface of approximately 1.5 m^2 per pass, hence $193/1.5 = 129$ passes will be required, or, say, 10 radiators of 13 passes per radiator.

It will be noted that in the above example, the tank is contributing about one-sixth of the total convection surface required. If the transformer were a 30/60 MVA ONAN/ODAF, having total losses at its 30 MVA ONAN rating of 100 kW, then for the same mean oil temperature rise the total convection surface required is about 333 m^2. The tank may have only increased to 4 m long × 3.6 m high × 1.7 m wide, so that it will contribute only 47.8 m^2 or about one-seventh of the area required and, clearly, as unit size increases the contribution from the tank is steadily reduced. At the ODAF rating when fans are brought into service, these will blow the radiator surface much more effectively than they will the tank, even if the radiator banks are tank mounted. Hence, it becomes less worthwhile including the tank surface in the cooling calculations. Additionally, there may be other reasons for discounting the tank, for example it may be necessary to provide an acoustic enclosure to reduce external noise. There can then be advantages in mounting the radiators in a separate bank. Some of these can be seen by reference to *Figure 4.39*.

An important parameter in an ONAN cooling arrangement is the mounting height of the radiators. The greater the height of the horizontal centre line of the radiators in relation to that of the tank, the greater will be the thermosiphon effect creating the circulation of the oil, and the better this circulation, the less will be the difference between inlet and outlet oil temperature. The net effect is to reduce the hot spot temperature rise for the same heat output and effective



(a) Height, 'h' of radiator centre line above tank centre line is a measure of the thermal head available to provide circulation of oil. The use of 'swan-necked' connecting pipes enables radiators to be raised and longer radiators to be used



(b) Provision of separate bank of radiators allows 'h' to be increased considerably

Figure 4.39 Arrangements of cooling radiators

cooling surface area. To fully appreciate this it is necessary to refer back to the derivation of the hot-spot temperature given above. This is related to the *top oil* temperature plus maximum gradient. The area of cooling surface determines the *mean oil* temperature, which is less than top oil by half the difference between inlet and outlet oil. Thus, the smaller this difference, the less will be the amount added to the mean oil temperature to arrive at top oil temperature and the lower will be the hot-spot temperature.

When the radiators are attached to the tank, there is a limit to the mounting height of these, although some degree of swan-neck connection is possible as shown in *Figure 4.39(a)*. If the radiators are separately mounted the height limitation is dictated solely by any restrictions which might be imposed by the location. In addition the tank height ceases to impose a limitation to the length of radiator which can be used and by the use of longer radiators fewer of them may be necessary.

4.6 TAPPINGS AND TAPCHANGERS

Almost all transformers incorporate some means of adjusting their voltage ratio by means of the addition or removal of tapping turns. This adjustment may be made on-load, as is the case for many large transformers, by means of an off-circuit switch, or by the selection of bolted link positions with the transformer totally isolated. The degree of sophistication of the system of tap selection depends on the frequency with which it is required to change taps and the size and importance of the transformer.

At the start, two definitions from the many which are set out in BS 171, Part 1: *principal tapping* is the tapping to which the rated quantities are related and, in particular, the *rated voltage ratio*. This used to be known as normal tapping and the term is still occasionally used. It should be avoided since it can easily lead to confusion. It should also be noted that in most transformers and throughout this book, except where expressly indicated otherwise, tappings are *full-power tappings*, that is, the power capability of the tapping is equal to rated power so that on plus tappings the rated current for the tapped winding must be reduced and on minus tappings the rated current for the winding is increased. This usually means that at minus tappings, because losses are proportional to current squared, losses are increased, although this need not always be the case.

Uses of tapchangers

Before considering the effects of tappings and tapchangers on transformer construction it is first necessary to examine the purposes of tapchangers and the way in which they are used. A more complete discussion of this subject will be found in a work dealing with the design and operation of electrical systems. Aspects of tapchanger use relating to particular types of transformers will be discussed further in Chapter 7, but the basic principles apply to all transformer types and are described below.

Transformer users require tappings for a number of reasons:

- To compensate for changes in the applied voltage on bulk supply and other system transformers.
- To compensate for regulation within the transformer and maintain the output voltage constant on the above types.

- On generator and interbus transformers to assist in the control of system VAr flows.
- To allow for compensation for factors not accurately known at the time of planning an electrical system.
- To allow for future changes in system conditions.

All the above represent sound reasons for the provision of tappings and, indeed, the use of tappings is so commonplace that most users are unlikely to consider whether or not they could dispense with them, or perhaps limit the extent of the tapping range specified. However, transformers without taps are simpler, cheaper and more reliable. The presence of tappings increases the cost and complexity of the transformer and also reduces the reliability. Whenever possible, therefore, the use of tappings should be avoided and, where this is not possible, the extent of the tapping range and the number of taps should be restricted to the minimum. The following represent some of the disadvantages of the use of tappings on transformers:

- Their use almost invariably leads to some variation of flux density in operation so that the design flux density must be lower than the optimum, to allow for the condition when it might be increased.
- The transformer impedance will vary with tap position so that system design must allow for this.
- Losses will vary with tap position, hence the cooler provided must be large enough to cater for maximum possible loss.
- There will inevitably be some conditions when parts of windings are not in use, leading to less than ideal electromagnetic balance within the transformer which in turn results in increased unbalanced forces in the event of close-up faults.
- The increased number of leads within the transformer increases complexity and possibility of internal faults.
- The tapchanger itself, particularly if of the on-load type, represents a significant source of unreliability.

One of the main requirements of any electrical system is that it should provide a voltage to the user which remains within closely defined limits regardless of the loading on the system, despite the regulation occurring within the many supply transformers and cables, which will vary greatly from conditions of light load to full load. Although in many industrial systems, in particular, the supply voltage must be high enough to ensure satisfactory starting of large motor drives, it must not be so high when the system is unloaded as to give rise to damaging overvoltages on, for example, sensitive electronic equipment. Some industrial processes will not operate correctly if the supply voltage is not high enough and some of these may even be protected by undervoltage relays which will shut down the process should the voltage become too low. Most domestic consumers are equally desirous of receiving a supply voltage at all times of day and night which is high enough to ensure satisfactory operation of television sets, personal computers washing machines and the like, but not so high as to shorten the life of filament lighting, which is often the first equipment to fail if the supply voltage is excessive.

In this situation, therefore, and despite the reservations concerning the use of tapchangers expressed above, many of the transformers within the public supply network must be provided with on-load tapchangers without which the economic design of the network would be near to impossible. In industry, transformers having on-load tapchangers are used in the provision of supplies to arc furnaces, electrolytic plants, chemical manufacturing processes and the like.

Figure 4.40 shows, typically, the transformations which might appear on a section of public electricity supply network from the generating station to the user. The voltage levels and stages in the distribution are those used in the UK but, although voltage levels may differ to some degree, the arrangement is similar to that used in many countries throughout the world.

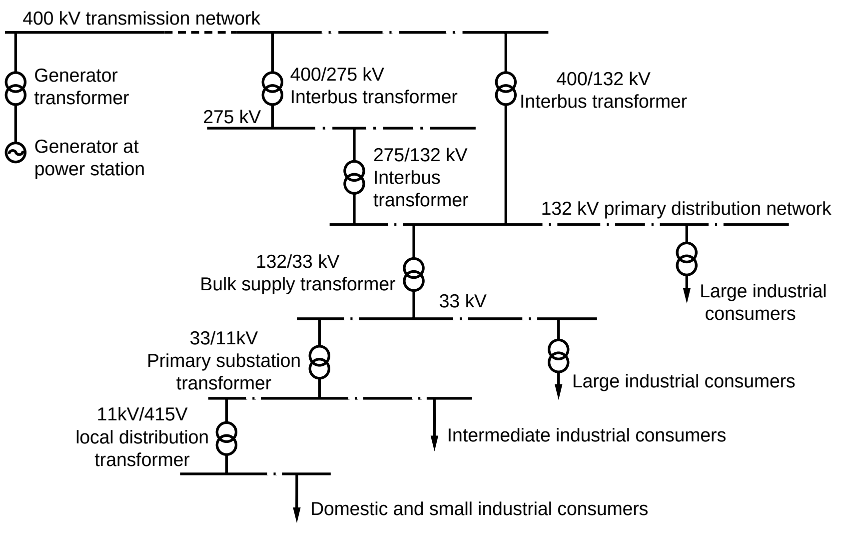
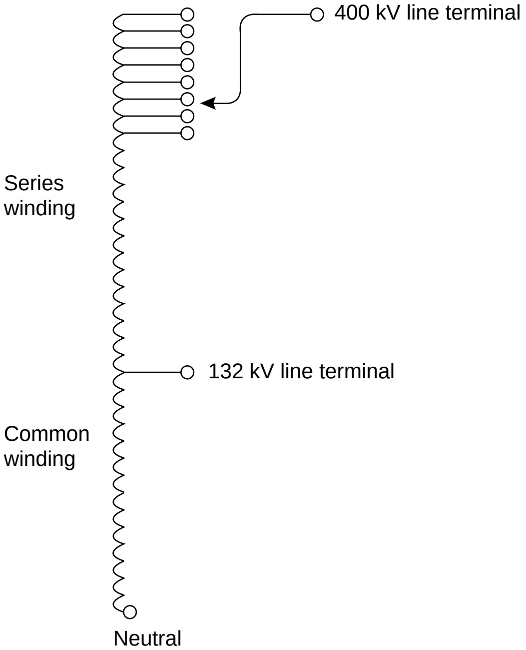


Figure 4.40 Typical public electricity supply network

The generator transformer is used to connect the generator whose voltage is probably maintained within ±5% of nominal, to a 400 kV system which normally may vary independently by ±5% and up to +10% for up to 15 minutes. This cannot be achieved without the ability to change taps on load. However, in addition to the requirement of the generator to produce megawatts, there may also be a requirement to generate or absorb VArs, according to the system conditions, which will vary due to several factors, for example time of day, system conditions and required power transfer. Generation of VArs will be effected by tapping-up on the generator transformer, that is, increasing the number of HV turns for a given 400 kV system voltage. Absorption of VArs will occur if the transformer is tapped down. This mode of operation leads to variation in flux density which must be taken into account when designing the transformer. The subject is fairly complex and will be described in more detail in Section 1 of Chapter 7 which deals specifically with generator transformers.

Interbus transformers interconnecting 400, 275 and 132 kV systems are most likely to be autoconnected. Variation of the ratio of transformation cannot therefore be easily arranged since adding or removing tapping turns at the neutral end changes the number of turns in both windings. If, for example, in the case of a 400/132 kV autotransformer it were required to maintain volts per turn and consequently 132 kV output voltage constant for a 10% increase in 400 kV system voltage then the additional turns required to be added to the common winding would be 10% of the total. But this would be equivalent to $10 \times 400/132 = 30.3\%$ additional turns in the 132 kV winding which would increase its output from 132 to 172 kV. In fact, to maintain a constant 132 kV output from this winding would require the *removal* of about 17.2% of the total turns. Since 10% additional volts applied to 17.2% fewer turns would result in about 33% increase in flux density this would require a very low flux density at the normal condition to avoid approaching saturation under overvoltage conditions, which would result in a very uneconomical design. Tappings must therefore be provided either at the 400 kV line end or at the 132 kV common point as shown in *Figure 4.41*. The former alternative requires the tapchanger to be insulated for 400 kV working but maintains flux density constant for 400 kV system voltage variation, the latter allows the tapchanger to operate at a more modest 132 kV, but still results in some flux density variation. Most practical schemes therefore utilise the latter arrangement. Alternatively these transformers may be used without tapchangers thereby avoiding the high cost of the tapchanger itself as well as all the other disadvantages associated with tapchangers identified above. The ‘cost’ of this simplification of the transformer is some slightly reduced flexibility in the operation of the 275 and 132 kV systems but this can be compensated for by the tappings on the 275/33 or 132/33 kV transformers, as explained below.

In the UK the 400 kV system is normally maintained within $\pm 5\%$ of its nominal value. If the transformers interconnecting with the 275 and 132 kV systems are not provided with taps then the variation of these systems will be greater than this because of the regulation within the interbus transformers. The 275 and 132 kV systems are thus normally maintained to within $\pm 10\%$ of nominal. Hence 275/33 kV and the more usual 132/33 kV bulk supplies transformers must have tapchangers which allow for this condition. If, in addition, these transformers are required to boost the 33 kV system volts at times of heavy loading on the system as described in Chapter 2, i.e. when the 275 or 132 kV system voltage is less than nominal, it is necessary to provide a tapping range extending to lower than -10%, so it is common for these transformers to have tapping ranges of $+10\%$ to -20%. This runs counter



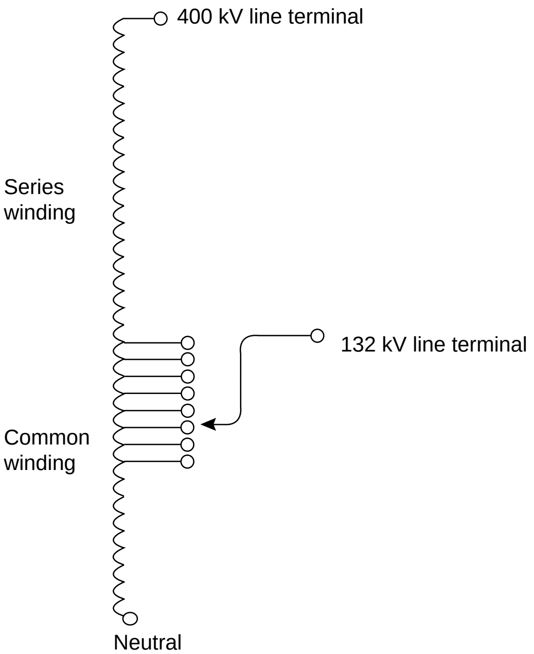


Figure 4.41 Alternative locations for tappings of 400/132 kV autotransformer

to the aim of limiting the extent of the tapping range for high reliability in transformers, identified earlier, but represents another of the complexities resulting from the reduced system flexibility caused by omitting tappings on the 400/132 kV transformers. Clearly tappings at the earthed neutral point of a star-connected 275 or 132 kV winding are likely to be more reliable and less costly than those operating at the 275 or 132 kV line end of a 400/275 or 132 kV interbus transformer.

The greater degree of control which can be maintained over the 33 kV system voltage compared with that for the 132 kV system means that 33/11 kV transformers normally need to be provided with tapping ranges of only ±10%. As in the case of 132/33 kV transformers, however, the HV taps can still be used as a means of boosting the LV output voltage to compensate for system voltage regulation. In this case this is usually achieved by the use of an open-circuit voltage ratio of 33/11.5 kV, i.e. at no load and with nominal voltage applied to the HV the output voltage is higher than nominal LV system volts.

The final transformers in the network, providing the 11/0.433 kV transformation, normally have a rating of 1600 kVA or less. These small low-cost units do not warrant the expense and complexity of on-load tapchangers and are thus normally provided with off-circuit taps, usually at ±2.5% and ±5%. This arrangement enables the voltage ratio to be adjusted to suit the local system conditions, usually when the transformer is initially placed into service, although the facility enables adjustments to be made at a later date should changes to the local system loading, for example, necessitate this.

Impedance variation

Variation of impedance with tap position is brought about by changes in flux linkages and leakage flux patterns as tapping turns are either added or removed

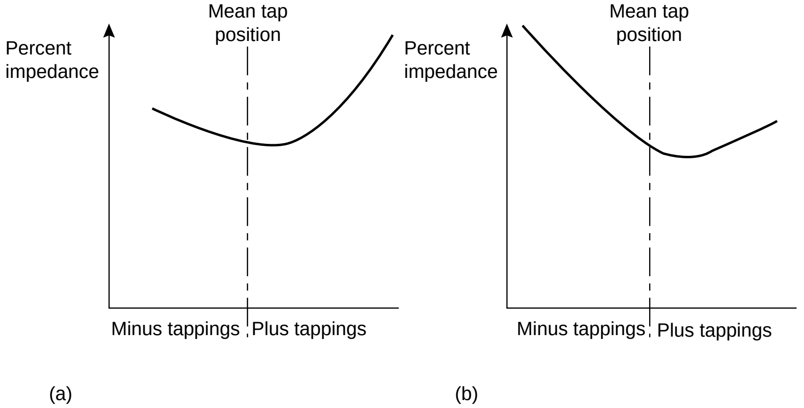


Figure 4.42 Typical variation of impedance with tap position for a two-winding transformer having taps in the body of one of the windings

from the tapped winding. Auxiliary system designers would, of course, prefer to be able to change the voltage ratio without affecting impedance but the best the transformer designer can do is to aim to minimise the variation or possibly achieve an impedance characteristic which is acceptable to the system designer rather than one which might aggravate his problems. It should be noted, however, that any special measures which the transformer designer is required to take are likely to increase first cost and must therefore be totally justified by system needs.

The magnitude and sense of the change depends on the winding configuration employed and the location of the taps. *Figure 4.42* shows typically the pattern of variation which may be obtained, although all of these options may not be available to the designer in every case. *Figures 4.42(a)* and *(b)* represent the type of variation to be expected when the taps are placed in the body of one of the windings.

Figure 4.43 represents a series of sections through the windings of a two-winding transformer having the tappings in the body of the HV winding. In all three cases the HV winding is slightly shorter than the LV winding in order to allow for the extra end insulation of the former. In *Figure 4.43(a)* all tappings are in circuit, *Figure 4.43(b)* shows the effective disposition of the windings on the principal tapping and *Figure 4.43(c)* when all the tappings are out of circuit. It can be seen that, although all the arrangements are symmetrical about the winding centre line and therefore have overall axial balance, the top and bottom halves are only balanced in the condition represented by *Figure 4.43(b)*. This condition will therefore have the minimum leakage flux and hence the minimum impedance. Addition or removal of tappings increases the unbalance and thus increases the impedance. It can also be seen that the degree of unbalance is greatest in *Figure 4.43(c)*, so that this is the condition corresponding to maximum impedance. This enables an explanation to be given for the form of impedance variation shown in *Figure 4.42*. *Figure 4.42(a)* corresponds to the winding configuration of *Figure 4.43*. It can be seen that the tap position for which the unbalance is minimum can be varied by the insertion of gaps in the untapped winding so that the plot can be reversed (*Figure 4.42(b)*) and, by careful manipulation of the gaps at the centre of the untapped winding and the ends of the tapped winding, a more or less symmetrical curve about the mean tap position can be obtained. This is usually the curve which gives minimum overall variation.

From this it will be apparent also that the variation will be reduced if the space which the taps occupy can be reduced to a minimum. While this can be achieved by increasing the current density in the tapping turns, the extent to which this can be done is limited by the need to ensure that the temperature rise in this section does not greatly exceed that of the body of the winding, since this would then create a hot-spot. If it is necessary to insert extra radial cooling ducts in order to limit the temperature rise, then the space taken up by these offsets some of the space savings gained from the increased current density. The designer's control of temperature rise in the taps tends to be

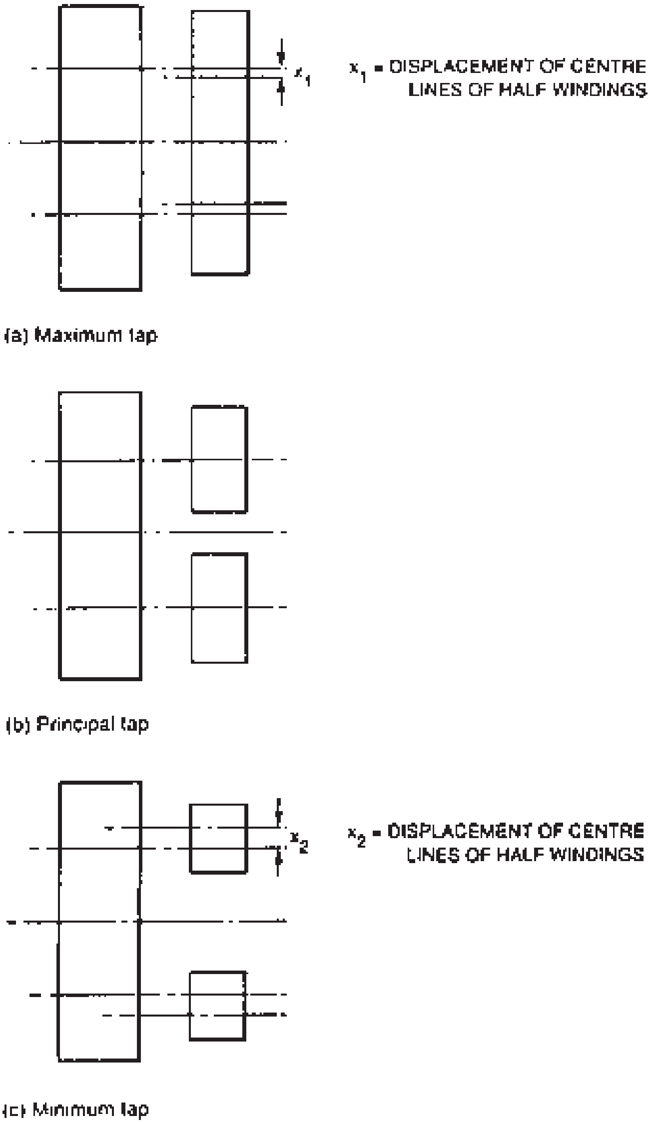


Figure 4.43 Effects of tappings within windings

less than that which can be achieved in the body of the winding, where the designer can vary the number of sections by adjusting the number of turns per section, with a radial cooling duct every one or two sections. In the taps, the turns per section are dictated by the need to ensure that the tapping leads appear at the appropriate position on the outside of a section, hence one tap must span an even number of sections, with a minimum of two.

With the tappings contained in a separate layer the degree of impedance variation throughout the tapping range tends to be less than for taps in the body of the HV winding but the slope of the characteristic can be reversed depending on where the taps are located. This is illustrated by reference to *Figure 4.44* which shows alternative arrangements having HV taps located either outside the main high-voltage winding or inside the low-voltage winding. Ampere-turn distributions for each extreme tap position are shown for both arrangements and also the resulting impedance variation characteristics. The arrangement having the taps located outside the HV winding is most commonly used in the UK and usually the transformer will have a star-connected HV winding

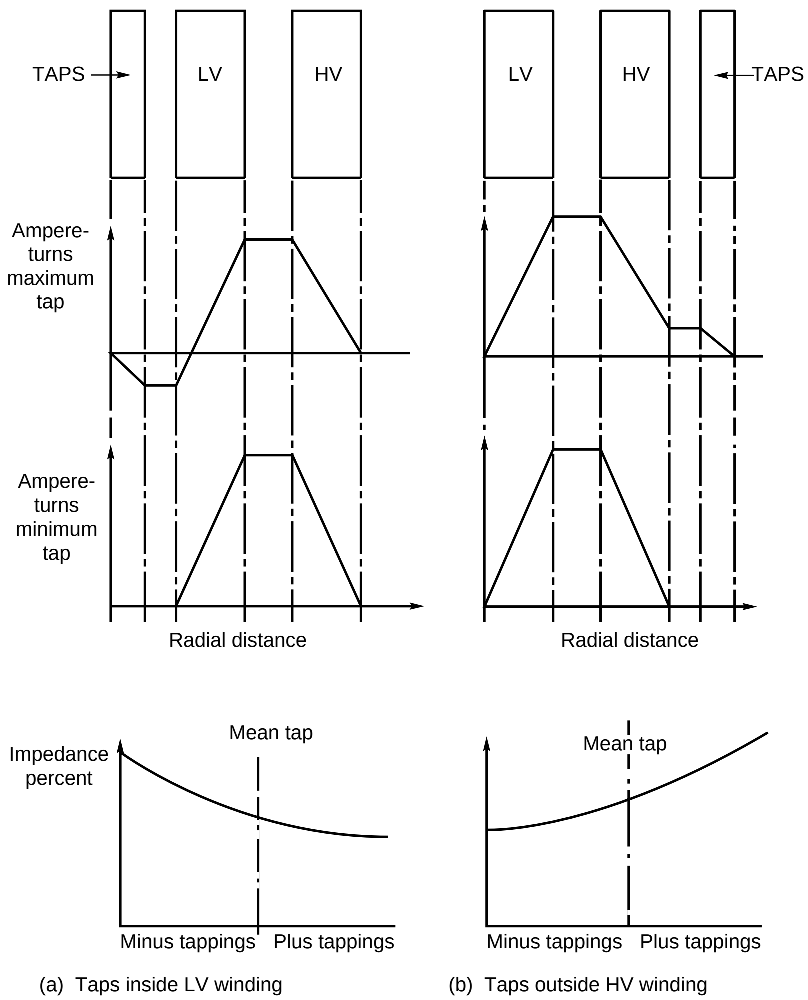


Figure 4.44 Impedance variation with tap position with taps in a separate layer. In both cases HV winding is tapped winding

employing non-uniform insulation. With this arrangement, described earlier in this chapter, the taps will probably have two sections in parallel and a centre gap to accommodate the HV line lead. The impedance characteristic shown in *Figure 4.44(b)* will in this case be modified by the additional distortion of the leakage flux created by the centre gap. This will probably result in an additional component of impedance and a resulting characteristic as shown in *Figure 4.45*.

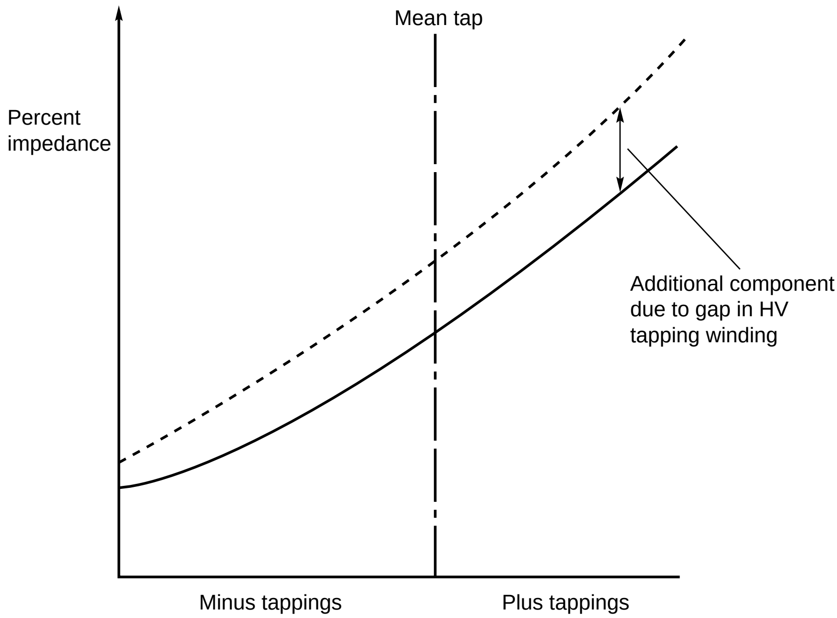


Figure 4.45 Effect of gap in HV tapping winding on percentage impedance

In the arrangements described above all the tappings are configured in a linear fashion, that is, for each increasing tap position an equal number of tapping turns are added. However, if these are contained in a separate layer, it is possible to configure these in a buck/boost arrangement as indicated in *Figure 4.46*. With this arrangement the taps are first inserted with a subtractive polarity, that is, minimum tap position is achieved by inserting all taps in such a sense as to oppose the voltage developed in the main HV winding, these are removed progressively with increasing tap position until on mean tap all tapping turns are out and they are then added in the reverse sense until on maximum tap all are inserted. The advantage of this arrangement is that it reduces the physical size of the tapping winding and also the voltage across the tapping range. The reduction in size is beneficial whether this is placed inside the LV winding or outside the HV winding. In the former case a smaller tap winding enables the diameters of both LV and HV main windings to be

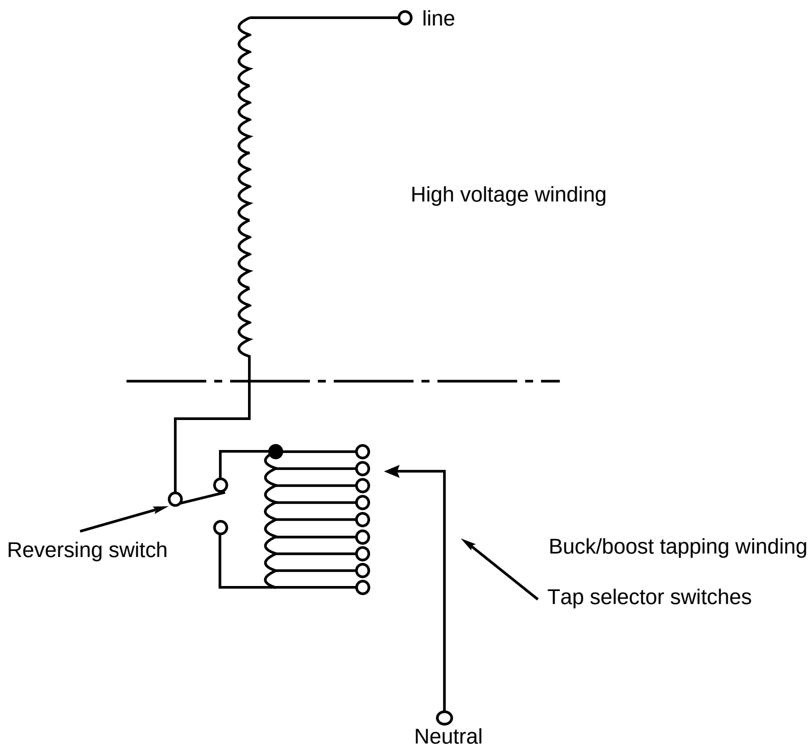
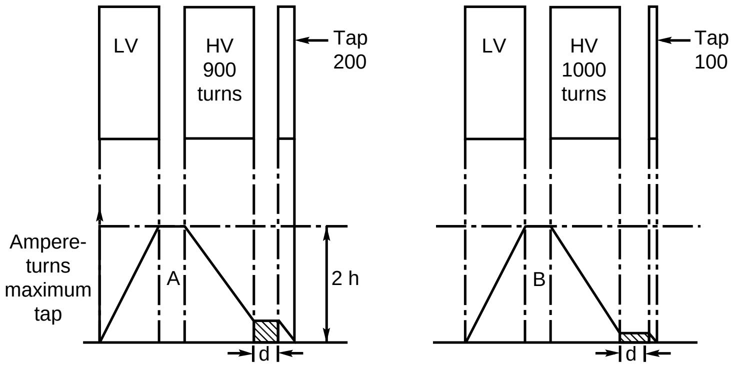


Figure 4.46 Connection of HV tapping winding in buck/boost arrangement

reduced. In both cases it produces a small reduction in impedance, which is often useful in the case of large high-voltage transformers, as well as reducing the number of tapping leads. The reason for the impedance reduction will be apparent from a simple example: a transformer requires 1000 turns on principal tap with a tapping range of ±10%. With a linear arrangement this would have 900 turns in the body of the HV winding and 200 in the tapping winding. This is represented by *Figure 4.47(a)*. If a buck/boost arrangement were used the HV winding would have 1000 turns in the main body and 100 turns in the tapping winding as shown in *Figure 4.47(b)*. Both arrangements utilise the same total number of turns but it is clear that the area of the ampere-turns diagram is less in the case of the buck/boost arrangement. The price to be paid for these benefits is a slightly more complicated and therefore more expensive tapchanger.

Tapchanger mechanisms

The principal of on-load tapchanging was developed in the late 1920s and requires a mechanism which will meet the following two conditions:



(a) Linear tapping arrangement (b) Buck/boost tapping arrangement

Area under ampere-turns curves differs by difference in shaded areas

for A, shaded area is:

$$d \times 2h.\frac{200}{1100}$$

$$= 0.36 \text{ dh}$$

for B, shaded area is:

$$d \times 2h.\frac{100}{1100}$$

$$= 0.18 \text{ dh}$$

Readers may wish to sketch the equivalent diagrams for the minimum tap condition. In this case the tapping winding makes no contribution to the total ampere-turns with the linear arrangement but adds negative ampere-turns with the buck/boost arrangement.

Figure 4.47 Effect of type of tapping winding on impedance

- The load current must not be interrupted during a tapchange.
- No section of the transformer winding may be short-circuited during a tapchange.

Early on-load tapchangers made use of reactors to achieve these ends but in modern on-load tapchangers these have been replaced by transition resistors which have many advantages. In fact, the first resistor-transition tapchanger made its appearance in 1929, but the system was not generally adopted in the UK until the 1950s. In the USA, the change to resistors only started to take place in the 1980s. Despite the fact that it was recognised that resistor transition had advantages of longer contact life, due to the relatively short arcing times associated with unity power factor switching, the centre-tapped reactor-type tapchanger was, in general, more popular because reactors could be designed to be continuously rated, whereas transition resistors had a finite time rating due to the high power dissipated when in circuit. This would have been of little consequence if positive mechanical tapchanger operations could have been assured but, although various attempts at achieving this were generally successful, there were risks of damage if a tapchanger failed to complete its cycle of operation.

With the earlier designs thermal protection arrangements were usually introduced, to initiate the tripping and isolation of the transformer. These early types of tapchangers operated at relatively low speeds and contact separation was slow enough for arcing to persist for several half cycles. Arc extinction finally took place at a current zero when the contact gap was wide enough to prevent a restrike. The arcing contacts were usually manufactured from plain copper.

The mechanical drive to these earlier tapchangers, both resistor or reactor types, was either direct drive or the stored energy type, the stored energy being contained in a flywheel or springs. But such drives were often associated with complicated gearing and shafting and the risk of failure had to be taken into account.

Most of these older designs have now been superseded by the introduction of the high-speed resistor-type tapchanger. Reliability of operation has been greatly improved, largely by the practice of building the stored energy drive into close association with the actual switching mechanism thus eliminating many of the weaknesses of earlier designs. The introduction of copper tungsten alloy arcing tips has brought about a substantial improvement in contact life and a complete change in switching philosophy. It is recognised that long contact life is associated with short arcing time, and breaking at the first current zero is now the general rule.

The bridging resistors are short time rated but with the improved mechanical methods of switch operation and the use of high-performance resistance materials, such as nickel chrome alloy, there is only a negligible risk of resistor damage as the resistors are only in circuit for a few milliseconds. The switching time of a flag cycle, double-resistor tapchanger (see below) is usually less than 75 ms.

A further advantage with high-speed resistor transition is that of greatly improved oil life. The oil surrounding the making and breaking contacts of the on-load tapchanger becomes contaminated with carbon formed in the immediate vicinity of the switching arc. This carbon formation bears a direct relationship to the load current and arcing time and whereas with earlier slow-speed designs the oil had to be treated or replaced after a few thousand operations a life of some 10 times this value is now obtainable.

The mid-point reactor type of tapchanger has some advantages over the high-speed resistor type, the main one being that since the reactor can be left in circuit between taps twice as many active working positions can be obtained for a given number of transformer tappings, giving a considerable advantage where a large number of tapping positions are required and this arrangement is still used by North American manufacturers. A number of special switching arrangements including shunting resistors, and modification to the winding arrangement of the reactor to enable use of vacuum switches, have been introduced to improve contact life where reactors are employed, but there are definite limits to the safe working voltage when interrupting circulating currents.

Recommendations for on-load tapchanging have been formulated as British Standard 4571 (CENELEC HD 367 S2) *On-load tap-changers* which is based on IEC 214 having the same title and IEC 542 *Application Guide for on-load* *tapchangers* and are primarily written to set performance standards and offer guidance on requirements for high-speed resistor-type equipment.

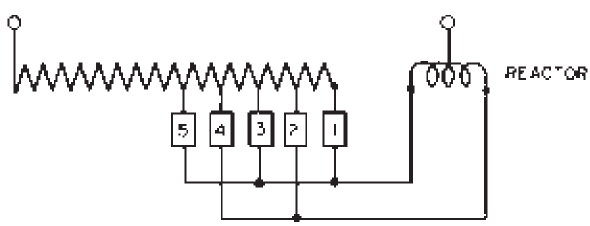
In some of the earliest designs of tapchangers the transformer was equipped with two parallel tapping windings. Each tap winding was provided with a form of selector and an isolating switch. When a tap change was required the isolating switch on one winding was opened, the load being transferred to the other tapping winding, the selector switch on the open circuit winding was then moved to its new position and the isolator reclosed. The second winding was treated in exactly the same manner and the operation was completed when both windings were finally connected in parallel on the new tapping position.

This scheme had the drawback that both halves of the windings were overloaded in turn, and the transformer had to be designed to restrict the circulating current which existed during the out-of-step mid-position. Any failure in the switching sequence or the switch mechanisms could be disastrous.

It is useful to explain the methods of tap changing which have been used in the past and those which are in use today.

On-load tap changing by reactor transition

The simplest form of reactor switching is that shown in *Figure 4.48*. There is only a single winding on the transformer and a switch is connected to each tapping position. Alternate switches are connected together to form two separate groups connected to the outer terminals of a separate mid-point reactor, the windings of which are continuously rated. The sequence of changing taps is shown in the table on the diagram. In the first position, switch No. 1 is closed and the circuit is completed through half the reactor winding.



POSITIONS		1	2	3	4	5	6	7	8	9
SWITCH	1	O	O							
	2		O	O	O					
	3				O	O	O			
	4						O	O	O	
	5								O	O

O INDICATES SWITCH CLOSED

Figure 4.48 On-load tap changing by reactor transition

To change taps by one position, switch No. 2 is closed in addition to switch No. 1, the reactor then bridges a winding section between two taps giving a mid-voltage position. For the next tap change switch No. 1 is opened and switch No. 2 is left closed so that the circuit then is via the second tap on the transformer winding. This particular type of tapchanger necessitates a relatively large number of current breaking switches which in turn produce a bulky unit and consequently a large oil volume is involved.

On-load reactor-type tapchanger using diverter switches

A modified type of reactor tapchanger is shown in *Figure 4.49*. This arrangement uses two separate selectors and two diverter switches. The selectors and diverter switches are mechanically interlocked and the sequence of operation is as follows. A tap change from position 1 to 2 is brought about by opening diverter switch No. 2, moving selector switch No. 2 from tap connection 11 to tapping connection 10 and then closing diverter switch No. 2.

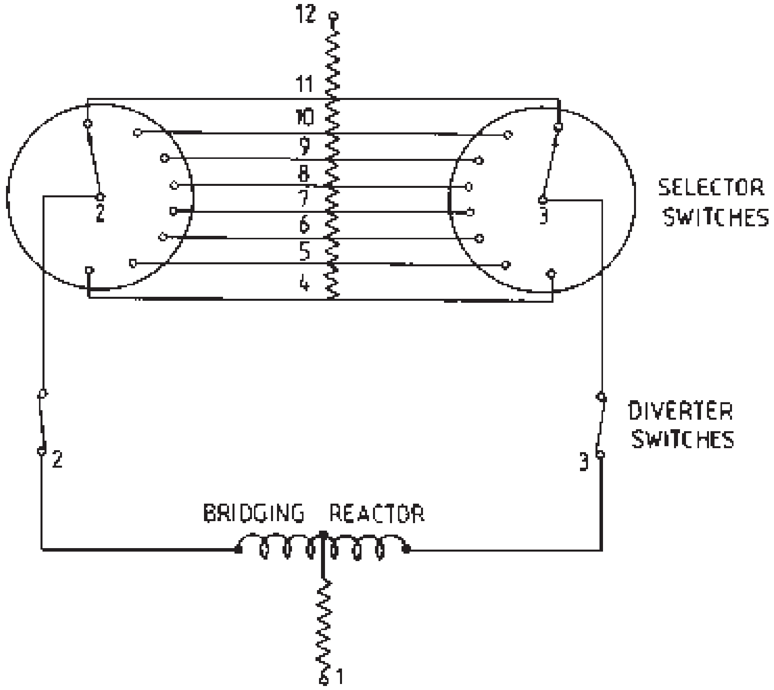
A tap change from position 2 to 3 initiates a similar sequence utilising selector and diverter switches No. 3 in place of switch No. 2.

On-load reactor-type tapchanger with vacuum switch

In some instances it is possible to utilise a vacuum interrupter in conjunction with a redesigned winding arrangement on the reactor-type tapchanger. A typical schematic diagram for this type of unit it shown in *Figure 4.50*.

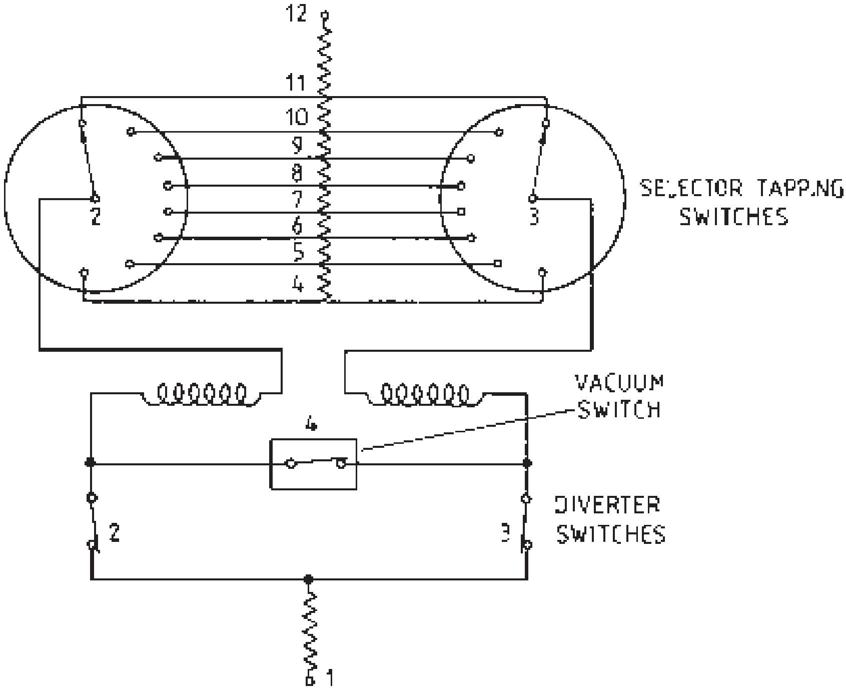
The running position for tap 1 is shown in the diagram with all switches closed. A tap change from tap position 1 to tap position 2 is as follows. Diverter switch No. 2 opens without arcing and the load current flows via selector switch No. 2, vacuum switch No. 4, in parallel with the circuit via diverter switch No. 3, selector switch No. 3 through diverter switch No. 3. Vacuum switch No. 4 opens, selector switch No. 2 moves from tap connection 11 to tap connection 10, vacuum switch No. 4 closes, diverter switch No. 2 closes, completing the tap change to tap position 2. A tap change from tap position 2 to tap position 3 utilises selector No. 3, diverter switch No. 3 and vacuum switch No. 4 in a similar manner to that explained for the movement from tap position 1 to tap position 2.

Whenever vacuum switches are used, the problem of protection against loss of vacuum must be considered. In North America, two approaches to this problem have been considered. The first is the current balance method where a current transformer detects the current flowing through the vacuum switch. If this does not cease on opening the switch mechanically the tapchanger locks out after one tap change during which the selector contact is called upon to break load and circulating currents. The second method utilises a transformer which applies a medium voltage across the vacuum gap between the closed contacts and a special metal contact sheath. If the gap breaks down, a relay ensures that the next tap change does not take place. A series contact disconnects this voltage before each tap change is initiated.



POSITION	CONNECTIONS	
	LEFT HAND SWITCH	RIGHT HAND SWITCH
1	2 – 11	3 – 11
2	2 – 10	3 – 11
3	2 – 10	3 – 10
4	2 – 9	3 – 10
5	2 – 9	3 – 9
6	2 – 8	3 – 9
7	2 – 8	3 – 8
8	2 – 7	3 – 8
9	2 – 7	3 – 7
10	2 – 6	3 – 7
11	2 – 6	3 – 6
12	2 – 5	3 – 6
13	2 – 5	3 – 5
14	2 – 4	3 – 5
15	2 – 4	3 – 4

Figure 4.49 On-load reactor-type tapchanger using diverter switches



POSITION	CONNECTIONS	
	LEFT HAND SWITCH	RIGHT HAND SWITCH
1	2 – 11	3 – 11
2	2 – 10	3 – 11
3	2 – 10	3 – 10
4	2 – 9	3 – 10
5	2 – 9	3 – 9
6	2 – 8	3 – 9
7	2 – 8	3 – 8
8	2 – 7	3 – 8
9	2 – 7	3 – 7
10	2 – 6	3 – 7
11	2 – 6	3 – 6
12	2 – 5	3 – 6
13	2 – 5	3 – 5
14	2 – 4	3 – 5
15	2 – 4	3 – 4

Figure 4.50 On-load reactor-type tapchanger with vacuum switch

Diverter resistor tapchangers

The concept of enclosure of the arc is attractive in many ways since it prevents oil contamination and eliminates the need for a separate diverter switch compartment. Even though the contact life of a high-speed resistor tapchanger is longer than that of a reactor type, the question of using vacuum switching of resistor units has been seriously considered for many years. Several designs have been proposed utilising the principle of removing the vacuum switches from the circuit and thereby from both current and voltage duties between tap changes.

In the USA, on-load tapchangers are frequently fitted on the low-voltage winding, and as stated in Clause 4.2 of ANSI C57.12.30-1977, $32 \times 5/8\%$ steps are quite normal. To meet these conditions it is more economical to use a reactor for the transition impedance and to utilise the bridging position as a tapping. This reduces the number of tapping sections required on the transformer winding. For this purpose, gapped iron-cored reactors with a single

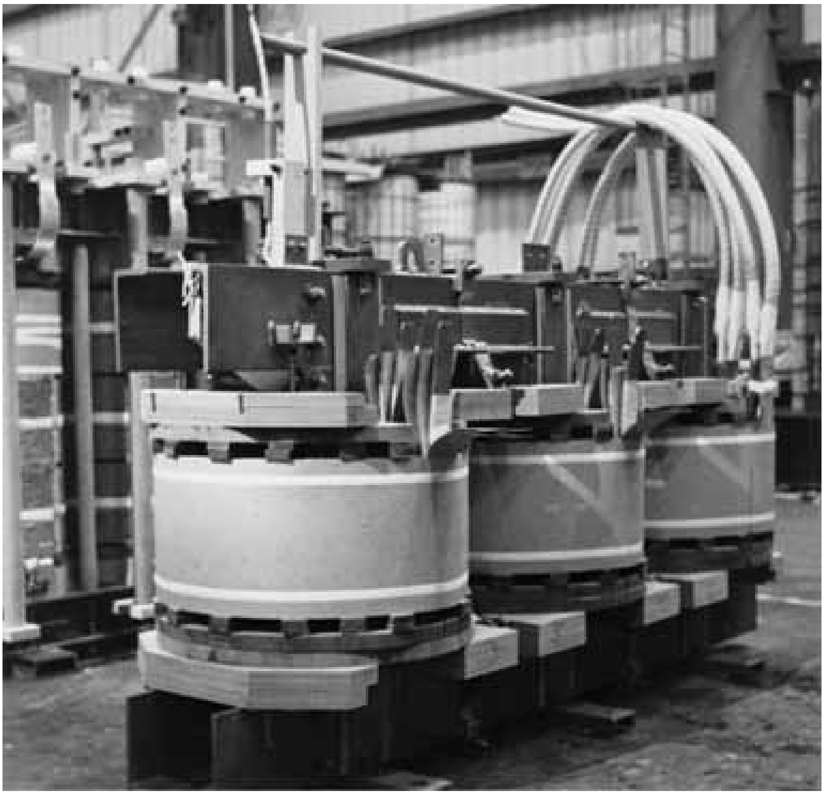


Figure 4.51 Three-phase reactor for a 200 MVA, 230/67 kV autotransformer with tappings at the LV line end (Federal Pacific Electric Co.)

centre-tapped winding are employed. The voltage across the reactor is equal to that of two tapping steps and the magnetising current at that voltage is approximately 40–50% of the maximum load current. *Figures 4.51* and *4.52* illustrate typical examples of North American practice employing reactor on-load tapchangers.

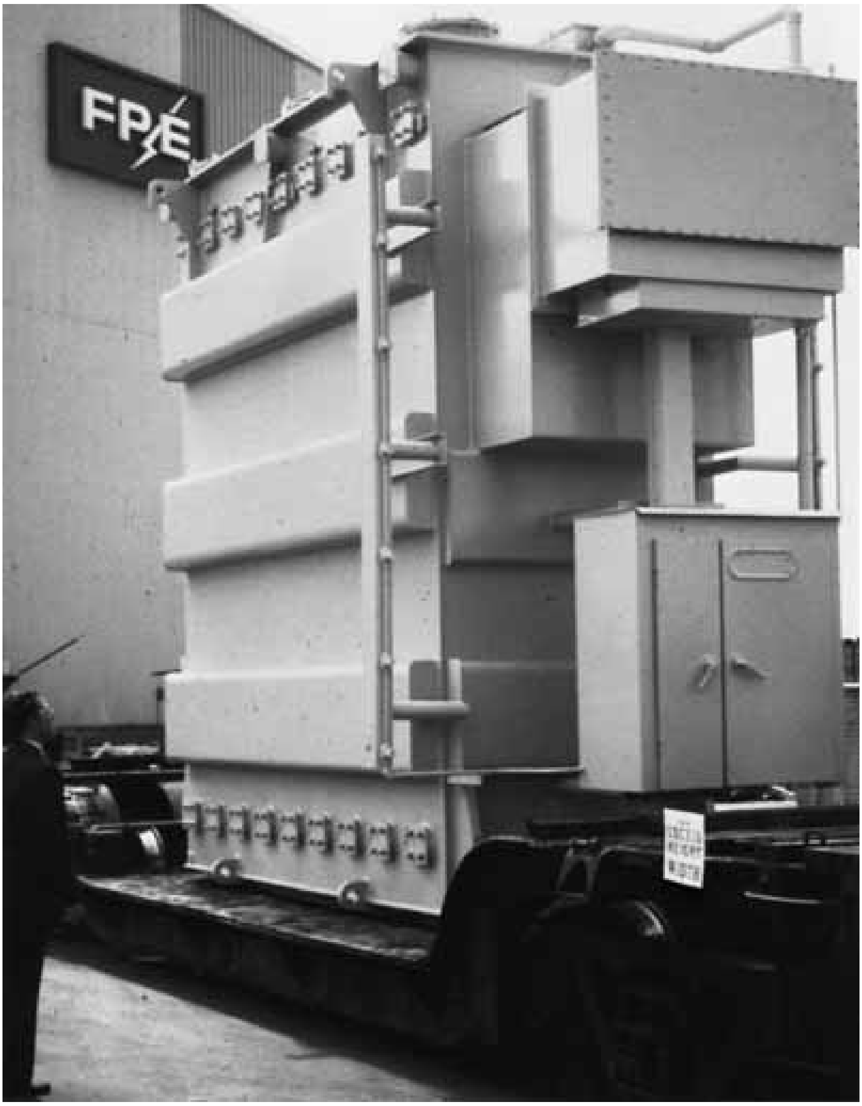


Figure 4.52 120 MVA, 230/13.8 kV, three-phase transformer with reactor pocket and the on-load tapchanger attached to the end of the tank (Federal Pacific Electric Co.)

As previously mentioned, high-speed resistor-type tapchangers have now almost completely superseded the reactor type in many parts of the world since it is easier and more economical to use resistors mounted in the tapchanger and the transformer tank need only be designed to accommodate the transformer core and windings.

In general high-speed diverter resistor tapchangers fall into two categories. The first is referred to as the double compartment type, having one compartment containing the selectors which when operating do not make or break load or circulating currents and a second compartment containing the diverter switches and resistors. It is in this compartment that all the switching and associated arcing takes place and where oil contamination occurs.

It is usual therefore to ensure that the oil in this chamber is kept separated from that in the main transformer tank. Double compartment-type tapchangers can also be considered to be of two types.

(a) In-tank type.
(b) Externally mounted type.

In-tank-type tapchangers

In the UK for many years the practice has been to house even the selector switches, which do not make or break current, in a separate compartment from the main tank so that these are not operating in the same oil as that which is providing cooling and insulation for the transformer. The operating mechanism for the selector switch contacts and the contacts themselves suffer wear and require maintenance, contact pressures have to be periodically checked, and minute metallic particles are produced and contaminate the oil. However, modern selector switch mechanisms have been developed since the early 1960s which need very little maintenance and cause very little oil contamination as a proportion of total quantity of oil in the main tank. These tapchangers have been designed for installation directly in the oil in the main tank, an arrangement which the manufacturers claim is cheaper, although the economic argument is a complex one.

They have the advantage that all tapping leads can be formed and connected to the appropriate selector switch contacts before the transformer is installed in the tank. With the separate compartment pattern, the usual practice is for selector switch contacts to be mounted on a base board of insulating material which is part of the main tank and forms the barrier between the oil in the main tank and that in the selector switch compartment. The tapping leads thus cannot be connected to the selector contacts until the core and windings have been installed in the tank. This is a difficult fitting task, requiring the tapping leads to be made up and run to a dummy selector switch base during erection of the transformer and then disconnected from this before tanking. Once the windings are within the tank, access for connection of the tapping leads is restricted and it is also difficult to ensure that the necessary electrical clearances between leads are maintained. With in-tank tapchangers it is still necessary to keep the diverter switch oil separate from the main-tank oil. This is usually achieved by housing the diverter switches within a cylinder of glass-reinforced resin mounted above the selector switch assembly. When the transformer is installed within the tank, removal of the inspection cover which forms the top plate of this cylinder provides access to the diverter switches. These are usually removable via the top of the cylinder for maintenance and contact inspection. Such an arrangement is employed on the Reinhausen type M series which is a German design, also manufactured in France under licence by the GEC Alsthom group.

Another claimed disadvantage of the in-tank tapchanger is that the selector switch contacts do, in fact, switch small capacitative currents thus generating gases which become dissolved in the oil. These dissolved gases can then cause confusion to any routine oil monitoring programme which is based on dissolved gas analysis (see Section 7 of Chapter 6). In addition it is, of course, necessary to take a drive from the diverter-switch compartment through to the selector switches and this usually requires a gland seal. There have been suggestions that this seal can allow contaminating gases to pass from the diverter-switch compartment into the main tank thus distorting dissolved gas figures. This was such a serious concern of those traditionally preferring separate compartment tapchangers that before acceptance of IEC 214 as a CENELEC harmonisation document an additional test was inserted into the *Service duty test* specification as a demonstration that hydrocarbon gases would not leak through the gland seal. This requires that the tapchanger undergoing service duty testing be placed in a chamber, not exceeding 10 times the volume of the diverter-switch compartment, filled with clean new transformer oil. At the end of the test sequence a sample of oil from this chamber is required to be tested for dissolved hydrocarbon gases which shall not show a total increase greater than 10 ppm (BS 4571: 1994, clause 8.2.1).

An example of an in-tank tapchanger is shown in *Figure 4.53*. The unit illustrated is rated at 300 A and 60 kV and is a three-phase 17-position linear regulator. This type of tapchanger is available for currents up to 500 A and a system voltage of 220 kV. In-tank tapchangers may also be utilised using three separate single-phase units; the advantage of this configuration lies in the fact that the phase to earth voltage only appears across the upper insulated housing which can be extended to provide appropriate insulation levels, while interphase clearances are determined by the design of the transformer. These clearances, together with an increase of the surrounding radial distance from the tank wall permit the working voltage to be extended to higher values more economically for certain applications than is the case with externally mounted tapchangers.

The diverter is designed as a three-pole segmental switch with the three sections spaced 120° apart. The sections of the diverter switches may be connected in parallel for currents up to 1500 A when the switch is used as a single-phase unit. When used on non-uniform insulation star point applications the diverter becomes a complete three-phase switch for currents up to 500 A.

Figure 4.53 Three-phase 300 A, 60 kV, 17 position linear in-tank tapchanger

The whole diverter switch assembly may be lifted out of the upper housing for inspection or contact changing, and this housing is completely sealed from the oil in the main tank with the exception of the drive to the selector switches. The selectors are built in a 'cage' whose vertical insulating bars retain the fixed contacts and the transformer tapping connections are bolted directly to these terminals, with the odd and even selectors concentrically driven by independent Geneva mechanisms. The cage design eliminates the need for a barrier board as on an externally mounted tapchanger, but access to the selectors necessitates removal of part or all of the transformer oil in the main tank.

If required, it is possible to install the equipment with separate tanks and barrier boards to improve selector accessibility but, of course, the main benefit of using an in-tank tapchanger is lost. *Figure 4.54* illustrates an in-tank type tapchanger mounted from the tank cover and showing the leads from the HV winding.

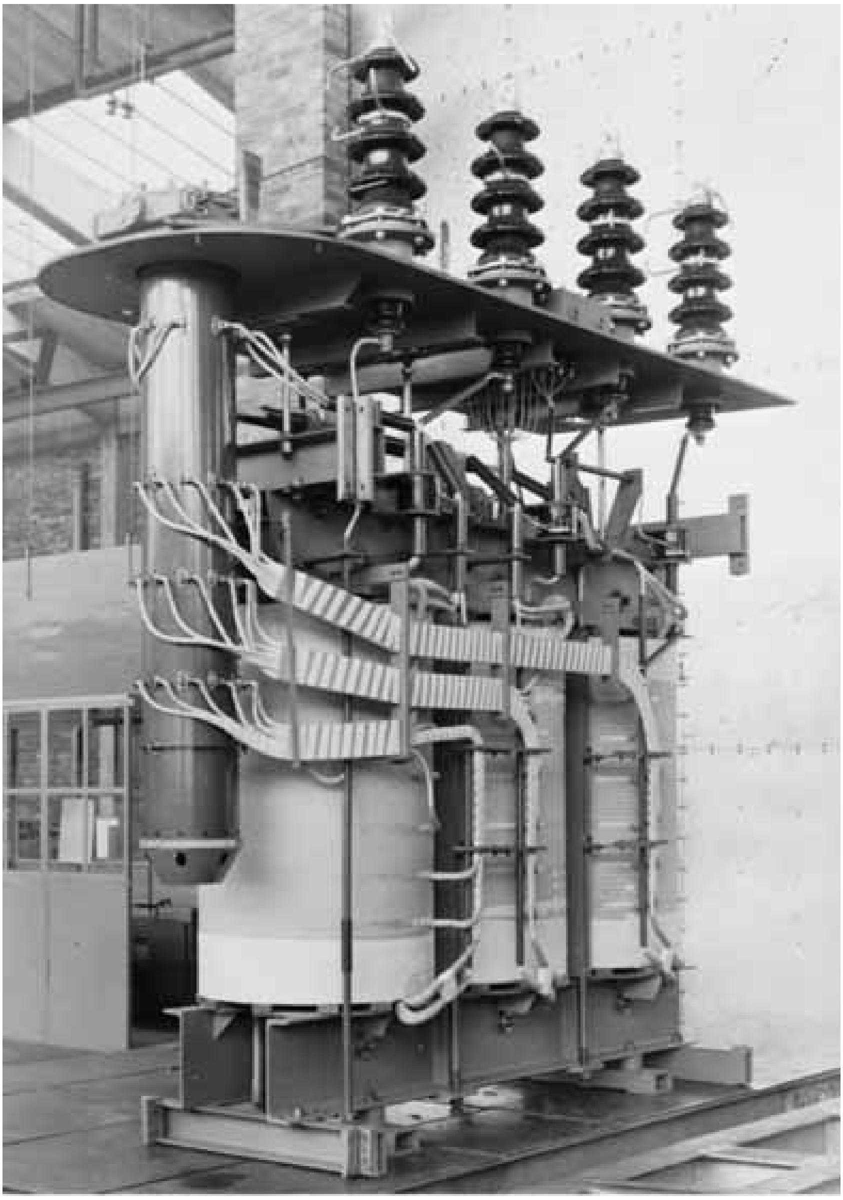


Figure 4.54 20 MVA, 33/11 kV three-phase core and windings fitted with an in-tank tapchanger (Bonar Long Ltd)

High-speed resistor tapchangers can be divided into two types, those which carry out selection and switching on the same contacts and generally use one resistor, and others which have selectors and separate diverter switches and which normally use two resistors. With a single resistor, load current and resistor circulating current have to be arranged to be subtractive, which dictates use with unidirectional power flow or reduced rating with reverse power flow. When two resistors are employed the duty imposed on the diverter switch is unchanged by a change in the direction of power flow. Recently versions of the combined diverter/selector types have been developed having double resistors and thus overcoming the unidirectional power flow limitation.

The two types fall into two classes, single and double compartment tapchangers. Most designs of the single compartment type employ a rotary form of selector switch and *Figure 4.55* shows diagrammatically the various switching arrangements for resistor-type changers. *Figure 4.55(a)* illustrates the method employed for the single compartment tapchanger and is known as the *pennant cycle*, while *Figures 4.55(b)* to *(d)* show the connections when two resistors and separate diverter switches are employed and is known as the *flag cycle*. (The derivation of the terms ‘flag cycle’ and ‘pennant cycle’ and the precise definition of these terms are explained in BS 4571. They arise from the appearance of the phasor diagrams showing the change in output voltage of the transformer in moving from one tapping to the adjacent one. In the ‘flag cycle’ the change of voltage comprises four steps, while in the ‘pennant cycle’ only two steps occur.)

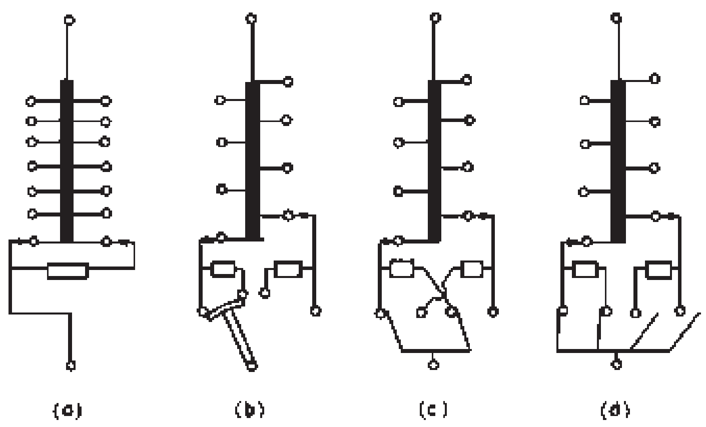


Figure 4.55 Types of resistor transition tap changing. (a) Pennant cycle; (b), (c) and (d) flag cycle

Single compartment tapchangers were largely developed in order to provide an economical arrangement for medium-sized local distribution transformers. On larger transformers, for example those used at bulk supply points, the on-load tap changing equipment is usually the double compartment type with separate tap selectors and diverter switches. The tap selectors are generally arranged in a circular form for a reversing or coarse/fine configuration, but are generally in line or in a crescent arrangement if a linear tapping range is required.

Figure 4.56 illustrates a double resistor-type tapchanger and a typical schematic and sequence diagram arrangement is shown in *Figure 4.57*. Switches $S1$ and $S2$ and the associated tapping winding connections are those associated with the selectors. These selectors are the contacts which do not make or break current and therefore can be contained in transformer oil fed from the main tank conservator. $M1$, $M2$, $T1$, $T2$, $R1$, $R2$ are the components of the diverter switch. Mounted on the diverter switch also are the main current-carrying contacts which, like the selector switches, do not make or break current.

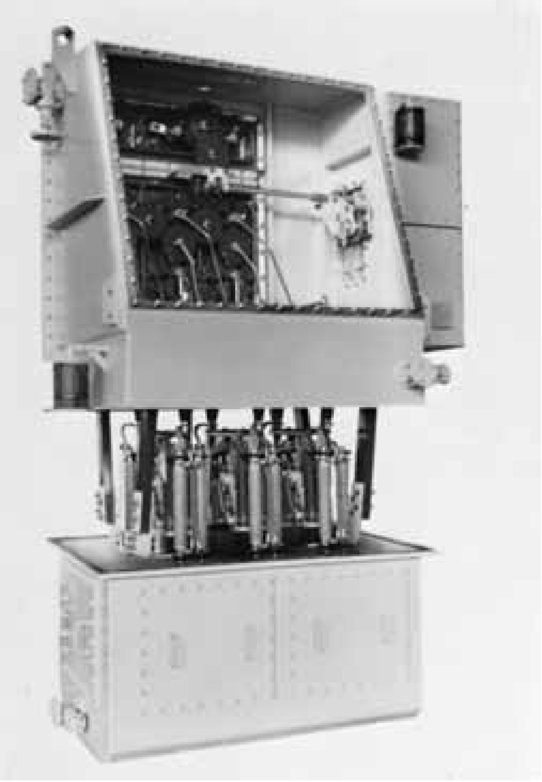


Figure 4.56 Three-phase 400 A, 44 kV high-speed resistor-type double compartment tapchanger with the diverter tank lowered (Associated Tapchangers Ltd)

The schematic diagram indicates that the right-hand selector switch $S1$ is on tap position 1 and the left-hand selector switch $S2$ is on tap 2 while the diverter switch is in the position associated with tap 1. A tap change from

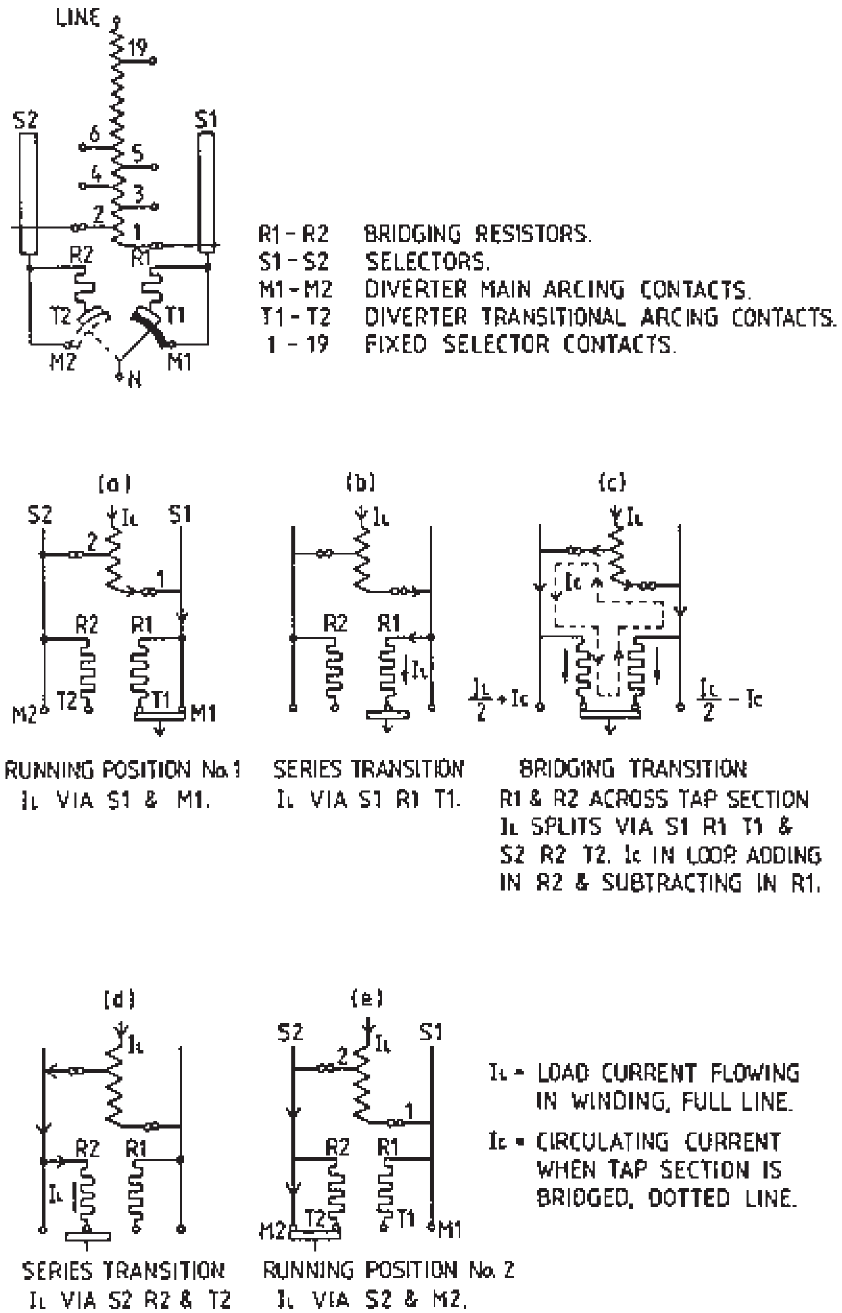


Figure 4.57 Typical schematic and sequence diagram of a double resistor-type tapchanger

position 1 to 2 requires a movement of the diverter switch from the right-hand side to the left side while a further tap change from tap position 2 to tap position 3 requires a movement of selector switch $S1$ from position 1 to position 3 before the diverter switch moves from the left-hand side to the right side. In order to produce this form of sequence the tapchanger utilises a mechanism known as a lost motion device. The sequence diagram assumes the tapchanger to be fitted to the neutral end of the HV winding of a step-down transformer.

Load current flows from the main winding through $S1$ and $M1$ of the diverter switch to the neutral. Initiation of a tap change causes the moving arcing contact to move from the right-hand side to the left-hand side. At (*b*) the moving contact has opened contact with the main fixed arcing contact I; arcing will continue across the gap between these two contacts until the first current zero is reached. After this the current will flow through the diverter resistor $R1$. This current passing through $R1$ induces a recovery voltage between $M1$ and the moving arcing contact. The value of the recovery voltage is $I_L R1$. Although initial examination at this point would suggest that the value of $R1$ be kept as low as possible in order to keep the recovery voltage down to a relatively low value, an examination at other positions produces a conflicting requirement to minimise the circulating current by maximising the resistor value, and therefore the actual value of the diverter resistor is a compromise.

At (*c*) the moving arcing contact is connected to both transition resistors $R1$ and $R2$. A circulating current now passes between tap position 2 and tap position 1 via $R2-R1$. The value of this circulating current is the step voltage between tap positions 2 and 1 divided by the value of $R1$ plus $R2$. Hence there is a requirement to make $R1$ plus $R2$ as high as possible to limit the circulating current.

At (*d*) the moving contact has now moved far enough to have broken contact with $T1$. Arcing will again have taken place between these two contacts until a current zero is reached. The recovery voltage across this gap will be the step voltage between the tap positions 2 and 1 minus the voltage drop across $R2$. It should be noted that when changing from tap 1 to tap 2 (*b*) produces a similar condition to that which occurs at (*d*) but the recovery voltage between the transition contact of $R2$ and the moving contact is the step voltage plus the voltage drop across $R1$. At (*e*) on the sequence diagram the tap change has been completed and load current I_L is now via $S2-M2$ to the neutral point of the winding.

If the sequence is continued through to the end of the tapping range it can be seen that the more onerous conditions of current switching and high recovery voltages occur on alternate sides. Should the power flow be reversed the same conditions will apply but occur on the other alternate positions of switching. The diagram shown for the movement between two tap positions is of the same configuration shown in IEC 214 for the flag cycle. For the single compartment tapchanger using only one diverter resistance there is considerable difference between that sequence and that of the double resistor unit.

Referring to *Figure 4.58* an explanation of the single resistor switching sequence is as follows. Assuming that the tapchanger is in the neutral end of the HV winding of a step-down transformer then position (*a*) is the normal operating position 1. Initiation of a tap change movement causes the transitional arcing contact to make connection with the fixed arcing contact of

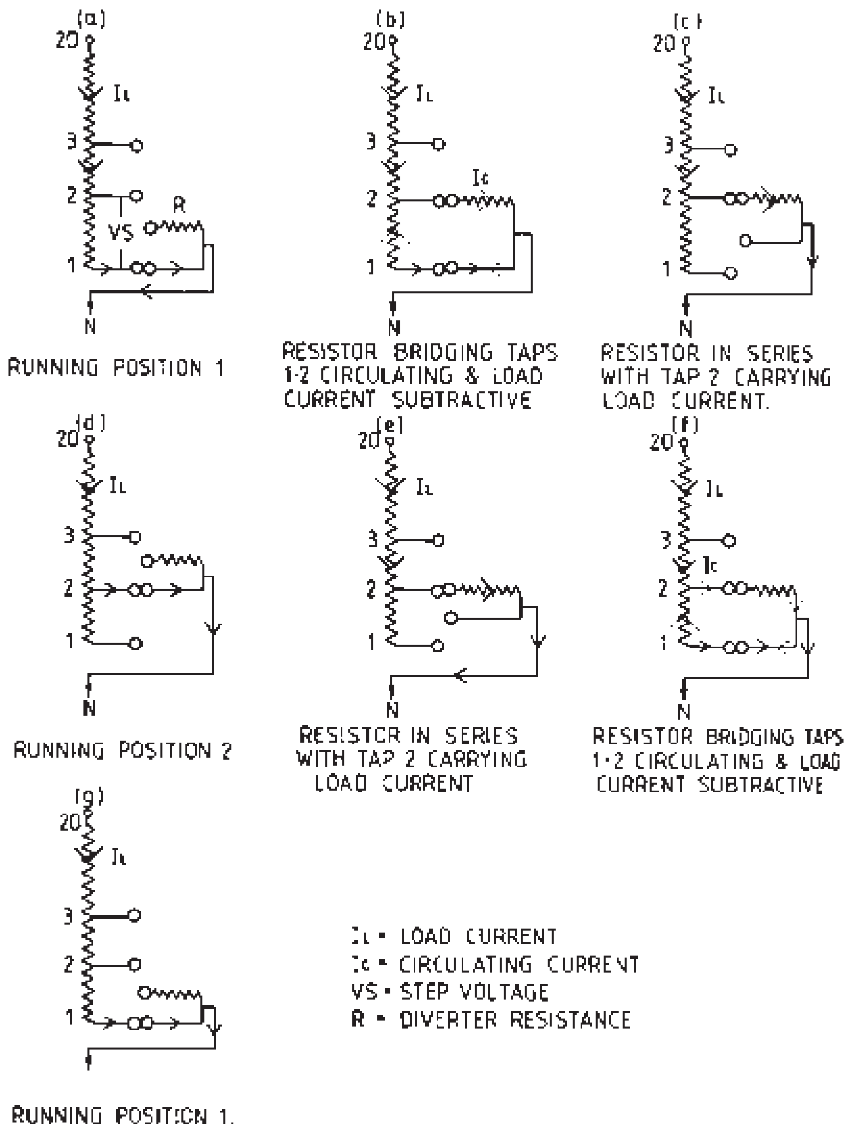


Figure 4.58 Typical schematic and sequence diagram of a single resistor-type tapchanger

tap position 2, the load current still passing to the neutral via tap position 1 but a circulating current now flows from tap position 2 to tap position 1. Diagram (c) now shows the position when the main arcing contact has left tap position 1, and it should be noted that the current interrupted by the opening of these contacts is the difference between I_L and I_c, the load and the circulating currents. The recovery voltage between the moving arc contact is the step

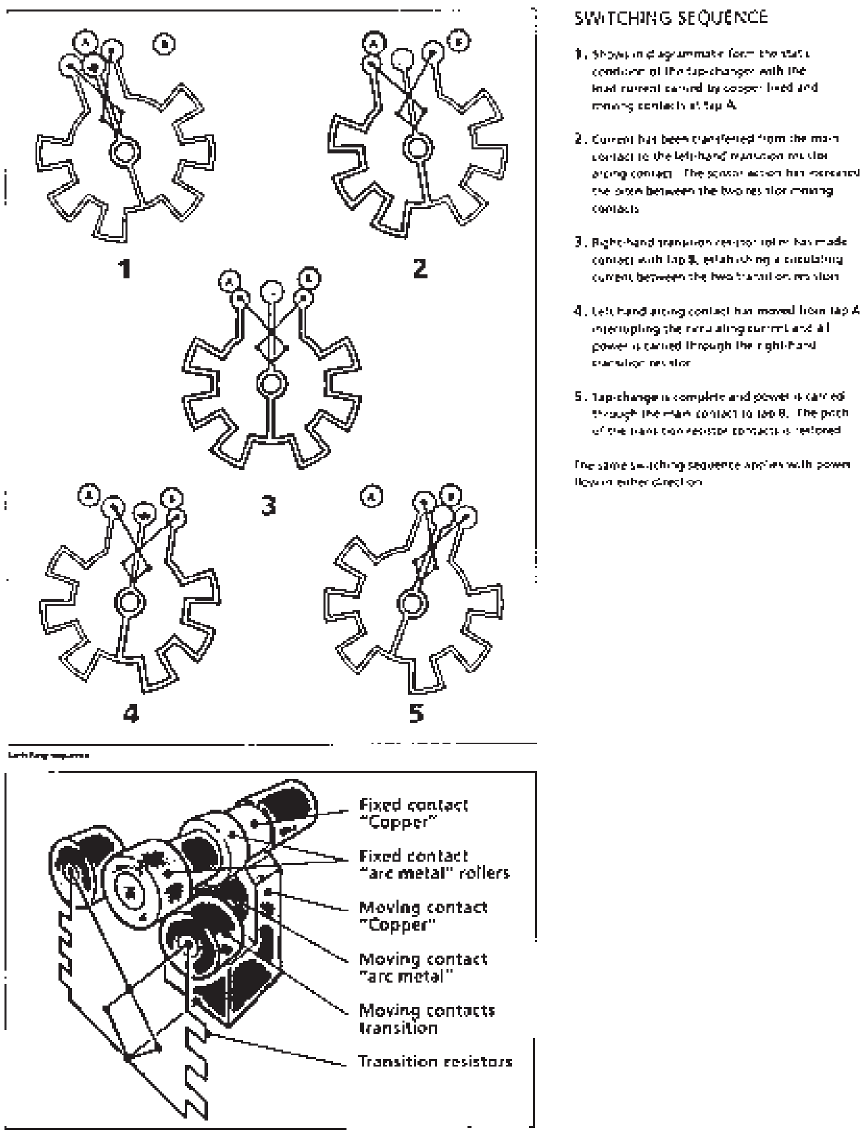


Figure 4.59 switching sequence for single compartment tapchanger (Associated Tapchangers)

voltage minus $I_L R$, the voltage drop across the diverter resistance. The main arcing contact continues its movement until it too makes connection with the fixed arcing contact of tap position 2; when this is achieved the load current now flows to the neutral via tap position 2 and the transitional arcing contact moves to an open position.

There is a difference of function when moving from a higher voltage tapping position to a lower position and this is explained as follows. Diagram (*d*) is the normal operating position for tap 2. When a tap change is initiated the transitional arcing contact moves from its open position to tap position 2, the main arcing contact moves off towards tap position 1. When it leaves tap position 2 arcing takes place, the current interrupted is I_L, and the recovery voltage between the main arcing moving contacts and the tap position 2 is $I_L R$.

Diagram (*f*) shows the condition when the main moving arcing contact has made connection at tap position 1, load current flow is via the main winding and tap position 1 to the neutral. Circulating current flows from tap position 2 to tap position 1; thus when the transitional moving contact leaves tap position 2 the current interrupted is the circulating current and the recovery voltage is the step voltage.

Figure 4.59 shows the switching sequence for a single compartment tapchanger which uses double resistor switching. Diagram (*a*) shows the condition with the transformer operating on tap position 1 with the load current carried by fixed and moving contacts. The first stage of the transition to tap position 2 is shown in diagram (*b*). Current has been transferred from the main contact to the left-hand transition resistor arcing contact and flows via resistor R_1. The next stage is shown in diagram (*c*) in which the right-hand transition contact has made contact with the tap 2 position. Load current is now shared between resistors R_1 and R_2 which also carry the tap circulating current. In diagram (*d*) the left-hand arcing contact has moved away from tap 1 interrupting the circulating current and all load current is now carried through the transition resistor R_2. The tap change is completed by the step shown in diagram (*e*) in which main and transition contacts are all fully made on tap 2. A single compartment tapchanger utilising this arrangement is shown in *Figure 4.60*.

As indicated above, when the tapping range is large or the system voltage very high, thus producing a considerable voltage between the extreme tappings, it is an advantage to halve the length of the tapping winding and to introduce a reversing or transfer switch. This not only halves the number of tappings to be brought out from the main winding of the transformer but also halves the voltage between the ends of tapping selector switch as shown in *Figure 4.61*.

In diagram B the tapped portion of the winding is shown divided into nine sections and a further untapped portion has a length equal to 10 sections. In the alternative diagrams C and D a section of the transformer winding itself is reversed. The choice of the tapchanger employed will depend on the design of the transformer. In diagrams A, B and C the tappings are shown at the neutral

Figure 4.60(a) A small single compartment tapchanger suitable for 300 A, 44 kV, 66 kV and 132 kV applications (Associated Tapchangers)

end of the star-connected winding and in diagram D the tapchanger is shown connected to an autotransformer with reversing tappings at the line end of the winding.

In the three examples where a changeover selector is shown, the tapping selectors are turned through two revolutions, one revolution for each position of the changeover selectors, thus with the circuits shown 18 voltage steps would be provided.

As also mentioned previously variation of impedance over the tapping range can often be reduced by the use of reversing arrangements or the coarse/fine switching circuits described earlier.

The working levels of voltage and the insulation test levels to which the tapping windings and thus the on-load tapchanger are to be subjected will have a great deal of bearing on the type of tapchanger selected by the transformer designer. It will be readily appreciated that a tapchanger for use at the line end of a transformer on a 132 kV system will be a very different type of equipment from an on-load tapchanger for use at the grounded neutral end of a star-connected 132 kV winding. The test levels to which both of these on-load tapchangers are likely to be subjected vary considerably as shown by the values given in *Table 4.1*.

Figure 4.60(b) 1 phase of moving selector switch assembly for above tapchanger showing scissor contact mechanism and change over selector (at top) for coarse/fine or reversing regulation. (Associated Tapchangers)

The test figures for the 132 kV line end as taken from the insulation test levels (line end) for windings and connected parts designed for impulse voltage tests given in IEC 76 are given in *Table 4.1*.

Figures 4.62 and 4.63(a) indicate the basic difference due to the insulation requirements between an earthed neutral end tapchanger for a 132 kV system compared with a line end tapchanger for the same voltage. In *Figure 4.62* the selectors are in the compartment which runs along the side of the transformer and the diverter switch compartment is mounted at the end of the selector compartment. Examination of *Figure 4.63(a)* illustrates a 240 MVA, 400/132 kV three-phase autotransformer with three individual 132 kV line end on-load tapchangers. The selector bases are mounted on the transformer tank and the diverter switches are contained in the tanks which are mounted on the top of the 132 kV bushings. *Figure 4.63(b)* is a cross-sectional view of the tapchanger illustrated in *Figure 4.63(a)*. The main tank housing the selector switches are arranged for bolting to the transformer tank together with the

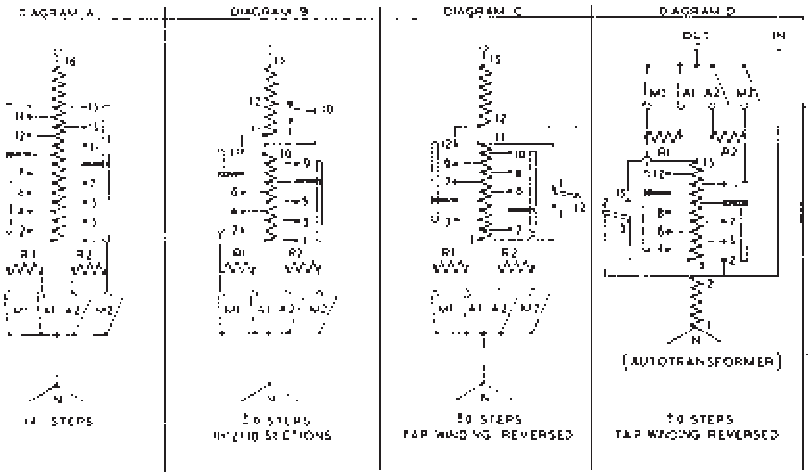


Figure 4.61 On-load tap changing circuits for resistor transition using diverter switches

Table 4.1

System highest voltage	*Insulation level*			
	Impulse test voltage (kV peak)		*Power frequency test voltage (kV rms)*	
kV rms	Standard 1	Standard 2	Standard 1	Standard 2
123	550	450	230	185
145	650	550	275	230

The Former British Electricity Boards Specification for tap changing specifies the following insulation levels:

Application	*Uniform (fully insulated)*	*Non-uniform (neutral end)*
Nominal system voltage between phases kV	132	132
Routine withstand to earth. 1 min power freq. kV	265	45
Minimum impulse withstand (1/50 wave) kV peak	640	110

terminal barrier board. Mounted directly on this tank is the porcelain bushing which supports the high-speed diverter switch assembly.

The main supporting insulation is a resin-bonded paper cylinder mounted at the base of the selector tank, and the mechanical drive is via a torsional porcelain insulator within this cylinder. Connections from the selector switches to the diverter switch are made by means of a double concentric condenser bushing and the mechanical drive shaft passes through the centre of this bushing.

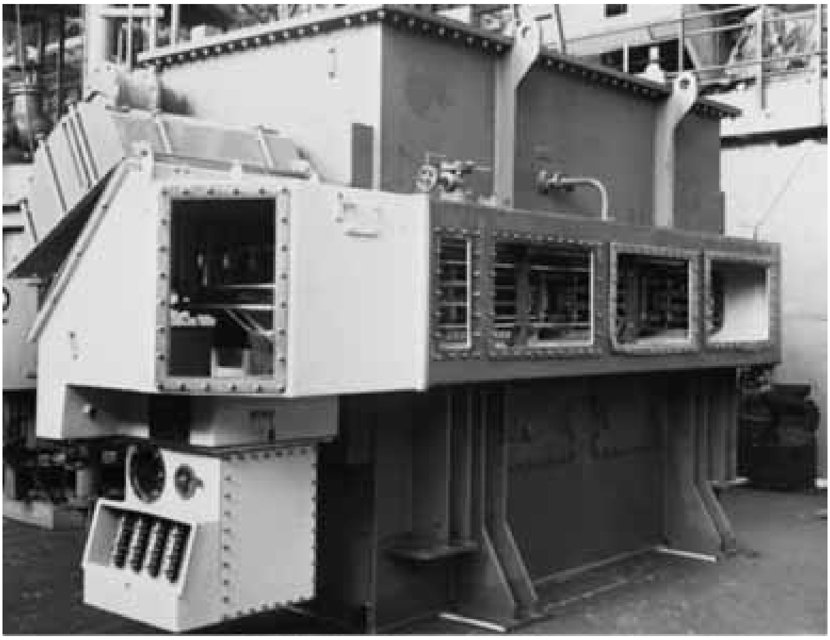


Figure 4.62 Three-phase, HV earthed neutral end, 132 kV tapchanger (Ferranti Engineering Ltd)

On the UK Grid System there are many 275/132 kV and 400/132 kV autotransformers installed where the on-load tapchangers are at the 132 kV point of the auto-winding. Earlier designs employed a reversing arrangement as shown in *Figure 4.64(a)* utilising a separate reversible regulating winding. More recently a linear arrangement has been used with the tapping sections of the winding forming part of the main winding as shown in *Figure 4.64(b)*.

In either case the tapping winding is usually a separate concentric winding. As mentioned earlier in this chapter, because of the high cost, particularly of the porcelain insulators required for the line end tapping arrangements, earthed neutral end tappings have also been used more particularly on the 400/132 kV autotransformers despite the fact that this introduces simultaneous changes in the effective number of turns in both primary and secondary and also results in a variation in the core flux density. The arrangement also introduces the complication of variable tertiary voltages. The latter can be corrected by introduction of a tertiary booster fed from the tapping windings.

On-load tapchangers have to be designed to meet the surge voltages arising under impulse conditions. In earlier high-voltage tapchangers it was quite a common practice to fit non-linear resistors (surge diverters) across individual tappings or across a tapping range.

These non-linear resistors have an inherent characteristic whereby the resistance decreases rapidly as the surge voltage increases. In modern

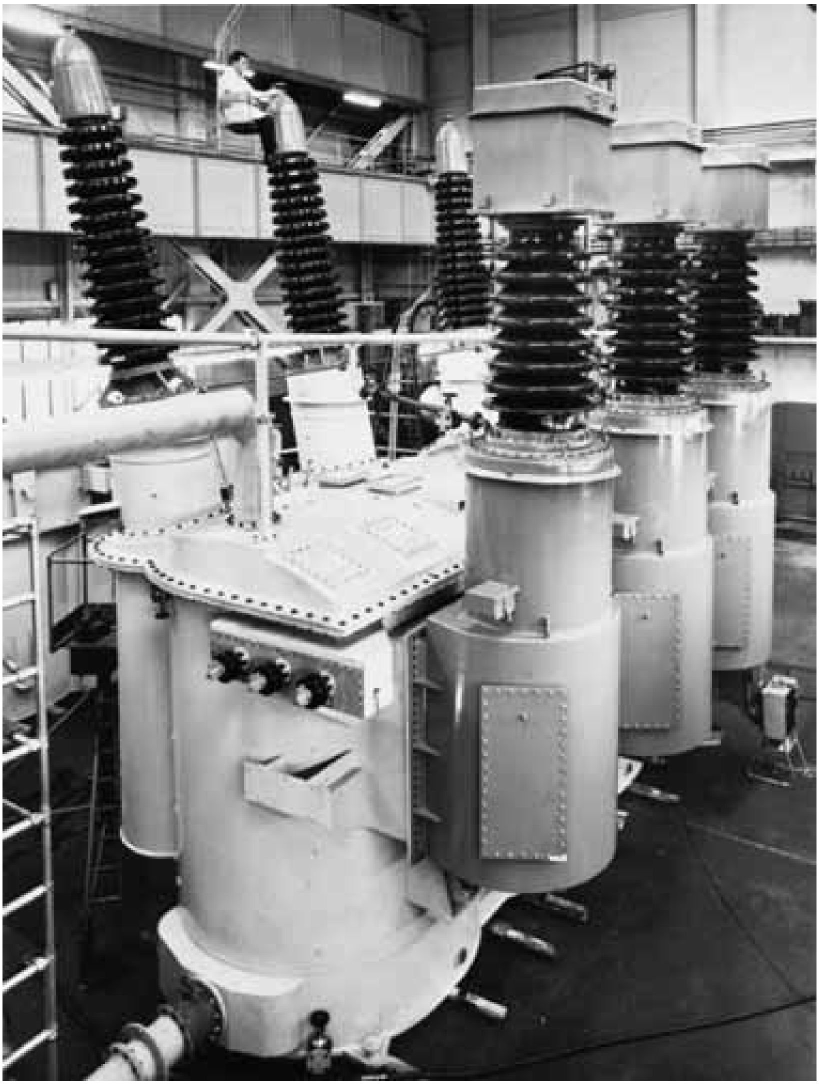


Figure 4.63(a) Three single-phase, fully insulated tapchangers fitted to the 132 kV tapping points of a 240 MVA, 400/132 kV autotransformer (Hawker Siddeley Power Transformers Ltd)

tapchangers this characteristic has, in general, been eliminated by improvement in design and positioning of contacts, such that appropriate clearances are provided where required. There is also now a much better understanding of basic transformer design and in particular the ways of improving surge voltage distribution to ensure that excessive values do not arise within tapping windings.

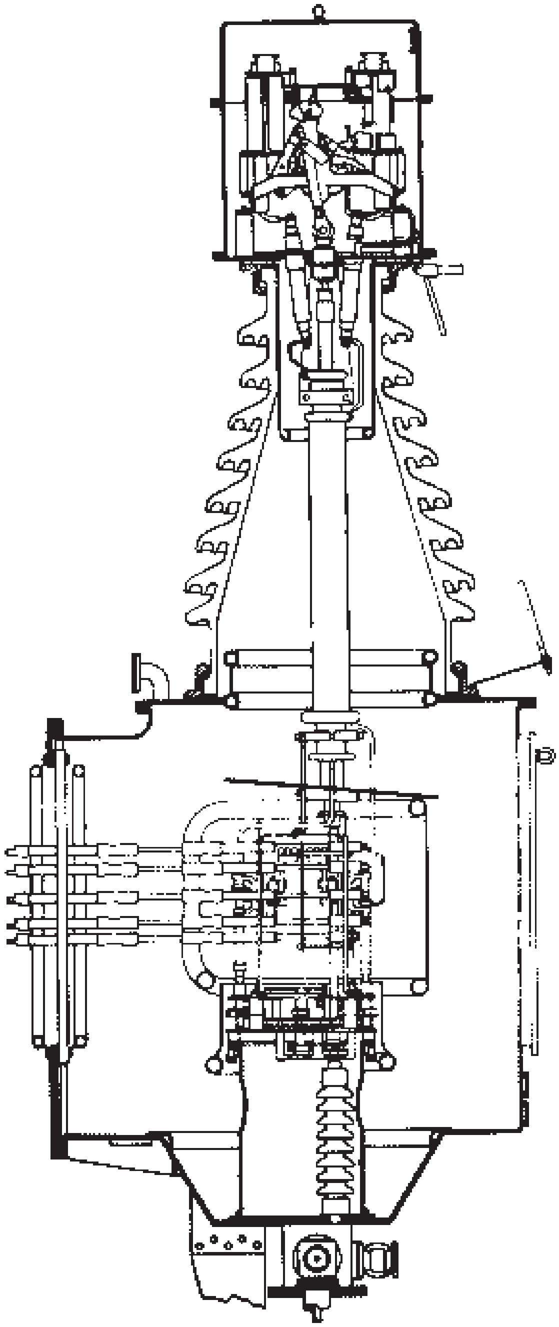


Figure 4.63(b) Cross-sectional drawing of the tapchanger illustrated in *Figure 4.63(a)*

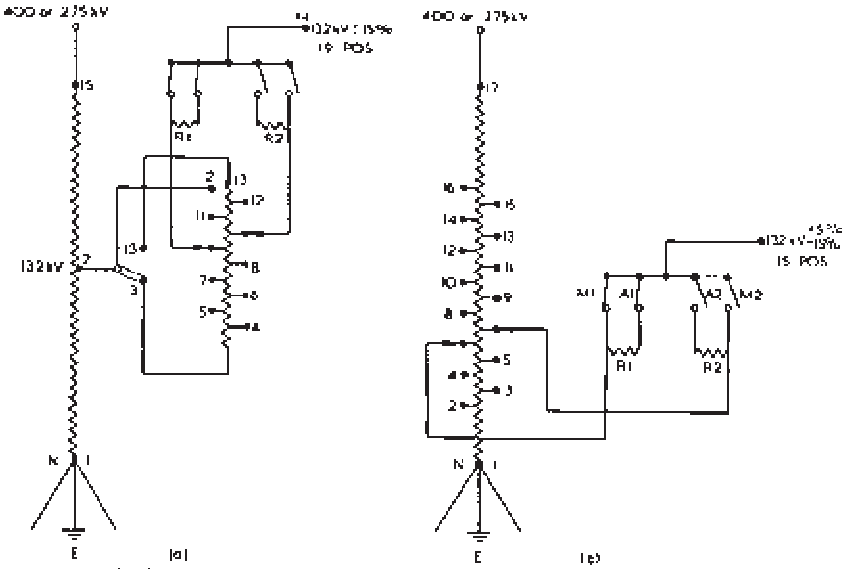


Figure 4.64 Diagrams of three-phase 400/132 kV and 275/132 kV autotransformers with 132 kV high-speed resistor-type tapchanger

If a bank of three single-phase transformers is used to make up a three-phase unit, then each phase must have its own tapchanger. This is often the case for large generator transformers. These need to be coupled so as to ensure that all three remain in step and, while it is possible to make this coupling electrically, it is far preferable and more reliable to use a single drive mechanism with a mechanical shaft coupling between phases. Assuming that the units have tappings at the neutral end of a star-connected HV winding, it is also necessary to make the HV neutral connection externally, usually by means of a copper busbar spanning the neutral bushings of each phase.

Another method of voltage regulation employed in transmission and distribution systems is one in which shunt regulating and series booster transformers are used. The former unit is connected between phases while the latter is connected in series with the line. Tappings on the secondary side of the shunt transformer are arranged to feed a variable voltage into the primary winding of the series transformer, these tappings being controlled by on-load tap changing equipment. The frame size or equivalent kVA of each transformer is equal to the throughput of the regulator multiplied by the required percentage buck or boost.

It should be noted that the voltage of the switching circuit of the regulator transformer to which the on-load tapchanger is connected can be an optimum value chosen only to suit the design and rating of the tap changing equipment. This arrangement of transformers is described as the series and shunt regulating transformer. It is normally arranged for 'in-phase' regulation but can also be employed for 'quadrature' regulation, or for both. *Figure 4.65* shows the connections for a typical 'in-phase' and 'quadrature' booster employing two tapchangers. Such a unit can be used for the interconnection of two systems for small variations of phase angle. Fuller descriptions of phase shifting transformers and quadrature boosters and their applications are given in Section 5 of Chapter 7.

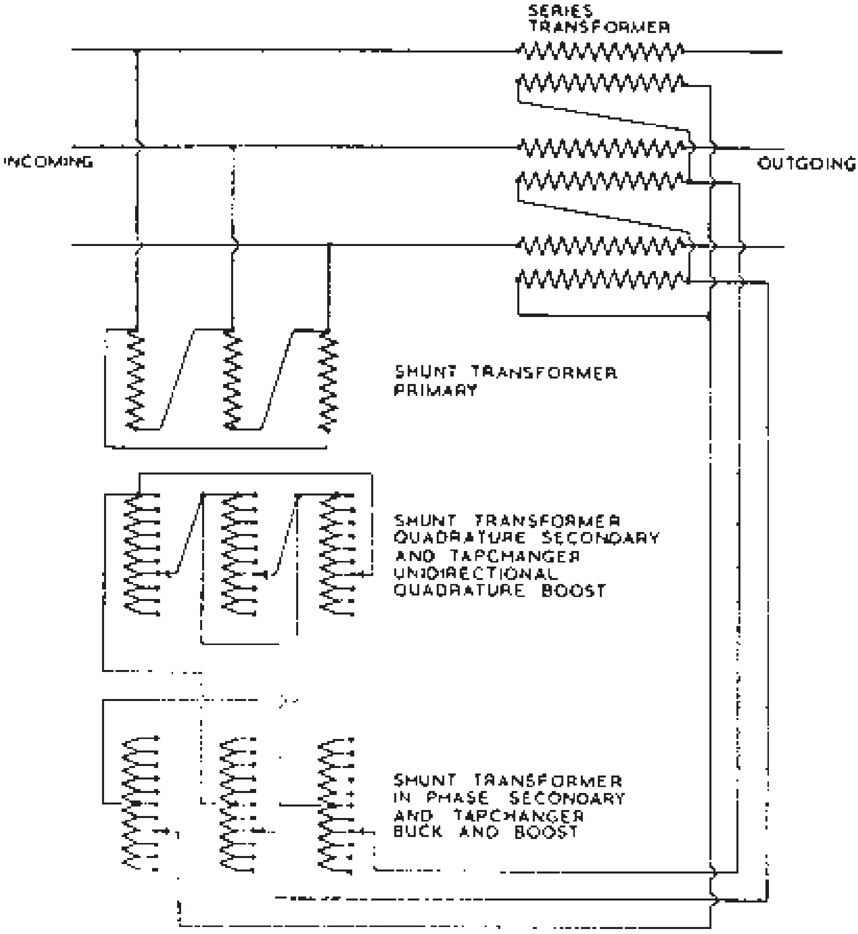


Figure 4.65 Diagram of connections for a three-phase 'in-phase' and 'quadrature' booster

Off-circuit tapchangers

As explained earlier in this chapter, the off-circuit tapping switch enables accurate electrical system voltage levels to be set when the transformer is put into operation. Once selected, the transformer may remain at that setting for the remainder of its operating life. The simplest arrangement is that in which the power transformer tappings are terminated just below oil level and there changed manually by means of bolted swinging links or plugs mounted on a suitable terminal board. The drawback to this arrangement is that it necessitates removing the transformer tank cover or handhole cover. It is, however, extremely simple, reliable and is the cheapest tap changing device. It is important to design the tap changing link device with captive parts as otherwise there is always the danger that loose nuts, washers, etc. may fall into the tank while the position of the taps is being altered. *Figure 4.66* shows one phase of this arrangement used to provide off-circuit taps on a 345 kV transformer. In this situation it is necessary to incorporate stress shielding into both the bridging-link and the open ends of the unconnected tapping leads.

Most off-circuit tapping switches use an arrangement similar to the selector switch mechanism of the on-load tapchanger, employing similar components, but if these selector contacts are not operated occasionally contact problems can occur. This can be particularly problematical for higher current-rating devices. An example is the case of power station unit transformers. On some large stations these can have ratings as high as 50 MVA at 23.5/11 kV. The 23.5 kV HV side is connected to the generator output terminals whose voltage is maintained within ±5% of nominal by the action of the generator automatic voltage regulator. The transformer is normally only in service when the unit is in operation and under these conditions its load tends to be fairly constant at near to rated load. An on-load tapchanger is therefore not essential and would reduce reliability, but off-circuit taps are desirable to enable fine trimming of the power station electrical auxiliary system voltage to take place when the station is commissioned. For a transformer of this rating the HV current can be up to 1300 A which for trouble-free operation demands a very low contact resistance. If this is not the case heating will take place resulting in a build-up of pyrolytic carbon which increases contact resistance still further. This can lead to contact arcing and, in turn, produces more carbon. Ultimately a runaway situation is reached and the transformer will probably trip on Buchholz protection, shutting down the associated generator as well. To avoid the formation of pyrolytic carbon on high-current off-circuit tapchangers, it is vital that the switch has adequate contact pressure and that it is operated, off-circuit, through its complete range during routine plant maintenance or preferably once per year to wipe the contact faces clean before returning it to the selected tapping. Because of these problems, the UK Central Electricity Generating Board in its latter years specified that ratio adjustments on unit transformers and other large power station auxiliary transformers, which would, hitherto, have had off-circuit tapping switches, should be carried out by means of links under oil within the transformer tank. The links need to be located at the top of the tank so that access can be obtained with the minimum removal of oil, but provided this is specified, tap changing is relatively simple and reliability is greatly improved. In fact, the greatest inconvenience from

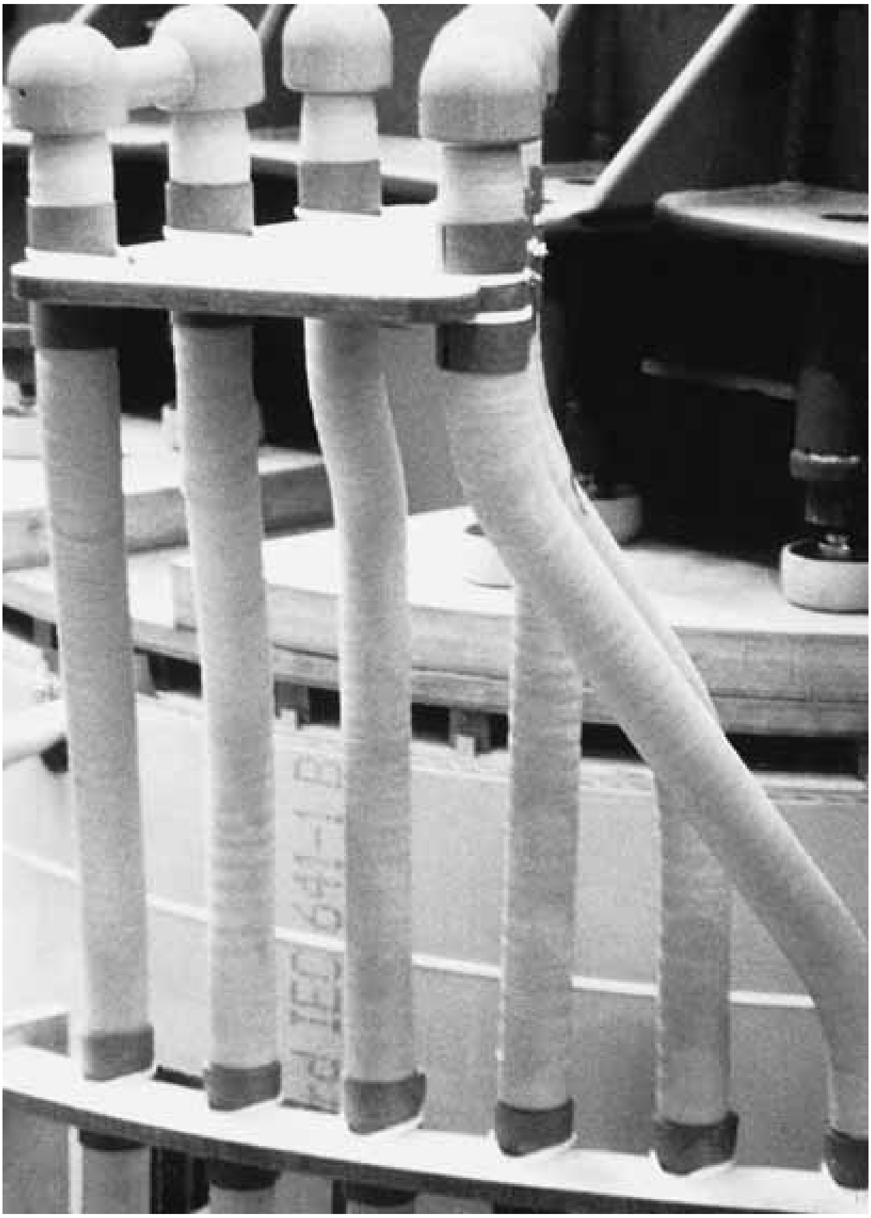


Figure 4.66 Arrangement of links under oil used to provide off-circuit taps on the HV winding of a 650 MVA, 20.9/345 kV, generator transformer supplied to the USA (Peebles Transformers)

this arrangement occurs during works testing, when the manufacturer has to plan his test sequence carefully in order to minimise the number of occasions when it is necessary to change taps. More tap changes will probably be made at this time than throughout the remainder of the transformer lifetime. This problem does not, of course, arise on the many small distribution and industrial transformers of 1 or 2 MVA or less operating at 11/0.433 kV. These have an HV current of less than 100 A which does not place high demands on contact performance when operating under oil. Very conveniently, therefore, these can be provided with simple off-circuit switches enabling the optimum ratio to be very easily selected at the time of placing in service. It is nevertheless worthwhile operating the switches, where fitted, whenever routine maintenance is carried out, particularly where the transformer is normally operating at or near full load when the oil temperature will consequently be high.

Construction of tapchangers

It is a fundamental requirement of all tapchangers that the selector and diverter switches shall operate in the correct sequence. One of the methods used is based on the Geneva wheel. *Figure 4.67* shows the mechanism and its main component parts. The drive shaft 46 is driven from the motor drive or manual operating mechanism via a duplex chain and sprocket 45, and is coupled at one end to the diverter drive 42, and at the other end to the selectors via the lost motion device 78 and the Geneva arm 77. Referring to *Figures 4.67(b)* and *(c)* the lost motion device operates as follows: the drive shaft 46 has a quadrant driving segment in contact at its left-hand side with a quadrant segment on the Geneva arm 77. If the drive shaft rotates in a clockwise direction then the Geneva arm will be driven. However, if the drive shaft rotates in an anticlockwise direction then no movement of the Geneva arm takes place until the drive shaft has rotated through 180°. During this 180° rotation the diverter switch driven by 42 will have completed a full operation. Further drive shaft rotation will move the appropriate Geneva wheel for a particular selector.

Examination of the operation of the four-position Geneva mechanism in *Figure 4.67(c)* shows the following:

- The Geneva drive does not engage until the Geneva drive arm itself has passed through approximately 45°.
- The driven period of the selector shaft occupies only 90° of the movement of the Geneva arm and the selector rotation rate is not constant. Entry of the Geneva arm into the slot produces an initial slow start increasing to maximum velocity after 45° of rotation when the drive wheel centres are in line and reducing to zero as the Geneva arm rotates through the second 45°.
- The Geneva arm travels a further 45° after disengaging from the Geneva drive wheel before the completion of a tap sequence.

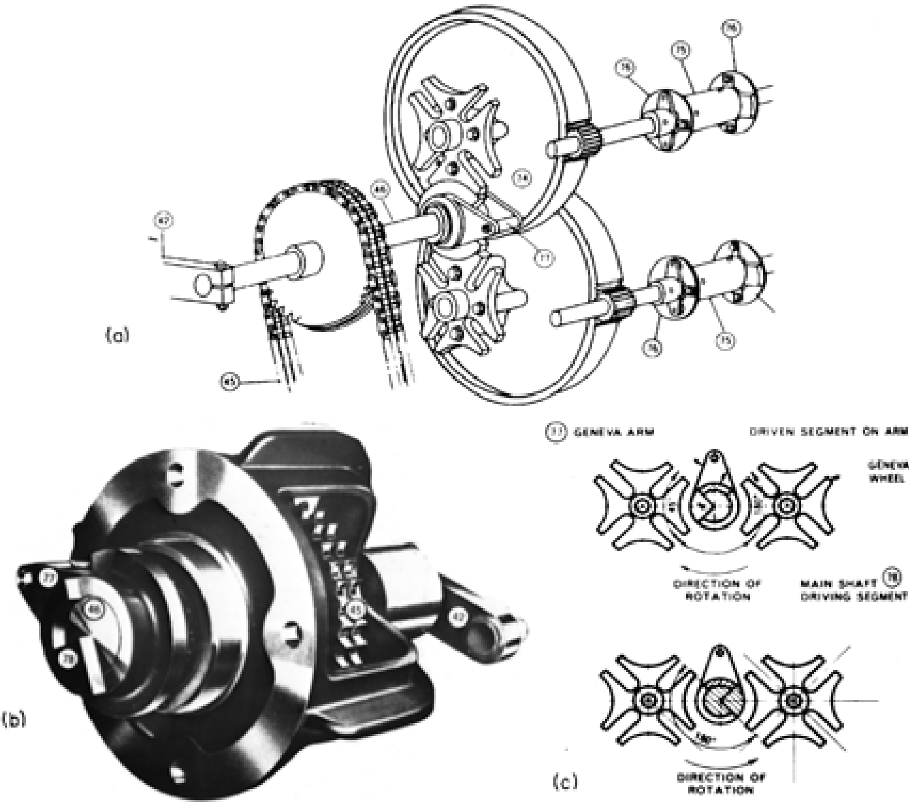


Figure 4.67 (a) Schematic drawing of a Geneva mechanism and drive; (b) 180° lost motion device; (c) Schematic drawing of 180° lost motion device and Geneva drive.

42. Diverter switch driving crank;
45. Driving chain and sprocket;
46. Selector switch drive shaft;
74. Selector switch Geneva mechanism;
75. Insulated driving shafts;
76. Flexible couplings;
77. Geneva arm;
78. 180° lost motion segment

The tapchanger design arranges for the diverter switch operation to occur after the moving selector has made contact with the fixed selector. In order to provide a definite switching action of the diverter switch it is usual to provide some form of positive stored energy device to operate the diverter switch of the single compartment unit.

Examples of stored energy devices are a spring charged across a toggle which is tripped mechanically at a predetermined time. Alternatively a falling weight is driven to a top dead centre position by a motor or by manual operation and once at that position provides sufficient energy to complete the tap change.

Highly reliable operation has been achieved and long contact life can be guaranteed; diverter switch contacts will now last generally for the useful life of the transformer itself. One type of three-phase single compartment tapchanger suitable for 44 kV, 600 A, 17 positions is illustrated in *Figure 4.68*. It is fitted with a low oil level and surge protection device which is shown at the top of the tapchanger housing.

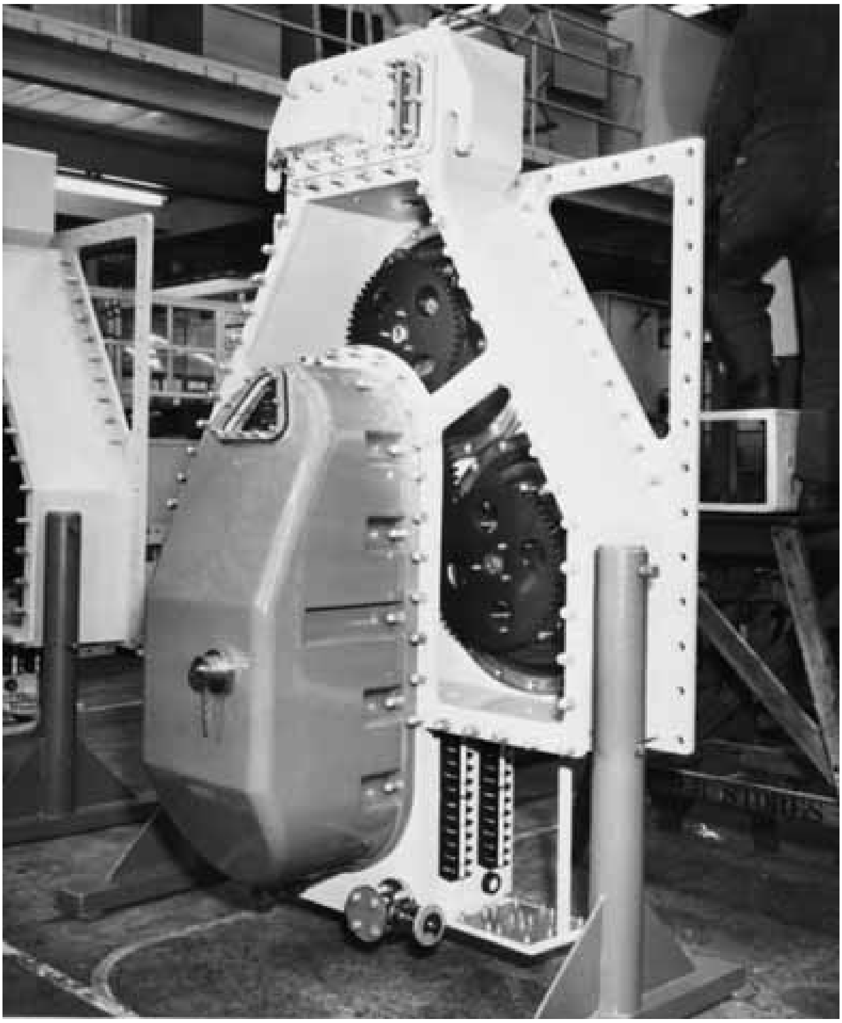


Figure 4.68 600 A, 44 kV three-phase 17 position single compartment tapchanger (Ferranti Engineering Ltd)

Figure 4.69 illustrates three single-phase 1600 A linear-type tapchangers mechanically coupled together and is suitable for connection at the neutral end of a 400 kV graded winding.

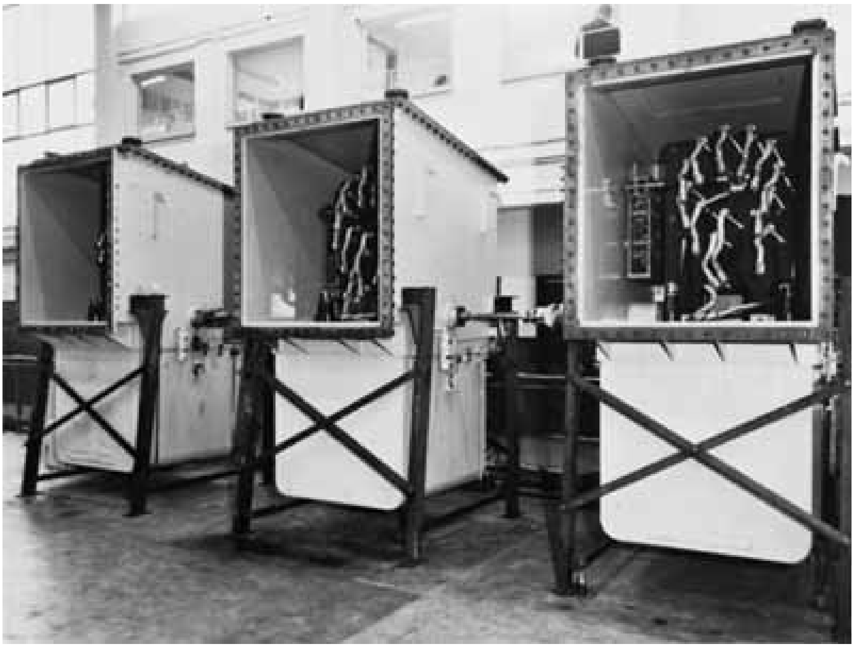


Figure 4.69 Three single-phase 19 position linear-type, 1600 A tapchangers mechanically coupled as a three-phase unit (Associated Tapchangers Ltd)

Figure 4.70 shows an example of a three-phase roller contact diverter switch which would be housed in the diverter compartment of the tapchanger shown in *Figure 4.62*.

Figure 4.71 illustrates a three-phase tapchanger which can be used as a coarse/fine or reversing regulator up to 33 positions, alternatively 17 positions as a linear switch. It is rated at 600 A with a power frequency insulation level of 70 kV, 200 kV impulse and is suitable for use at the neutral end of a 132 kV winding. On the right-hand side of the tapchanger is the separate compartment containing the driving mechanism and incorporated into this chamber is the Ferranti ‘integral solid-state voltage and temperature control unit’. This feature dispenses with the necessity of a separate tapchanger and cooling circuit control cubicle.

Control of on-load tapchangers

Many advances have been made in the design of control circuits associated with on-load tap changing. Mention has already been made of driving mechanisms and the fundamental circuits associated with the starting of the motor for carrying out a tap change. While these vary from one maker to another they are comparatively simple. In general, the motor is run up in one direction

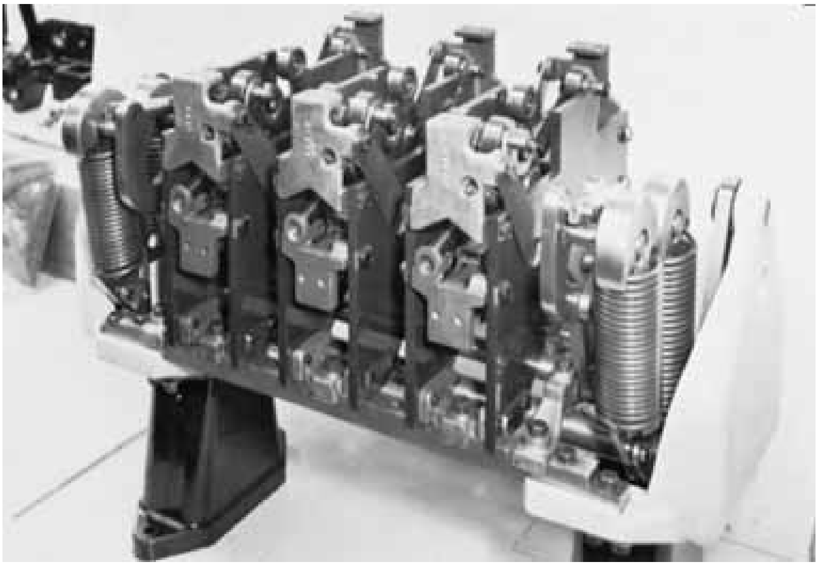


Figure 4.70 Three-phase roller contact diverter switch rated 650 A, normally housed in the diverter compartment of the tapchanger shown in *Figure 4.62* having 70 kV test level (Ferranti Engineering Ltd)

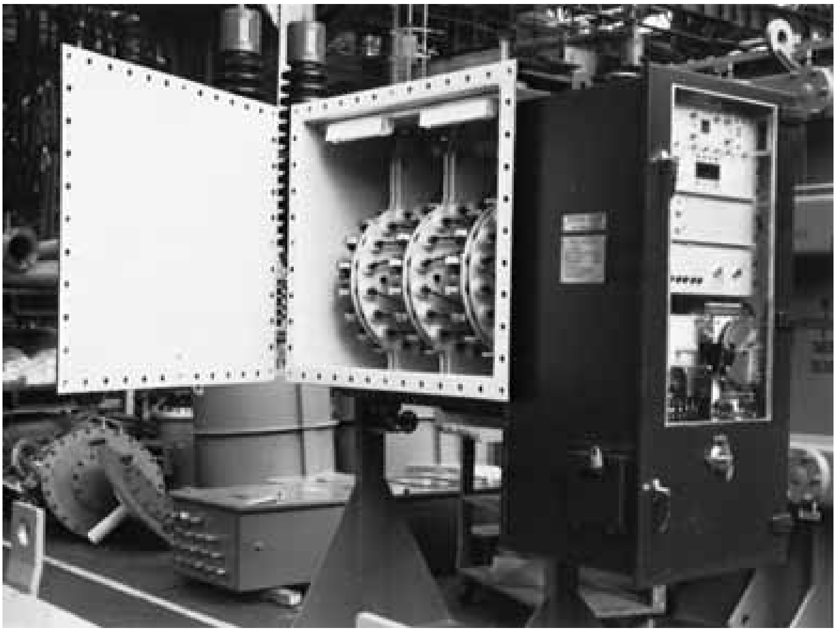


Figure 4.71 Three-phase, 600 A, single compartment tapchanger fitted with an integrated solid-state voltage and temperature control unit (Ferranti Engineering Ltd)

for a 'raise' tap change and in the reverse direction for a 'lower' tap change. In some cases a brake is employed to bring the motor to rest while in others clutching and declutching are carried out electrically or mechanically. It is, however, the initiation of the tap change and the control of transformers operating in parallel where the main interest lies and where operational problems can arise if the tapchangers are 'out of step'.

Manual operation must always be available for emergency use and in some cases tapchangers are supplied for hand operation only.

Many installations are designed for simple pushbutton control but there has been a tendency towards unattended automatic voltage control at substations so that a predetermined constant or compensated busbar voltage can be maintained. In general, with these schemes a tapchanger is provided on a transformer for maintaining a predetermined outgoing voltage where the incoming voltage is subject to variations due to voltage drops and other system variations.

It is reasonable to expect that with the advent of digital control it will become possible to perform all the operations necessary for the control and operation of tapchangers and the monitoring of their performance by a single device using digital computer technology coupled to low-burden output voltage and current transformers, thereby enabling very accurate control to be obtained with much simplified equipment. At the present time, however, the basic control devices remain within the class which is generally termed 'relays', even though these may utilise solid-state technology, and tapchanger control continues to operate on principles which have developed since the early days of on-load tap changing, with individual circuit elements performing discrete functions. The following descriptions therefore describe these traditional systems.

Voltage control of the main transformer requires a voltage transformer energised from the controlled voltage side of the main transformer. The voltage transformer output is used to energise a voltage relay with output signals which initiate a tap change in the required direction as the voltage to be controlled varies outside predetermined limits. It is usual to introduce a time delay element either separately or within the voltage relay itself to prevent unnecessary operation or 'hunting' of the tapchanger during transient voltage changes.

The 'balance' voltage of the relay, namely the value at which it remains inoperative, can be preset using a variable resistor in the voltage-sensing circuit of the relay so that any predetermined voltage within the available range can be maintained.

Often it is required to maintain remote busbars at a fixed voltage and to increase the transformer output voltage to compensate for the line drop which increases with load and this is achieved by means of a line drop compensator. This comprises a combination of a variable resistor and a tapped reactor fed from the secondary of a current transformer whose primary carries the load current. By suitable adjustment of the resistance and reactance components, which depend upon the line characteristics it is possible to obtain a constant voltage at some distant point on a system irrespective of the load or power factor.

Figure 4.72 shows the principle of the compensator which for simplicity is shown as a single-phase circuit. The voltage transformer is connected between lines and the current transformer is connected as shown to the variable resistance and reactance components. These are so connected in the voltage relay circuit that the voltage developed across them is subtracted from the supply voltage, then as load current increases the voltage regulating relay becomes unbalanced and operates the main regulating device to raise the line voltage at the sending end by an amount equal to the line impedance drop and so restore the relay to balance. The reverse action takes place when the load current decreases. The regulating relay and compensator are usually employed in three-phase circuits, but since the relay voltage coil is single phase, usually connected across two phases, the only difference between the arrangement used and that shown in *Figure 4.72* is that the arrangement of the voltage and current transformer primary connections must be such as to provide the proper phase relation between the voltage and the current.

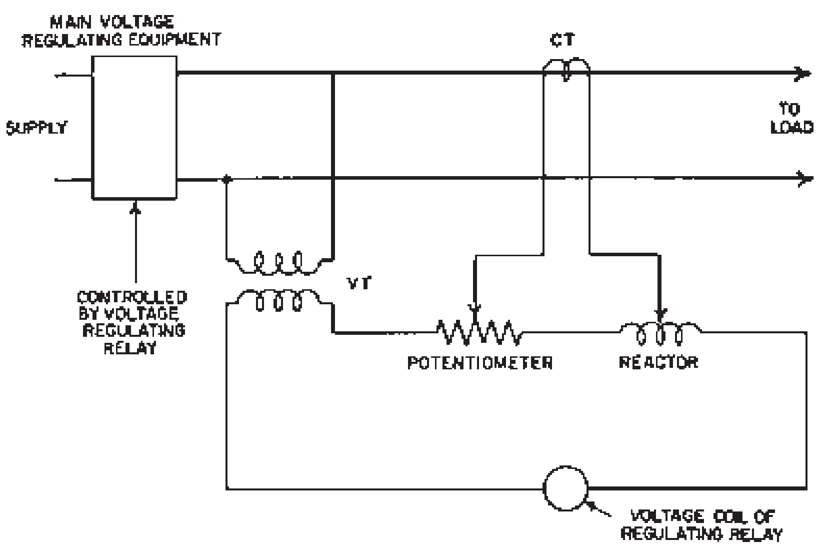


Figure 4.72 Single-phase diagram showing the principle of line drop compensation

The voltage transformer is connected across the A and C phases and the current transformer in the A phase. Different phases may be used provided the phase relationship is maintained. The compensation afforded by this method is not strictly correct since there is a 30° phase displacement between the voltage and the load current at unity load power factor. Since line drop compensation is usually a compromise this method is acceptable in many cases.

In *Figure 4.72* a single current transformer is shown in the line connection for the current supply to the compensator. It is usual practice to have an interposing current transformer in order to obtain the correct full-load secondary current but, at the same time, provide protection against damage due to overloads or fault currents in the line. The interposing current transformer is specifically designed to saturate under such conditions, thus avoiding the introduction of high overload currents to the compensator circuit. If greater accuracy is desired another method may be used with this scheme – the voltage transformer is connected across A and B phases with the main current transformer primary in C phase. Alternative phases may be used provided the phase relationship between voltage and the current is maintained. With this connection, since the current and voltage are in quadrature at unity load power factor, the resistor and reactor provide the reactance and resistance compensation respectively. In all other respects this compensator is identical with that described for the first scheme but there is no phase angle error.

For many years the automatic voltage relay (AVR) used was the balanced plunger electromechanical type and many of these are still in service. Nowadays a solid-state voltage relay is used. For the former type a standard arrangement of line drop compensator has the external series resistor and mean setting adjustment rheostat for the regulating element of the voltage regulator mounted in the compensator, which has three adjustable components providing the following: variation of 90–110% of the nominal no-load voltage setting, continuously variable range of 0–15% compensation for resistance and 0–15% reactive compensation.

If compensation is required for line resistance only, a simple potentiometer resistor is used instead of the complete compensator and the external resistor and mean setting adjustment are supplied separately. When the compensator has been installed and all transformer polarities correctly checked, the regulating relay may be set to balance at the desired no-load voltage. The resistance and reactance voltage drops calculated from the line characteristics may then be set at the appropriate values.

A voltage control cubicle with voltage regulating relay and line drop compensation is shown in *Figure 4.73*. The voltage regulating relay is of the balanced plunger electromechanical type and a simplified arrangement of the relay is shown in *Figure 4.74*. The design of the solenoid regulating element ensures that the magnetic circuit is open throughout the operating range. Therefore, the reluctance of the circuit is now appreciably affected by movement of the core and the unit operates with a very small change in ampere-turns.

Basically the element consists of a solenoid C with a floating iron core guided by two leaf springs LS which permit vertical but not lateral movement. Control spring S, which has one end anchored to the relay frame and the other attached to the moving iron core 'a', is carefully adjusted to balance

Figure 4.73 Control cubicle with voltage regulating relay (Bonar Long Ltd)

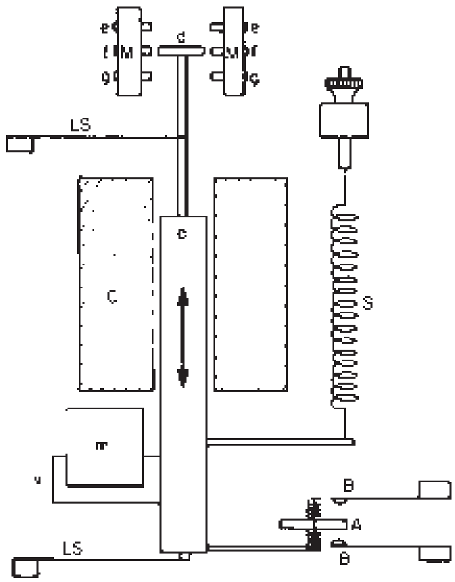


Figure 4.74 Simplified arrangement of the regulating element of the AVE 5 relay (GEC Measurements)

the weight of the core and the magnetic pull of the solenoid holding the disc ‘d’ at the mid-position ‘f’ with contact A between contacts B with nominal voltage applied. When the voltage increases or decreases the magnetic forces move the core up or down along the axis of the solenoid. The moving core carries a contact A which makes with the ‘high-volt’ and ‘low-volt’ fixed contacts B.

Positive action is ensured by the ‘hold-on’ device. This consists of an iron disc ‘d’ attached to the core, which moves between the poles of a permanent magnet M. Pole pieces ‘e’, ‘f’ and ‘g’ concentrate the flux of the permanent magnet, and therefore its influence on the disc ‘d’, at positions corresponding to high, normal and low positions of the core and tend to restrain it at these positions. An eddy-current damper consisting of fixed magnet ‘m’ and moving copper vane ‘v’ minimises oscillations set up by momentary voltage fluctuations.

To eliminate errors due to the variations of coil resistance with temperature, a comparatively high value of resistance having a negligible temperature coefficient is connected in series with the coil.

There is an advantage in providing means by which a sudden wide change in voltage can be more quickly corrected and solid-state voltage relays can provide this characteristic. These relays have a solid-state voltage-sensing circuit and an inverse time characteristic so that the delay is inversely proportional to the voltage change. Two such relays are the VTJC and STAR, both of which are illustrated in *Figure 4.75*. They can be used with a line drop

Figure 4.75 Static voltage regulating relays. (a) Brush STAR relay (Brush Electrical Machines Ltd); (b) GEC VTJC relay (GEC Measurements)

compensator and a voltage reduction facility to give specified load shedding features.

Where two or more transformers with automatically controlled on-load tapchangers are operating in parallel, it is normally necessary to keep them either on the same tapping position or a maximum of one tap step apart. If transformers are operated in parallel on different tappings circulating currents will be set up and in general one step is the most that can be tolerated.

Many different schemes of parallel control have been devised, several of which are in regular use. If it is considered necessary that all transformers must operate on the same tapping this can be achieved by a master-follower system or by a simultaneous operation method.

Master/follower control

With this type of control system one of the units is selected as the master and the remaining units operate as followers. Built-in contacts in the on-load tapchanger mechanisms are connected so that once a tap change has been completed on the master unit each follower is initiated in turn from the interconnected auxiliary contacts to carry out the tap change in the same direction as that carried out by the master. A simplified schematic diagram of the master and follower circuit is shown in *Figure 4.76*. The disadvantage of master/follower schemes is their complexity, so that nowadays they are very seldom used.

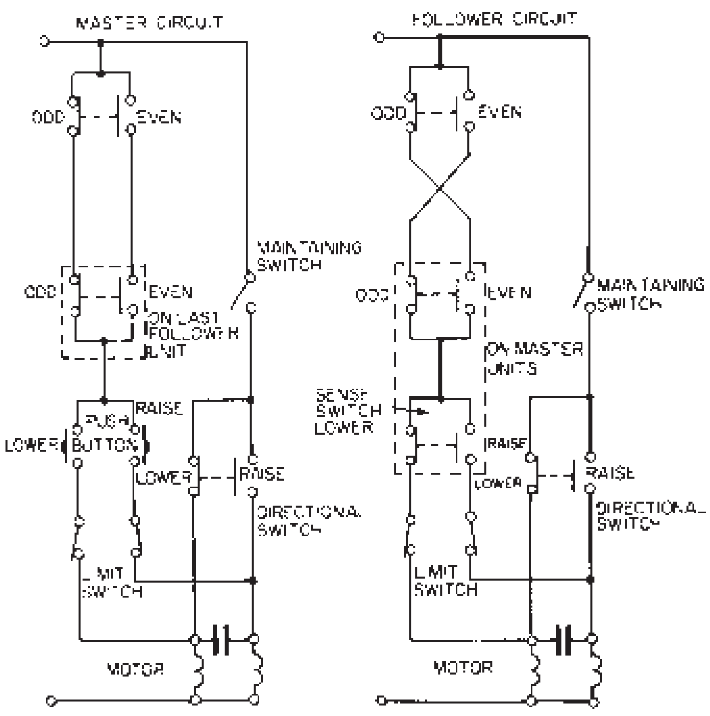


Figure 4.76 Master/follower circuit diagrams

With simultaneous operation, all tapchangers of a group are arranged to start their operation at the same time. This is a simpler arrangement although it is still necessary to provide lock-out arrangements to take care of any individual failure.

Circulating current control

Where two or more transformers of similar impedance are operated in parallel they will each provide an equal share of the load current. In the event of one of these transformers changing to a higher tapping position, a circulating current will flow between this transformer and the remaining units. This circulating current will appear as a lagging current from the unit which has changed taps. It will be equally divided between the other transformers which are in parallel and will appear to these transformers as a leading current.

It is possible by judicious connection of current transformers to separate this circulating current from the load current and introduce it into components in the automatic voltage regulating (AVR) circuit. These are so connected into the AVR circuit such as to provide an additional voltage to the AVR which has tapped up and a subtractive voltage to the remaining AVRs controlling the parallel-connected transformers. Using this method and carefully adjusted components, transformers can be kept within close tapping positions of each other.

There has been much development in the supervisory control of system voltages, and on some systems centralised control has been achieved by the operations of tapchangers by remote supervisory methods. This is usually confined to supervisory remote pushbutton control, with an indication of the tapchanger position, but more complicated schemes have been installed and are being satisfactorily operated where tapchangers are controlled from automatic relays on their respective control panels, with supervisory adjustment of their preset voltage and selection of groups operating in parallel, and with all necessary indications reported back by supervisory means to the central control room.

Runaway prevention

The danger with any automatic voltage control scheme is that a fault in the control circuitry, either the voltage-sensing relay or, more probably, fuse failure of a voltage transformer, can cause a false signal to be given to the control equipment thus incorrectly driving it to one end of the range. Such a fault not only causes incorrect voltage to be applied to the system fed by the transformer but can also result in the transformer itself having an incorrect voltage applied to it. For example, the failure of a fuse of a voltage transformer monitoring the transformer low-voltage system will send a signal to the control scheme to raise volts. This will result in the transformer tapping down on the high-voltage side and it will continue to do so until it reaches the minimum tap position. The applied voltage on the transformer high-voltage side could, in fact, be at or near nominal, or even above nominal, so that this can result in the transformer being seriously overfluxed. Various schemes can be devised to guard against this condition, the most reliable being possible when two or more transformers are controlled in parallel. In this situation the AVC scheme outputs for each one can be compared. If they attempt to signal their respective transformer tapchangers to become more than two steps out of step then both schemes are locked out and an alarm given. All such schemes can only be as reliable as their input information and the principal requirement of any reliable scheme such as the one described must be that controls compared should operate from *independent* voltage transformer signals. Where the provision of an independent voltage transformer signal is difficult, as can be the case for a single transformer with on-load tapchanger supplying a tail-end feeder, it is possible to utilise a VT fuse monitoring relay. This usually compares phase voltages of the VT output and alarms if any one of these does not match the other two.

Moving coil regulator

The moving coil regulator does not suffer from the limitations of the on-load tapchangers finite voltage steps and has a wide range of application. It can be used in both low- and medium-voltage distribution systems, giving a smooth variable range of control. A shell-type core carries two coils connected in series opposition mounted vertically above the other. An outer third coil is short-circuited and mounted concentrically so that it can be moved vertically from a point completely covering the top coil to a lower position covering the bottom coil. This arrangement produces an output voltage proportional to the relative impedance between the fixed and moving coil which is smoothly variable over the range. *Figure 4.77* illustrates the principle of the moving coil regulator and the core and windings of two three-phase 50 Hz regulators are shown in *Figure 4.78*. They are designed for a variable input of 11 kV $\pm$ 15%, an output of 11 kV $\pm$ 1% and a throughput of 5 MVA.

The Brentford linear regulating transformer

The Brentford voltage regulating transformer is an autotransformer having a single layer coil on which carbon rollers make electrical contact with each successive turn of the winding. It can be designed for single- or three-phase operation and for either oil-immersed or dry-type construction. The winding is of the helical type which allows three-phase units to be built with a three-limb core as for a conventional transformer.

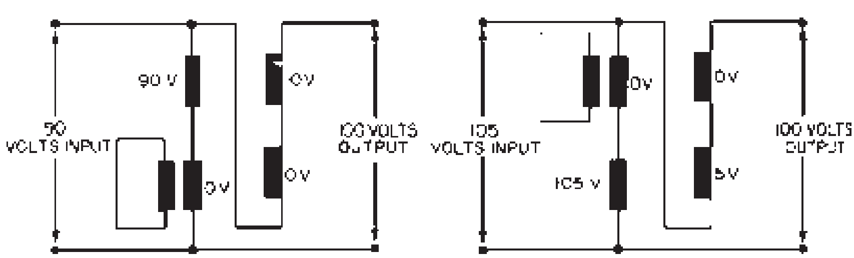


Figure 4.77 Principle of the moving coil type of voltage regulator

The helical winding permits a wide range of copper conductor sizes, winding diameter and length. The turns are insulated with glass tape and after winding the coils are varnish impregnated and cured. A vertical track is then machined

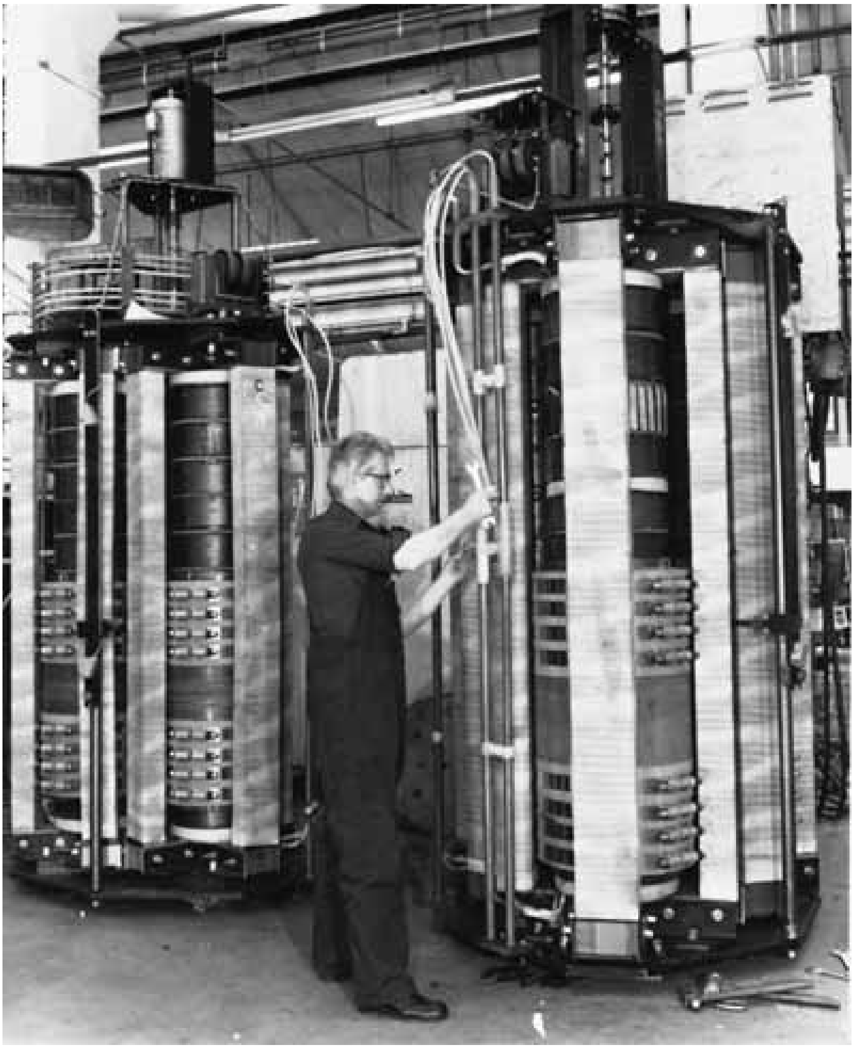


Figure 4.78 Core and coil assemblies of a three-phase, 5 MVA throughput 50 Hz moving coil regulator (Allenwest Brentford Ltd)

through the surface insulation to expose each turn of the winding. The chain driven carbon roller contacts supported on carriers operate over the full length of the winding to provide continuously variable tapping points for the output voltage.

As the contacts move they short-circuit a turn and a great deal of research has been carried out to obtain the optimum current and heat transfer conditions at the coil surface. These conditions are related to the voltage between adjacent turns and the composition of the material of the carbon roller contacts.

The short-circuit current does not affect the life of the winding insulation or the winding conductor. The carbon rollers are carried in spring-loaded, self-aligning carriers and rotate as they travel along the coil face. Wear is minimal and the rolling action is superior to the sliding action of brush contacts. In normal use the contact life exceeds 100 km of travel with negligible wear on the winding surface. *Figure 4.79* illustrates how the sensitivity of a regulator may be varied to suit a particular system application. If it is required to stabilise a 100 V supply which is varying by ±10% a voltage regulating transformer (VRT) would have say 100 turns so that by moving the roller contact from one turn to the next the output would change by 1 volt or 1%. However, if the VRT supplies a transformer which bucks or boosts 10% the roller contact needs to move 10 turns to change the voltage by 1%, hence the sensitivity of the regulator is increased 10 times.

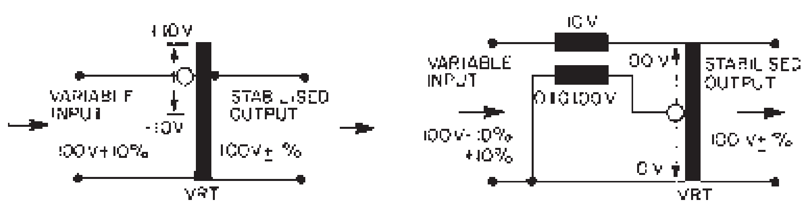


Figure 4.79 Diagram illustrating variation of sensitivity of a voltage regulating transformer

The contacts are easily removed for inspection by unscrewing the retaining plate and turning the contact assembly away from the coil face: contacts are then lifted vertically out of their carrier. Replacement is straightforward and with normal usage an operating life of three to five years can be expected.

Linear voltage regulators are available in ratings up to 1 MVA as a single frame and up to 15 MVA with multiple unit construction. Also on HV systems designs of regulators can be combined with on-load tapping selector switches connected to the transformer windings to provide power ratings in excess of 25 MVA.

Control of regulators over the operating range can be arranged for manual, pushbutton motor operation or fully automatic control regulating the output by means of a voltage-sensing relay.

Figure 4.80 shows the core and windings of a 72 kVA three-phase regulator designed for an input of 415 V 50 Hz and a stepless output of 0−415 V with a current over the range of 100 A. For the smaller low-voltage line−end boosters built into rural distribution systems, the regulator is often a single-sided equipment, and contact is made only to one side of the helical winding. For larger units, and those for networks up to 33 kV, the regulator is used in conjunction with series-booster and shunt-connected main transformers to give a wider range of power and voltage capabilities.

Figure 4.80 Three-phase, 100 A, 72 kVA, 415/0–415 V regulator (Allenwest Brentford Ltd)

The schematic diagram, *Figure 4.81*, shows the basic connection for an lnterstep regulating equipment designed to provide stepless control of its output voltage from zero to 100%.

For the purposes of simplifying the explanation, the main transformer is auto-wound and provided with 8 tappings but depending upon the rating up to a maximum of 16 tappings can be used. Also for those applications where because of other considerations it is necessary to use a double wound transformer, it is often more economical for a restricted voltage range to utilise

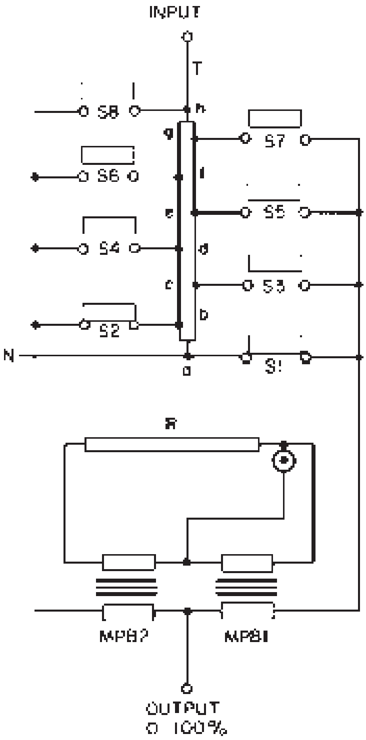


Figure 4.81 Schematic diagram of one phase of a three-phase Brentford interstep regulating unit employing an 8-position selector switch. Output voltage range is 0–100%. T – Main tapped transformer; R – Brentford stepless regulator; *MPB*1, *MPB*2 – double wound booster transformers connected in series; (a) to (h) – tappings on main transformer; *S*1 to *S*8 – 8-position selector switch

tappings on the primary winding, and not employ a separate tapped autotransformer.

Also provided in the equipment is a coordinating gear box which mechanically synchronises the operation of the switches and the regulator. The tappings on the autotransformer are connected to the selector switches *S*1 to *S*8 and the regulator and booster transformers are arranged to act as a trimming device between any two adjacent tappings. For example, if switches *S*1 and *S*2 are closed and the regulator is in the position shown, then the secondary winding of booster transformer *MPB*1 is effectively short-circuited and the voltage at the output terminal is equal to tap position (a), i.e. zero potential.

To raise the output voltage, the contact of the regulator is moved progressively across the winding and this action changes the voltage sharing of the two booster transformers until *MPB*2 is short-circuited and the output voltage is equal to tap position (b). Under these conditions switch contact *S*1 can be opened, because effectively there is no current flowing through it and switch *S*3 can be closed.

To increase the output voltage further, the contact of the regulator is moved to the opposite end of the winding when *S*2 opens and *S*4 closes, and this procedure is repeated until the maximum voltage position is reached, which corresponds to switches *S*7 and *S*8 being closed with the secondary winding of *MPB*2 short-circuited. For this application the regulator is double sided, having both sides of the regulating winding in contact with the roller contacts and driven in opposite directions on either side of the coil to produce a 'buck' and 'boost' output from the regulator which is fed to the low-voltage side of the series transformer. The most common arrangement of this is shown diagrammatically in *Figure 4.82* but a number of alternative arrangements with patented 'double boost' connections are available.

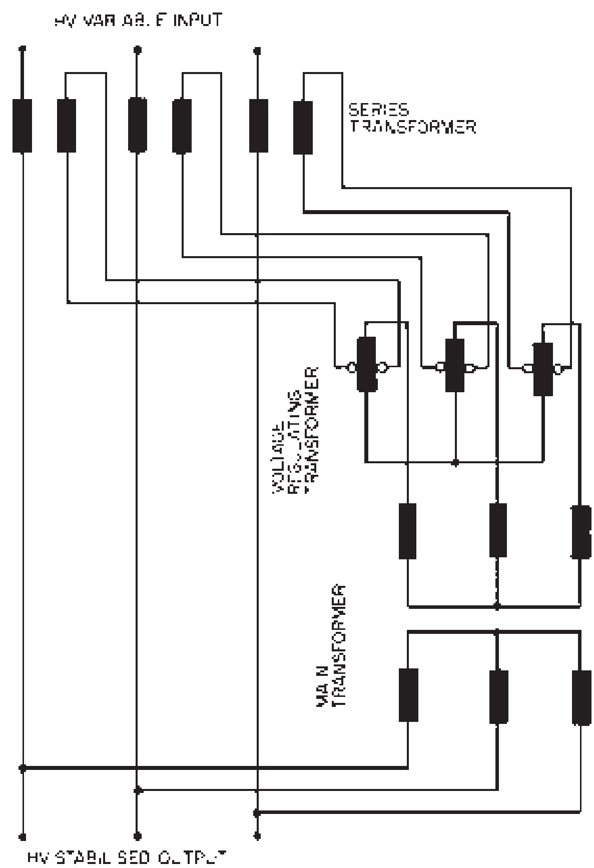


Figure 4.82 Diagram of connections of a regulator employed in conjunction with series and main transformers

4.7 WINDING FORCES AND PERFORMANCE UNDER SHORT-CIRCUIT

The effect of short-circuit currents on transformers, as on most other items of electrical plant, fall into two categories:

- Thermal effects.
- Mechanical effects.

Thermal effects

It is a fairly simple matter to deal with the thermal effects of a short-circuit. This is deemed to persist for a known period of time, BS 171, Part 5 specifies 2 s, allowing for clearance of the fault by back-up protection. During this brief time, it is a safe assumption that all the heat generated remains in the copper. Therefore knowing the mass of the copper, its initial temperature and the heat input, the temperature which it can reach can be fairly easily calculated. It simply remains to ensure that this is below a permitted maximum which for oil-immersed paper-insulated windings is taken to be 250°C, in accordance with Table III of BS 171, Part 5. Strictly speaking, the resistivity of the copper will change significantly between its initial temperature, which might be in the region of 115°C, and this permitted final temperature, and there is also some change in its specific heat over this temperature range; hence, a rigorous calculation would involve an integration with respect to time of the I^2R loss, which is increasing, plus the eddy-current loss, which is decreasing, divided by the copper weight times the specific heat, which is also increasing with temperature. In reality the likely temperature rise occurring within the permitted two seconds will fall so far short of the specified figure that an approximate calculation based on average resistivity and specific heat will be quite adequate. Current on short-circuit will be given by the expression:

$$F = \frac{1}{(e_z + e_s)} \tag{4.1}$$

where F = factor for short-circuit current as multiple of rated full-load current

e_z = *per unit* impedance of transformer

e_s = impedance of supply, *per unit*, expressed on the basis of the transformer rating

The supply impedance is normally quoted in terms of system short-circuit apparent power (fault level) rather than as a percentage. This may be expressed in percentage terms on the basis of the transformer rating in MVA as follows:

$$e_s = \frac{\mathrm{MVA}}{S} \tag{4.2}$$

where S is the system short-circuit apparent power in MVA.

An approximate expression for the temperature rise of the conductor after t seconds is then:

$$\theta = \frac{t \quad 1 + \dfrac{e}{100} \quad D^2 \rho F^2}{\mathrm{d}h}$$

where θ = temperature rise in degrees centigrade
e = winding eddy-current loss, %
D = current density in windings, A/mm^2
ρ = resistivity of the conductor material
d = density of the conductor material
h = specific heat of the conductor material

For copper the density may be taken as 8.89 g/cm^3 and the specific heat as 0.397 J/g°C. An average resistivity value for fully cold-worked material at, say, 140°C may be taken as 0.0259 Ω mm^2/m. Substituting these and a value of t equal to 2 s in the above expression gives:

$$\theta = 0.0147 \quad 1 + \frac{e}{100} \quad D^2 F^2 \tag{4.3}$$

An indication of the typical magnitude of the temperature rise produced after 2 s can be gained by considering, for example, a 60 MVA, 132 kV grid transformer having an impedance of 13.5%. The UK 132 kV system can have a fault level of up to 5000 MVA. Using expression (4.2) this equates to 1.2% based on 60 MVA and inserting this together with the transformer impedance in expression (4.1) gives a short-circuit current factor of 6.8 times. A 60 MVA ODAF transformer might, typically, have a current density of up to 6 A/mm^2. The winding eddy-current losses could, typically, be up to 20%. Placing these values in expression (4.3) gives:

$$\theta = 0.0147 \left(1 + \frac{20}{100}\right. \quad 6^2 6.8^2 = 29.4^\circ\mathrm{C}$$

which is quite modest. With a hot spot temperature before the short-circuit of 125°C (which is possible for some designs of OFAF transformer in a maximum ambient of 40°C) the temperature at the end of the short-circuit is unlikely to exceed 155°C, which is considerably less than the permitted maximum.

The limiting factor for this condition is the temperature reached by the insulation in contact with the copper, since copper itself will not be significantly weakened at a temperature of 250°C. Although some damage to the paper will occur at this temperature, short-circuits are deemed to be sufficiently infrequent that the effect on insulation life is considered to be negligible. If the winding were made from aluminium, then this amount of heating of the conductor would not be considered acceptable and risk of distortion or creepage of the aluminium would be incurred, so that the limiting temperature for aluminium is restricted to 200°C.

Mechanical effects

Mechanical short-circuit forces are more complex. Firstly, there is a radial force which is a mutual repulsion between LV and HV windings. This tends to crush the LV winding inwards and burst the HV winding outwards. Resisting the crushing of the LV winding is relatively easy since the core lies immediately beneath and it is only necessary to ensure that there is ample support, in the form of the number and width of axial strips, to transmit the force to the core. The outwards bursting force in the HV winding is resisted by the tension in the copper, coupled with the friction force produced by the large number of HV turns which resists their slackening off. This is usually referred to as the ‘capstan effect’. Since the tensile strength of the copper is quite adequate in these circumstances, the outward bursting force in the HV winding does not normally represent too serious a problem either. An exception is any outer winding having a small number of turns, particularly if these are wound in a simple helix. This can be the case with an outer tapping winding or sometimes the HV winding of a large system transformer where the voltage is low in relation to the rating. Such a transformer will probably have a large frame size, a high volts per turn and hence relatively few turns on both LV and HV. In these situations it is important to ensure that adequate measures are taken to resist the bursting forces under short-circuit. These might involve fitting a tube of insulation material over the winding or simply securing the ends by means of taping, not forgetting the ends of any tapping sections if included. Another alternative is to provide ‘keeper sticks’ over the outer surface of the coil which are threaded through the interturn spacers. Such an arrangement is shown in *Figure 4.83* in which keeper sticks are used over the helical winding of a large reactor.

Secondly, there may also be a very substantial axial force under short-circuit. This has two components. The first results from the fact that two conductors running in parallel and carrying current in the same direction are drawn together, producing a compressive force. This force arises as a result of the flux produced by the conductors themselves. However, the conductors of each winding are also acted upon by the leakage flux arising from the conductors of the other winding. As will be seen by reference to *Figure 4.84(a),* the radial component of this leakage flux, which gives rise to the axial force, will in one direction at the top of the leg and the other direction at the bottom. Since the current is in the same direction at both top and bottom this produces axial forces in opposite directions which, if the primary and secondary windings are balanced so that the leakage flux pattern is symmetrical, will cancel out as far as the resultant force on the winding as a whole is concerned. Any initial magnetic unbalance between primary and secondary windings, i.e. axial displacement between their magnetic centres (*Figure 4.84(b)*) will result in the forces in each half of the winding being unequal, with the result that there is a net axial force tending to increase the displacement even further.

In very large transformers the designer aims to achieve as close a balance as possible between primary and secondary windings in order to limit these

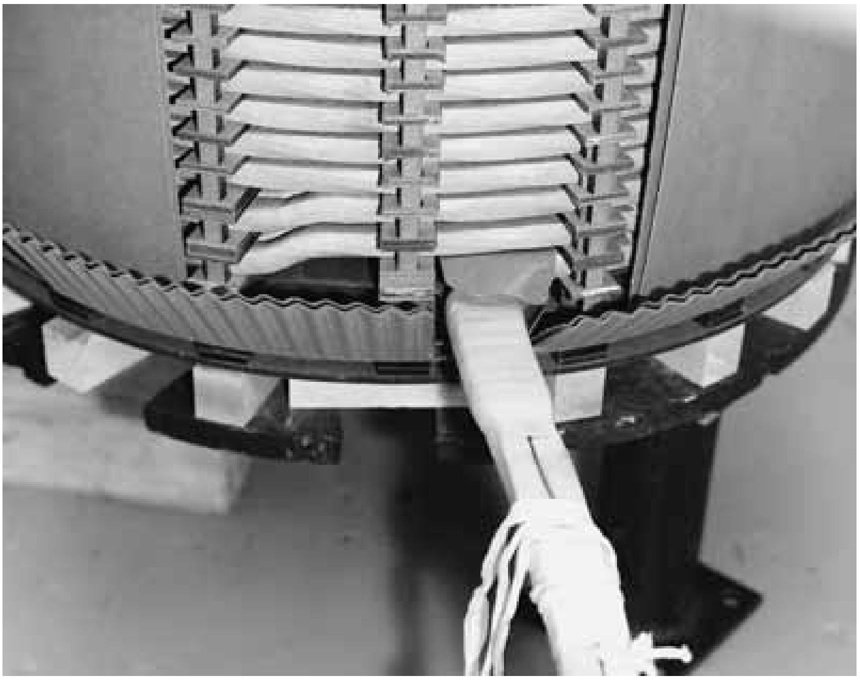


Figure 4.83 Part of a winding of a saturated reactor showing detail of external bracing (GEC Alsthom)

axial forces and he will certainly aim to ensure that primary and secondary windings as a whole are balanced, but complete balance of all elements of the winding cannot be achieved entirely for a number of reasons. One is the problem of tappings. Putting these in a separate layer so that there are no gaps in the main body of the HV when taps are not in circuit helps to some extent. However, there will be some unbalance unless each tap occupies the full winding length in the separate layer. One way of doing this would be to use a multistart helical tapping winding but, as mentioned above, simple helical windings placed outside the HV winding would be very difficult to brace against the outward bursting force. In addition spreading the tapping turns throughout the full length of the layer would create problems if the HV line lead were taken from the centre of the winding. Another factor which makes it difficult to obtain complete magnetic balance is the dimensional accuracy and stability of the materials used. Paper insulation and pressboard in a large winding can shrink axially by several centimetres during dry-out and assembly of the windings. Although the manufacturer can assess the degree of shrinkage expected fairly accurately, and will attempt to ensure that it is evenly distributed, it is difficult to do this with sufficient precision to ensure complete balance.

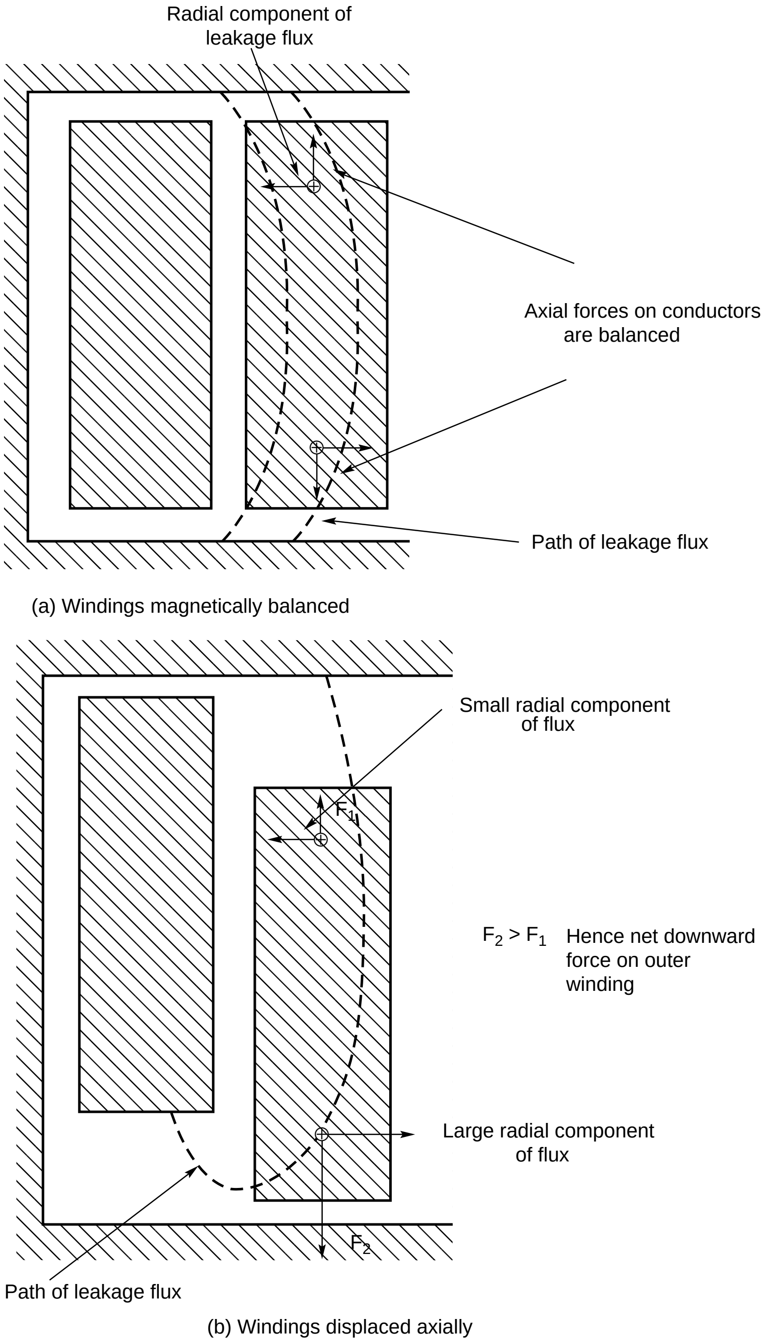


Figure 4.84 Forces within windings

Furthermore, shrinkage of insulation continues to occur in service and, although the design of the transformer should ensure that the windings remain in compression, it is more difficult to ensure that such shrinkage will be uniform. With careful design and manufacture the degree of unbalance will be small. Nevertheless it must be remembered that short-circuit forces are proportional to current squared and that the current in question is the initial peak asymmetrical current and not the r.m.s. value. Considering the 60 MVA transformer of the previous example for which the r.m.s. short-circuit current was calculated as 6.8 times full-load current. BS 171, Part 5, lists in Table V values of asymmetry factor, $k\sqrt{2}$, against X/R ratio for the circuit. These are reproduced in *Table 4.2*. For most grid transformer circuits this is likely to fall into the greater than or equal to 14 category, so that $k\sqrt{2}$ is 2.55. Thus the first peak of the current is $2.55 \times 6.8 = 17.34$ times full-load current. Force is proportional to the square of this, i.e. over 300 times that occurring under normal full-load current conditions.

Table 4.2 Values of factor $k\sqrt{2}$

X/R	1	1.5	2	3	4	5	6	8	10	≥14
$k\sqrt{2}$	1.51	1.64	1.76	1.95	2.09	2.19	2.27	2.38	2.46	2.55

Note. For other values of X/R between 1 and 14, the factor $k\sqrt{2}$ may be determined by linear interpolation.

Expressing the above in general terms, the first peak of the short-circuit current will be:

$$\hat{I}_{sc} = \frac{k\sqrt{2}\ \text{MVA}\ 10^6}{\sqrt{3}V(e_z + e_s)} \text{amperes} \tag{4.4}$$

where $k\sqrt{2}$ is the asymmetry factor
MVA is the transformer rating in mega voltamperes
V is the transformer rated voltage in volts

Axial forces under short-circuit are resisted by transmitting them to the core. The top and bottom core frames incorporate pads which bear on the ends of the windings, these pads distributing the load by means of heavy-section pressboard or compressed laminated-wood platforms. The top and bottom core frames, in turn, are linked together by steel tie-bars which have the dual function of resisting axial short-circuit forces and ensuring that when the core and coils are lifted via the top core frames on the assembly, the load is supported from the lower frames. These tie-bars can be seen in *Figure 4.7* which shows a completed core before fitting of the windings.

Calculation of forces

The precise magnitude of the short-circuit forces depends very much upon the leakage flux pattern, and the leakage flux pattern also determines such important parameters as the leakage reactance and the magnitude of the stray losses. Manufacturers nowadays have computer programs based on finite element analysis which enable them to accurately determine the leakage flux throughout the windings. These computer programs can be very simply extended for the calculation of short-circuit forces to enable manufacturers to accurately design for these. Occasionally, however, it might be necessary to make a longhand calculation and in this case the following, which is based on an ERA Report Ref. Q/T134, 'The measurement and Calculation of Axial Electromagnetic Forces in Concentric Transformer Windings', by M. Waters, BSc, FIEE., and a paper with the same title published in the *Proceedings of the Institution of Electrical Engineers*, Vol. 10, Part II, No. 79, February 1954, will be of assistance.

Short-circuit currents

The calculations are based on the first peak of short-circuit current derived in expression (4.4) above.

The limb current $I_{\max}$ corresponding to this value is used in force calculations.

The impedance voltage e_z is dependent upon the tapping position, and to calculate the forces accurately it is necessary to use the value of impedance corresponding to the tapping position being considered. For normal tapping arrangements the change in the percentage impedance due to tappings is of the order of 10%, and if this is neglected the force may be in error by an amount up to $\pm 20\%$.

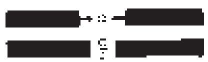
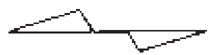
For preliminary calculations, or if a margin of safety is required, the minimum percentage impedance which may be obtained on any tapping should be used, and in the case of tapping arrangements shown in column one of *Table 4.3* this corresponds to the tapping giving the best balance of ampere-turns along the length of the limb. However, in large transformers, where a good ampere-turn balance is essential to keep the forces within practical limits, the change in percentage impedance is small and can usually be neglected.

When calculating forces the magnetising current of the transformer is neglected, and the primary and secondary windings are assumed to have equal and opposite ampere-turns. All forces are proportional to the square of the ampere-turns, with any given arrangement of windings.

Mechanical strength

It has been suggested by other authors that the mechanical strength of a power transformer should be defined as the ratio of the r.ms. value of the symmetrical short-circuit current to the rated full-load current. The corresponding stresses which the transformer must withstand are based upon the peak value of the short-circuit current assuming an asymmetry referred to earlier. A transformer

Table 4.3

Arrangement of tappings	Residual ampere-turn diagram	P_A, kN	$\Lambda\left(\dfrac{\text{Window height}}{\text{Core circle}}\right) = 4.2$	$\Lambda\left(\dfrac{\text{Window height}}{\text{Core circle}}\right) = 2.3$
A 		$\dfrac{2\pi a(NI_{max})^2\Lambda}{10^{10}}$	5.5	6.4
B 		$\dfrac{\pi a(NI_{max})^2\Lambda}{2\times 10^{10}}$	5.8	6.6
C 		$\dfrac{\pi a(NI_{max})^2\Lambda}{4(1-\frac{1}{2}a)\times 10^{10}}$	5.8	6.6
D 		$\dfrac{\pi a(NI_{max})^2\Lambda}{8\times 10^{10}}$	6.0	6.8
E 		$\dfrac{\pi a(NI_{max})^2\Lambda}{16(1-\frac{1}{2}a)\times 10^{10}}$	6.0	6.8

designed to withstand the current given by equation (4.4) would thus have a strength of $i/(e_z + e_s)$.

It will be appreciated that the strength of a transformer for a single fault may be considerably greater than that for a series of faults, since weakening of the windings and axial displacement may be progressive. Moreover, a transformer will have a mechanical strength equal only to the strength of the weakest component in a complex structure. Progressive weakening also implies a short-circuit 'life' in addition to a short-circuit strength. The problem of relating system conditions to short-circuit strength is a complex one and insufficient is yet known about it for definite conclusions to be drawn.

Radial electromagnetic forces

These forces are relatively easy to calculate since the axial field producing them is accurately represented by the simple two-dimensional picture used for reactance calculations. They produce a hoop stress in the outer winding, and a compressive stress in the inner winding.

The mean hoop stress σ_{mean} in the conductors of the outer winding at the peak of the first half-wave of short-circuit current, assuming an asymmetry factor of 2.55 and a supply impedance e_s is given by:

$$\hat{\sigma}_{\text{mean}} = \frac{0.031W_{cu}}{h(e_z + e_s)^2} \text{ kN/mm}^2\text{(peak)} \tag{4.5}$$

where $W_{cu} = I^2R_{dc}$ loss in the winding in kW at rated full load and at 75°C
h = axial height of the windings in mm

Normally this stress increases with the kVA per limb but it is important only for ratings above about 10 MVA per limb. Fully annealed copper has a very low mechanical strength and a great deal of the strength of a copper conductor depends upon the cold working it receives after annealing, due to coiling, wrapping, etc. It has been suggested that 0.054 kN/mm^2 represents the maximum permissible stress in the copper, if undue permanent set in the outer winding is to be avoided. For very large transformers, some increase in strength may be obtained by lightly cold working the copper or by some form of mechanical restraint. Ordinary high-conductivity copper when lightly cold worked softens very slowly at transformer temperatures and retains adequate strength during the life of an oil-filled transformer.

The radial electromagnetic force is greatest for the inner conductor and decreases linearly to zero for the outermost conductor. The internal stress relationship in a disc coil is such that considerable levelling up takes place and it is usually considered that the mean stress as given in equation (4.5) may be used in calculations.

The same assumption is often made for multilayer windings, when the construction is such that the spacing strips between layers are able to transmit the pressure effectively from one layer to the next. If this is not so then the stress in the layer next to the duct is twice the mean value.

Inner windings tend to become crushed against the core, and it is common practice to support the winding from the core and to treat the winding as a continuous beam with equidistant supports, ignoring the slight increase of strength due to curvature. The mean radial load per mm length of conductor of a disc coil is:

$$W = \frac{0.031\hat{\sigma}A_c}{D_w} \text{ kN/mm length}$$

or alternatively,

$$W = \frac{510U \times 1}{(e_z + e_s)fd_1\pi D_m N} \text{ kN/mm length} \tag{4.6}$$

where A_c = cross-sectional area of the conductor upon which the force is required, mm^2
D_w = mean diameter of winding, mm
U = rated kVA per limb
f = frequency, Hz
$\hat{\sigma}$ = peak value of mean hoop stress, kN/mm^2, from equation (4.5)
d_1 = equivalent duct width, mm
D_m = mean diameter of transformer (i.e. of HV and LV windings), mm
N = number of turns in the winding

Equation (4.6) gives the total load per millimetre length upon a turn or conductor occupying the full radial thickness of the winding. In a multilayer winding with k layers the value for the layer next to the duct would be $(2k - 1)/k$ times this value, for the second layer $(2k - 3)/k$, and so on.

Where the stresses cannot be transferred directly to the core, the winding itself must be strong enough to withstand the external pressure. Some work has been carried out on this problem, but no method of calculation proved by tests has yet emerged. It has been proposed, however, to treat the inner winding as a cylinder under external pressure, and although not yet firmly established by tests, this method shows promise of being useful to transformer designers.

Axial electromagnetic forces

Forces in the axial direction can cause failure by producing collapse of the winding, fracture of the end rings or clamping system, and bending of the conductors between spacers; or by compressing the insulation to such an extent that slackness occurs which can lead to displacement of spacers and subsequent failure.

Measurement of axial forces

A simple method is available, developed by ERA Technology Limited (formerly the Electrical Research Association), for measuring the total axial force upon the whole or part of a concentric winding. This method does not indicate how the force is distributed round the circumference of the winding but this is only a minor disadvantage.

If the axial flux linked with each coil of a dise winding at a given current is plotted against the axial position, the curve represents, to a scale which can be calculated, the axial compression curve of the winding. From such a curve the total axial force upon the whole or any part of a winding may be read off directly.

The flux density of the radial component of leakage field is proportional to the rate of change of axial flux with distance along the winding. The curve of axial flux plotted against distance thus represents the integration of the radial flux density and gives the compression curve of the winding if the points of zero compression are marked.

The voltage per turn is a measure of the axial flux, and in practice the voltage of each disc coil is measured, and the voltage per turn plotted against the mid-point of the coil on a diagram with the winding length as abscissa. The method can only be applied to a continuous disc winding by piercing the insulation at each crossover.

The test is most conveniently carried out with the transformer short-circuited as for the copper-loss test.

The scale of force at 50 Hz is given by

$$1 \text{ volt (r.m.s.)} = \frac{\text{r.m.s. ampere-turns per mm}}{15\,750} \text{ kN (peak)}$$

To convert the measured voltages to forces under short-circuit conditions the values must be multiplied by $(2.55I_{sc}/I_t)^2$ where I_{sc} is the symmetrical short-circuit current and I_t the current at which the test is carried out.

To obtain the compression curve it is necessary to know the points of zero compression, and these have to be determined by inspection. This is not difficult since each arrangement of windings produces zero points in well-defined positions.

A simple mutual inductance potentiometer can be used instead of a volt-meter, and a circuit of this type is described in ERA Report, Ref. Q/T 113, the balance being independent of current and frequency.

Figure 4.85 shows typical axial compression curves obtained on a transformer having untapped windings of equal heights. There are no forces tending to separate the turns in the axial direction. The ordinates represent the forces between coils at all points, due to the current in the windings. Since the slope of the curve represents the force developed per coil it will be seen that only in the end coils are there any appreciable forces. The dotted curve, which is the sum of the axial compression forces for the inner and outer curves, has a maximum value given by:

$$P_c = \frac{510U}{(e_z + e_s)fh} \text{ kN} \tag{4.7}$$

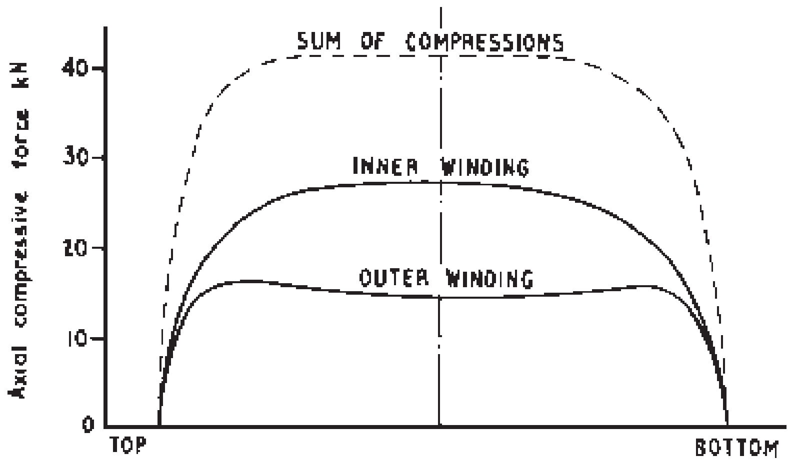


Figure 4.85 Axial compression curves for untapped transformer windings

in terms of *U* the rated kVA per limb and *h* the axial height of the windings in millimetres. This is the force at the peak of the first half cycle of fault current, assuming an asymmetry factor of 2.55.

The results shown in *Figure 4.85* and other similar figures appearing later in this chapter were obtained on a three-phase transformer constructed so that the voltage across each disc coil in both inner and outer coil stacks could easily be measured. To ensure very accurate ampere-turn balance along the whole length of the windings, primary and secondary windings consisted of disc coils identical in all respects except diameter, and spacing sectors common to both windings were used so that each disc coil was in exactly the same axial position as the corresponding coil in the other winding.

It will be noted that the forces in a transformer winding depend only upon its proportions and on the total ampere-turns, and not upon its physical size. Thus, model transformers are suitable for investigating forces, and for large units where calculation is difficult it may be more economical to construct a model and measure the forces than to carry out elaborate calculations.

The voltage per turn method has proved very useful in detecting small accidental axial displacements of two windings from the normal position.

Calculation of axial electromagnetic forces

The problem of calculating the magnitude of the radial leakage field and hence the axial forces of transformer windings has received considerable attention and precise solutions have been determined by various authors. These methods are complex and a computer is necessary if results are to be obtained quickly and economically. The residual ampere-turn method gives reliable results, and attempts to produce closer approximations add greatly to the complexity without a corresponding gain in accuracy. This method does not give the force on individual coils, but a number of simple formulae of reasonable accuracy are available for this purpose.

Residual ampere-turn method

The axial forces are calculated by assuming the winding is divided into two groups, each having balanced ampere-turns. Radial ampere-turns are assumed to produce a radial flux which causes the axial forces between windings.

The radial ampere-turns at any point in the winding are calculated by taking the algebraic sum of the ampere-turns of the primary and secondary windings between that point and either end of the windings. A curve plotted for all points is a residual or unbalanced ampere-turn diagram from which the method derives its name. It is clear that for untapped windings of equal length and without displacement there are no residual ampere-turns or forces between windings. Nevertheless, although there is no axial thrust between windings, internal compressive forces and forces on the end coils are present. A simple expedient enables the compressive forces present when the ampere-turns are balanced to be taken into account with sufficient accuracy for most design purposes.

The method of determining the distribution of radial ampere-turns is illustrated in *Figure 4.86* for the simple case of a concentric winding having a fraction a of the total length tapped out at the end of the outer winding. The two components I and II of *Figure 4.86(b)* are both balanced ampere-turn groups which, when superimposed, produce the given ampere-turn arrangement. The diagram showing the radial ampere-turns plotted against distance along the winding is a triangle, as shown in *Figure 4.86(c)*, having a maximum value of $a(NI_{\max})$, where $(NI_{\max})$ represents the ampere-turns of either the primary or secondary winding.

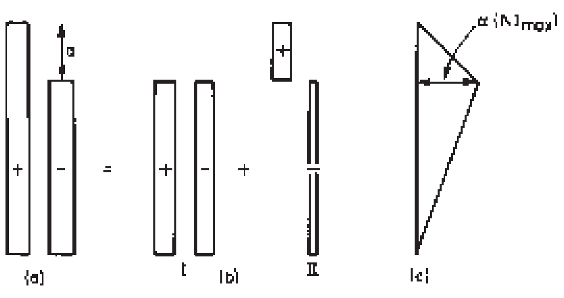


Figure 4.86 Determination of residual ampere-turn diagram for winding tapped at one end

To determine the axial forces, it is necessary to find the radial flux produced by the radial ampere-turns or, in other words, to know the effective length of path for the radial flux for all points along the winding. The assumption is made that this length is constant and does not vary with axial position in the winding. Tests show that this approximation is reasonably accurate, and that the flux does, in fact, follow a triangular distribution curve of a shape similar to the residual ampere-turn curve.

The calculation of the axial thrust in the case shown in *Figure 4.86* can now be made as follows. If l_{eff} is the effective length of path for the radial flux, and since the mean value of the radial ampere-turns is $\frac{1}{2}a(NI_{\text{max}})$, the mean radial flux density at the mean diameter of the transformer is:

$$B_r = \frac{4\pi}{10^4}\frac{a(NI_{\text{max}})}{2l_{\text{eff}}} \text{ teslas}$$

and the axial force on either winding of NI_{max} ampere-turns is:

$$P_A = \frac{2\pi a(NI_{\text{max}})^2}{10^{10}}\frac{\pi D_m}{l_{\text{eff}}} \text{ kN} \tag{4.8}$$

The second factor of this expression, $\pi D_m/l_{\text{eff}}$, is the permeance per unit axial length of the limb for the radial flux, referred to the mean diameter of the transformer. It is independent of the physical size of the transformer and depends only upon the configuration of the core and windings. Forces are greatest in the middle limb of a three-phase transformer, and therefore the middle limb only need be considered. A review of the various factors involved indicates that the forces are similar in a single-phase transformer wound on two limbs. Thus if equation (4.8) is written as:

$$P_A = \frac{2\pi a(NI_{\text{max}})^2}{10^{10}}\Lambda \text{ kN} \tag{4.9}$$

where $\Lambda = \pi D_m/l_{\text{eff}}$ and is the permeance per unit axial length of limb, it gives the force for all transformers having the same proportions whatever their physical size. Since the ampere-turns can be determined without difficulty, in order to cover all cases it is necessary to study only how the constant Λ varies with the proportions of the core, arrangement of tappings, dimensions of the winding duct and proximity of tank.

Reducing the duct width increases the axial forces slightly, and this effect is greater with tapping arrangements which give low values of residual ampere-turns. However, for the range of duct widths used in practice the effect is small.

Where the equivalent duct width is abnormally low, say less than 8% of the mean diameter, forces calculated using the values given in *Table 4.3* should be increased by approximately 20% for tappings at two points equidistant from the middle and ends, and 10% for tappings at the middle. The axial forces are also influenced by the clearance between the inner winding and core. The closer the core is to the windings, the greater is the force.

The effect of tank proximity is to increase Λ in all cases, and for the outer limbs of a three-phase transformer by an appreciable amount; however, the middle limb remains practically unaffected unless the tank sides are very close to it. As would be expected, the presence of the tank has the greatest effect for tappings at one end of the winding, and the least with tappings at two points equidistant from the middle and ends of the winding. As far as limited tests can show, the presence of the tank never increases the forces in the outer limbs to values greater than those in the middle limb, and has no appreciable effect upon the middle limb with practical tapping arrangements. The only case in which the tank would have appreciable effect is in that of a single-phase transformer wound on one limb, and in this case the value of Λ would again not exceed that for the middle phase of a three-phase transformer.

The location of the tappings is the predominating influence on the axial forces since it controls the residual ampere-turn diagram. Forces due to arrangement E in *Table 4.3* are only about one-thirty-second of those due to arrangement A. The value of Λ is only slightly affected by the arrangement of tappings so that practically the whole of the reduction to be expected from a better arrangement of tappings can be realised. It varies slightly with the ratio of limb length to core circle diameter, and also if the limbs are more widely spaced.

In *Table 4.3* values of Λ are given for the various tapping arrangements and for two values of the ratio, window height/core circle diameter. The formula for calculating the axial force on the portion of either winding under each triangle of the residual ampere-turn diagram is given in each case. The values of Λ apply to the middle limb with three-phase excitation, and for the tapping sections in the outer winding.

Axial forces for various tapping arrangements

Additional axial forces due to tappings can be avoided by arranging the tappings in a separate coil so that each tapping section occupies the full winding height. Under these conditions there are no ampere-turns acting radially and the forces are the same as for untapped windings of equal length. Another method is to arrange the untapped winding in a number of parallel sections in such a way that there is a redistribution of ampere-turns when the tapping position is changed and complete balance of ampere-turns is retained.

(i) Transformer with tappings at the middle of the outer winding

To calculate the radial field the windings are divided into two components as shown in *Figure 4.87*. Winding group II produces a radial field diagram as shown in (*c*). The two halves of the outer winding are subjected to forces in opposite directions towards the yokes while there is an axial compression of similar magnitude at the middle of the inner winding.

Measured curves are given in *Figure 4.88* for the case of $13\frac{1}{3}$% tapped out of the middle of the outer winding. The maximum compression in the outer winding is only slightly greater than the end thrust, and it occurs at four to

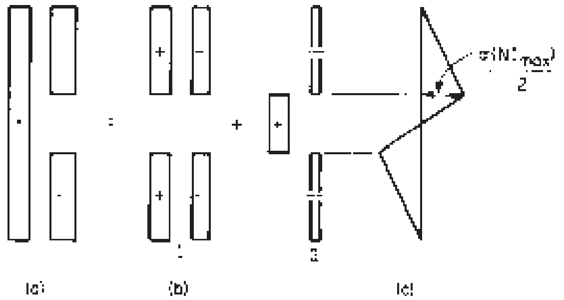


Figure 4.87 Determination of residual ampere-turn diagram for winding tapped at middle

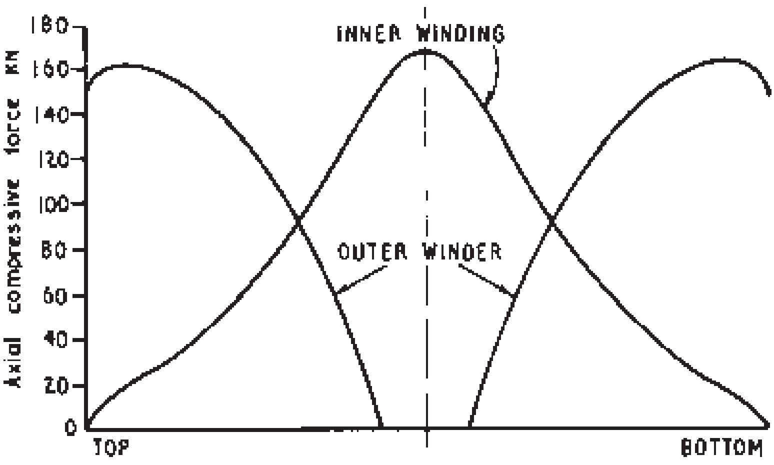


Figure 4.88 Axial compression curves for $13\frac{1}{3}$% tapped out of the middle of the outer winding

five coils from the ends. The maximum compression in the inner winding is at the middle.

Axial end thrust The axial end thrust is given by:

$$P_A = \frac{\pi a (NI_{\max})^2 \Lambda}{2 \times 10^{10}} \text{ kN} \tag{4.10}$$

Maximum compression If P_c is the sum of both compressions as given by equation (4.9) and it is assumed that two-thirds of this is the inner winding, then the maximum compression in the inner winding is given by:

$$P_{max} = \frac{2}{3} \times \frac{51U}{(e_z + e_s)fh} + \frac{\pi a (NI_{max})^2 \Lambda}{2 \times 10^{10}} \text{ kN} \tag{4.11}$$

The maximum compression in the outer winding is slightly less than this.

Figure 4.89 shows curves of maximum compression in the inner and outer windings, and of end thrust plotted against the fraction of winding tapped out for the same transformer. Equation (4.10) represents the line through the origin.

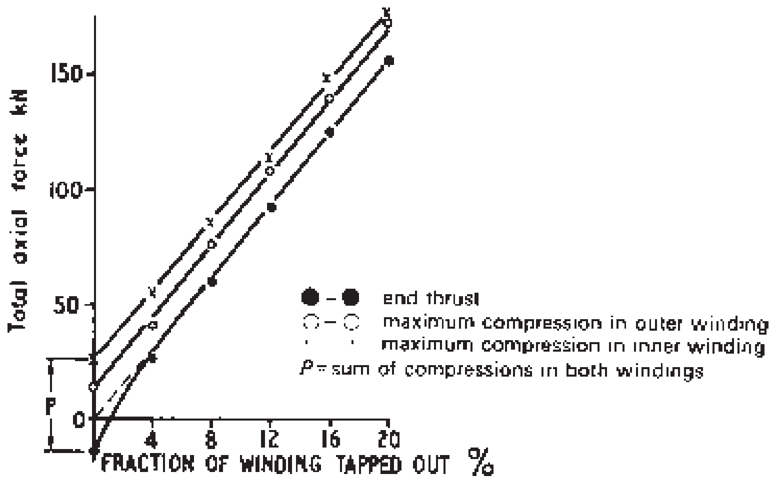


Figure 4.89 Curves of end thrust and maximum compression for tappings at the middle of the outer winding

Most highly stressed turn or coil The largest electromagnetic force is exerted upon the coils immediately adjacent to the tapped out portion of a winding and it is in these coils that the maximum bending stresses occur when sector spacers are used. The force upon a coil or turn in the outer winding immediately adjacent to the gap is given theoretically by:

$$P_A = 7.73 q P_r \log_{10}\left(\frac{2a'}{w} + 1\right) \text{ kN} \tag{4.12}$$

where P_r = total radial bursting force of transformer, kN
q = fraction of total ampere-turns in a coil or winding
w = axial length of coil including insulation, mm
a' = axial length of winding tapped out

There is reasonable agreement between calculated and measured forces; the calculated values are 10–20% high, no doubt owing to the assumption that the windings have zero radial thickness.

The coils in the inner winding exactly opposite to the most highly stressed coils in the outer winding have forces acting upon them of a similar, but rather lower, magnitude.

(ii) Tappings at the middle of the outer winding but with thinning of the inner winding

The forces in the previous arrangement may be halved by thinning down the ampere-turns per unit length to half the normal value in the portion of the untapped winding opposite the tappings. Alternatively, a gap may be left in the untapped winding of half the length of the maximum gap in the tapped winding. With these arrangements there is an axial end thrust from the untapped winding when all the tapped winding is in circuit, and an end thrust of similar magnitude in the tapped winding when all the tappings are out of circuit. In the mid-position there are no appreciable additional forces compared with untapped windings.

(a) Axial end thrust When all tappings are in circuit the end thrust of the untapped winding may be calculated by means of equation (4.10), substituting for a the fractional length of the gap in the untapped winding. When all tappings are out of circuit the end thrust is given by:

$$P_A = \frac{\pi a (NI_{\max})^2 \Lambda}{4(1 - \frac{1}{2}a)10^{10}} \text{ kN} \tag{4.13}$$

where a, the fraction of the axial length tapped out, is partially compensated by a length $\frac{1}{2}a$ omitted from the untapped winding. The constant Λ has the same value as in equation (4.10). The forces are similar when the ampere-turns are thinned down instead of a definite gap being used.

(b) Maximum compression In either of the two preceding cases the maximum compression exceeds the end thrust by an amount rather less than the force given by equation (4.7).

(c) Most highly stressed coil or turn When all tappings are in circuit, the force upon the coil or turn adjacent to the compensating gap in the untapped winding may be calculated by applying equation (4.12); in such a case a would be the length of the gap expressed as a fraction. It should be noted, however, that since thinning or provision of a compensating gap is usually carried out on the inner winding, the presence of the core increases the force slightly. Hence this equation is likely to give results a few per cent low in this case. On the other hand, when thinning is used, the force upon the coil adjacent to the thinned-out portion of winding is rather less than given by equation (4.12).

(iii) Two tapping points midway between the middle and ends of the outer winding

(a) Without thinning of the untapped winding A typical example of the compression in the inner and outer windings is given in *Figure 4.90* for the case of approximately 13% tapped out of the outer winding, half being at each of two points midway between the middle and ends of the winding.

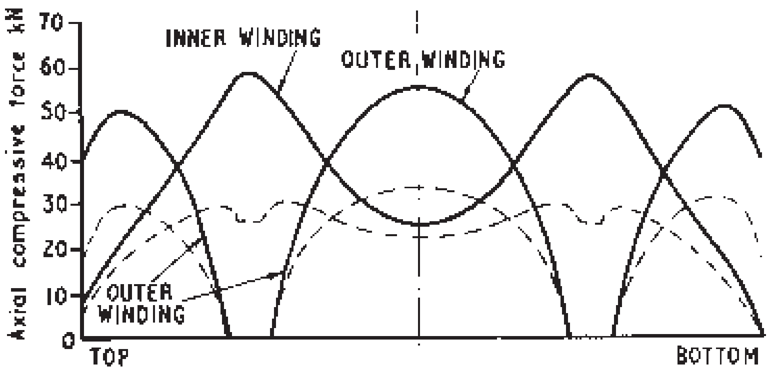


Figure 4.90 Axial compression curve for tappings at two points in the outer winding. Dashed curves show force with thinning of the inner winding opposite each tapping point

There are three points of maximum compression in the outer winding, the middle one being the largest. In the inner winding there are two equal maxima opposite the gaps in the outer winding.

The axial force upon each quarter of either winding due to the tappings is given by:

$$P_A = \frac{\pi a (NI_{\max})^2 \Lambda}{8 \times 10^{10}} \text{ kN} \tag{4.14}$$

where a is the total fraction of axial length tapped out, and the constant Λ has the value given in *Table 4.3*.

This force acts towards the yokes in the two end sections of the outer winding, so that equation (4.10) gives the axial end thrust for the larger values of a. The curve of end thrust plotted against the fraction tapped out can be estimated without difficulty since it deviates only slightly from the straight line of equation (4.14).

The forces with this arrangement of tappings are only about one-sixteenth of the forces due to tappings at one end of the winding, and they are of the same order as the forces in the untapped winding.

The most highly stressed coils are those adjacent to the tapping points, and the forces may be calculated from equation (4.12) by substituting $\frac{1}{2}a$ for a.

(b) With thinning of the untapped winding This practice represents the optimum method of reducing forces when a section is tapped out of a winding, and the dashed curves in *Figure 4.90* show the forces obtained when the inner winding is thinned opposite each of the two gaps in the outer winding to an extent of 50% of the total tapping range. The force upon each quarter of either winding is

$$P_A = \frac{\pi a (NI_{\max})^2 \Lambda}{16 \times 10^{10}} \text{ kN} \tag{4.15}$$

when all tappings are in circuit, and:

$$P_A = \frac{\pi a (NI_{\max})^2 \Lambda}{16(1 - \frac{1}{2}a)10^{10}} \text{ kN} \tag{4.16}$$

when all tappings are out of circuit. In these equations Λ has the value given in *Table 4.3,* and a represents the total fraction tapped out.

The forces upon the coils immediately adjacent to the gaps may be calculated as described in equation (4.12), since these forces are determined by the lengths of the gaps and not by their positions in the winding.

4.8 TANKS AND ANCILLARY EQUIPMENT

Transformer tanks

The transformer tank provides the containment for the core and windings and for the dielectric fluid. It must withstand the forces imposed on it during transport. On larger transformers, it usually also provides additional structural support for the core during transport. All but the smallest transformers are impregnated with oil under vacuum: the tank acts as the vacuum vessel for this operation.

Transformer tanks are almost invariably constructed of welded boiler plate to BS 4630 although in the case of some large transformers manufactured in the UK in the 1960s, aluminium was used in order to enable these to remain within the road transport weight limitations. The tank must have a removable cover so that access can be obtained for the installation and future removal, if necessary, of core and windings. The cover is fastened by a flange around the tank, usually bolted but on occasions welded – more on this aspect later – usually at a high level so that it can be removed for inspection of core and windings, if required, without draining all the oil. The cover is normally the simplest of fabrications, often no more than a stiffened flat plate. It should be inclined to the horizontal at about 1°, so that it will not collect rainwater: any stiffeners should also be arranged so that they will not collect water, either by the provision of drain holes or by forming them from channel sections with the open face downwards.

Even when they are to be finally sealed by means of continuous welding (see below) the joints between the main cover and the tank, and all smaller access covers, are made oil tight by means of gaskets. These are normally of synthetic rubber-bonded cork, or neoprene-bonded cork. This material consists of small cork chippings formed into sheets by means of a sythetic rubber compound. The thickness of the gaskets varies from around 6 to 15 mm according to the cross-section of the joint; however, the important feature is that the material is synthetic rubber based rather than using natural rubber since the former material has a far greater resistance to degradation by contact with mineral oil.

The tank is provided with an adequate number of smaller removable covers, allowing access to bushing connections, winding temperature CTs, core earthing links, off-circuit tapping links and the rear of tapping selector switches. Since the manufacturer needs to have access to these items in the works the designer ensures that adequate provision is made. All gasketed joints on the tank represent a potential source of oil leakage, so these inspection covers should be kept to a minimum. The main tank cover flange usually represents the greatest oil leakage threat, since, being of large cross-section, it tends to provide a path for leakage flux, with the resultant eddy-current heating leading to overheating and degradation of gaskets. Removable covers should be large enough to provide adequate safe access, able to withstand vacuum and pressure conditions and should also be small and light enough to enable them to be handled safely by maintenance personnel on site. This latter requirement usually means that they should not exceed 25 kg in weight.

Occasionally, the tanks of larger transformers may be provided with deep top main covers, so that the headroom necessary to lift the core and windings from the tank is reduced. This arrangement should be avoided, if possible, since a greater quantity of oil needs to be removed should it be necessary to lift the cover and it requires a more complex cover fabrication. It is also possible to provide a flange at low level, which may be additional to or instead of a high-level flange. This enables the cover to be removed on site, thus giving access to core and windings, without the need to lift these heavier items out of the tank. A tank having this arrangement of low-level flange is shown in *Figure 4.91*. It should be noted that while it can in certain circumstances be worthwhile incorporating such features into the design, it is never a straightforward matter to work on large high-voltage transformers on site so that this should not be considered as normal practice. (Nevertheless, in the UK, the CEGB has on a number of occasions carried out successful site repairs which have necessitated detanking of core and windings. Such on-site working does require careful planning and skilled operators and on these occasions was only undertaken when a clear knowledge of the scope of the work required and the ability to carry this out was evident. Often it is the ability to satisfactorily test on site the efficacy of the work after completion, which can be a critical factor in making the decision to do the work on site.)

Tanks which are required to withstand vacuum must be subjected to a type test to prove the design capability. This usually involves subjecting the first tank of any new design, when empty of oil, to a specified vacuum and measuring the permanent deformation remaining after the vacuum has been

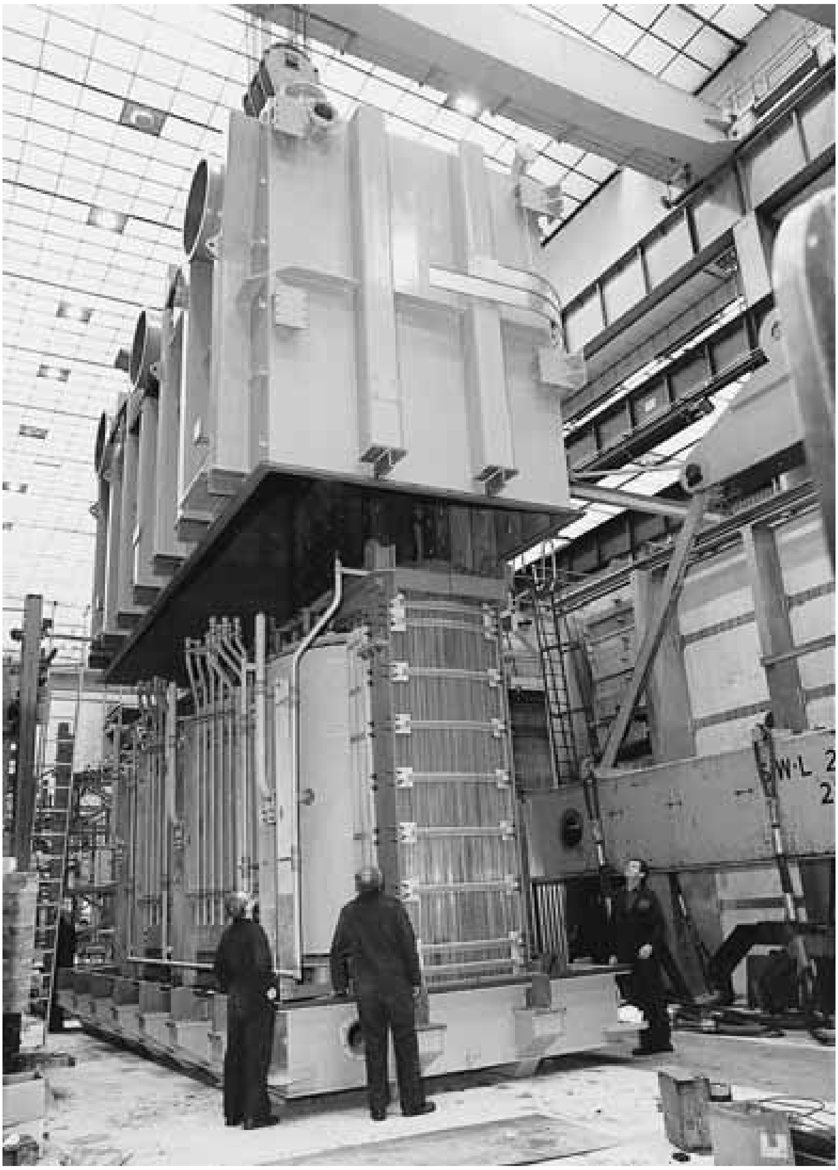


Figure 4.91 Transformer tank with low-level flange

released. The degree of vacuum applied usually depends on the voltage class which will determine the vacuum necessary when the tank is used as an impregnation vessel. Up to and including 132 kV transformer tanks, a vacuum equivalent to 330 mbar absolute pressure is usually specified and for higher voltage transformers the vacuum should be 25 mbar absolute. The acceptable permanent deflection after release of the vacuum depends on the dimensions of the tank. *Table 4.4* gives an indication of the levels of deflection which may be considered acceptable for particular sizes of tanks.

Table 4.4 Maximum permissible permanent deflection of tanks and other assemblies following vacuum withstand test

Minimum dimension of tank or fabricated assembly (metres)	*Maximum permanent deflection after release of vacuum (mm)*
Not exceeding 1.3	3
Exceeding 1.3 but not exceeding 2	6
Exceeding 2 but not exceeding 2.5	10
Exceeding 2.5	13

Mention has been made of the need to avoid, or reduce, the likelihood of oil leaks. The welding of transformer tanks does not demand any sophisticated processes but it is nevertheless important to ensure that those welds associated with the tank-lifting lugs are of good quality. These are usually crack tested, either ultrasonically or with dye penetrant. Tanks must also be given an adequate test for oil tightness during manufacture. Good practice is to fill with white spirit or some other fairly penetrating low-viscosity liquid and apply a pressure of about 700 mbar, or the normal pressure plus 350 mbar, whichever is the greater, for 24 hours. This must be contained without any leakage.

The tank must carry the means of making the electrical connections. Cable boxes are usual for all voltages up to and including 11 kV, although for pole-mounted distribution transformers the preferred arrangement is to terminate the connecting cable in an air sealing-end and jumper across to 11 or 3.3 kV bushings on the transformer. Such an arrangement is shown in *Figure 4.92*. Above this voltage air bushings are normally used, although increasing use is now being made of SF_6-filled connections between transformer and switchgear at 132 kV and above this can be particularly convenient in poluted locations or on sites where space is not available for the necessary air clearances required by bushings.

Tanks must be provided with valves for filling and draining, and to allow oil sampling when required. These also enable the oil to be circulated through external filtration and drying equipment prior to initial energisation on site, or during service when oil has been replaced after obtaining access to the core and windings. Lifting lugs or, on small units, lifting eyes must be provided, as well as jacking pads and haulage holes to enable the transformer to be manoeuvred on site. On all but the smaller distribution transformers an oil sampling valve must also be provided to enable a sample of the oil to be taken for analysis with the minimum of disturbance or turbulence, which might cause changes to the dissolved gas content of the sample and thereby lead to erroneous diagnosis. Periodic sampling and analysis of the oil is the most reliable guide to the condition of the transformer in service and an important part of the

Figure 4.92 11 kV pole mounted transformer supplied via 11 kV cable having air sealing ends connected via jumpers to bushings on the transformer. Note that the 415 V output from the transformer is also taken away via a cable

maintenance routine. This subject is dealt with in Section 7 of Chapter 6. The sampling valve is normally located about one metre above the tank base in order to obtain as representative a sample as possible.

Transformer tanks must also have one or more devices to allow the relief of any sudden internal pressure rise, such as that resulting from an internal fault. Until a few years ago, this device was usually a bursting diaphragm set in an upstand pipe mounted on the cover and arranged to discharge clear of the tank itself. This had the disadvantage that, once it had burst, it allowed an indefinite amount of oil to be released, which might aggravate any fire associated with the fault, and also it left the windings open to the atmosphere. The bursting diaphragm has been superseded by a spring-operated self-resealing device which only releases the volume of oil necessary to relieve the excess pressure before resealing the tank. As shown in *Figure 4.93*, it is essentially a spring-loaded valve providing instantaneous amplification of the actuation force.

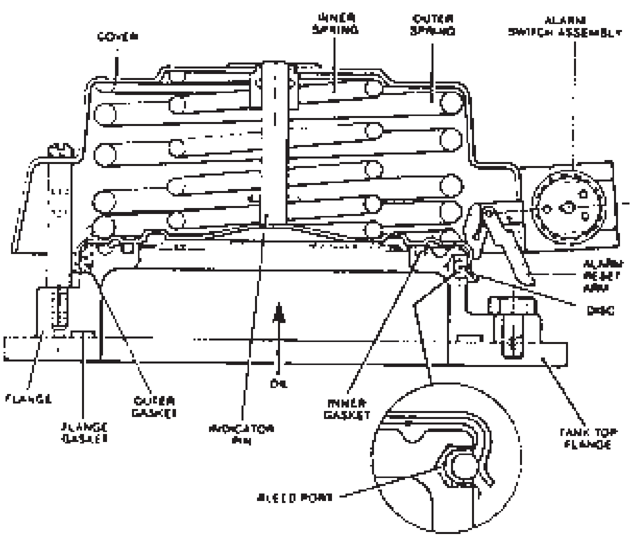


Figure 4.93 Qualitrol pressure relief device

The unit is mounted on a transformer by lugs on the flange and sealed by a mounting gasket. A spring-loaded valve disc is sealed against inner and outer gasket rings by the springs. The valve operates when the oil pressure acting on the area inside the inner gasket ring exceeds the closing force established by the springs. As the disc moves upwards slightly from the inner gasket ring, the oil pressure quickly becomes exposed to the disc area over the diameter of the outer gasket ring, resulting in a greatly increased force, and causing immediate full opening of the valve corresponding to the closed height of the springs. The transformer pressure is rapidly reduced to normal and the springs then return the valve disc to the closed position. A minute bleed port to the outside atmosphere from the volume entrapped between the gasket rings prevents inadvertent valve opening if foreign particles on the inner gasket ring prevent a perfect ring-to-disc seal. A mechanical indicator pin in the cover, although not fastened to the valve disc, moves with it during operation and is held in the operated position by an O-ring in the pin bushing. This remains clearly visible, indicating that the valve has operated.

No pressure relief device can provide complete protection against all internal pressure transients. On the largest tanks, two such devices at opposite ends of the tank improve the protection. It is usual to place the pressure relief device as high on the tank as possible. This minimises the static head applied to the spring, thus reducing the likelihood of spurious operation in the event of a ‘normal’ pressure transient, for example the starting of an oil pump.

However, with the pressure relief device located at high level, there is the risk that operation might drench an operator with hot oil; to prevent this, an enclosure is provided around the device to contain and direct the oil safely down to plinth level. Such enclosure must not, of course, create any significant back pressure which would prevent the relief device from performing its function properly: a minimum cross-section for any ducting of about 300 cm^2 is usually adequate.

To complete the list of fittings on the transformer tank, it is usual to provide a pocket, or pockets, in the cover to take a thermometer for measurement of top oil temperature, a diagram/nameplate to provide information of transformer details, and an earthing terminal for the main tank earth connection.

Oil preservation equipment–conservators

Although it is now common for many of the smaller distribution transformers to dispense with a conservator all of the larger more important oil-filled transformers benefit greatly by the use of a conservator.

The use of a conservator allows the main tank to be filled to the cover, thus permitting cover-mounted bushings, where required, and it also makes possible the use of a Buchholz relay (see below). However, the most important feature of a conservator is that it reduces the surface area of the oil exposed to atmospheric air. This reduces the rate of oxidisation of the oil and also reduces the level of dissolved oxygen, which would otherwise tend to shorten insulation life. The full significance of this aspect of conservators will be made clear in Section 7 of Chapter 6. (See also Section 5 of Chapter 3.)

Recent investigation, for example that of Shroff and Stannett (1985) [4.2], has highlighted the part played by dissolved oxygen in accelerating insulation ageing. Although to date there are no published reports of specific measures which have been implemented to reduce levels of dissolved oxygen beyond the use of conservators, it is possible that some arrangement might be introduced to reduce further the degree of contact between oil and air; for example, this could be simply achieved by the use of a parallel-sided conservator having a ‘float’ covering the surface of the oil. (Some transformer operators in areas with high ambient temperatures and high humidity do, of course, incorporate measures mainly aimed at reducing moisture ingress into the oil. This is discussed further below and in Chapter 7.)

It is necessary to exclude moisture from the air space above the conservator oil level, in order to maintain the dryness of the transformer oil. For transformers below 132 kV, this space is vented through a device containing a drying agent (usually silica gel, impregnated with cobalt chloride) through which the air entering the conservator is passed. When the moisture content of the silica gel becomes excessive, as indicated by the change in colour of the cobalt chloride from blue to pink, its ability to extract further moisture is reduced and it must be replaced by a further charge of dry material. The saturated gel can be reactivated by drying it in an oven when the colour of the crystals will revert to blue.

The effectiveness of this type of breather depends upon a number of factors; the dryness of the gel, the moisture content of the incoming air and the ambient temperature being the most significant.

If optimum performance is to be obtained from a transformer having an HV winding of 132 kV and above or, indeed, any generator transformer operating at high load factor, then it is desirable to maintain a high degree of dryness of the oil, typically less than 10 parts per million by volume at 20°C. Although oil treatment on initial filling can achieve these levels, moisture levels tend to increase over and above any moisture which is taken in through breathing, since water is a product of normal insulation degradation, and this is taking place all the time that the transformer is on-load. It is desirable, therefore, to maintain something akin to a continuous treatment to extract moisture from the oil. This is the principle employed in the refrigeration type of breather, illustrated in *Figure 4.94*. Incoming air is passed through a low-temperature chamber which causes any water vapour present to be collected on the chamber walls. The chamber is cooled by means of thermoelectric modules in which a temperature difference is generated by the passage of an electric current (the Peltier effect). Periodically the current is reversed; the accumulated ice melts and drains away. In addition to the drying of the incoming air, this type of breather can be arranged such that the thermosyphon action created between the air in the cooled duct and that in the air space of the conservator creates a continuous circulation and, therefore, a continuous drying action. As the air space in the conservator becomes increasingly dried, the equilibrium level of moisture in the oil for the pressure and temperature conditions prevailing will be reduced so that the oil will give up water to the air in the space above the oil to restore the equilibrium and this, in turn, causes further moisture to migrate from the insulation to the oil, so that a continuous drying process takes place.

The conservator is provided with a sump by arranging that the pipe connecting with the transformer projects into the bottom by about 75.0 mm. This collects any sludge which might be formed over a period of years by oxidation of the oil. A lockable drain valve is normally fitted and one end of the conservator is usually made removable so that, if necessary, the internals

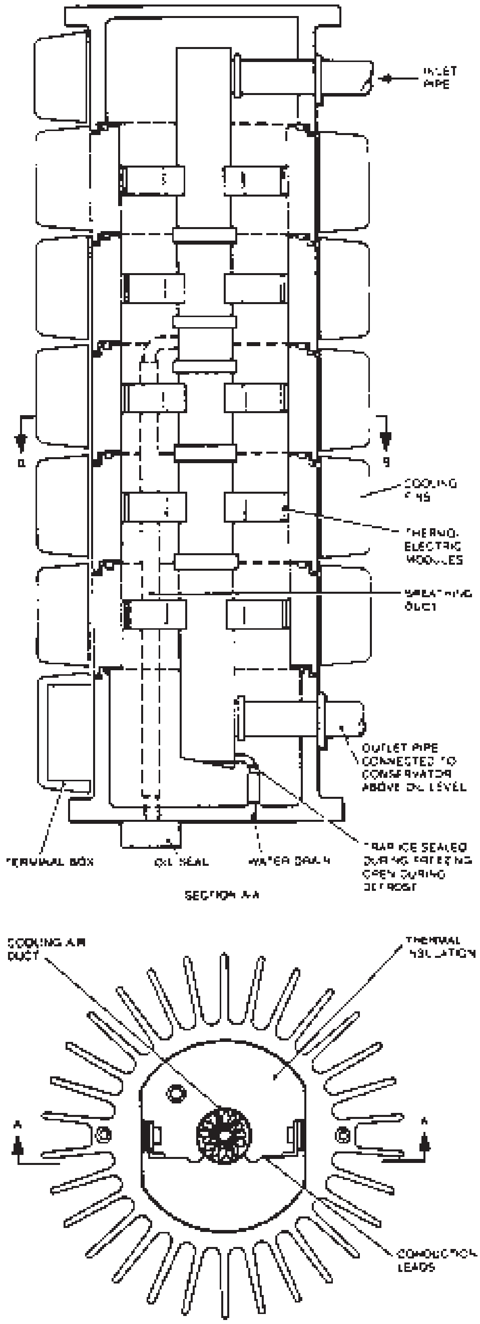


Figure 4.94 Refrigeration breather

may be cleaned out. One end face usually incorporates a prismatic oil level gauge or a magnetic dial-type gauge: these should be angled downwards by some 10–15° so that they can be easily viewed from plinth level. It is usual to show the minimum, cold oil, 75°C and maximum oil levels on whichever type of gauge is provided.

Alternative oil preservation systems

Refrigeration breathers are usually considered too costly to be used on any but the larger more expensive transformers operating at 132 kV or higher for which a high level of oil dryness is necessary. In very humid climates such as those prevailing in many tropical countries the task of maintaining a satisfactory level of dryness of the drying agent in a silica gel-type breather can be too demanding so that alternative forms of breathing arrangements must be adopted. The most common is the air-bag system shown diagramatically in *Figure 4.95*. With this arrangement the transformer has what is basically a normal conservator except that the space above the oil is filled with a synthetic rubber bag. The interior of the bag is then connected to atmosphere so that it can breathe in air when the transformer cools and the oil volume is reduced and breathe this out when the transformer heats up. With this arrangement the oil is prevented from coming into direct contact with the air and thereby lies its disadvantage. Water is one of the products of the degradation of paper insulation and as explained in Chapter 3 the presence of moisture also accelerates the degradation process. If the air space within

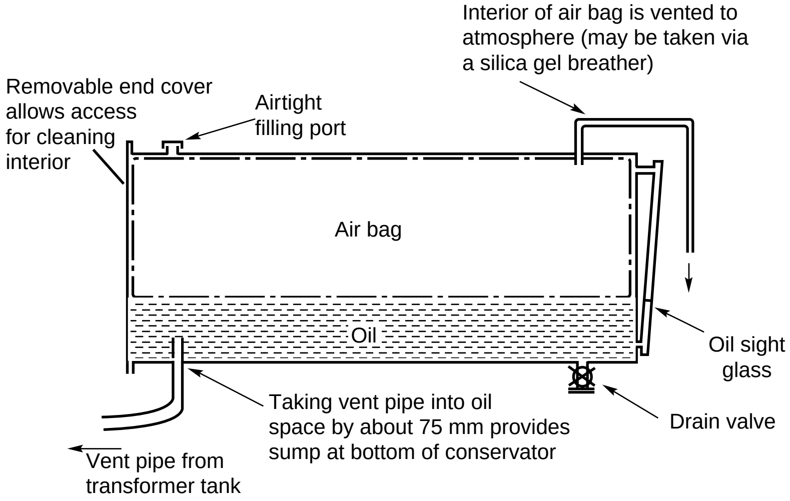


Figure 4.95 Coventionally designed conservator tank but with air space filled with synthetic rubber bag to prevent contact between oil and external air

the conservator is maintained in a dry condition, either by means of a well-maintained silica gel breather or by a refrigeration breather, this will allow moisture to migrate from the oil, and ultimately from the paper insulation to maintain this in a dry condition and minimise ageing. If this moisture remains trapped in the transformer by the presence of a synthetic rubber diaphragm or by other means, the rate of ageing will be increased.

A better arrangement than that just described is again to use basically a normal conservator but to arrange that the space above the oil is filled with dry nitrogen. This can be provided from a cylinder of compressed gas via a pressure reducing valve. When the transformer breathes in due to a reduction in load or ambient temperature the pressure reducing valve allows more nitrogen to be released. When the oil volume increases nitrogen is vented to atmosphere by means of a vent valve. Because the nitrogen is always maintained in a dry state, this arrangement has the great advantage that it maintains the oil and insulation in as dry a condition as possible. The only disadvantage is the supply and cost of the nitrogen needed to maintain a constant supply thus adding to the routine maintenance activities.

It is now common practice, not only in climates having high humidity, for smaller oil-filled distribution transformers to be permanently hermetically sealed. This has the great advantage of being cheap and of requiring virtually no maintenance. Since transformer oil is incompressible, with a sealed arrangement it is necessary to provide space above the oil, filled with either dry air or nitrogen, to act as a cushion for expansion and contraction of the oil. Without this cushion the tank internals would experience very large changes of pressure between the no-load and the loaded condition. (To some extent, this problem is reduced if the transformer has a corrugated tank, see below.) These pressure variations can cause joints to leak so that external air is drawn in at light load conditions, usually bringing in with it moisture or even water, or they can cause dissolved gas in the oil to be brought out of solution and thus form voids leading to internal electrical discharges and ultimate failure. The more sophisticated or strategically important sealed transformers are provided with a pressure gauge which shows an internal positive pressure when the transformer is loaded, thus indicating that the seal remains sound.

Corrugated tanks

A convenient way of providing some means of accommodating expansion and contraction of the oil as well as dissipating losses from small sealed distribution transformers is to use a corrugated tank as shown in *Figure 4.96*. The corrugations are formed from light gauge steel. They may be from 80 to 200 mm deep and about 400 mm high at about 20 mm spacing, thus forming the sides of the tank into cooling fins. The top and bottom edges are seam-welded and the fins are able to expand and close-up concertina fashion as the tank internal pressure varies, thus absorbing some of the pressure variation. The system is not without its disadvantages; it is necessary to maintain a high level of quality control on the seam-welded fin edges and, because of the thin

Figure 4.96 Three-phase 200 kVA, 11 kV, 50 Hz pole-mounted transformer showing a corrugated tank (Bonar Long Ltd)

gauge of the metal used, a good paint protective treatment is necessary. This might not be readily achieved if the fins are too deep and too closely spaced. To minimise these problems it is considered that the material thickness should be no less than 1.5 mm.

Gas and oil-actuated relays

As mentioned above, the provision of a conservator also permits the installation of a Buchholz relay. This is installed in the run of pipe connecting the conservator to the main tank. In this location, the relay collects any gas produced by a fault inside the tank. The presence of this gas causes a float to be depressed which is then arranged to operate a pair of contacts which can be set to 'alarm', or 'trip', or both, dependent upon the rate of gas production. A more detailed description of this device will be found in the section dealing with transformer protection (Section 6 of Chapter 6). In order to ensure that any gas evolved in the tank is vented to the conservator it is necessary to vent every high point on the tank cover, for example each bushing turret, and to connect these to the conservator feed pipe on the tank side of the Buchholz relay, normally using about 20 mm bore pipework. The main connecting pipe between tank and conservator is 75 or 100 mm bore, depending upon the size of the transformer.

Bushing connections

A bushing is a means of bringing an electrical connection from the inside to the outside of the tank. It provides the necessary insulation between the winding electrical connection and the main tank which is at earth potential. The bushing forms a pressure-tight barrier enabling the necessary vacuum to be drawn for the purpose of oil impregnation of the windings. It must ensure freedom from leaks during the operating lifetime of the transformer and be capable of maintaining electrical insulation under all conditions such as driving rain, ice and fog and has to provide the required current-carrying path with an acceptable temperature rise. Varying degrees of sophistication are necessary to meet these requirements, depending on the voltage and/or current rating of the bushing. *Figure 4.97* shows an 11 kV bushing with a current rating of about 1000 A. This has a central current-carrying stem, usually of copper, and the insulation is provided by a combination of the porcelain shell and the transformer oil. Under oil, the porcelain surface creepage strength is very much greater than in air, so that the 'below oil' portion of the bushing has a plain porcelain surface. The 'air' portion has the familiar shedded profile in order to provide a very much longer creepage path, a proportion of which is 'protected' so that it remains dry in rainy or foggy conditions.

At 33 kV and above, it is necessary to provide additional stress control between the central high-voltage lead and the external, 'earthy' metal mounting flange. This can take the form either of a synthetic resin-bonded paper multifoil capacitor or of an oil-impregnated paper capacitor of similar construction. This type of bushing is usually known as a condenser bushing. *Figure 4.98* shows a 400 kV oil-impregnated paper bushing in part section. The radial electrical stress is graded through the insulant by means of the concentric capacitor foils and the axial stress is controlled by the graded lengths of these. The capacitor is housed between an inner current conducting tube and the outer porcelain casing which is in two parts, the upper part is a weatherproof shedded porcelain and the lower part (the oil-immersed end) is plain porcelain. The interspace is oil filled and the bushing head, or 'helmet', provides oil-expansion space and is fitted with a prismatic sight glass to give indication of the bushing oil level. This head also allows space for an air or gas cushion to allow for expansion and contraction of the oil. This expansion space must be adequately sealed against the ingress of atmospheric air (and hence moisture) and it is usual in such designs to incorporate a spring pack, housed in the top cap, to maintain pressure loading on gasketed joints while allowing for expansion and contraction of the different components during temperature changes.

Clearly, this type of bushing is designed for installation at, or near, the vertical position. The bushing illustrated is of the so-called 're-entrant' pattern in that the connection to the line lead is housed within the lower end of the bushing. This has the effect of foreshortening the under-oil end of the bushing but requires a more complex lower porcelain section which adds considerably to the cost. In order to make the electrical connection to the bushing, the HV lead terminates in a flexible pigtail which is threaded through the central tube and connected inside the head of the bushing. In some higher current versions the pigtail is replaced by a copper tube, in which case it is necessary to incorporate some flexible section to accommodate relative movement, thermal

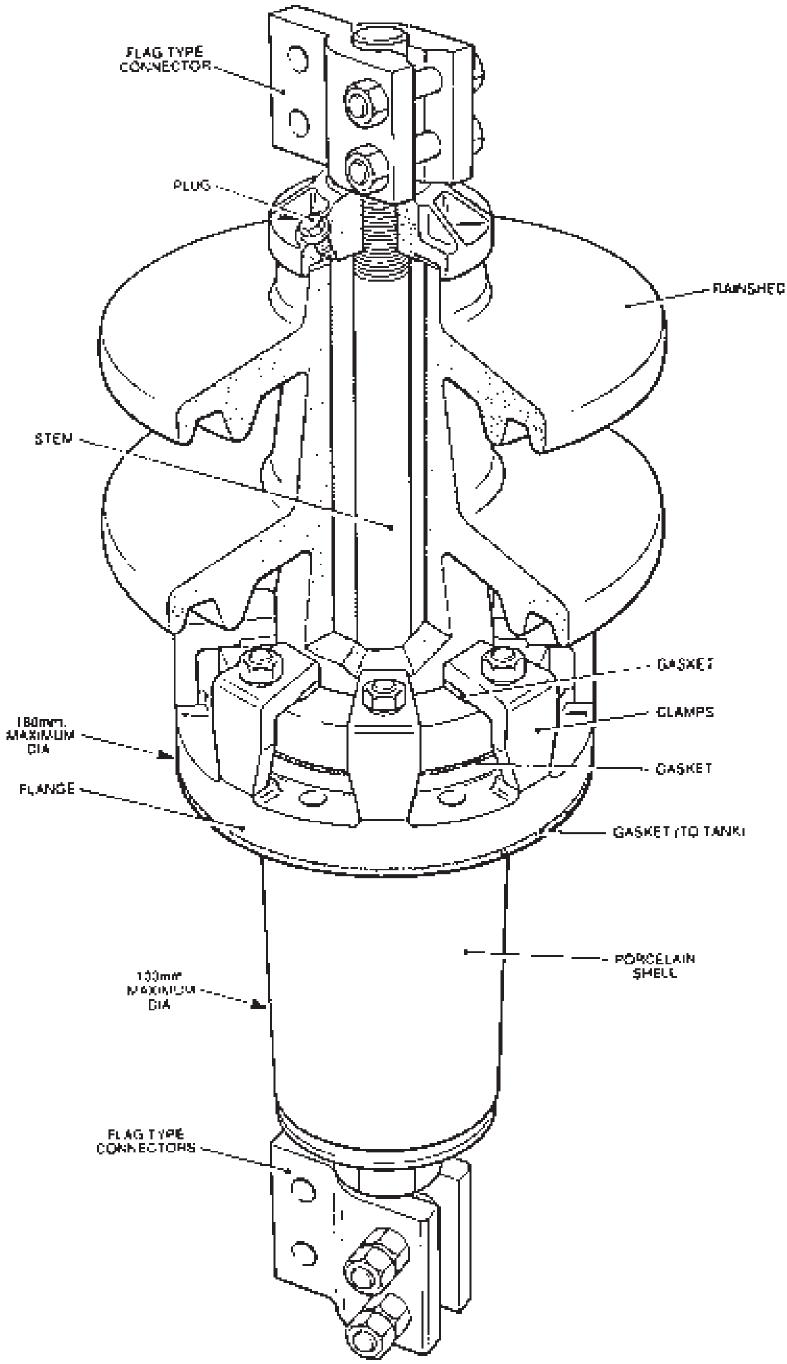


Figure 4.97 11 kV bushing

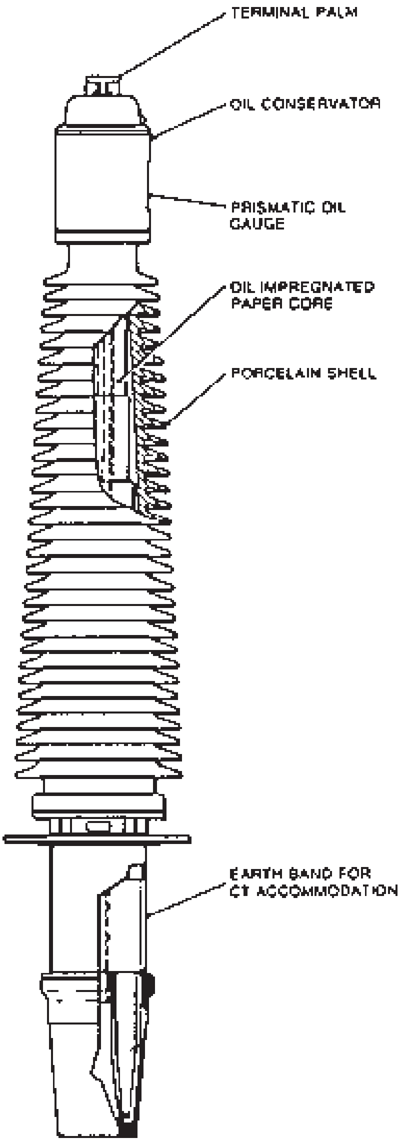


Figure 4.98 400 kV oil-impregnated paper bushing

and mechanical between the transformer internals and the head of the bushing. This must be capable of withstanding the mechanical vibration and of carrying the maximum rated current of the transformer. The heavy insulation on the line lead, is only taken just inside the re-entrant end of the bushing. With this arrangement, an inverted conical section gas-bubble deflector must be fitted beneath the re-entrant end of the bushing to ensure that any gas evolved within the transformer tank is directed to the Buchholz relay and not allowed to collect within the central stem of the bushing.

Versions of 400 kV oil-impregnated paper bushing have been developed in which the under-oil porcelain is replaced by a cast epoxy resin section. This material is able to withstand a higher electrical creepage stress under oil than porcelain which thus allows a plain tapered profile to be used instead of the re-entrant arrangement. With this type of bushing the transformer lead can be connected directly to a palm at the lower end of the bushing as shown in *Figure 4.99*.

The most recent development in EHV bushings is to replace the oil-impregnated paper capacitor by one using epoxy resin-impregnated paper (frequently abbreviated to e.r.i.p.). These bushings were originally developed for use with SF_6 but are now widely used for air/oil interfaces. These bushings still retain porcelain oil-filled upper casings, since it is difficult to find an alternative material with the weathering and abrasion resistance properties of porcelain, but the under-oil end is totally resin encapsulated.

In most EHV bushings provision is made for accommodation of a number of toroidally wound current transformers by incorporating an earth band at the oil-immersed end just below the mounting flange. The bushing is usually mounted on top of a 'turret' which provides a housing for the current transformers and the arrangement is usually such that the bushing can be removed without disturbing the separately mounted current transformers. The current transformer secondary connections are brought to a terminal housing mounted on the side of the turret.

In 400 and 275 kV bushings, the designer's main difficulty is to provide an insulation system capable of withstanding the high working voltage. The low-voltage bushings of a large generator transformer present a different problem. Here, the electrical stress is modest but the difficulty is in providing a current rating of up to 14 000 A, the phase current of an 800 MVA unit. *Figure 4.100* shows a bushing rated at 33 kV, 14 000 A. The current is carried by the large central copper cylinder, each end of which carries a palm assembly to provide the heavy current connections to the bushing. The superior cooling capability provided by the transformer oil at the 'under-oil' end of the bushing means that only two parallel palms are required. At the air end of the bushing, it is necessary to provide a very much larger palm surface area and to adopt a configuration which ensures a uniform distribution of the current. It has been found that an arrangement approximating to a circular cross-section – here, octagonal – achieves this better than one having plain parallel palms. These palms may be silver plated to improve their electrical contact with the external connectors, but if the contact face temperature can be limited to 90 °C a more reliable connection can be made to plain copper palms, provided that the joint is made correctly.

Insulation is provided by a synthetic resin-bonded paper tube and, as can be seen from the diagram, this also provides the means of mounting the flange.

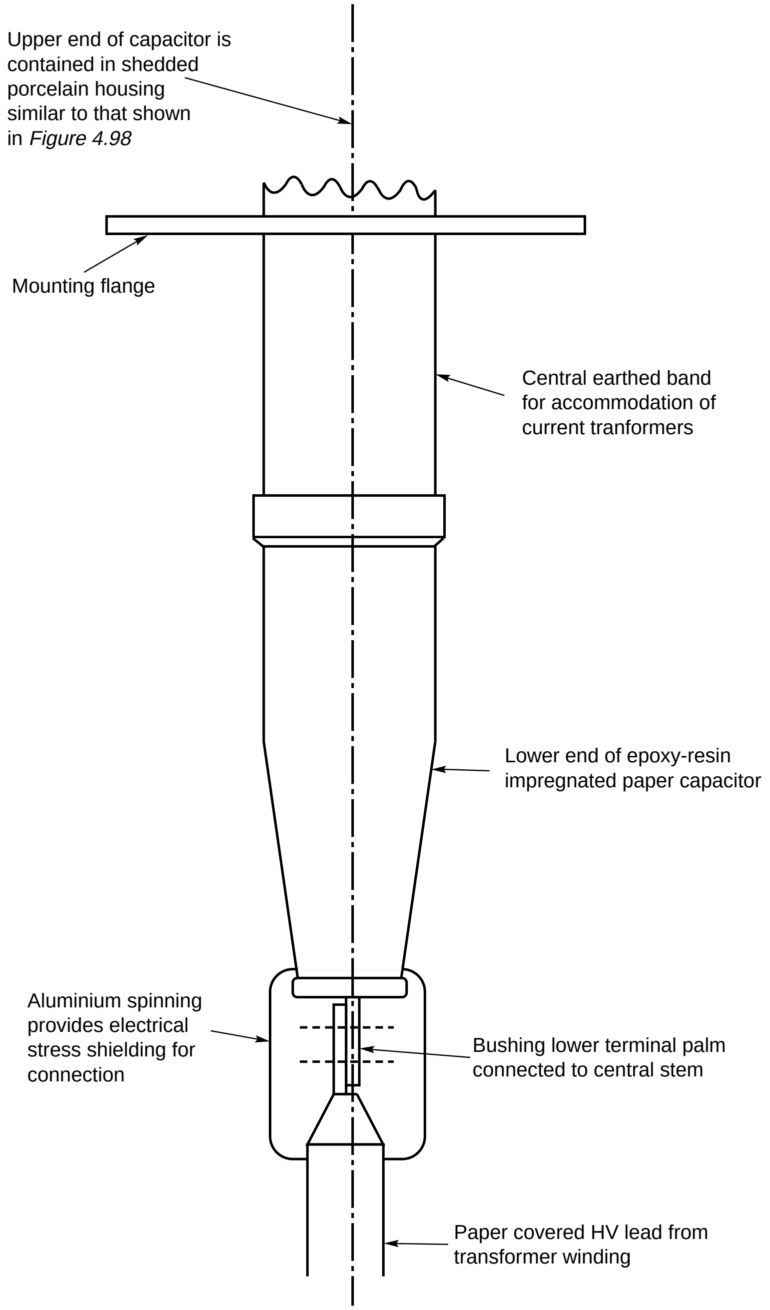


Figure 4.99 Arrangement of connection of transformer 400 kV HV lead to lower end of epoxy resin-impregnated paper (e.r.i.p.) bushing

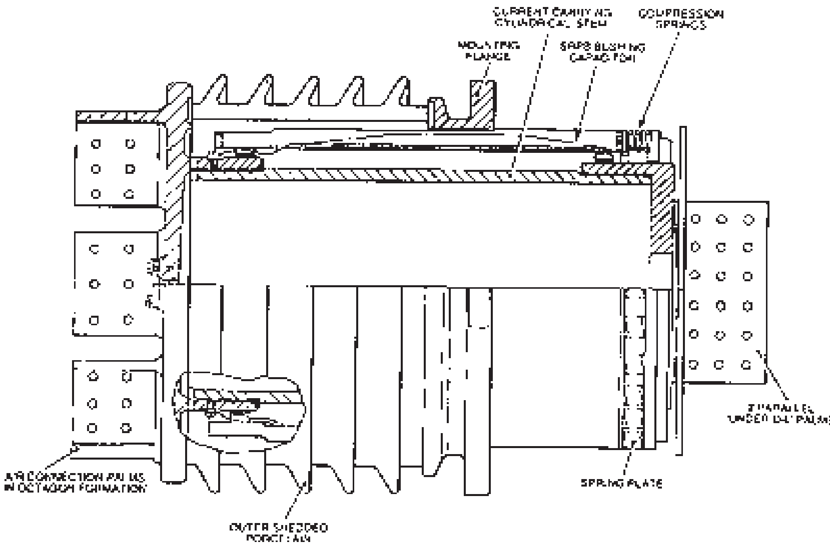


Figure 4.100 Simplified cross-section of a 33 kV, 14 000 A bushing

External weather protection for the air end is provided by the conventional shedded porcelain housing. Where the bushing is to be accommodated within external phase-isolated connections an air-release plug on the upper-end flange allows air to be bled from the inside of the assembly, so that it can be filled with oil under the head of the conservator.

SF_6 connections

With the introduction of 400 kV SF_6-insulated metalclad switchgear into the UK in the late 1970s, the benefits of making a direct connection between the switchgear and the transformer were quickly recognised. At the former CEGB's (now First Hydro company's) Dinorwig power station, for example, transformers and 400 kV switchgear are accommodated underground. The transformer hall is immediately below the 400 kV switchgear gallery and 400 kV metalclad connections pass directly through the floor of this to connect to the transformers beneath. Even where transformers and switchgear cannot be quite so conveniently located, there are significant space saving benefits if 400 kV connections can be made direct to the transformer, totally enclosed within SF_6 trunking. *Figure 4.101* shows a typical arrangement which might be used for the connection of a 400 kV generator transformer. The 400 kV cable which connects to the 400 kV substation is terminated with an SF_6 sealing end. SF_6 trunking houses line isolator, earth switch and surge diverter. By mounting the 400 kV SF_6/oil bushing horizontally, the overall height of the cable sealing-end structure can be reduced.

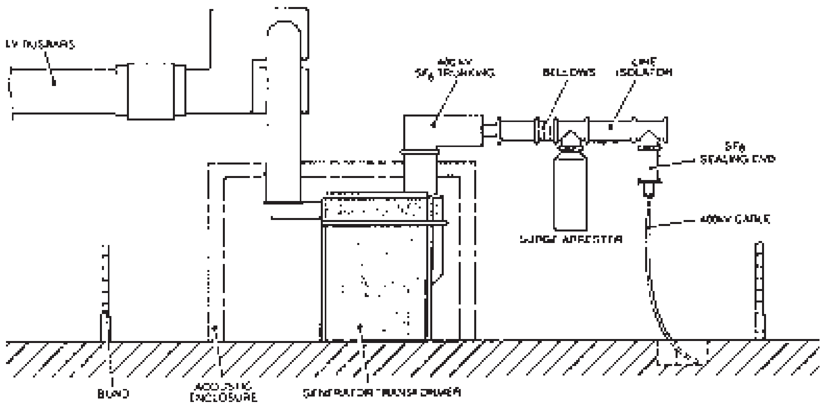


Figure 4.101 Simplified arrangement of 400 kV SF_6 connection to generator transformer

The construction of the 400 kV SF_6/oil bushing is similar to that of the air/oil bushing described previously in that stress control is achieved by means of an e.r.i.p. capacitor housed within a cast resin rather than a porcelain shell. The 'under-oil' end is 'conventional', i.e. it is not re-entrant, and, since there is no need for the lengthy air-creepage path used in an air/oil bushing, the SF_6 end is very much shorter than its air equivalent.

Cable box connections

Cable boxes are the preferred means of making connections at 11, 6.6, 3.3 kV and 415 V in industrial complexes, as for most other electrical plant installed in these locations. Cabling principles are not within the scope of this volume and practices differ widely, but the following section reviews what might be considered best practice for power transformer terminations on HV systems having high fault levels.

Modern polymeric-insulated cables can be housed in air-insulated boxes. Such connections can be disconnected with relative simplicity and it is not therefore necessary to provide the separate disconnecting chamber needed for a compound-filled cable box with a paper-insulated cable. LV line currents can occasionally be as high as 3000 A at 11 kV, for example on the station transformers of a large power station, and, with cable current ratings limited to 600–800 A, as many as five cables per phase can be necessary. For small transformers of 1 MVA or less on high fault level installations it is still advantageous to use one cable per phase since generally this will restrict faults to single phase to earth. On fuse-protected circuits at this rating three-core cables are a possibility. Since the very rapid price rise of copper which took place in the 1960s, many power cables are made of aluminium. The solid conductors tend to be bulkier and stiffer than their copper counterparts and this has to be taken into account in the cable box design if aluminium-cored cables are to be used. Each cable has its own individual glandplate so that the cable jointer can gland the cable, manoeuvre it into position and connect it to the terminal. Both cable core and bushing will usually have palm-type terminations which are connected with a single bolt. To give the jointer some flexibility and to provide the necessary tolerances, it is desirable that the glandplate-to-bushing terminal separation should be at least 320 mm.

For cable ratings of up to 400 A, non-magnetic glandplates should be used. For ratings above 400 A, the entire box should be constructed of non-magnetic material in order to reduce stray losses within the shell which would otherwise increase its temperature rise, with the possible risk of overheating the cable insulation. To enable the box to breathe and to avoid the build-up of internal condensation, a small drain hole, say 12 mm in diameter, is provided in one glandplate.

Figure 4.102 shows a typical 3.3 kV air-insulated cable box having a rating of about 2400 A with 4×400 mm^2 aluminium cables per bushing.

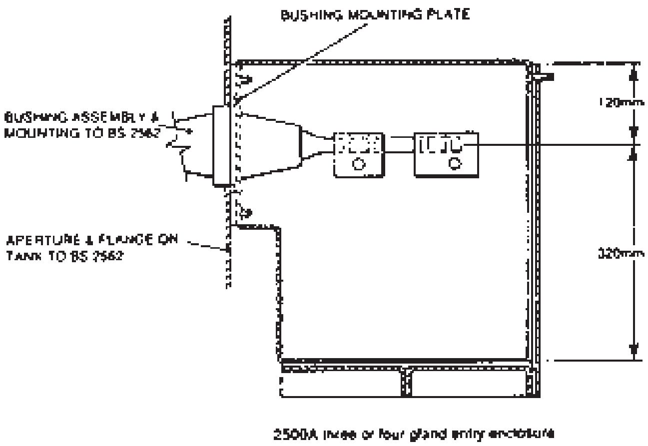


Figure 4.102 3.3 kV cable box

At 11 kV, some stress control is required in an air-insulated box, so the bushing and cable terminations are designed as an integrated assembly, as shown in *Figure 4.103(a)*.

Figure 4.103(b) shows a cross-section of a typical moulded-rubber socket connector which is fitted to the end of an 11 kV cable. This has internal and external semi conductive screens: the inner screen, the cable conductor connector and the outer provides continuity for the cable outer screen, so that this encloses the entire termination. The external screen is bonded to earth by connection to the external lug shown in the figure. The joint is assembled by fitting the socket connector over the mating bushing and then screwing the insulating plug, containing a metal threaded insert, onto the end

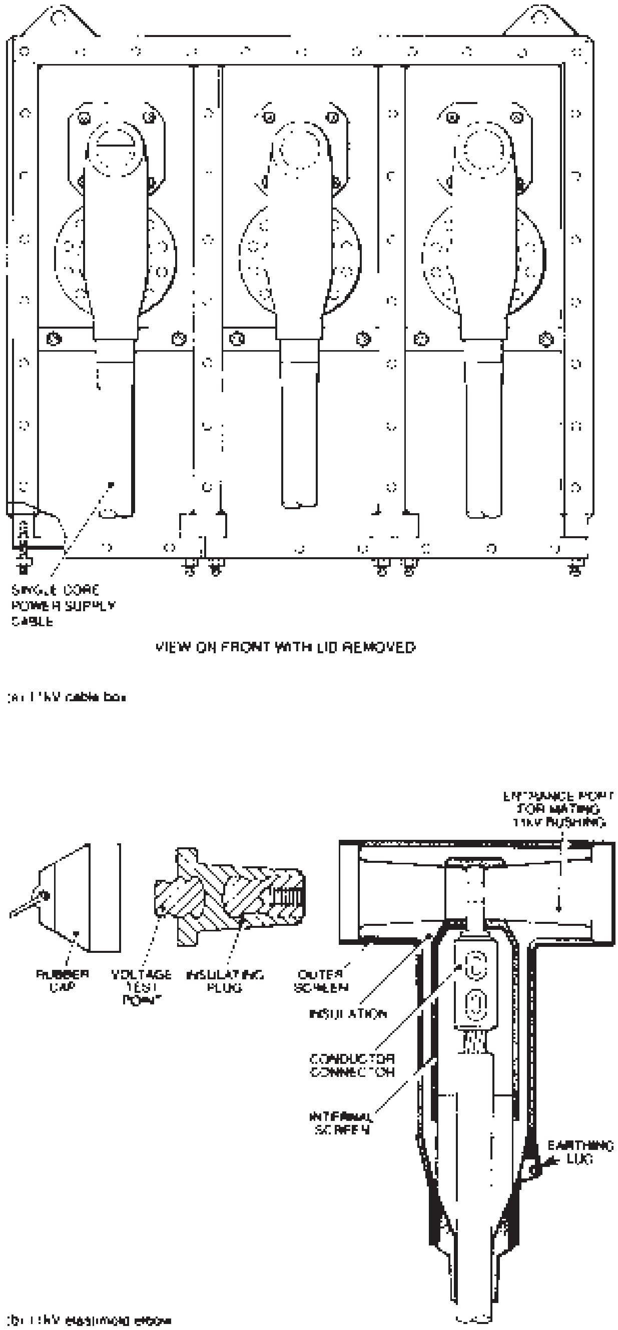


Figure 4.103 11 kV cable box and section of 11 kV elastimold elbow termination

of the bushing stem. This is tightened by means of a spanner applied to the hexagonal-nut insert in the outer end of this plug. This insert also serves as a capacitative voltage test point. After making the joint, this is finally covered by the semiconducting moulded-rubber cap.

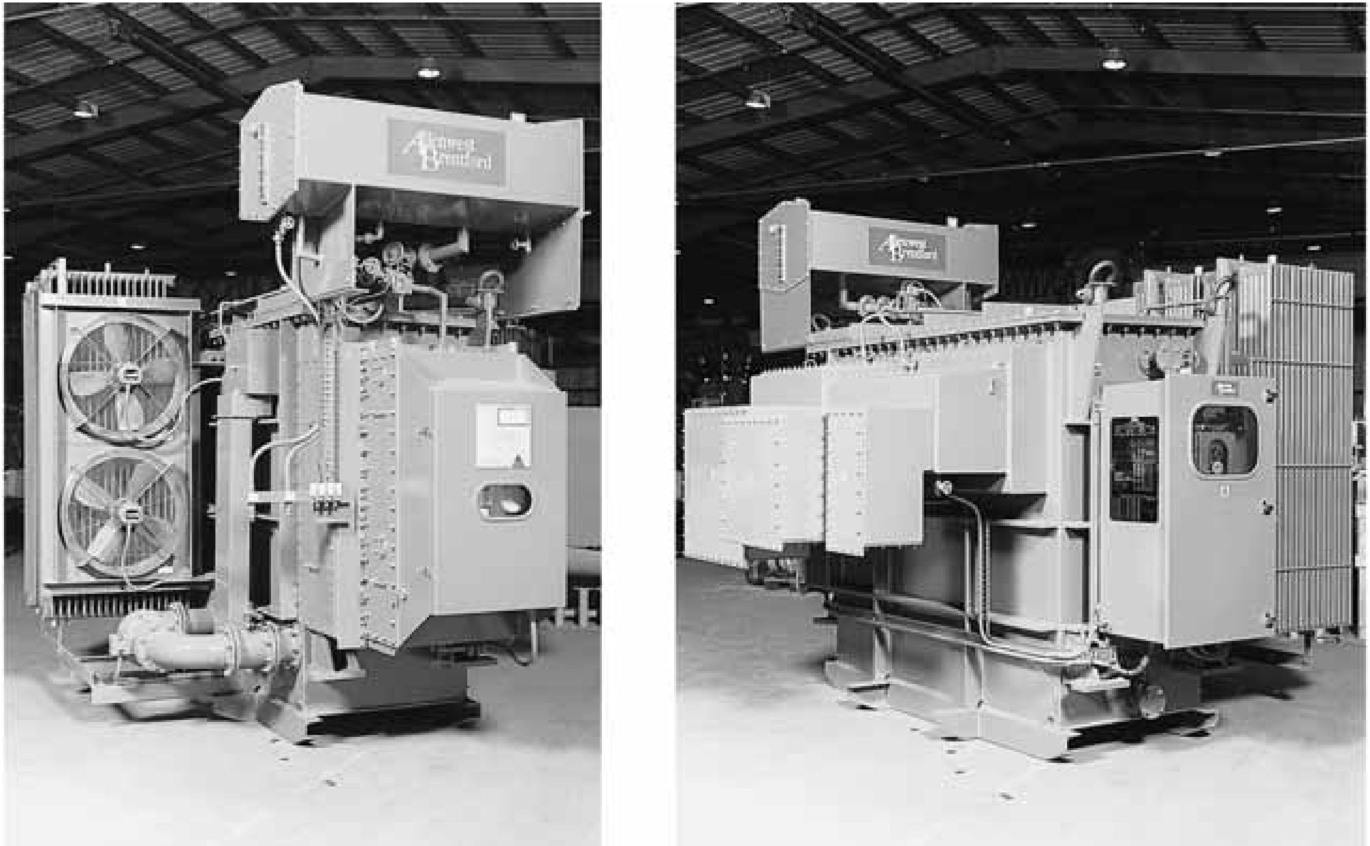
Since the external semiconductive coating of this type of connector is bonded to earth, there would be no electrical hazard resulting from its use without any external enclosure and, indeed, it is common practice for a connector of this type to be used in this way in many European countries provided that the area has restricted access. However, UK practice is usually to enclose the termination within a non-magnetic sheet-steel box to provide mechanical protection and phase isolation. Should a fault occur, this must be contained by the box which ensures that it remains a phase-to-earth fault, normally limited by a resistor at the system neutral point, rather than developing into an unrestricted phase-to-phase fault.

For higher voltage terminations, that is at 132, 275 and 400 kV, direct cable connections were occasionally made to transformers. These usually consisted of an oil-filled sealing-end chamber with a link connected to an oil/oil bushing through the transformer tank cover. Cable connections are now invariably made via an intermediate section of SF_6 trunking as described above.

Tank-mounted coolers

Tank-mounted pressed-steel radiators now represent the most widely used arrangement for cooling smaller transformers for which tank surface alone is not adequate. These can now be manufactured so cheaply and fitted so easily that they have totally replaced the arrangement of tubes which were commonly used for most distribution transformers. They are available in various patterns but all consist basically of a number of flat ‘passes’ of edge-welded plates connecting a top and bottom header. Oil flows into the top and out of the bottom of the radiators via the headers and is cooled as it flows downwards through the thin sheet-steel passes. The arrangement is most suited to transformers having natural oil and natural air circulations, i.e. ONAN cooling, as defined in BS 171.

For larger units it is be possible to suspend a fan below or on the side of the radiators to provide a forced draught, ONAF arrangement. This might enable the transformer rating to be increased by some 25%, but only at the extra cost and complexity of control gear and cabling for, say, two or four fans. Achievement of this modest uprating would require that the radiators be grouped in such as way as to obtain optimum coverage by the fans. With small transformers of this class, much of the tank surface is normally taken up with cable boxes, so that very little flexibility remains for location of radiators. For units of around 30 MVA the system becomes a more feasible option, particularly at 132/33 kV where connections are frequently via bushings on the tank cover rather than cable boxes on the sides. One problem with this arrangement is that in order to provide space below the radiator for installation



(a) (b)

Figure 4.104 Two views of a 4/8 MVA, three-phase, 33/11 kV, 50 Hz transformer with tank-mounted radiators of a fan the height of the radiator must be reduced, so that the area for self-cooling is reduced, the alternative of hanging the fans from the side of the radiators requires that careful consideration be given to the grouping of these to ensure that the fans blow a significant area of the radiator surface.

Figure 4.104 shows two views of a small 33/11 kV unit with tank-mounted radiators having side mounted fans. By clever design it has been possible to include an oil pump in the cooling circuit to provide forced circulation and, because the unit has been designed for low losses, only two radiators are necessary, leaving plenty of room for cable boxes. Note, however, that these are significantly higher than the transformer tank. The transformer has an ONAN rating of 4 MVA which can be increased to 8 MVA with the pump and fans in operation.

It is frequently a problem to accommodate tank-mounted radiators while leaving adequate space for access to cable boxes, the pressure relief vent pipe and the like. The cooling-surface area can be increased by increasing the number of passes on the radiators, but there is a limit to the extent to which this can be done, dictated by the weight which can be hung from the top and bottom headers. If fans are to be hung from the radiators this further increases the cantilever load. It is possible to make the radiators slightly higher than the tank so that the top header has a swan-necked shape: this has the added benefit that it also improves the oil circulation by increasing the thermal head developed in the radiator. However, this arrangement also increases the overhung weight and has the disadvantage that a swan-necked header is not as rigid as a straight header, so that the weight-bearing limit is probably reached sooner. The permissible overhang on the radiators can be increased by providing a small stool at the outboard end, so that a proportion of the weight bears directly onto the transformer plinth; however, since this support is not available during transport, one of the major benefits from tank-mounted radiators, namely, the ability to transport the transformer full of oil and fully assembled, is lost.

On all but the smallest transformers each radiator should be provided with isolating valves in the top and bottom headers as well as drain and venting plugs, so that it can be isolated, drained and removed should it leak. The valves may be of the cam-operated butterfly pattern and, if the radiator is not replaced immediately, should be backed up by fitting of blanking plates with gaskets.

Radiator leakage can arise from corrosion of the thin sheet steel, and measures should be taken to protect against this. Because of their construction it is very difficult to prepare the surface adequately and to apply paint protection to radiators under site conditions, so that if the original paint finish has been allowed to deteriorate, either due to weather conditions or from damage in transit, it can become a major problem to make this good. This is particularly so at coastal sites. Many users specify that sheet-steel radiators must be hot-dip galvanised in the manufacturer's works prior to receiving an etch prime, followed by the usual paint treatment in the works.

Separate cooler banks

As already indicated, one of the problems with tank-mounted radiators is that a stage is reached when it becomes difficult to accommodate all the required radiators on the tank surface, particularly if a significant proportion of this is taken up with cable boxes. In addition, with the radiators mounted on the tank, the only straightforward option for forced cooling is the use of forced or induced draught fans, and, as was explained in Section 5 of this chapter, the greater benefits in terms of increasing rating are gained by forcing and directing the oil flow. It is possible to mount radiators, usually in groups of three, around the tank on small sub-headers with an oil circulating pump supplying each of these sub-headers as shown in *Figure 4.105*. This is an arrangement used by many utilities worldwide. It has the advantage that the unit can be despatched from the works virtually complete and ready for service. The major disadvantage is the larger number of fans and their associated control gear which must be provided compared with an arrangement using a separate free-standing cooler bank. It is therefore worthwhile considering the merits and disadvantages of mounting all cooler equipment on the tank compared with a separate free-standing cooler arrangement favoured by many utilities in the UK.

Advantages of all tank-mounted equipment

- More compact arrangement saves space on site.
- The transformer can be transported ready filled and assembled as a single entity, which considerably reduces site-erection work.
- The saving of pipework and headers and frame/support structure reduces the first cost of the transformer.

Disadvantages

- Forced cooling must usually be restricted to fans only, due to the complication involved in providing a pumped oil system. If oil pumps are used a large number are required with a lot of control gear.
- Access to the transformer tank and to the radiators themselves for maintenance/painting is extremely difficult.
- A noise-attenuating enclosure cannot be fitted close to the tank.

If these advantages are examined more closely, it becomes apparent that these may be less real than at first sight. Although the transformer itself might well be more compact, if it is to achieve any significant increase in rating from forced cooling, a large number of fans will be required, and a considerable unrestricted space must be left around the unit to ensure a free airflow without the danger of recirculation. In addition, since the use of forced and directed oil allows a very much more efficient forced cooled design to be produced, the apparent saving in pipework and cooler structure can be easily offset. Looking at the disadvantages, the inability to fit a noise-attenuating

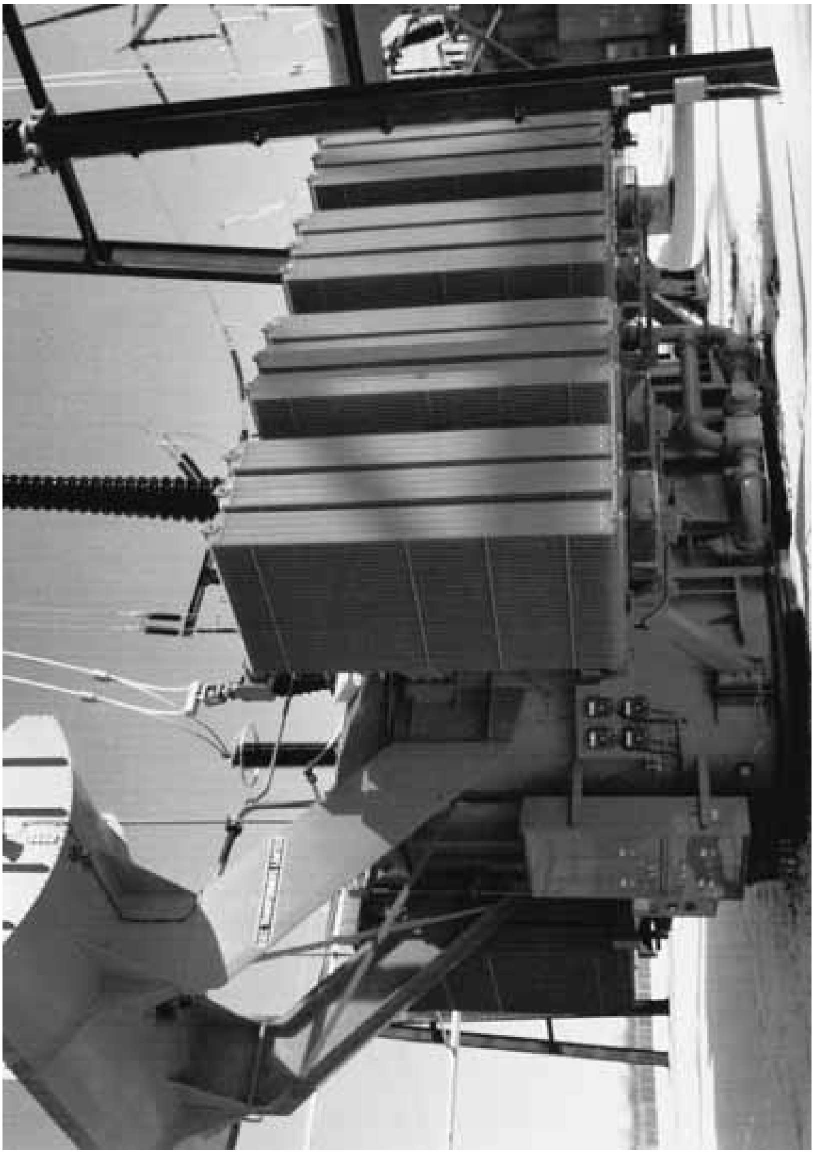


Figure 4.105 Single phase 765/242 kV 300 MVA autotransformer showing tank mounted radiators in groups on sub-headers with oil pumps and fans (GEC Alsthom)

enclosure can be a serious problem for larger transformers as environmental considerations acquire increasingly more prominence.

The protagonists of tank-mounted radiators tend to use bushings mounted on the tank cover for both HV and LV connections, thus leaving the tank side almost entirely free for radiators.

Having stated the arguments in favour of free-standing cooler banks, it is appropriate to consider the merits and disadvantages of forced cooling as against natural cooling.

The adoption of ODAF cooling for, say, a 60 MVA bulk supplies transformer, incurs the operating cost of pumps and fans, as well as their additional first cost and that of the necessary control gear and cabling. Also, the inherent reliability is lower with a transformer which relies on electrically driven auxiliary equipment compared with an ONAN transformer which has none. On the credit side, there is a considerable reduction in the plan area of the cooler bank, resulting in significant space saving for the overall layout. A typical ONAN/ODAF-cooled bulk supplies transformer is rated to deliver full output for conditions of peak system loading and then only when the substation of which it forms part is close to its maximum design load, i.e. near to requiring reinforcement, so for most of its life the loading will be no more than its 30 MVA ONAN rating. Under these circumstances, it is reasonable to accept the theoretical reduction in reliability and the occasional cooler equipment losses as a fair price for the saving in space. On the other hand, a 50 MVA unit transformer at a power station normally operates at or near to full output whenever its associated generator is on load, so reliance on other ancillary equipment is less desirable and, if at all possible, it is preferable to find space in the power station layout to enable it to be totally naturally cooled.

Where a transformer is provided with a separate free-standing cooler bank, it is possible to raise the level of the radiators to a height which will create an adequate thermal head to ensure optimum natural circulation. The longest available radiators can be used to minimise the plan area of the bank consistent with maintaining a sufficient area to allow the required number of fans to be fitted. It is usual to specify that full forced cooled output can be obtained with one fan out of action. Similarly, pump failure should be catered for by the provision of two pumps, each capable of delivering full flow. If these are installed in parallel branches of cooler pipework, then it is necessary to ensure that the non-running pump branch cannot provide a return path for the oil, thus allowing this to bypass the transformer tank. Normally this would be achieved by incorporating a non-return valve in each branch. However, such a valve could create too much head loss to allow the natural circulation necessary to provide an ONAN rating. One solution is to use a flap valve of the type shown in *Figure 4.106*, which provides the same function when a pump is running but will take up a central position with minimal head loss for thermally-induced natural circulation.

Water cooling

Water cooling of the oil is an option which is available for large transformers and in the past was a common choice of cooling for many power station transformers, including practically all generator transformers and many station and unit transformers. It is also convenient in the case of large furnace transformers, for example, where, of necessity, the transformers must be close

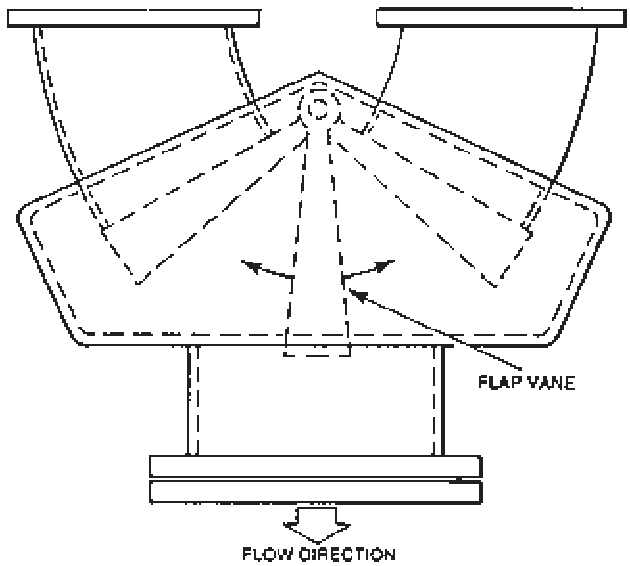


Figure 4.106 Oil flap value

to the load – the furnace – but in this location ambients are not generally conducive to efficient air cooling. The choice of oil/water was equally logical for power station transformers since there is usually an ample source of cooling water available in the vicinity and oil/water heat exchangers are compact and thermally efficient. The arrangement does not provide for a self-cooled rating, since the head loss in oil/water heat exchangers precludes natural oil circulation, but a self-cooled rating is only an option in the case of the station transformer anyway. Generally when the unit is on load both generator and unit transformers are near to fully loaded.

The risk of water entering the transformer tank due to a cooler leak has long been recognised as the principle hazard associated with water cooling. This is normally avoided by ensuring that the oil pressure is at all times greater than that of the water, so that leakage will always be in the direction of oil into water. It is difficult to ensure that this pressure difference is maintained under all possible conditions of operation and malfunction. Under normal conditions, the height of the transformer conservator tank can be arranged such that the minimum oil head will always be above that of the water. However, it is difficult to make allowance for operational errors, for example the wrong valve being closed, so that maximum pump discharge pressure is applied to an oil/water interface, or for equipment faults, such as a pressure reducing valve which sticks open at full pressure.

The precise cost of cooling water depends on the source, but at power stations it is often pumped from river or sea and when the cost of this is taken into consideration, the economics of water cooling become far less certain.

In the early 1970s, after a major generator transformer failure attributable to water entering the oil through cooler leaks, the UK Central Electricity Generating Board reassessed the merits of use of water cooling. The high cost of the failure, both in terms of increased generating costs due to the need to operate lower-merit plant and the repair costs, as well as pumping costs, resulted in a decision to adopt an induced draught air-cooled arrangement for the Littlebrook D generator transformers and this subsequently became the standard, whenever practicable.

In water cooling installations, it is common practice to use devices such as pressure reducing valves or orifice plates to reduce the waterside pressures. However, no matter how reliable a pressure reducing valve might be, the time will come when it will fail, and an orifice plate will only produce a pressure reduction with water flowing through it, so that should a fault occur which prevents the flow, full pressure will be applied to the system.

There are still occasions when it would be very inconvenient to avoid water cooling, for example in the case of furnace transformers mentioned above. Another example is the former CEGB's Dinorwig pumped-storage power station now owned by First Hydro where the generator transformers are located underground, making air cooling impracticable on grounds of space and noise as well as the undesirability of releasing large quantities of heat to the cavern environment. *Figure 4.107* shows a diagrammatic arrangement

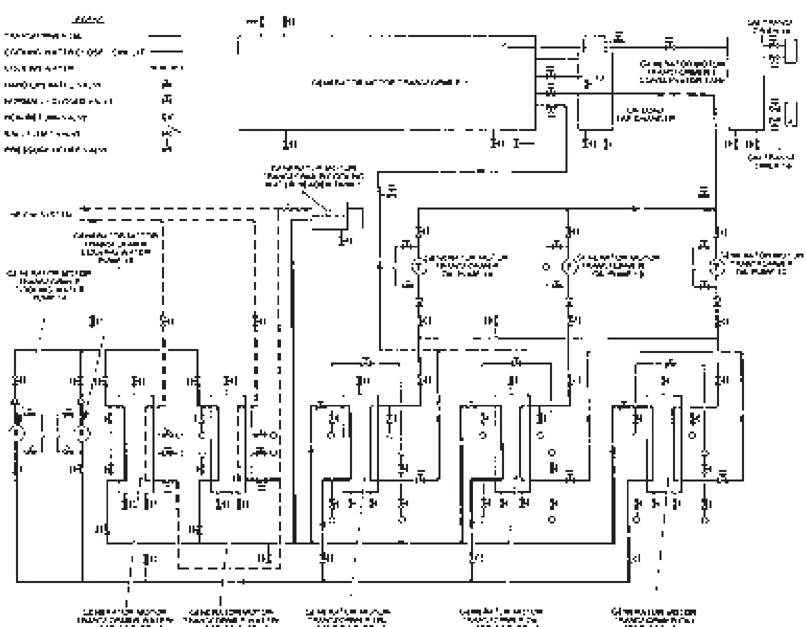


Figure 4.107 Diagrammatic arrangement of Dinorwig generator transformer cooler circuits

of the cooling adopted for the Dinorwig generator transformers. This uses a two-stage arrangement having oil/towns-water heat exchangers as the first stage, with second-stage water/water heat exchangers having high-pressure lake-water cooling the intermediate towns water. The use of the intermediate stage with recirculating towns water enables the pressure of this water to be closely controlled and, being towns water, waterside corrosion/erosion of the oil/water heat exchangers – the most likely cause of cooler leaks – is also kept very much under control. Pressure control is ensured by the use of a header tank maintained at atmospheric pressure. The level in this tank is topped up via the ball valve and a very generously sized overflow is provided so that, if this valve should stick open, the header tank will not become pressurised. The position of the water pump in the circuit and the direction of flow is such that should the water outlet valve of the oil/water heat exchanger be inadvertently closed, this too would not cause pressurisation of the heat exchanger. A float switch in the header tank connected to provide a high level alarm warns of either failure of the ball valve or leakage of the raw lake water into the intermediate towns-water circuit.

Other situations in which water cooling is justified such as those in which the ambient air temperature is high, so that a significantly greater temperature rise of the transformer can be permitted if water cooling is employed, might use an arrangement similar to that for Dinorwig described above, or alternatively, a double-tube/double-tubeplate cooler might be employed. With such an arrangement, shown diagrammatically in *Figure 4.108*, oil and water circuits are separated by an interspace so that any fluid leakage will be collected in this space and will raise an alarm. Coolers of this type are, of course, significantly more expensive than simple single-tube and plate types and heat transfer is not quite so efficient, so it is necessary to consider the economics carefully before adopting a double-tube/double-tubeplate cooler in preference to an air-cooled arrangement.

Another possible option which might be considered in a situation where water cooling appears preferable is the use of sophisticated materials, for example titanium-tubed coolers. This is usually less economic than a double-tubed/double-tubeplate cooler as described above.

Passing mention has been made of the need to avoid both corrosion and erosion of the waterside of cooler tubes. A third problem which can arise is the formation of deposits on the waterside of cooler tubes which impair heat transfer. The avoidance of all of these requires careful attention to the design of the cooling system and to carefully controlled operation. Corrosion problems can be minimised by correct selection of tube and tubeplate materials to suit the analysis of the cooling water. Deposition is avoided by ensuring that an adequate rate of water flow is maintained, but allowing this to become excessive will lead to tube erosion.

If the cooling medium is sea water, corrosion problems can be aggravated and these might require the use of measures, such as the installation of sacrificial anodes or cathodic protection. These measures have been used with

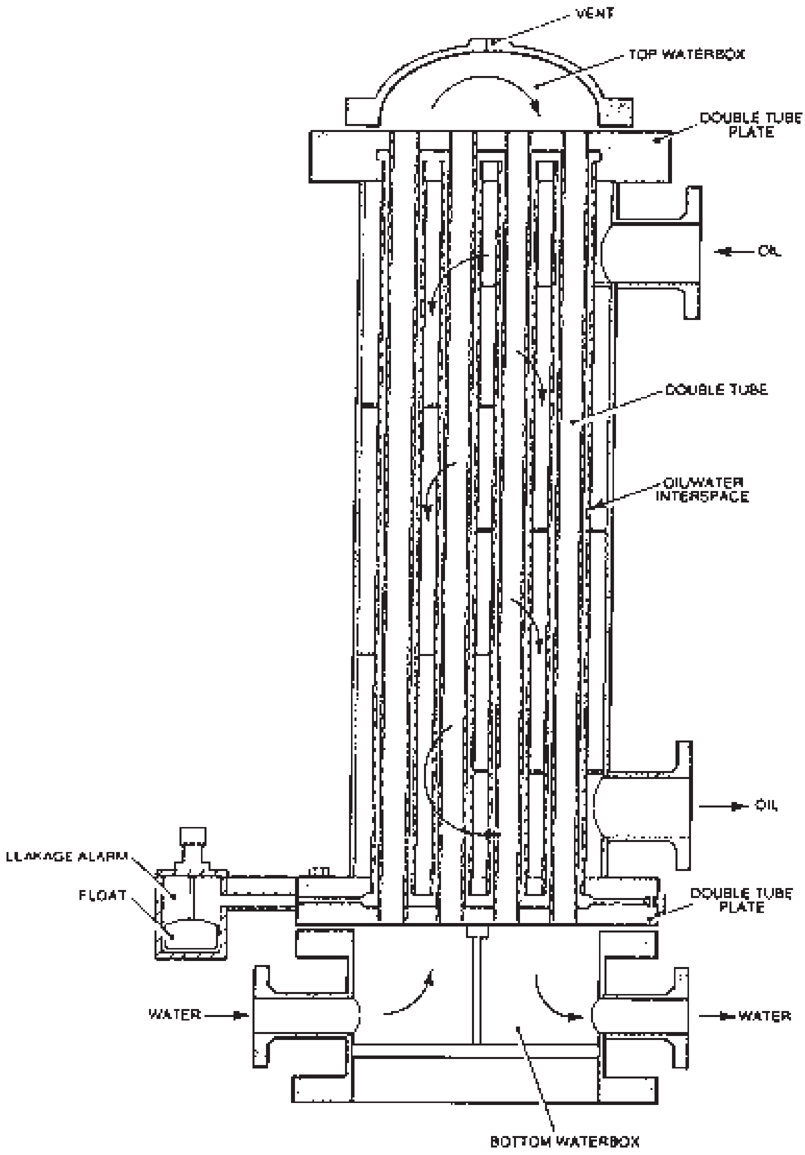


Figure 4.108 Double tube, double tubeplate oil/water heat exchanger

success in UK power stations, but it is important to recognise that they impose a very much greater burden on maintenance staff than does an air cooler, and the consequences of a small amount of neglect can be disastrous.

A fan and its control equipment can operate continuously or under automatic control for periods of two or three years or more, and maintenance usually means no more than greasing bearings and inspection of contactor contacts. By contrast, to ensure maximum freedom from leaks, most operators of oil/water heat exchangers in UK power stations routinely strip them down annually to inspect tubes, tubeplates and water boxes. Each tube is then non-destructively tested for wall thickness and freedom from defects, using an eddy-current probe. Suspect tubes can be blanked off but, since it will only be permissible to blank off a small proportion of these without impairing cooling, a stage can be reached when complete replacement tubenests are necessary.

In view of the significant maintenance requirement on oil/water heat exchangers, it is advisable to provide a spare cooler and standard practice has, therefore, been to install three 50%-rated coolers, one of which will be kept in a wet standby condition, i.e. with the oil side full of transformer oil and with the water side inlet and outlet valves closed but full of clean water, and the other two in service.

Cooler control

Ancillary plant to control and operate forced cooling plant must be provided with auxiliary power supplies and the means of control. At its most basic, this takes the form of manual switching at a local marshalling panel, housing auxiliary power supplies, fuses, overloads protection relays and contactors. In many utilities due to high labour costs the philosophy has been to reduce the amount of at-plant operator control and so it is usual to provide remote and/or automatic operation.

The simplest form of automatic control uses the contacts of a winding temperature indicator to initiate the starting and stopping of pumps and fans. Further sophistication can be introduced to limit the extent of forced cooling lost should a pump or fan fail. One approach is to subdivide the cooler bank into two halves, using two 50%-rated pumps and two sets of fans. Equipment failure would thus normally not result in loss of more than half of the forced cooling. As has been explained above, many forced-cooled transformers have a rating which is adequate for normal system operation when totally self-cooled, so an arrangement which requires slightly less pipework having parallel 100%-rated duty and standby pumps, as shown in *Figure 4.109*, can be advantageous. This means that flow switches must be provided to sense the failure of a duty pump and to initiate start-up of the standby should the winding temperature sense that forced cooling is required.

A large generator transformer has virtually no self-cooled rating, so pumps can be initiated from a voltage-sensing relay, fed from a voltage transformer which is energised whenever the transformer is energised. Two 100% duty and standby oil pumps are provided, with automatic initiation of the standby pump should flow failure be detected on the duty pump. Fans may still be controlled from a winding temperature indicator, but it is usual to divide these into two groups initiated in stages, the first group being switched on at a winding temperature of 80 °C and out at 70 °C. The second group is switched on at 95 °C and out at 80 °C. The total number of fans provided is such that

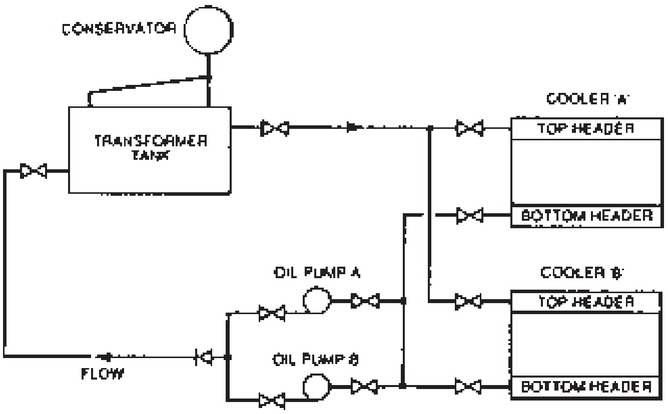


Figure 4.109 Oil circuit for ONAN/ODAF-cooled unit transformer

failure of any one fan still enables full rating to be achieved with an ambient temperature of 30 °C. The control scheme also allows each oil pump to serve either in the duty or standby mode and the fans to be selected for either first- or second-stage temperature operation. A multiposition mode selector switch allows both pumps and fans to be selected for 'test' to check the operation of the control circuitry. The scheme is also provided with 'indication' and 'alarm' relay contacts connected to the station data processor.

For water-cooled generator transformers, the fans are replaced by water pumps which are controlled from voltage transformer signals in the same way as the oil pumps. Two 100% duty and standby pumps are provided, with the standby initiated from a flow switch detecting loss of flow from the selected duty pump.

There is a view that automatic control of generator transformer air coolers is unnecessary and that these should run continuously whenever the generator transformer is energised. This would simplify control arrangements and reduce equipment costs but there is an operational cost for auxiliary power. Modern fans have a high reliability, so they can be run for long periods continuously without attention. For many large generator transformers, running of fans (whether required or not) results in a reduction of transformer load loss, due to the reduced winding temperature, which more than offsets the additional fan power requirement, so that this method of operation actually reduces operating cost. In addition, the lower winding temperature reduces the rate of usage of the transformer insulation life. An example will assist in making this clear.

An 800 MVA generator transformer might typically operate at a throughput of 660 MW and 200 MVAr, which is equivalent to 690 MVA. At 800 MVA, it will have resistance rise and top-oil rise of 70° and 60 °C, respectively, if the manufacturer has designed these to the BS limits. At 690 MVA, these could be reduced to 45 °C and 41 °C, respectively, dependent on the particular design. Then, as explained in Section 5 of this chapter, the winding hot-spot temperature at an ambient temperature of, say, 10 °C will be given by:

Ambient	10
Rise by resistance	45
Half (outlet−inlet) oil	6
Maximum gradient−average gradient	4
Total	65 °C

At this ambient, the first fan group will operate under automatic control, tripping in when the hot-spot temperature reaches 80 °C and out at 70 °C. It is reasonable to assume, therefore, that with these fans running intermittently, an average temperature of 75 °C will be maintained. Hence, continuous running of all fans will achieve a temperature reduction of about 10 °C.

For an actual case estimating the extra auxiliary power absorbed by running the fans continuously would probably involve making observations of operation in the automatic control mode first. However, by way of illustration, it is convenient to make some very approximate estimates.

The power absorbed by 12 fans on a transformer of this rating might typically be 36 kW. If, at this ambient, the first group would run for about 80% of the time and the second group would not run at all, the average auxiliary power absorbed would be 0.8 times 18 kW, equals 14.4 kW, say 15 kW. Running them all continuously therefore absorbs an extra (36 − 15) kW equals 21 kW.

The load loss of an 800 MVA generator transformer at rated power could be 1600 kW. At 690 MVA this would be reduced to about 1190 kW. If it is assumed that 85% of this figure represents resistive loss, then this equates to 1012 kW, approximately. A 10 °C reduction in the average winding temperature would produce a reduction of resistance at 75 °C of about 3.3%, hence about 33.4 kW of load loss would be saved. Strictly speaking, this reduction in resistance would cause an approximately 3.3% increase in the other 15% of the load losses, that is, about 6 kW additional stray losses would be incurred, so that the total power saved would be 33.4 kW at a cost of (21 + 6) equals 27 kW, i.e. 6.4 kW net saving. However, the figures used are only very approximate but they demonstrate that the cost of the increased auxiliary power is largely offset by load loss savings. The important feature, though, is that the lower hot-spot temperature increases insulation life. For example, referring to Section 5 of this chapter, the 10 °C reduction obtained in the above example would, theoretically, increase the life of the insulation somewhere between three and fourfold.

Winding temperature indicators

In the foregoing paragraphs mention was made of control of cooling equipment from a winding temperature indicator. Before leaving this section dealing with ancillary equipment it is perhaps appropriate to say a little more about winding temperature indicators, or more precisely, transformer temperature controllers. One such device is shown in *Figure 4.110*. This consists of a liquid-filled bulb at the end of a steel capillary. The bulb is placed in the hottest oil in the top of the transformer tank and the capillary is taken to the transformer marshalling cubicle where it terminates in a steel bellows unit within the temperature controller. The controller contains a second bellows unit connected to another capillary which follows the same route as that from the transformer tank but this has no bulb at its remote end and it acts as a means of compensation for variations in ambient temperature, since with changes in ambient the liquid in both capillaries expands or contracts with respect to the capillaries and both bellows therefore move together. For changes in oil temperature only the bellows connected to the bulb will move. Movement of both sets of bellows has no effect on the mechanism of the instrument while movement only of the bellows connected to the bulb causes the rotation of a temperature indicating pointer and a rotating disc which carries up to four mercury switches. The pointer can be set to give a local visual indication of oil temperature and the mercury switches can be individually set to change over at predetermined temperature settings. The mercury switches can thus provide oil temperature alarm and trip signals and also a means of sending a start signal to pumps

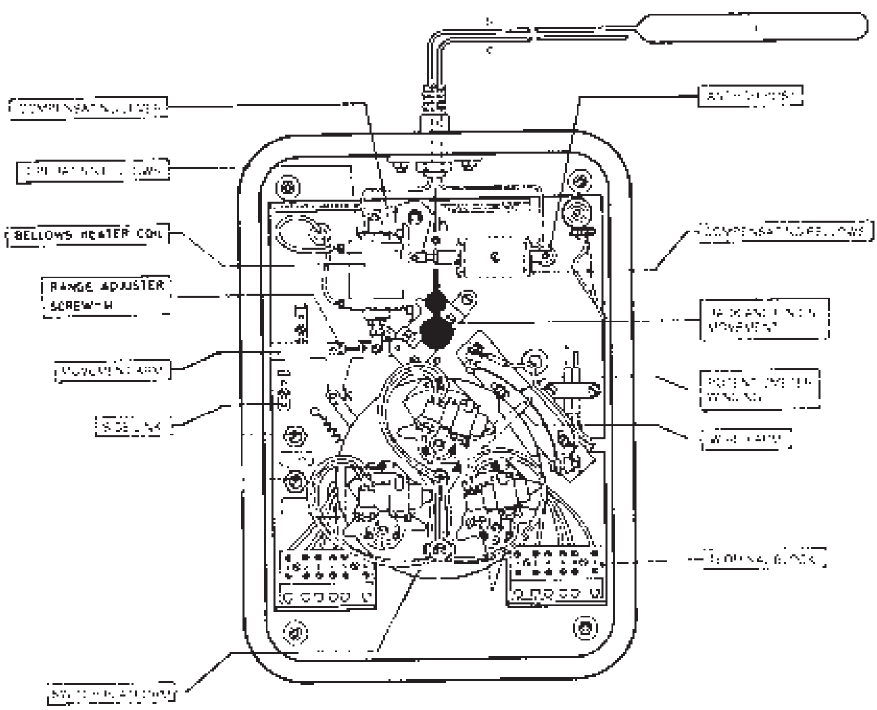


Figure 4.110 Transformers temperature controller (Accurate Controls Ltd)

and/or fans. The pointer is also connected to a potentiometer which can be used to provide remote indication of temperature. If it is required to have an indication of winding temperature the sensing bulb can be located in the hottest oil but surrounded by a heater coil supplied from a current transformer in either HV or LV winding leads. The heater coil is then designed to produce a temperature rise above hottest oil equivalent to the temperature rise of the HV or LV hot spot above the hottest oil. This is known as a *thermal image* device. The heater coil is provided with an adjustable shunt so that the precise thermal image can be set by shunting a portion of the CT output current. Of course, the setting of this heater coil current requires that the designer is able to make an accurate estimate of the hot-spot rise, and, as indicated in Section 5 of this chapter, this might not always be the case. If the transformer is subjected to a temperature rise test in the works, it is usual practice to carry out a final setting of the winding temperature indicators after the individual winding temperature rises have been calculated. On larger transformers one each will be provided for HV and LV windings.

4.9 PROCESSING AND DRY-OUT

The paper insulation and pressboard material, which make up a significant proportion by volume of transformer windings, have the capacity to absorb large amounts of moisture from the atmosphere. The presence of this moisture brings about a reduction in the dielectric strength of the material and also an increase in its volume. The increase in volume is such that, on a large transformer, until the windings have been given an initial dry-out, it is impossible to reduce their length sufficiently to fit them on to the leg of the core and to fit the top yoke in place.

The final drying out is commenced either when the core and windings are placed in an autoclave or when they are fitted into their tank, all main connections made, and the tank placed in an oven and connected to the drying system. The tapping switch may be fitted at this stage, or later, depending on the ability of the tapping switch components to withstand the drying process.

Traditional methods of drying out involve heating the windings and insulation to between 85 and 120°C, by circulating heated dry air and finally applying a vacuum to complete the removal of water vapour and air from the interstices of the paper before admitting transformer oil to cover the windings. For a small transformer operating at up to, say, 11 kV, this heating could be carried out by placing the complete unit in a steam or gas-heated oven. For a large transformer the process could take several days, or even weeks, so that nowadays the preference is to use a *vapour-phase* heating system in which a liquid, such as white spirit, is heated and admitted to the transformer tank under low pressure as vapour. This condenses on the core and windings, and as it does so it releases its latent heat of vaporisation, thus causing the tank internals to be rapidly heated. It is necessary to ensure that the insulation does not exceed a temperature of about 130°C to prevent ageing damage: when this temperature is reached, the white spirit and water vapour is pumped off. Finally, a vacuum equivalent of between 0.2 and 0.5 mbar absolute pressure is applied to the tank to complete the removal of all air and vapours. During this phase, it is necessary to supply further heat to provide the latent heat of vaporisation; this is usually done by heating coils in an autoclave, or by circulating hot air around the tank within the dry-out oven.

The vapour phase dry-out process is similar to systems used previously, the only difference being in the use of the vapour to reduce the heating time. It is not a certain method of achieving a drier transformer and, in fact, it is possible that the drying of large masses of insulation might be less efficient since, being limited by the rate of diffusion of water through the material, it is a process which cannot be speeded up. This is an area where further research might be beneficial. Particular problem areas are laminated pressboard end support structures and laminated wood used in the same location, where moisture will tend to migrate along the laminations rather than cross through the interlaminar layers of adhesive. Designers need to give special consideration to such structures and can often improve the dry-out process by arranging to have holes drilled in places where these will assist the release of moisture without weakening the structure. Another aspect of this system of drying out which requires special attention is that of the compatibility of the transformer components with the heat transfer medium. For example, prior to the use of the vapour phase process, some nylon materials were used for transformer internals, notably in a type of self-locking nut. This nylon is attacked by hot white spirit, so it was necessary to find an alternative.

Even in the case of small transformers, where dry-out will probably be carried out using a heated oven, there is still a need for careful attention in certain difficult areas. One of these is for multilayer high-voltage windings using round conductors. This type of winding usually has a layer of paper insulation between conductor layers. The moisture trapped within this interlayer insulation will have to travel up to half the length of the layer in order to be released to the atmosphere. This can take many hours, even days, at 130°C.

Monitoring insulation dryness during processing usually involves measurement of some parameter which is directly dependent on moisture content. Insulation resistance or power factor would meet this requirement. Since there are no absolute values for these applicable to all transformers, it is usual to plot readings graphically and dry-out is taken to be completed when a levelling out of power factor and a sharp rise in insulation resistance is observed. *Figure 4.111* shows typical insulation resistance and power factor curves obtained during a dry-out. Vacuum is applied when the initial reduction in the rate of change of these parameters is noted: the ability to achieve and maintain the required vacuum, coupled with a reduction and levelling out of the quantity of water removed and supported by the indication given by monitoring of the above parameters, will confirm that the required dryness is being reached. For a vapour phase drying system, since it could be dangerous to monitor electrical parameters, drying termination is identified by monitoring

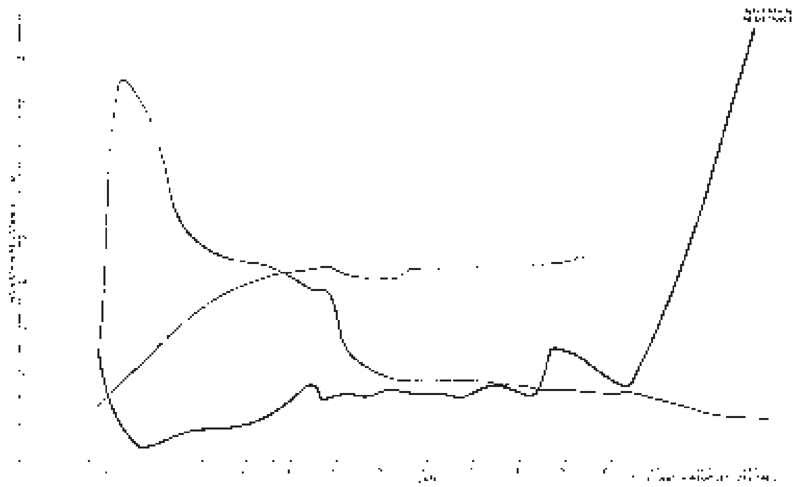


Figure 4.111 Insulation resistance and power factor curves during dry-out

water condensate in the vacuum pumping system. At this point oil filling is begun with dry, filtered degassed oil at a temperature of about 75°C being slowly admitted to the tank and at such a rate as to allow the vacuum already applied to be maintained.

Drying out of insulation is accompanied by significant shrinkage, so it is usual practice for a large transformer to be de-tanked immediately following initial oil impregnation to allow for retightening of all windings, as well as cleats and clamps on all leads and insulation materials. This operation is carried out as quickly as possible in order to reduce the time for which windings are exposed to the atmosphere. However, once they have been impregnated with oil, their tendency to absorb moisture is considerably reduced so that, provided the transformer is not out of its tank for more than about 24 hours, it is not necessary to repeat the dry-out process. On returning the core and windings to the tank, the manufacturer will probably have a rule which says that vacuum should be reapplied for a time equal to that for which they were uncovered, before refilling with hot, filtered, degassed oil.

Before commencement of final works tests, the transformer is then usually left to stand for several days to allow the oil to permeate the insulation fully and any remaining air bubbles to become absorbed by the oil.

References

4.1 Montsinger, V.M. (1930) ‘Loading transformers by temperature’. *Trans. AIEE*, **49**, 776.

4.2 Shroff, D.H. and Stannett, A.W. (1984) ‘A review of paper ageing in power transformers’. *Proc. IEE*, **132**, 312–319.

The remainder of this chapter is devoted to illustrations of typical transformers from the smallest to the largest size (see *Figures 4.11* to *4.141*). These are shown with different types of tanks and with different terminal arrangements, and are typical of modern practice in the design of power transformers.

Figure 4.112 Single-phase 11 kV, 50 Hz, pole-mounted transformers. Rated 16–50 kVA (Allenwest Brentford Ltd)

Figure 4.113 Three-phase 500 kVA, 11 kV, 50 Hz substation transformer showing the provision made for mounting LV fusegear on the left and an HV ring main unit on the right (ABB Power T&D Ltd)

Figure 4.114 Three-phase 750 kVA, 11 000/395 V, 50 Hz sealed-type transformer with welded cover; viewed from HV side. The HV cable box is attached to a disconnecting chamber (ABB Power T&D Ltd)

Figure 4.115 Three-phase 750 kVA, 11/3.3 kV transformer fitted with conservator, Buchholz relay and explosion vent. Tappings over a range -2.5% to $+7.5\%$ are brought out to an off-circuit selector switch (ABB Power T&D Ltd)

Figure 4.116 Three-phase dry-type mining transformer 3300/1130-565 V, 50 Hz. High-voltage SF_6 switchgear is mounted on the near end of the tank with LV chamber containing earth-leakage equipment at far end (Brush Transformers Ltd)

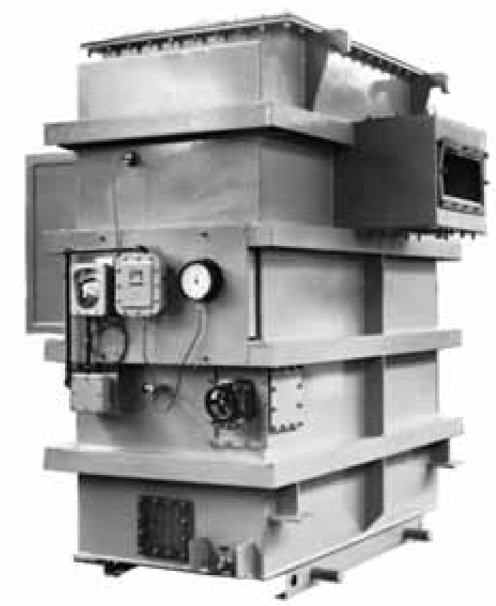


Figure 4.117 Three-phase 11 kV, 50 Hz dry-type nitrogen-fitted sealed transformer (Allenwest Brentford Ltd)

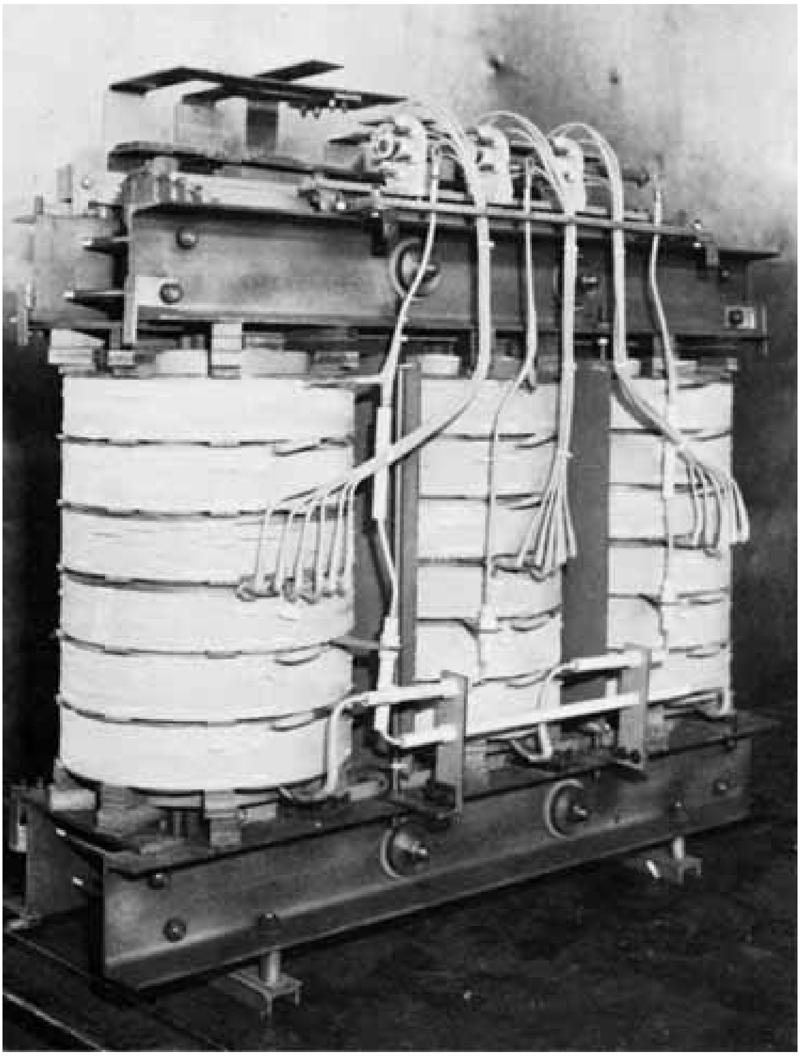


Figure 4.118 Three-phase 1750 kVA, 13800/480 V, 50 Hz core and windings. HV tappings brought to an off-circuit tap selector (Bonar Long Ltd)

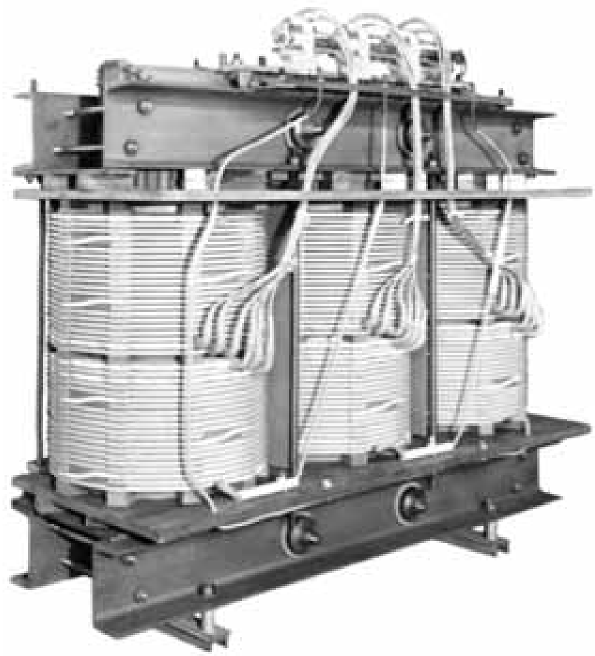


Figure 4.119 Three-phase 1500 kVA, 13.8/3.3 kV, 50 Hz core and windings. HV tappings at ±2.5% and ±5% taken from the HV disc type windings (Bonar Long Ltd)

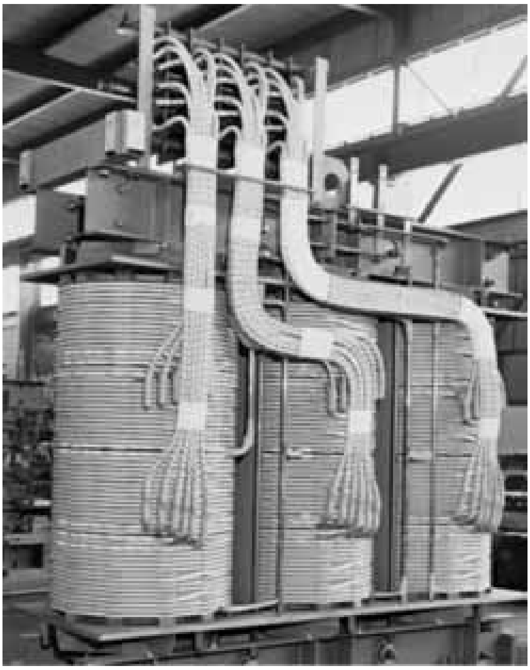


Figure 4.120 Three-phase 6 MVA, 600/3450 V, 50 Hz core and windings with HV tappings brought to an off-circuit selector. The HV disc winding is arranged in two parallel halves to reduce axial forces (ABB Power T&D Ltd)

Figure 4.121 Core windings of three single-phase units each rated at 10 000 A and desiged for rectifier testing duty (Allenwest Brentford Ltd)

Figure 4.122 Two 90 MVA, 385/18.7 kV units in service at CERN (The European Organisation for Nuclear Research). The units provide power for what is claimed to be the world's largest nuclear particle accelerator; a 400 GeV proton synchroton. The units have to withstand three million pulses per year at a peak load of 148 MW, 50% above their nominal rating (Hawker Siddeley Power Transformers Ltd)

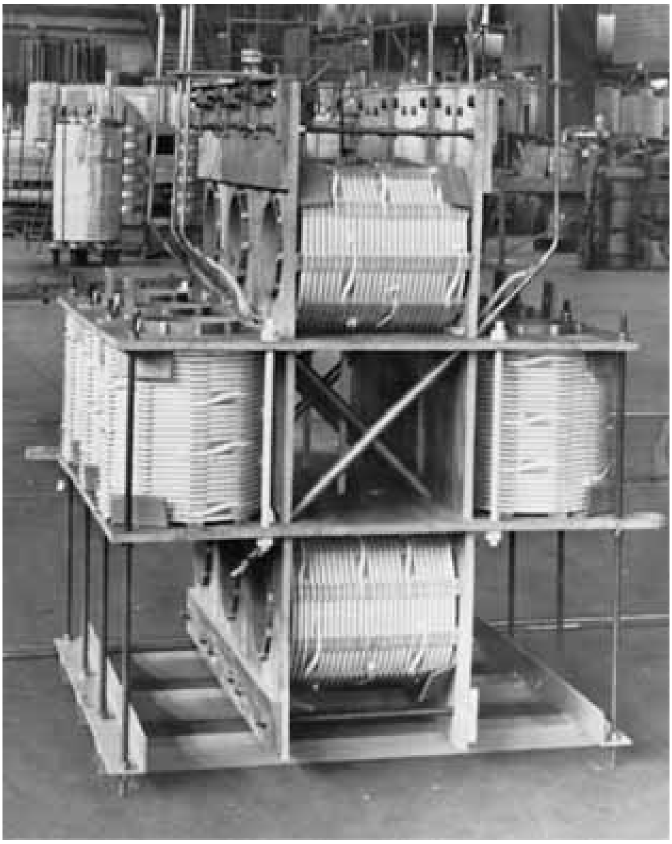


Figure 4.123 Frame and windings of a three-phase air-cored reactor, 20 MVA, 11/6.6 kV, 4% $\times$ 50 Hz, shown out of its tank (ABB Power T&D Ltd)

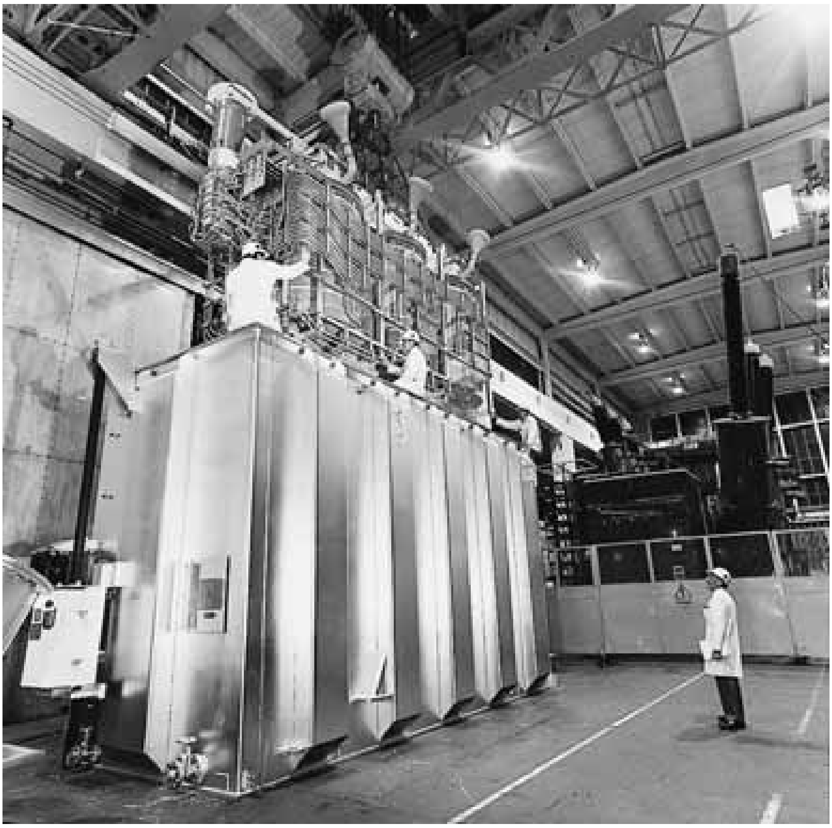


Figure 4.124 Lowering the core and windings of a 148 MVA 275 kV 50 Hz, three-phase generator transformer into its tank (ABB Power T&D Ltd)

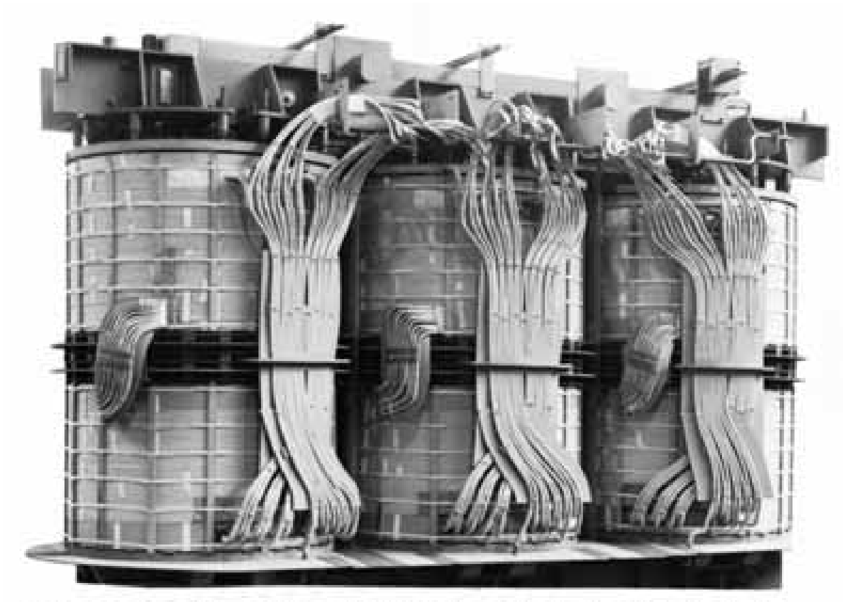


Figure 4.125 Three-phase 60 MVA, 132/33 kV, 50 Hz core and windings showing the outer tapping winding and the tapping leads assembly (ABB Power T&D Ltd)

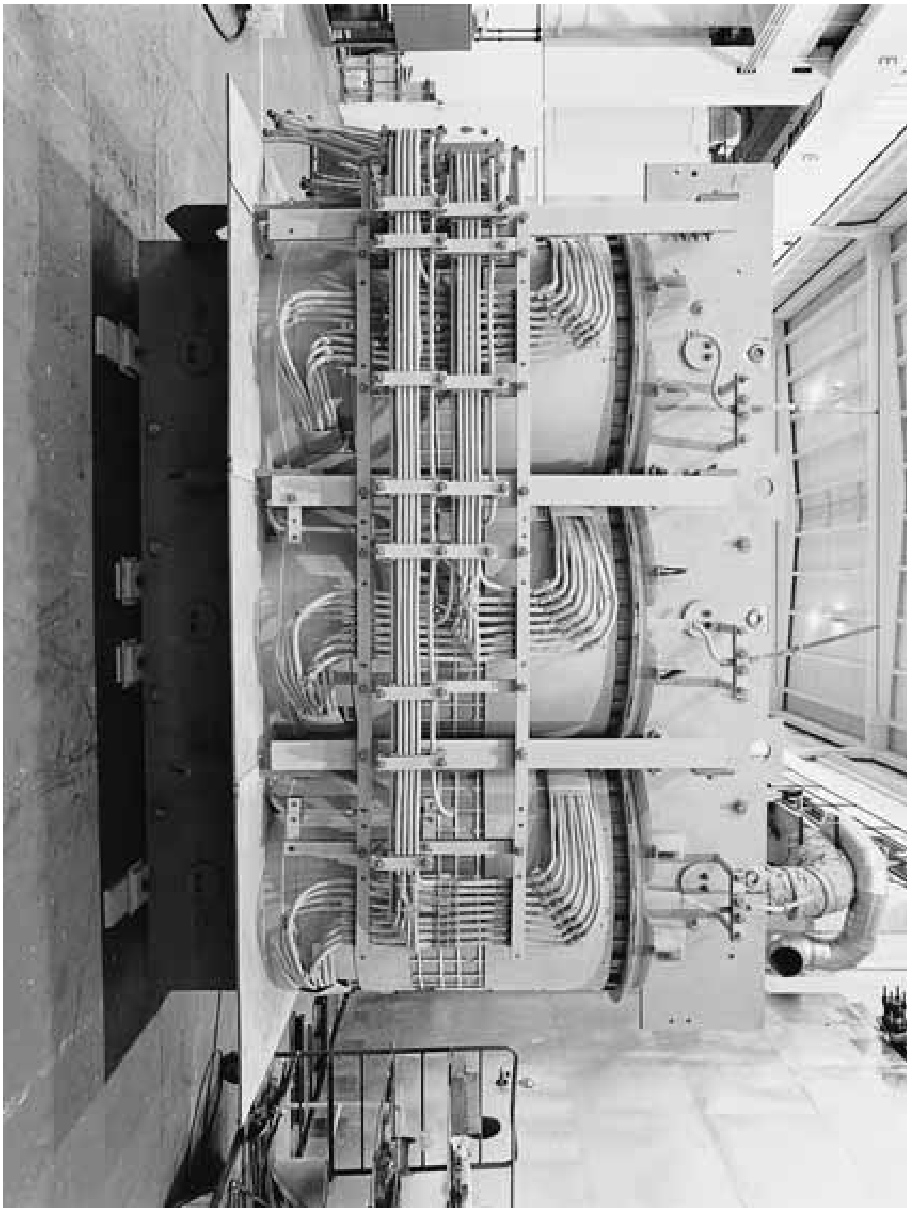
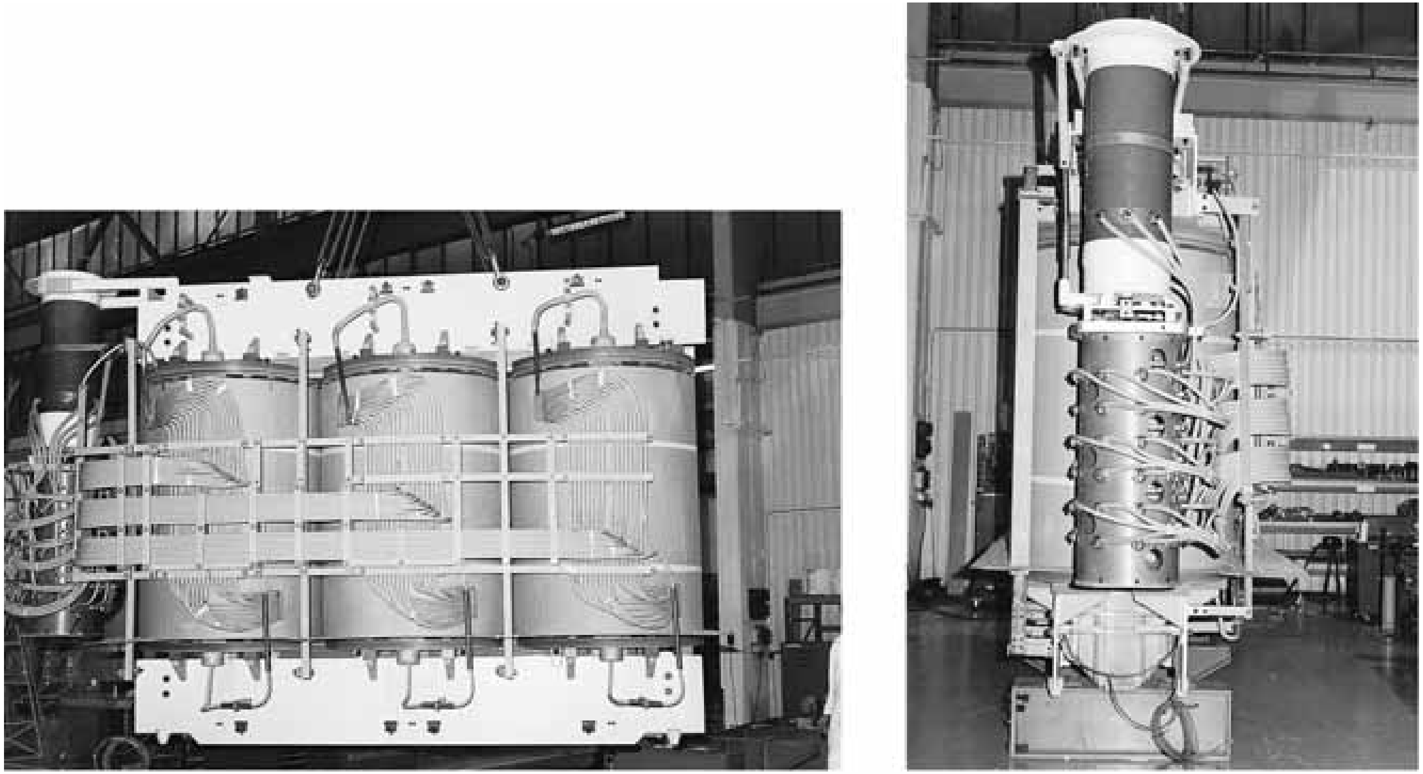


Figure 4.126 Core and windings of 46 MVA, 72.8/11.5 kV, 50 Hz, three-phase transformer with tappings brought out for connection to on-load tapchanger (ABB Power T&D Ltd)



(a) (b)

Figure 4.127 Two views of the core & windings of a three-phase 90 MVA, 132/33 kV, 50 Hz transformer connected star-delta and fitted with a +10% to −20% tappings on 18 steps of 1.67% at the neutral end of the HV winding. (ABB Power T&D Ltd)

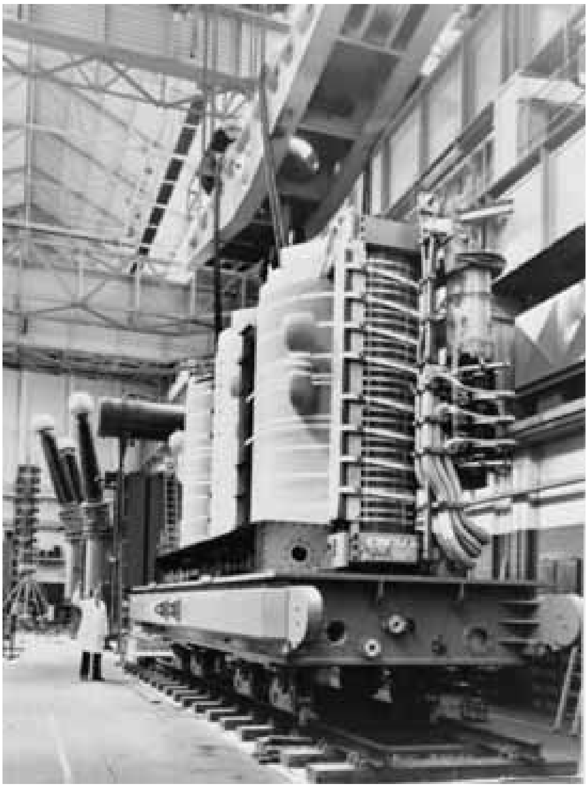


Figure 4.128 Core and windings of a 250 MVA, 400/121 kV power transformer manufactured for the Czechoslovakian Supply Authorities being fitted to its special Schnabel tank base (Hawker Siddeley Power Transformers Ltd)

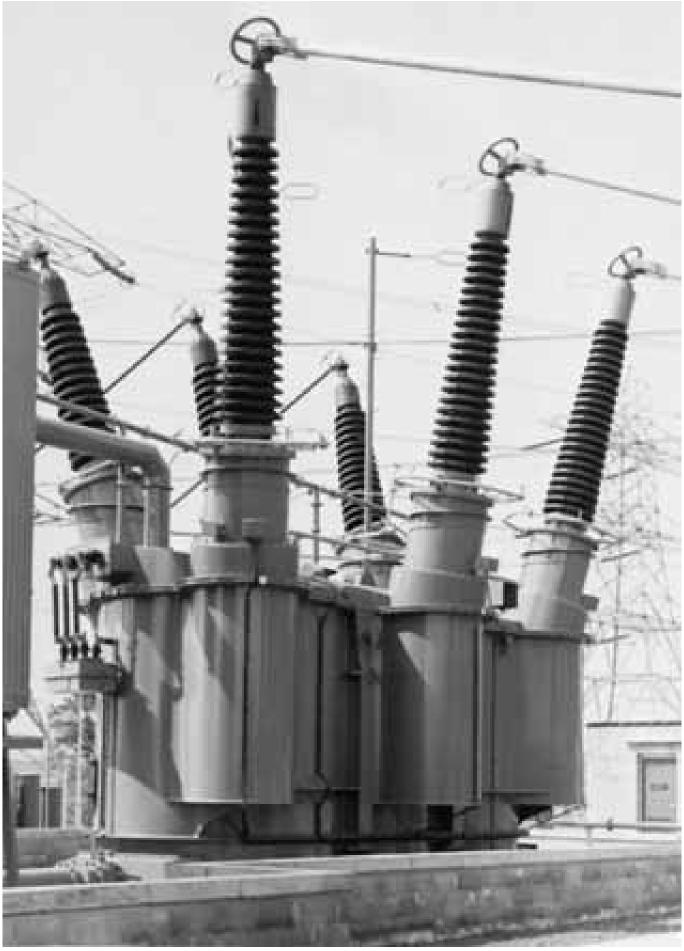


Figure 4.129 A 500 MVA transformer linking the National Grid Companies' 400 kV and 275 kV Supergrid Systems (Hawker Siddeley Power Transformers Ltd)

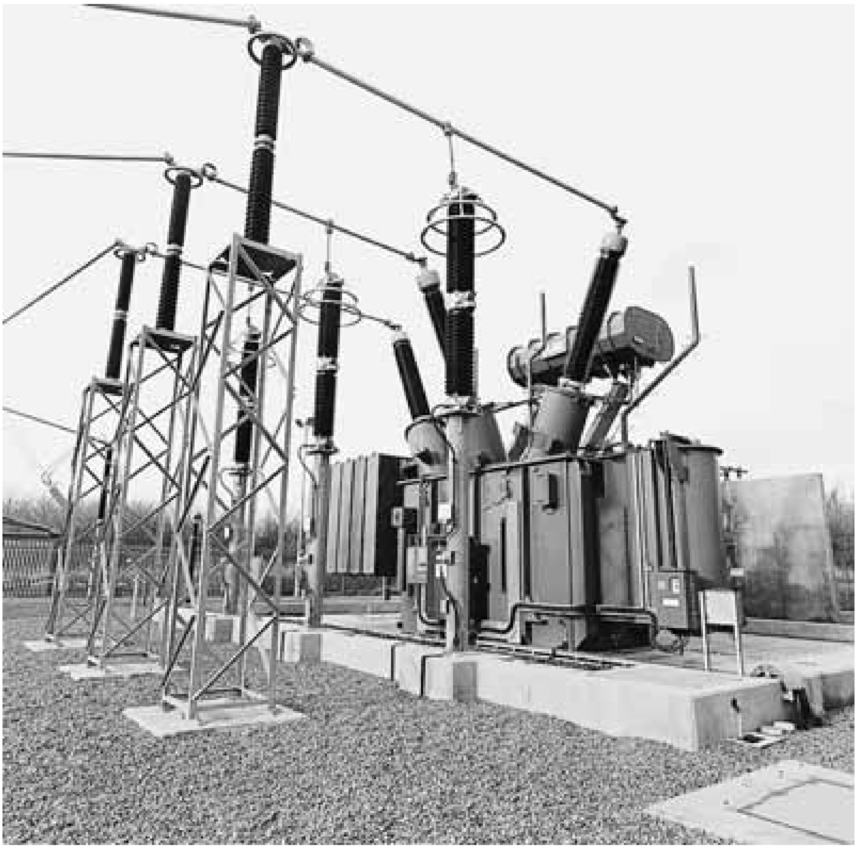


Figure 4.130 Site installation of a 40 MVA, 275 kV, 50 Hz, three-phase, step-down transformer on the UK grid system (ABB Power T&D Ltd)

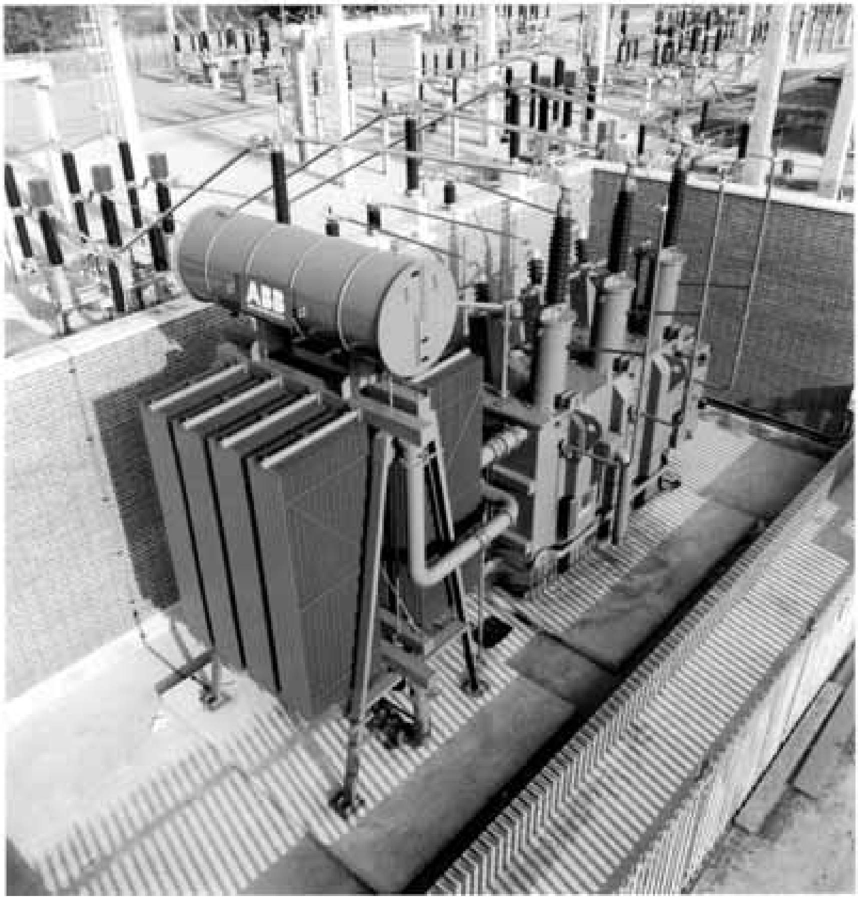


Figure 4.131 Site installation of a 90 MVA, 132/33 kV, 50 Hz, three-phase transformer showing separate cooler bank (ABB Power T&D Ltd)

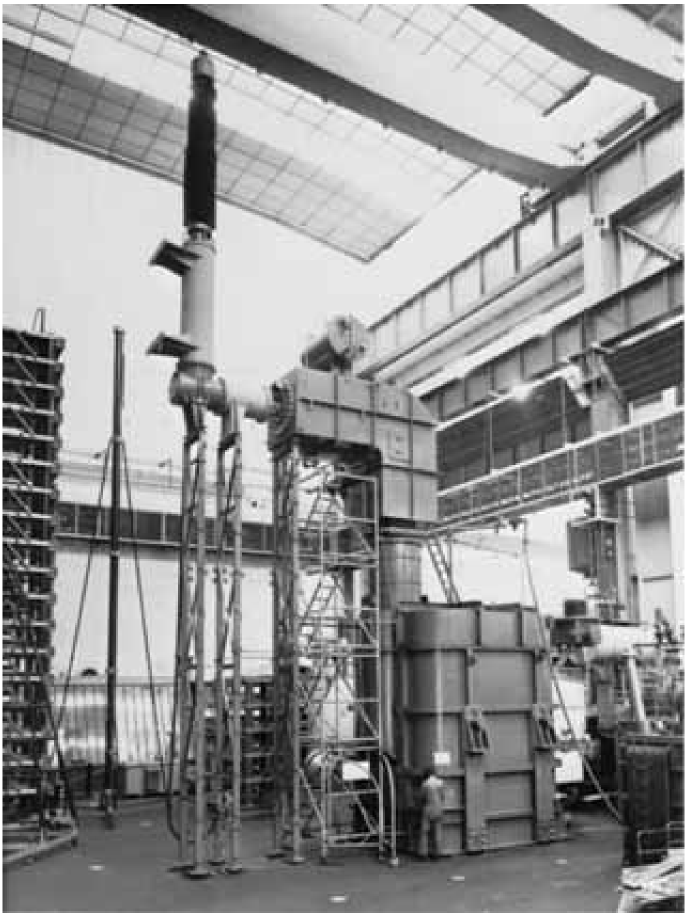


Figure 4.132 Single-phase 267 MVA, 23.5/249 kV, 50 Hz generator transformer type ODAF. Three such units form an 800 MVA, 23.5/432 kV bank. The interposing SF_6 chamber, fitted for test purposes, can be seen on the HV side (Peebles Transformers)

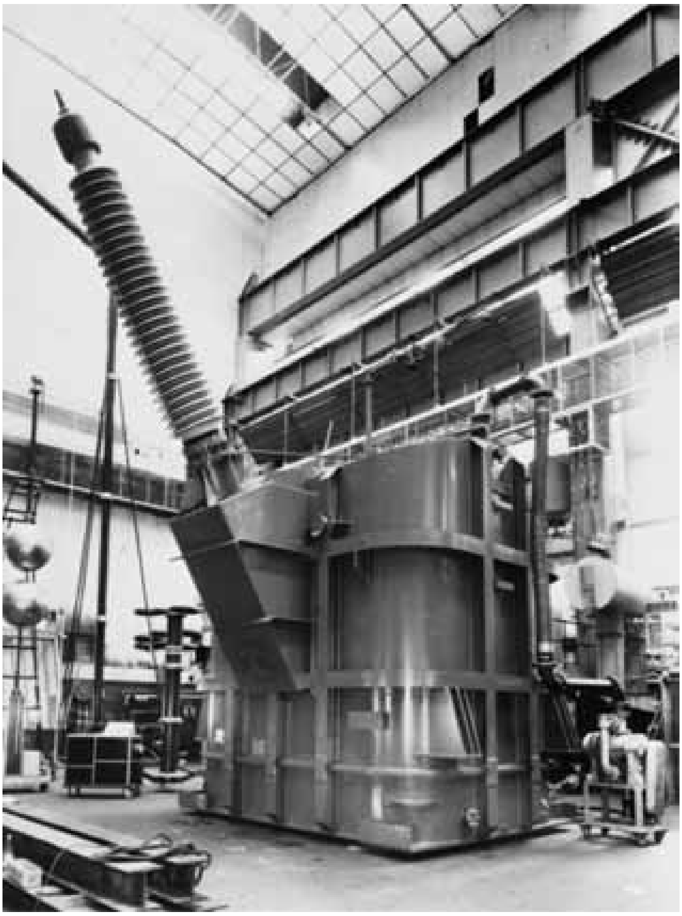


Figure 4.133 Single-phase 239 MVA, 21.5/231 kV, 50 Hz generator transformer. Three such units form a 717 MVA, 21.5/400 kV three-phase bank (Peebles Transformers)

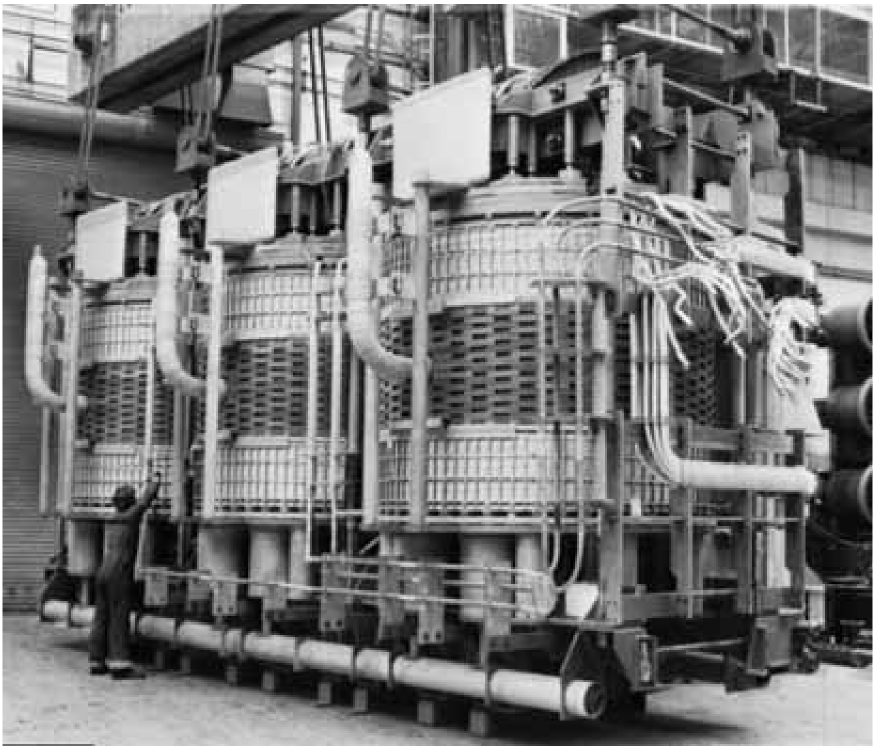


Figure 4.134 Core and windings of a 340 MVA, 18/420 kV, 50 Hz three-phase transformer, type ODWF (Peebles Transformers)

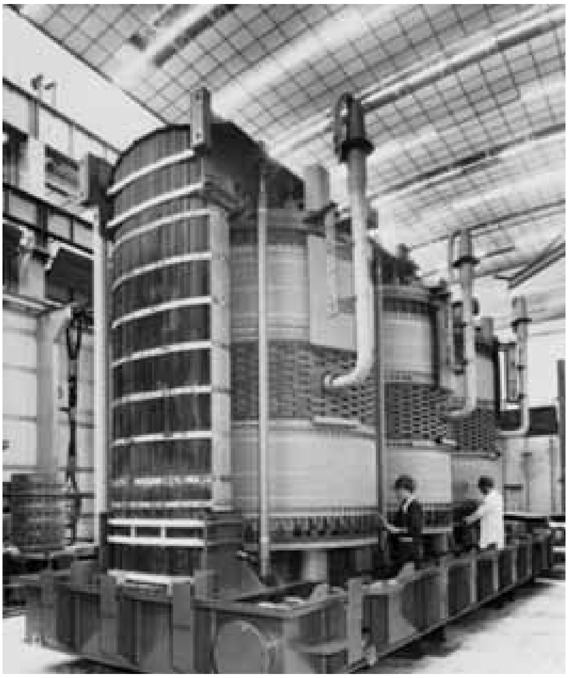


Figure 4.135 Core and windings of a 776 MVA, 23.5/285 kV three-phase generator transformer, type ODWF (Peebles Transformers)

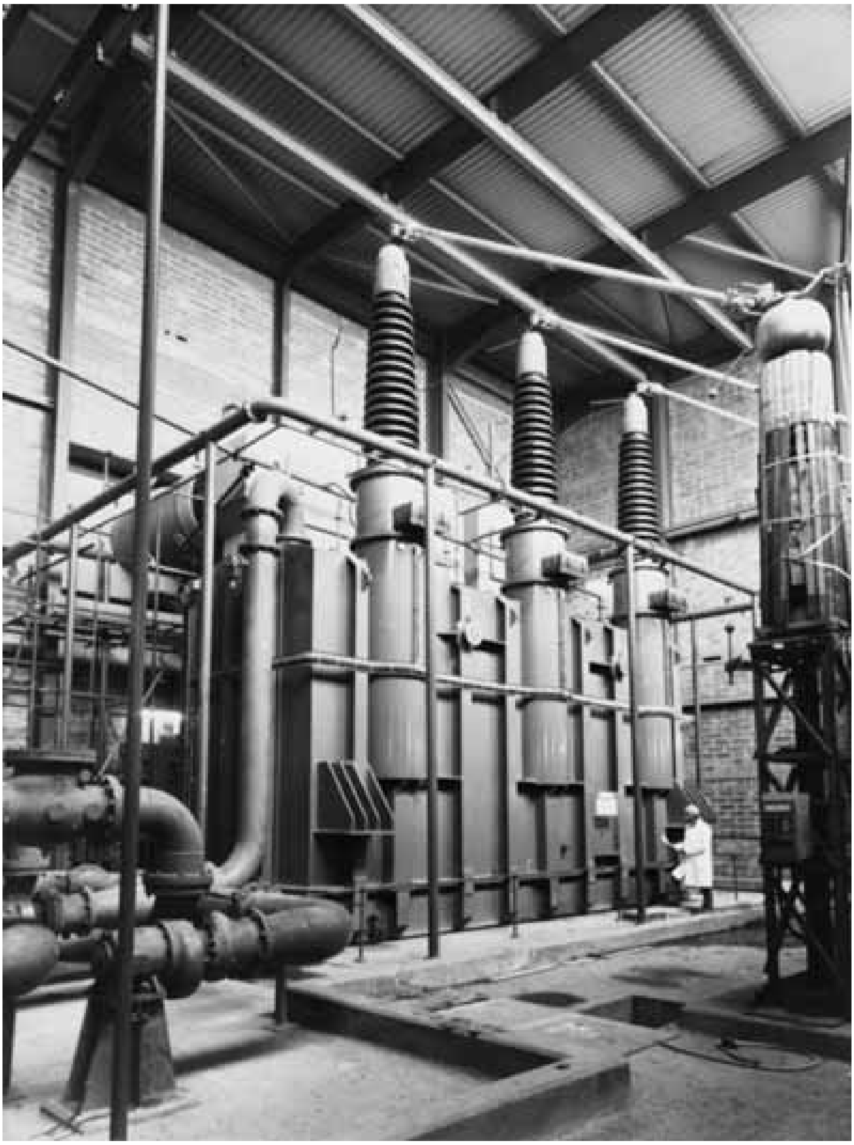


Figure 4.136 External view of the 776 MVA, 23.5/285 KV three-phase transformer shown in *Figure 4.135* (Peebles Transformers)

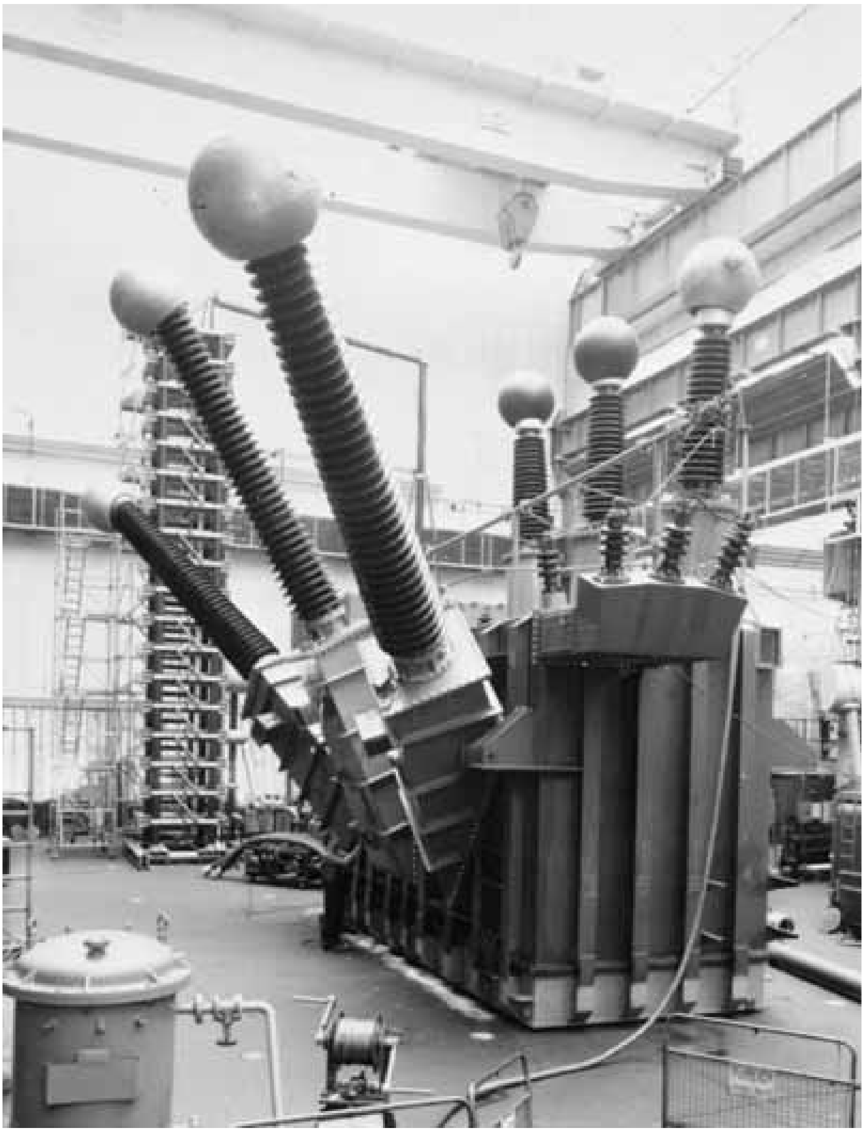


Figure 4.137 600 MVA, 515/230 kV, 50 Hz three-phase autotransformer, type ONAN/ODAF (Peebles Transformers)

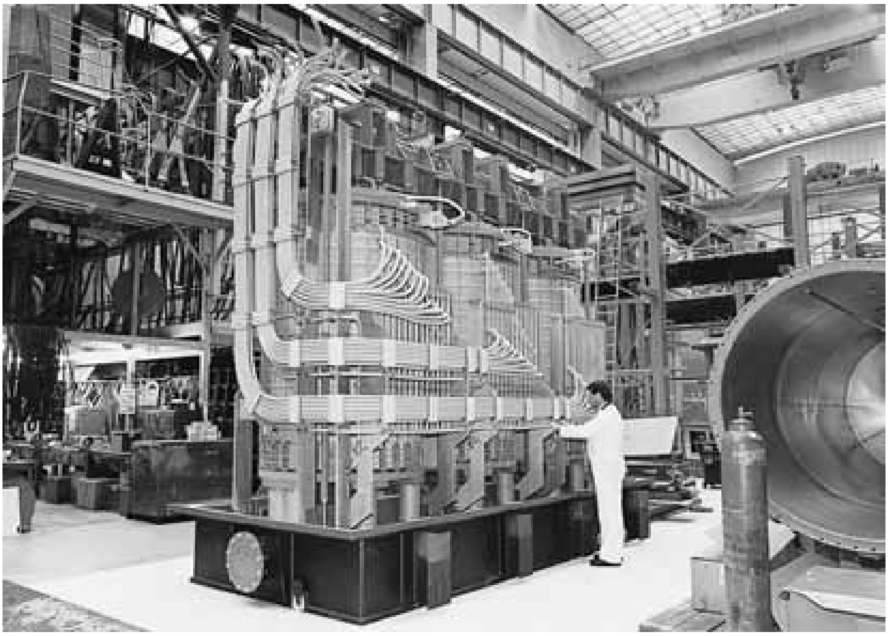


Figure 4.138 130 MVA, 132/10.5 kV generator transformer for Connaught Bridge PS, Malaysia. The on-load tapping leads were brought up one end of the unit and over a weir to enable the tapchanger to be removed for maintenance without draining oil from the main tank (Peebles Transformers)

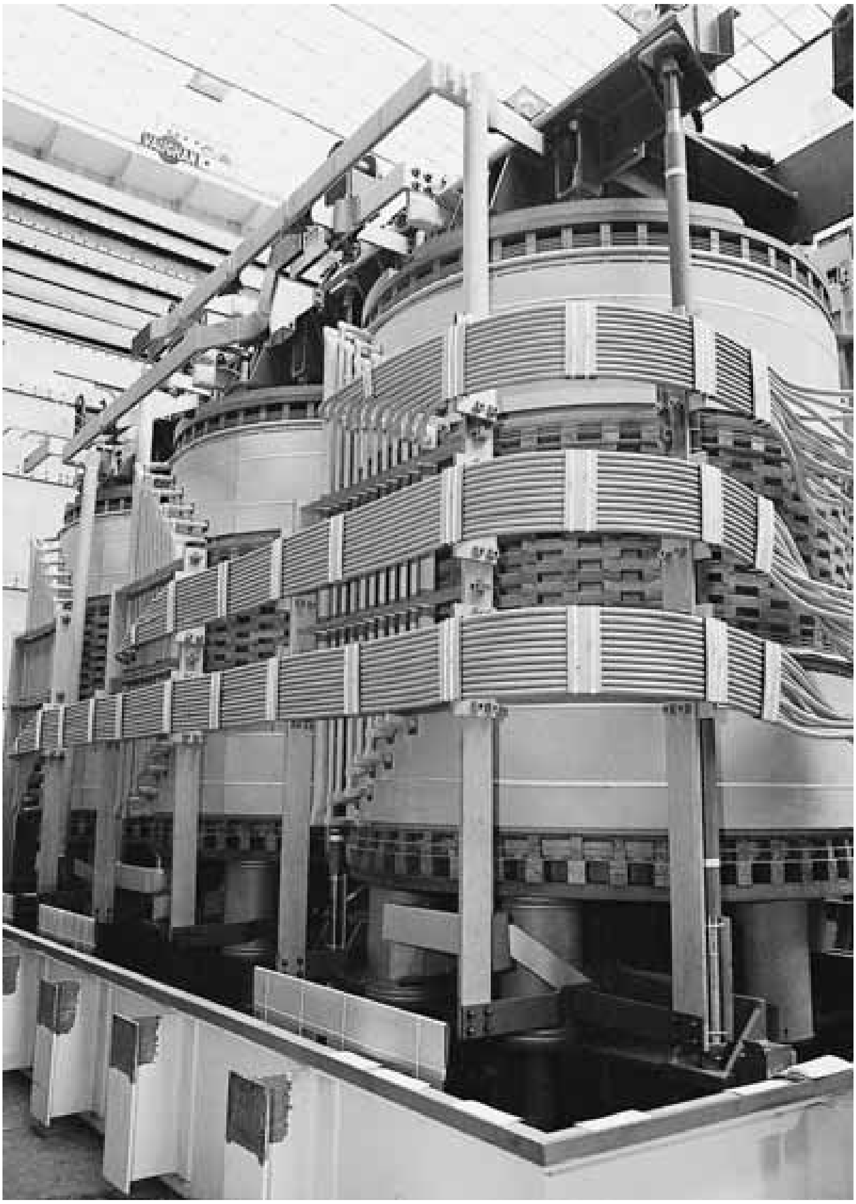


Figure 4.139 331 MVA, 15.5/430 kV generator transformer for Keadby Power Station viewed along the LV side showing the on-load tapping leads (Peebles Transformers)

Figure 4.140 Core and windings of a 760 MVA, 275 kV quadrature booster showing the shunt unit on the left and the series unit on the right. On this size of QB both assemblies are housed in a common tank (see also *Figure 7.17* (Peebles Transformers))

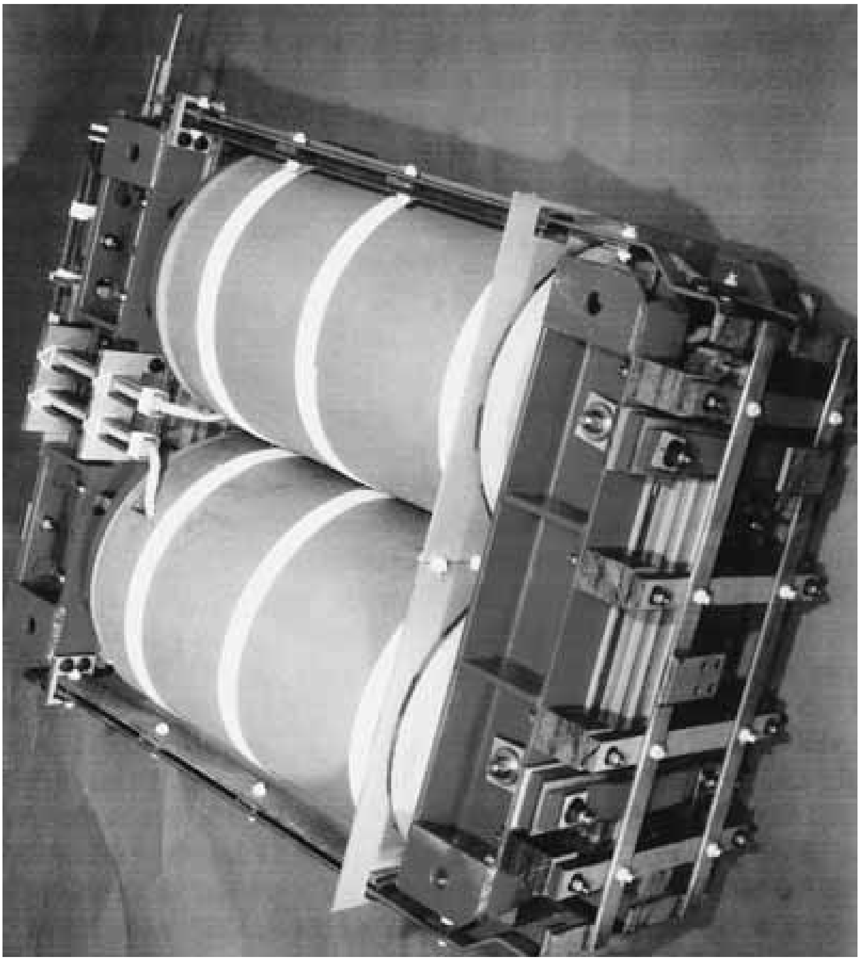


Figure 4.141(a) 1496 kVA, 25 kV, single phase (Electric Multiple Unit) transformer for the former British Rail Class 319 unit. These transformers are slung horizontally under the driving carriage of an EMU coach. The photo shows both HV (at top) and LV (at bottom) leads (GEC Alsthom)

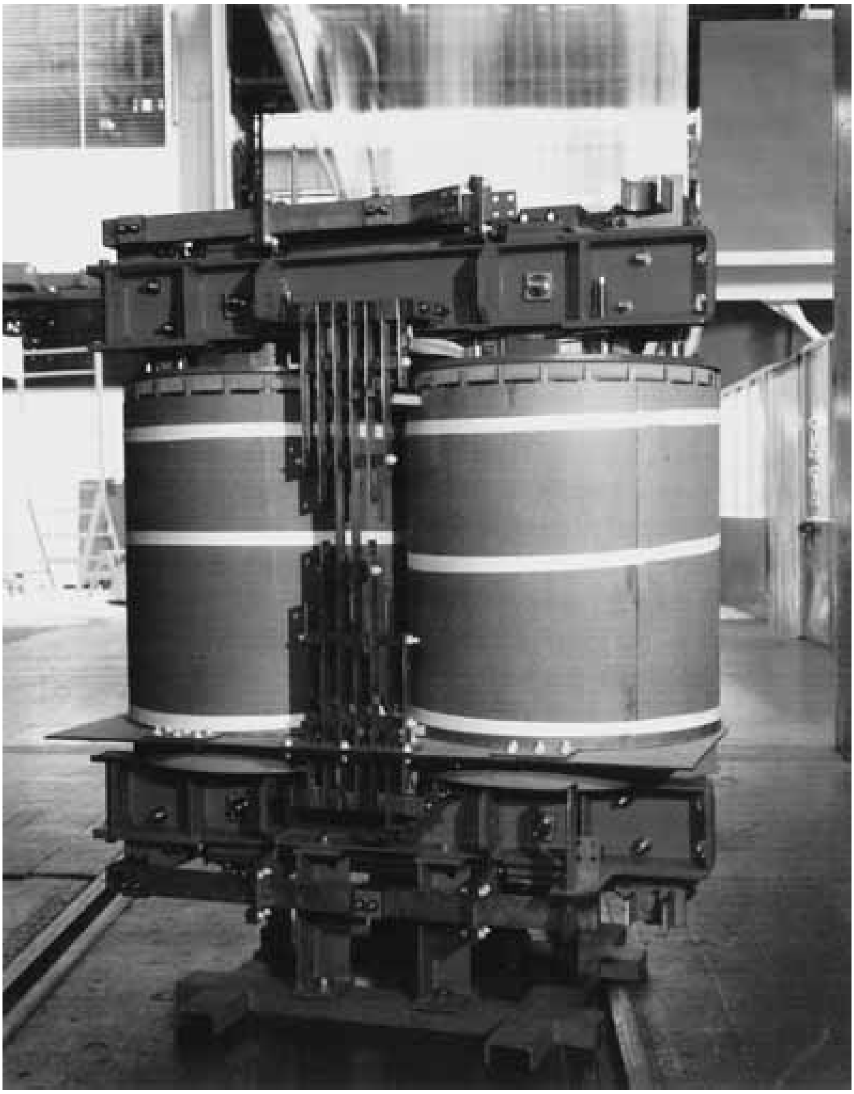


Figure 4.141(b) 7843 kVA, 25 kV, single phase locomotive transformer for the former British Rail Class 91 locomotive. This transformer has 4 primaries, 4 secondaries and 5 tertiaries: and would sit upright in the locomotive (GEC Alsthom)

5 Testing of transformers

5.1 TESTING AND QUALITY ASSURANCE (QA) DURING MANUFACTURE

Unlike many items of electrical power plant (for example, switchgear and motors) most transformers are still virtually handmade, little or no mass production is employed in manufacture and each is produced very much as a one-off. This means that the user cannot rely on extensive type testing of pre-production prototypes to satisfy himself that the design and manufacture renders the transformer fit for service, but must have such proving as is considered necessary carried out on the transformer itself. From a series of works tests, which might at most be spread over a few days, it is necessary to ascertain that the transformer will be suitable for 30 years or more in service. It is therefore logical that this testing should be complemented by a system of QA procedures which operate on each individual unit and throughout the whole design and manufacturing process.

The final tests, with which this chapter mainly deals, are checks on all QA procedures carried out throughout the period of manufacture. The stringency and thoroughness of these tests are of vital importance. This chapter gives a detailed description of the various methods employed. To obtain accurate results it is essential that low power factor wattmeters, precision grade ammeters, voltmeters, and class 0.1 (see BS 3938 and 3941) current and voltage transformers are used. These instruments should be checked at intervals not exceeding 12 months to ensure that the requisite accuracy is maintained.

The above comments might be less true for small distribution transformers where a degree of standardisation, automation and mass production technology is tending to appear in some production areas, notably in the manufacture of cores, insulation components and resin-encapsulated windings for dry types. Distribution transformers and dry-type transformers will be considered further in Chapter 7 and most of the following comments concerning QA and testing refer to larger transformers which are still manufactured by ‘conventional’ methods.

Details of operation of QA systems are beyond the scope of this volume and are covered adequately elsewhere, for example by BS 5750, *Quality Systems*, but it must be pointed out that testing alone will not demonstrate that the transformer is fully compliant with all the requirements which may be placed upon it. Many factors which will have a strong bearing on the service life of a large high-voltage transformer are very dependent on attention to detail in the design and manufacture and the need for a high standard of QA, and a culture of quality consciousness in the manufacturer’s works cannot be emphasised too strongly.

Tests during manufacture

As part of the manufacturer’s QA system some testing will of necessity be carried out during manufacture and it is appropriate to consider the most important of these in some detail. These are:

Core-plate checks. Incoming core plate is checked for thickness and quality of insulation coating. A sample of the material is cut and built up into a small loop known as an Epstein Square from which a measurement of specific loss is made. Such a procedure is described in BS 6404 (IEC 404), Part 2 *Methods of measurement of magnetic, electrical and physical properties of magnetic sheet and strip*. Core-plate insulation resistance should be checked to ensure that the transformer manufacturer’s specified values are achieved. BS 6404, Part 2 gives two alternative methods for carrying out this measurement. The actual method to be used should be agreed between purchaser and supplier.

Core-frame insulation resistance. This is checked by Megger and by application of a 2 kV r.m.s. or 3 kV DC test voltage on completion of erection of the core. These checks are repeated following replacement of the top yoke after fitting the windings. A similar test is applied to any electrostatic shield and across any insulated breaks in the core frames.

Many authorities consider that for large transformers a test of the core and core-frame insulation resistance at 2 kV r.m.s. or 3 kV DC is not sufficiently searching. Modern processing techniques will enable only a very small physical dimension of pressboard to achieve this level under the ideal conditions within the manufacturer’s works. The core and the windings supported from it can have a very large mass so that relatively minor shocks suffered during transport can easily lead to damage or dislocation of components so that the small clearances necessary to withstand the test voltage are lost, with the result that core and core-frame insulation which was satisfactory in the factory gives a low insulation resistance reading when tested on site. For this reason in the UK, the CEGB specified increased insulation test requirements for the core/frame/tank for transformers operating at 275 and 400 kV to that appropriate to 3.3 kV class, i.e. in the dry state prior to oil filling the test voltage becomes 8 kV r.m.s. and immediately prior to despatch but while still oil filled these tests must be repeated at 16 kV r.m.s.

Core-loss measurement. If there are any novel features associated with a core design or if the manufacturer has any other reason to doubt whether the guaranteed core loss will be achieved, then this can be measured by the application of temporary turns to allow the core to be excited at normal flux density before the windings are fitted.

Winding copper checks. If continuously transposed conductor (see Section 2 of Chapter 4) is to be used for any of the windings, strand-to-strand checks of the enamel insulation should be carried out directly the conductor is received in the works.

Tank tests. The first tank of any new design should be checked for stiffness and vacuum-withstand capability. For 275 and 400 kV transformers, a vacuum equivalent to 25 mbar absolute pressure should be applied. This need only be held long enough to take the necessary readings and verify that the vacuum is indeed being held, which might take up to 2 hours for a large tank. After release of the vacuum, the permanent deflection of the tank sides should be measured and should not exceed specified limits, depending on length. Typically a permanent deflection of up to 13 mm would be considered reasonable. Following this test, a further test for the purpose of checking mechanical-withstand capability should be carried out. Typically a pressure equivalent to 3 mbar absolute should be applied for 8 hours.

For transformers rated 132 kV and below a more modest vacuum test equivalent to 330 mbar absolute pressure should be applied. The permissible permanent deflections following this test should be similar to those allowed for 275 and 400 kV transformer tanks reduced pro-rata for smaller tanks.

Wherever practicable, all tanks should be checked for leak tightness by filling with a fluid of lower viscosity than transformer oil, usually white spirit, and applying a pressure of 700 mbar, or the normal pressure plus 350 mbar, whichever is the greater, for 24 hours. All welds are painted for this test with a flat white paint which aids detection of any leaks.

5.2 FINAL TESTING

Final works tests for a transformer fall into three categories:

- *Tests to prove that the transformer has been built correctly*. These include ratio, polarity, resistance, and tap change operation.

- *Tests to prove guarantees*. These are losses, impedance, temperature rise, noise level.
- *Tests to prove that the transformer will be satisfactory in service for at least 30 years*. The tests in this category are the most important and the most difficult to frame: they include all the dielectric or overvoltage tests, and load current runs.

All the tests in the first two categories can be found in BS 171. BS 171 (or the basically similar IEC 76) also describes dielectric tests and load current runs, so it is largely possible to meet all of the three requirements by testing to this International Standard. However, for large, important transformers it is desirable to go beyond the requirements of the standard if it is required to gain maximum reassurance in the third category and this aspect will be discussed later.

Firstly, however, it is appropriate to consider the testing requirements set out in BS 171.

Testing to the British Standard

Routine tests

All transformers are subjected to the following tests:

1. Voltage ratio and polarity.
2. Winding resistance.
3. Impedance voltage, short-circuit impedance and load loss.
4. Dielectric tests.
   (a) Separate source AC voltage.
   (b) Induced overvoltage.
   (c) Lightning impulse tests.
5. No-load losses and current.
6. On-load tap changers, where appropriate.

Type tests

Type tests are tests made on a transformer which is representative of other transformers to demonstrate that they comply with specified requirements not covered by routine tests.

1. Temperature rise test.
2. Noise level test.

Special tests

Special tests are tests, other than routine or type tests, agreed between manufacturer and purchaser, for example:

1. Test with lightning impulse chopped on the tail.
2. Zero-sequence impedance on three-phase transformers.

3. Short-circuit test.
4. Harmonics on the no-load current.
5. Power taken by fan and oil-pump motors.

The requirement for type or special tests to be performed, or for any tests to be performed in the presence of the purchaser or his representative, must be determined for particular contracts.

These tests are briefly described for three-phase transformers in the following text. The procedure is generally similar for single-phase units.

Voltage ratio and polarity test

Measurements are made on every transformer to ensure that the turns ratio of the windings, tapping positions and winding connections are correct. The BS tolerance at no-load on the principal tapping is the smaller of either:

(a) ±0.5% of the declared ratio, or
(b) a percentage of the declared ratio equal to one-tenth of the actual percentage impedance voltage at rated current.

These measurements are usually carried out during assembly of both the core and windings, while all the connections are accessible, and finally when the transformer is fully assembled with terminals and tap changing mechanism.

In order to obtain the required accuracy it is usual to use a ratiometer rather than to energise the transformer from a low-voltage supply and measure the HV and LV voltages.

Ratiometer method

The diagram of connections for this test is shown in *Figure 5.1*. The ratiometer is designed to give a measurement accuracy of 0.1% over a ratio range up to 1110:1. The ratiometer is used in a ‘bridge’ circuit where the voltages of the windings of the transformer under test are balanced against the voltages developed across the fixed and variable resistors of the ratiometer. Adjustment of the calibrated variable resistor until zero deflection is obtained on the galvanometer then gives the ratio to unity of the transformer windings from the ratio of the resistors. This method also confirms the polarity of the windings since a zero reading would not be obtained if one of the winding connections was reversed.

With this type of ratiometer the test can be performed at normal mains supply voltage without loss of accuracy, limiting the highest voltage present during the test to the mains supply voltage.

One disadvantage in the use of low-voltage supplies for ratio measurements is that shorted turns in windings with a high number of turns or windings that have parallel connections can be very difficult to detect. A method of overcoming this is to supply the LV winding with a voltage which will produce

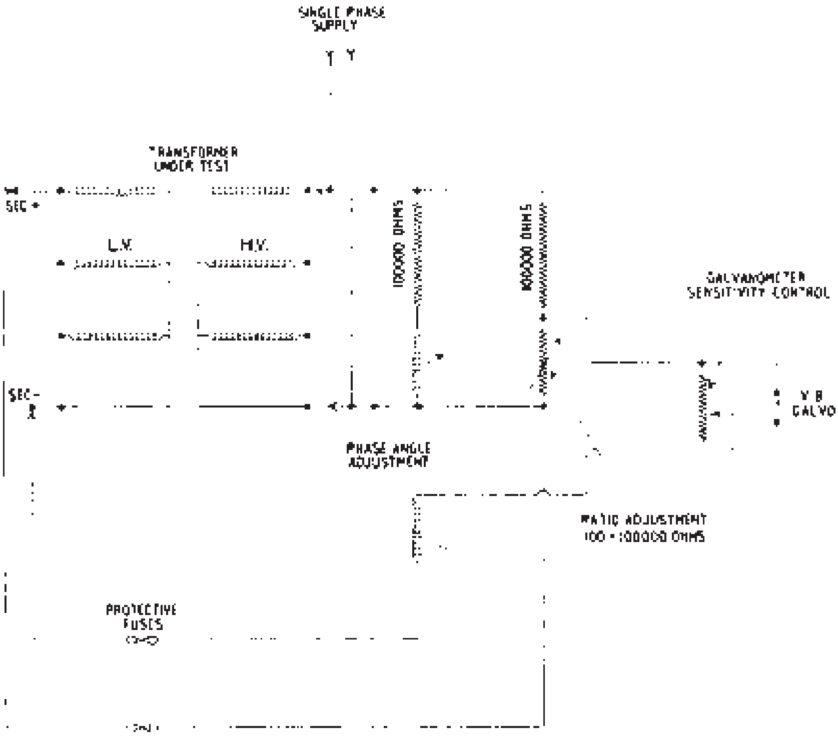


Figure 5.1 No-load voltage ratio test

about 1000 V in the HV and then scan the winding with a sensitive flux meter while monitoring the supply current. A shorted turn will then appear as a marked change in the leakage flux without any corresponding change in current. This check must, of course, be carried out before the transformer is installed in the tank.

Polarity of windings and phasor group connections

Polarity and interphase connections may be checked while measuring the ratio by the ratiometer method but care must be taken to study the diagram of connections and the phasor diagram for the transformer before connecting up for test. A ratiometer may not always be available and this is usually the case on site so that the polarity must be checked by voltmeter. The primary and secondary windings are connected together at one point as indicated in *Figure 5.2*. A low-voltage three-phase supply is then applied to the HV terminals. Voltage measurements are then taken between various pairs of terminals as indicated in the diagram and the readings obtained should be the phasor sum of the separate voltages of each winding under consideration.

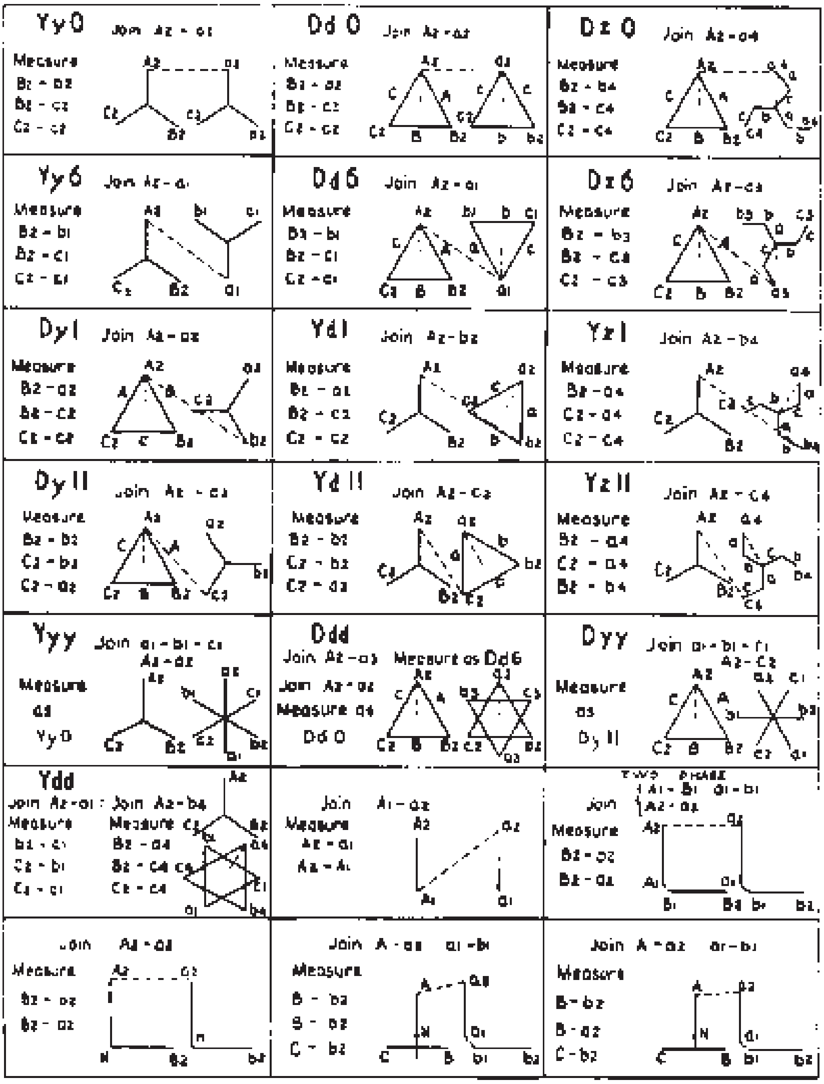


Figure 5.2 Diagrams for checking polarity by voltmeter

Load-loss test and impedance test

These two tests are carried out simultaneously, and the connections are shown in *Figure 5.3*. The two-wattmeter method can be employed for measuring the load (copper) loss of a three-phase transformer, one instrument normally being used, the connections from which are changed over from any one phase of the transformer to any other by means of a double pole switch. Closing the

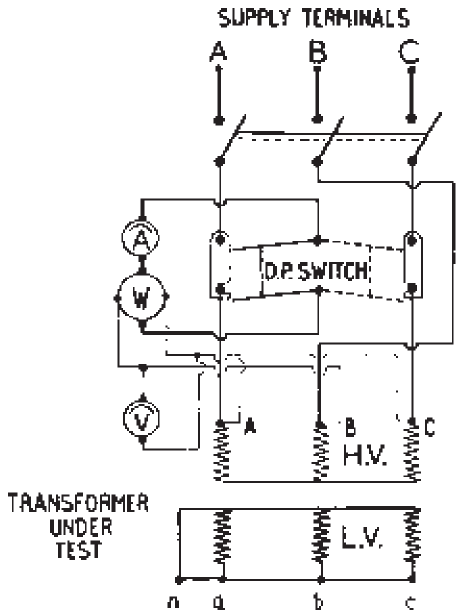


Figure 5.3 Copper-loss and impedance voltage test: two-wattmeter method

double pole switch on phase A places the ammeter and the current coil of the wattmeter in series with that phase. The wattmeter voltage coil and the voltmeter are connected across phases A and B, both leads from the wattmeter voltage coil being taken direct to the transformer terminals. When the double pole switch is subsequently closed on phase C, the ammeter and the wattmeter current coil are in series with that phase, and the wattmeter voltage coil and the voltmeter will be connected across phases B and C, the one voltage coil lead being changed from phase A to phase C. Voltage is applied to the HV windings, the LV being short-circuited. The links in A and C phases are closed and a low voltage is applied to the HV windings, the initial value being a fraction of the calculated impedance voltage. The double pole switch is then closed and the link on phase A opened. The applied voltage is gradually increased until the ammeter in the HV circuit indicates the normal full-load current when wattmeter, ammeter and voltmeter readings are noted. The link in phase A is then closed, the double pole switch changed over, the link in C opened, and the wattmeter voltage coil connection changed over from A to C phase. Wattmeter, ammeter and voltmeter readings are again taken. These readings complete the test and the total copper loss is the algebraic sum of the two wattmeter readings. The impedance voltage is given by the voltmeter reading obtained across either phase. The copper loss would be the same if measured on the LV side, but it is more convenient to supply the HV winding. It is important that a copper-loss test should be carried out at the frequency for which the transformer is designed, as the frequency affects the eddy-current copper-loss component, though not affecting the I^2R losses. The connections given and procedure outlined are exactly the same whatever the interphase connections of the transformer windings. For single-phase transformers the total copper loss is given by a single wattmeter reading only, and similarly for the impedance voltage. In many cases, in practice it is necessary to employ instrument transformers while conducting the tests described earlier, and in such cases the reference to the changing of current and voltage coils when making wattmeter connections refers to the secondary circuits of any instrument transformers employed in the test.

For power transformers having normal impedance values the flux density in the core during the short-circuit test is very small, and the iron loss may therefore be neglected. The losses as shown by the wattmeter readings may thus be taken as the true copper loss, subject to any instrument corrections that may be necessary. In the case, however, of high-reactance transformers the core loss may be appreciable. In order to determine the true copper loss on such a transformer the power input should be measured under short-circuit conditions and then with the short-circuiting connection removed (i.e. under open-circuit conditions) the core loss should be measured with an applied voltage equal to the measured impedance voltage. This second test will give the iron loss at the impedance voltage, and the true copper loss will be obtained by the difference between these two loss measurements.

When making the copper loss test it must be remembered that the ohmic resistance of the LV winding may be very small, and therefore the resistance of the short-circuiting links may considerably affect the loss. Care must be taken to see that the cross-sectional area of the short-circuiting links is adequate to carry the test current, and that good contact is obtained at all joints.

To obtain a true measurement it is essential that the voltage coil of the wattmeter be connected directly across the HV windings, and the necessary correction made to the instrument reading.

The temperature of the windings at which the test is carried out must be measured accurately and also the test must be completed as quickly as possible to ensure that the winding temperature does not change during the test. Should several copper-loss and impedance tests be required on a transformer (i.e. on various tappings) then it is advisable to carry out these tests at reduced currents, in no case at less than half the rated current, and correct the results to rated values of current.

A disadvantage of the two wattmeter method of measurement is that at the low power factors encountered this will produce two large readings, one positive and one negative, which when summated algebraically produce a small difference with a relatively large error. Most manufacturers of large transformers will therefore prefer to use three wattmeters.

The three-wattmeter method can also be adopted for copper-loss measurement with advantage where the test supply is unbalanced. This test is essentially the same as the two-wattmeter method where one winding is short-circuited and a three-phase supply is applied to the other winding, but in this case the wattmeter current coil is connected to carry the current in each phase while the voltage coil is connected across the terminals of that phase and neutral. The sum of the three readings taken on each phase successively is the total copper loss of the transformer. During this test the current in each phase can be corrected to the required value before noting wattmeter readings. On large transformers where the impedance of the transformer causes a low power factor it is essential that wattmeters designed for such duty are employed.

The copper loss and impedance are normally guaranteed at 75°C but in fact both are normally measured at test room temperature and the results obtained corrected to 75°C on the assumption that the direct load loss (I^2R) varies with temperature as the variation in resistance, and the stray load loss varies with the temperature inversely as the variation in resistance.

The tolerance allowed by BS 171 on impedance is ±10% for a two-winding transformer and ±10–15% for a multi-winding transformer, both on the principal tapping. The copper loss at 75°C is subject to a tolerance of +15% but iron plus copper losses in total must not exceed +10% of the guaranteed value.

The test connections for a three-phase, interconnected-star earthing transformer are shown in *Figure 5.4*. The single-phase current I in the supply lines is equal to the earth fault current and the current in each phase winding is one-third of the line current. Under these loading conditions the wattmeter indicates the total copper loss in the earthing transformer windings at this particular current while the voltmeter gives the impedance voltage from line to neutral. The copper loss measured in this test occurs only under system earth fault conditions. Normally earthing transformers have a short time rating (i.e. for 30 s) and it may be necessary to conduct the test at a reduced value of current, and to omit the measurement of the copper loss, thus testing impedance only.

At the same time as the copper loss is being measured on the three-phase interconnected-star earthing transformer, the zero phase sequence impedance Z_0 and resistance R_0 can be obtained as follows:

$$Z_0 \text{ per phase (ohms)} = \frac{3V}{I}$$

where I = current in the neutral during the test and

$$R_0 \text{ per phase (ohms)} = \frac{3 \times \text{ power (watts)}}{I^2}$$

All other tests on earthing transformers are carried out in the same way as for power transformers.

Insulation resistance test

Insulation resistance tests are carried out on all windings, core and core clamping bolts. The standard Megger testing equipment is used, the 'line' terminal of which is connected to the winding or core bolt under test. When making the test on the windings, so long as the phases are connected, together, either by

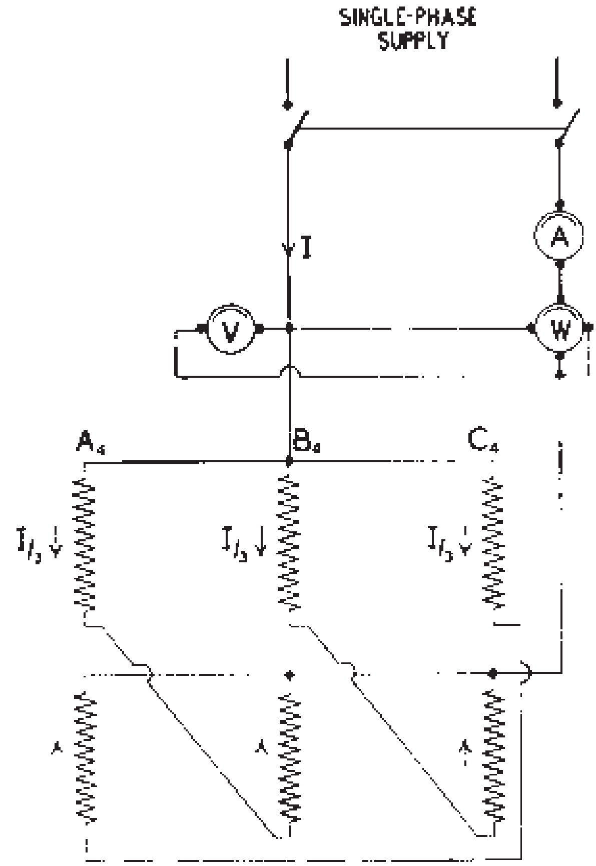


Figure 5.4 Copper-loss and impedance voltage test for a three-phase interconnected-star neutral earthing transformer

the neutral lead in the case of the star connection or the interphase connections in the case of the delta, it is only necessary to make one connection between the Megger and the windings. The HV and LV windings are, of course, tested separately, and in either case the procedure is identical. In the case of core bolts, should there be any, each bolt is tested separately.

Should it be required to determine exactly the insulation of each separate winding to earth or between each separate winding, then the guard of the Megger should be used. For example, to measure the insulation resistance of the HV winding to earth the line terminal of the Megger is connected to one of the HV terminals, the earth terminal to the transformer tank, and the guard terminal to the LV winding. By connecting the windings and the instrument in this way any leakage current from the HV winding to the LV windings is not included in the instrument reading and thus a true measurement of the HV insulation to earth is obtained.

Resistance of windings

The DC resistances of both HV and LV windings can be measured simply by the voltmeter/ammeter method, and this information provides the data necessary to permit the separation of I^2R and eddy-current losses in the windings. This is necessary in order that transformer performances may be calculated at any specified temperature.

The voltmeter/ammeter method is not entirely satisfactory and a more accurate method such as measurement with the Wheatstone or Kelvin double bridge should be employed. It is essential that the temperature of the windings is accurately measured, remembering that at test room ambient temperature the temperature at the top of the winding can differ from the temperature at the bottom of the winding. Care also must be taken to ensure that the direct current circulating in the windings has settled down before measurements are made. In some cases this may take several minutes depending upon the winding inductance unless series swamping resistors are employed. If resistance of the winding is required ultimately for temperature rise purposes then the 'settling down' time when measuring the cold winding resistance should be noted and again employed when measuring hot resistances taken at the end of the load test.

Iron-loss test and no-load current test

These two tests are also carried out simultaneously and the connections are shown in *Figure 5.5*. This diagram is similar to *Figure 5.3*, except that in *Figure 5.5* voltage is applied to the LV windings with the HV open-circuited, and one wattmeter voltage coil lead is connected to the transformer side of the current coil. The two-wattmeter method is adopted in precisely the same way as described for the copper-loss test, the double pole switch being first closed on phase A. The rated LV voltage at the specified frequency (both of which have previously been adjusted to the correct values) is first applied to the LV windings, and then readjusted if necessary, the links being closed in phases A and C. The double pole switch is then closed, the link opened in phase A and wattmeter, ammeter and voltmeter readings noted. The wattmeter is then changed over to phase C, and one voltmeter connection changed from phase A to phase C. Wattmeter, ammeter and voltmeter readings are again noted. These readings complete the test, and the total iron loss is the algebraic sum of the two wattmeter readings. The no-load current is given by the ammeter reading obtained in each phase. The iron loss would be the same if measured on the HV side, but the application of voltage to the LV winding is more convenient. The no-load current would, however, be different, and when checking a test certificate, note should be taken of the winding on which this test has been carried out. The same comments apply with regard to accuracy of the two-wattmeter method as made in relation to load-loss measurements except that the power factor for no-load loss is not quite so low as for load loss. Many manufacturers would thus prefer to use three wattmeters.

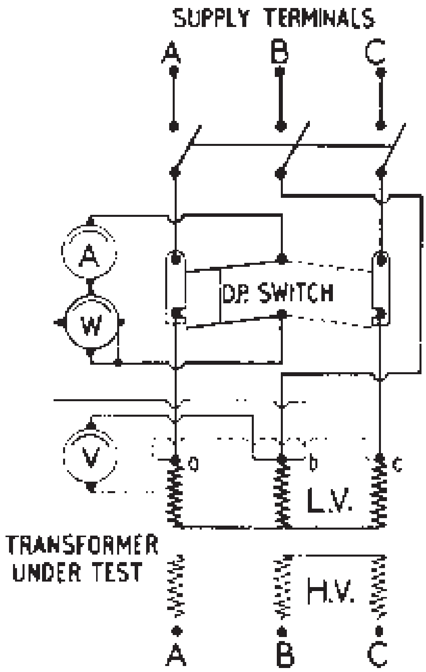


Figure 5.5 Iron-loss and no-load current test: two-wattmeter method

The connections given and procedure outlined are exactly the same whatever the interphase connections of the transformer windings. For single-phase transformers the iron loss is obtained simply by one wattmeter reading.

For all transformers except those having low-voltage primary and secondary windings this test is conducted with the transformer in its tank immersed in oil.

If the LV voltage is in excess of 1000 V, instrument transformers will be required and the remark made earlier equally applies.

In making this test it is generally advisable to supply to the LV winding for two reasons: firstly, the LV voltage is more easily obtained, and secondly, the no-load current is sufficiently large for convenient reading.

The supply voltage can be varied either by varying the excitation of the alternator or by using an induction regulator. A variable resistor in series with the transformer winding should not be used for voltage adjustment because of the effect upon the voltage wave shape and the transformer iron loss.

The iron loss will be the same if measured on either winding, but the value of the no-load current will be in inverse proportion to the ratio of the turns. This no-load loss actually comprises the iron loss including stray losses due to the exciting current, the dielectric loss and the I^2R loss due to the exciting current.

In practice the loss due to the resistance of the windings may be neglected.

It is sometimes more convenient to measure the iron loss by the three-wattmeter method, particularly when the LV voltages are of a high order. In all cases low power factor wattmeters must be used.

If only one wattmeter is available a possible method of connection is shown in *Figure 5.6*.

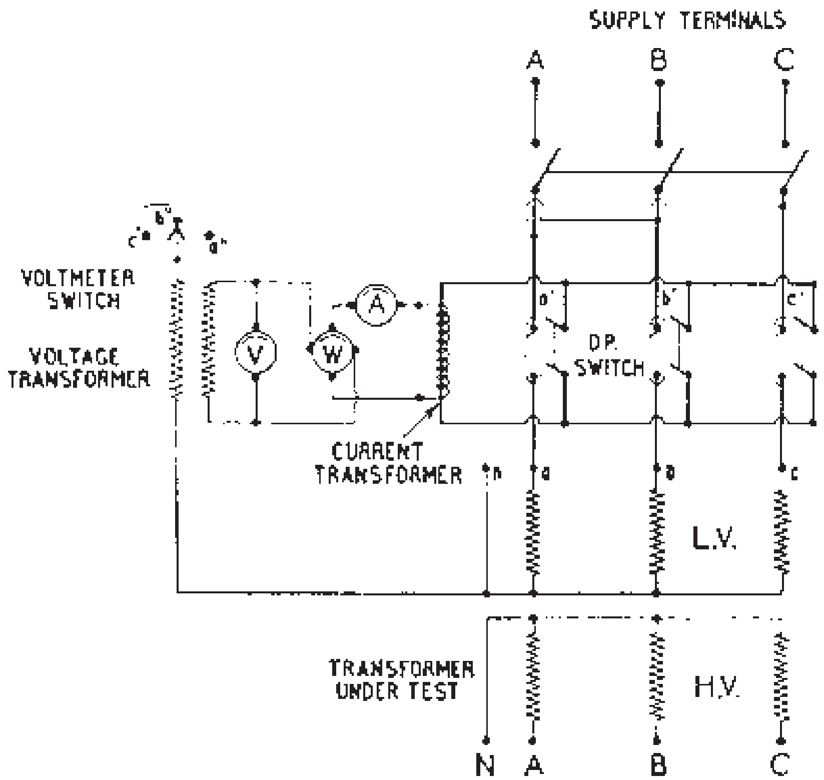


Figure 5.6 Iron-loss and no-load current test: three-wattmeter method

The test is conducted as follows.

The double pole switch a′ is closed and the link opened, switches b′ and c′ being open with their corresponding links closed. The voltmeter switch is put on to the contact a″. The supply voltage is adjusted until the voltmeter reads the correct phase voltage. The frequency being adjusted to the correct value, ammeter, voltmeter and wattmeter readings are taken. The link on the double pole switch a′ is then closed and the switch opened. Switch b′ is closed and the corresponding link opened, while the voltmeter switch is moved to contact b″. Any slight adjustment of the voltage that may be necessary should be made and the meter readings again noted. This operation is again repeated for phase C.

The algebraic sum of the three wattmeter readings will then give the total iron loss. The BS 171 tolerance on iron loss is +15% but the combined iron loss plus copper loss must not exceed +10% of the declared value; the tolerance on no-load current is +30% of the declared value.

It is essential that the supply voltage waveform is approximately sinusoidal and that the test is carried out at the rated frequency of the transformer under test.

For normal transformers, except three-phase transformers without a delta-connected winding, the voltage should be set by an instrument actuated by the mean value of the voltage wave between lines but scaled to read the r.m.s. value of the sinusoidal wave having the same mean value.

For three-phase transformers without a delta-connected winding the no-load losses should be measured at a r.m.s. voltage indicated by a normal instrument actuated by the r.m.s. value of the voltage wave, and the waveform of the supply voltage between lines should not contain more than 5% as a sum of the 5th and 7th harmonics.

In all cases when testing iron losses, the rating of the alternator must be considerably in excess of the input to the transformer under test.

In the *routine* testing of transformers it is not necessary to separate the components of hysteresis and eddy-current loss of the magnetic circuit, but for investigational purposes or for any iron-loss correction, which may be necessary on account of non-sinusoidal applied voltage, such procedure may be required. The losses may be separated graphically or by calculation, making use of test results at various frequencies. Generally, loss tests at a minimum of three frequencies, say at 25, 50 and 60 Hz, are sufficient for the purpose. All the tests are carried out in the standard manner already indicated, and at a constant flux density, the value of the latter usually being that corresponding to the normal excitation condition of the transformer. The two methods are then as follows:

(a) *Graphical*

This method is illustrated by *Figure 5.7*. The measured losses are converted into total energy loss per cycle by dividing the total power by the frequency, and the results are then plotted against the respective frequencies. The resulting graph should be a straight line, intercepting the vertical axis as shown. The ratio of the ordinate value at the vertical axis (i.e. at zero frequency) to the ordinate value at any other frequency gives the ratio of hysteresis loss per cycle to total measured iron loss per cycle at that frequency, and the hysteresis loss per cycle in watts can then be determined.

(b) *By calculation*

The hysteresis loss component varies directly with frequency, while the eddy-current loss component varies with the square of the frequency. Having measured the total iron loss at two frequencies, adjusting the applied voltage to maintain constant flux density, the loss component can be separated by substitution of the total loss values into simultaneous equations derived from

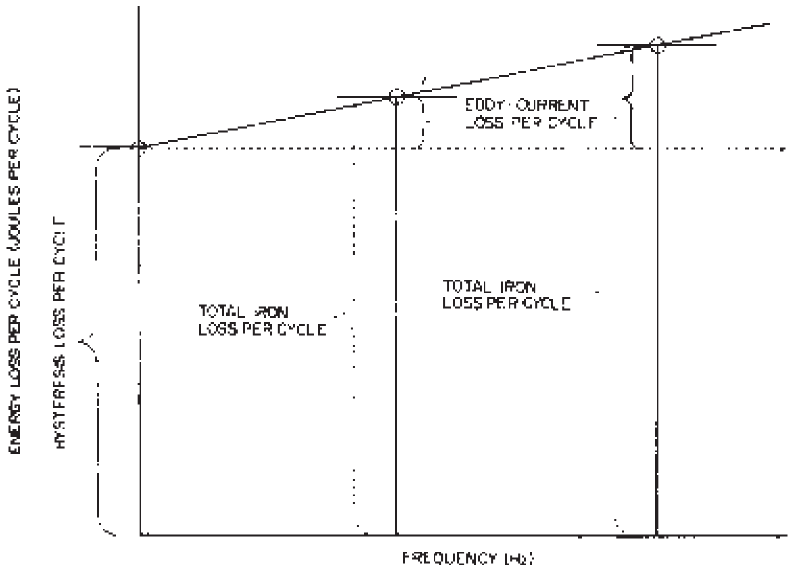


Figure 5.7 Graphical method of separating hysteresis and eddy-current losses

the relationship given in equation (5.1).

$$P_f = fP_h + f^2P_e \tag{5.1}$$

where P_h and P_e are the hysteresis and eddy-current losses respectively. If the iron-loss tests have been made at 25 and 50 Hz and the total iron losses are P_{f25} and P_{f50} respectively, then, from equation (5.1):

$$P_{f50} = 50P_h + 2500P_e \tag{5.2}$$

$$P_{f25} = 25P_h + 625P_e \tag{5.3}$$

Multiplying equation (5.3) by 2 and subtracting the result from equation (5.2) eliminates P_h and so enables P_e to be determined, as then

$$P_e = \frac{P_{f50} - 2P_{f25}}{1250} \tag{5.4}$$

Substitution of the value of P_e in equation (5.2) or (5.3) then enables P_h to be determined at the relevant frequency.

Dielectric tests – windings

The insulation of the HV and LV windings of all transformers is tested before leaving the factory. These tests consist of:

(a) induced overvoltage withstand test;
(b) separate-source voltage withstand test;
(c) impulse withstand tests when required.

Table 5.1 indicates withstand voltage levels for transformers installed on power distribution or industrial systems. Test voltages are related to the *highest voltage for equipment* U_m. For a more detailed explanation of the selection of transformer insulation levels, test voltages and detailed requirements, reference should be made to BS 171, Part 3 (IEC 76-3).

Table 5.1 Typical rated withstand voltages

<table>
<tr><th>System higher voltage (kV r.m.s.)</th><th>Power frequency test voltage (kV r.m.s.)</th><th colspan="2">Lightning impulse withstand voltage (kV peak)</th><th>Category of winding insulation</th></tr>
<tr><td colspan="5">System highest voltage < 300 kV</td></tr>
<tr><td></td><td></td><td>(a)</td><td>(b)</td><td></td></tr>
<tr><td>1.1</td><td>3</td><td>–</td><td>–</td><td rowspan="13">Uniform and non-uniform</td></tr>
<tr><td>3.6</td><td>10</td><td>20</td><td>40</td></tr>
<tr><td>7.2</td><td>20</td><td>40</td><td>60</td></tr>
<tr><td>12</td><td>28</td><td>60</td><td>75</td></tr>
<tr><td>17</td><td>38</td><td>75</td><td>95</td></tr>
<tr><td>24</td><td>50</td><td>95</td><td>125</td></tr>
<tr><td>36</td><td>70</td><td>145</td><td>170</td></tr>
<tr><td>52</td><td>95</td><td colspan="2">250</td></tr>
<tr><td>72.5</td><td>140</td><td colspan="2">325</td></tr>
<tr><td>123</td><td>185</td><td colspan="2">450</td></tr>
<tr><td>145</td><td>230</td><td colspan="2">550</td></tr>
<tr><td>170</td><td>275</td><td colspan="2">650</td></tr>
<tr><td>245</td><td>360</td><td colspan="2">850</td></tr>
<tr><td colspan="5">System highest voltage ≥ 300 kV – Method 1</td></tr>
<tr><td>300</td><td>460</td><td colspan="2">1050</td><td rowspan="3">Non-uniform</td></tr>
<tr><td>362</td><td>510</td><td colspan="2">1175</td></tr>
<tr><td>420</td><td>630</td><td colspan="2">1425</td></tr>
<tr><td colspan="5">System highest voltage ≥ 300 kV – Method 2</td></tr>
<tr><td>System highest voltage (kV r.m.s.)</td><td>Switching impulse withstand voltage (kV peak) (phase-neutral)*</td><td colspan="2">Lightning impulse withstand voltage (kV peak)</td><td>Category of winding insulation</td></tr>
<tr><td>300</td><td>850</td><td colspan="2">1050</td><td rowspan="5">Non-uniform</td></tr>
<tr><td>362</td><td>950</td><td colspan="2">1175</td></tr>
<tr><td>420</td><td>1050</td><td colspan="2">1300</td></tr>
<tr><td>525</td><td>1175</td><td colspan="2">1425</td></tr>
<tr><td>765</td><td>1550</td><td colspan="2">1800</td></tr>
</table>

*The specified test voltage shall appear between the line and the earthed neutral in a three-phase transformer, the voltage developed between lines during this test shall be approximately 1.5 times the voltage between line and neutral terminals.

The values of withstand test voltages are typical values employed in the UK and many parts of the world. However, some national standards vary considerably from those tabled, particularly in the USA. It will be seen that for system highest voltages lower than 52 kV alternative impulse withstand voltages are shown, the choice between levels (a) and (b) depending on the severity of the overvoltage conditions to be expected in the system and on the importance of the installation. The test levels and methods must be agreed at the time of placing a contract.

If it is required to repeat tests on transformers which have already withstood complete dielectric tests then the test voltages may be reduced to 75% of the original values. When the required test value cannot be applied then a reduced voltage may be applied for longer periods as indicated in *Table 5.2*. If DC is used for testing then the peak value of the rectified DC supply should not exceed the peak value of the AC test value.

Table 5.2 Typical values of insulation test voltages with reference to duration of test

Duration of test in multiples of standard period	*Per cent of standard test voltage*	
	Test at works	*Test on site*
1	100	75
2	83	70
3	75	66
4	70	62
5	66	60
10	60	54
15	57	50

There are two alternative methods for the specification and testing of transformers with non-uniform insulation for 300 kV and above. These differ mainly with regard to the way in which the induced overvoltage test is carried out. When high-voltage transformers were first designed and manufactured insulation test levels were arbitrarily set at twice normal volts. This represented a convenient factor of safety over rated conditions and ensured that equipment in service was never likely to be stressed to a level approaching that to which it had been tested. However, as rated equipment voltages increased, the use of a test level of twice normal volts was seen in some quarters as a very crude method of proving satisfactory manufacturing quality and it also resulted in the need for some very high-voltages in factory test facilities requiring very large structures in order to achieve the necessary safety clearances. An alternative method was thus devised as representing a more sophisticated approach than simply applying a high level of overstress in the hope of producing breakdown of substandard insulation. This uses a much more modest degree of overstress but relies on the detection of weakness or ‘incipient breakdown’, which might indicate that defects exist within the insulation structure which will result in unacceptable performance in service. The disadvantage of this alternative method, as seen by the ‘traditionalists’, is that although the induced overvoltage test is the principal means of testing the insulation at the line end for transformers with non-uniform insulation, including that between line lead and tank, core and core frame, as well as between HV and LV windings, HV and taps and across the tapping range, it is also primarily designed as the means of testing insulation between turns and since, even in quite large transformers, the volts per turn is rarely more than 200, and on many occasions considerably less, then under induced overvoltage conditions the voltage between turns will still be quite modest. It has also to be recognised that under factory test conditions the insulation should be in a far better state and the oil more highly ‘polished’ than it is ever likely to be again during service, hence it is to be expected that its electrical withstand strength will be greatly superior than it is ever likely to be again.

The counter to this argument is that insulation between turns is tested by the impulse test, particularly the impulse test including chopped waves, but then the advocates of the twice normal volts test would say that for many winding arrangements there are significant sections of the winding, i.e. those remote from its ends, which might not be adequately tested by impulse testing. Many manufacturers, in particular, have reservations concerning the application of twice normal volts, not only because of the high voltages appearing externally within the factory test bay, but also between the line lead internally, both to the tank and to the core frame structure.

Since, at an international level it has not been possible to achieve agreement between the two viewpoints, both methods of testing remain. These can be summarised as follows:

Method 1. This is the ‘traditional’ test. It uses a rated lightning impulse withstand voltage and a short duration power-frequency withstand voltage, the latter representing a sufficient withstand strength against switching impulse voltages.

Method 2. Uses a rated lightning impulse withstand voltage and a rated switching impulse withstand voltage. The induced power-frequency overvoltage test conditions are considerably lower than those of Method 1 but are maintained for considerably longer and the test criterion is based on the measurement of partial discharges in the transformer which are taken as the indication of ‘incipient breakdown’ referred to above.

Another of the criticisms levelled against Method 2 is that the acceptance levels of partial discharge are set entirely arbitrarily – there is a statement that the levels are provisional and subject to review in the light of experience – and there is even choice of the degree of overvoltage to be applied with its associated acceptable level of partial discharge, but defenders of this method would no doubt argue that the twice normal voltage criterion is no less arbitrary in the way in which it was selected.

Partial discharge measurement

It is appropriate at this point to consider the nature of partial discharges. A partial discharge is an electrical discharge that only partially bridges the insulation between conductors. Such a discharge is generally considered to take place as a precursor to total insulation failure but may exist for a long period of time, possibly years, before total breakdown occurs. In some circumstances the existence of the discharge will modify the stress distribution so as to initially reduce the tendency to total breakdown. In time, however, total breakdown will always result, often because the discharge itself leads to chemical breakdown of the insulation which reduces its electrical strength. Clearly, in a healthy transformer under normal operating conditions the only acceptable level of partial discharge is nil. 'Normal operating conditions' means any non-fault condition which is likely to occur in operation, for example system overvoltages which may occur following a reduction in system load until corrected by tapchanger operation or operator intervention, where necessary. It should be noted also that since many electrical systems frequently experience continuous overvoltages of up to 10% there should be no partial discharge present with this level of overvoltage.

Detection of partial discharge relies on the fact that in a transformer, these cause transient changes of voltage to earth at every available winding terminal.

The actual charge transferred at the location of a partial discharge cannot be measured directly. The preferred measure of the intensity of a partial discharge is the apparent charge 'q' as defined in IEC Publication 270. The specified provisional acceptance values of apparent charge referred to above (the actual values are detailed in the description of the test Method 2, above) are based on practical partial discharge measurements made on transformers which have passed traditional power-frequency dielectric tests.

The measuring equipment is connected to the terminals by matched coaxial cables. The measuring impedance in its simplest form is the matching impedance of the cable, which may, in turn, be the input impedance of the measuring instrument. The signal-to-noise ratio of the complete measuring system may be improved by the use of tuned circuits, pulse transformers and amplifiers between the test terminals and the cable. The circuit must present a fairly constant impedance to the test terminals over the frequency range used for the partial discharge measurements.

When measuring partial discharge between the line terminal of a winding and the earthed tank a measuring impedance Z_m is connected between the bushing tapping and the earthed flange. Calibration of the measuring circuit is carried out by injecting a series of known charges at the calibration terminals from a calibration generator.

Figure 5.8(a) shows a measurement and calibration circuit of this type where the calibration generator consists of a pulse generator and a series capacitor C_0 of approximately 50 pF. Where the calibration terminals present a capacitance much greater than C_0 the injected charge will be:

$$q_0 = U_0 \cdot C_0$$

where U_0 is the voltage step

Figure 5.8(b) illustrates an arrangement where a bushing tapping is not available and the measuring impedance, with protective spark gap, is connected to

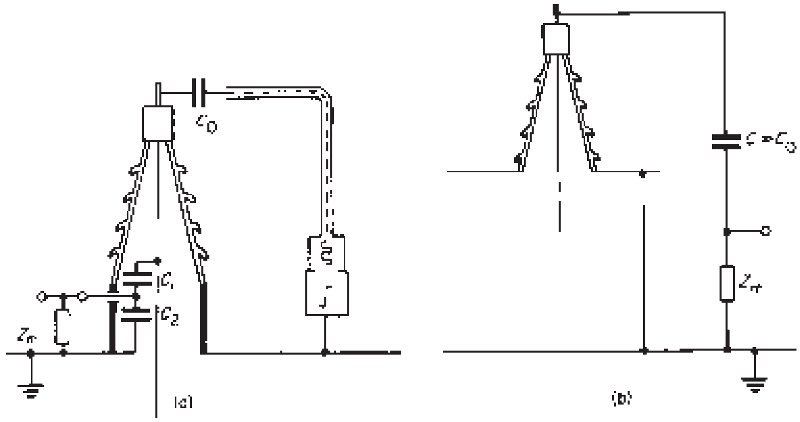


Figure 5.8 Partial discharge calibration and measurement circuits. (a) Using a condenser bushing capacitance tap; (b) using a high-voltage coupling capacitor

the LV terminal of a partial discharge-free HV coupling capacitor C, whose value is large compared with C_0. There are two types of measuring instrument in use: (a) narrow-band and (b) wide-band.

Precautions must be taken to eliminate interference from radio broadcast stations, spurious partial discharges from other sources in the surrounding area, the power supply source and the terminal bushings. These include the fitting of electrostatic shielding on the outside of the transformer and oscillographic monitoring of the test. If a transformer exhibits unacceptable partial discharge levels then, because visible traces of partial discharge are not usually found, attempts must be made to identify the source without removing the transformer from its tank. It may be useful to consider the following possibilities:

(a) Partial discharge in the insulation system may be caused by insufficient drying or oil impregnation. Reprocessing or a period of rest, followed by repetition of the test, may therefore be effective.
(b) A particular partial discharge gives rise to different values of apparent charge at different terminals of the transformer and the comparison of simultaneous indications at different terminals may give information about the location of the partial discharge source.
(c) Acoustic or ultrasonic detection of the physical location of the source within the tank.

The reader is referred to BS 171 for additional information.

Induced overvoltage withstand test

BS 171 identifies three alternative methods for carrying out the induced overvoltage withstand test. One is for uniform insulation and non-uniform insulation less than 300 kV plus the two options described above for non-uniform insulation above 300 kV; however, in effect those for uniform insulation and Method 1 for non-uniform insulation above 300 kV differ only in the way in which the transformer must be connected in order to achieve the specified test voltages.

The basic test remains the one at twice the rated voltage. This test is carried out by supplying the specified test voltage to the LV windings from an HV testing transformer at a frequency higher than the rated value. *Figure 5.9* shows a diagram of connections for carrying out the twice normal volts-induced overvoltage test.

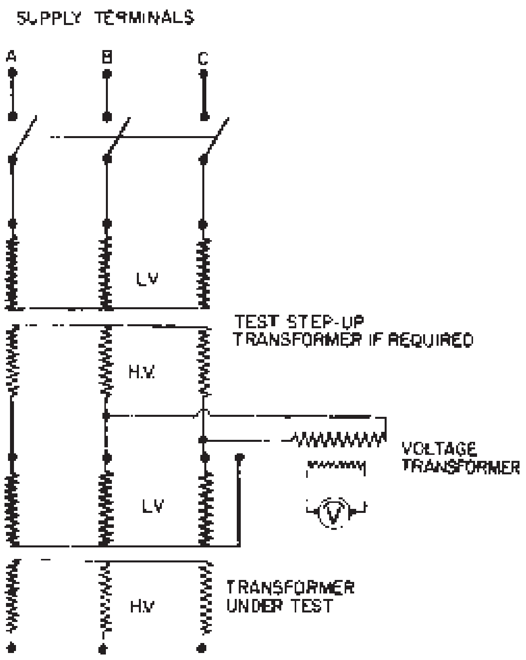


Figure 5.9 Voltage tests: induced overvoltage test

The HV windings are left open-circuit, the test voltage being applied to the LV windings. The test voltage may be measured on the LV side of the transformer under test, either directly or using a voltage transformer, or the peak value of the voltage induced in the HV winding can be measured using an electrostatic voltmeter or a suitable voltage divider.

The connections given and procedure outlined for the voltage tests are exactly the same for single-phase and three-phase transformers whatever the interphase connections of the windings. The tests are carried out with the transformer assembled as for service except for the optional fitting of cooling and supervisory equipment.

During the test the supply frequency is increased, usually to at least twice the rated frequency, to avoid overfluxing the core. Care must be taken to ensure that excessive voltages do not occur across the windings. Any winding not having non-uniform insulation may be earthed at any convenient point during the test. Windings having non-uniform insulation should be earthed at a point that will ensure the required test voltage appearing between each line terminal and earth, the test being repeated under other earthing conditions when necessary to ensure the application of the specified test voltage to each terminal.

The test should be commenced at a voltage not greater than one-third of the test value and increased to the test value as rapidly as is consistent with measurement. At the end of the test the voltage should be reduced rapidly to less than one-third of the test value before switching off.

The duration of the test should be 60 s at any frequency up to and including twice the rated frequency. When the frequency exceeds twice the rated frequency the duration of the test should be equal to:

$$120 \times \frac{\text{rated frequency}}{\text{test frequency}} \text{ seconds but not less than 15 s}$$

In the case of polyphase transformers, especially three-phase high-voltage units, it is permissible to apply the test voltage to individual phases in succession. *Figure 5.10* shows the connections for this test.

The induced voltage test on series parallel windings should be made with the windings connected in series and repeated in parallel.

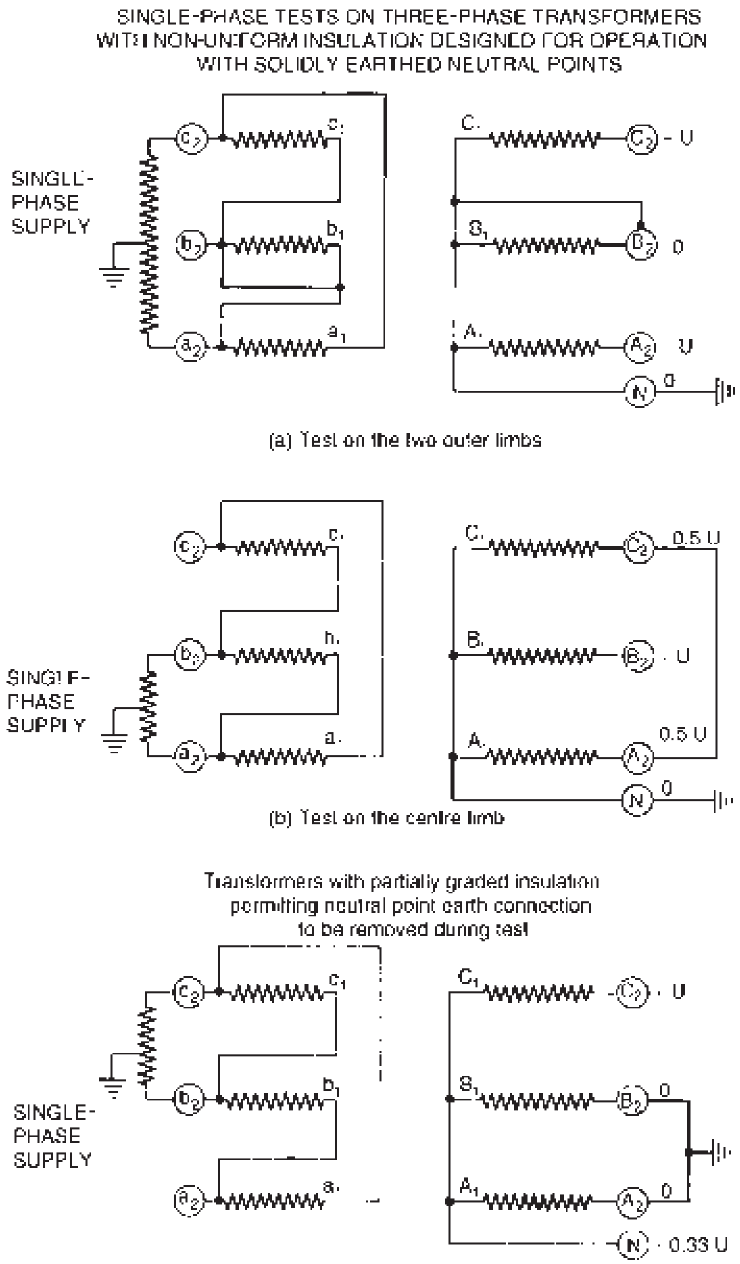
Induced overvoltage test in accordance with Method 2

The test is applied to all the non-uniformly insulated windings of the transformer. The neutral terminal of the winding under test is earthed. For other separate windings, if they are star connected they are earthed at the neutral and if they are delta connected they are earthed at one of the terminals.

Three-phase transformers may be tested either phase by phase in a single-phase connection that gives the voltages on the line terminals as shown in *Figure 5.11*, or in symmetrical three-phase connection.

The time sequence for application of the test voltage is as shown in *Figure 5.12*. The test voltage is to be switched on at a level not greater than one-third of U_2, raised to U_2, held there for a duration of 5 min, raised to U_1, held there for a duration of 5 s, immediately reduced again without interruption to U_2, held there for a duration of 30 min, and reduced to a value of below one-third of U_2 before switching off.

During the whole application of test voltage, partial discharges are to be monitored as described below. The 'apparent charge' q must not exceed a specified value dependent upon the options adopted for U_2. The test voltages



(c) Connection for test on one limb C (test to be repeated on the other limbs A & B using the appropriate connections)

Note 'U' denotes the test voltage between line terminal and earth

Figure 5.10 Induced overvoltage tests

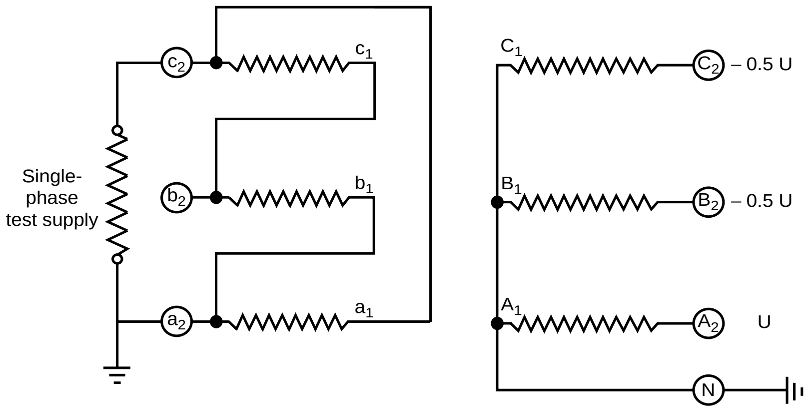


Figure 5.11 Phase-by-phase test on a three-phase transformer

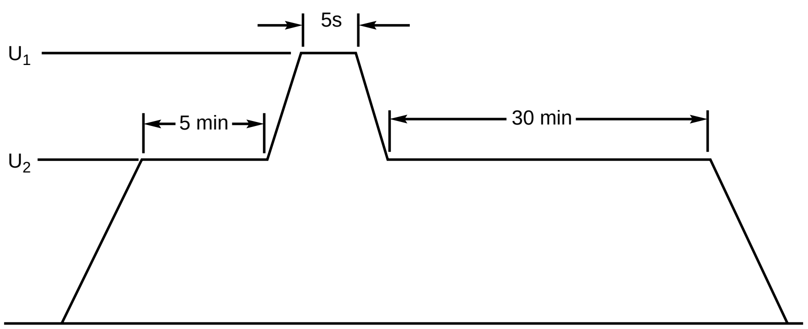


Figure 5.12 Time sequence for test voltage

between line and neutral terminals expressed in terms of $U_m/\sqrt{3}$ may be as follows:

$$U_1 \text{ is to be } \sqrt{3}.U_m/\sqrt{3} = U_m$$

$$U_2 \text{ may be either } 1.5U_m/\sqrt{3} \text{ with specified value of } q = 500 \text{ pC}$$

$$\text{or } 1.3U_m/\sqrt{3} \text{ with specified value of } q = 300 \text{ pC}$$

The choice of value for U_2 is to be agreed between manufacturer and purchaser at the time of placing the order.

During the raising of voltage up to the level U_2 and reduction from U_2 down again, possible inception and extinction voltages for partial discharge should be noted. A reading of partial discharge is to be taken during the first period at voltage U_2. Observations during the short application of voltage U_1 are not required. During the whole of the second period at voltage U_2, the partial discharge level is to be continuously observed and readings at intervals recorded.

The test is successful if:

- no collapse of the test voltage occurs;
- the continuous level of 'apparent charge' during the last 29 of the 30 minute application of voltage U_2 stays below the specified limit in all the measuring channels, and does not show a significant, steadily rising trend near this limit.

The value of U_1 is set at $\sqrt{3} \cdot U_m/\sqrt{3}$ since this is the highest voltage which is likely to be applied to the transformer in service under fault conditions. If a solid earth fault appears close to one of the line terminals of a star-connected winding with earthed neutral, the other two phases can have line voltage impressed across them until the fault is cleared. Hence the test is designed to show that the brief application of this fault condition cannot initiate a sequence of partial discharges which will escalate leading ultimately to insulation failure. The partial discharge acceptance levels of 300 and 500 pCs, depending on the level set for U_2, were set a number of years ago when measurement techniques were less sophisticated than the present time and were at that time agreed as values which could clearly be distinguished from background; however, if it is recognised that the object during the 30 minute observation period following the application of the prestress voltage, U_2, is simply to ensure that there is no tendency for the partial discharge to increase and run away, then the absolute value of this partial discharge is not important.

Separate-source voltage withstand test

The terminal ends of the winding under test are connected to one HV terminal of the testing transformer, the other terminal being earthed. All the other winding ends, core, frame and tank are earthed. *Figure 5.13* shows the connections for testing the HV windings of a transformer.

The test should be commenced at a voltage not greater than one-third of the test value and increased to the test value as rapidly as is consistent with measurement. At the end of the test the voltage should be reduced rapidly to less than one-third of the test value before switching off.

The full test voltage is applied for 60 s, the peak value being measured and this divided by $\sqrt{2}$ must be equal to the test value. In the case of transformers having considerable electrostatic capacitance, the peak value of the test voltage is determined by means of an electrostatic voltmeter or a suitable voltage divider.

The value of test voltage to be applied depends on a number of factors which include whether the transformer windings are (a) air or oil insulated, (b) uniformly or non-uniformly insulated.

The test voltage applied to dry-type transformers for use at altitudes between 1000 and 3000 m above sea level, but tested at normal altitudes, is to be increased by 6.25% for each 500 m by which the working altitude exceeds 1000 m. This does not apply to sealed dry-type or oil-immersed transformers,

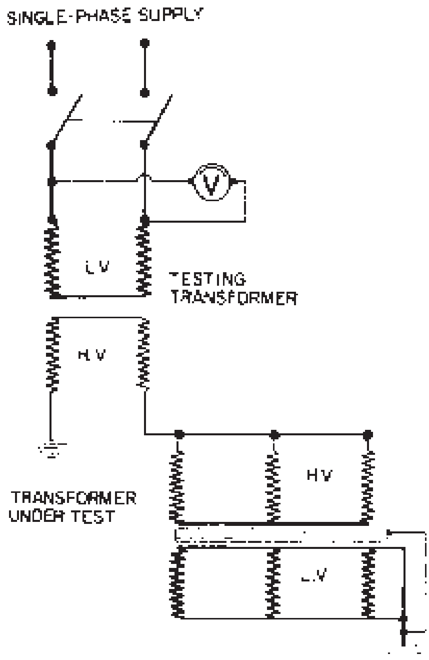


Figure 5.13 Voltage tests: separate source test

but it may be necessary to select a bushing designed for a higher insulation level than that of the windings.

Impulse testing of transformers

Impulse test levels

Impulse voltage test levels have been chosen after many years' study of surges on supply systems. These levels are based on uniform and non-uniform insulation. Impulse voltage withstand test levels for transformers have been standardised in BS 171 and values appropriate to the highest system voltages are given in *Table 5.3*.

Transformers to be impulse tested are completely erected with all fittings in position, including the bushings, so that, in addition to applying the surge voltage to the windings, the test is applied simultaneously to all ancillary equipment such as tapchangers, etc., together with a test on clearances between bushings and to earth.

Impulse voltage wave shapes

A double exponential wave of the form $v = V(e^{\alpha t} - e^{\beta t})$ is used for laboratory impulse tests. This wave shape is further defined by the nominal duration of

Table 5.3 Rated transformer impulse withstand voltages

Highest system voltage (kV r.m.s.)	*Lightning impulse withstand voltage (kV peak)*				*Category of winding insulation*
	*Dry type**		*Oil immersed †*		
	(a)	(b)	(c)	(d)	
3.6	20	40	20	40	
7.2	40	60	40	60	
12	60	75	60	75	
17.5	75	95	75	95	
24	95	125	95	125	
36	145	170	145	170	Uniform and
52	–		250		non-uniform
72.5	–		325		
123	–		450		
145	–		550		
170	–		650		
245	–		850		
300	–		1050		
362	–		1175		Non-uniform
420	–		1425		
300	–		950		
362	–		1050		
420	–		1175	§	Non-uniform
525	–		1425		
765	–		1800		

* Refer to *Table 5.1*.
† Refer to *Table 5.2*.
§ Refer to *Table 5.2* and the alternative method of testing.

the wavefront and the total time to half value of the tail, both times being given in microseconds and measured from the start of the wave. BS 923, the British Standard for impulse testing, defines the standard wave shape as being 1.2/50 μs and gives the methods by which the duration of the front and tail can be obtained. The nominal wavefront is 1.25 times the time interval between points on the wavefront at 10 and 90% of the peak voltage; a straight line drawn through the same two points cuts the time axis ($v = 0$) at O_1 the nominal start of the wave. The time to half value of the wave tail is the total time taken for the impulse voltage to rise to peak value and fall to half peak value, measured from the start as previously defined. The tolerances allowed on these values are $\pm 30\%$ on the wavefront, and $\pm 20\%$ on the wave tail. A typical wave shape, the method of measuring it and the tolerance allowed are shown in *Figure 5.14*.

Another waveform used in transformer impulse testing is the 'chopped wave' which simulates an incoming surge chopped by a flashover of the coordination gaps close to the transformer. During this test a triggered-type chopping gap with adjustable timing is used, although a rod gap is permitted to produce a chopping of the voltage after 2–6 μs. An impulse chopped on the tail is a special test and when made it is combined with the full-wave

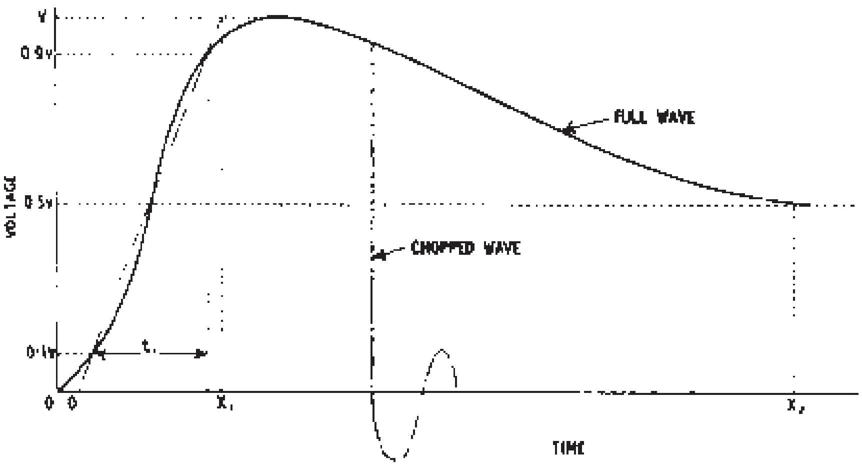


Figure 5.14 Standard impulse voltage wave shape: 1.2/50 μs. Nominal wavefront $O_1X_1 = 1.2$ μs, tolerance ±30%. Nominal wave tail $O_1X_2 = 50$ μs, tolerance ±20%

test. The peak value of the chopped impulse is nowadays specified to be the same as for a full-wave impulse; however, before the introduction of triggered chopping gaps which can be relied upon to operate within the required tolerances it was customary to specify that the chopped-wave tests, which relied on the operation of rod gaps to provide the chopping, should be carried out using a wave having 115% of the full-wave peak value and some authorities have continued to specify this level.

The clearances of the electrodes from floor, walls and earthed metal in all directions must be adequate. A chopped-wave shape is also shown in *Figure 5.14* and can be compared with the 1.2/50 μs wave shape.

Impulse generators

The production of voltage impulses is achieved by the discharge of a capacitor or number of capacitors into a wave-forming circuit and the voltage impulse so produced is applied to the object under test. For conducting high-voltage impulse tests a multi-stage generator as shown in *Figure 5.15*, a modified version of Marx's original circuit, is now used. This consists of a number of capacitors initially charged in parallel and discharged in series by the sequential firing of the interstage spark gaps.

A simple single-stage impulse generator is shown in *Figure 5.16*. The generator consists of a capacitor C which is charged by direct current and discharged through a sphere gap G. A resistor R_c limits the charging current while the resistors R_t and R_f control the wave shape of the surge voltage produced by the generator. The output voltage of the generator can be increased by adding

Figure 5.15 Impulse generator having an open-circuit test voltage of 3.6 MV and stored energy of 100 kWsec. Each of the 18 stages has an output of 200 kV (Peebles Transformers)

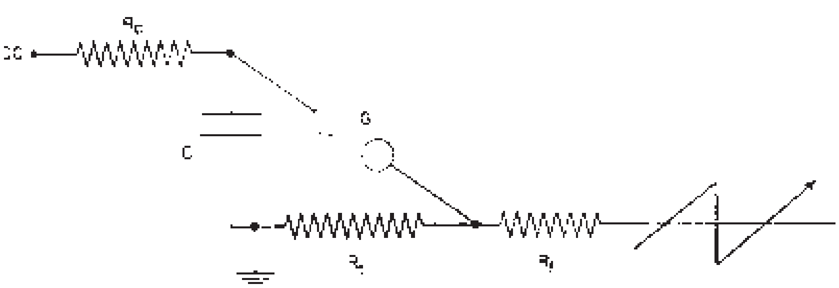


Figure 5.16 Single-stage impulse generator

more stages and frequently up to 20 stages are employed for this purpose. Additional stages are shown in *Figure 5.17* and as will be seen from this diagram all stages are so arranged that the capacitors C_1, C_2, C_3, etc. are charged in parallel. When the stage voltage reaches the required level V the first gap G_1 discharges and the voltage V is momentarily applied to one electrode of the capacitor C_2. The other electrode of C_2 is immediately raised to $2V$ and the second gap G_2 discharges. This process is repeated throughout all stages of the generator and if there are n stages the resultant voltage appearing at the output terminal is nV. This output is the surge voltage which is applied to the test object.

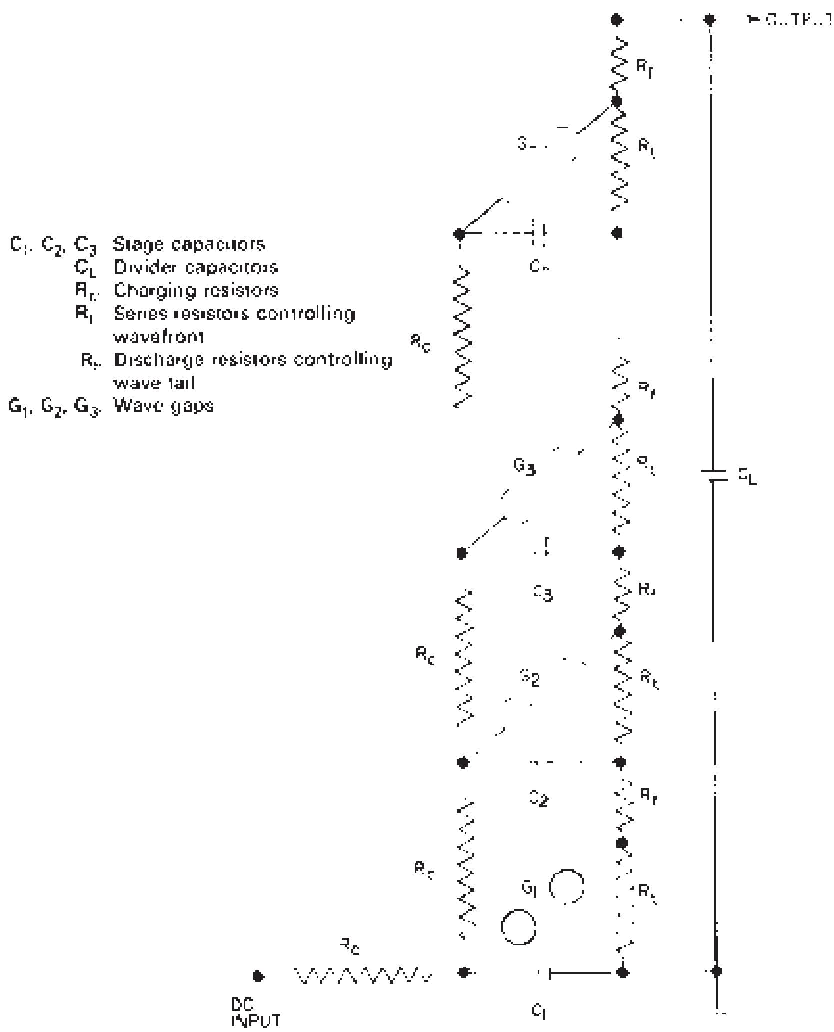


Figure 5.17 Impulse generator

Impulse voltage measurement

There are a number of devices available for the measurement of impulse voltage, the two most common methods being as follows.

The first is the sphere gap. Details of this method and the required gap settings are given in BS 358. This method has the disadvantages of requiring a large number of voltage applications to obtain the 50% flashover value and of giving no indication of the shape of the voltage wave.

The second method of measurement requires a voltage divider and a high-speed oscilloscope. These oscilloscopes use sealed-off tubes with accelerating voltages of 10–25 kV or continuously evacuated tubes with accelerating voltages of up to 60 kV. Besides giving the amplitude of the voltage wave, the oscilloscope can also be used to provide a photographic record from which the wavefront time and the time to half value on the tail of the wave can be determined.

The full peak voltage cannot be applied directly to the deflecting plates of the oscilloscope as the input voltage to these instruments is usually limited to 1 or 2 kV. The necessary reduction in voltage is obtained by means of the voltage divider. The ratio of the divider can be determined accurately and hence by suitable calibration and measurement at the low-voltage tapping point, the amplitude of the impulse voltage can be ascertained.

Impulse tests on transformers

The withstand impulse voltages to be applied to a transformer under test are specified in BS 171 and the test voltages are required to be applied in the following order:

1. One calibration shot at between 50 and 75% of the standard insulation level.
2. Three full-wave shots at the standard level.

The application of voltages 1 and 2 comprises a standard impulse-type test and they are applied successively to each line terminal of the transformer. If during any application, flashover of a bushing gap occurs, that particular application shall be disregarded and repeated.

Where chopped waves are specified, the test sequence is as follows:

(a) One reduced full wave, at 50–75% of the test level.
(b) One full wave at the test level.
(c) One or more reduced chopped waves.
(d) Two chopped waves.
(e) Two full waves at the test level.

For oil-immersed transformers the test voltage is normally of negative polarity since this reduces the risk of erratic external flashover.

The time interval between successive applications of voltage should be as short as possible.

These tests employ the 1.2/50 μs wave shape and the chopped waves can be obtained by setting the gap in parallel with the transformer under test. Values of rod gap setting are given in *Table 5.4*.

Table 5.4 Standard rod gap spacing for critical flashover on 1.2/50 microsecond wave

Impulse test level, full-wave, 1.2/50 μs (kV peak)	*Spacing of standard rod gap*	
	Positive polarity (mm)	*Negative polarity (mm)*
45	45	40
60	65	55
75	89	70
95	115	90
125	165	135
170	235	195
250	380	290
325	510	400
380	600	485
450	710	580
550	880	720
650	1050	890
900	1490	1270
1050	1750	1520
1175	1980	1720
1425	2400	2120

The rod gap spacings given in *Table 5.4* are for standard atmospheric conditions, i.e.:

barometric pressure (p)	760 mm
temperature (t)	20°C
humidity	11 grams of water vapour per cubic metre

(11 g/m^3 = 65% relative humidity at 20°C)

For other atmospheric conditions a correction should be made to the rod gap spacing as follows. The spacing should be corrected in an *inverse* proportion to the relative air density d, at the test room where:

$$d = 0.386\frac{p}{273 + t}$$

The gap spacing should be increased by 1.0% for each 1 g/m^3 that the humidity is *below* the standard value and vice versa.

In some cases when testing large transformers, particularly those having comparatively few winding turns, the impedance may be so low that the standard wave shape of 1.2/50 μs cannot be obtained from the impulse generator even with a number of stages connected in parallel. It is permissible in such cases for a shorter wave shape than the standard to be agreed between the purchaser and the manufacturer. When the low-voltage winding cannot be subjected to lightning overvoltages, by agreement between the manufacturer and the purchaser this winding may be impulse tested with surges transferred from the high-voltage winding. Alternatively the non-tested terminals may be earthed through resistors but the value should not exceed 500 Ω.

Voltage oscillograms are recorded for all shots and, in addition, as part of the fault detection technique, oscillographic records can be taken of one more of the following:

(a) The current flowing in the earthed end of the winding under test.
(b) The total current flowing to earth through a shunt connected between the tank insulated from earth and the earthing system.
(c) The transformed voltage appearing across another winding.

These records are additional to those obtained of the applied surge voltage and the method adopted from either (a), (b) or (c) is chosen by the transformer manufacturer in agreement with the purchaser according to which is the most appropriate and effective for the particular transformer under test.

During an impulse test the transformer tank is earthed, either directly or through a shunt which may be used for current measurement. The winding under test has one terminal connected to the impulse generator while the other end is connected to earth. In the case of star-connected windings having no neutral point brought out to a separate terminal, or in the case of delta-connected windings, it is usual to connect the two remaining terminals together and earth via a measuring shunt unless otherwise agreed between the manufacturer and the purchaser. It is essential that all line terminals and windings not being tested shall also be earthed directly or through a suitable resistance in order to limit the voltage to not more than 75% of the rated lightning impulse withstand voltage.

Where arcing gaps are fitted to bushings they should be set to the maximum permissible gap in order to prevent flashover during testing.

The general arrangement of the various pieces of equipment employed for an impulse test on a transformer is shown diagrammatically in *Figure 5.18*.

Fault detection during impulse tests

Detection of a breakdown in the major insulation of a transformer usually presents no problem as comparison of the voltage oscillograms with that obtained during the calibration shot at reduced voltage level gives a clear indication of this type of breakdown. The principal indications are as follows:

1. Any change of wave shape as shown by comparison with the full-wave voltage oscillograms taken before and after the chopped-wave shots.

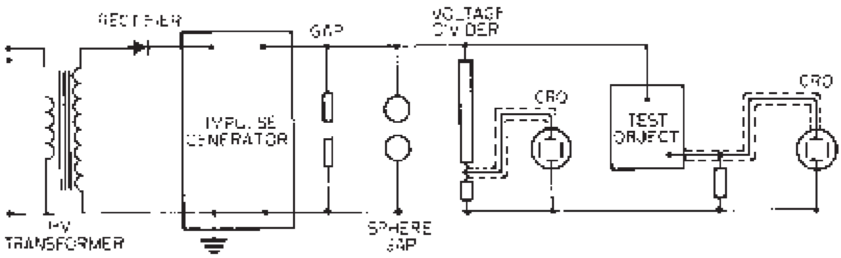


Figure 5.18 General arrangement of equipment for an impulse test (diagrammatic only)

2. Any difference in the chopped-wave voltage oscillograms, up to the time of chopping, by comparison with the full-wave oscillograms.
3. The presence of a chopped wave in the oscillogram of any application of voltage for which no external flashover was observed.

A breakdown between turns or between sections of a coil is, however, not always readily detected by examination of the voltage oscillograms and it is to facilitate the detection of this type of fault that current or other oscillograms are recorded. A comparison can then be made of the current oscillograms obtained from the full-wave shots and the calibrating oscillograms obtained at reduced voltage.

The differential method of recording neutral current is occasionally used and may be sensitive to single turn faults. All neutral current detection methods lose sensitivity when short-circuited windings are magnetically coupled to the winding being tested. Connections for this and other typical methods of fault detection are shown in *Figure 5.19(a)* to *(e)*.

In all cases the current flows to earth through a non-inductive shunt resistor or resistor/capacitor combination and the voltage appearing across this impedance is applied to the deflection plates of an oscilloscope.

Another indication is the detection of any audible noise within the transformer tank at the instant of applying an impulse voltage. This has given rise to a completely different method of fault detection known as the electro-acoustic probe, which records pressure vibrations caused by discharges in the oil when a fault occurs. The mechanical vibration set up in the oil is detected by a microphone suspended below the oil surface. The electrical oscillation produced by the microphone is amplified and applied to an oscilloscope, from which a photographic record is obtained. Alternatively acoustic devices may be attached to the external surfaces of the tank to detect these discharges.

Fault location

The location of the fault after an indication of breakdown is often a long and tedious procedure which may involve the complete dismantling of the

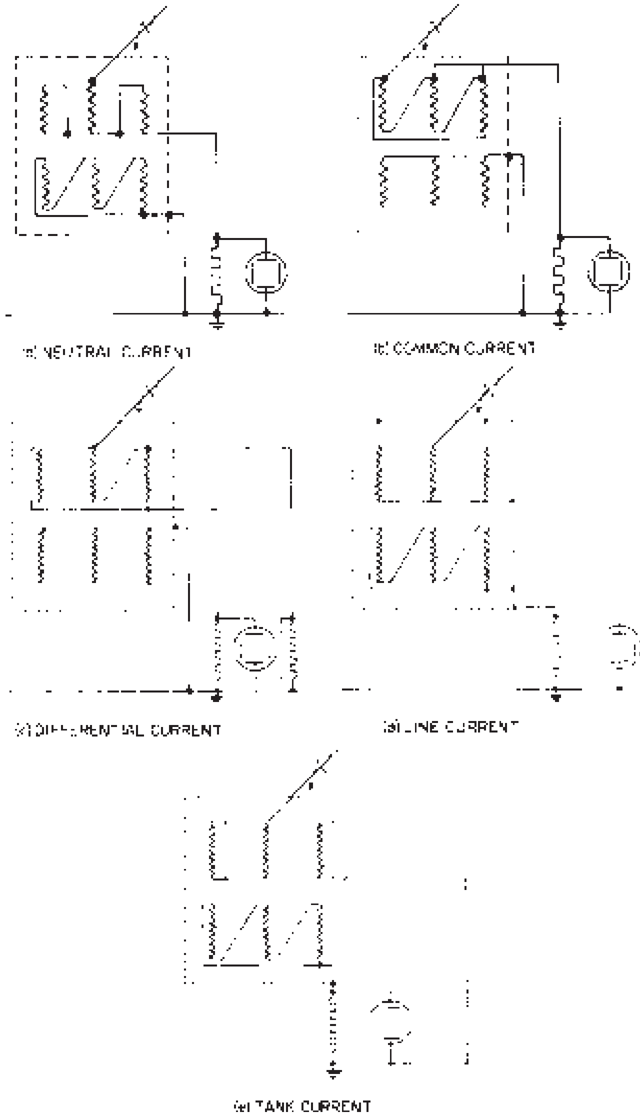


Figure 5.19 Connections used for fault detection when impulse testing transformers. *Note*: Terminals of windings not under test shall be earthed either directly or through resistors. Each phase should be damped by a suitable resistor

transformer and even then an interturn or interlayer fault may escape detection. Any indication of the approximate position in the winding of the breakdown will help to reduce the time spent in locating the fault.

Current oscillograms may give an indication of this position by a burst of high-frequency oscillations or a divergence from the ‘no-fault’ wave shape.

Since the speed of propagation of the wave through a winding is about 150 m/μs, the time interval between the entry of the wave into the winding and the fault indication can be used to obtain the approximate position of the fault, provided the breakdown has occurred before a reflection from the end of the winding has taken place. The location of faults by examination of current oscillograms is much facilitated by recording the traces against a number of different time bases. Distortion of the voltage oscillogram may also help in the location of a fault but it generally requires a large fault current to distort the voltage wave and the breakdown is then usually obvious.

Figure 5.20 illustrates a typical set of voltage and neutral current oscillograms associated with an impulse withstand test, and *Figure 5.21* those obtained with increasing impulse voltage levels up to breakdown, which is clearly shown in *Figure 5.21(f)*.

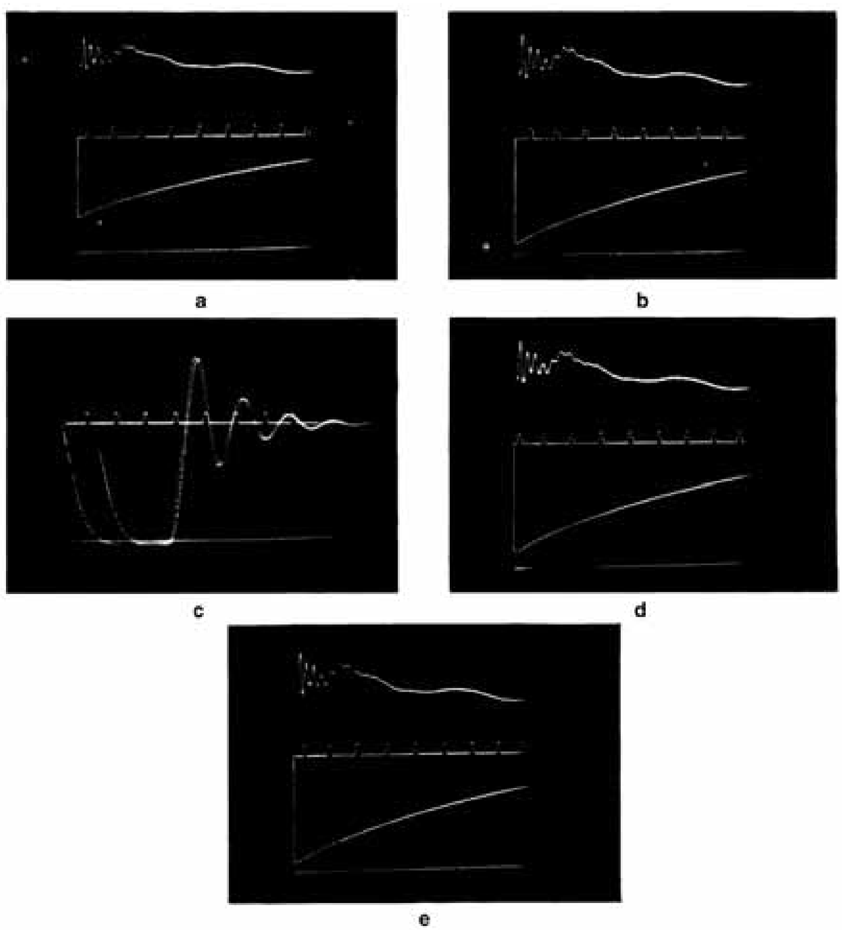


Figure 5.20

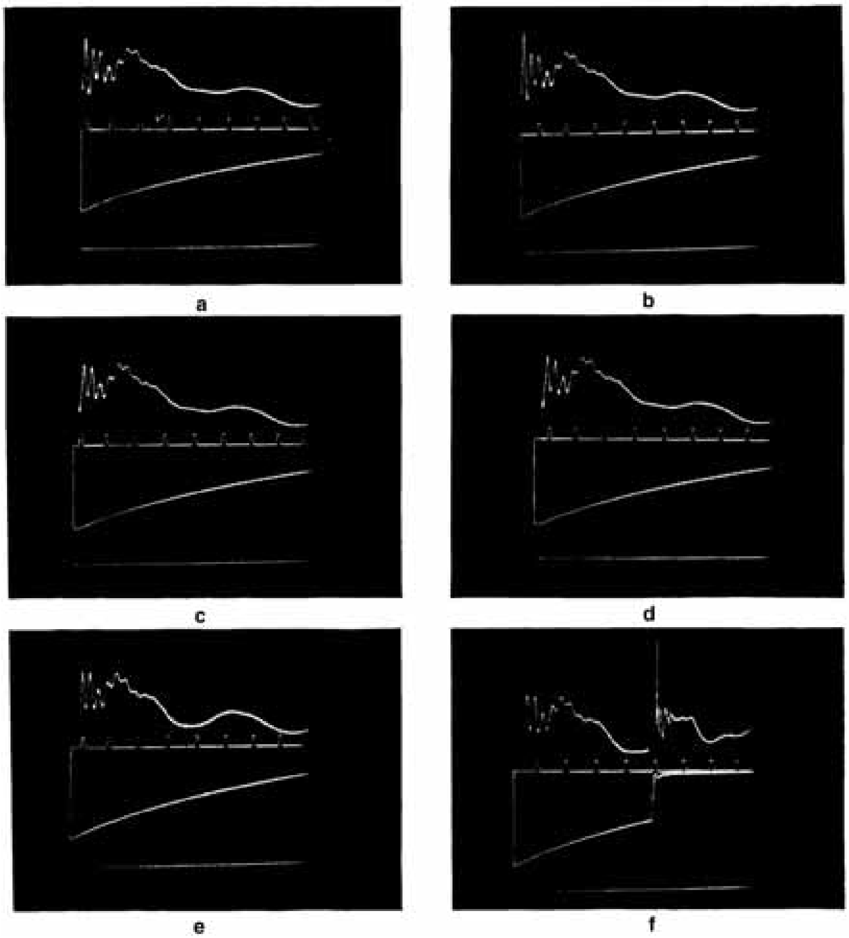


Figure 5.21

A wave of negative polarity and having a wave shape of 1.06/48 μs was employed for all tests. The voltage calibration corresponds to 107.4 kV and the time corresponds to 10 μs.

Switching impulse test

Surges generated by lightning strikes have very steep rise-times which cause transformer windings to appear as a string of distributed capacitance rather than the inductance which is presented to a power-frequency voltage. Surges generated by system switching do not have such rapid rise-times – times of 20 μs are typical – and at this frequency the transformer winding behaves much as it would do at 50 Hz. The voltage is evenly distributed, flux is established in the core and voltages are induced in other windings in proportion to the turns ratio. The magnitude of switching surges, though generally lower than lightning surges, is considerably greater than the normal system voltage (perhaps 1.5 times or twice), so that the overpotential test is not an adequate test for this condition. Switching-surge tests are therefore carried out on all transformers which might be subjected to switching surges in service. The test is a routine test for windings rated at 300 kV and above.

The impulses are applied either directly from the impulse voltage source to a line terminal of the winding under test, or to lower voltage winding so that the test voltage is inductively transferred to the winding under test. The specified test voltage must appear between phase and neutral and the neutral is to be earthed. In a three-phase transformer the voltage developed between phases during the test is normally 1.5 times the voltage between phase and neutral. The test voltage is normally of negative polarity because this reduces the risk of external flashover in the test circuit.

The voltages developed across different windings of the transformer are approximately proportional to their effective number of turns, and the maximum voltage will be determined by the winding with the highest voltage rating.

The voltage impulse shall have a virtual front time of at least 20 μs, a time above 90% of the specified amplitude of at least 200 μs, and a total duration to the first zero of at least 500 μs. *Figure 5.22* shows a typical switching impulse wave shape.

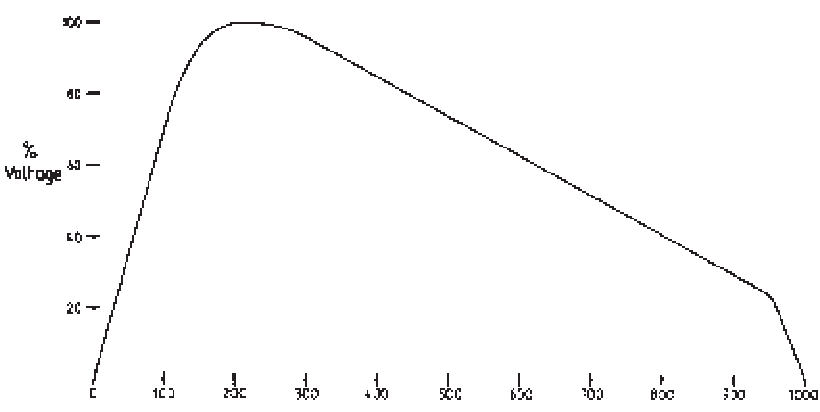


Figure 5.22 Typical switching impulse wave shape

The front time is selected by the manufacturer in agreement with the purchaser so that the voltage distribution along the winding under test will be essentially uniform. Its value is usually less than 250 μs. During the test, considerable flux is developed in the magnetic circuit. The impulse voltage can be sustained up to the instant when the core reaches saturation and the magnetising impedance of the transformer becomes considerably reduced. The maximum possible impulse duration can be increased by introducing remanence of opposite polarity before each full voltage test impulse. This is accomplished by applying lower voltage impulses of similar shape but of opposite polarity or by temporary connection to a DC source of supply.

The test sequence consists of one calibration impulse at a voltage level between 50 and 75% of the full test voltage, and three subsequent impulses at full voltage. Oscillograph records are taken of at least the impulse wave shape on the line terminal being tested. If the oscillographic recording should fail that application is disregarded and a further application made. During the test the transformer must be on no-load and this presents sufficient impedance; windings not being tested are earthed at one point but not short-circuited. The test is successful if there is no collapse of the voltage as indicated by the oscillograms but it should be noted that due to the influence of magnetic saturation successive oscillograms may differ in wave shape.

Digital data collection systems

With the increasing use of computers in all areas of technology at the present time, it must be inevitable that these should be applied to the gathering and processing of transformer impulse testing data. Accordingly manufacturers of high-speed oscilloscopes which have been almost exclusively used hitherto as the means of recording of impulse waves, have in recent years turned their attention to the production of software enabling voltage and current signals to be digitised in such a manner as to enable them to be recorded, analysed and printed out by computer. Some such systems have been in use by some transformer manufacturers since the mid-1980s. Many transformer engineers, however, have been cautious in their acceptance of this new technology. Because of the very rapid rates of change involved in transformer impulse waves it is necessary to utilise exceedingly high sampling rates in order to accurately represent them otherwise there is a danger that some high-frequency elements might be significantly distorted or even lost entirely. It is possible for software to record a voltage wave and compute the front and tail times, but if the wave shape departs from the ideal depicted in *Figure 5.14* by being ‘peaky’, for example as shown in *Figure 5.23*, then the software will arrive at very different front and tail times than an operator who would use his judgement in taking measurements from oscilloscope records. On the credit side, the digital software can be made to perform comparisons between test impulses and the reference record so as to provide a plot of difference versus time, but even when performing this function start time and sampling discrepancies can lead to differences being identified which do not exist.

Low-voltage surge tests

The insulation of a transformer must be proportioned to the surge voltages which will appear at the various points throughout the windings. High-voltage

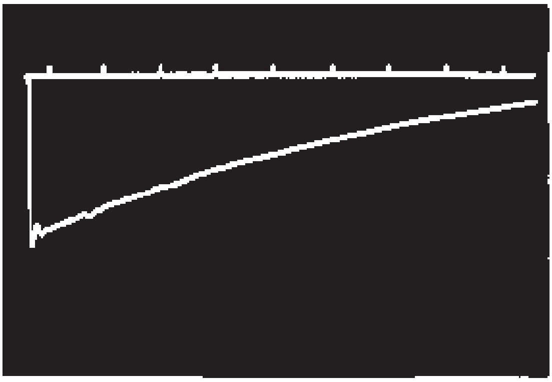


Figure 5.23 ‘Peaky’ impulse voltage record

surge tests on a completed transformer are costly and take a great deal of time. In addition, these are pass or fail tests and they do not give an indication of margins and failures can be expensive. In order to obtain the maximum possible amount of information it is desirable to have electrical contact with the maximum number of points on the winding.

Furthermore, for high-voltage transformers the core and windings must be immersed in oil and mounted in the tank. This condition does not facilitate the collection of data. Tests have shown that the surge voltage distribution in a winding is independent of the magnitude of the applied voltage and that the same results may be obtained by applying a reduced surge voltage, of the order of a few hundred volts.

These tests are made with a recurrent surge generator which consists of a capacitor charged to a suitable voltage and discharged by means of a thyratron into a circuit which is designed to generate the required low-voltage surge of the standard wave shape. The charge and discharge sequence is repeated at such a rate as will allow the effect of each applied surge to have totally decayed before application of the subsequent one. Fifty times per second is usually found to be convenient. The output voltage from the recurrent surge generator is applied to the terminal of the transformer winding under investigation, in a similar manner to that in which a high-voltage surge test would be conducted, while the surge voltage appearing at any point of the winding can be measured and displayed on the screen of an oscilloscope.

The time base is arranged so that it is synchronised with the recurrent discharge of the capacitor. By this means it is possible to obtain a standing picture on the screen of the applied voltage and of the voltage appearing at points along the winding, together with a time calibration wave which can be viewed directly by the operator or photographed for permanent record and later analysis.

In order to increase the usefulness of the recurrent surge oscilloscope for development and research investigations, facilities to vary the wavefront and wave tail, to produce chopped waves, and to give variable time sweeps and timing waves, are incorporated in the equipment.

Temperature rise test – oil-immersed transformers

When a test for temperature rise is specified it is necessary to measure the temperature rise of the oil and the windings at continuous full load, and the various methods of conducting this test are as follows:

(a) short-circuit equivalent test;
(b) back-to-back test;
(c) delta/delta test;
(d) open-circuit test.

The temperature rise limits are valid for all tappings; except in special cases, the temperature rise test need be carried out on only one tapping.

Method (a)
The general procedure under this method is as follows.

One winding of the transformer is short-circuited and a voltage applied to the other winding of such a value that the power input is equal to the total normal full-load losses of the transformer at the temperature corresponding to continuous full load. Hence it is necessary first of all to measure the iron and copper losses as described earlier in this chapter. As these measurements are generally taken with the transformer at ambient temperature, the next step is to calculate the value of the copper loss at the temperature corresponding to continuous full load.

Assuming the copper loss has been measured at 15°C, the copper loss at the continuous full-load temperature will be equal to the measured copper loss increased by a *percentage* equal to 0.4 times the anticipated temperature rise. This calculation assumes the copper loss varies directly as the resistance of the windings. This is not quite true, however, since a portion of the copper loss consists of eddy-current loss, and this portion will decrease as the resistance of the windings increases. The inaccuracy is slight, however, and has the advantage that it tends to increase the power supplied and consequently to shorten the test. Before commencing the test it is desirable to calculate also the approximate current required in order to avoid an excessive current density. At the commencement of the test this will be given by:

$$\text{normal current} \times \left(\frac{\text{iron loss} + \text{hot copper loss}}{\text{cold copper loss}}\right.$$

and at the end of the test by

$$\text{normal current} \times \left(1 + \frac{\text{iron loss}}{\text{hot copper loss}}\right.$$

However, to ensure greater accuracy, the test is made by measuring the power input, which is finally increased to include the hot copper loss, though the current obtained by the above calculation indicates how much the winding will be overloaded from the current density point of view. In general it will be seen that this test is most suitable when the copper loss is high compared with the iron loss, and conversely discretion is needed when dealing with transformers having relatively high iron losses.

When the normal temperature rise is approached the copper loss should be measured and any necessary current adjustment should then be made in order to correct the power input to obtain the true losses under normal full-load conditions, i.e. as regards current and temperature rise.

The short-circuit equivalent test should not be adopted when the ratio of copper loss to iron loss is less than two to one; for loss ratios below the figure mentioned the open-circuit test is preferable.

Single-phase transformers

The LV winding is short-circuited and the HV winding connected to a single-phase supply with an ammeter, voltmeter and wattmeter in circuit, as shown in *Figure 5.24*. The current in the HV winding is adjusted until the power input is equal to the sum of the calculated hot copper loss and the iron loss. The

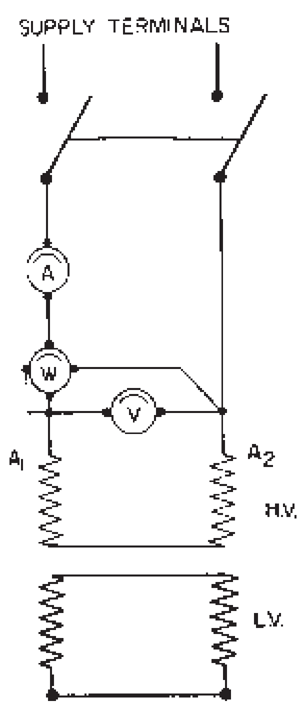


Figure 5.24 Single-phase short-circuit equivalent

current required is in excess of the full-load current, and the voltage across the phases is higher than the impedance voltage in order to compensate for the inclusion of the iron loss with the copper loss.

Three-phase transformers

The various means of utilising this test for three-phase transformers are shown in *Figures 5.25*, *5.26* and *5.27*.

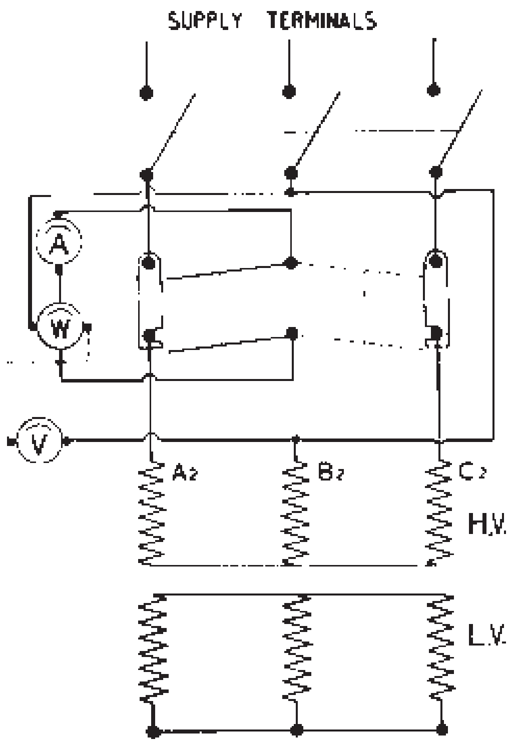


Figure 5.25 Three-phase short-circuit equivalent

Figure 5.25 shows a star/star-connected transformer ready for the test, the HV windings of the transformer being connected to a low-voltage three-phase supply, and the LV windings being short-circuited. Links are provided in the supply leads to phases A and C, and the various instruments are connected to a double pole changeover switch such that by closing the switch in either phase and opening the corresponding link, the ammeter and wattmeter current coil will be in series with that phase, and the voltmeter and wattmeter voltage coil will be connected between the same phase and phase B. The three-phase supply switch is first closed and the double pole switch then closed in phase A, the link in A then being opened. The supply voltage is increased until the

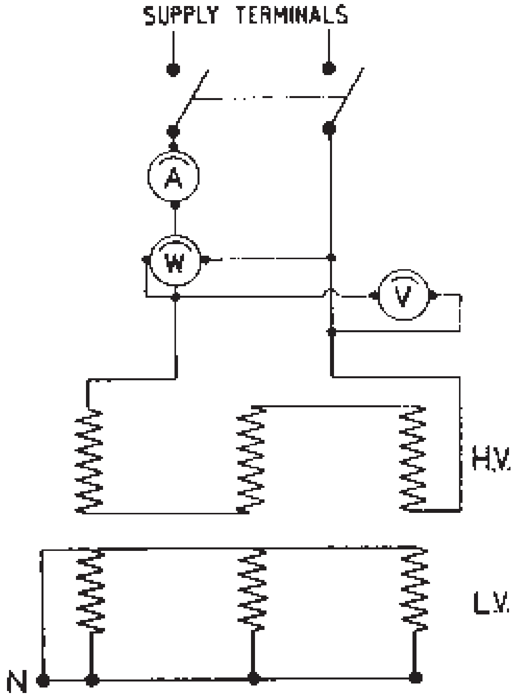


Figure 5.26 Single-phase 'series HV' short-circuit equivalent

current shown by the ammeter is slightly in excess of the full-load HV current. This current may be calculated as previously explained. The wattmeter reading is then noted.

The link in phase A is next closed and the double pole switch changed over to phase C, the link in this phase being then opened, and the wattmeter reading again noted. This process is repeated until, after making the necessary adjustments, the algebraic sum of the two wattmeter readings is equal to the sum of the iron and hot copper losses.

Figure 5.26 shows an alternative method of connecting up a star/star transformer for test. The LV windings in this case are short-circuited through the neutral, the HV being temporarily 'series' connected. The two open ends of the HV windings are then connected to a single-phase supply through a wattmeter and ammeter. The current is adjusted until the power input is equal to the sum of the iron and hot copper losses. This current is somewhat higher than the normal full-load line current if the transformer is normally star connected, and somewhat higher than the normal full-load line current divided by $\sqrt{3}$ if the transformer is normally delta connected. The corresponding value of the applied single-phase voltage required will be somewhat higher than three times the transformer impedance voltage per phase. Of course, this method can only be used if the HV star connection is capable of being temporarily opened.

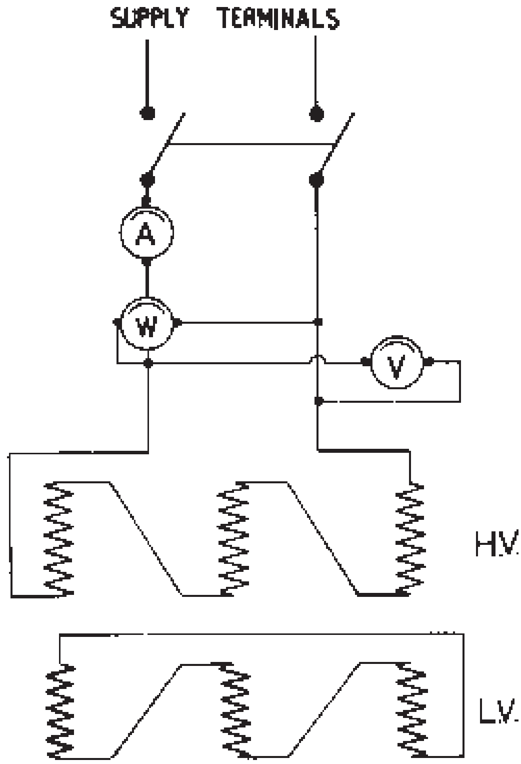


Figure 5.27 Single-phase ‘open delta HV’ short-circuit equivalent

Figure 5.27 shows a further method in which the LV windings are connected in closed delta, and the HV in open delta.* It is, of course, only possible to use this method provided the HV delta connection can be opened. The method is applicable to any three-phase transformer whatever the normal interphase connections, and temporary connections are made as necessary. The test should be confined to transformers of low and medium impedances, however, and it should not be used for transformers of high impedance. For the latter the short-circuit equivalent test illustrated by *Figure 5.26* is recommended. The HV windings are connected to a single-phase supply, and the same procedure as described for *Figure 5.27* is followed. The current and voltage required will be the same as given for *Figure 5.26*.

Method (b)

In this method, known as the back-to-back (or Sumpner) test, the transformer is excited at normal voltage and the full-load current is circulated by means of an auxiliary transformer.

* This must not be confused with the so-called open delta or vee connection for giving a three-phase supply from two single-phase transformers.

Single-phase transformers

Figure 5.28 shows the method of connection for single-phase transformers. The transformers (two identical units are required) are placed not less than 1 m apart with the HV sides adjacent. The HV windings are then connected in opposition through an ammeter. The LV winding of one transformer is connected to a single-phase supply, and the other is connected in parallel with it, but the LV winding of a suitable auxiliary transformer is included in this circuit. The HV winding of the auxiliary transformer is either supplied from a separate source as shown in *Figure 5.28* or is placed in parallel across the other mains with a variable resistor in series with it.

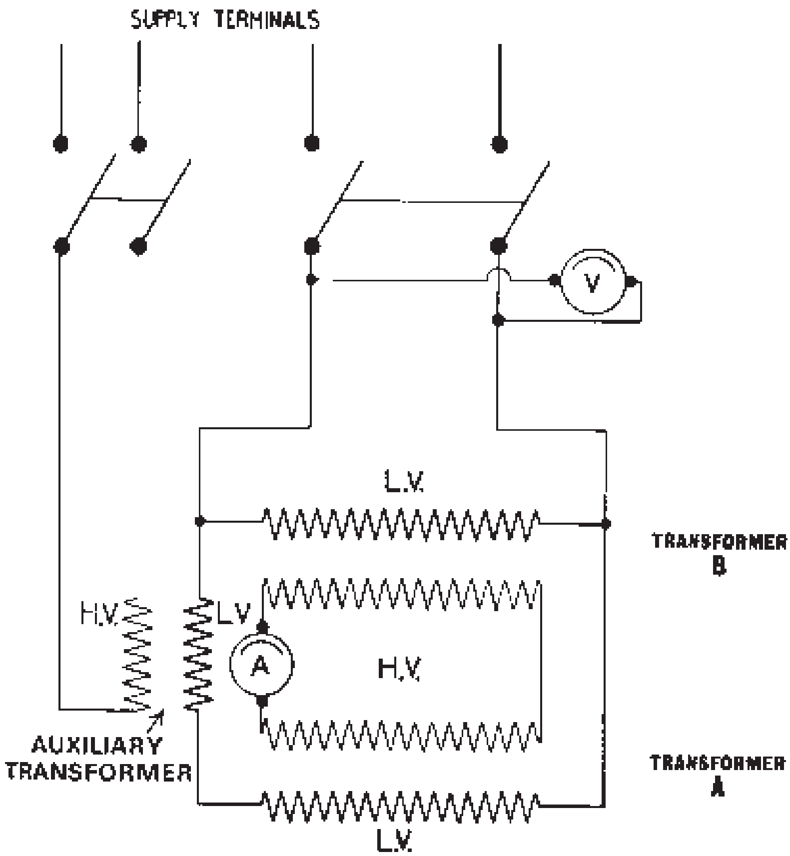


Figure 5.28 Single-phase back to back

Normal LV voltage at the correct frequency is then applied to the LV windings in parallel, and the supply voltage to the HV winding of the auxiliary transformer is adjusted at correct frequency until the ammeter in the HV circuit of the transformer under test reads the normal full-load current. If the variable resistor connection is used for the auxiliary transformer, its resistance is adjusted until the ammeter in the HV circuit of the transformer under test indicates the normal HV full-load current.

It should be noted that in this method no wattmeter is used, as the actual full-load conditions, i.e. normal excitation and full-load current, are reproduced. The copper and iron losses must therefore be those which would normally occur, and there is consequently no need to measure them during this test.

The machine supplying the LV windings in parallel must be capable of giving the *normal* LV voltage of the transformer under test and twice the no-load current, and it is this circuit that supplies the iron losses.

The LV winding of the auxiliary transformer must supply twice the impedance voltage of the transformer under test at the normal LV full-load current, and when the method shown in *Figure 5.28* is used, the machine supplying the auxiliary transformer must be capable of giving a voltage equal to the ratio of transformation of the auxiliary transformer multiplied by twice the impedance voltage of the transformer under test, and a current equal to the LV current of the transformer under test divided by the ratio of transformation of the auxiliary transformer. This circuit supplies the copper losses to the transformers under test.

There is a further method of making a back-to-back test on two similar single-phase transformers which is possible when the transformers are provided with suitable tappings. The transformers are connected as shown in *Figure 5.29* which is similar to the previous method except that the auxiliary transformer is omitted and the current circulation is obtained by cutting out a portion of the HV winding of one of the transformers.

It will be evident that the percentage difference between the numbers of turns in the two HV windings should be approximately equal to the sum of the percentage impedances. For example, if the transformers are provided with ± 2.5 and 5% tappings and the impedance of each is 3.75%, this test could be made by using the $+5\%$ tapping on one transformer and the -2.5% tapping on the other transformer.

An ammeter is connected in the HV side, as in the previous test, and the supply to the LV windings in parallel is given at the normal voltage and frequency. If it is found that with the best available tappings the ammeter does not indicate exactly the correct full-load HV current, the supply voltage may be varied slightly up or down and the power input adjusted as already described for method (a), i.e. the short-circuit equivalent test. When it is necessary to raise the supply voltage above normal in order to obtain the correct power input, it is evident that the transformers have a greater iron loss and lower copper loss than would be the case under normal full loading and excitation. The converse, of course, holds true when it is necessary to lower the supply voltage below normal in order to obtain the correct power input.

It should be noted that the tappings are assumed to be on the HV winding as this arrangement is more common, but the test may be made equally well if the tappings are on the LV winding.

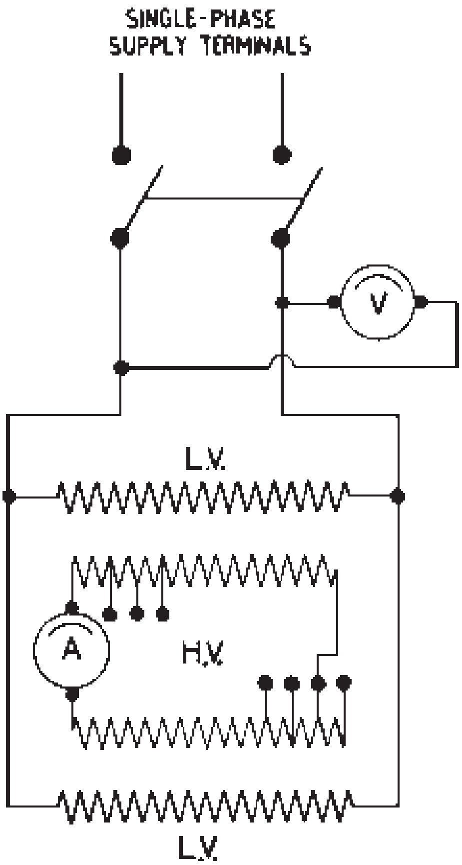


Figure 5.29 Single-phase back to back

Three-phase transformers

The diagram of connections for the test on three-phase transformers is shown in *Figure 5.30* which corresponds to *Figure 5.28* for single-phase transformers. The diagram shows two star/star-connected transformers, but the external connections are the same for any other combination of interphase connections. The ammeter on the HV side of the transformers under test is, for the sake of simplicity, shown permanently connected in the middle phase, but it would actually be arranged for connecting in any phase by means of changeover switches. The same remark applies also to the voltmeter across the supply. The method of procedure is the same as described for single-phase transformers connected as in *Figure 5.28*.

Figure 5.31 indicates the connections for two star/star transformers, using the voltage adjusting tapping method, though these would be the same irrespective of the normal interphase connections, temporary connections being

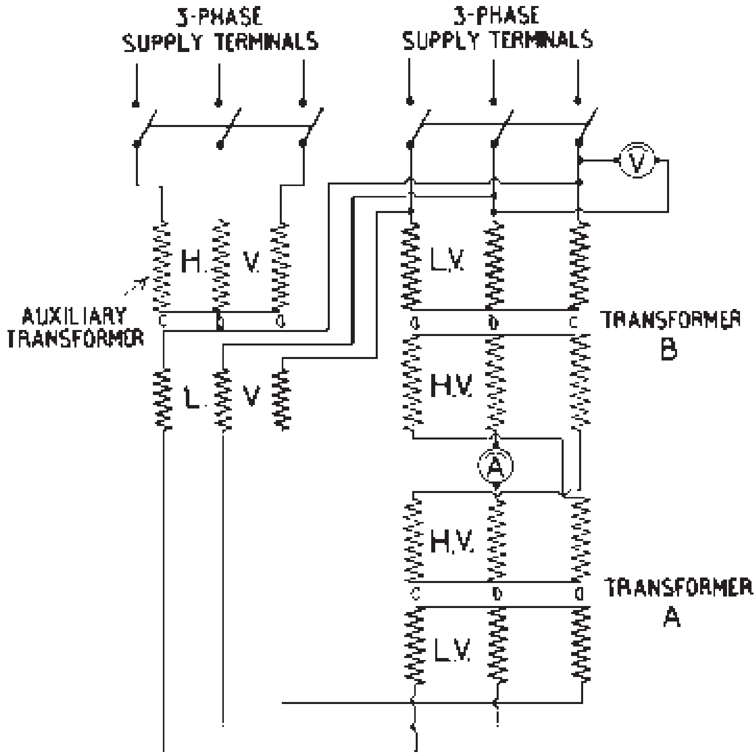


Figure 5.30 Three-phase back to back

made as desired. The general procedure is identical with that outlined for the single-phase transformers shown in *Figure 5.29*. The LV windings of the two transformers are connected in parallel and excited at the normal voltage while the HV windings are connected in opposition, but at the same time suitable tappings are selected to give the voltage difference necessary to provide the circulating full-load current.

When these methods of testing are used it will be found that one transformer has a temperature rise higher than that of the other. This is due to the fact that the copper loss is supplied by means of a common circulating current, whereas the iron loss is supplied to the two transformers in parallel. The no-load current is out of phase with the circulating current, but not actually in quadrature with it, and consequently the phasor sum of the no-load and circulating currents in one LV winding is greater than the corresponding sum in the other LV winding.

The back-to-back tests illustrated by *Figures 5.28* to *5.31* inclusive may, of course, be applied to delta/star and to star/interconnected-star transformers.

Two alternative forms of three-phase, back-to-back temperature rise tests are illustrated in *Figures 5.32* and *5.33*. The arrangement shown in *Figure 5.32*

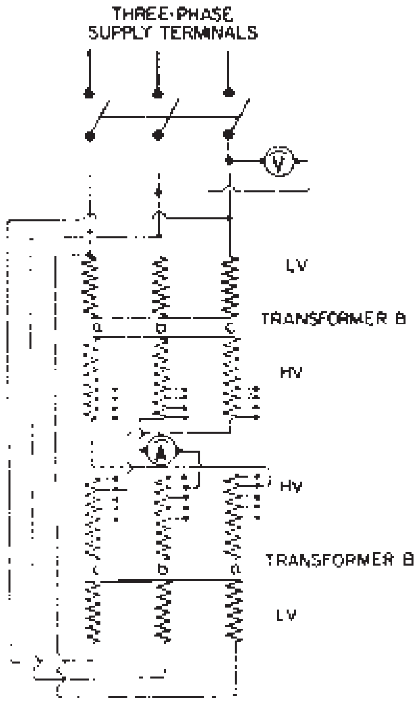


Figure 5.31 Three-phase back to back

may be applied to three-phase transformers of any type, of any combination of primary and secondary connections, and of any impedance, it only being necessary that the two transformers under test are identical. As shown in the diagram, an auxiliary booster transformer is used for providing the circulating current passing through the windings of the transformers under test, and the normal excitation supply is applied to the centre points of the secondary winding of the booster transformer. In the event of no centre points being accessible on the booster windings, the normal excitation supply may be applied to the terminals of either transformer, in which case one transformer would have a slightly lower voltage across its terminals than the other, due to the impedance drop in the secondary windings of the booster transformer.

Where the normal excitation is applied to the centre points of the booster transformer, the supply voltage should be slightly higher than the rated voltage of the transformers under test in order to compensate for the impedance drop in the secondary winding of the booster transformer.

The copper losses are supplied from the three-phase source which provides the necessary circulating currents via the primary windings of the booster transformer, while the iron losses are supplied from the three-phase source which supplies the normal excitation to the transformers. The primary windings of the booster transformer are supplied at a voltage which is approximately

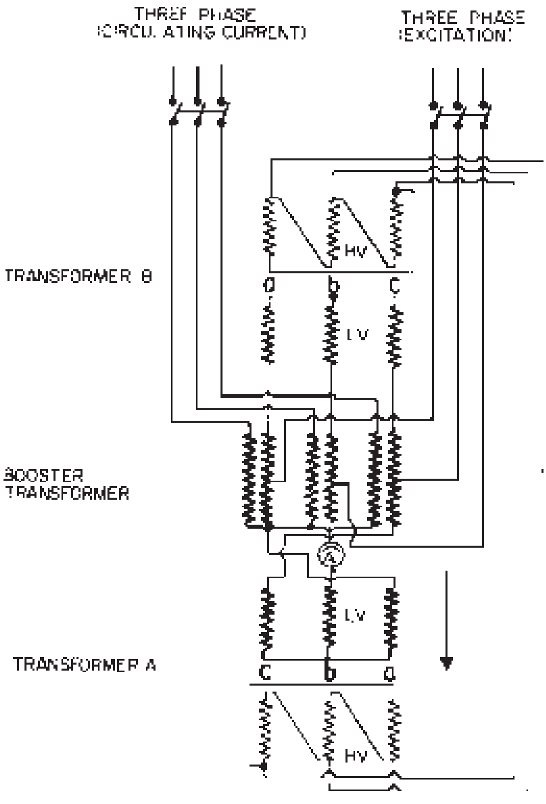


Figure 5.32 Three-phase back to back, employing three-phase excitation and current circulation

equal to the sum of the impedance voltages of the two transformers under test multiplied by the booster transformer ratio.

This method has an advantage that it is not necessary to make any temporary connections inside the transformers, nor is it necessary to reinforce any connection temporarily to carry any special heavy test currents.

Figures 5.33(a) and *(b)* illustrate a type of test which is applicable to three-phase delta/star and star/star transformers. The LV windings are connected back to back, and current is circulated in them from a single-phase supply. The LV windings are excited at their normal rated voltage, so that this method also simulates very closely the heating conditions which arise in the ordinary course of operation.

With this connection the neutral leads on the star sides must be reinforced to carry three times the normal full-load current. Circulating current is supplied from a single-phase source, so that the currents in all three limbs are equal and in phase. The leakage flux between windings returns partly through the tank walls, and for this reason the method indicated by *Figure 5.33* should

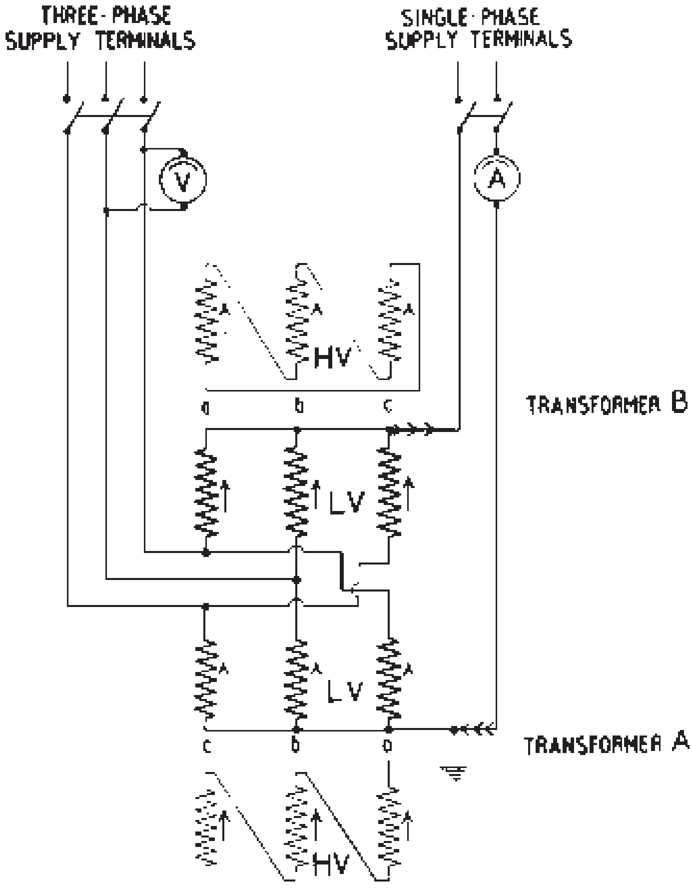


Figure 5.33(a) Three-phase back to back on two delta/star-connected transformers

not be used for transformers where the impedance exceeds 5%. Otherwise it is quite a satisfactory method of conducting a load test and one which is frequently used.

Method (c)

This method, known as the delta/delta test, is applicable to single- as well as three-phase transformers where the single-phase transformers can be connected up as a three-phase group.

Figure 5.34 shows the diagram of connections often employed. The LV windings are connected in closed delta, and supplied from a three-phase source. The HV windings are connected in open delta* and include an

* This must not be confused with the so-called open delta or vee connection for giving a three-phase supply from two single-phase transformers.

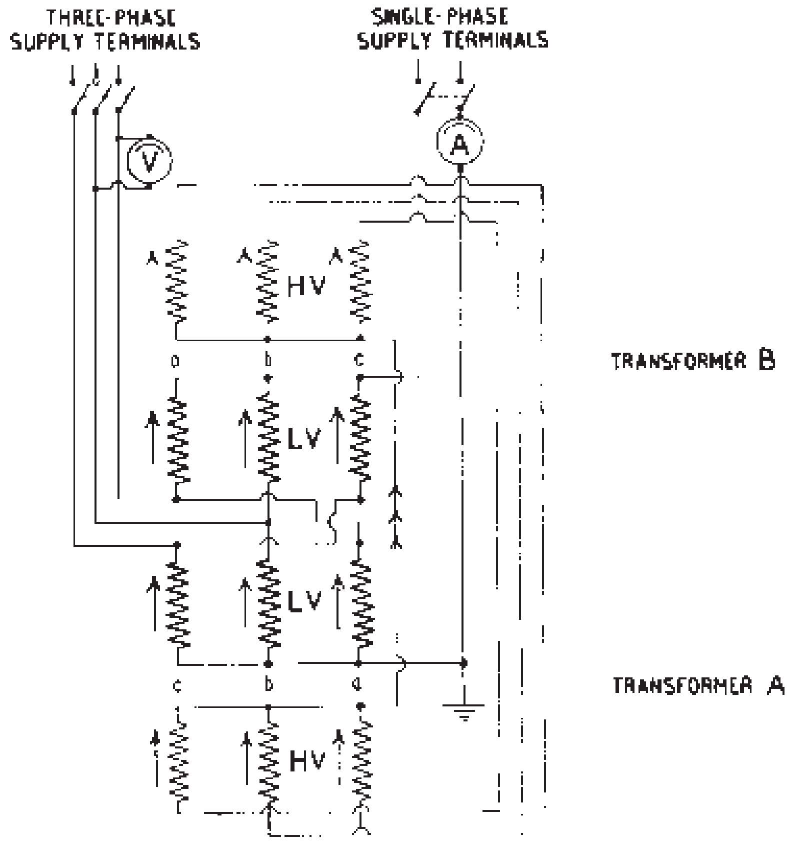


Figure 5.33(b) Three-phase back to back on two star/star-connected transformers

ammeter. Voltmeters are connected between phases in the LV circuit. Three-phase voltage at the correct frequency is applied to the LV windings and is adjusted until it equals the normal LV voltage. Single-phase current is supplied separately to the HV windings and is adjusted to the normal HV full-load current.

This method may be used whatever the normal internal connections of the transformer, temporary connections being made if necessary. The voltages and currents required under this test for various normal interphase connections are given in *Tables 5.5* and *5.6*.

If the normal HV voltage is of the order of 11 000 V and above, the method shown in *Figure 5.35* is safest. In this method the HV winding is simply closed delta connected, the LV being connected in open delta. A three-phase voltage equal to the normal LV *phase* voltage is applied to the LV winding at the correct frequency, and the LV copper-loss current is supplied single phase.

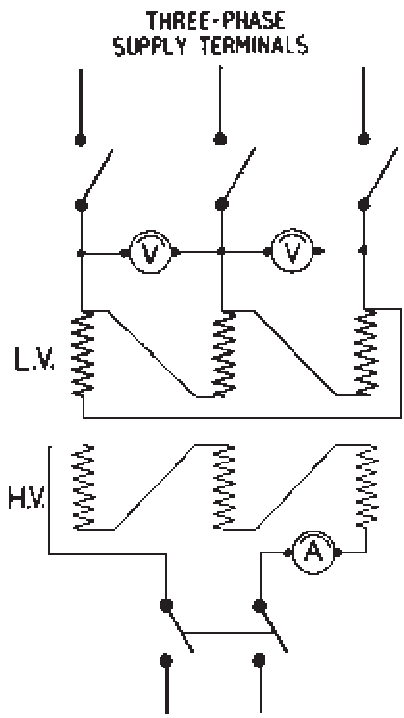


Figure 5.34 Delta/delta connection

Table 5.5

Application of voltage or current	*l.v. connection*	
	Delta	*Star*
Voltage applied to l.v.	V	$V/\sqrt{3}$
Current applied to l.v.	I_0	$I_0 \times \sqrt{3}$

$V =$ normal line voltage
$I_0 =$ normal no-load current.

Table 5.6

Application of voltage or current	*h.v. connection*	
	Delta	*Star*
Voltage applied to h.v.	$V_2 \times 3$	$V_2 \times \sqrt{3}$
Current applied to h.v.	$I/\sqrt{3}$	I

$V_2 =$ h.v. impedance voltage
$I =$ normal line current.

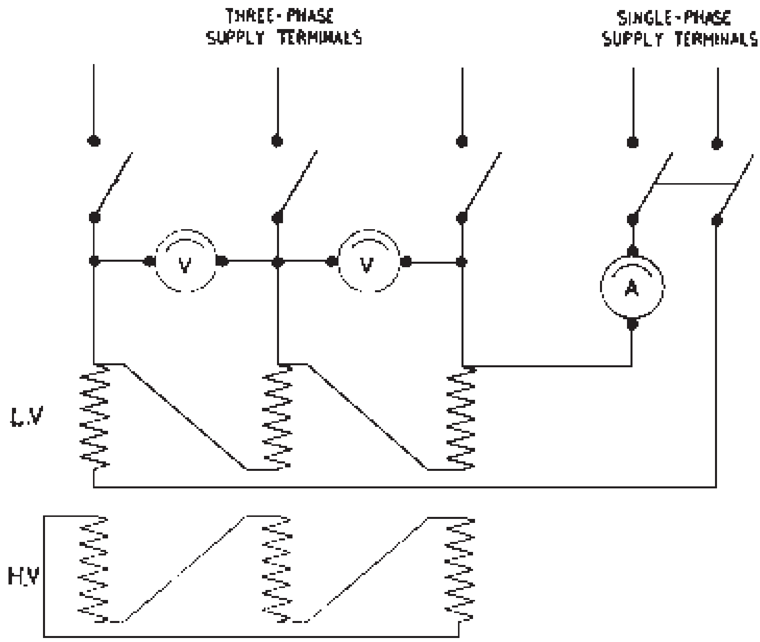


Figure 5.35 Delta/delta connection

Method (d)

If it happens that a transformer possesses a low ratio of copper loss to iron loss it is generally impossible to conduct a temperature rise test by the short-circuit method. This is because the required power input necessitates an excessive current in the windings on the supply side of the transformer, so that a prohibitively high current density would be reached. In such cases it may be possible to test the transformer on open circuit, the normal losses being dissipated in the iron circuit.

If a supply at a frequency considerably below the normal rated frequency of the transformer is available, a condition may be obtained whereby the total losses are dissipated at a test voltage and current in the neighbourhood of the normal rated voltage and current of the transformer. If, however, a lower frequency supply is not available, the transformer may be run at the normal rated frequency with a supply voltage greater than the normal rated voltage, and of such a value that the total losses are dissipated in the iron circuit.

Assuming that the iron loss varies as the square of the voltage, the required voltage under these conditions is given by the formula:

$$\text{normal voltage} \quad \left(1 + \frac{1.2 \times \text{cold copper loss}}{\text{normal iron loss}}\right.$$

Either side of the transformer may be supplied according to which is the more convenient. The method can be applied to both single-phase and polyphase transformers.

It is important that instruments connected in HV circuits should be earthed; alternatively voltmeters and ammeters should be operated through voltage and current transformers respectively.

Temperature readings

The top oil temperature of the transformer under test is measured by means of a thermometer so placed that its bulb is immersed just below the upper surface of the oil in the transformer tank.

When bulb thermometers are employed in places where there is a varying magnetic field, those containing alcohol should be employed in preference to the mercury type, in which eddy currents may produce sufficient heat to yield misleading results.

Surface temperatures

When measuring the temperature of a surface, such as a core or a winding, the thermometer bulb should be wrapped in a single layer of tin foil at least 0.025 mm thick and then secured to the surface. The exposed part of the wrapped bulb should then be covered with a pad of insulating material without unduly shielding the test surface from normal cooling.

Cooling air

The cooling air temperature should be measured by means of several thermometers placed at different points around the transformer at a distance of 1 to 2 m from the cooling surface, and at a level approximately midway up the transformer cooling surface. The thermometers should be protected from draughts and abnormal heat radiation. In the case where forced air cooling is employed and there is a well-defined flow of air towards the coolers then the thermometers should be placed in this cooling stream.

To avoid errors due to the time lag between variations in the temperature of the transformer and that of the cooling air, the thermometers may be immersed in a cup containing a suitable liquid, such as oil, having a time constant of about 2 hours.

The temperature of the cooling air for the test is taken as the average of the thermometer readings taken at equal intervals during the last quarter of the test period.

The carrying out of temperature rise tests is an activity which has been very much simplified in recent years by the use of electronic data-logging equipment. Although the measurement of temperatures using thermometers as described above remains a totally acceptable method, it is likely that most manufacturers would now replace these with thermocouples monitored by electronic temperature measuring equipment.

The temperature rise test of a transformer should be of such duration that sufficient evidence is available to show that the temperature rise would not exceed the guaranteed limits if the test were prolonged (see BS 171, Part 2). One way of determining this is by taking readings of the top oil temperature at regular intervals and plotting a curve on linear coordinate paper. *Figure 5.36* illustrates a typical time/temperature rise curve obtained from a test. Alternatively, the temperature test may be continued until the temperature rise does not exceed 1°C per hour during four consecutive hourly readings.

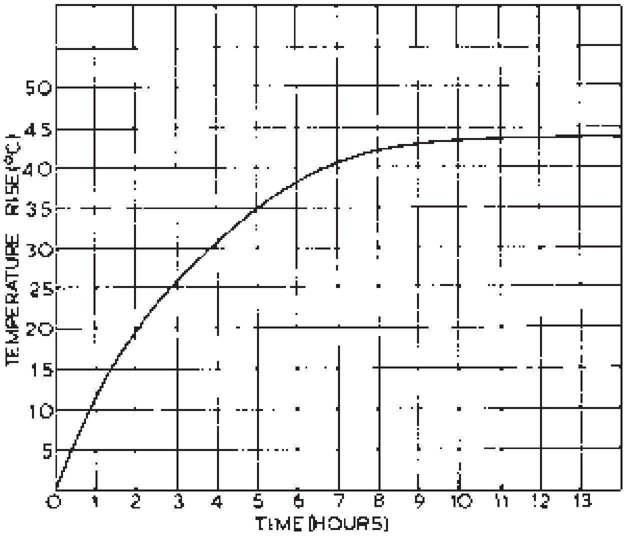


Figure 5.36 Typical time/temperature rise curve

In addition to ascertaining the temperature rise of the oil, it is usual to calculate the temperature rise of the windings from measurements of the increase of resistance. To do this, it is necessary to measure the resistance of the windings before the test (R_1) noting the temperature of the windings at the time of the reading, and to measure the resistance (R_2) at the close of the test. Over the normal working temperature range the resistance of copper is directly proportional to its temperature above −235°C.

Top oil temperature

The top oil temperature rise is obtained by subtracting the cooling medium temperature from the measured top oil temperature.

If the total losses cannot be supplied then a value not less than 80% may be used and the measured top oil temperature rise corrected using the following correction factor:

$$\left(\frac{\text{total losses}}{\text{test losses}}\right)^x$$

where $x = 0.8$ for AN circulation and $x = 1.0$ for AF or WF circulation.

To obtain an accurate value of the temperature rise of the windings the temperature T_1 must be the temperature at which the resistance of the windings is R_1. Due care must be taken in the measurement of T_1, particularly in the case of large transformers because even if a transformer is left unenergised for days, the oil temperature usually varies from the top to the bottom of the tank, so that the top oil temperature may differ from the mean temperature of the windings by some degrees.

Dry-type transformers

When measuring the cold winding resistance the winding temperature should be approximately equal to that of the surrounding medium. This is confirmed by mounting at least three thermometers on the surface of the winding. The winding resistance and temperature should be measured simultaneously.

Temperature rise tests on dry-type transformers should be performed with the core excited at normal flux density; so that two loading methods are available, either a direct load test or a back-to-back test.

The test may be carried out at a current not less than 90% of the rated current, or at a current supplying the total losses of the transformer. When the winding test current I_1 is lower than the rated current I_N, the temperature rise $\Delta\theta_t$ of the windings, measured by the resistance method, after reading steady-state conditions should be corrected to that for the rated load condition, $\Delta\theta_N$, using the following formula:

$$\Delta\theta_N = \Delta\theta_t \left(\frac{I_N}{I_t}\right)^q$$

where $q = 1.6$ for AN transformers and $q = 1.8$ for AF transformers.

Winding temperature

The temperature of a winding at the end of the test period is usually calculated from its resistance R_c at that time and resistance R measured at a known temperature T_c, usually the ambient temperature. Care must be taken in measuring T_c, particularly for large transformers, because even though a transformer has been de-energised for several days a temperature gradient of several degrees may exist between the top and bottom of the tank, so that the top oil temperature differs from the mean winding temperature.

Over the normal working temperature range the temperature T_h corresponding to the resistance R_h may be obtained from the formulae:

$$T_h = \frac{R_h}{R_c}(T_c + 235) - 235 \text{ for copper}$$

and

$$T_h = \frac{R_h}{R_c}(T_c + 225) - 225 \text{ for aluminium}$$

At the end of the temperature rise test, when the power supply to the transformer is shut off, the temperature of windings is appreciably higher than the mean temperature of the cooling medium, which is the oil around the windings in the case of oil-immersed transformers or the surrounding air in the case of dry-type transformers. Consequently, the windings cool in an exponential manner towards the cooling medium temperature, the thermal time constant of this phase of the cooling being that of the windings only, and of short duration, e.g. 5–20 minutes.

The winding resistance R_h may be obtained by one of two methods: (a) without interruption of the supply, by the superposition method where a DC measuring current is superposed onto the load current; (b) by taking resistance measurements after switching off, using a Kelvin bridge, having allowed the inductive effect of the windings to disappear. Fans and water pumps must be stopped but oil pumps are left running. A correction must then be applied for the delay between shutdown and the commencement of measurement. The correction is calculated by plotting a resistance/time curve for the cooling winding using either linear or log/linear scales and extrapolating back to the time of shutdown.

It is usually more accurate to preset the bridge before each reading and to note the time at which the bridge meter reads zero.

Linear scales *Figure 5.37* illustrates this method in which decreases in resistance corresponding to equal intervals of time are projected horizontally at the appropriate points of the ordinate to give a straight line L. The resistance at the instant of shutdown is derived by plotting the resistance projections for equal intervals back to zero time from this line.

Figure 5.38 illustrates a typical curve for the HV winding of a 1000 kVA transformer which was plotted using projection intervals of 1 minute.

Log/linear scales The difference $\Delta R'$ between the measured resistance and the resistance R', corresponding to the temperature to which the winding is cooling after switching off the supply, is plotted with $\Delta R'$ as the logarithmic axis and time as the linear axis. The resistance R' is chosen in such a way that a straight line is obtained. The resistance at zero time is then equal to $R' + \Delta R'_0$ where $\Delta R'_0$ is found by extrapolating the line back to zero time.

Electronic data-loggers

As in the case of measurement of temperature, mentioned above, resistance measurements after shutdown can now be recorded by means of an electronic data-logger. Winding resistance is computed by the voltage/current method but because it is only necessary to make one initial connection to the windings, a higher driving voltage can be used than would be the case for manual measurements which speeds up current stabilisation. *Figure 5.39* shows a

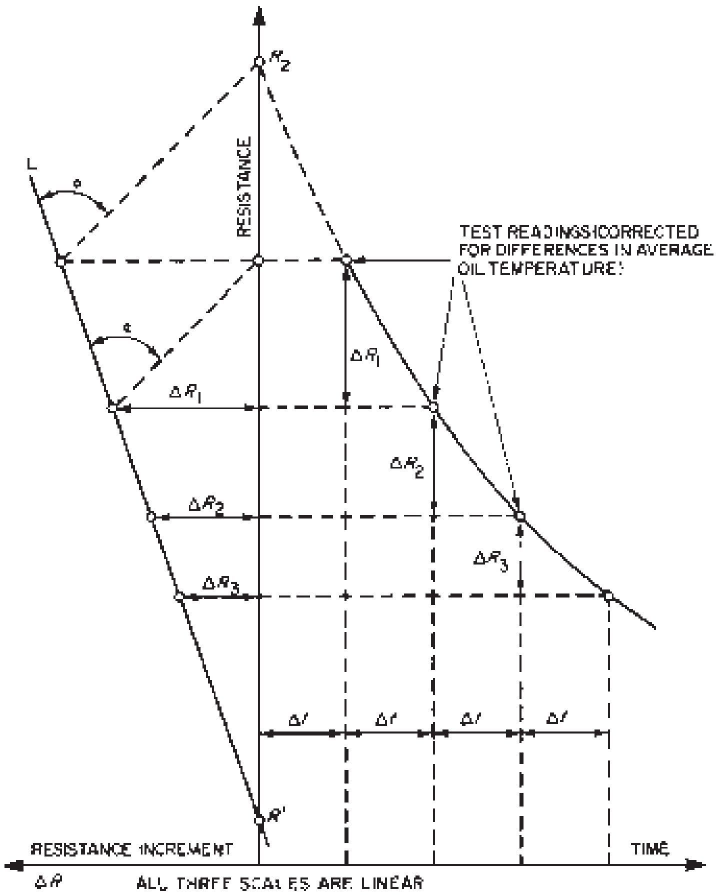


Figure 5.37 Extrapolation method for winding resistance at shutdown

typical circuit used for measurements using a data-logger. The series resistors limit the current flow to around 20–30 A and by inputting the appropriate voltages across windings and standard shunts the resistances can be computed. These equipments can be set up to take a series of resistance measurements over a predetermined time period, plot a resistance/time curve and extrapolate this back to shutdown automatically to provide the values of winding resistances at the instant of shutdown.

Winding temperature rise

The winding temperature rise is obtained by subtracting the external cooling medium temperature from the average winding temperature measured by one of the methods described above. In these cases a correction must be applied

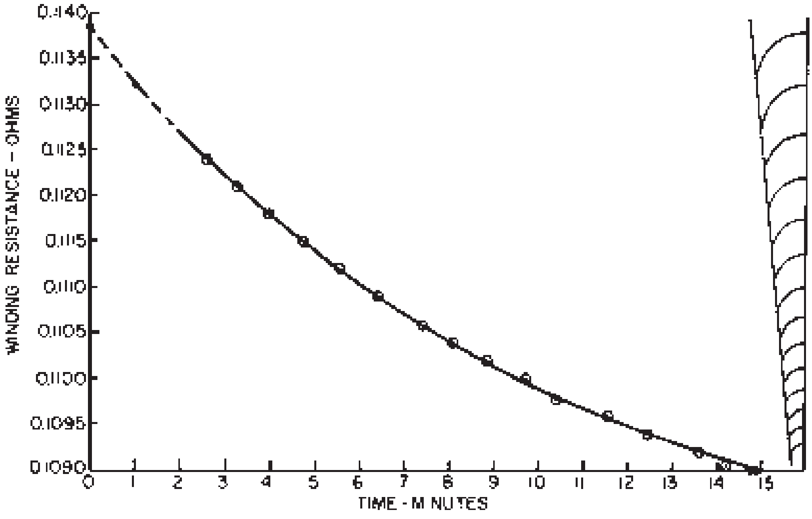


Figure 5.38 Cooling curve for a 1000 kVA transformer plotted with linear scales

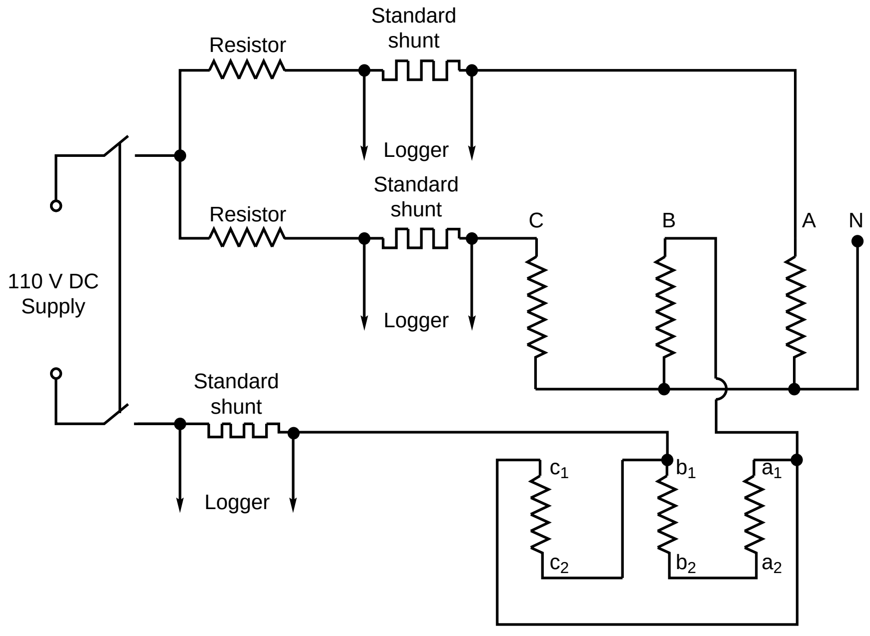


Figure 5.39 Method of connecting three-phase star/delta transformer for inputing resistance measurements to data-logger

to the winding temperature rise using the following correction factor:

$$\left(\frac{\text{rated current}}{\text{test current}}\right)^{y}$$

where $y = 1.6$ for ON and OF oil circulation and $y = 2.0$ for OD oil circulation.

Duration of temperature rise tests

In general, temperature rise tests last from six to 15 hours. They may be shortened, if necessary, by overloading the transformer at the commencement of the test and then reverting to full-load losses as the final temperature is approached, but this method should only be adopted in special cases because, if insufficient time is allowed for the windings to attain their correct steady temperature, errors will be introduced.

As an alternative method it is possible, in the case of separate radiators or coolers, to restrict the normal oil flow and so accelerate the temperature rise of the oil in the early stages of the test. Further information is given in BS 171 regarding the measurement of oil and winding temperatures at the end of a temperature rise test.

Noise level tests

Reference should be made to Section 3 of Chapter 6 for details of measurement of transformer noise.

Test certificate

At each stage in the testing of a transformer the results are recorded on the testing department's records and subsequently these are transferred to an official test certificate for transmission to the customer. Typical test certificates are shown in *Figures 5.40* and *5.41*.

5.3 POSSIBLE ADDITIONAL TESTING FOR IMPORTANT TRANSFORMERS

In the introduction to this chapter it was suggested that there are tests over and above those described in BS 171 which can be considered for important transformers for which it is required to have the highest level of confidence in their integrity and suitability for service in a demanding situation. Such additional testing will, in itself, add to the first cost of the transformer and it might be that the manufacturer will wish to design into the transformer some additional safety factors which will also add to the first cost. However, this will add to the confidence in the integrity of the unit which was one of the objects of the exercise. Transformers which might appropriately be included in this category for special treatment would be all of those operating at 275 and 400 kV as well as strategically important lower voltage transformers, possibly

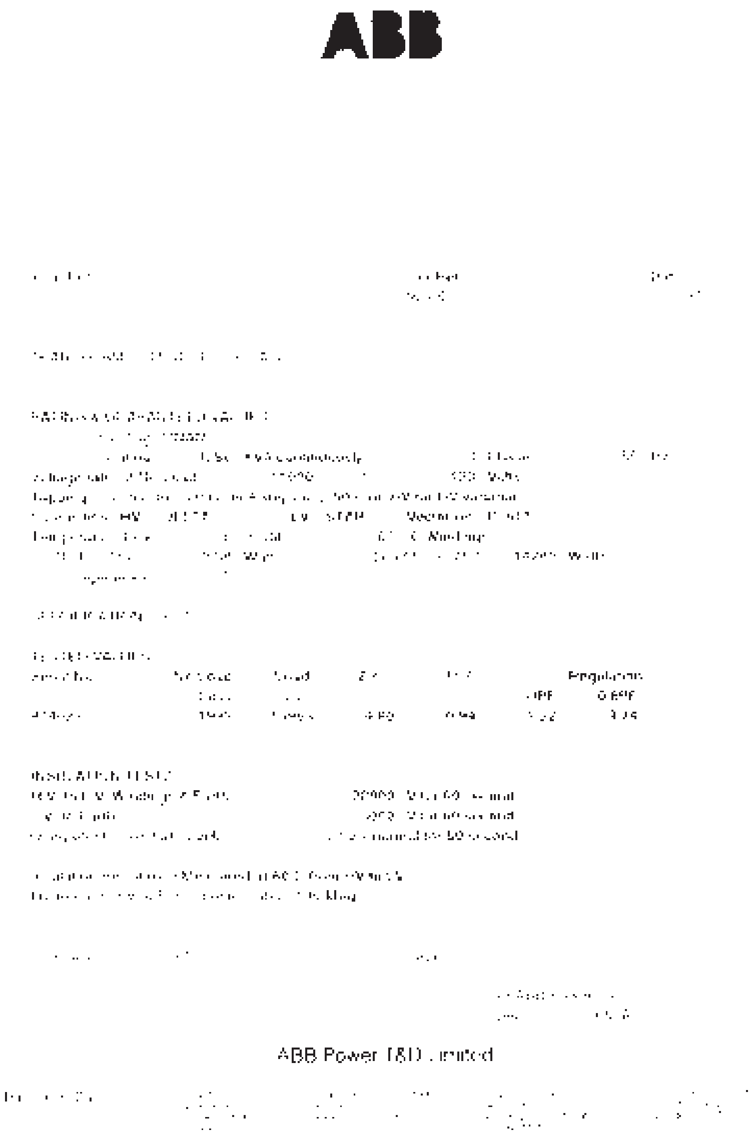


Figure 5.40 Typical transformer test certificate

supplying a steel smelter or other important process plant. It is clearly the responsibility of the user to decide whether his transformer is to be considered important or not.

What additional testing might be carried out? This is a question which was posed by CEGB in the early 1970s. At this time there was great concern expressed at the highest level within that organisation at the high failure rate

TRANSFORMER HEAT RUN SCHEDULE

Customer – Your Ref – Our Ref. – 962155/1

Rating – 1000 KVA Phase – 3 50Hz Cooling – ONAN

Type Of Test Heat Run(SC) Tap Position – 3(N)

No Load – 960 Load Loss – 12832 Total Loss – 13792

Guaranteed Oil/Winding Rises – 55/65 Spec No. – FL014

Time	Volts A	Volts B	Volts C	Meas Watts	Amps A	Amps B	Amps C	Air Temp	Oil Temp	Temp Rise	Rad Top	Rad Bot
4.00pm	593.0	593.0	593.0	11652	54.9	54.9	54.9	18.5	18.5	-	-	-
6.30am	595.8	591.5	598.1	13840	54.4	53.9	54.7	17.5	68.5	51.0	60.0	41.0
7.00	595.0	596.0	596.7	13800	54.3	53.8	54.6	17.5	68.5	51.0	60.0	41.0
7.30	595.2	590.8	596.9	13820	53.8	53.8	54.6	17.5	68.5	51.0	60.0	41.0
8.00	595.0	599.0	596.8	13800	54.3	53.8	54.7	17.5	68.5	51.0	60.0	41.0
8.30	595.8	591.5	598.1	13840	54.4	53.9	54.7	17.5	68.5	51.0	60.0	41.0
9.00	REDUCED TO FL				52.5	52.5	52.5	17.5	68.5	51.0	60.0	41.0
9.30	SHUTDOWN AND HOT RESISTANCE TAKEN							17.5	68.0	50.5	57.0	41.0

Final Results

Across	HV – A–B		LV – a–b	
Cold Temp = 18.5	Cold	Hot	Cold	Hot
Resistance –	1.314	1.536	0.001772	0.002209
Wind Temp Rise =	43.849		63.628	

Print Name

Customer's Inspecting Engineers – ____________ Signed – ____________

Signed on behalf of
ABB POWER T&D Ltd Date – 6/11/96

Figure 5.41 Typical transformer temperature rise test report

of large-generator transformers. At one time a CEGB internal report predicted that, on a purely statistical basis derived from the observed incidence of failures in the organisation's existing generator transformer population, one of the largest generator transformers was expected to fail every 0.7 years! Concern was expressed by management that many of the observed failures occurred in early life and the question was asked as to why works testing had not detected incipient weakness in these transformers. Not surprisingly, management demanded that as a matter of urgency measures should be put in hand to remedy the situation and, logically, one arm of the strategy was to devise and implement a regime of more effective testing. The next problem, then, was to set about establishing this more effective testing.

To do this, it is reasonable to start by considering how the transformer is likely to fail. There are, of course, many failure mechanisms for something as involved as a large transformer, but from an assessment of the failures experienced it could be concluded that these are likely to fall into one of three classes:

- Insulation will break down under the influence of the applied voltage stress.
- Insulation will be prematurely aged, due to overheating.
- Windings will suffer mechanical failure, due to inability to withstand the applied forces.

Since failure mechanisms are often complex, some of these were difficult to classify, being possibly due to a combination of more than one of the above causes. Overheating, for example, especially if not too severe, often will not itself cause failure, but will reduce the mechanical strength of the insulation, so that when the transformer is subjected to some mechanical shock, such as a system fault close to the terminals, it will then fail. It is possible, too, that inadequate mechanical strength, on occasions, allowed movement of conductors which reduced electrical clearance so that electrical breakdown actually caused failure. Common among many of the failure modes was an area of localised overheating due to poor joints, high leakage flux or inadequate local cooling.

Even though failure modes are not always straightforward, the study provided a basis for objective discussion of appropriate methods of testing and the next step was to consider existing tests and identify their shortcomings in the light of the experience gained.

Power-frequency overvoltage tests

The traditional approach towards demonstrating that insulation will not be broken down by the applied voltage has been to apply a test voltage which is very much greater than that likely to be seen in service. This is the philosophy behind the overpotential test, described above, which involves the application of twice normal voltage. Traditionally this was applied for one minute, but BS 171 now allows this to be for a period of 120 times the rated frequency divided by the test frequency (in seconds), or 15 s, whichever is the greater. The test frequency is increased to at least twice the nominal frequency for the transformer to avoid overfluxing of the core and is often of the order of 400 Hz, so that test times of 15 to 20 seconds are the norm. As explained above, this test is thought by many to be a very crude one akin to striking a test specimen with a very large hammer and observing whether or not it breaks.

Considerable thought has therefore been applied in recent times in many quarters to improving this test and this was the process which brought about by the introduction of partial-discharge measurements during the application of overvoltage as described for the IEC Method 2 test in the previous section. However, in the CEGB at that time it was not considered that the degree of overvoltage to be applied should be reduced in the way this was done for the standard Method 2 overpotential test. At a time of recognising poor transformer reliability it does not seem appropriate to reduce test levels. In addition, as has been indicated above, it was not felt that sufficient was known about the levels of partial discharge which might be indicative of possible premature failure. In fact, it has proved to be the case that some manufacturers' designs regularly achieve very much lower partial discharge levels than those of other manufacturers so the establishment of acceptance/rejection limits would be very difficult. Hence it was decided to retain the existing BS overpotential tests levels (i.e. those appropriate for Method 1), but to specify the monitoring of partial discharge as a means of learning as much as possible from the induced overvoltage test.

Discharge measurements are made at the HV terminal of the winding under test during the raising and the lowering of the voltage. These are recorded at 1.2 times and 1.6 times nominal working voltage to earth. At the time that this test method was developed, CEGB engineers favoured the measurement of Radio Interference Voltage (RIV), measured in microvolts, as a convenient means of detecting and quantifying partial discharge. This method has since tended to have been dropped in favour of the system described earlier, which, it is claimed, is absolute in that it gives a value in picocoulombs which is indicative of the actual quantity of discharge which is taking place. Unfortunately there is no simple relationship between microvolts and picocoulombs. CEGB specified that for their test the RIV measured at 1.2 times nominal volts should not exceed 100 microvolts including background. Background was to be measured before and after the test and was not to exceed 25 microvolts. The figure of 100 microvolts was recognised as not a very exacting one. Should this be exceeded at only 1.2 times nominal volts it was considered that there would be little doubt that all was not well with some part of the insulation structure.

Very occasionally, partial-discharge measurements made in this way can give a warning preceding total failure and the test voltage can be removed before complete breakdown, thus avoiding extensive damage. More often, however, the diagnosis is less clear-cut. It could be that measurements taken as the test voltage is being reduced indicate a tendency towards hysteresis, i.e. the discharge values for falling voltage tend to be greater than those measured as the voltage was increased. This could indicate that application of the test voltage has caused damage. As the overvoltage is reduced, the discharge should fall to a low level, ideally considerably less than the specified 100 microvolts, by the time the voltage has fallen to a safe margin above the normal working level, hence the specification of the value at 1.2 times normal volts. During the 13 years of the author's involvement with this means of testing, up to the end of the CEGB's existence upon privatisation, only one unit is on record as having been rejected on test on the strength of this partial-discharge measurement alone. Much more numerous were the occasions on which manufacturers withdrew units from test in order to investigate high levels of partial discharge occurring at voltages much nearer to the full overpotential level.

A further point to be noted is that, while the induced overvoltage test is usually thought of as a 'twice normal voltage' test, for very high-voltage transformers with non-uniform insulation, the way it is customarily carried out in the UK it can be even more severe than this. *Figure 5.42(a)* shows the arrangement for carrying out the induced overvoltage test on a 400 kV transformer having non-uniform insulation on the star-connected HV winding and a delta-connected LV winding. The test supply is taken from a single-phase generator connected to each phase of the LV in turn. The diagram shows the arrangement for testing phase A. In accordance with BS 171, Clause 11.3 and Table IV (and included in *Table 5.1* of this chapter), a voltage of 630 kV to earth must be induced at the line terminal. BS 171 does not specify on which tapping the transformer should be connected and so the manufacturer usually opts for position 1 which corresponds to maximum turns in circuit in the HV winding. This might be the +6.66% tap for a generator transformer, which could correspond to 460.5 kV for a transformer having an open-circuit voltage

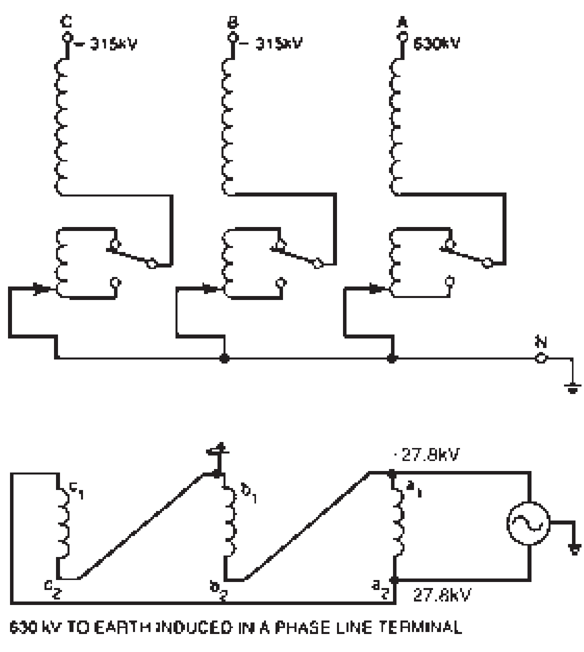


Figure 5.42(a) Arrangement of induced overvoltage test on a three-phase star/delta 400/23.5 kV generator transformer

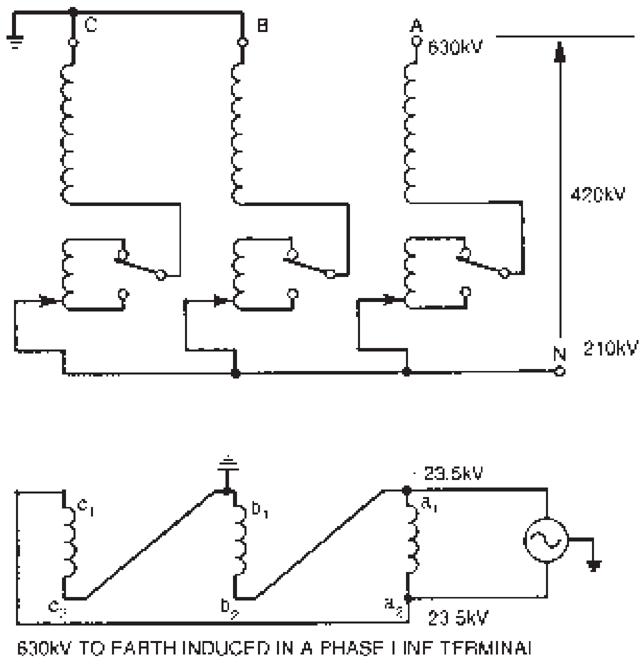


Figure 5.42(b) Distribution of test voltages with B & C phase terminals earthed and HV neutral disconnected from earth

of 432 kV on the principal tap. This is the line voltage, so the phase voltage appropriate to position 1 is $460.5/\sqrt{3} = 265.8$ kV: the test voltage of 630 kV induced in this winding therefore represents 2.37 times the normal volts/turn.

The necessity for carrying out the test as described above arises because of the need to retain the neutral connection to earth due to the very modest test level specified for the neutral when non-uniform insulation is used (BS 171, Clause 5.5.2 specifies 38 kV test, CEGB practice was to specify 45 kV). If the voltage on the neutral can be allowed to rise to about one-third of the specified test level for the line terminal then the minimum test requirements can be met by carrying out the test using the arrangement shown in *Figure 5.42(b)*. With this arrangement the neutral earth connection is removed and the line terminals of the two phases not being tested are connected to earth. An induced voltage of exactly twice normal volts for a 400 kV transformer would result in a minimum voltage of 420 kV in the phase under test on any tapping higher than −9% with the neutral being raised to 210 kV, and the line terminal of the phase under test is raised to 630 kV as specified.

The test voltage of 210 kV for the neutral is, of course, rather high to obtain the full benefit of non-uniform insulation, so the advantage to be gained from this test method for 400 kV transformers might not be considered worthwhile; however, for 132 kV transformers tested at 230 kV the neutral will be raised to a more modest 77 kV. At this level, the neutral is unlikely to need more insulation than what would be required for mechanical integrity, except possibly a higher voltage class of neutral terminal and it is possible to install a suitable terminal on a temporary basis simply for the purpose of carrying out the induced overvoltage test.

Choice as to the method of carrying out the induced overvoltage test ultimately resides with the purchaser of the transformer. Clearly, if the customer considers that high integrity and long life expectancy are his priorities then a test method which involves the application of 2.4 times normal voltage is likely to be more attractive than one at a mere twice normal.

It will be seen from *Figure 5.42(a)* that during the induced overvoltage test, although all parts of the windings experience a voltage of more than twice that which normally appears between them, that section of the winding which is nearest to earth is not subjected to a very high-voltage to earth. This is so even for fully insulated windings which, when tested, must have some point tied to earth. It is therefore necessary to carry out a test of the insulation to earth (usually termed 'major insulation' to distinguish this from interturn insulation) and, for a fully insulated winding, this is usually tested at about twice normal volts. For a winding having graded insulation, the test is at some nominal voltage; for example, for 400, 275 and 132 kV transformers, it is specified as 38 kV in BS 171.

In addition to partial-discharge measurement, another diagnostic technique for detection of incipient failure introduced by the CEGB has in recent years become increasingly recognised: this is the detection and analysis of dissolved gases in the transformer oil. This was initially regarded as applicable only to transformers in service. When partial discharge or flashover or excessive heating takes place in transformer oil, the oil breaks down into hydrocarbon gases. The actual gases produced and their relative ratios are dependent on the temperature reached. This forms the basis of the dissolved-gas analysis technique which is described in greater depth in Section 7 of Chapter 6. When faults occur during works tests, the volumes of the gases produced are very small and these diffuse through very large quantities of oil. Although the starting condition of the oil is known and its purity is very high, very careful sampling and accurate analysis of the oil is necessary to detect these gases. Analysis is assisted if the time for the test can be made as long as possible, and this was the philosophy behind the three-hour overpotential test which was introduced by the CEGB in the early 1970s as another of the measures aimed at improving generator transformer reliability. It must be emphasised that this test is carried out in addition to the 'twice normal volts' test. 130% of normal volts is induced for a period of three hours. In order that the magnetic circuit, as well as the windings, receives some degree of overstressing, the test frequency is increased only to 60 Hz rather than the 65 Hz which would be necessary to prevent any overfluxing of the core. Partial-discharge levels are also monitored throughout the three hours. Oil samples for dissolved-gas analysis are taken before the test, at the midway stage and at the conclusion.

Impulse tests differ from power-frequency tests in that, although very large test currents flow, they do so only for a very short time. The power level is therefore quite low and the damage done in the event of a failure is relatively slight.

If a manufacturer suspects that a transformer has a fault, say from the measurement of high partial discharge during the overpotential test, he may prefer to withdraw the transformer from this test and apply an impulse test which, if an insulation fault is present, will produce a less damaging breakdown. On the other hand, the very fact that damage tends to be slight can make the location of an impulse test failure exceedingly difficult. Diagnosis of impulse test failures can themselves be difficult, since sometimes only very slight changes in the record traces are produced. For further information on impulse testing and diagnosis techniques the reader is referred to IEC Publication 722 *Guide to the lightning impulse and switching impulse testing of power transformers and reactors* or any other standard textbook on the subject.

Load-current runs

The second possible mode of transformer failure identified earlier in this section is premature ageing of insulation due to overheating. It was therefore considered important that the opportunity should be taken to investigate the thermal performance of the transformer during works testing as fully as possible, in an attempt to try to ensure that no overheating will be present during the normal service operating condition.

Conventional temperature rise tests, for example, in accordance with BS 171, are less than ideal in two respects:

- They only measure *average* temperature rises of oil and windings.
- By reducing the cooling during the heat-up period, manufacturers can shorten the time for the test to as little as 8 or 10 hours.

Such tests will have little chance of identifying localised hot spots which might be due to a concentration of leakage flux or an area of the winding which has been starved of cooling oil. The CEGB approach to searching out such possible problems was to subject the transformer to a run during which it should carry a modest degree of overcurrent for about 30 hours. The test was specified as a period at 110% full-load current, or a current equivalent to full-load losses supplied, whichever is the greater, for 12 hours at each extreme tap position, with each 12 hours commencing from the time at which it reaches normal working temperature. Also, during this load-current run, the opportunity can be taken to monitor tank temperatures, particularly in the vicinity of heavy flanges, cable boxes and bushing pockets, and heavy current bushings. Both extremes of the tapping range are specified since the leakage flux pattern, and therefore the stray loss pattern, is likely to vary with the amount and/or sense of tapping winding in circuit. Oil samples for dissolved-gas analysis are taken before the test and at the conclusion of each 12-hour run as a further aid to identification of any small areas of localised overheating. If the transformer is the first of a new design, then gradients, top oil and resistance rises are measured in accordance with the specified temperature rise test procedure of BS 171. However, the main purpose of the test is not to check the guarantees but to uncover evidence of any areas of overheating should these exist.

Short-circuit testing

It is in relation to short-circuit performance and the demonstration that a transformer has adequate mechanical strength that the customer is in the weakest position. Yet this is the third common cause of failure listed at the beginning of this section. Section 7 of Chapter 4 describes the nature of the mechanical short-circuit forces and makes an estimate of their magnitude. However, for all but the smallest transformers, the performance of practical tests is impossible due to the enormous rating of test plant that would be required. IEC 76-5 deals with the subject of ability to withstand both thermal and mechanical effects of short-circuit. This it does under the separate headings of *thermal* and *dynamic* ability.

For *thermal ability*, the method of deriving the r.m.s. value of the symmetrical short-circuit current is defined, as is the time for which this is required to be carried, and the maximum permissible value of average winding temperature permitted after short-circuit (dependent on the insulation class). The method of calculating this temperature for a given transformer is also defined. Thus this requirement is proved entirely by calculation.

For the latter, it is stated that the *dynamic ability* to withstand short-circuit can only be demonstrated by testing; however, it is acknowledged that transformers over 40 MVA cannot normally be tested. A procedure for testing transformers below this rating involving the actual application of a short-circuit is described. Oscillographic records of voltage and current are taken for each application of the short-circuit and the assessment of the test results involves an examination of these, as well as an examination of the core and windings after removal from the tank. The Buchholz relay, if fitted, is checked for any gas collection. Final assessment on whether the test has been withstood is based on a comparison of impedance measurements taken before and after the tests. It is suggested that a change of more than 2% in the measured values of impedance are indicative of possible failure.

This leaves a large group of transformers which cannot be tested. Although this is not very satisfactory, service experience with these larger transformers over a considerable period of time has tended to confirm that design calculations of the type described in the previous chapter are producing fairly accurate results. Careful examination of service failures of large transformers, especially where there may be a suspicion that short-circuits have occurred close to the transformer terminals, can yield valuable information concerning mechanical strength as well as highlighting specific weaknesses and giving indication where weaknesses may be expected in other similar designs of transformer. For large important transformers which cannot be tested for short-circuit strength, there is no better method of assessing their capability than carrying out a critical review of manufacturers' design calculations questioning the assumptions made and seeking reassurance that these follow the manufacturers' own established practices proven in service. Where, by virtue of extending designs beyond previously proven ratings, it is necessary to make extrapolation, then such extrapolation should be clearly identified and the basis for this fully understood.

5.4 TRANSPORT, INSTALLATION AND COMMISSIONING

Transport

Generator transformers and 400 kV interbus transformers are among the largest and heaviest single loads to be transported in the UK. Unlike in the case of many of the countries of continental Europe, these are invariably transported by road. Transport considerations will therefore have a considerable bearing on their design and more will be said on this aspect in the sections dealing specifically with these transformers in Chapter 7. For many other large transformers (grid bulk-supplies transformers, power-station and unit transformers, primary distribution transformers), it is usually only necessary to ship these without oil to ensure that they are comfortably within the appropriate transport limits, although it is necessary to check that when mounted on the transport vehicle the height is within the overbridge clearances which, for trunk roads within the United Kingdom, allows a maximum travelling height of 4.87 m (16 feet).

If the tank has been drained for transport, it is necessary for the oil to be replaced either by dry air or nitrogen, which must then be maintained at a slight positive pressure above the outside atmosphere to ensure that the windings remain as dry as possible while the oil is absent. This is usually arranged by fitting a high-pressure gas cylinder with a reducing valve to one of the tank filter valves and setting this to produce a slow gas flow sufficient to make good the leakage from the tank flanges. A spare cylinder is usually carried to ensure continuity of supply should the first cylinder become exhausted.

Transporters for the larger transformers consist of two beams which span front and rear bogies and allow the tank to sit between them resting on platforms which project from the sides of the tank. Thus the maximum travelling height is the height of the tank itself plus the necessary ground clearance (usually taken to be 75 mm but capable of reduction for low bridges). *Figure 5.43* shows a 267 MVA single-phase transformer arranged for transport.

Smaller transformers, i.e. primary distribution transformers having ratings of up to 30 MVA, can usually be shipped completely erected and full of oil.

Installation and site erection

In view of their size and weight, most transformers present special handling problems on site. The manufacturer in his works will have crane capacity, possibly capable of lifting up to 260 tonnes based on transport weight limit including vehicles of 400 tonnes, the normally permitted maximum for UK roads, but on-site such lifts are out of the question except in the turbine hall of

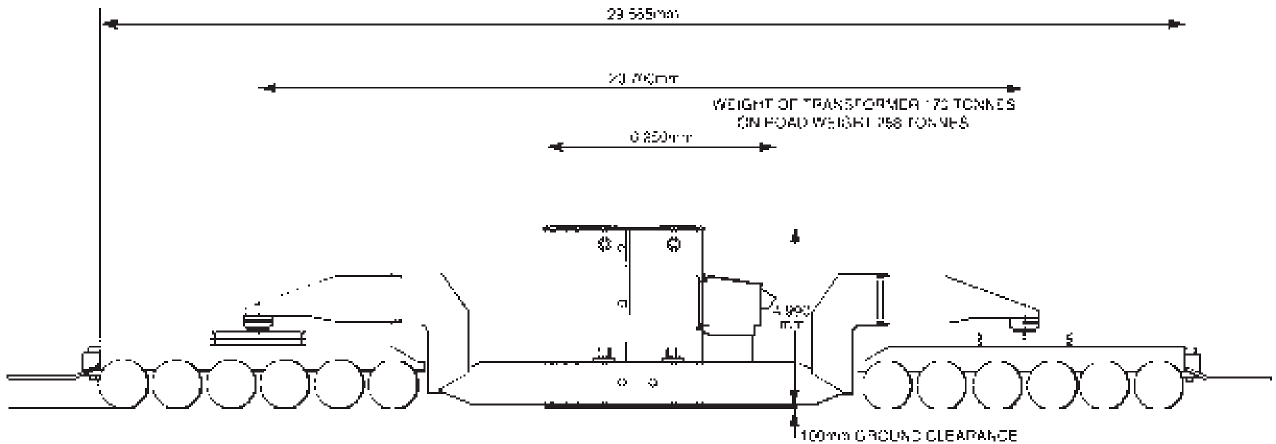


Figure 5.43 Transport arrangements for a 267 MVA single-phase generator transformer

a power station where a permanent crane will probably have been installed for lifting the generator stator and rotor. Site handling is therefore difficult and must be restricted to the absolute minimum. The transformer plinth should be completed and clear access available, allowing the main tank to be placed directly onto it when it arrives on site. A good access road must also be available, as well as the surface over any space between access road and plinth. Transformer and vehicle can then be brought to a position adjacent to the plinth. The load is then taken on jacks and the transport beams removed. Then, using a system of packers and jacks, the tank is lowered onto a pair of greased rails along which it can be slid to its position over the plinth. The required position of the tank on the plinth must be accurately marked, particularly if the transformer is to mate up with metal-clad connections on either the LV or HV side.

When the tank is correctly positioned on the plinth it must then be carefully examined for any signs of damage or any other indication that it might have been mishandled during transport. Any special provisions by way of protection applied during transport must be removed. If additional clamping has been applied to the core and windings for transport, this must be released or removed according to the instruction manual. The coolers and pipework, if they have been removed for transport, are installed. Bushings and turrets which will probably also have been removed for transport are fitted and connected, requiring the removal of blanking plates giving access to the tank. Such opening of the tank must be kept to a minimum time, to reduce the possibility of moisture entering the tank; to assist in this, manufacturers of large high-voltage transformers provide equipment to blow dry air into the tank and thus maintain a positive internal pressure. If the transformer has been transported with the tank full of nitrogen, it is necessary to purge this fully with dry air if anyone has to enter the tank.

When all bushings have been fitted, access covers replaced, and conservator and Buchholz pipework erected, any cooler bank erected and associated pipework installed or tank-mounted radiators fitted, preparations can begin for filling with oil. Even if the transformer is not required for service for some months, it is desirable that it should be filled with oil as soon as possible and certainly within three months of the original date of draining the oil in the factory. If it is being kept in storage for a period longer than three months at some location other than its final position, it should similarly be filled with oil.

Oil filling and preparation for service

The degree of complexity of the preparation for service depends on the size and voltage class of the unit. Modern 400 kV transformers, and to a slightly lesser extent those for 275 kV, are designed and constructed to very close tolerances. The materials used in their construction are highly stressed both electrically and mechanically, and to achieve satisfactory operation extensive precautions are taken in manufacture, particularly in respect of insulation quality. This quality is achieved by careful processing involving extended vacuum treatment to remove moisture and air followed by filling with high-quality oil as described in the previous chapter. Treatment on site must be to a standard which will ensure that the same high quality of insulation is maintained.

132 kV transformers and those for lower voltages generally do not require the same high processing standards and in the following description, which is related to the highest voltage class of transformers, an indication will be given of where procedures may be simplified for lower voltage units.

After completion of site erection, a vacuum pump is applied to the tank and the air exhausted until a vacuum equivalent to between 5 and 10 mbar can be maintained. If this work is carried out by the transformer manufacturer, or his appointed subcontractor, there will be no doubt as to the ability of the tank to withstand the applied vacuum. In all other cases the manufacturer's instruction manuals must be consulted as to permitted vacuum withstand capability. Some transformer tanks are designed to have additional external stiffeners fitted to enable them to withstand the vacuum. If this is the case a check should be made to ensure that these are in place. If the transformer has an externally mounted tapchanger it is likely that the barrier board separating this from the main tank will not withstand the vacuum. Any manufacturer's instructions for equalising the pressure across this board must also be noted and carefully observed. For transformers rated at 132 kV and below it is likely that the vacuum withstand capability of the tank will be no more than 330 mbar absolute pressure.

When a new 400 kV transformer is processed in the factory as described in the previous chapter, the aim is to obtain a moisture content in the cellulose insulation of less than 0.5%. When an oiled cellulose insulation is exposed to atmosphere, the rate of absorption of moisture depends on the relative humidity of the atmosphere, and a general objective of manufacturers of 400 kV transformers is that insulation should not be exposed for more than 24 hours at a humidity of 35% or less. Pro rata this would be 12 hours at 70% relative humidity. During this time the moisture would be absorbed by the outer surfaces of the insulation; increased exposure time causing gradual migration of the moisture into the inner layers. It is relatively easy, if a sufficiently high vacuum is applied, to remove moisture from the outer surfaces of the insulation, even if the outer surface content may be as high as 10%.

However, once moisture has commenced migration into the intermediary layers of the insulation, although a high vacuum would quickly dry the outer layers, time is then required at the highest vacuum attainable to pull the moisture from the inner layers to the surface and out of the insulation. It must be noted also that on exposure, air is being absorbed into the oil-soaked insulation at an equivalent rate to the moisture absorption, and that any air voids remaining after oil filling and processing could initiate partial discharges and subsequent breakdown. This is the reason for the recommendation, given above, that if the transformer is to be put into storage, it should not be left without oil for a period longer than three months. While left without oil, even if filled with dry air or nitrogen, that oil which remained in the windings initially will slowly drain out of these, leaving voids which will require many hours of high vacuum to remove the gas from them to be replaced by the oil when the transformer is finally filled.

Provided the appropriate procedures have been observed during the site erection, the amount of moisture entering the insulation during the period of site erection will have been small and its penetration will largely have been restricted to the outer layers. However, even then, the length of time required for the maintenance of vacuum is not easily determined, and, if possible the manufacturer's recommendations should be sought and followed. A vacuum of 5 mbar should be maintained for at least 6 hours before oil filling, many authorities would suggest a figure of not less than 12 hours.

Heated, degassed and filtered oil is then slowly admitted to the bottom of the tank in the same way as was done in the works, until the tank is full. Since, despite all the precautions taken, some moisture will undoubtedly have entered the tank during site erection, the oil must then be circulated, heated and filtered until a moisture content of around 2 ppm by volume is achieved for a 400 or 275 kV transformer. For other transformers having a high-voltage of not greater than 132 kV, a figure of around 10 ppm is acceptable. More will be said about moisture levels in oil and insulation in Section 7 of Chapter 6.

If the windings have been exposed for a period of longer than 24 hours, or if there is any other reason to suspect that the insulation dryness obtained in the factory has been lost, for example loss of the positive internal pressure during shipment, then it is necessary to dry the unit out. Without the facilities which are available in the factory, this will be a very difficult and time-consuming process. The drying-out process is greatly assisted by any heating which can be applied to the windings and major insulation.

Drying out on site

Oil companies, transformer manufacturers and supply authorities have mobile filter plants and test equipment available to undertake the filling of transformers and any subsequent treatment. Modern practice for the drying of both oil and transformers tends to employ the method in which oil is circulated under vacuum in the oil treatment plant.

Heating, in addition to that supplied by the mobile plant, can be obtained by the application of short-circuit current and can be conserved by the use of lagging such as wagon sheets, sacking or other suitable material.

The temperature is controlled by thermostats incorporated in the mobile treatment plant heaters so that the oil cannot be overheated even in the event of any inadvertent reduction in flow. Interlocking systems control flows and levels to prevent flooding or voiding in either tank or plant.

The treatment units supplied by the oil companies usually incorporate a fully equipped laboratory manned by a chemist and capable of testing oil for electric strength, dielectric dissipation factor, resistivity, water content and air content as a routine. Other tests can be carried out if deemed necessary. The results of these tests carried out in a pattern according to the transformer to be processed can be plotted to show how the drying process is proceeding and its satisfactory completion.

Other tests, normally carried out by the electrical engineer, should include (a) insulation resistance between high-voltage and low-voltage windings and between each winding and earthed metal, and (b) temperature. These plotted with insulation resistance and also temperature as ordinates, against time as abscissae, give an indication of the progress of the drying-out operation.

There are three stages in the complete process. Firstly, the heating-up stage when the temperature is increasing from ambient to the recommended maximum for drying out and the insulation resistance of the windings is falling. Secondly, the longest and real drying period when the temperature is maintained at a constant level with the insulation resistance also becoming constant for a period followed by an increase indicating that nearly all the moisture has been removed. Thirdly, the cooling period, with the heating and circulation stopped, during which the normal equilibrium condition of the transformer is restored, with the temperature falling and insulation resistances increasing. Typical drying-out curves are shown in *Figure 5.44*.

Where mobile vacuum treatment plant is not available for site drying alternative methods need to be employed. These are the oil-immersed resistor heating and short-circuit methods which though less appropriate for large high-voltage transformers, can prove satisfactory if no alternative is available.

Oil-immersed resistor heating

This method consists of drying the transformer and oil simultaneously in the transformer tank. Suitable resistor units are lowered into the bottom of the tank in order to raise the oil temperature.

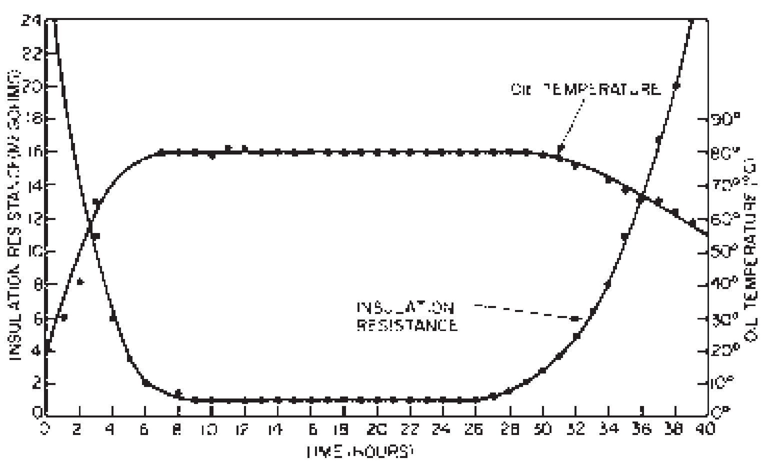


Figure 5.44 Drying out curves of a 500 kVA three-phase 50 Hz transformer

The tank should be filled with oil to the working level and the oil should be allowed to stand for an hour or so. The tank cover should be raised at least 30 mm, or, better still, removed altogether in order to allow perfectly free egress of the moisture vaporised during the drying-out process. In order to conserve the heat generated in the resistors the sides of the transformer tank should preferably be well lagged using, say, wagon sheets, sackings, or any similar coverings which may be available. The resistors should be spaced as symmetrically as possible round the inside of the tank in order to distribute the heat. During the drying-out process the top oil temperature should be maintained at a value not exceeding 85°C. It should be borne in mind that in the immediate vicinity of the resistor units the oil will be at a higher temperature than is indicated at the top of the tank, and consequently the temperature near the resistors is the limiting factor. The temperature may be measured by a thermometer immersed on the top layers of the oil.

During the drying-out process the following readings should be taken at frequent regular intervals:

(a) Insulation resistance between high-voltage and low-voltage windings and between each winding and earth.
(b) Temperature.
(c) Time.

There are three stages in the complete process. Firstly, the heating-up stage, which is of relatively short duration, when the temperature is increasing from the ambient to the recommended maximum for drying out and the insulation resistance of the windings is falling. Secondly, the longest and real drying period, when the temperature is maintained constant and the insulation resistance becomes approximately constant but starts to rise at a point towards the end of this period. Thirdly, which is again of short duration, when the supply to the resistors is cut off, the temperature falling, and the insulation resistance increasing.

Important notice. On no account should a transformer be left unattended during any part of the drying-out process.

Short-circuit method

This method is also used for:

(a) Drying out the transformer and oil simultaneously in the transformer tank.
(b) Drying the transformer only, out of its tank.

Dealing first with (a), the same initial precautions are taken as described earlier. The low-voltage winding is short-circuited, a low single-phase or three-phase voltage being applied to the high-voltage windings, and of a value approaching

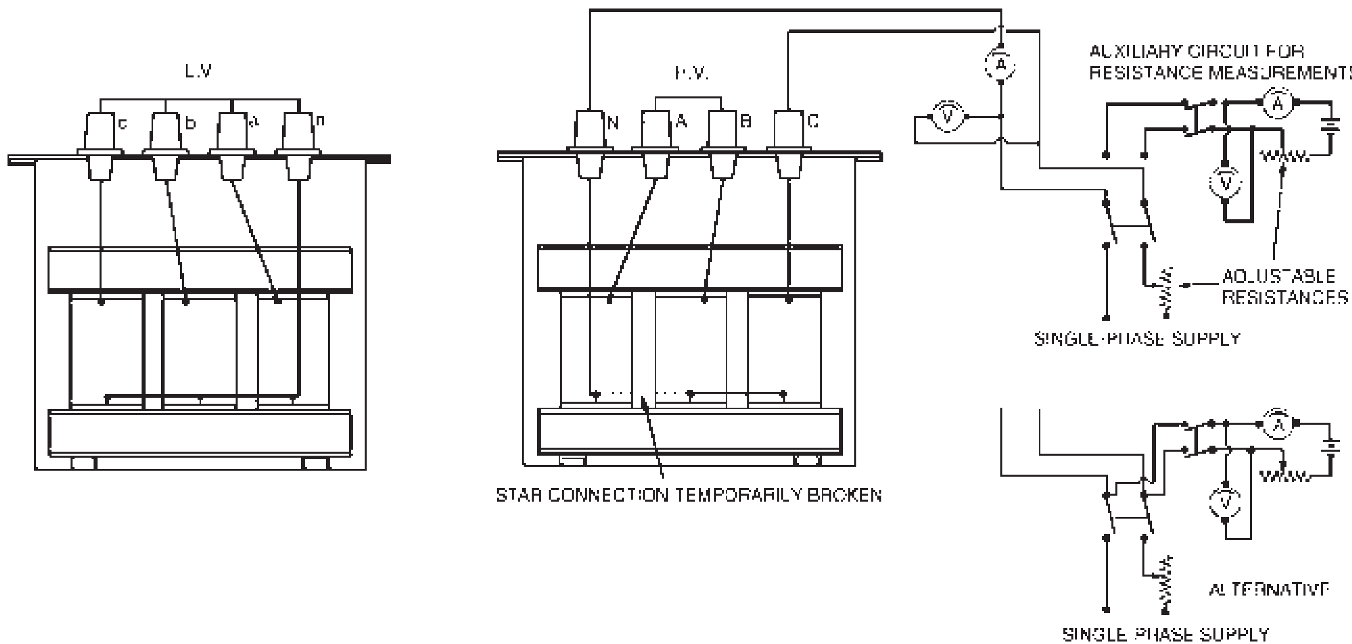


Figure 5.45 Connections for drying out a three-phase transformer
by the single-phase short-circuit method

the full-load impedance voltage of the transformer. If a suitable single-phase voltage only is available, the high-voltage windings should temporarily be connected in series, as shown in *Figure 5.45*. A voltmeter, ammeter and fuses should be connected in circuit on the high-voltage side. If the voltage available is not suitable for supplying the high-voltage winding, but could suitably be applied to the low voltage, this may be done and the high-voltage winding instead short-circuited. In this case special care must be taken to avoid breaking the short-circuiting connection as, if this is broken, a high-voltage will be induced in the high-voltage winding which will be dangerous to the operator.

The temperature should be measured both by a thermometer in the oil and, if possible, by the resistance of the windings. In the former case it is preferable to use spirit thermometers, but if mercury thermometers only are available, they should be placed outside the influence of leakage magnetic fields, as otherwise eddy currents may be induced in the mercury, and the thermometers will give a reading higher than the true oil temperature. The resistance measurements are taken periodically during the drying-out period. These measurements are made by utilising any suitable DC supply available, and *Figures 5.45* and *5.46* indicate the connections. If tappings are fitted to either winding the tapping selector or link device should be positioned so that all winding turns are in circuit during the drying-out process. The AC supply for heating the transformer is, of course, temporarily interrupted when taking DC resistance measurements.

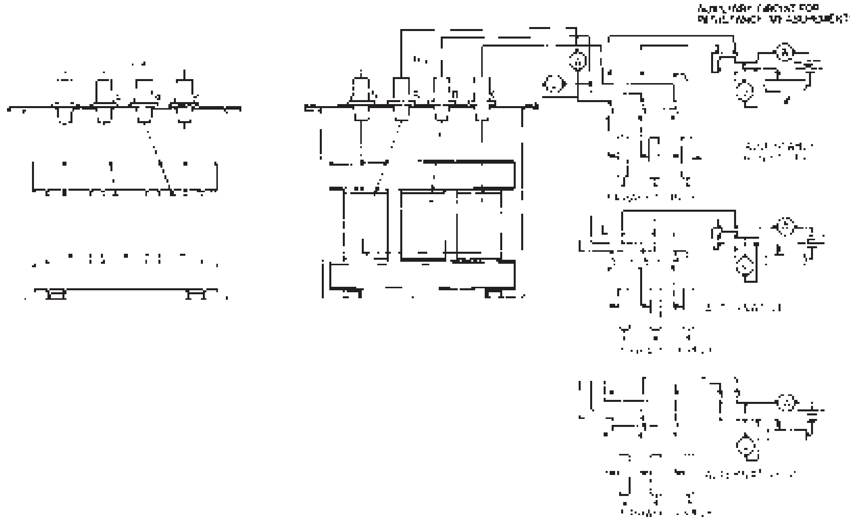


Figure 5.46 Connections for drying out a three-phase transformer by the three-phase short-circuit method

The temperature in °C corresponding to any measured resistance is given by the following formula:

$$T_2 = \frac{R_1}{R_2}(235 + T_1) - 235 \text{ for copper}$$

(*Note*: 235 becomes 225 for aluminium)

where T_2 = temperature of the windings when hot
T_1 = temperature of the windings when cold
R_2 = resistance of the windings when hot
R_1 = resistance of the windings when cold
Temperature rise of the windings is $T_2 - T_1$

The maximum average temperature of each winding measured by resistance should not be allowed to exceed 95°C. If it is not possible to take the resistance of the windings, the top oil temperature should not exceed 85°C.

Dealing next with (b), the transformer being dried out separately and out of its tank, the method is electrically the same as for (a), but the applied voltage must be lower. The transformer should be placed in a shielded position to exclude draughts, and the steady drying-out temperature measured by resistance must not exceed 95°C.

The value of drying-out currents will, of course, be less than when drying out the transformer in oil, but the attainment of the specified maximum permissible temperature is the true indication of the current required.

If the transformer has been stored on its plinth full of oil, it will also be necessary to erect the cooler and pipework and fill this with oil before it can go into service. Initially, any free-standing separate cooler should be filled with the main tank isolating valves closed and the oil circulated via a tank by-pass pipe to dislodge any small bubbles of air which can be vented via the cooler vent plugs. Normally, such a tank bypass would probably be installed by the manufacturer as a temporary fitment provided that he was given the responsibility for site installation, but it is a worthwhile practice to retain them as permanent features on large transformers so that the feature is readily available at any time in the future when work on the transformer necessitates any draining of the oil.

If tank-mounted radiators have been fitted at site so that these must be filled with oil, then they must be vented of all air before the valves connecting these with the main tank are opened.

The oil necessary to reach the minimum operating level can then be added via the conservator filling valve and, once the conservator is brought into operation, the breather should be put into service. If of the silica gel type, this should be checked to ensure it is fully charged with active material and that the oil seal is filled in accordance with the maker's instructions. If a refrigeration breather is supplied, as may be the case for transformers of 275 kV and above, this needs an auxiliary power supply which should, if necessary, be supplied from site supplies, so that the breather can be made alive as soon as possible without waiting for the marshalling kiosk to be installed and energised.

Site commissioning

Transport to site could well have involved a journey of many hundreds of miles, part possibly by sea. The transformer will have had at least two lots of handling. There is, however, very little testing which can be done at site which can demonstrate that it has not suffered damage. It is therefore vital that such tests as can be carried out at site should be done as thoroughly and as carefully as possible. These may include:

- Ratio measurement on all taps.
- Phasor group check.
- Winding resistance measurements on all taps.
- Operation of tapchanger up and down its range. Check the continuity of tapped winding throughout the operation.
- Insulation resistance between all windings and each winding to earth. Insulation resistance core-to-earth, core-to-frame and core frame-to-earth.
- No-load current measurement at reduced voltage; very likely this will be done at 415 V and compared with the current obtained at the same voltage in the works.
- Oil samples taken and checked for breakdown strength and moisture content. For a large, important transformer for which the oil is to be tested periodically for dissolved-gas content (see Section 7 of Chapter 6), this sample would also be checked for gas content and taken as the starting point.
- All control, alarms, protection and cooler gear checked for correct operation. Alarm settings and protection trips set to appropriate level for initial energisation.
- Tank and cooler earth connections checked as well as the earthing of the HV neutral, if appropriate.

Insulators outside the tank should be cleaned with a dry cloth. The transformer tank and cover should be effectively earthed in a direct and positive manner while, in order to comply with any statutory regulations, the low-voltage neutral point of substation and similar transformers should also be earthed.

In unattended substations it is an advantage to fit each transformer with a maximum indicating thermometer, so that a check can be kept upon the temperature rise.

The setting of alarms is dependent on local ambient and loading conditions, but is usually based on the BS maximum oil temperature rise of 60°C. Alarm thermometers, which depend upon oil temperature, might be set at 85 and 90°C respectively to take account of the inherent time lag between maximum and top oil temperatures. Winding temperature indicators, which more closely follow variations of winding temperature, are used for all large transformers and might have a warning alarm set at 105°C and a trip at 110°C: these values are similarly subject to local ambient and loading conditions. (Selection of settings for oil and winding temperature alarms and trips is discussed in greater depth in Section 8 of Chapter 6 which deals with effects of sustained abnormal operating conditions.)

It must be borne in mind that there will be a temperature gradient between the actual maximum temperature of the copper conductors and that registered in the top of the oil, the former, of course, being the higher. This accounts for the differences suggested between the permissible continuous temperature and the alarm temperatures.

Protection settings may be set to a lower level than the recommended permanent settings for the initial energisation.

If the transformer is not required to operate in parallel with other transformers, the voltage may now be applied. It is desirable to leave the transformer on no-load for as long a period as possible preceding its actual use, so that it may be warmed by the heat from the iron loss, as this minimises the possible absorption of moisture and enables any trapped air to be dispelled by the convection currents set up in the heated oil. The same objective would be achieved by switching in directly on load, but for transformers fitted with gas-actuated relay protection the supply may be interrupted by the dispelled gas from the oil actuating the relay, which could then trip the supply breaker.

If, however, the transformer has to operate in parallel with another unit, it should be correctly phased in, as described in the chapter dealing with parallel operation, before switching on the primary voltage. It is essential that the secondary terminal voltages should be identical, otherwise circulating currents will be produced in the transformer windings even at no-load. Transformers of which the ratings are greater than three to one should not be operated in parallel.

Switching in or out should be kept to an absolute minimum. In the case of switching in, the transformer is always subject to the application of steep-fronted travelling voltage waves and inrush current, both of which tend to stress the insulation of the windings, electrically and mechanically, so increasing the possibility of ultimate breakdown and short-circuit between turns. From the point of view of voltage concentration it is an advantage, wherever possible, to excite the transformers from the low-voltage side, although, on the other hand, the heaviest inrush current are experienced when switching in on the low-voltage side. The procedure adopted will therefore be one of expediency, as determined from a consideration of voltage surges and heavy inrush current. If the protection settings have been put to a lower level for initial energisation, these should be returned to their recommended values for permanent service.

Installation of dry-type transformers

Compared with its oil-filled counterpart, installation of a dry-type transformer is a very much simpler operation. Many of the aspects to be considered are, however, similar.

The unit must first be carefully examined to ensure that it has not sustained damage during shipment. This task is made simpler than for an oil-filled unit in that the core and coils themselves are visible. Leads and busbars, however, do not have the benefit of a steel tank for protection. Off-loading and handling on site represent particularly hazardous activities for these components so it is important to ensure that these are all intact on completion of this operation. The exterior of all windings must be unmarked and windings must be securely located. It is likely that the transformer will be installed inside a sheet-steel enclosure. If so, this must be firmly bolted down and the unit correctly located and secured within the enclosure so that all electrical clearances are correctly obtained.

The following electrical checks should be made before any connections are made to the transformer:

- Insulation resistance, between all windings and each winding to earth.
- Voltage ratio on all taps.
- Phasor group check.

On satisfactory completion of checks to prove the electrical integrity of the transformer the electrical connections may be installed. If this activity is likely to take some time, arrangements should be made to keep the transformer clean, warm and dry in the intervening period. Connections could involve links to the HV terminals from a cable terminating box on the outside of the transformer enclosure, or direct connection of HV cable tails to the HV winding terminals. Low-voltage connections will very likely be direct to the busbars of the incoming circuit breaker of a distribution switchboard. Following completion of the connections, repeat HV and LV insulation resistance measurements to earth should be carried out, bonding of the core and core frame to the switchgear earth should be verified and correct operation of any control and/or protective devices should be proven. The appropriate tap position should be selected on any off-circuit tapping selector. Protection trips should be set to the appropriate level for initial energisation.

When all electrical checks have been satisfactorily concluded, preparations can be made for closing the HV circuit breaker; all construction materials removed from the transformer cubicle, any temporary earths removed, covers replaced, doors closed to release any mechanical interlock keys for the HV breaker.

There is not the necessity to allow a period of ‘soak’ following initial energisation of a dry-type transformer as in the case of an oil-filled unit since there is no possibility of entrapped air needing to be released, or any other warming-up mechanism best carried out off-load. If the transformer is to operate in parallel with an existing supply it must be phased in across the LV circuit breaker in the same way as described for oil-filled units. When the LV circuit breaker has been closed the protection trips should be set to their specified running settings.

6 Operation and maintenance

6.1 DESIGN AND LAYOUT OF TRANSFORMER INSTALLATIONS

Outdoor substations

In planning a transformer layout there are a number of requirements to be considered.

All power transformers containing BS 148 oil are considered to represent a potential fire hazard and awareness of this must be a primary consideration when designing a transformer substation. They should be located in such a way that, should a transformer initiate a fire, this will be limited to the transformer itself and its immediate ancillary equipment and not involve any other unit or equipment, cabling or services associated with any other unit. This requirement is particularly important if two or more transformers are to be installed in the same substation as standby to each other.

Fire hazard imposed by mineral oil-filled transformers

In having regard to the above recommendations it should be recognised that mineral oil is less of a fire hazard than is often thought to be the case. The closed flash point (see Section 5 of Chapter 3) is specified as not lower than 140°C, that is, it shall not be possible to accumulate sufficient vapour in an enclosed space to be ignited upon exposure to a flame or other source of ignition at temperatures below this figure. In non-enclosed spaces the temperature will be proportionally higher. It is generally considered that mineral oil needs a wick in order for it to produce sufficient vapour to enable it to burn freely. The incidence of fires involving transformers is small and continues to confirm work done some time ago when a review of UK electricity supply industry statistics carried out within the CEGB (and unpublished) suggested that the likelihood of a fire resulting from an incident involving a transformer below 132 kV is very low. This is probably because at the lower system voltages, fault levels and protection operating times are such that it is not possible to input sufficient energy in a fault to raise bulk oil temperature to the level necessary to support combustion. Provided the sensible precautions identified below are taken, therefore, mineral oil-filled transformers of 33 kV HV voltage and below can be installed within reasonable proximity of buildings and other plant without the need to resort to the use of fire resistant fluids, dry-type or cast resin-insulated transformers. Such measures only become necessary when transformers are installed inside buildings and indoor installations will be discussed separately below.

Where fires have been initiated in the past, it has usually been the case that a fault has occurred which has split the tank resulting in very rapid loss of the oil. If the site of the fault, at which, almost by definition, a high temperature will exist, is, as a result, exposed to the atmosphere ignition will occur and the transformer insulation will then serve as the wick to sustain the combustion. Again this emphasises that where the fault energy is not so high as to cause rupture of the tank, the fire risk is greatly reduced. Rapid fault clearance times will, of course, also reduce the energy input into the fault and adequate provision of pressure relief devices, i.e. more than one on a large tank, will reduce the risk of tank rupture. Consideration may be given to arranging that operation of the pressure relief device trips the transformer, but any resultant risk of spurious tripping will need to be balanced against a possible gain in respect of reduced fire risk.

Any potential low-energy ignition mechanism must also be guarded against. Typically this can occur where a fault causes a gradual drip or seepage of oil onto a heated surface. Such a situation may arise when an external bushing connection overheats due to a high contact resistance. If this reaches a temperature at which the thermal movement cracks a porcelain insulator so that oil leaks onto the overheated joint, this can be ignited and the continuing slow feed of oil can turn the area into a blow torch. One of the dangers of incidents of this type is that electrical protection is not initiated and the fault can remain undetected until the fire has reached a very serious level.

Minimising the fire hazard

The conventional practice for many years has been to provide a surface of chippings in substations containing oil-filled transformers and switchgear with a drainage sump so that any oil spilled will quickly be taken off the surface and thus prevented from feeding any fire resulting from a major fault. However, as a result of the UK Central Electricity Generating Board's investigations in the 1960s into a number of serious generator transformer fires, it became clear that chippings which had become oily over the years and had acquired a coating of grime, tended to provide the wick which, when a fire had been initiated, made this more difficult to extinguish.

Of course, in the case of isolated substations it is not always possible to provide an arrangement better than chippings, but the CEGB, following the above investigations, developed a system which proved very effective in preventing major fires following the type of incidents which had on earlier occasions given rise to them. This involves providing each transformer with a fixed waterspray fire protection installation. It consists of a system of spray nozzles located around the transformer and directed towards it which provide a total deluge when initiated, usually by the bursting of any one of a series of glass detector bulbs (frangible bulbs) in an air-filled detector pipe placed around and above the transformer. The whole installation is normally empty of water and when a detector bulb initiates the resultant air pressure drop releases a water control valve allowing water into the projector pipework and thence to the spray nozzles. As the water is normally maintained at a pressure of 8.5 bar it immediately begins to control the fire and back-up fire pumps are started to maintain the water supply pressure. An important part of the strategy for rapid extinguishing of a fire is the swift removal of any spilled oil from the surface of the plinth. When stone-covered sumps were provided this often resulted in any oil which had collected with time being washed back up to the surface due to the spray water displacing it. To avoid this, instead of chippings, the surface must be smooth concrete. Large drainage trenches are provided and these must have an adequate fall to a transformer oil collection and containment system.

Clearly large quantities of oil and water cannot be allowed to enter the normal stormwater drainage system, so the drainage trenches are taken to interceptor chambers which allow settlement and separation of the oil before allowing the water to be admitted to the normal stormwater drainage system. A typical arrangement shown in *Figure 6.1*. Although the plinths are designed to drain rapidly, it is important to ensure that any water which might be contaminated with oil is not allowed to flood into neighbouring areas, so each plinth must be contained within a bund wall which will hold, as a minimum, the total contents of the transformer tank, plus five minutes, operation of the fire protection, and this after heavy rain has fallen onto the area.

The system is costly in terms of civil works and it requires the availability of the copious quantity of water necessary to support the waterspray fire protection system, so it cannot normally be considered for other than transformers in power stations or important transformers in major transmission substations where such resource can be made available, but in these types of situations it is clearly the most effective method of dealing with the fire risk. Good housekeeping in transformer compounds is also of considerable benefit.

Oil containment

Even where the more traditional system of chippings and sump is used as a base for the transformer compound, consideration will need to be given to the

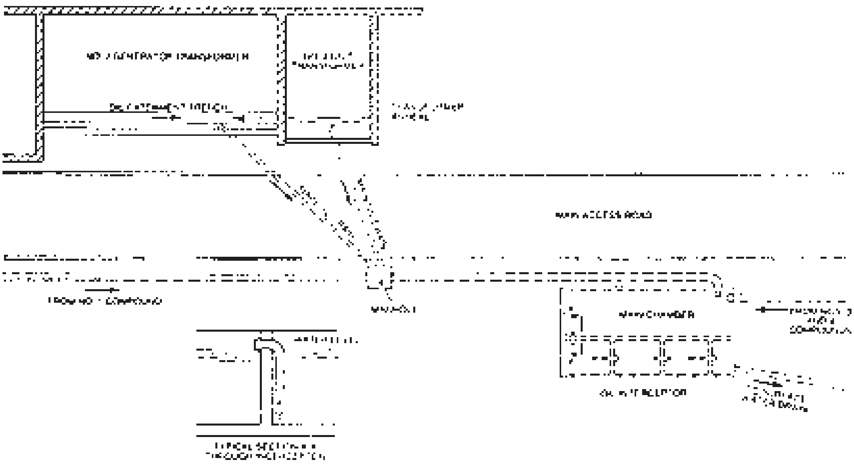


Figure 6.1 Arrangement of water and oil drains for transformer plinth

possibility of loss of all the oil from the transformer tank and its cooler. Suitable provision must be made to ensure that this will not enter drains or water courses. Such provision will normally be by means of a bund wall surrounding the transformer and its cooler which together with any sump must be capable of containing the total oil quantity in addition to the maximum likely rainfall over the area. Since the bunded area will under normal operating conditions need provision for stormwater drainage, then suitable oil interception arrangements must be made for separation and holding any oil released.

Segregation and separation

Where it is not economic to consider the type of elaborate measures described above, then other design features must be incorporated to allow for the possibility of fire. Such features involve segregation or separation of equipment.

Separation involves locating the transformer at a safe distance from its standby, where one is provided, or any other plant and equipment which must be protected from the fire hazard. A distance of 10 metres is usually considered to be sufficient. This means that not only must the transformer be a minimum of 10 metres from its standby, but all connections and auxiliary cabling and services must be separated by at least this distance.

On most sites such an arrangement will be considered too demanding of space, so this leads alternatively to the use of a system of *segregation,* which relies on the use of fire-resistant barriers between duty and standby plant and all their associated auxiliaries. The integrity of the barrier must be maintained regardless of how severe the fire on one transformer or of how long the fire persists. In addition the barrier must not be breached by an explosion in one of the transformers, so it will normally be necessary to construct it from reinforced concrete and of such an extent that flying debris from one transformer cannot impinge on any equipment, including bushings, cables, cooler and cooler pipework or switchgear associated with its standby. Generally for access reasons transformers should be at least 1 metre from any wall but this space may need to be increased to allow for cooling air as described below.

Other considerations for substation layout

In addition to the requirements to preserve the integrity of standby from duty plant and vice versa as outlined above, an important consideration when arranging the layout of a transformer substation is that of ensuring correct phase relationships. The need for these to be correct to enable transformers to be paralleled is discussed further in Section 4 of this chapter. Every site should have a supply system phasing diagram prepared showing incoming circuits and plant within the site. Although the principles are very simple errors are found during commissioning with surprising regularity. It greatly helps the avoidance of such errors to rigorously adhere to a convention when arranging the layout of a transformer. Low-voltage cables between transformer and switchgear can be transposed to enable these to appear in the correct sequence at the switchboard, but it is not always easy to transpose HV overhead connections or metal-clad phase-isolated busbars, so the transformer should always be positioned in such a way as to allow these to run in the correct sequence and connect directly to its terminals without any requirement for interchanging phases. In the UK the convention is that the phase sequence when viewed from the HV side of the transformer is A,B,C left to right. This means that viewed from the LV side the phase sequence will run c,b,a left to right or a,b,c right to left. If there is a neutral on HV or LV, or both, these may be at either end but they must be shown on the transformer nameplate in their correct relationship with the line terminals. Phasor relationships are referred to the HV side of the transformer with A phase taken as the 12 o'clock position. Phasors are assumed to rotate anticlockwise in the sequence A,B,C.

In the concluding section of the previous chapter it was explained that movement of a large transformer on site is a difficult process. In designing the substation layout, therefore, another important factor is that of access for the transformer and its transporter. Small transformers up to, say, 25 tonnes might be lifted from the transporter using a mobile crane and set down in the correct orientation directly onto their foundations. However, most will require to be manoeuvred by means of jacks and greased rails into their correct position. Allowance must therefore be made for positioning of the transporter adjacent to the raft in the best position for carrying out this operation, and appropriately located anchor points must be provided for haulage equipment. Of course, although transformers are extremely reliable items of plant, they do occasionally fail, so that allowance should also be made for possible future removal with minimum disturbance to other equipment in the event of the need for replacement.

In planning the layout of the transformer substation, except where the transformers are water cooled, consideration should also be given to the need for dissipation of the losses. Whether radiators are tank mounted or in separate free-standing banks there must be adequate space for circulation of cooling air. If the cooler is too closely confined by blast walls and/or adjacent buildings it is possible that a recirculation system can be set up so that the cooler is drawing in air which has already received some heating from the transformer. Ideally the cooler, or the transformer and its radiators if these are tank mounted, should have a space on all sides equal to its plan dimensions.

Figure 6.2 shows a typical two-transformer substation layout having consideration for the above requirements and with the appropriate features identified.

Transformers in buildings

Although all the recent experience and evidence emphasise the low fire risk associated with oil-filled power transformers, particularly those having an HV voltage below 33 kV and a rating of less than, say, 10 MVA, where a power transformer is to be installed within a building the fire risk is perceived to be such that the use of mineral oil is best avoided. Such a condition is likely to be imposed by insurers even if design engineers or architects were to suggest that this might not be necessary.

The use of all types of electrical equipment in buildings is nowadays extensive and the consequent magnitude of the electrical load has meant that many office blocks and commercial buildings take an electricity supply at least at 3.3 kV so that this must be transformed down to 415 V for internal distribution. There is thus a growing market for fire-resistant transformers. There is also a great diversity of types of transformers available.

As discussed in Section 5 of Chapter 3, until the non-flammable dielectrics of the type based on polychlorinated biphenyls (PCBs) were deemed to be unacceptable in view of their adverse environmental impact, they had little competition as the choice of dielectric for transformers installed in buildings. Possibly some manufacturers and users saw benefit in avoiding the use of liquid dielectric entirely and turning to dry-type transformers, but at this time class C dry-type materials were unreliable unless provided with a good, clean, dry environment and cast resin was very expensive as well as having questionable reliability. There was therefore very little call in textbooks for sections such as this, since the choice was very simple and the installation and operating problems of PCB transformers were few.

PCB was such an excellent dielectric that none of the possible replacements are quite able to match its electrical performance or its fire resistance. In addition, there is now a greater awareness of the need to avoid environmental hazards, not only those resulting from leakage of the dielectric or faults within the transformer but also from the combustion products should the transformer be engulfed in an external fire, so that for any prospective new dielectric there is a very stringent series of obstacles to overcome. Nowadays the designer

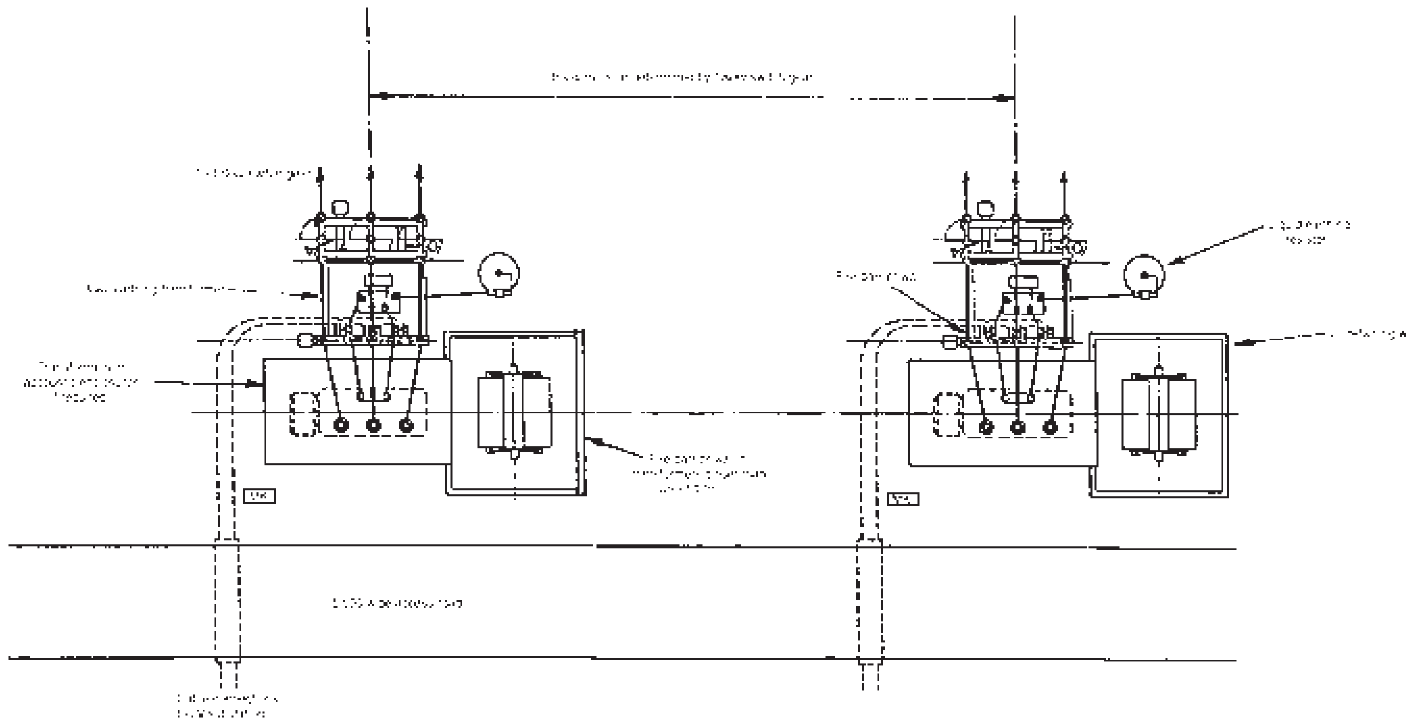


Figure 6.2 Typical two transformer arrangement within 132 kV sub-station

of an installation within a building must have satisfactory assurance on the following points:

- The dielectric must be non-toxic, biodegradable and must not present a hazard to the environment.
- The dielectric must have a fire point above 300°C to be classified as a fire-resistant fluid.
- The dielectric must not contribute to or increase the spread of an external fire nor must the products of combustion be toxic.
- Normal operation, electrical discharges or severe arcing within the transformer must not generate fumes or other products which are toxic or corrosive.

The liquid dielectrics identified in Chapter 3 will meet all of the above requirements. The fire performance of cast resin is dependent on the type of resin and the type and quantity of filler which is used. Cast resin-encapsulated transformers supplied by most reputable manufacturers will be satisfactory on these aspects, but, if there is any doubt, the designer of the installation should seek assurance from the supplier of the transformer.

Generally, a liquid-filled transformer will be cheaper and smaller than a resin-encapsulated or other dry-type unit but the installation must make provision for a total spillage of the dielectric, that is, a sump or a bunded catchment area must be provided to prevent the fluid entering the building drains. If the transformer is installed at higher than ground floor level, and electrical annexes on the roof are frequently favoured by architects, then the installation must prevent leakage of the fluid onto lower floors. The cost of these measures could outweigh the saving on the cost of the transformer and the extra space taken by a bunded enclosure could offset any saving in space resulting from the more compact transformer. Conversely, where cast resin or dry-type transformers are used, other services within the building, particularly water mains, should be located so as to ensure that the transformer and its associated switchgear are not deluged in the event of a pipe leak. Such events unfortunately appear to be common during the finishing phase of a new building. Needless to say the area where the transformer is to be located should be completed and weatherproof before installation of a dry-type transformer. (While manufacturers of cast resin transformers will, no doubt, be keen to stress their ability to withstand onerous conditions such as condensation or dripping water, both the HV and LV connections to the transformer are unlikely to be quite so tolerant of these adverse conditions.)

A dry-type or cast resin transformer will probably be housed in a sheet-steel cubicle integral with the switchboard with LV busbars connected directly to the switchboard incoming circuit breaker. The cubicle and transformer will very likely be delivered and installed as separate items, although some manufacturers are now able to supply these as a single unit. The cubicle should be securely bolted to the switchroom floor and, when installed, the transformer

Table 6.1 Typical total weights of oil-filled and cast resin insulated transformers – 3 phase, 11 kV

Rating (kVA)	*Cast resin insulated*		*Oil-filled without conservator*	*Oil-filled with conservator*
	Weight (kg)	*Total losses to be dissipated (W)*	*Weight (kg)*	
100	650	2 500		
160	800	3 600		
250	1000	4 500		
315	1200	5 160	1610	1720
500	1600	7 800	2020	2130
630	1700	9 000		
800	2200	10 000	2840	2950
1000	2500	12 000	2960	3090
1250	2900	16 200	3490	3620
1600	3500	16 800	4400	4550
2000	5500	20 400	5390	5540
2500	6000	25 000	6490	6800

It should be noted that the above weights are typical only for transformers having average impedance and losses. Significant departures from the above values may be found in specific cases. Losses of up to 30% less are easily obtained but weights would be considerably greater in proportion

Figure 6.3 415 V switchboard with integral 11/0.415 kV cast resin transformer (Merlin Gerin)

Figure 6.4 A synthetic liquid filled 11/0.415 kV transformer suitable for indoor or outdoor installation and designed for connection via 415 V cables to its MV switchboard (Merlin Gerin)

should be positively located and fixed within the cubicle. The floor finish (screed) should be smooth and level so that the transformer can easily be rolled into or out from its cubicle and the floor should be capable of withstanding the imposed loading of the complete transformer, see *Table 6.1*, at any location within the switchroom. A minimum spacing of 0.75 m should be allowed between the transformer cubicle and the rear of the switchroom and ample space must be provided in front of the cubicle for manoeuvring the core and windings in and out. Switchroom doors should be large enough to enable the transformer to enter and also to be removed at some later date should a problem arise in service. This is an aspect which is often overlooked and it is not uncommon for switchroom doors to be hastily modified when the transformer arrives on site before it can be taken into the switchroom. *Figure 6.3* shows a typical arrangement of 415 V switchboard with integral 11/0.415 kV transformer.

While it is desirable that the switchroom should be clean, dry and have some heating in service before the transformer is installed, the heat dissipated by the transformer must also be taken into account in the design of the heating and ventilation system. The iron loss, which could amount to 2 kW for a 1 MVA transformer, will need to be dissipated from the time that the transformer is put into service. Load loss could be up to 10 kW at full load for a 1 MVA unit, so a considerable demand is likely to be imposed on the HV system. *Table 6.1* gives typical losses for other ratings of transformers.

In order to obtain the full rated output and any overloads, indoor transformers should always be accommodated in a well-ventilated location which at the same time provides the necessary protection against rain and dripping water. Too great a stress cannot be laid upon the necessity for providing adequate ventilation, since it is principally the thermal conditions which decide the life of a transformer. Badly ventilated and inadequately sized switchrooms undoubtedly shorten the useful life of transformers, and hence should be avoided.

A liquid-filled transformer does not lend itself so conveniently to incorporation into the MV switchgear in the same way as a dry type, since it will be installed within a bunded area with the switchboard on the outside of this. Although it is possible to bring out 415 connections via 'monobloc'-type bushings suitable for connecting to busbar trunking, this has less flexibility as regards layout than 415 V cables. It is likely, therefore that a cable connection would be the preferred choice. *Figure 6.4* shows a synthetic liquid-filled 11/0.415 kV transformer suitable for indoor or outdoor installation and designed for connection via 415 V cable to its MV switchboard. Such a transformer has the advantage that it is virtually maintenance free.

6.2 NEUTRAL EARTHING

The subject of neutral earthing is a complex one and, whenever it is discussed by electrical engineers, views are varied and the discussion lengthy. It can and has been made the subject of entire textbooks, so that in devoting no more than part of a chapter to the topic it is only possible to briefly look at the principal aspects in so far as they affect transformer design and operation. Practices vary in different countries, and even within different utilities in the same country. From time to time over the years individual utilities have had occasion to re-examine their practices and this has sometimes resulted in detail changes being made to them. Fortunately for transformer designers, earthing of a system neutral can only fall into one of three categories. These are:

- Neutral solidly earthed.
- Neutral earthed via an impedance.
- Neutral isolated.

Due to the problems and disadvantages of the third alternative, it is unlikely that it will be encountered in practice so that it is only necessary to be able to design for the first two.

It is intended mainly in this section to examine earthing practices in the UK, where the guiding principles in relation to earthing are determined by statute, in the form of the Electricity Supply Regulations 1988.

The above regulations replaced those of 1937 and the Electricity (Overhead Lines) Regulations 1970 as well as certain sections of the Schedule to the Electric Lighting (Clauses) Act 1899, and they represent mainly a rationalisation and updating process rather than any major change of UK practice. Part II of the 1988 regulations contains the provisions relating to earthing. It says that:

- Every electrical system rated at greater than 50 V shall be connected to earth.
- How that earth connection is to be made differs between high-voltage and low-voltage systems.

Low voltage is defined as exceeding 50 V but not exceeding 1000 V and is mainly referring to 415 V distribution networks. In the case of a high-voltage system, beyond the requirement that it shall be connected to earth, the method of making the connection is not specified, but for a low-voltage system the regulations say that 'no impedance shall be inserted in any connection with earth ... other than that required for the operation of switching devices, instruments, control or telemetering equipment'. In other words low-voltage systems *must* be *solidly* earthed. The system of protective multiple earthing, which can be advantageous on 415 V distribution networks in some situations, is permitted on low-voltage systems subject to certain other conditions but this still requires that the neutral should be solidly earthed 'at or as near as is reasonably practicable to the source of voltage'.

Earthing of high-voltage systems

As stated above, the statutory requirement in the UK is that basically all electrical systems should be connected to earth, so a discussion of the technical merits and demerits is somewhat academic. However, it is essential that readers of a volume such as this understand these fully, so they may be set out as follows:

Advantages of connecting a high voltage system to earth

- An earth fault effectively becomes a short-circuit from line to neutral. The high-voltage oscillations to which systems having isolated neutrals are susceptible and which can cause serious damage to such systems, are reduced to a minimum, and consequently the factor of safety of the system against earth faults is largely increased. This reasoning applies to systems having overhead lines or underground cables, though to a greater extent the former.

- An earthed neutral allows rapid operation of protection immediately an earth fault occurs on the system. In HV networks most of the line faults take place to earth. Particularly in the case of underground cables, were these on a system employing an isolated neutral, these would take the form of a site of intense arcing activity which, in the case of multicore cables, would result ultimately in a short-circuit between phases. The earthed neutral in conjunction with sensitive earth fault protection results in the faulty section being isolated at an early stage of the fault.
- If the neutral is solidly earthed, the voltage of any live conductor cannot exceed the voltage from line to neutral. As under such conditions the neutral point will be at zero potential, it is possible to effect appreciable reductions in the insulation to earth of cables and overhead lines, which produces a corresponding saving in cost. It is also possible to make similar insulation reductions in transformers and, by the use of non-uniform insulation, make further reductions in the amount of insulation applied to the neutral end of HV windings. In the UK, non-uniform insulation is used for system voltages of 132 kV and above.

  A stable earth fault on one line of a system having an isolated neutral raises the voltage of the two sound lines to full line voltage above earth, which is maintained so long as the fault persists. The insulation of all equipment connected to the sound lines is subjected to this higher voltage, and although it may be able to withstand some overvoltage, it will eventually fail. In extra-high-voltage systems, because of capacitance effects, the voltage of the two sound lines may, initially, reach a value approaching twice the normal line voltage by the same phenomenon as that of voltage doubling which takes place when switching a pure capacitance into circuit, and the insulation of the system will be correspondingly overstressed.
- On an unearthed system the voltage to earth of any line conductor may have any value up to the breakdown value of the insulation to earth, even though the normal voltage between lines and from line to neutral is maintained. Such a condition may easily arise from capacitance effects on systems having overhead lines, as these are particularly subject to induced static charge from adjacent charged clouds, dust, sleet, fog and rain, and to changes in altitude of the lines. If provision is not made for limiting these induced charges, gradual accumulation takes place, and the line and the equipment connected to it may reach a high ‘floating’ potential above earth until this is relieved by breakdown to earth of the line or machine insulation or by the operation of coordinating gaps or surge arresters.

  If, however, the neutral point is earthed either directly or through a current-limiting device, the induced static charges are conducted to earth as they appear, and all danger to the insulation of the line and equipment is removed. No part of a solidly earthed neutral system can reach a voltage above earth greater than the normal voltage from line to neutral.

Disadvantages of connecting a high-voltage system to earth

- The only disadvantage of connecting a high-voltage system to earth is that this introduces the first earth from the outset and it thus increases the susceptibility to earth faults. This can be inconvenient in the case of a long overhead line, particularly in areas of high lightning incidence; however, such faults are usually of a transient nature and normally cleared immediately the line is tripped so that delayed auto-reclosure of the line circuit quickly restores supplies.

It is clear, therefore, that the advantages of connection to earth far outweigh the disadvantages. For transformer designers by far the most significant advantage is the ability to utilise non-uniform insulation.

Multiple earthing

One notable difference between the Electricity Supply Regulations of 1988 and those which preceded them is the attitude to multiple earthing. The regulations of 1937 required that each system should be earthed at one point only and stated that interconnection of systems which were each earthed at one point was not permitted except by special permission of the Electricity Commissioners with the concurrence of the Postmaster-General, who at that time had statutory responsibility for telecommunications. The reason for this was, of course, concern that earthing a system at more than one point would lead to the circulation of harmonic currents via the multiple earth points. As explained in Chapter 2, the third-order harmonic voltages of a three-phase system are in phase with each other so that if two points of the system are earthed concurrently, the third-order harmonic voltages will act to produce circulating currents. The higher frequency components, in particular, of these circulating currents can cause interference with telecommunications circuits and this was the cause of the concern to the Postmaster-General. Although the current regulations have removed the statutory limitation on earthing a system at more than one point, the requirement that the supply system must not cause interference with telecommunications equipment is covered by the more general provisions of the European Union's Directive concerning electromagnetic compatibility which places the onus on all users of electrical equipment to ensure that it does not cause electromagnetic interference. How this is achieved is the responsibility of the user of the equipment and there could be sound technical reasons for wishing to have more than one earth on the system. In this situation the user may elect to guard against generating interference by the use of a third-harmonic suppresser, that is, a device, usually a reactor, in one of the neutral connections, which has minimal impedance to 50 or 60 Hz currents but much higher impedance to higher order harmonics.

Solid v. impedance earthing of transformer neutral points

As indicated above, for high-voltage systems, the Regulations are not specific as to how the system earthing should be carried out. From a practical viewpoint, however, if it is required to utilise non-uniform insulation, it is necessary to ensure that the voltage of the neutral remains at the lowest practicable level for all fault conditions, that is, a solid earth connection is required. The economic benefits of non-uniform insulation become marked at 132 kV and above and it is thus standard practice throughout the UK to solidly earth systems of 132 kV and above. The option for impedance earthing is thus available without any economic penalty as far as the transformer insulation is concerned for all other systems classed as high-voltage systems. This in practical terms means systems from 66 kV down to 3.3 kV inclusive.

The next decision to be made is whether impedance earthing will be beneficial if utilised for these systems and, if so, what criteria should be used to decide the value and type of impedance. In answering this question it is necessary to consider why impedance earthing might be desirable, and the reason for this is that it limits the current which will flow in the event of an earth fault. Hence the damage caused at the point of the fault is greatly reduced. Applying this logic alone would result in the option for a high value of impedance, but the problem then is that some earth faults can themselves have a high impedance and in this situation there could be a problem that the protection will be slow in detecting their existence. Usually the level of impedance selected is such as to result in the flow of system full-load line current for a solid, i.e. zero-impedance, earth fault. On this basis a 60 MVA transformer providing a 33 kV supply to a grid bulk supply point would have the 33 kV neutral earthed with a value of impedance to limit the earth fault current to

$$\frac{60\,000\,000}{\sqrt{3} \times 33\,000} = 1050 \text{ A}$$

It was the practice of the UK Electricity Supply Industry to place a lower limit on the value of earth fault current, so that for a 30 MVA, 33 kV transformer supply the impedance would be such as to allow a fault current of 750 A rather than 525 A.* Other supply companies may wish to standardise on, say, 1000 A as a convenient round figure.

Earthing of delta-connected transformers

In the above example it is likely that the transformer providing the 33 kV bulk supply would have its primary connected at 132 kV, which, to take advantage of the use of non-uniform insulation, would have its HV winding star connected with the neutral solidly earthed. The 33 kV winding would thus probably be connected in delta and hence would not provide a 33 kV

* The exception to this rule was at CEGB generating stations from the mid-1970s at which the generator earth fault current was limited to the very low value of about 10 A. These systems are described in more detail in Section 13 of Chapter 7

system neutral point for connection to earth. Hence a neutral point must be provided artificially by the use of auxiliary apparatus specially designed for the purpose. This usually takes the form of an interconnected-star neutral earthing transformer, although very occasionally a star/delta transformer might be used.

The two schemes are shown diagrammatically in *Figures 6.5* and *6.6*. The interconnected-star connection is described in Chapter 2. It is effectively a one-to-one autotransformer with the windings so arranged that, while the voltages from each line to earth are maintained under normal operating conditions, a minimum impedance is offered to the flow of single-phase fault current, such as is produced by an earth fault on one line of a system having an earthed neutral. Under normal operating conditions the currents flowing through the windings are the magnetising currents of the earthing transformer only, but the windings are designed to carry the maximum possible fault current to which they may be subjected, usually for a period of 30 seconds. The apparatus is built exactly as a three-phase core-type transformer, and is oil immersed.

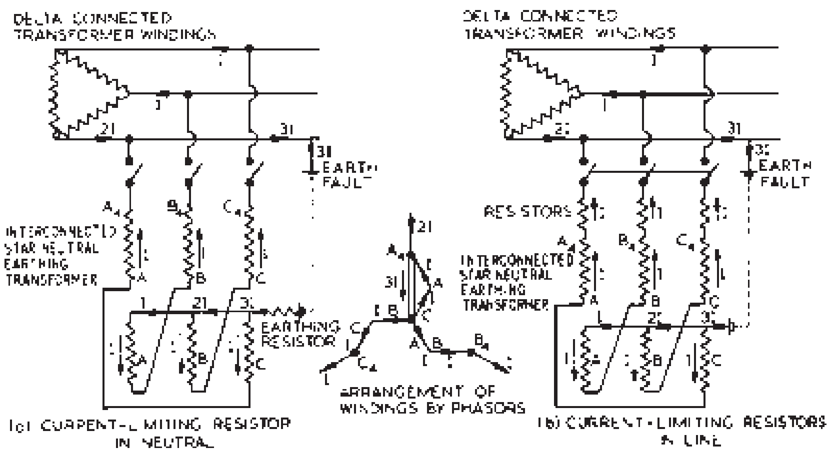


Figure 6.5 Interconnected star neutral earthing transformer

While the interconnected-star earthing transformer is the type most often used for providing an artificial neutral point, an alternative may be adopted in the form of an ordinary three-phase core-type transformer having star-connected primary windings, the neutral of which is earthed and the line ends connected to the three-phase lines, while the secondary windings are connected in closed delta, but otherwise isolated. Normally the current taken by the transformer is the magnetising current only, but under fault conditions the closed delta windings act to distribute the fault currents in all three phases on the primary side of the transformer, and as primary and secondary fault ampere-turns balance each other, the unit offers a low impedance to the current flow.

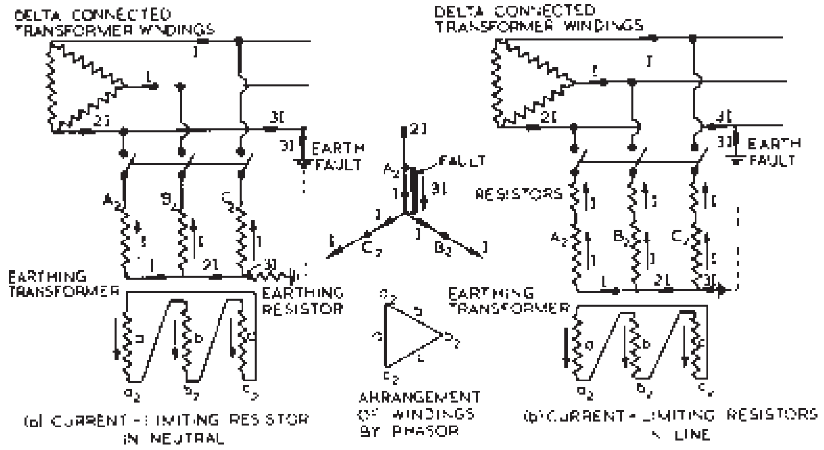


Figure 6.6 Three-phase, star/delta neutral earthing transformer

The transformer is rated on the same basis as outlined for the interconnected-star earthing transformer and it is constructed exactly the same as an ordinary power transformer.

For the purpose of fault current limitation, resistors may be used in conjunction with either of the above types of earthing transformer, and they may be inserted between the neutral point and earth, or between the terminals of the earthing transformer and the lines. In the former case one resistor is required, but it must be designed to carry the total fault current, while it should be insulated for a voltage equal to the phase voltage of the system. On the other hand, the neutral point of the earthing transformer windings will rise to a voltage above earth under fault conditions equal to the voltage drop across the earthing resistor, and the transformer windings will have to be insulated for the full line voltage above earth.

While in any case this latter procedure may be adopted, it is not desirable to subject the earthing transformer windings to sudden voltage surges any higher than can be avoided, as the insulated windings are the most vulnerable part of the equipment. If suitably proportioned resistors are placed between the terminals of the earthing transformer and the lines instead of between neutral and earth, exactly the same purpose is served so far as fault current limitation is concerned, while the neutral point of the earthing transformer always remains at earth potential, and the windings are not subjected to any high voltages. On the other hand the resistors must now be insulated for full line voltage, but this is a relatively easy and cheap procedure. For the same fault current and voltage drop across the resistors the ohmic value of each of those placed between the earthing transformer terminals and lines is three times the ohmic value of the single resistor connected between the neutral and earth, but the current rating of each resistor in the line is one-third of the current rating of a resistor in the neutral, as under fault conditions the three resistors in the lines operate in parallel to give the desired protection.

Value of earthing impedance

For any of the arrangements described above, the magnitude of resistor required can be determined by a simple application of Ohm's law:

$$I = \frac{V/\sqrt{3}}{Z_N}$$

$$Z_N = \frac{V/\sqrt{3}}{I}$$

Neutral earthing apparatus

The most common device used for connection in the HV neutral is the liquid neutral earthing resistor or LNER. These are relatively inexpensive, sturdy and can easily be constructed to carry earth fault currents of the order of up to 1500 A. They are generally designed to carry the fault current for up to 30 seconds. The ohmic value of the resistor is a function of the system voltage to earth and of the permissible fault current. A minor disadvantage of liquid resistors is that they require maintenance in the form of ensuring that the electrolyte is kept topped up and at the correct strength, which might present a slightly increased burden in hot climates and in temperate climates they require heaters to prevent freezing in winter. For this reason metallic resistors are sometimes preferred. These may take the form of pressed grids or stainless steel wound modules which can be connected with the appropriate numbers in series and parallel to provide the required voltage and current rating. These have high reliability and ruggedness, their only disadvantage being cost.

An alternative to resistance earthing is the use of an arc suppression coil. The arc suppression coil was first devised by W. Petersen in 1916, and is hence the generally known as a *Petersen coil*. Use of an arc suppression coil enables a power system to benefit from the advantage normally associated with unearthed systems without suffering their disadvantages. Basically, it is a reactor connected between the neutral of the supply transformer and earth. The reactance of the coil is tuned to match the capacitance of the power system it is protecting.

As indicated above, the majority of faults on an HV network are earth faults and most of these involve single phase to earth contact of an arcing nature [6.1]. With an arc suppression coil installed, intermittent faults are made self-clearing. This is due to the resonance established between the capacitance of the system and the inductance of the arc suppression coil which results in balancing of the leading and lagging components of current at the point of the fault. Any small residual earth current sufficient to sustain the arc is substantially in phase with the voltage of the faulty conductor, and since both pass through zero at the same instant, the arc is extinguished. The resonance delays the recovery voltage build-up after arc extinction which enables the dielectric strength of the insulation at the point of the fault to recover and prevent restriking of the arc. *Figure 6.7* shows a typical oscillogram of recovery voltage following arc extinction in such an installation.

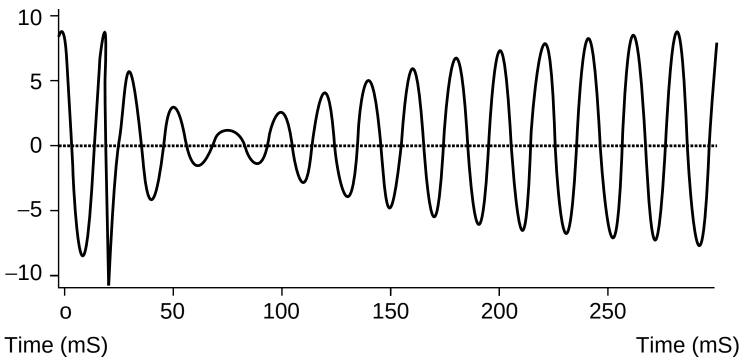


Figure 6.7 Recovery voltage after the initial arc extinction

In the event of a sustained phase to earth fault, the arc suppression coil allows the power system to be operated in a faulted condition until the fault can be located and removed. The residual fault current is normally of the order of 5–10% of the total capacitative fault current. The phasor relationship between the voltages on the three-phase conductors and the currents through the fault and the arc suppression coil is shown in *Figure 6.8*. Nowadays, solid-state control devices can be used in conjunction with arc suppression coils which, in

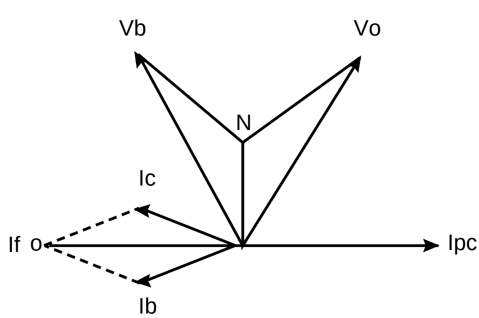


Figure 6.8 Voltages and currents at the point of an earth fault on a Petesen Coil earthed system

conjunction with automatic switching of taps on the arc suppression coil during the fault, enable optimum compensation to be achieved. This technique is particularly useful for systems with multiple feeders, where an earth fault on one feeder results in a different magnitude of fault current to an earth fault on another feeder.

The insulation level of all the plant and apparatus on the system on which arc suppression coils are installed must be adequate to allow operation for a period with one line earthed, and it is generally found uneconomic to install them on systems operating above 66 kV. Up to this voltage, the standard insulation level, without grading, is likely to be employed for all transformers. It is recommended that a higher insulation level should be considered if operation of the system with one line earthed is likely for more than 8 hours in any 24, or more than 125 hours in any year.

The choice of whether to continue operation with a sustained fault on the network lies with the operator. Although it has been shown that arc suppression coils allow this, other factors must be considered, the most important being the safety of personnel. For example, the fault may have been caused by a broken line conductor which would clearly constitute a danger. Should the utility decide not to operate with sustained faults the faulted section must be isolated as soon as a sustained fault is detected. Previously it was common practice to short circuit the arc suppression coil after a specified time to allow protection relays to operate. When the coil is short-circuited a significant inrush of fault current may occur, which would cause a voltage dip. Now, using modern protection devices [6.2, 6.3], it is possible to leave the arc suppression coil in service. Isolation of the faulted section can be carried out, for example, using admittance-sensing relays [6.4] which can determine changes in the admittances of the lines, instead of overcurrent relays as traditionally used.

Earth connection

When dealing with the question of neutral point earthing it is important to give careful attention to the earth connection itself, that is, to the electrode buried in the earth for the purpose of obtaining a sound earth. If the earthing system is not carefully installed and maintained, then serious danger may occur under fault conditions from touch and step potentials (see below).

For obtaining a direct earth contact copper or cast iron plates, iron pipes, driven copper rods, copper strips or galvanised iron strips may be employed.

It is not always appreciated that it is very difficult to obtain resistance values of less than about 2 Ω from a single earth plate, and often it is still more difficult to *maintain* the value after the earthing system has been installed for some time. On account of this it is usual to install several earth plates, pipes, etc., in parallel, so that the combined resistance of the installation is reduced to a reasonably low value of 1 Ω or less. Where a parallel arrangement is employed, each plate, rod, etc., should be installed outside the resistance area of any other. Strictly, this requires a separation of the order of 10 metres which, however, can often be reduced without increasing the total resistance by more than a few per cent.

The chief points to be borne in mind when installing an earthing equipment are, that it must possess sufficient total cross-sectional area to carry the maximum fault current, and it must have a very low resistance in order to keep down to a safe value the potential gradient in the earth surrounding the plates, etc., under fault conditions. As most of the resistance of the earthing system exists in the immediate vicinity of the plates, etc., the potential gradient in the earth under fault conditions is naturally similarly located, and in order that this shall be kept to such a value as will not endanger life, the current density in the earth installation should be kept to a low figure either by using a number of the plates, pipes, etc., in parallel, or else by burying to a considerable depth, making the connection to them by means of insulated cable. The former arrangement is one which can best be adopted where there are facilities for obtaining good earths, but in cases where, on account of the nature of the ground, it has been difficult to obtain a good earth, driven rods have been sunk to a depth of 10 m and more. The maximum current density around an electrode is, in general, minimised by making its dimensions in one direction large with respect to those in the other two, as is the case with a pipe, rod or strip.

Earth plates are usually made of galvanised cast iron not less than 12 mm thick, or of copper not less than 2.5 mm in thickness, the sizes in common use being between 0.6 and 1.2 m^2. If an earth of greater conductivity is required, it is preferable to use two or more such plates in parallel.

Earth pipes may be of cast iron up to 100 mm diameter, 12 mm thick and 2.5–3 m long, and they must be buried in a similar manner to earth plates. Alternatively, in small installations, driven mild steel pipes of 30–50 mm diameter are sometimes employed.

Where the driving technique is adopted, copper rods are more generally used. These consist of 12–20 mm diameter copper in sections of 1–1.5 m, with screwed couplers and a driving tip. Deeply driven rods are effective where the soil resistivity decreases with depth but, in general, a group of shorter rods arranged in parallel is to be preferred.

In cases where high-resistivity soil (or impenetrable strata) underlies a shallow surface layer of low-resistivity soil an earthing installation may be made up of untinned copper strip of section not less than 20 by 3 mm or of bare stranded copper conductor.

If a site can be utilised which is naturally moist and poorly drained, it is likely to exhibit a low soil resistivity. A site kept moist by running water should, however, be avoided. The conductivity of a site may be improved by chemical treatment of the soil, but it should be verified that there will be no deleterious effect on the electrode material. To ensure maximum conductivity, earth electrodes must be in firm direct contact with the earth.

It is most important that the connections from the neutral or auxiliary apparatus to the earth installation itself should be of ample cross-sectional area, so that there is adequate margin over the maximum fault current, and so that no abnormal voltage drop occurs over their length; the connections to the earthing structure having ample surface contact.

Earthing of low-voltage systems

As indicated in the introduction to this section, low-voltage systems are defined in the UK as being above 50 V but below 1000 V and this is mainly intended to embrace all industrial three-phase systems operating at 415 V and domestic single-phase 240 V systems supplied from one phase and neutral of the 415 V network. Although the recent development of the earth leakage circuit breaker has resulted in some changes to safety philosophy, these systems are still mainly protected by fuses, and in order to provide maximum protection to personnel by ensuring rapid fuse operation and disconnection of faulty equipment, the systems are designed to have the lowest practicable earth loop impedance. This means that a solid neutral earth connection must be provided.

The fundamental importance of the solid earth connection is underlined by its embodiment in the 1988 Supply Regulations and also the benefits of the system of protective multiple earthing in assisting the achievement of low earth loop impedance in areas where this might not otherwise be possible is acknowledged by the inclusion of a clause setting down how this is to be carried out.

The requirement for solid earthing of the low-voltage neutral also aims to ensure that the likelihood of the presence of any voltage above normal appearing in the low-voltage circuit is reduced to a minimum since, in the event of insulation breakdown between high-voltage and low-voltage windings of the step-down transformer the resulting earth fault on the high-voltage system should ensure rapid operation of the HV system earth fault protection. The exception is when the high-voltage side of the transformer is connected to earth through a continuously rated arc suppression coil. In this case the point of fault between windings remains at close to its potential determined by its location in the low-voltage winding, i.e. the voltages on the low-voltage system change very little from those occurring under healthy conditions, and the distribution of voltages on the high-voltage side is adjusted accordingly. In practice, breakdown between high-voltage and low-voltage windings of any transformer connected to a high-voltage system is such an unlikely occurrence as to be discounted in the carrying out of any risk assessment.

Earthing system design

At the start of this section the view was expressed that the subject of neutral earthing was a complex one, so that, clearly, the design of earthing systems is not a topic to be covered in a few paragraphs in a textbook dealing with transformers. However, it is necessary to say a little about the subject of earthing system design, at least to explain the philosophy, which has changed somewhat in recent years and, in particular, since earlier editions of this work were written. The most significant change is that now the earthing system must be designed to ensure that the potentials in its vicinity during a fault are below appropriate limits. Previously it was established practice to design the earthing system to achieve a certain impedance value.

When an earth fault occurs and current flows to ground via an earth electrode, or system of electrodes, the potential on the electrodes or any equipment connected to them will rise above true earth potential. This potential rise can be particularly substantial, of the order of several thousand volts in the case of large substations subjected to severe faults. The objective in seeking to obtain a satisfactory earthing system design is to ensure 'safety to personnel' by avoiding the creation of dangerous touch, step or transferred potentials, while acknowledging that the earth potential rise under severe fault conditions must inevitably exist.

The philosophy will be made clearer by definition of the above terms. Interpretation of the definitions will be made clear by reference to *Figure 6.9*. When the potential rise of an earth electrode occurs due to a fault, this will form a potential gradient in the surrounding earth. For a single electrode the potential gradient will be as shown in the figure. A person in the vicinity of this electrode may be subjected to three different types of hazard as a result of this potential gradient:

- *Step potential*. Person 'a' in the figure illustrates 'step potential'. Here the potential difference V_1 seen by the body is limited to the value between two points on the ground separated by the distance of one pace. Since

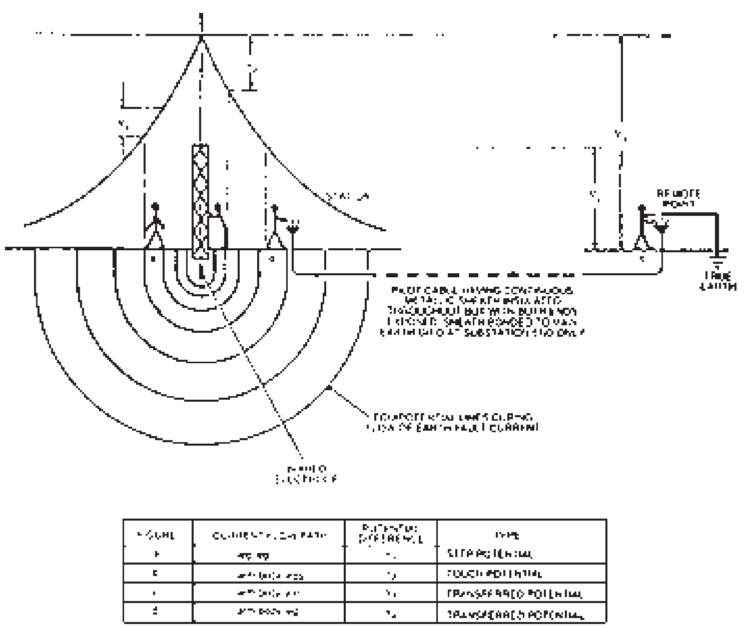


Figure 6.9 Differences in earth potential

the potential gradient in the ground is greatest immediately adjacent to the electrode area, it follows that the maximum step potential under earth fault conditions will be experienced by a person who has one foot in the area of maximum rise and one foot one step towards true earth.

- *Touch potential*. Person ‘b’ in the figure illustrates ‘touch potential’. Here the potential difference V_2 seen by the body is the result of hand-to-both-feet contact. Again the highest potential will occur if there were a metal structure on the edge of the highest potential area, and the person stood one pace away and touched the metal. The risk from this type of contact is higher than for step potential because the voltage is applied across the body and could affect the heart muscles.
- *Transferred potential*. The distance between the high-potential area and that of true earth may be sufficient to form a physical separation rendering a person in the high-potential area immune from the possibility of simultaneous contact with zero potential. However, a metal object having sufficient length, such as a fence, cable sheath or cable core may be located in a manner that would bridge this physical separation. By such means, zero earth potential may be transferred into a high-potential area or vice versa. Person ‘c’ in *Figure 6.9* illustrates the case of a high potential being transferred into a zero-potential area via the armour of a cable. If the armour is bonded to earth at the substation, i.e. the fault location, the voltage V_3 will be the full ‘rise of earth potential of the substation’. In the case illustrated the person at ‘c’ is making simultaneous contact hand to hand with the cable sheath and true earth. However, if the person is standing on true earth then the voltage V_3 seen by the body could be hand-to-both-feet contact. Person ‘d’ represents the case of zero potential being transferred to a high-potential area via a cable core which is earthed at the remote point. In this case, the voltage V_4 is lower than V_3 which represents the substation rise of earth potential, because person ‘d’ is located some distance from the main earth electrode and therefore benefits from the ground potential gradient. Clearly, if person ‘d’ had been on or touching the main electrode he would have experienced the full rise of earth potential V_3.

It will be apparent from the above that transferred potentials can present the greatest risk, since the shock voltage can be equal to the full rise of earth potential and not a fraction of it as is the case with step or touch potentials. Historically limits on transfer potentials have been set at 650 and 430 V in the UK, depending on the type of installation, above which special precautions are required. The higher value is normally taken to apply for high-reliability systems having high-speed protection. No limiting clearance time is quoted for these systems but it is generally accepted that these will clear in 0.2 seconds. The lower figure is for systems protected by overcurrent protection, and although again no limiting clearance time is specified, a time of 0.46 seconds is generally assumed.

If the earth electrode system cannot be designed to comply with the above criteria, then the type of special precautions which might be considered to protect against transferred potentials is the provision of local bonding to ensure that all metalwork to which simultaneous contact can be made is at the same potential. Consideration might also be given to restricting telephone and SCADA connections with remote locations to those using fibre optic cables. Guard rings buried at increasing depths around an electrode can be used to modify the ground surface potential to protect against step potentials.

For those contemplating the design of an earthing system a number of standards and codes of practice are available. In the UK the most important of these are:

- BS 7354:1990 *Code of practice for design of high-voltage open terminal stations*.
- BS 7430:1991 *Code of practice for earthing*.
- BS 7671:1992 *Requirements for electrical installations. IEE wiring regulations. Sixteenth edition*.
- EA Engineering Recommendation S34:1986 *A guide for assessing the rise of earth potential at substation sites*.
- EA Technical Specification 41-24:1992 *Guidelines for the design, testing and main earthing systems in substations*.

The book *Earthing Practice* published by the Copper Development Association [6.5] also contains much useful information.

6.3 TRANSFORMER NOISE

Basic theory

One definition of noise is 'an unpleasant or unwanted sound'. 'Sound' is the sensation at the ear which is the result of a disturbance in the air in which an elementary portion of the air transfers momentum to an adjacent elementary portion, so giving that elementary portion motion. A vibrating solid object sets the air in contact with it in motion and thus starts a 'wave' in the air. Any movement of a solid object may cause sound provided that the intensity and frequency are such that the ear can detect it.

Thus any piece of machinery which vibrates radiates acoustical energy. *Sound power* is the rate at which energy is radiated (energy per unit time). *Sound intensity* is the rate of energy flow at a point, that is, through a unit area. To completely describe this flow rate the direction of flow must be included. Sound intensity is thus a vector quantity. *Sound pressure* is the scalar equivalent quantity, having only magnitude. Normal microphones are only capable of measuring sound pressure, but this is sufficient for the majority of transformer noise measurement situations.

A sound source radiates *power*. What we *hear* is the sound pressure, but it is *caused* by the sound power emitted from the source. The sound pressure that we hear or measure with a microphone is dependent on the distance from the source and the acoustic environment (or sound field) in which sound waves are present. By measuring sound pressure we cannot necessarily quantify how much noise a machine makes. We have to find the sound power because this quantity is more or less independent of the environment and is the unique descriptor of the 'noisiness' of a sound source.

Sound propagation in air can be likened to ripples on a pond. The ripples spread out uniformly in all directions, decreasing in amplitude as they move further from the source. This is only true when there are no objects in the sound path. With an obstacle in the sound path, part of the sound will be 'reflected', part 'absorbed' and the remainder will be transmitted through the object. How much sound is reflected, absorbed or transmitted depends on the properties of the object, its size, and the wavelength of the sound. In order to be able to predict or modify sound pressure levels at any position away from a 'vibrating' machine's surface, it is therefore necessary to know both its sound power and its surrounding environmental properties.

Noise emission by transformers in operation is inevitable. It can give rise to complaints which, for various reasons, are difficult to resolve. The two main problems are: first, distribution transformers are normally located closer to houses or offices than are other types of equipment; and, second, since they operate throughout the 24 hours of every day, the noise continues during the night when it is most noticeable.

In approaching the noise problem it is therefore essential to consider not only the engineering aspects, but also to remember that noise is a subjective phenomenon involving the vagaries of human nature.

The subjective nature of noise

The subjective nature of noise is underlined by the standard definition in BS 661 *Glossary of acoustical terms* which states that it is 'sound which is undesired by the recipient'. It is thus easy to see how people at a party can enjoy it, while neighbours wishing to sleep find it both disturbing and annoying. It also shows why some sounds such as the dripping of a tap can be classified as noise, especially since intermittent sounds are usually more annoying than continuous ones.

Fortunately, transformer noise is not only continuous, but also largely confined to the medium range of audio frequencies, which are the least disagreeable to the human ear. The absence of inherently objectionable features means that the annoyance value of transformer noise is roughly proportional to its apparent loudness. A good starting point for tackling the problem is therefore to determine the apparent loudness of the noise emitted by transformers of different types and sizes.

Methods of measuring noise

The measurement of noise is by no means as simple as that of physical or electrical quantities. Loudness, like annoyance, is a subjective sensation dependent to a large extent on the characteristics of the human ear. It must therefore be dealt with on a statistical basis, and research in this field has shown that the loudness figure allocated to a given sound by a panel of average observers is a reasonably well-defined function of its sound pressure and frequency.

Since sound pressure and frequency are the objective characteristics measured by a sound level meter, it is possible to obtain a rating proportional to the loudness of a sound from the appropriate meter readings. A sound level meter is illustrated in *Figure 6.10*, while a more comprehensive analysing meter is shown in *Figure 6.11*.

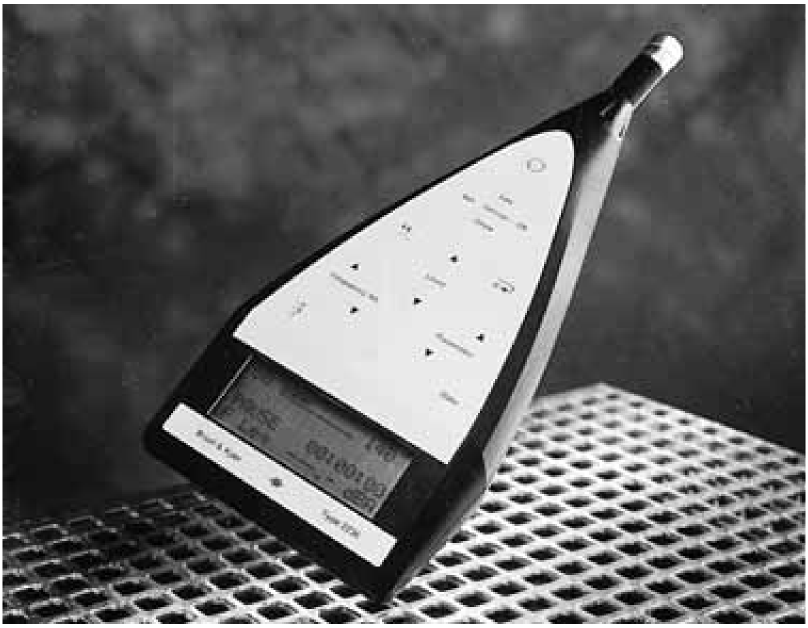


Figure 6.10 Sound level meter (Brüel & Kjaer)

To enable meter readings to be correlated with loudness values, a quantitative picture of the response of the human ear to different sounds must be available. Standardised loudness curves from BS 3383 are reproduced in *Figure 6.12*. They show how the sensitivity of hearing of the average person varies with changes in both the frequency and pressure of the sound. Sensitivity decreases towards the low and high limits of the audio frequency range, so that sounds falling outside the band from approximately 16 Hz to 16 kHz are inaudible to most human observers.

The microphone of sound measuring instruments is in effect a transducer for measuring sound pressures, which are normally expressed in newtons/metre^2 or pascals. Since the sensitivity of the human ear falls off in a roughly logarithmic fashion with increasing sound pressure, it is usual to calibrate

Figure 6.11 Sound level meter with octave band filter (Brüel & Kjaer)

instruments for measuring sound levels on a logarithmic scale, graduated in decibels, or dB.

The scale uses as base an r.m.s. pressure level of 20 μPa, which is approximately the threshold of hearing of an acute ear at 1000 Hz. Thus noise having an r.m.s. pressure level of d pascals (or d newtons per square metre) would be said to have a sound pressure level of $20 \log_{10} d/0.00002$ dB. The decibel

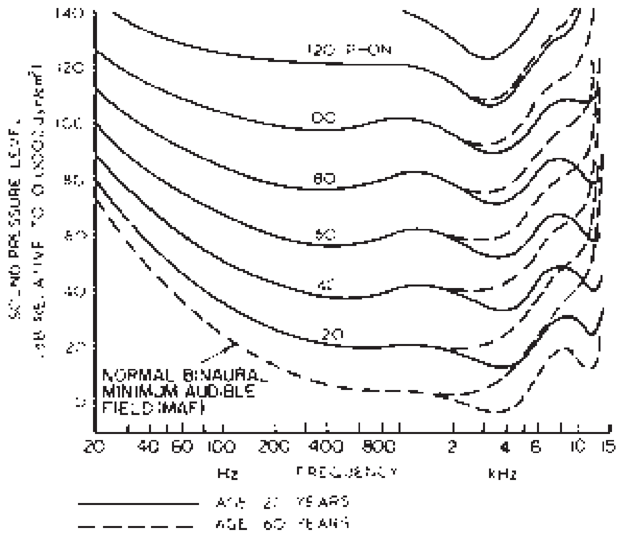


Figure 6.12 Equal loudness curves (Robinson and Dadson)

scale is used for the ordinate of *Figure 6.12*, each 20 dB rise in sound level representing a tenfold increase in sound pressure.

The curves of *Figure 6.12* represent equal loudness contours for a pure note under free-field conditions. They show that the average human ear will ascribe equal loudness to pure notes of sound level 78 dB at 30 Hz, 51 dB at 100 Hz, 40 dB at 1000 Hz, 34 dB at 3000 Hz, 40 dB at 6000 Hz and 47 dB at 10 000 Hz. Thus at 30 Hz, the ear is 38 dB less sensitive than at 1000 Hz, and so on.

The loudness level of any pure tone is numerically equal to the decibel rating of the 1000 Hz note appearing to be equally loud. From this definition, it follows that the loudness level of any 1000 Hz tone is equal to the decibel rating. At other frequencies this does not hold, as the figures in the previous paragraph show.

Determining loudness

The equal-loudness curves show how the sensitivity of the ear varies with frequency, but do not indicate how the ear responds to changes in sound pressure level. For this purpose, the sone scale of loudness has been standardised. The reference point of this scale is taken arbitrarily as a loudness of 1 sone for a level of 40 phons, that is 40 dB at 1000 Hz. It has been found that each rise or fall of 10 phons in loudness level corresponds to a doubling or halving respectively of the loudness (*Figure 6.13*).

The sone scale is linear, so that a noise having a loudness of 2A sones sounds twice as loud as a noise of A sones. It should be noted that the noise emitted by two similar sources does not sound twice as loud as the noise

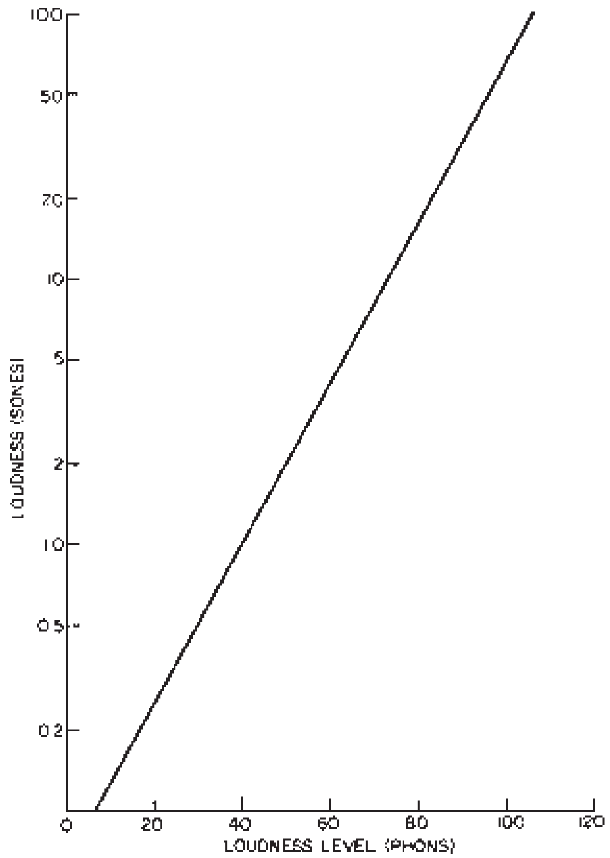


Figure 6.13 Relation between loudness and loudness level

emitted by each source separately. The sound pressure level is increased only by 3 dB and the apparent loudness by about one-quarter.

Sound measuring instruments

The equal loudness contours shown in *Figure 6.12* were used to derive simple weighting networks built into instruments for measuring sound level.

Sound level is defined as the weighted sound pressure level. The construction of a sound level meter is shown diagrammatically in *Figure 6.14*. Historically, A, B and C weighting networks were intended to simulate the response of the ear at low, medium and high sound levels, respectively. However, extensive tests have shown that in many cases the A weighted sound level is found to correlate best with subjective noise ratings and is now used almost exclusively. Although C weighting is retained in more comprehensive meters, B weighting has fallen into disuse.

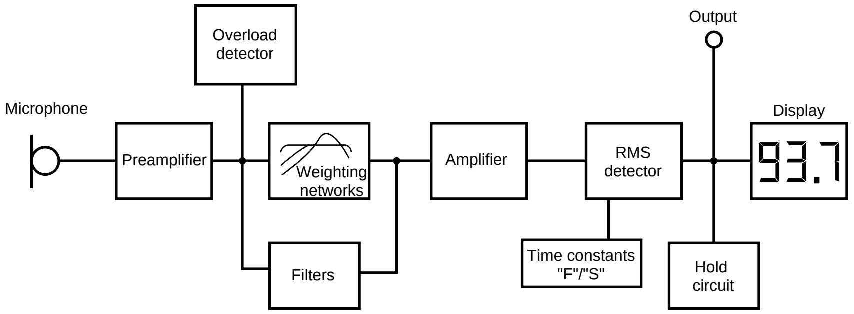


Figure 6.14 Block diagram for sound level meter

The meter illustrated in *Figure 6.11* and shown in block form in *Figure 6.14* offers A and C weightings at the touch of a button, and also a linear (unweighted) option for frequency analysis purposes and where the actual sound pressure level is to be measured.

The microphone used in a sound level meter is non-directional and the A weighted frequency characteristic and dynamic response of the meter closely follow that of the human ear. As the range of the ear is around 140 dB, while the meter illustrated has a linear 30 dB scale, attenuators are necessary to cover the full measuring range required. The range switch is adjusted until a convenient scale reading is obtained, and the sound level of the noise is then the sum of the meter reading and of the attenuator setting.

If noise is fluctuating very rapidly, the meter response may not be fast enough to reach the actual level of a noise peak before it has subsided again. The meter illustrated will, however, measure and display the maximum r.m.s. level of a noise event at the touch of a button.

A sound level meter effectively sums up a given noise in terms of a single decibel value. Although sufficient for many requirements, this yields little information as to the character of the noise, as it represents only its magnitude. To determine the character of noise, a frequency spectrum must be measured by means of an audio frequency analyser such as that illustrated in *Figure 6.15*. This instrument is essentially a variable filter which suppresses noise components at all frequencies outside the desired band. As it is tuned over the audio band, any marked amount of noise at a particular frequency is clearly demonstrated by a sharp rise in the meter reading. From the readings obtained, a continuous spectrum can be derived.

Where less discrimination is acceptable, a filter of wider bandwidth may be used to sum up all components of the noise in a certain frequency range. The most common bandwidth is one octave, although one-third octave filters are also used for more precise applications. The mid-band frequencies are internationally standardised; for octave band filters they are 31.5 Hz, 63 Hz, 125 Hz, 250 Hz, 500 Hz, 1000 Hz, 2000 Hz, 4000 Hz and higher for precision (Class 1) grade meters. The 250 Hz band, for example, spans the octave 180–360 Hz.

Figure 6.15 Audio frequency analyser (Brüel & Kjaer)

The day-to-day performance of a sound level meter is usually checked periodically using a calibrator. The latter produces an accurately known sound level against which the meter can be set up. To ensure that the calibration is not affected by extraneous noise, the calibrator is usually fitted over the microphone to form a closed cavity. This not only greatly reduces ambient noise, but also ensures that the source to microphone spacing is exactly the same at every calibration.

Sound level measurements of transformers

As explained above, in making measurements of noise at a particular point in space using a microphone, the quantity measured is the *sound pressure level*. The quantity is expressed in decibels, usually with an A scale weighting, and abbreviated as dBA. For many years transformer users and manufacturers quantified the noise produced by a transformer in terms of these microphone readings to provide an *average surface sound pressure level* or *average surface noise level* which was an average of sound pressure level readings taken at approximately 1 m intervals around its perimeter at a distance of 0.3 m from the tank surface. As a means of comparing the noise produced by individual transformers this provided a fairly satisfactory method of making an assessment. Clearly, a transformer with an average surface noise level (usually simply termed 'noise level') of 65 dBA was quieter than one having a noise level of 70 dBA. However, with recent environmental requirements demanding low noise levels, it has become necessary to be able to predict the sound pressure level at a distance of, say, 100 m from the substation. It is therefore essential to know the sound power level of the transformer(s). This is expressed in terms of the integral of sound pressure over a hemispherical surface having the transformer at its centre. The units of measurement remain decibels. This approach has the benefit of allowing the noise contribution from the transformer to be assessed at any distance and the contributions from different sources to be added (applying an inverse square law to the distance and adding logarithmically) and is now the preferred method by noise specialists for expressing transformer noise levels. There is, unfortunately, confusion between the two quantities which is not helped by the fact that both are measured in the same units. Many transformer users still specify average surface noise level when procuring a transformer or expect the sound power level to be the same in numerical terms as the average surface noise level. In fact, in numerical terms the sound power level is likely to be around 20 dB greater than the average surface sound pressure level. The actual relationship will be derived below.

In the UK noise measurements are made in accordance with BS EN 60551 *Determination of transformer and reactor sound levels*. This is based on the European standard EN 60551. It requires that measurements are made using a Type 1 sound level meter complying with IEC 651, which in the UK is BS 5969 *Specification for sound level meters*. A check of the meter using a calibrated noise source should be made before and after the measurement sequence.

Measurements are taken at no load and all readings are recorded using the A weighting. If an octave band analysis is required the linear response is used. The transformer is excited on its principal tapping at rated voltage and frequency, but preliminary check tests may be made to see if there is any significant variation of noise between different tapping positions. For transformers with a tank height less than 2.5 m, measurements are taken at half the tank height. For transformers with a tank height equal to or greater than 2.5 m, measurements are taken at one-third and two-thirds of the tank height. Measuring points around the tank perimeter are to be spaced not more than 1 m apart. For transformers having no forced cooling, or with forced cooling equipment mounted on a separate structure at least 3 m distant from the main tank, or for dry-type transformers installed within enclosures, the microphone is placed at a distance of approximately 0.3 m from a string contour encircling the transformer (see *Figure 6.16*). The string contour is defined as *the principal radiating surface* of the transformer and is to include all cooling equipment attached to the tank, tank stiffeners, cable boxes, tapchanger, etc., but exclude any forced air cooling auxiliaries, bushings, oil pipework, valves, jacking and transport lugs, or any projection above the tank cover height.

The background noise level is measured, and if this is clearly much lower than the combined level of transformer plus background, i.e. not less than 10 dB lower, this may be measured at one point only and no correction made to the measured level for the transformer. If the difference between background alone and background plus transformer is between 3 and 10 dB, a correction may be applied to the combined measurement to give a value for the transformer alone, but background measurements must be taken at

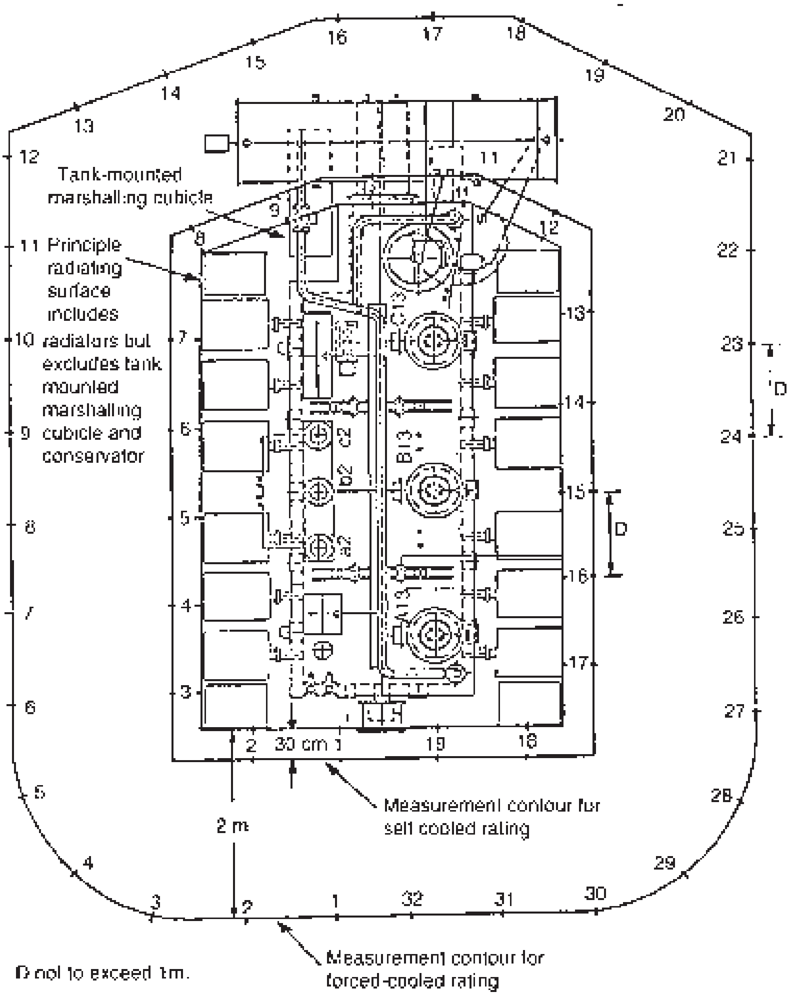


Figure 6.16 Plan view of transformer with tank-mounted radiators showing principal sound radiating surface and measurement contours for self-cooled and forced-cooled ratings

every microphone position. The corrections which may be applied are given in *Table 6.2*.

For forced-cooled transformers with the coolers mounted directly on the tank or on a separate structure less than 3 m from the main tank, two sets of measurements are to be made, both with the transformer at no load, one with the forced cooling equipment out of service, and the second with the forced cooling, pumps and fans, in service. For the first series of measurements the microphone is to be at a distance of 0.3 m from the principal radiating surface as for self-cooled transformers, and for the second series of measurements

Table 6.2 Correction for influence of background noise

Difference between sound pressure level measured with the equipment operating and background sound pressure level alone *dB*	*Correction to be subtracted from sound pressure level measured with the equipment operating to obtain sound pressure level due to the equipment* *dB*
3	3
4–5	2
6–8	1
9–10	0.5

the microphone positions are to be 2 m from the principal radiating surface (*Figure 6.16*).

Separate cooling structures mounted at least 3 m from the main tank are treated as completely separate entities and a separate series of measurements taken at a distance of 2 m from the principal radiating surface with pumps and fans running but with the transformer de-energised. *Figure 6.17* shows the location of the principal radiating surface and the microphone positions. The microphone height is to be at half the cooler height for structures less than 4 m high and at one-third and two-thirds height for structures equal to or greater than 4 m high.

The average surface sound pressure level is then generally computed by taking a simple arithmetic average of the series of measurements taken around the perimeter of the equipment as described above. Strictly speaking, however, the average should be logarithmic but provided the range of values does not exceed 5 dB, taking an arithmetic average will give rise to an error of no greater than 0.7 dB. A true average is given by the expression:

$$\overline{L}_{pA} = 10\log_{10}\left(\frac{1}{N}\sum_{i=1}^{N}10^{0.1\mathrm{L}_{pAi}}\right) - K \tag{6.1}$$

where $\overline{L}_{pA}$ = A-weighted surface sound pressure level in decibels
L_{pAi} = A-weighted sound pressure level at the ith measuring position corrected for the background noise according to *Table 6.2*, in decibels
N = Total number of measuring positions
K = Environmental correction to take account of test location

Ideally the test environment should provide approximately free-field conditions, certainly free of reflecting objects or surfaces within 3 m of the transformer. In the early days of investigations into transformer noise, manufacturers built anechoic chambers such as that shown in *Figure 6.18* for carrying out measurements. There is a limit to the size of such chambers,

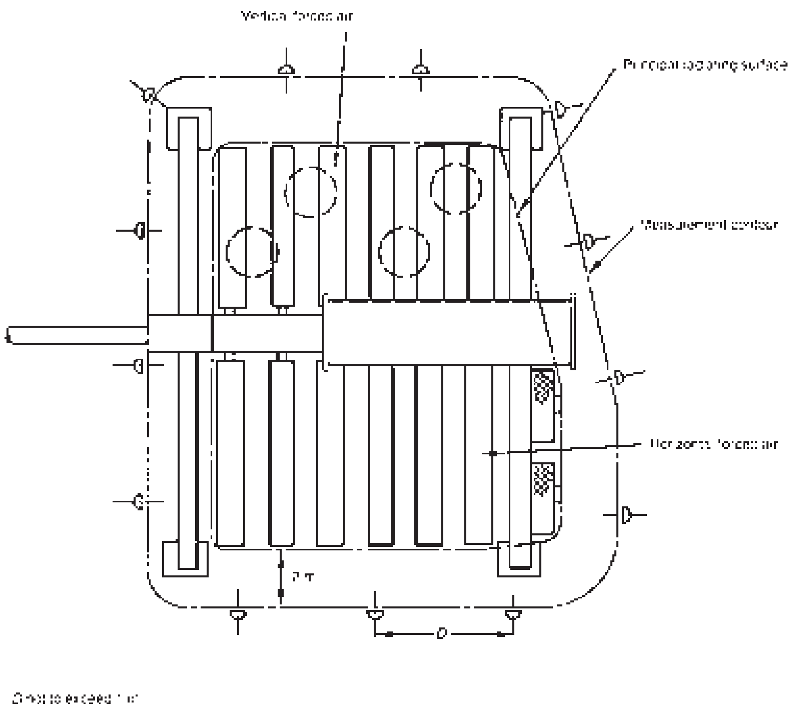


Figure 6.17 Typical microphone positions for noise measurement on forced air cooling auxiliaries mounted on a separate structure spaced not less than 3 m away from the principal radiating surface of the transformer tank

however, and these cannot normally be provided for large high-voltage transformers. BS EN 60551 acknowledges this and allows for the measurements to be made within a normal factory test bay by incorporating the correction K, as shown in the expression above, to allow for reflections from the walls and ceiling, and Appendix A of that document describes methods of determining its value. K is generally of the order of 2–5 dB depending on the volume of the test bay in relation to the size of the transformer.

Calculation of sound power level

The sound power level can be calculated using the sound pressure levels determined above by computing the effective area for the measurement surface according to the relevant method of measurement and relating this to the standard measurement surface, which is one square metre. The A-weighted sound power level is thus:

$$L_{WA} = \overline{L}_{pA} + 10\ \log_{10} \frac{S}{S_0}$$

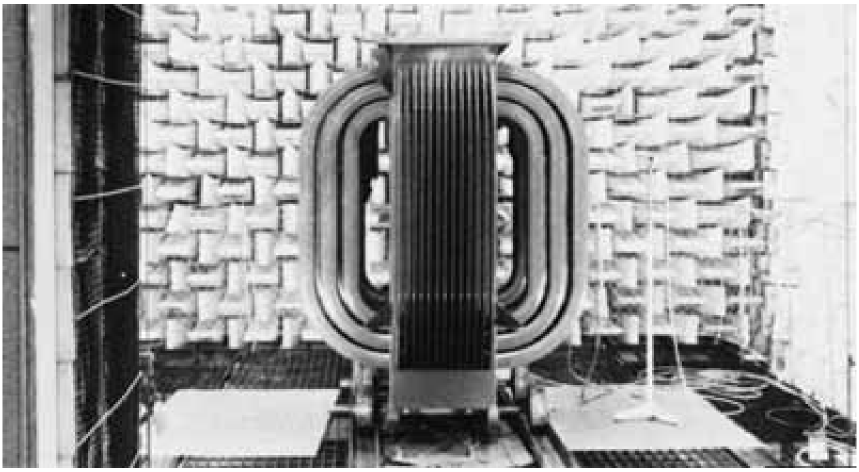


Figure 6.18 Transformer undergoing a noise test in an anechoic chamber (ABB Power T&D Ltd)

where L_{WA} = A-weighted sound power level in decibels with respect to 10^{-12} W

S = area of the measurement surface, in square metres with respect to $S_0 = 1\text{m}^2$

The measurement surface S then has the following values:

For self-cooled transformers, or forced-cooled transformers with the forced cooling equipment unenergised, and measurements made at 0.3 m from the principal radiating surface:

$$S = 1.25\ hl_{\text{m}} \tag{6.2}$$

where h = height in metres of the transformer tank

l_{m} = length in metres of the contour along which measurements were made

1.25 = empirical factor to take account of the sound energy radiated by the upper part of the transformer over which no measurements were made

For forced-cooled transformers with forced cooling equipment also energised:

$$S = (h + 2)l_{\text{m}} \tag{6.3}$$

where 2 = measurement distance in metres

For measurements on separate free-standing cooling structures

$$S = (H + 2)l_{\text{m}} \tag{6.4}$$

where H = height of the cooling equipment, including fans, in metres (see *Figure 6.19*)

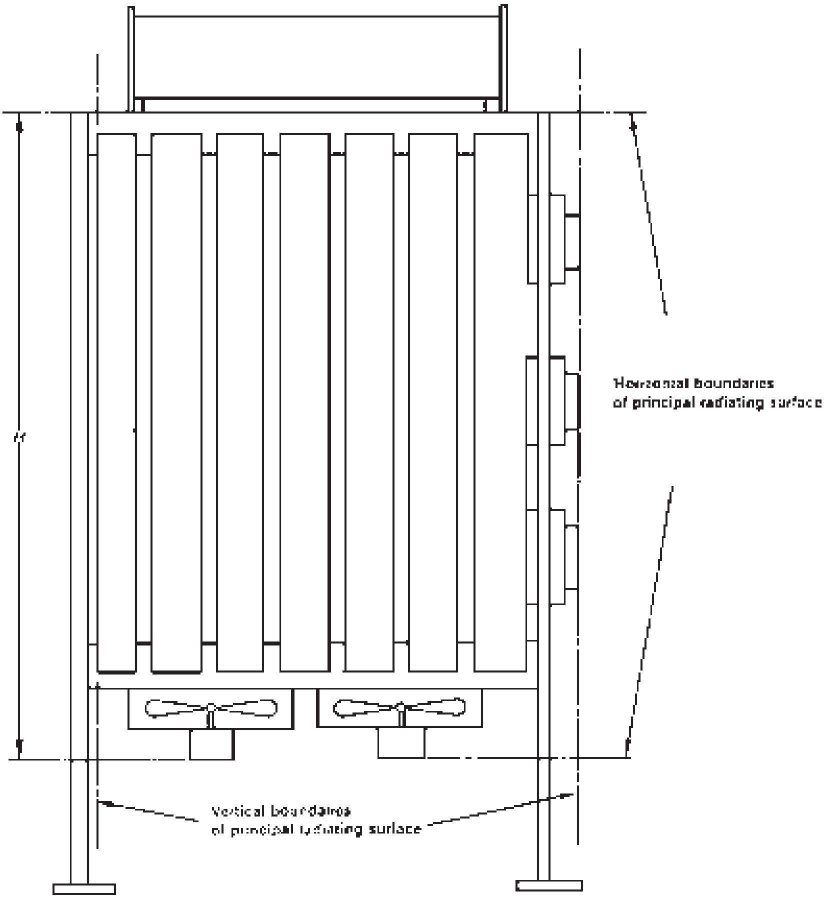


Figure 6.19 Cooler with forced air cooling auxiliaries showing boundaries of principal radiating surface

Interpretation of transformer noise

A typical analysis of transformer noise is reproduced in *Figure 6.20*, which can be considered as a composite graph of a large number of readings. In this diagram, the ordinates indicate the magnitude of the various individual constituents of the noise whose frequencies represent the abscissae. The most striking point is the strength of the component at 100 Hz or twice the normal operating frequency of the transformer. Consideration of magnetostrictive strain in the transformer core reveals that magnetostriction can be expected to produce a longitudinal vibration in the laminations at just this measured frequency. Unfortunately, the magnetostrictive strain is not truly sinusoidal in character, which leads to the introduction of the harmonics seen in *Figure 6.20*.

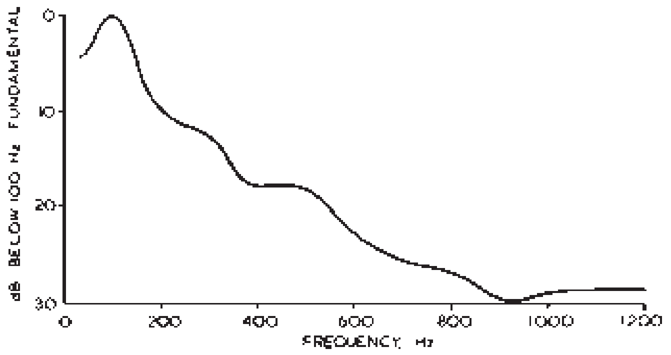


Figure 6.20 Typical analysis of noise emitted by transformers

Deviation from a ‘square-law’ magnetostrictive characteristic would result in even harmonics (at 200, 400, 600 Hz, etc.), while the different values of magnetostrictive strain for increasing and decreasing flux densities – a pseudohysteresis effect – lead to the introduction of odd harmonics (at 300, 500, 700 Hz, etc.).

Reference to *Figure 6.12* indicates that the sensitivity of the ear to noise increases rapidly at frequencies above 100 Hz. On the 40 phon contour, it requires an increase of 12 dB in intensity to make a sound at 100 Hz appear as loud as one at 1000 Hz. The harmonics in a transformer noise may thus have a substantial effect on an observer even though their level is 10 dB or more lower than that of the 100 Hz fundamental.

Although longitudinal vibration is the natural consequence of magnetostriction, the need to restrain the laminations by clamping also leads to transverse vibrations, this effect being illustrated in *Figure 6.21*. Measurements taken on this effect suggest that transverse vibrations contribute roughly as much sound energy to the total noise as do the longitudinal vibrations. As already pointed out, two similar sources sound about 25% louder than one. By the same token, complete elimination of the transverse vibration would reduce the loudness of the transformer noise by only about a fifth. Although valuable, this reduction, even if technically and economically possible, is insignificant compared with the halving of the loudness which can be achieved by a reduction of 10 dB in the noise level of both longitudinal and transverse vibrations.

The other main source of noise from the transformer core is due to alternating attractive and repulsive forces between the laminations caused by flux transfer across the air gaps at the leg to yoke and inter-yoke joints. These forces can be reduced by special building and design techniques of which the best known and most widely used is the step-lap form of construction described in Section 1 of Chapter 4.

Figure 6.20 covers typical transformers incorporating cold-rolled laminated cores operating at flux densities between 1.6 and 1.8 tesla. Even variations of 10% in flux density have been shown to produce changes of noise level of

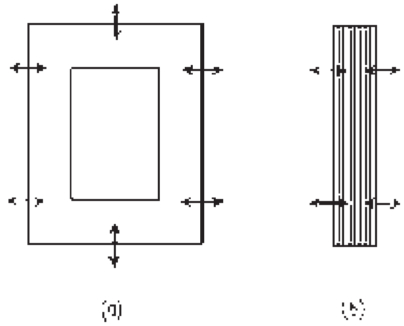


Figure 6.21 Vibrations due to magnetostriction: (a) longitudinal and (b) transverse

the order of only about 2 dB, although the character of the noise may vary appreciably. From this it will be apparent that it is most uneconomic to obtain a reduction in noise level by the employment of low flux densities. This is perhaps demonstrated best by reference to experience with cold-rolled steel. To make the optimum use of these newer materials, it is necessary to operate them at flux densities of 1.65–1.85 tesla. While this higher flux density tends to lead to a higher noise level for a given size of core, current results suggest that the difference is quite small for a given transformer rating, due to the smaller core made possible by the use of the higher flux density material. Considerable work is being undertaken to obtain even quieter operation by suitable treatment of the raw material and by particularly careful assembly of the finished core laminations.

Turning to other possible sources of noise emitted by a transformer, the forces present between the individual conductors in the winding when the transformer is loaded must be considered. These forces are, however, of a sinusoidal nature so that any vibration consists of a fundamental at 100 Hz with negligible harmonics. The fundamental is thus effectively dwarfed by the much greater 100 Hz fundamental generated by the core, while there are no harmonics to add to the annoyance value. Acoustic measurements confirm this conclusion by showing that the noise level on most transformers increases by not more than 2 dB (15% rise in loudness) from no load to full load. Any variation is in fact attributable more to changes in flux density than to variations in the forces in the windings.

The other major source of noise is the transformer cooler. Fans produce noise in the frequency range 500–2000 Hz, a band to which the ear is more sensitive than it is to the 100 Hz fundamental produced by the core. The predominant frequencies are dependent on many factors including speed, number of blades and blade profile. Sound power level is dependent upon number and size of fans as well as speed and, for many forced-cooled transformers, the cooler can prove to be a significantly greater source of noise than the transformer itself. An example is the transformer shown in plan view in *Figure 6.16*. This is a 40 MVA ONAN rated 132/33 kV transformer with tank-mounted radiators having an emergency ODAF rating, using two pumps and eight fans, of 80 MVA. By careful attention to core design and use of modern HiB steel, an average surface sound pressure level of only 47 dBA, corrected for background, has been achieved at the ONAN rating with a sound power level of 66 dBA. However, with all pumps and fans running for the emergency ODAF rating, the average surface sound pressure level is increased to 60 dBA and the sound power level to 82 dBA.

These comments on transformer noise assume the absence of resonance in any part of the unit. Normally the minimum natural frequency of the core and windings lies in the region of 1000 Hz. *Figure 6.20* indicates that the exciting forces are very low at this or higher frequencies. Accordingly, it can confidently be expected that the unfortunate effects associated with resonance will be avoided. The natural frequency of the tank or fittings being lower, resonance of these is much more likely to occur, since the vibrations of the core can be transmitted by the oil to the tank. If any part of the structure has a natural frequency at or near 100, 200, 300, 400 Hz, etc., the result will be an amplification of noise at that particular frequency.

Noise reduction on site

Control of the noise emitted by a transformer rests almost entirely with the manufacturer, who will endeavour to achieve the customer's specified requirements wherever possible. A certain amount of noise is, however, inevitable and, if it proves offensive, must be dealt with by the purchaser who can do much to ensure acceptance of the transformer long before it is delivered.

Typical average sound levels of a range of transformers are given in *Figure 6.22*. They should, of course, be compared with any test figures for the actual transformer to be installed, as soon as any figures become available. The levels quoted in *Figure 6.22* will, however, provide a reasonable basis for preparatory action. The reduction of noise level with distance must be allowed for. Doubling the distance from a point source of noise means that a given amount of sound must be spread over four times the area. From this cause alone, doubling of distance results in a 6 dB fall in sound level. In practice, scattering combined with the absorption by the air itself ensures that the noise reduction is greater, particularly at the higher frequencies.

Figure 6.23 shows measured values of attenuation with distance for typical transformer ratings. Assuming that there is no screening between the transformer and a given building, these curves enable the noise level outside the building to be computed.

Normally it is not necessary to reduce transformer noise in the vicinity of residential buildings to such a level that it is inaudible. Experience suggests that the transformer noise will be acceptable if it is not audible inside a bedroom of the nearest house at night time when a small window of the room is open. Under these conditions the transformer noise level outside the house can be considered as the permitted maximum transformer noise at this

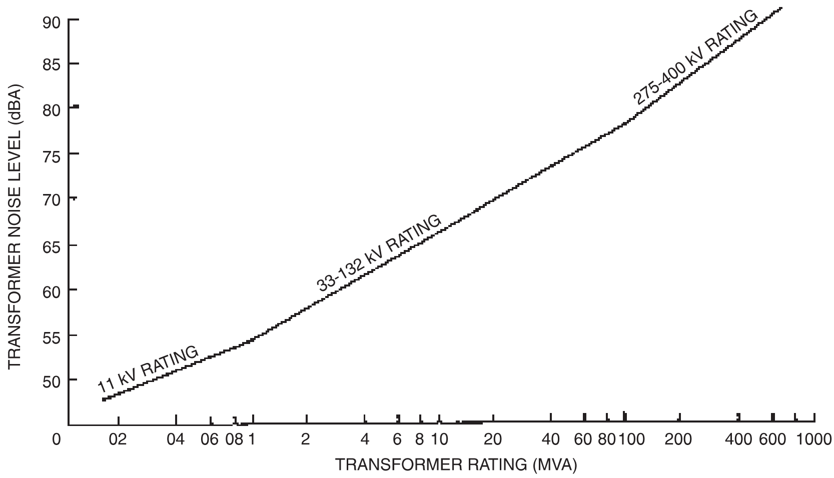


Figure 6.22 Typical transformer average surface noise levels

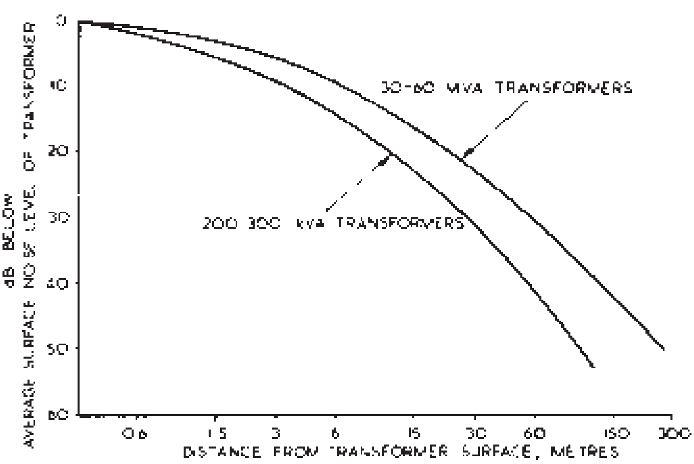


Figure 6.23 Curves showing measured attenuation of transformer noise with distance

position. Provided the sound level meter reading taken outside the house is not more than 2 dB above the bedroom background level, both being measured at the A weighting, the acceptable noise level inside will not be exceeded. From *Table 6.3* which also gives the calculated equivalent 'phon' values of the transformer noise as obtained from the typical composition and equal loudness contours and tone summation curve, it will be seen that three types of background level have been given, and these are considered to be representative of conditions existing at night in neighbourhoods of the kinds referred to.

Table 6.3 Acceptable maximum noise levels outside dwellings

Locality	*Bedroom background noise level in dB (A)*	*Transformer noise*	
		Sound level in dB (A)	*Calculated equivalent phon (or dB (A) at 1000 Hz) value*
Rural	20	22	30
Urban-residential	26	28	40
Industrial	35	37	50

From CIGRE Paper No 108 (1956) Transformer noise limitation. Brownsey. Glever and Harper

Using the values from *Table 6.3* as a basis, it is possible to determine whether the noise level within nearby bedrooms will be acceptable if the transformer is sited at various alternative locations. One or other location may well ensure that no householder is subjected to an unduly high noise level. Failing this, the investigation may still show the minimum attenuation necessary to bring the noise level down to an acceptable level. The most appropriate method of achieving this object can then be selected and work put in hand immediately, so that the site is ready when the transformer is delivered.

Provided the noise level resulting from transformer operation is below that given in the above table, conditions should be satisfactory and no corrective action is necessary. In fact, with well-designed transformers, acoustic conditions will normally be satisfactory under urban conditions at all points beyond 15 m from the transformer for a rating of 200 kVA and 25 m for a rating of 500 kVA. Assuming that bedroom windows do not face directly on the transformer, it is possible to decrease these distances by about two-thirds.

Attenuation

In urban areas, it is normally impracticable to site transformers more than 100 m from the nearest dwelling. In this case, transformers with ratings in excess of about 15 MVA will probably need to be provided with some form of attenuation giving a noise reduction of between 10 and 25 dB.

The most obvious method of attenuation is by the provision of a suitable barrier between the transformer and the listener. The simplest form of barrier is a screening wall, the effectiveness of which will vary with height and density as well as with the frequency of the noise. The attenuation of a 100 Hz noise by a 6 m wall will not normally exceed 10 dB outside the immediate ‘shadow’ cast by the wall.

Such attenuation just reaches the bottom of the range cited but some slight further attenuation can be achieved by judicious use of absorbent material. This treatment may result in an attenuation as small as 2 dB and will seldom give a figure in excess of 6 dB. While absorbent material may give some relief on existing installations or may make a single wall shielding a transformer in one direction more effective, it will not usually provide a complete solution where an untreated screen wall is itself unsatisfactory.

Noise and vibration from large transformers will also be transmitted via the ground. Ground-borne vibration can cause adjacent structures to vibrate which may then amplify and retransmit the noise. These effects can be reduced by placing the transformer on anti-vibration mountings – strips of rubber or other resilient material, usually 80 mm wide and 40 mm thick. The number of strips and the spacing of these is arranged to ensure that the loading is optimised as near as possible for the material. They may be simply set out perpendicular to the major dimension of the tank base with an even spacing or in a more elaborate pattern as, for example, in *Figure 6.24* which aims to provide a more even loading taking into account irregularities in the plinth and the tank base. Whichever arrangement is used, the openings around the perimeter of the tank base should be closed, otherwise the spaces between the pads can provide resonant chambers for amplification of the sound.

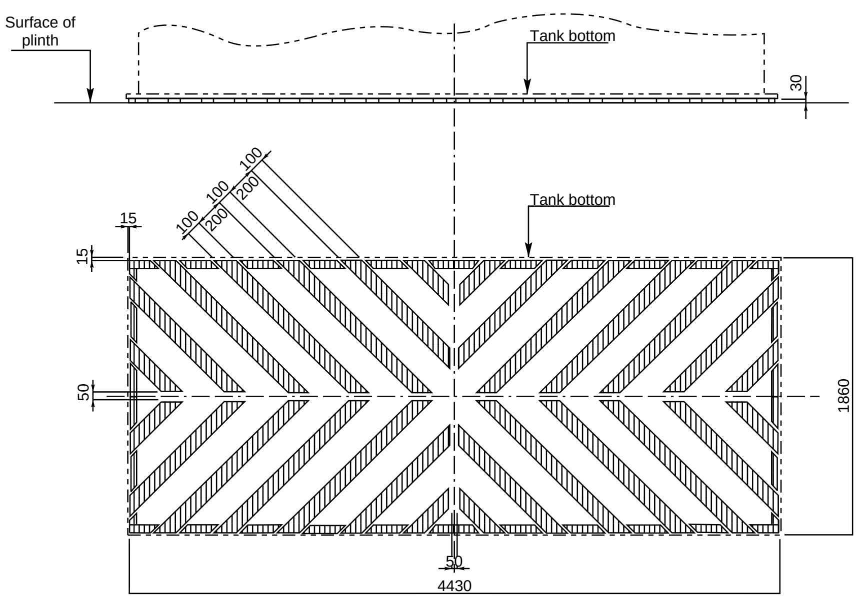


Figure 6.24 Typical arrangement of antivibration mountings for 60 MVA transformer

In the UK it was CEGB practice to provide concrete or steel acoustic enclosures for large generator transformers, since these can be a source of high levels of off-site noise. For transmission transformers and grid bulk-supplies transformers it was the practice to specify that these be made suitable for the future fitting of an acoustic enclosure should this be found to be necessary after the transformer has entered service. Such provision also allows for the transformer to be installed at alternative sites, some of which might be more

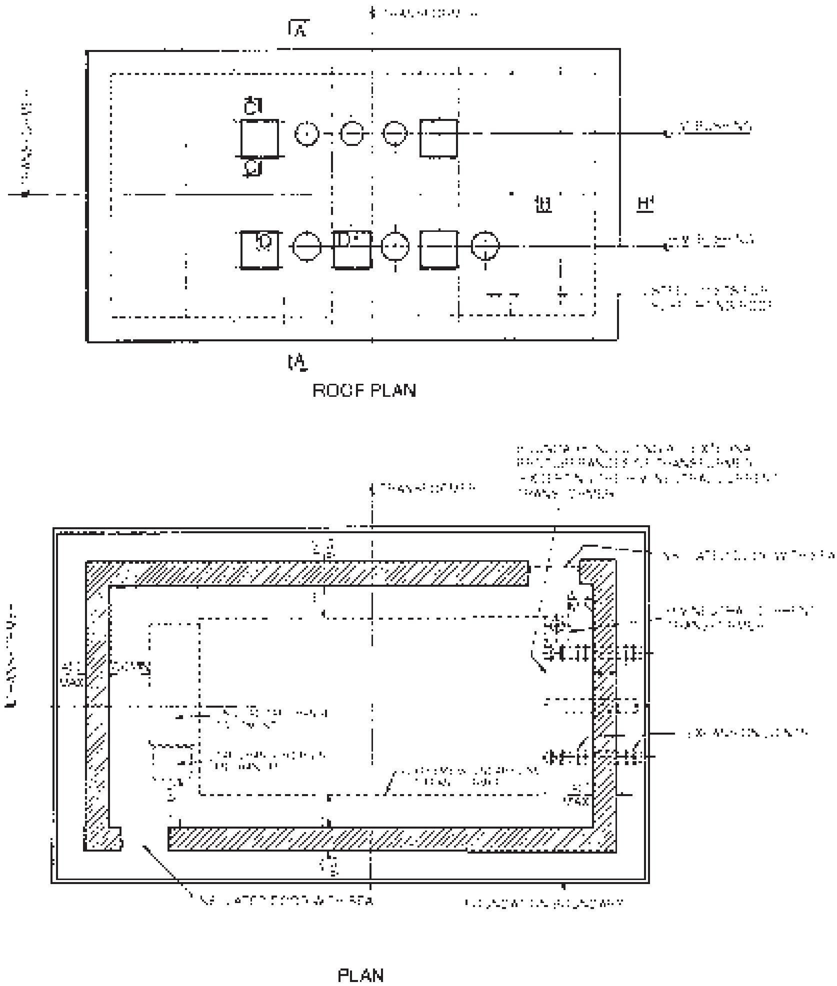


Figure 6.25a Typical accoustic enclosure for 132 kV transformer

environmentally sensitive than others. Provision mainly involves the installation of bushings on extended turrets which will pass through the structure of the enclosure. A typical acoustic enclosure capable of producing an attenuation of around 25–30 dB is shown in *Figure 6.25*.

The need for enclosures of this type has tended to lessen in recent years in view of the steady improvements in noise reduction measures adopted by transformer manufacturers and, of course, installation within an acoustic enclosure has the major disadvantage that a separate free-standing cooler bank must be provided outside the enclosure. This adds to the overall costs of the transformer, and any fans associated with the cooler will probably contribute considerably more to the off-site noise anyway than would the transformer

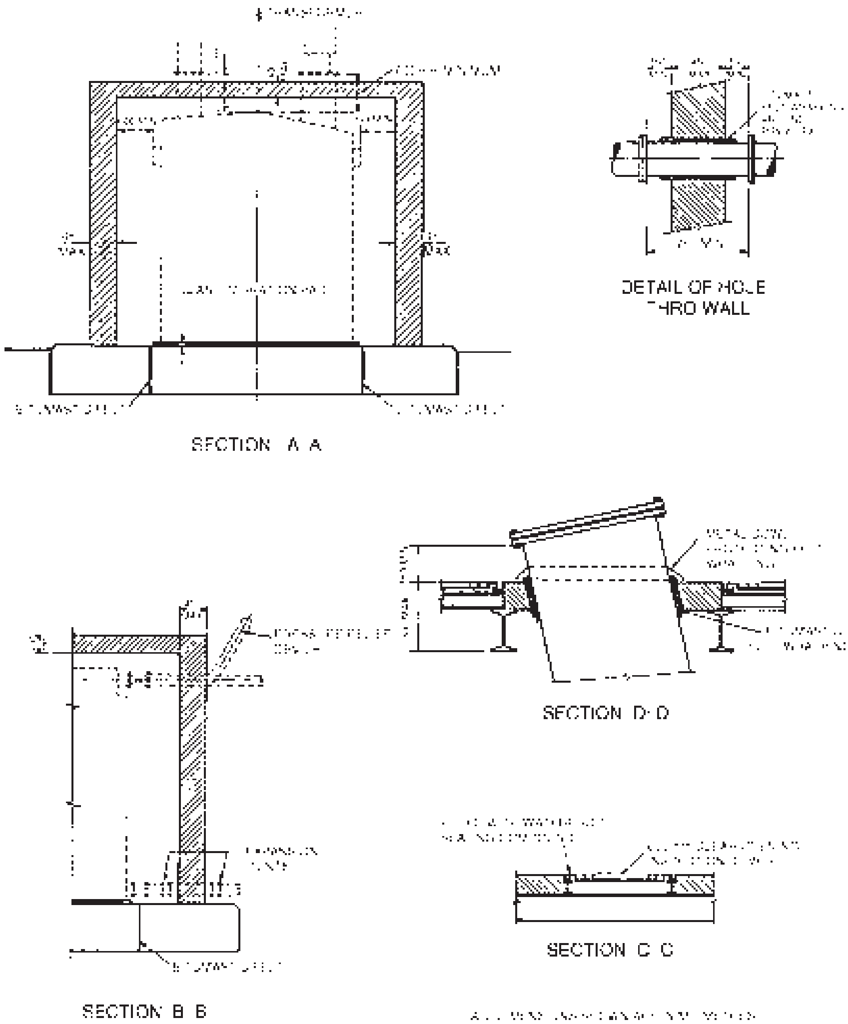


Figure 6.25b

itself, as will be evident from the typical cooler noise levels quoted above. Fan noise can be reduced by the provision of attenuators in the form of inlet and outlet ducts. These add considerably to the size of the cooler, since to be effective they must have a length of the order of one or two times the diameter of the fans on either side of the fan. *Figure 6.26* shows a large induced draught transformer-oil cooler with fans installed within inlet and outlet noise attenuators. The cooler has a total of eighteen fans provided to dissipate over 3.3 MW of losses from a large quadrature booster. The attenuators enable a noise level of 60 dBA to be obtained at a distance of 2 m from the cooler.

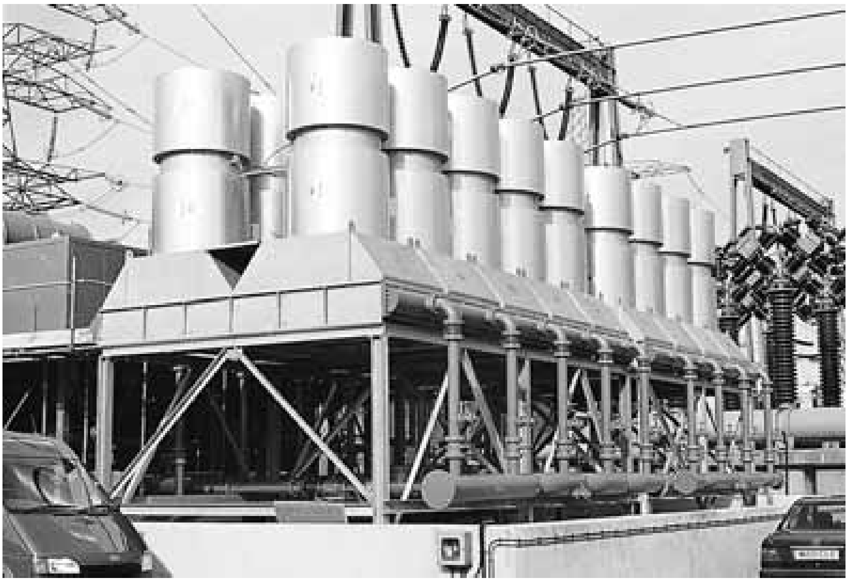


Figure 6.26 Induced draft cooler for 2000 MVA quadrature booster. The cooler has 5 sections for the shunt unit and 4 for the series unit. These are designed to dissipate 1900 kW and 1425 kW, respectively, with one section of each out of service. A noise level of 60 dBA at 2 m from the cooler was obtained by means of inlet and outlet attenuators on each of the fans (GEA Spiro-Gills Ltd)

Harmonic content of noise

Provided openings are located at the optimum position, the attenuation given by any reasonable structure will normally be above that necessary to give tolerable conditions in nearby houses. An important factor in this connection is the relatively great attenuation of the harmonic content of the noise, which has been shown earlier in this section to have a nuisance value out of all proportion to its magnitude.

Once such a structure has been erected, adequate maintenance is of the utmost importance if the initial attenuation is to be maintained. Any openings and doors should be checked frequently, as gaps may develop to a sufficient size to permit considerable escape of sound energy.

It is often advisable to compare a frequency spectrum of the noise emitted by the transformer to be installed against the spectrum of the background noise at the proposed location. In the values quoted earlier, typical frequency spectra have been assumed. Any marked deviations of the actual noises from the character attributed to them can lead to a considerable reduction in the masking power of the background noise. For this reason alone, a frequency analysis on site is valuable, even if it is compared only with an average spectrum for transformer noise, such as that given in *Figure 6.20*.

Location of transformer

Topographical features of the site should be exploited to the full in order to reduce noise. Where possible the transformer should be located in the prevailing down-wind direction from houses. Existing walls and mounds should, if possible, be kept between dwellings and the transformer. Natural hollows can sometimes be used to increase the effective height of screen walls, as can artificially constructed pits.

Cultivated shrubs and trees form only an ineffective barrier to noise as sound attenuation is largely determined by the mass of the barrier. In some cases where the smaller ratings of distribution transformers are installed, the psychological effect, however, may be sufficient to avoid a complaint simply because the transformer becomes hidden by the trees and is therefore not visible.

6.4 PARALLEL OPERATION

Parallel operation of transformers is effected when both the HV and LV windings of two (or more) transformers are connected to the same set of HV and LV busbars respectively. Since connecting two impedances in parallel will result in a combined impedance which is very much less than either of the components (paralleling two identical transformers results in a combination which has an impedance of half that of each, individually) the primary result of this is to increase the fault level of the LV busbar. Care must therefore be taken to ensure that the fault capability of the LV switchgear is not exceeded. Unless fuse protection is provided each of the outgoing circuits would also need to be designed and cabled to withstand the full fault level of the paralleled transformers.

In the study of the parallel operation of transformers, polarity and phase sequence play important parts, and so it is essential to consider these characteristics in some detail before passing on to the more general treatment of parallel operation. The points to consider are the relative directions of the windings, the voltages in the windings and the relative positions of leads from coils to terminals. To understand how each of these factors interact it is best to consider transformer operation in instantaneous voltage terms relating directly to a phasor diagram, that is, by studying transformer polarity diagrams basing an explanation upon the instantaneous voltages *induced* in both windings, as this procedure avoids any reference to primary and secondary windings. This can be seen to be logical as transformer polarity and phase sequence are independent of such a distinction.

As discussed in Chapter 2, the voltages induced in the primary and secondary windings are due to a common flux. The induced voltages in each turn of each of the windings must be in the same direction, since any individual turn cannot be said to possess one particular direction around the core any more than it possesses the opposite one. Direction is given to a complete winding, however, when a number of these individual turns are connected in series, one end of the winding being labelled ‘start’ and the other ‘finish’, or one being called, say, A_1 and the other end A_2. The directions of the total voltages induced in the primary and secondary windings will therefore depend upon the relative directions of the respective windings between their associated terminals. In considering direction of windings it is necessary to do so from similarly labelled or assumed similar terminals; that is, both primary and secondary windings should be considered in the direction from start to finish terminals (or even the reverse if desired), but they should not be considered one from start to finish and the other from finish to start. Where the start and finish of the windings are not known, adjacent primary and secondary terminals may be assumed initially to correspond to similar ends of the respective windings, but this must be verified by carrying out an induced voltage test at reduced voltage as described below.

Transformer terminal marking, position of terminals and phasor diagrams

Terminal markings

Transformer markings are standardised in various national specifications. For many years the British Standard, BS 171, has used ABCN, abcn as the phase symbols unlike many other parts of the world where the letters UVW, uvw have been used for the phases. A few years ago there was some move in the UK toward the adoption of the international UVW, uvw system. However, such a change must always be slow to take effect because of the amount of existing plant using the earlier system. Some of the momentum for change now appears to have been lost so that both systems are in use in the UK. For this text the nomenclature $ABCY_N(Z_N)$ and $abcy_n(z_n)$ is used.

Individual phase windings are given descriptive letters and the same letter in combination with suffix numbers is then used for all windings of one phase. The HV winding has been given a capital letter and the LV winding on the same phase a corresponding small letter. The following designations are used. For single-phase transformers:

A: for the HV winding

3A: for the third winding (if any)

a: for the LV winding

For two-phase windings on a common core or separate cores in a common tank:

AB: for the HV windings

ab: for the LV windings

For three-phase transformers:

ABC: for the HV windings

3A3B3C: for the third windings (if any)

abc: for the LV windings

Figure 6.27 shows an example of standard marking of a single-phase transformer.

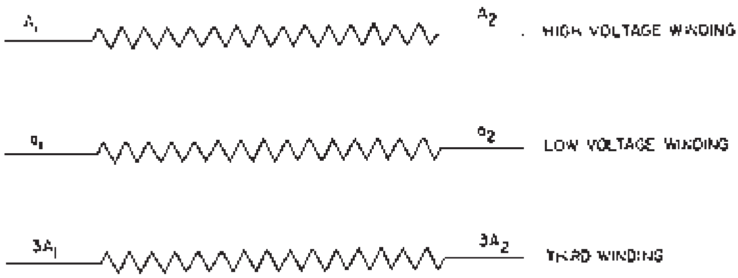


Figure 6.27 Terminal marking of a single-phase transformer having a third winding

Position of terminals

For three-phase transformers when facing the HV side the terminals are located from left to right NABC, and when facing the LV side cban. The neutral terminal may be at either end, but if no preference is stated, it should be at the left-hand end when viewed from the HV side and the LV neutral will accordingly be at the right-hand end when viewed from the LV side. Examples of both single-and three-phase terminal marking are shown in *Figure 6.28*.

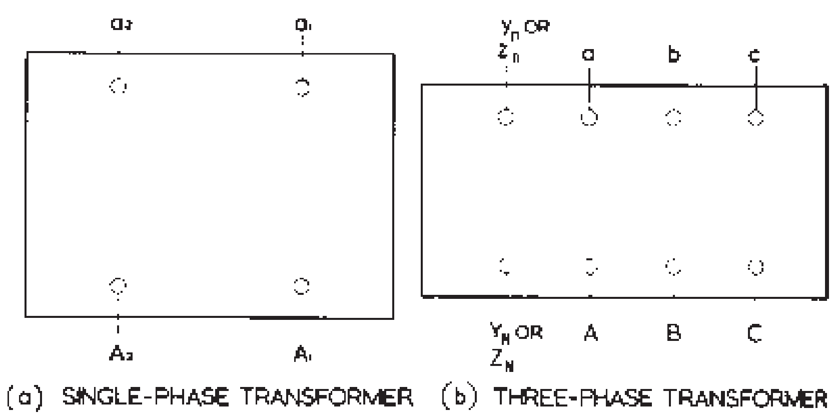


Figure 6.28 Relative position of terminals of two-winding transformers

In addition to the letter marking of terminals, suffix numbers are given to all tapping points and to the ends of the winding. These suffix numbers begin at unity and then with ascending numbers are ascribed to all tapping points, such that the sequence represents the direction of the induced e.m.f. at some instant of time. For three-phase star-connected windings lowest suffix numbered connections are taken to the neutral, highest numbered are taken to the line terminals. In the case of an HV winding without tappings for which the phase marking is A, the ends of the winding would be marked A_1, A_2. If this were the A phase of a three-phase star-connected transformer, A_1 would be connected to the star point, A_2 would be the line terminal. Similarly the LV winding would be marked a_1, a_2. As described later in this section, it is an easy matter to check the terminal marking (see *Figure 6.35*). Typical examples of the marking of tappings are shown in *Figure 6.29*.

The neutral connection, when brought out in the form of an external terminal, is marked Y_N in the case of an HV winding and y_n in the case of an LV winding. No suffix number is required.

Autotransformer terminal marking includes the appropriate phase and suffix number and it should be noted that for tappings the higher suffix numbers correspond to the higher voltages. *Figure 6.29(d)* shows a typical terminal marking for an autotransformer.

Phasor diagrams

Phasors in transformer phasor diagrams represent the induced e.m.f.s and the counterclockwise direction of rotation of the phasor is employed. The phasor representing any phase voltage of the LV winding is shown parallel to that representing the corresponding phase voltage of the HV winding.

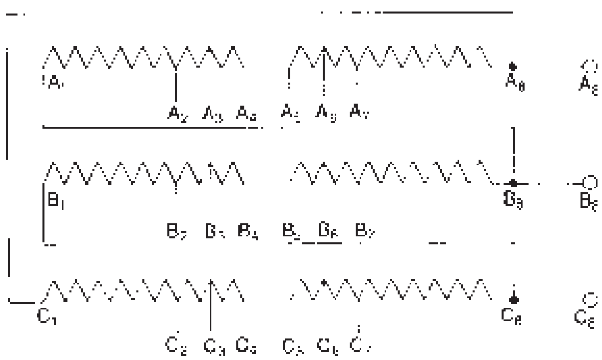
Various types of interphase connections for three-phase transformers having the same phase displacement between the HV and LV windings can be grouped together and the four groups are shown in *Table 6.4*.

In *Table 6.4* it will be seen that the phase displacement has a corresponding clock hour number. The phase displacement is the angle of phase advancement turned through by the phasor representing the induced e.m.f. between a high-voltage terminal and the neutral point which may, in some cases, be imaginary, and the phasor representing the induced e.m.f. between the LV terminal having the same letter and the neutral point. An internationally adopted convention for indicating phase displacement is to use a figure which represents the hour indicated by a clock where the minute hand replaces the line to neutral voltage phasor for the HV winding and is set at 12 o'clock and where the hour hand represents the line to neutral voltage phasor for the LV winding. It therefore follows that the clock hour number is obtained by dividing the phase displacement angle in degrees by 30. The phase angles of the various windings of three-phase transformers are determined with reference to the highest voltage being taken as the phasor of origin.

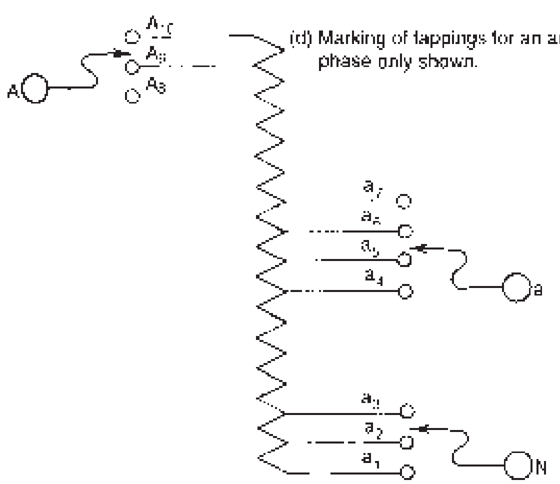
The phasor diagram, the phase displacement and the terminal marking are all identifiable by the use of symbols which for transformers having two windings, if taken in order, have the following significance:

(a) SINGLE-PHASE WINDING WITH TAPPINGS AT THE ENDS.

(b) SINGLE-PHASE WINDING WITH TAPPINGS AT THE MIDDLE.



(c) THREE-PHASE WINDING WITH TAPPINGS AT THE MIDDLE.



(d) Marking of tappings for an autotransformer – one phase only shown.

Figure 6.29 Marking of tappings on phase windings

First symbol: HV winding connection.

Second symbol: LV winding connection.

Third symbol: phase displacement expressed as the clock hour number (see *Table 6.4,* column 3).

The interphase connections of the HV and LV windings are indicated by the use of the initial letters as given in *Table 6.5* and the terms high and low voltage used in this table are used in a relative sense only.

Table 6.4 Group numbers

Group number	*Phase displacement*	*Clock hour number*
I	0°	0
II	180°	6
III	−30°	1
IV	+30°	11

A transformer having a delta-connected high-voltage winding, a star-connected lower voltage winding and a phase displacement of +30° (corresponding to a clock hour number of 11), therefore has the symbol Dy11.

Table 6.5 Winding connection designations

Winding connection		*Designation*
high voltage	delta	D
	star	Y
	interconnected star	Z
low voltage	delta	d
	star	y
	interconnected star	z

The following standard phasor diagrams which are frequently encountered in practice are included for single-, two- and three-phase transformers.

Three-phase transformers, phase displacement	0°	see *Figure 6.30*
Three-phase transformers, phase displacement	180°	see *Figure 6.31*
Three-phase transformers, phase displacement	−30°	see *Figure 6.32*
Three-phase transformers, phase displacement	+30°	see *Figure 6.33*
Single-, two-, three- to two-phase transformers		see *Figure 6.34*

Various other combinations of interphase connections having other phasor relationships occur but they are only infrequently manufactured and it is left to the reader to evolve the phasor diagram and symbol.

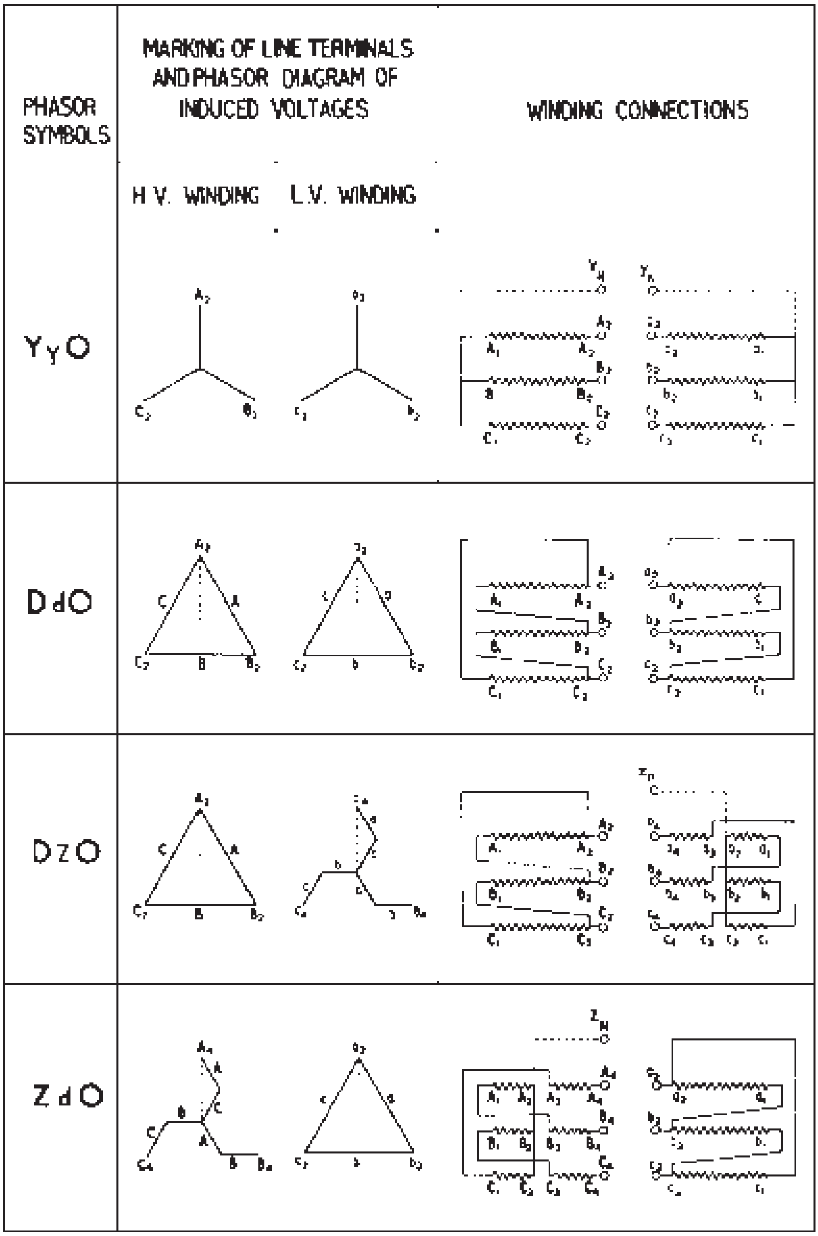


Figure 6.30 Phasor diagrams for three-phase transformers. Group No. I: phase displacement = 0°

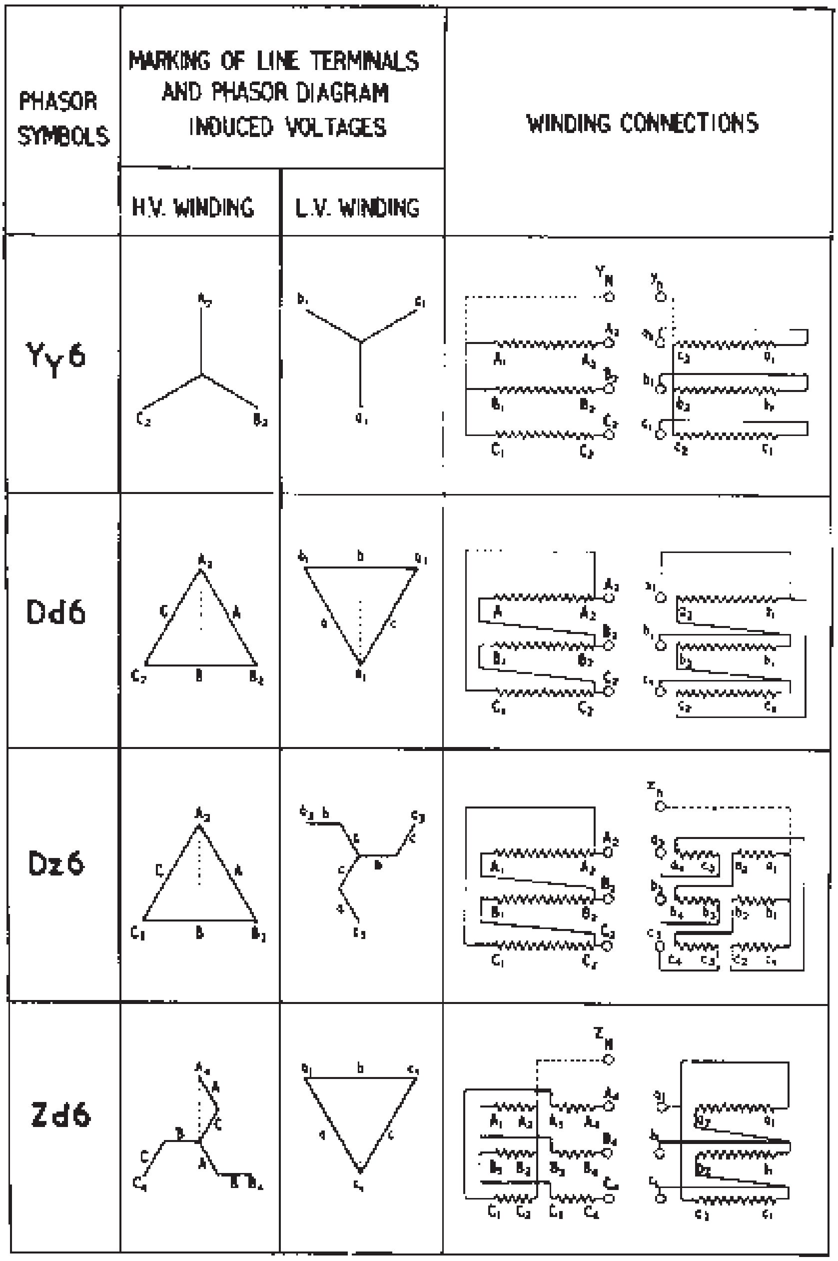


Figure 6.31 Phasor diagrams for three-phase transformers. Group No. II: phase displacement = 180°

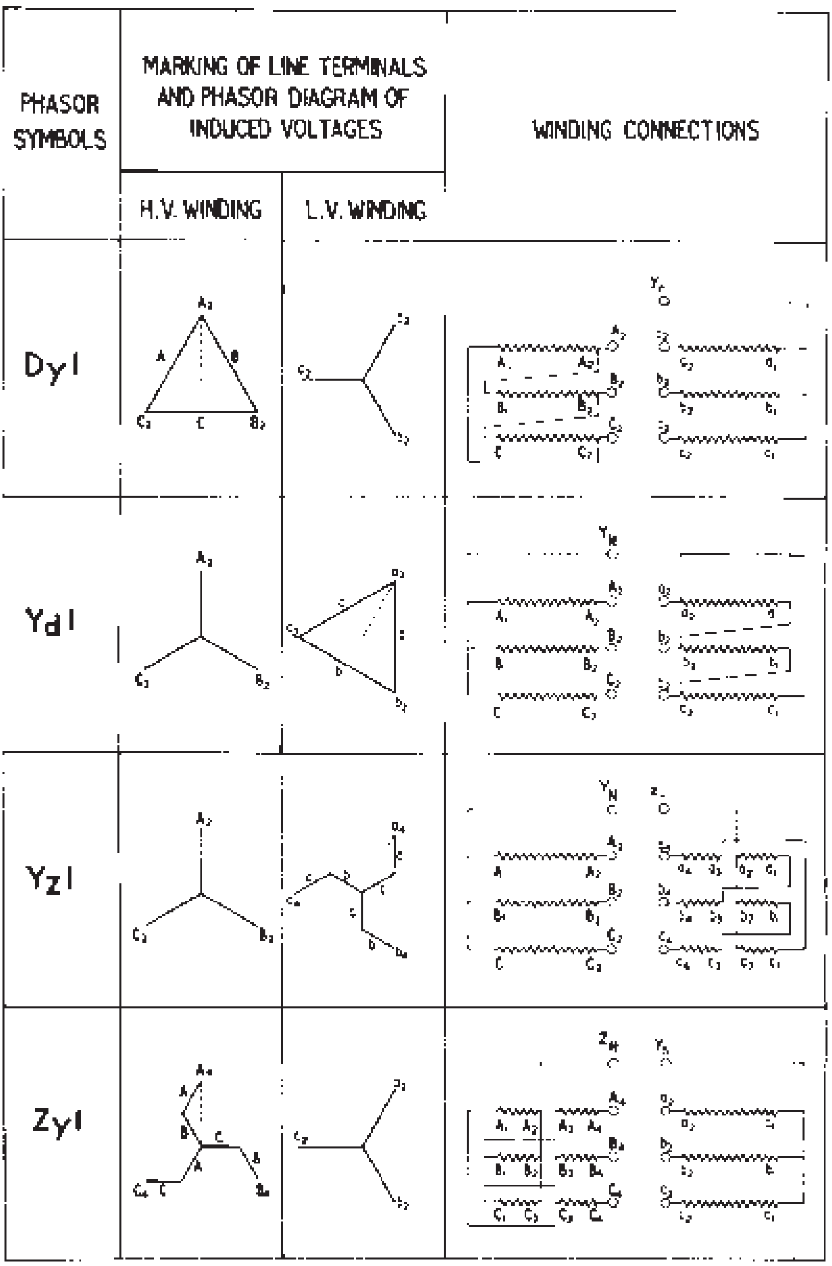


Figure 6.32 Phasor diagrams for three-phase transformers. Group No. III: phase displacement = $-30°$

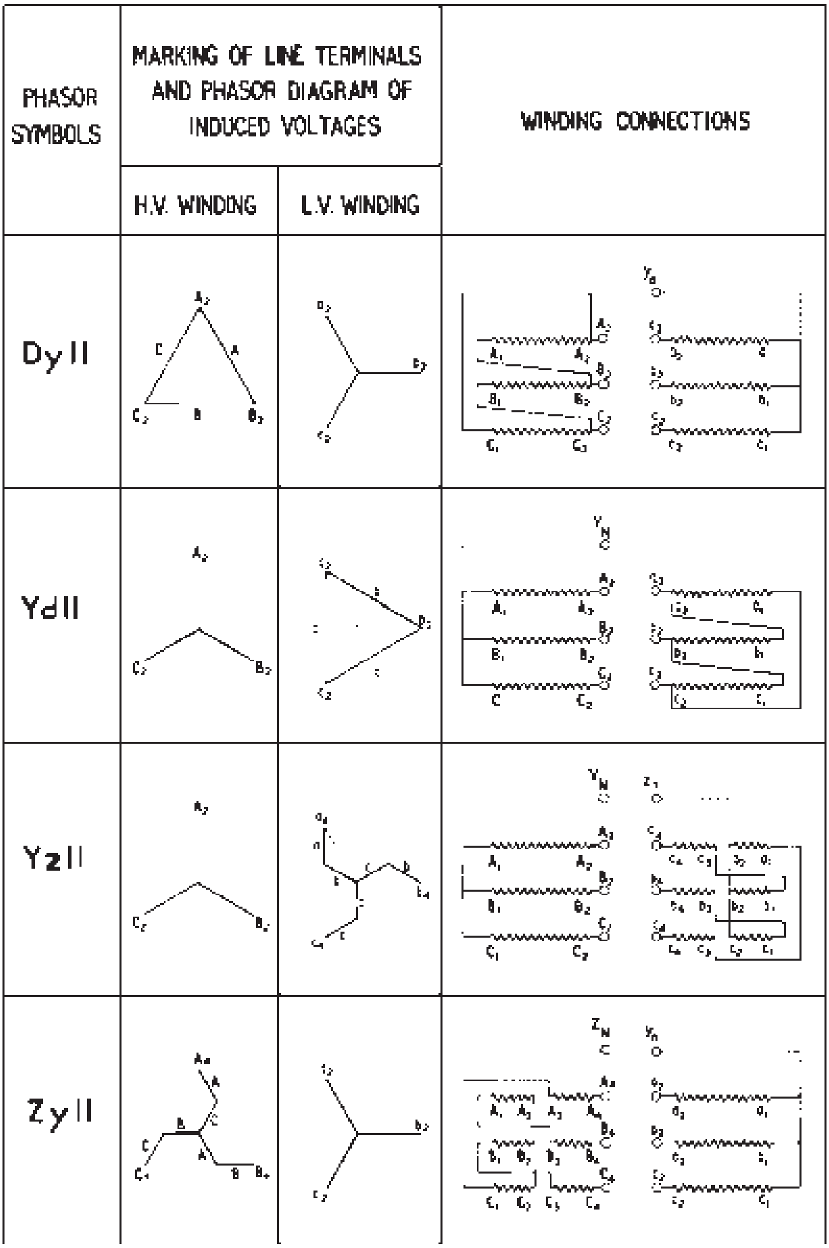


Figure 6.33 Phasor diagrams for three-phase transformers. Group No. IV: phase displacement = plus 30°

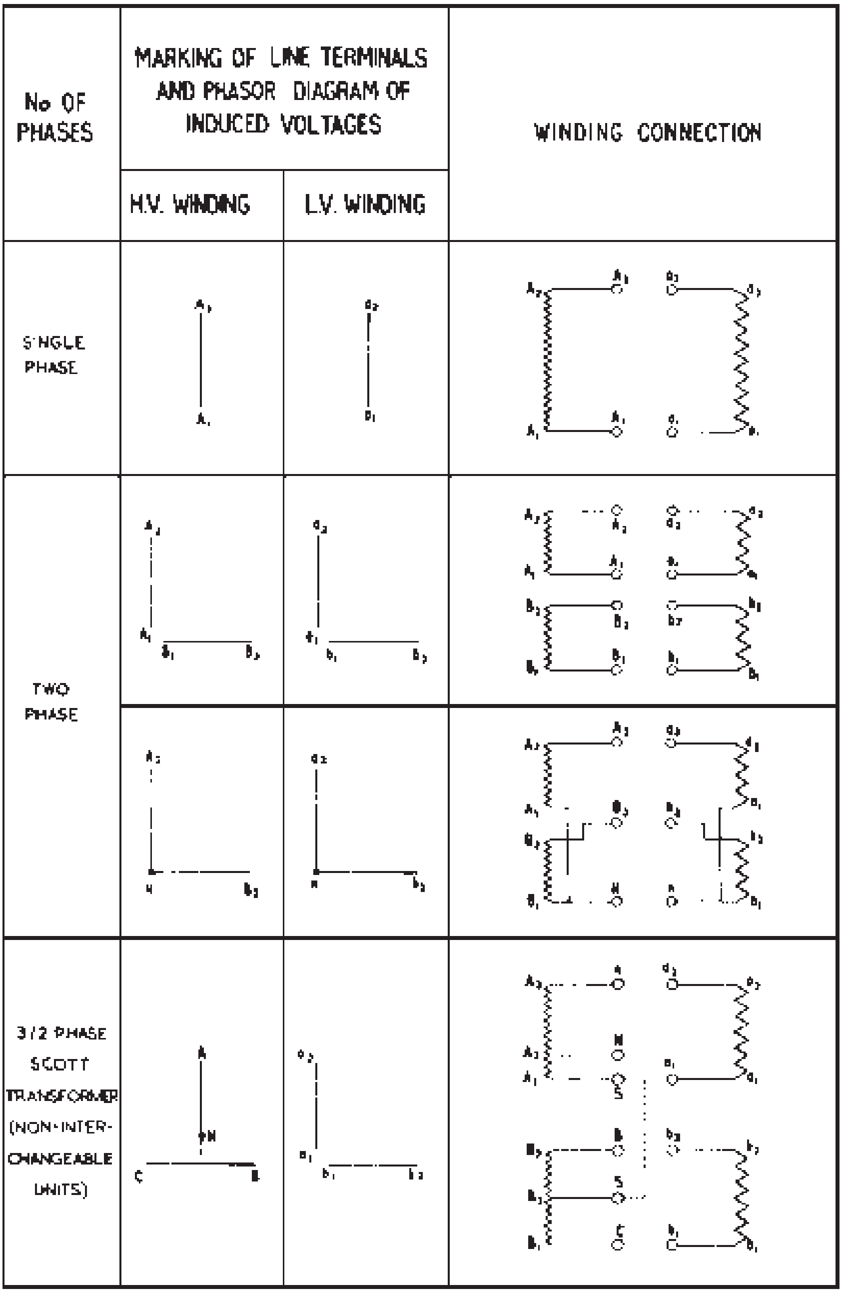


Figure 6.34 Phasor diagrams for single-, two- and three- to two-phase transformers

Polarity

In the more general sense the term polarity, when used with reference to the parallel operation of electrical machinery, is understood to refer to a certain relationship existing between *two or more* units, but the term can also be applied to two separate windings of any individual piece of apparatus. That is, while two separate transformers may, under certain conditions of internal and external connection, have the same or opposite polarity, the primary and secondary windings of any individual transformer may, under certain conditions of coil winding, internal connections, and connections to terminals, have the same or opposite polarity. In the case of the primary and secondary windings of an individual transformer when the respective induced terminal voltages are in the same direction, that is, when the polarity of the two windings is the same, this polarity is generally referred to as being subtractive; while when the induced terminal voltages are in the opposite direction, the windings are of opposite polarity, generally referred to as being additive.

This subject of polarity which was explained briefly in Chapter 2 can cause a great deal of confusion so it is worthwhile considering this a little more fully in order to obtain a complete understanding. It is helpful to consider, as an example, a plain helical winding, although, of course, the principle applies to any type of winding be this helical, disc, or crossover coils.

Starting from one end of a cylindrical former, assumed for the purpose of illustration to be horizontal, in order to produce a helical winding, it is most convenient for the winder to anchor the conductor to the top of the former and rotate this away from him, that is, so that the upper surface moves away from him. If he starts at the left-hand end the conductor will then be laid in the manner of a normal right-hand screw thread and if he starts at the right-hand end the conductor will take the form of a left-hand screw thread. If, at the completion of a layer, the winder wishes to continue with a second layer he must now start at the opposite end, so that if the first layer were wound left to right, the second layer will be wound right to left. The two layers thus wound will have *additive polarity*, that is, the voltage output from this two-layer winding will be the sum of the voltages produced by each of the layers. If, however, on completion of the first layer the winder had terminated the conductor and then started again winding a second layer from the same end as he started the first layer, and then connected together the two finishes, then the voltage output from this two-layer winding will be nil. These two layers have thus been wound with *subtractive polarity*. The foregoing description can be equally applicable to separate windings as to individual layers within a multilayer winding, so that the terms additive and subtractive polarity can be used to describe the manner of producing the windings of a complete transformer. The HV and LV windings of a two-winding transformer may thus have additive or subtractive polarity.

It will be seen from the above illustration that when both windings are wound in the same sense, the result is that their polarities are subtractive.

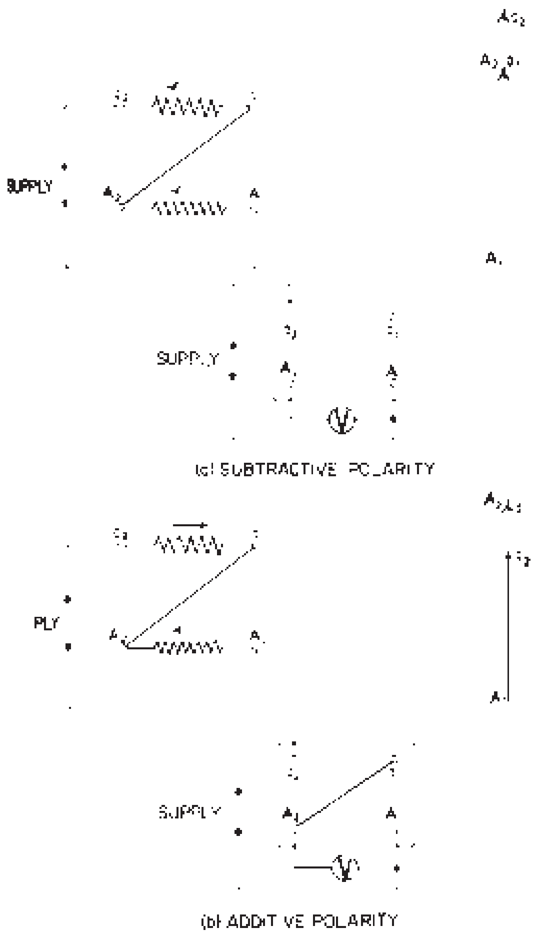


Figure 6.35 Test connections for determining single-phase transformer winding polarity

To determine the polarity of a transformer by testing, the method is to connect together corresponding terminals of HV and LV windings, *Figure 6.35*, which is equivalent to the winder connecting together the corresponding ends of the layers of the two-layer windings in the above example. If the HV winding has terminals A_1 and A_2 and the LV winding a_1 and a_2, then if terminals A_2 and a_2 are connected together with a voltage applied to $A_1 - A_2$, then the voltage measured across $A_1 - a_1$ will be less than that applied to $A_1 - A_2$ if the polarity is subtractive and more than that applied to $A_1 - A_2$ if the polarity is additive.

Manufacturers will normally designate a particular method of winding, i.e. start left or start right as described in the above example, as their *standard* winding method. They will also have a standard method of designating terminals, say 'starts' to become the lowest numbered terminal, 'finishes' to have the highest numbered terminal. They will then prefer to wind and connect the transformers according to these standards, in other words they will normally wind all windings in the same sense, so that most transformers will normally have subtractive polarity.

For three-phase transformers the testing procedure is similar, except that the windings must, of course, be excited from a three-phase supply, and considerably more voltage measurements have to be made before the exact polarity and phase sequence can be determined. *Figure 6.36* shows the test connections and results for a star/star-connected transformer with subtractive polarity.

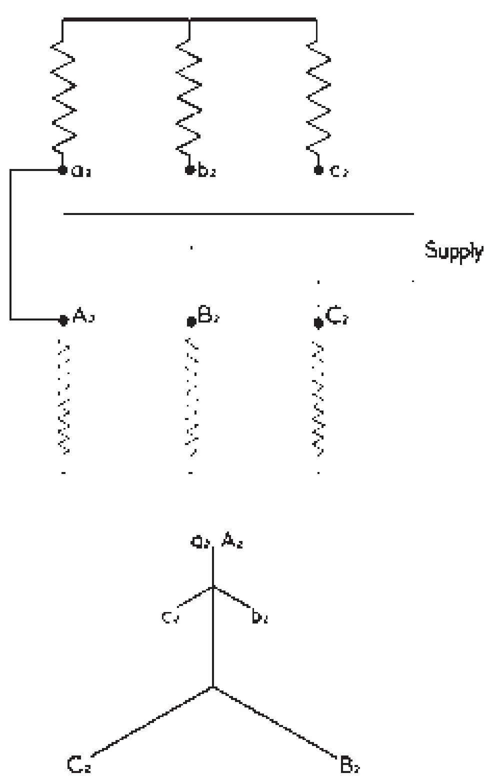


Figure 6.36 Test connections for determining three-phase transformer winding polarity

Phase sequence

Phase sequence is the term given to indicate the angular direction in which the voltage and current phasors of a polyphase system reach their respective maximum values during a sequence of time. This angular direction may be clockwise or counterclockwise, but for two transformers to operate satisfactorily in parallel it must be the same for both. Phase sequence of polyphase transformers is, however, intimately bound up with the question of polarity.

It should be remembered that phase sequence is really a question of the sequence of *line terminal* voltages, and not necessarily of the voltages across individual windings. While the actual phase sequence of the supply is fixed by the system configuration and maintained by the generating plant, the sequence in which the secondary voltages of a transformer attain their maximum values can be in one direction or the other, according to the order in which the primary terminals of the transformer are supplied.

Figure 6.37 shows four instances of a delta/star-connected transformer under different conditions of polarity and phase sequence, and a comparison of these diagrams shows that interchanging any one pair of the supply connections to the primary terminals reverses the phase sequence. If, however, the internal connections on the secondary side of the transformer are reversed, the interchanging of any two primary supply connections will produce reverse phase sequence and non-standard polarity. If with reverse internal connections on one side the primary connections are not interchanged, the resulting phase sequence will be the same and the polarity will be non-standard. The above remarks apply strictly to transformers in which the primary and secondary windings have different connections, such as delta/star, but where these are the same, such as star/star, the polarity can only be changed by reversing the internal connections on one side of the transformer. The phase sequence alone may, however, be reversed by interchanging two of the primary supply leads.

If tests indicate that two transformers have the same polarity and reverse phase sequence, they may be connected in parallel on the secondary side simply by interchanging a certain pair of leads to the busbars of one of the transformers. Referring to *Figure 6.37*, for instance, transformers to diagrams *(a)* and *(d)* can be paralleled so long as the secondary leads from a_1 and c_1 to the busbars are interchanged.

The satisfactory parallel operation of transformers is dependent upon five principal characteristics; that is, any two or more transformers which it is desired to operate in parallel should possess:

1. The same inherent phase angle difference between primary and secondary terminals.
2. The same voltage ratio.
3. The same percentage impedance.

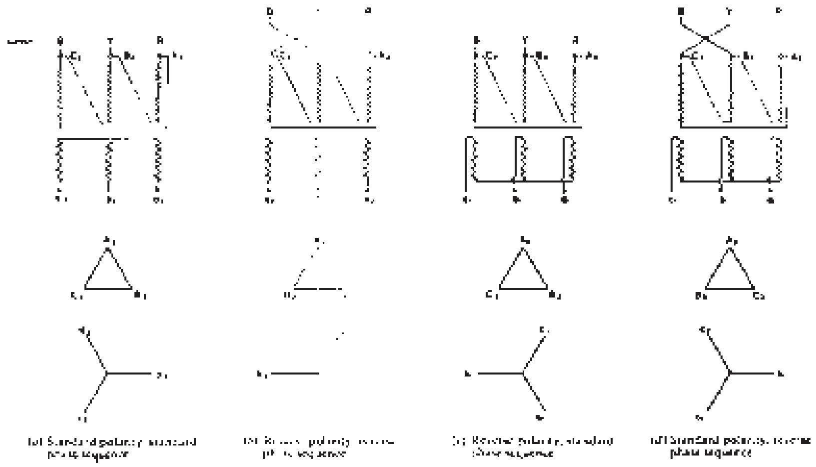


Figure 6.37 Diagrams showing four examples of a three-phase delta/star-connected transformer having differing polarity and phase sequence

4. The same polarity.
5. The same phase sequence.

To a much smaller extent parallel operation is affected by the relative outputs of the transformers, but actually this aspect is reflected into the third characteristic since, if the disparity in outputs of any two transformers exceeds three to one it may be difficult to incorporate sufficient impedance in the smaller transformer to produce the correct loading conditions for each unit.

Characteristics 1 and 5 only apply to polyphase transformers. A very small degree of latitude may be allowed with regard to the second characteristic mentioned above, while a somewhat greater tolerance may be allowed with the third, but the polarity and phase sequence, where applicable, of all transformers operating in parallel *must* be the same.

Single-phase transformers

The theory of the parallel operation of single-phase transformers is essentially the same as for three-phase, but the actual practice for obtaining suitable connections between any two single-phase transformers is considerably simpler than the determination of the correct connections for any two three-phase transformers.

Phase angle difference between primary and secondary terminals

In single-phase transformers this point does not arise, as by the proper selection of external leads any two single-phase transformers can be connected so that the phase angle difference between primary and secondary terminals is the same for each. Consequently the question really becomes one of polarity.

Voltage ratio

It is very desirable that the voltage ratios of any two or more transformers operating in parallel should be the same, for if there is any difference whatever a circulating current will flow in the secondary windings of the transformers when they are connected in parallel, and even before they are connected to any external load. Such a circulating current may or may not be permissible. This is dependent firstly on its actual magnitude and, secondly, on whether the load to be supplied is less than or equal to the sum of the rated outputs of the transformers operating in parallel. As a rule, however, every effort should be made to obtain identical ratios, and particular attention should be given to obtaining these at all ratios when transformers are fitted with tappings. In passing, it may be well to point out that when a manufacturer is asked to design a transformer to operate in parallel with existing transformers, the actual ratio of primary and secondary *turns* should be given, as this ratio can easily be obtained exactly. Such figures would, of course, be obtained from the works test certificate for the existing transformers.

Equations (6.5) to (6.23) inclusive show how the values of these circulating currents can be calculated when certain of the transformer characteristics differ. Equations (6.5) to (6.9) show how to derive the circulating currents when two single- or three-phase transformers, having different ratios, operate in parallel, while equations (6.10) to (6.14) apply to the case of three single- or three-phase transformers.

It is to be noted that this flow of circulating current takes place before the transformers are connected up to any external load. A circulating current in the transformer windings of the order of, say, 5% of the full-load current may generally be allowed in the case of modern transformers without any fear of serious overheating occurring. It is sometimes very difficult to design new transformers to give a turns ratio on, say, four tappings identical to what an existing one may possess, and while it is desirable that the ratios should be the same, it is not necessary to *insist* on their being identical.

Equation (6.5): The circulating current in amperes at no load in two single- or three-phase transformers A and B connected in parallel, having different voltage ratios, the same or different outputs, the same or different impedances, and the impedances having the same ratios of resistance to reactance, is equal to:

$$\frac{V_A - V_B}{Z_A - Z_B} \tag{6.5}$$

where $V_A =$ secondary line terminal voltage of transformer A having the lower ratio, i.e. the higher secondary voltage

$V_B =$ secondary line terminal voltage for transformer B having the higher ratio, i.e. the lower secondary voltage

$^*Z_A,\ Z_B =$ ohmic impedances of transformers A and B respectively, and are obtained from the equations:

* These quantities are the transformer resistances and reactances between two secondary line terminals.

$$Z_A = \frac{V_{ZA}V_A}{100I_A} \quad Z_B = \frac{V_{ZB}V_B}{100I_B} \tag{6.6}$$

where V_{ZA}, V_{ZB} = percentage impedance voltage drops at full-load ratings of the transformers A and B respectively;

I_A, I_B = full-load line currents in amperes of transformers A and B respectively.

In the case of certain system transformers operating in parallel it is relatively common practice to set the on-load tap changers to give a 'tap stagger' so that the system voltage profile at the point where the transformers are located can be varied by adjusting the reactive load flows at that point. Such practice results in local circulating currents between the transformers irrespective of their load throughput.

Equation (6.7): The circulating current in amperes at no load in two single- or three-phase transformers A and B connected in parallel, having different voltage ratios, the same or different outputs, the same or different impedances, but the impedances having different ratios of resistance to reactance, is equal to:

$$\frac{V_A - V_B}{Z} \tag{6.7}$$

where V_A = secondary terminal voltage of transformer A, having the lower ratio, i.e. the higher secondary voltage

V_B = secondary line terminal voltage of transformer B, having the higher ratio, i.e the lower secondary voltage

$^*Z$ = vector sum of the ohmic impedances of transformers A and B, and is obtained from the equation:

$$Z = \sqrt{\{(R_A + R_B)^2 + (X_A + X_B)^2\}} \tag{6.8}$$

where

$$\begin{aligned}
^*R_A &= \text{ohmic resistance of transformer A, and equals } \frac{V_{RA}V_A}{100I_A} \\
^*R_B &= \text{ohmic resistance of transformer B, and equals } \frac{V_{RB}V_B}{100I_B} \\
^*X_A &= \text{ohmic reactance of transformer A, and equals } \frac{V_{XA}V_A}{100I_A} \\
^*X_B &= \text{ohmic reactance of transformer B, and equals } \frac{V_{XB}V_B}{100I_B}
\end{aligned} \tag{6.9}$$

$V_{RA},\ V_{RB}$ = percentage resistance voltage drops at normal full-load ratings of transformers A and B respectively

$V_{XA},\ V_{XB}$ = percentage reactance voltage drops at normal full-load ratings of transformers A and B respectively

$I_A,\ I_B$ = normal full-load line currents in amperes of transformers A and B respectively

Equations (6.10)–(6.12): The circulating currents in amperes at no load in three single- or three-phase transformers A, B and C connected in parallel, each having different voltage ratios, the same or different impedances, the same or different outputs, and the impedances having the same ratio of resistance to reactance, are given by:

In transformer A

$$\frac{V_A - M}{Z_A} \tag{6.10}$$

In transformer B

$$\frac{V_B - M}{Z_B} \tag{6.11}$$

and in transformer C

$$\frac{V_C - M}{Z_C} \tag{6.12}$$

where V_A = secondary line terminal voltage of transformer A, having the lowest ratio, i.e. the highest secondary voltage

V_B = secondary line terminal voltage of transformer B, having the next higher ratio, i.e. the next lower secondary voltage

V_C = secondary line terminal voltage of transformer C, having the highest ratio, i.e. the lowest secondary voltage

And where for transformers A, B and C, respectively,

*$Z_A,\ Z_B,\ Z_C$ = ohmic impedances and are obtained from the equations:

$$Z_A = \frac{V_{ZA}V_A}{100I_A}$$

$$Z_B = \frac{V_{ZB}V_B}{100I_B} \tag{6.13}$$

$$Z_C = \frac{V_{ZC}V_C}{100I_C}$$

where $V_{ZA},\ V_{ZB},\ V_{ZC}$ = percentage impedance voltage drops at full-load ratings

$I_A,\ I_B,\ I_C$ = full-load line currents in amperes

$$M = \frac{V_A Z_B Z_C + V_B Z_A Z_C + V_C Z_A Z_B}{Z_A Z_B + Z_B Z_C + Z_C Z_A} \tag{6.14}$$

Equations (6.15)–(6.17): The circulating currents in amperes at no load in three single- or three-phase transformers A, B and C connected in parallel, having different voltage ratios, the same or different outputs, the same or different impedances, but the impedances having different ratios of resistance to reactance, are given by:

$$\text{In transformer A} \quad \frac{100 I_A}{V_A V_{ZA}} \sqrt{\{(V_A - S)^2 + T^2\}} \tag{6.15}$$

$$\text{In transformer B} \quad \frac{100 I_B}{V_B V_{ZB}} \sqrt{\{(V_B - S)^2 + T^2\}} \tag{6.16}$$

$$\text{and in transformer C} \quad \frac{100 I_C}{V_C V_{ZC}} \sqrt{\{(V_C - S)^2 + T^2\}} \tag{6.17}$$

where

$$T = \frac{\left(\sum \frac{IV_R}{V_Z^2 V} \sum \frac{IV_X}{V_Z^2}\right. - \left(\sum \frac{IV_X}{V_Z^2 V} \sum \frac{IV_R}{V_Z^2}\right.}{\left(\sum \frac{IV_X}{V_Z^2 V}\right.^{2} + \left(\sum \frac{IV_R}{V_Z^2 V}\right.^{2}} \tag{6.18}$$

$$S = \frac{\left(\sum \frac{IV_X}{V_Z^2 V} \sum \frac{IV_X}{V_Z^2}\right. + \left(\sum \frac{IV_R}{V_Z^2 V} \sum \frac{IV_R}{V_Z^2}\right.}{\left(\sum \frac{IV_X}{V_Z^2 V}\right.^{2} + \left(\sum \frac{IV_R}{V_Z^2 V}\right.^{2}} \tag{6.19}$$

The symbol 'Σ' has the usual mathematical significance, i.e.

$$\sum \frac{IV_R}{V_Z^2 V} = \frac{I_A V_{RA}}{V_{ZA}^2 V_A} + \frac{I_B V_{RB}}{V_{ZB}^2 V_B} + \frac{I_C V_{RC}}{V_{ZC}^2 V_C} \tag{6.20}$$

$$\sum \frac{IV_X}{V_Z^2} = \frac{I_A V_{XA}}{V_{ZA}^2} + \frac{I_B V_{XB}}{V_{ZB}^2} + \frac{I_C V_{XC}}{V_{ZC}^2}$$

The angle of lag* between the circulating current and the normal secondary line terminal voltages of transformers A, B and C respectively is equal to:

$$\text{for transformer A:} \tan^{-1} \frac{V_{XA} V_A - V_{XA} S - V_{RA} T}{V_{RA} V_A - V_{RA} S + V_{XA} T} \tag{6.21}$$

$$\text{for transformer B:} \tan^{-1} \frac{V_{XB} V_B - V_{XB} S - V_{RB} T}{V_{RB} V_B - V_{RB} S + V_{XB} T} \tag{6.22}$$

$$\text{and for transformer C:} \tan^{-1} \frac{V_{XC} V_C - V_{XC} S - V_{RC} T}{V_{RC} V_C - V_{RC} S + V_{XC} T} \tag{6.23}$$

* The angle of lag is taken as being positive. If the sign of any of these expression is negative the angle is leading.

where T and S have the same values as before. The remaining symbols used have the following meanings for transformers A, B and C respectively:

V_A, V_B, V_C = secondary line terminal voltages

I_A, I_B, I_C = normal full-load line currents

V_{ZA}, V_{ZB}, V_{ZC} = percentage impedance voltage drops at full-load rating

V_{RA}, V_{RB}, V_{RC} = percentage resistance voltage drops at full-load rating

V_{XA}, V_{XB}, V_{XC} = percentage reactance voltage drops at full-load rating

Percentage impedance voltage drop

The percentage impedance voltage drop is a factor inherent in the design of any transformer, and is a characteristic to which particular attention must be paid when designing for parallel operation. The percentage impedance drop is determined by the formula

$$V_Z = \sqrt{(V_R^2 + V_X^2)} \tag{6.24}$$

where V_Z is the percentage impedance drop, V_R the percentage resistance drop and V_X the percentage reactance drop, corresponding to the full-load rating of the transformer. Assuming that all other characteristics are the same, the percentage impedance drop determines the load carried by each transformer, and in the simplest case, viz, of two transformers of the same output operating in parallel, the percentage impedances must also be identical if the transformers are to share the total load equally. If, for instance, of two transformers connected in parallel having the same output, voltage ratio, etc., one has an impedance of 4% and the other an impedance of 2%, the transformer having the larger impedance will supply a third of the total bank output and the other transformer will supply two-thirds, so that the transformer having the higher impedance will only be carrying 66% of its normal load while the other transformer will be carrying 33% overload.

Equations (6.25) to (6.45) inclusive show how the division of load currents can be calculated when certain of the transformer characteristics differ. Equations (6.25) to (6.33) show how to derive the transformer load currents when two single- or three-phase transformers having different impedances operate in parallel, while equations (6.34) to (6.45) apply to the case of three single-or three-phase transformers.

When there is a phase displacement between transformer and total load currents, the phase angles can also be calculated from the equations.

Equations (6.25) and (6.26): The division of total load current I_L amperes between two single- or three-phase transformers A and B connected in parallel, having the same or different outputs, the same voltage ratios, the same or different impedances, and the same ratios of resistance to reactance, is given by:

$$I_A = \frac{I_L N_A}{N_A + N_B} \tag{6.25}$$

$$I_B = \frac{I_L N_B}{N_A + N_B} \tag{6.26}$$

where, for transformers A and B respectively

$$I_A, I_B = \text{line currents in amperes.}$$

$$\begin{aligned} N_A &= \frac{K_A}{V_{ZA}} \\ N_B &= \frac{K_B}{V_{ZB}} \end{aligned} \tag{6.27}$$

and

$$K_A, K_B = \text{normal rated outputs in kVA}$$

$$V_{ZA}, V_{ZB} = \text{percentage impedance voltage drops at full-load ratings}$$

Note. The load currents in transformers A and B are in phase with each other and with the total load current.

Equations (6.28) and (6.29): The division of total load current I_L amperes between two single-or three-phase transformers A and B connected in parallel, having the same or different outputs, the same voltage ratios, the same or different impedances, but different ratios of resistance to reactance, is given by:

$$I_A = \frac{I_L N_A}{\sqrt{(N_A^2 + N_B^2 + 2N_A N_B \cos\theta)}} \tag{6.28}$$

$$I_B = \frac{I_L N_B}{\sqrt{(N_A^2 + N_B^2 + 2N_A N_B \cos\theta)}} \tag{6.29}$$

where

$$\begin{aligned} N_A &= \frac{K_A}{V_{ZA}} \\ N_B &= \frac{K_B}{V_{ZB}} \end{aligned} \tag{6.30}$$

$$\theta = \left(\tan^{-1}\frac{V_{XB}}{V_{RB}}\right. - \left(\tan^{-1}\frac{V_{XA}}{V_{RA}}\right. \tag{6.31}$$

$$\beta = \sin^{-1}\frac{I_A \sin\theta}{I_L} \tag{6.32}$$

$$\alpha = \theta - \beta \ (\textit{Figure 6.38}) \tag{6.33}$$

and where for transformers A and B respectively:

I_A, I_B = line currents in amperes
K_A, K_B = normal rated outputs in kVA
V_{ZA}, V_{ZB} = percentage impedance voltage drops at full-load ratings
V_{XA}, V_{XB} = percentage reactance voltage drops at full-load ratings
V_{RA}, V_{RB} = percentage resistance voltage drops at full-load ratings
θ = phase angle difference between the load currents I_A and I_B, see *Figure 6.38*
β = phase angle difference between I_L and I_B, see *Figure 6.38*
α = phase angle difference between I_L and I_A, see *Figure 6.38*

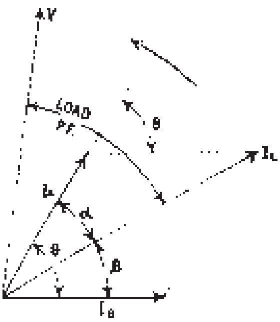


Figure 6.38 Phasor diagram showing current distribution with three transformers in parallel having different ratios of resistance to reactance

For the diagram in *Figure 6.38*

θ is positive;

I_A is leading I_L;

I_B is lagging I_L;

Transformer A has the smaller value of V_X/V_R.

Transformer B has the greater value of V_X/V_R.

When θ is negative:

I_A is lagging I_L;

I_B is leading I_L.

Transformer A has the greater value of V_X/V_R.

Transformer B has the smaller value of V_X/V_R.

Equations (6.34) to (6.36): The division of total load current I_L between three single- or three-phase transformers A, B and C connected in parallel, having the same or different outputs, the same voltage ratio, the same or different impedances, and the same ratios of resistance to reactance, is given by:

$$I_A = \frac{N_A I_L}{N_A + N_B + N_C} \tag{6.34}$$

$$I_B = \frac{N_B I_L}{N_A + N_B + N_C} \tag{6.35}$$

$$I_C = \frac{N_C I_L}{N_A + N_B + N_C} \tag{6.36}$$

where for transformers A, B and C respectively

$I_A,\ I_B,\ I_C =$ line currents in amperes

$$N_A = \frac{K_A}{V_{ZA}}$$

$$N_B = \frac{K_B}{V_{ZB}} \tag{6.37}$$

$$N_C = \frac{K_C}{V_{ZC}}$$

and where $K_A, K_B, K_C =$ normal rated outputs in kVA
$V_{ZA}, V_{ZB}, V_{ZC} =$ percentage impedance voltage drops at full-load ratings

Equations (6.38) to (6.40): The division of total load current I_L between three single- or three-phase transformers A, B and C connected in parallel, having the same or different outputs, the same voltage ratios, the same or different impedances, but different ratios of resistance to reactance, is given by:

$$I_A = \frac{I_L}{\sqrt{\{1 + k_1^2 + 2k_1 \cos(\theta_2 + \beta)\}}} \tag{6.38}$$

$$I_B = \frac{I_A N_B}{N_A} \tag{6.39}$$

$$I_C = \frac{I_A N_C}{N_A} \tag{6.40}$$

where $I_A, I_B, I_C =$ line currents in amperes
k_1 is a constant and equals:

$$\frac{1}{N_A}\sqrt{(N_B^2 + N_C^2 + 2N_B N_C \cos\theta_1)} \tag{6.41}$$

$$N_A = \frac{K_A}{V_{ZA}}$$
$$N_B = \frac{K_B}{V_{ZB}} \tag{6.42}$$
$$N_C = \frac{K_C}{V_{ZC}}$$

β is an angular constant and equals (*Figure 6.39*):

$$\sin^{-1}\left(\frac{N_C \sin\theta_1}{N_A k_1}\right. \tag{6.43}$$

$$\theta_1 = \tan^{-1}\left(\frac{V_{XB}}{V_{RB}}\right. - \tan^{-1}\left(\frac{V_{XC}}{V_{RC}}\right. \tag{6.44}$$

$$\theta_2 = \tan^{-1}\left(\frac{V_{XA}}{V_{RA}}\right. - \tan^{-1}\left(\frac{V_{XB}}{V_{RB}}\right. \tag{6.45}$$

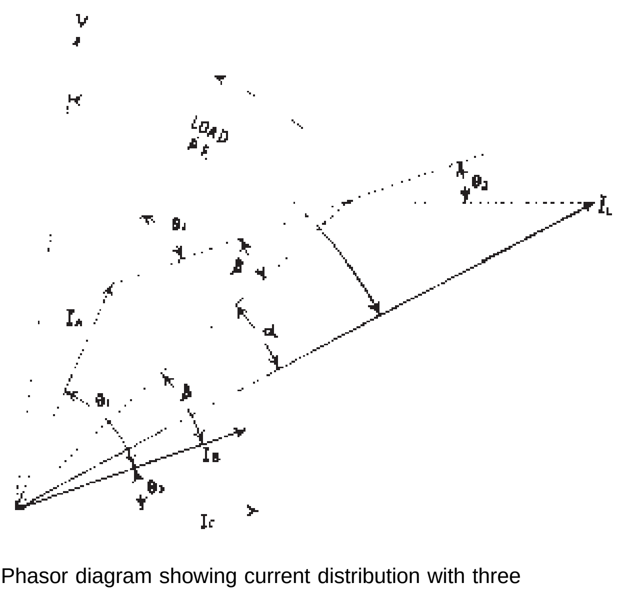


Figure 6.39 Phasor diagram showing current distribution with three transformers in parallel having different ratios of resistance to reactance

and where for transformers A, B and C respectively:

K_A, K_B, K_C = normal rated outputs in kVA
V_{ZA}, V_{ZB}, V_{ZC} = percentage impedance voltage drops at full-load ratings
V_{XA}, V_{XB}, V_{XC} = percentage reactance voltage drops at full-load ratings
V_{RA}, V_{RB}, V_{RC} = percentage resistance voltage drops at full-load ratings

θ_1 = phase angle difference between the load currents I_A and I_B
θ_2 = phase angle difference between the load currents I_B and I_C

From the geometry of the figure,

$$\alpha = \sin^{-1} \frac{I_C}{I_L} \sin(\beta + \theta_2)$$

and the phase angle difference between the load current I_A in transformer A and the total load current I_L is $(\theta_1 - \beta + \alpha)$. Having fixed the phase relationship of the total load current to the load current in one transformer, it is a simple matter to determine the angles between the total load current and the load currents in the remaining two transformers. If β is greater than α, the load current I_B in transformer B is lagging with respect to I_L: if β is smaller than α, I_B is leading with respect to I_L.

For the diagram in *Figure 6.39*

θ_1 and θ_2 are positive;

I_A is leading I_L;

I_C is lagging I_L.

Transformer A has the smallest ratio of V_X/V_R.

Transformer C has the greatest ratio of V_X/V_R.

I_B may lead or lag I_L, according to the inter-relationship of its value of V_X/V_R with the values of V_X/V_R of the other two transformers.

When θ_1 and θ_2 are negative:

I_A is lagging I_L;

I_C is leading I_L.

Transformer A has the greatest ratio of V_X/V_R.

Transformer C has the smallest ratio of V_X/V_R.

As before, I_B may lead or lag I_L, depending upon the various values of V_X/V_R.

When dealing with transformers having different outputs and different impedances which are to operate in parallel, it should be remembered that the impedance drop of a single transformer is based on its own rated full-load current, and this point should not be overlooked when determining the current distribution of two such transformers operating in parallel. If the *ohmic* values of the impedances of the individual transformers are deduced from the impedance drop and normal full-load current of each and the results inserted in the usual formula for resistances in parallel, the same final results for current distribution are obtained by already well-known and simple methods. In using this ohmic method care should be taken to notice whether the ratio of resistance to reactance is the same with all transformers, for, if it is not, the value of the impedance voltage drop as such cannot directly be used for determining the current distribution, but it must be split up into its power and reactive components.

When operating transformers in parallel the output of the smallest transformer should not be less than one-third of the output of the largest, as otherwise it is extremely difficult, as mentioned above, to incorporate the necessary impedance in the smallest transformer.

Polarity

The term polarity when used with reference to the parallel operation of electrical machinery is generally understood to refer to a certain relationship existing between *two or more units*, though, as stated previously, it can be applied so as to indicate the directional relationship of primary and secondary terminal voltages of a single unit. Any two single-phase transformers have the same polarity when their instantaneous *terminal* voltages are in phase. With this condition a voltmeter connected across similar terminals will indicate zero.

Single-phase transformers are essentially simple to phase in, as for any given pair of transformers there are only two possible sets of external connections, one of which must be correct. If two single-phase transformers, say X and Y, have to be phased in for parallel operation, the first procedure is to connect both primary and secondary terminals of, say, transformer X, to their corresponding busbars, and then to connect the primary terminals of transformer Y to their busbars. If the two transformers have the same polarity, corresponding secondary terminals will be at the same potential, but in order to ascertain if this is so it is necessary to connect one secondary terminal of transformer Y to what is thought to be its corresponding busbar. It is necessary to make the connection from one secondary terminal of transformer Y, so that when taking voltage readings there is a return path for the current flowing through the voltmeter. The voltage across the disconnected secondary terminal of transformer Y and the other busbar is then measured, and if a zero reading is obtained the transformers have the same polarity, and permanent connections can accordingly be made. If, however, the voltage measured is twice the normal secondary voltage, then the two transformers have opposite polarity. To rectify this it is only necessary to cross-connect the secondary terminals of transformer Y to the busbars. If, however, it is more convenient to cross-connect the primary terminals, such a procedure will give exactly the same results.

Phase sequence

In single-phase transformers this point does not arise, as phase sequence is a characteristic of polyphase transformers.

Polyphase transformers

Phase angle difference between primary and secondary terminals

The determination of suitable external connections which will enable two or more polyphase transformers to operate satisfactorily in parallel is more complicated than is a similar determination for single-phase transformers, largely on account of the phase angle difference between primary and secondary terminals of the various connections. It becomes necessary, therefore, to study carefully the internal connections of polyphase transformers which are to be operated in parallel before attempting to phase them in.

Transformers made to comply with the same specification and having similar characteristics and phase-angle relations can be operated in parallel by connecting together terminals with the same symbol. With reference to *Figures 6.30* to *6.33* transformers belonging to the same group number may be operated in parallel; in addition it is possible to arrange the external connections of a transformer from group number 3 to enable it to operate in parallel with another transformer connected to group number 4 without changing any internal connections. *Figure 6.40* indicates how this can be

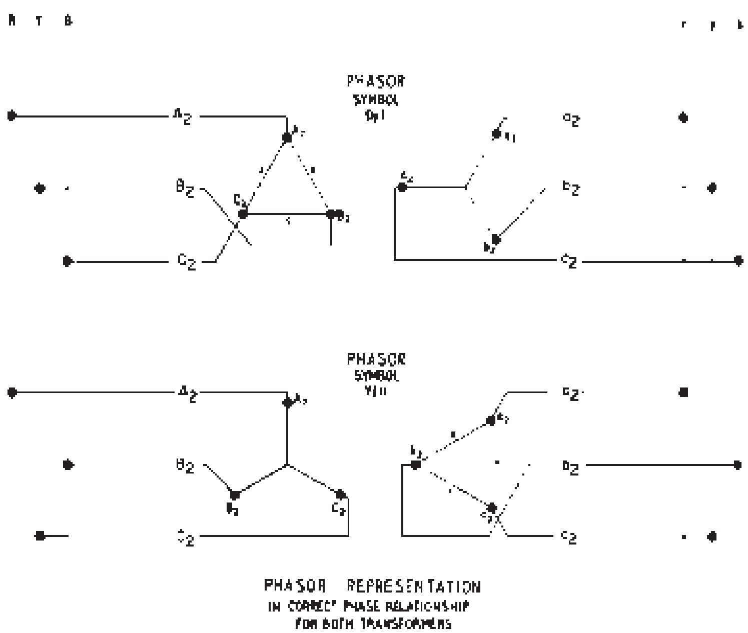


Figure 6.40 Example of parallel operation of transformers in groups 3 and 4. The phasor diagram of the transformer Dy1 is identical with Figure 6.32, but that for the transformers Yd11, for which the phase sequence has been reversed from A-B-C to A-C-B, differs from Figure 6.33

achieved, and it will be seen that two of the HV connections and the corresponding LV connections are interchanged.

Transformers connected in accordance with phasor groups 1 and 2 respectively *cannot* be operated in parallel with one another without altering the internal connections of one of them and thus bringing the transformer so altered within the other group of connections.

Figure 6.41 shows the range of three to three-phase connections met with in practice, and it will be noticed that the diagram is divided up into four main sections. The pairs of connections in the groups of the upper left-hand section may be connected in parallel with each other, and those in the lower right-hand section may also be connected in parallel with one another, but the remaining pairs in the other two groups cannot so be connected, as there is a 30° phase displacement between corresponding secondary terminals. This displacement is indicated by the dotted lines joining the pairs of secondaries.

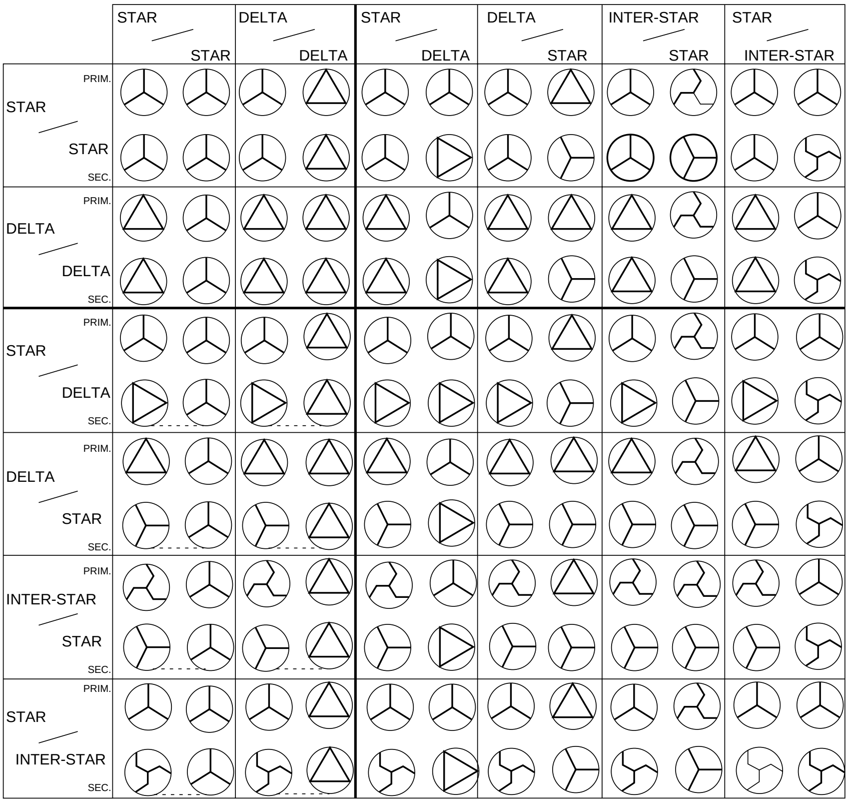


Figure 6.41 Diagram showing the pairs of three- to three-phase transformer connections which will and which will not operate together in parallel

It should be noted that this question of phase displacement is one of displacement between the *line terminals*, and not necessarily of any internal displacement which may occur between the phasors representing the voltages across the individual phase windings.

Voltage ratio

With polyphase transformers, exactly the same remarks apply as outlined for single-phase transformers. Equations (6.5) to (6.23), inclusive, also apply in the same way, but the currents, voltages and impedances should all be based on the line values.

Percentage impedance

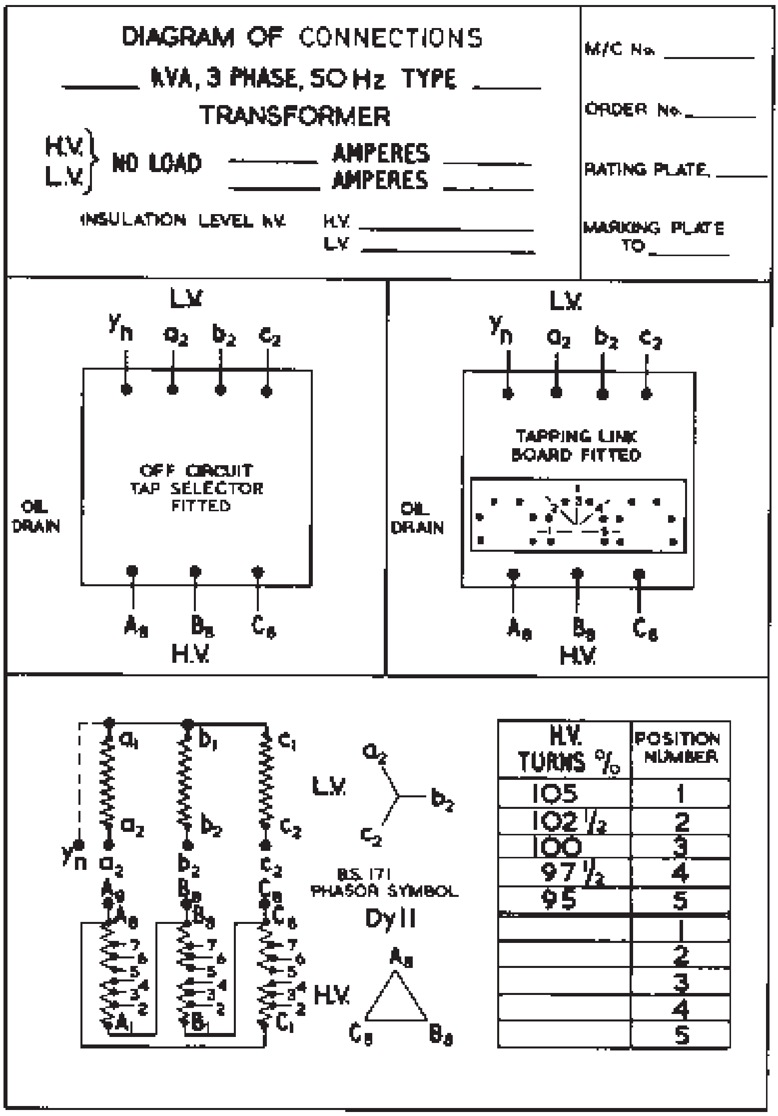
The treatment given in equations (6.25) to (6.45), inclusive, applies exactly for polyphase transformers, the currents, voltages and impedances being based on line values.

Polarity and phase sequence

When phasing in any two or more transformers it is essential that both their polarity and phase sequence should be the same. The phase sequence may be clockwise or counterclockwise, but so long as it is the same with both transformers, the direction is immaterial. It is generally advisable, when installing two or more transformers for parallel operation, to test that corresponding secondary terminals have the same instantaneous voltage, both in magnitude and phase.

With regard to the actual procedure to be followed for determining the correct external connections, there are two ways in which this may be done. The first one is to place the two transformers in parallel on the primary side and take voltage measurements across the secondaries, while the other is to refer to the manufacturer's diagram. *Figure 6.42* shows examples of two typical nameplate diagrams, that in *Figure 6.42(a)* is for a transformer having fairly simple connections and off-circuit tappings, while that in *Figure 6.42(b)* shows a more complex arrangement having tappings selected on load by means of a 19 position tapchanger and an arrangement of links which allows alternative connections for YNd1 and YNd11 winding arrangements to be obtained. From a diagram of this kind, together, if necessary, with the key diagrams which are given in *Figure 6.43*, it is an easy matter to obtain precisely the correct external connections which will enable the transformers to operate in parallel.

Dealing first with the method in which a series of voltage readings are taken for the purpose of determining how the transformers shall be connected, assume two transformers X and Y having the same voltage ratios and impedances and with their internal connections corresponding to any one pair of the permissible combinations given in *Figure 6.41*. The first procedure is to connect all the primary terminals of both transformers to their corresponding



Selector position	Tappings connected
1	4, 5
2	5, 4
3	3, 6
4	7, 3
5	2, 7

Figure 6.42a Manufacturer's typical diagram of connections

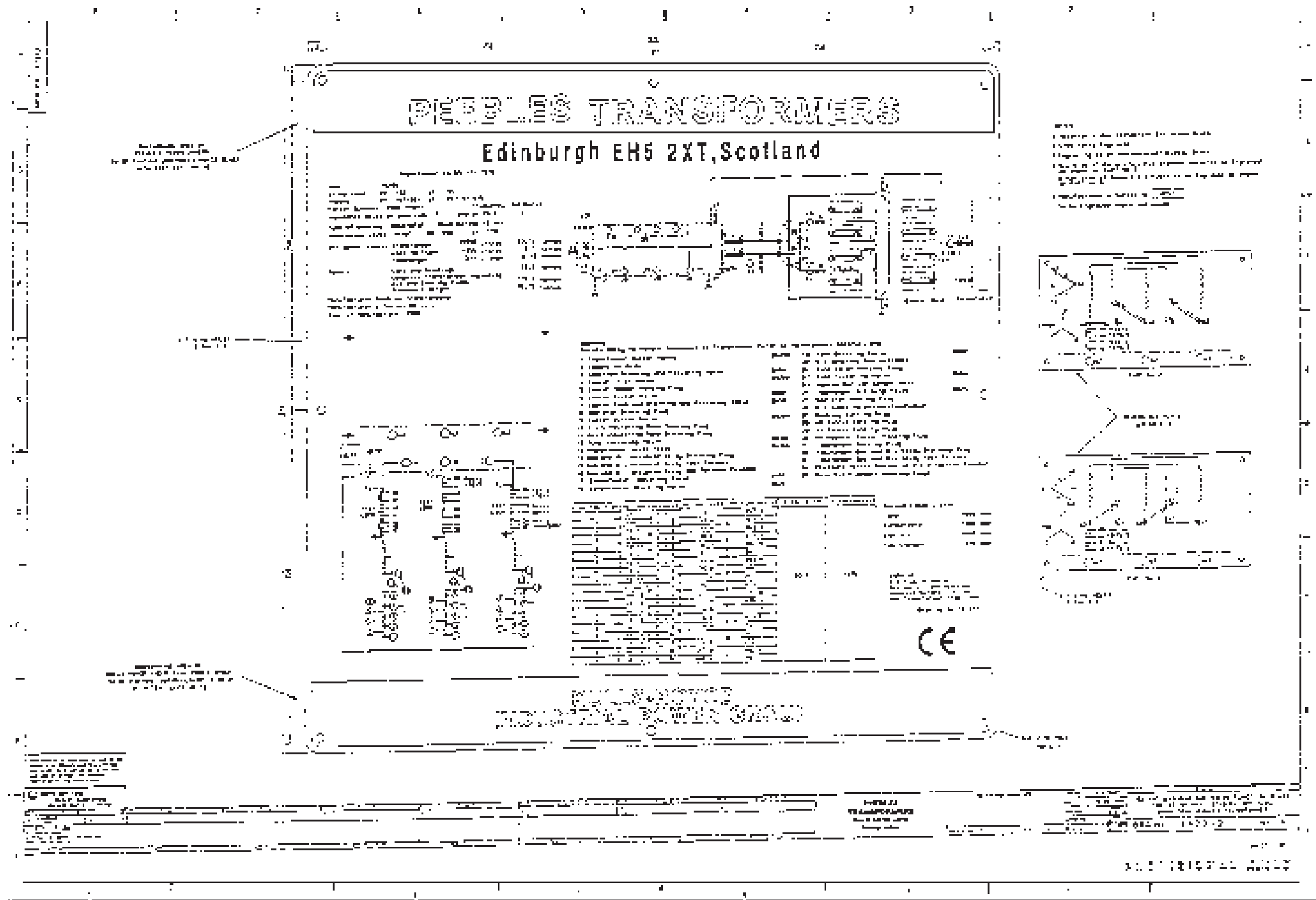


Figure 6.42b Manufacturer's typical diagram of connections

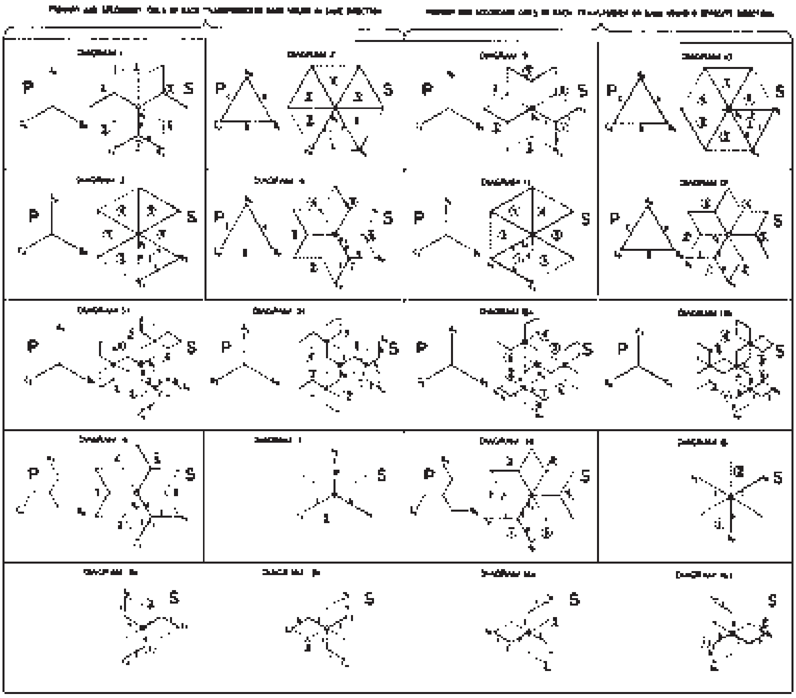


Figure 6.43 Key diagrams for the phasing-in of three- to three-phase transformers

busbars, and to connect all the secondary terminals of *one* transformer, say X, to its busbars. Assuming that both secondary windings are unearthed, it is next necessary to establish a link between the secondary windings of the two transformers, and for this purpose any one terminal of transformer Y should be connected, via the busbars, to what is thought to be the corresponding terminal of the other transformer. These connections are shown in *Figure 6.44*. Voltage measurements should now be taken across the terminals aa′ and bb′, and if in both instances zero readings are indicated, the transformers are of the same polarity and phase sequence, and permanent connections may be made to the busbars. If, however, such measurements do not give zero indications, it is sometimes helpful to take, in addition, further measurements, that is, between terminals ab′ and ba′, as such measurements will facilitate the laying out of the exact phasor relationship of the voltages across the two transformer secondary windings *Figure 6.43* gives key diagrams of the different positions that the secondary voltage phasors of a transformer could take with respect to another transformer depending upon their relative connections, polarity, phase sequence and the similarity or not of those terminals which form the common junction, and this will serve as a guide for determining to what the test conditions correspond on any two transformers.

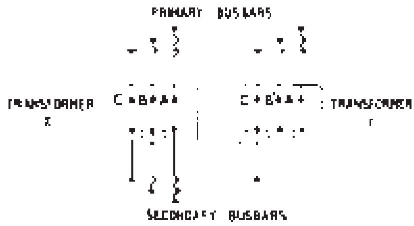


Figure 6.44 Phasing-in a three-phase transformer

In the case of transformers of which the primary and secondary connections are different, such as delta/star, it is only necessary when one of the transformers is of opposite polarity, to change over any two of the primary *or* secondary connections of *either* transformer. As such a procedure also reverses the phase sequence, care must be exercised finally to join those pairs of secondary terminals across which zero readings are obtained. When, however, the connections on the primary and secondary sides are the same, such as, for instance, delta/delta, transformers of opposite polarity cannot be phased in unless their *internal* connections are reversed. When the phase sequence is opposite, it is only a question of changing over the lettering of the terminals of one transformer, and, provided the polarity is correct, connecting together similarly lettered terminals; in other words, two of the secondary connections of one transformer to the busbars must be interchanged. With two transformers both having star-connected secondaries, the preliminary common link between the two can be made by connecting the star points together if these are available for the purpose, and this leaves all terminals free for the purpose of making voltage measurements. As a result, this procedure makes the result much more apparent at first glance owing to the increased number of voltage measurements obtained.

Dealing next with the method in which the transformer manufacturer's diagram is used for obtaining the correct external connections, *Figure 6.45* shows the six most common combinations of connections for three- to three-phase transformers. This diagram illustrates the standard internal connections between phases of the transformers, and also gives the corresponding polarity phasor diagrams. It is to be noted that the phasors indicate instantaneous induced voltages, as by arranging them in this way the phasor diagrams apply equally well irrespective of which winding is the primary and which the secondary.

Both primary and secondary coils of the transformers are wound in the same direction, and the diagrams apply equally well irrespective of what the actual direction is. With the standard polarities shown in *Figure 6.45*, it is only necessary to join together similarly placed terminals of those transformers which have connections allowing of parallel operation, to ensure a choice of the correct external connections. That is, there are two main groups only, the first comprising the star/star and the delta/delta connection, while the other consists of the star/delta, delta/star, interconnected star/star and star/interconnected star.

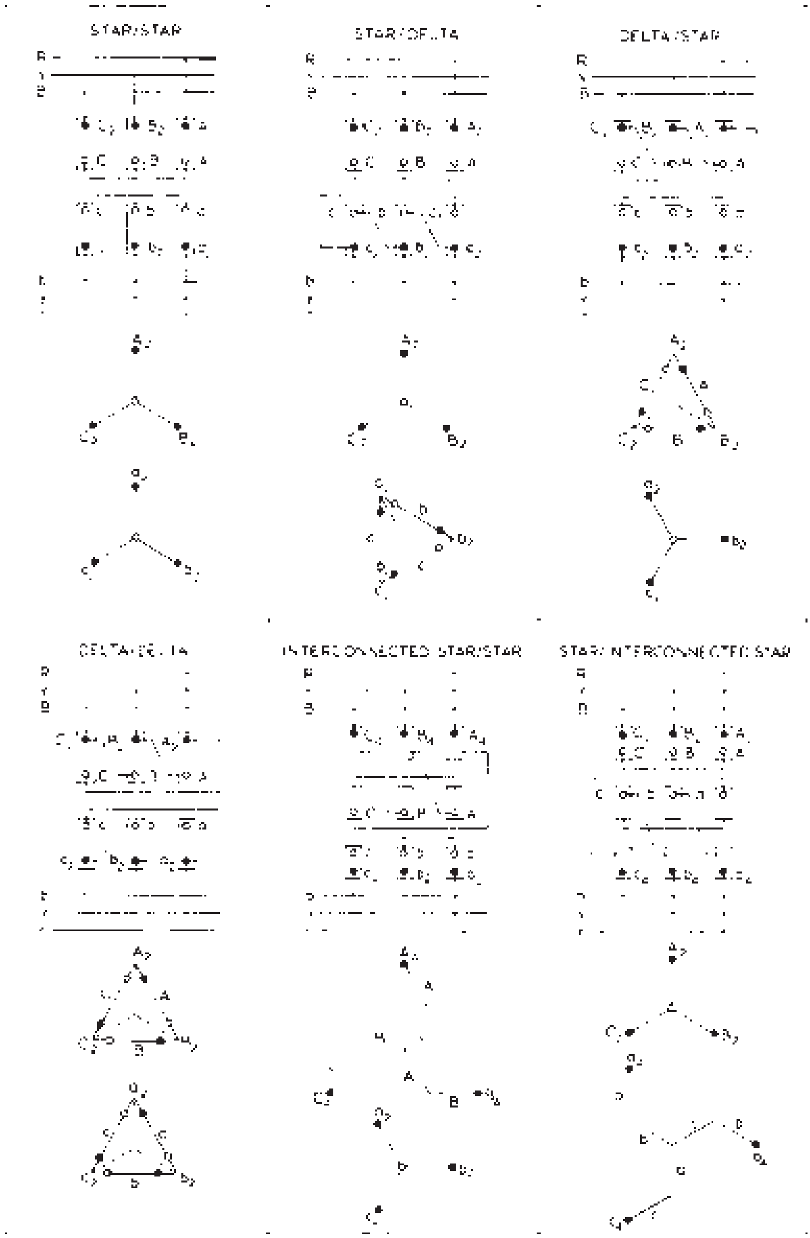


Figure 6.45 Standard connections and polarities for three- to three-phase transformers. Note: primary and secondary coils wound in the same direction; ● indicates start of windings, ○ indicates finish of windings

When phasing in any two transformers having connections different from the star or the delta, such as, for instance, two Scott-connected transformer groups to give a three- to two-phase transformation, particular care must be taken to connect the three-phase windings symmetrically to corresponding busbars. If this is not done the two-phase windings will be 30° out of phase, and *Figure 6.46* shows the correct and incorrect connections together with the corresponding phasor diagrams.

A further point to bear in mind when phasing in Scott-connected transformer banks for two- to three-phase transformation is that similar ends of the teaser windings on the primary and secondary sides must be connected together. This applies with particular force when the three-phase neutrals are to be connected together for earthing. If the connection between the teaser transformer and the main transformer of one bank is taken from the wrong end of the teaser winding, the neutral point on the three-phase side of that bank will be at a potential above earth equal to half the phase voltage to neutral when the voltage distribution of the three-phase line terminals is symmetrical with respect to earth.

Other features which should be taken into account when paralleling transformers may briefly be referred to as follows:

1. The length of cables on either side of the main junction should be chosen, as far as possible, so that their percentage resistance and reactance will assist the transformers to share the load according to the rated capacity of the individual units.
2. When two or more transformers both having a number of voltage adjusting tappings are connected in parallel, care should be taken to see that the transformers are working on the same percentage tappings. If they are connected on different tappings, the result will be that the two transformers will have different ratios, and consequently a circulating current will be produced between the transformers on no-load.

The parallel operation of networks supplied through transformers

Thus far this section has dealt exclusively with the parallel operation of transformers located in the same substation or supplying a common circuit. As the loads on a given system increase and as the system extends, due to new load requirements in more distant areas of supply, it frequently becomes necessary to interconnect either, or both, the high-voltage and low-voltage networks at different points, in order to produce an economical distribution of load through the mains, and to minimise voltage drops at the more remote points of the networks. This problem of network interconnection due to increasing loads and extended areas of supply becomes, perhaps, most pressing in the case of systems which originally have been planned, either partially or wholly, as radial systems.

In such cases, particularly, perhaps, when the problem is one of interconnecting higher voltage supplies to extensive low-voltage networks, it may be

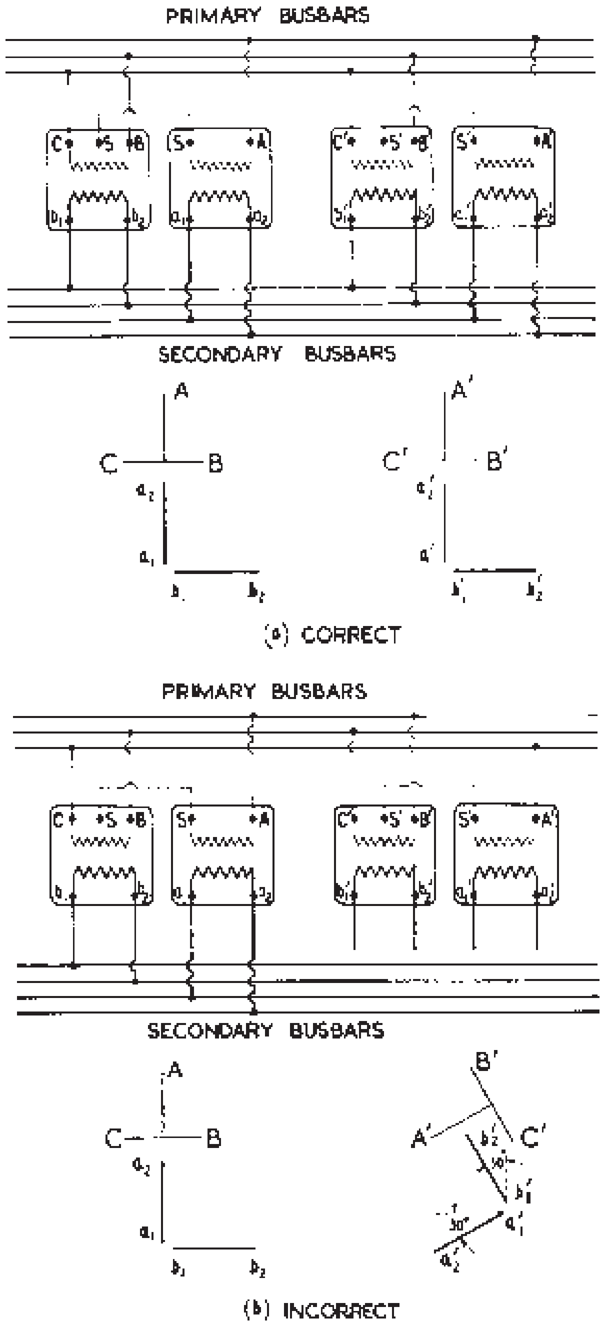


Figure 6.46 Correct and incorrect method of paralleling two Scott-connected groups for three- to two-phase transformation

found that the different circuits between the common source of supply and the proposed point, or points, of interconnection, contain one or more transformers, which may, or may not, have the same combinations of primary and secondary connections, the same impedances, etc. The different circuits, moreover, may not contain the same number of transforming points.

It has been stated previously that two delta/star or star/delta transformers, for instance, may be paralleled satisfactorily simply by a suitable choice of external connections to the busbars, provided their no-load voltage ratios are the same, and such transformers will share the total load in direct proportion to their rated outputs provided their percentage impedances are equal. When, however, two or more compound circuits each comprising, say, transformers and overhead lines, or underground cables, are required to be connected in parallel at some point remote from the source of supply, the question of permissible parallel operation is affected by the combined effect of the numbers of transformers in the different circuits and the transformer connections.

A typical instance of what might be encountered is shown in *Figure 6.47* where a common LV network is fed from a power station through two parallel HV circuits A and B, one of which, A, contains a step-up transformer and a step-down transformer, both having delta-connected primaries and star-connected secondaries, while the other, B, contains one transformer only, having its primary windings delta connected and its secondary windings in star. From such a scheme it might be thought at first that the switches at the points X and Y might be closed safely, and that successful parallel operation would ensue. Actually, this would not be the case.

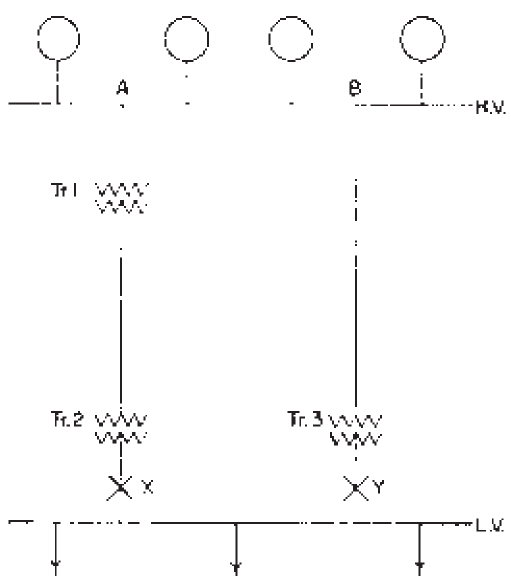


Figure 6.47 Network layout

Figure 6.48 shows the phasor diagrams of the voltages at the generating station and at the different transforming points for the two parallel circuits lying between the power station and the common LV network, and it will be seen from these that there is a 30° phase displacement between the secondary line of neutral voltage phasors of the two transformers. (2) and (3), which are connected directly to the LV network. This phase displacement cannot be eliminated by any alternative choice of external connections to the busbars on either primary or secondary sides of any of the delta/star transformers, nor by changing any of the internal connections between the phase windings. The difficulty is created by the double transformation in circuit A employing delta/star connections in both cases, and actually the sum total result is the same as if the two transformers concerned were connected star/star. As mentioned earlier in this chapter, it is impossible to connect a star/star transformer and a delta/star in parallel.

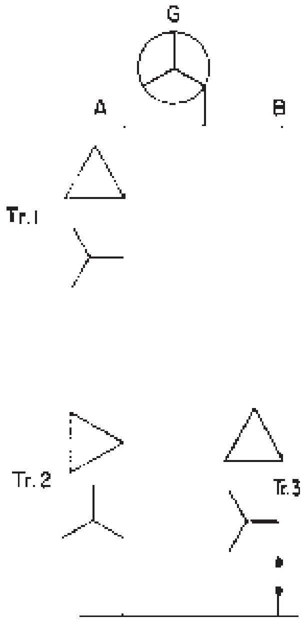


Figure 6.48 Connections not permitting parallel operation

The two circuits could be paralleled if the windings of any of the three transformers were connected star/star as shown at *(a)*, *(b)* and *(c)* in *Figure 6.49* or delta/interconnected star as shown in *(a)*, *(b)* and *(c)* of *Figure 6.50*.

Apart from the fact that the delta/interconnected star-transformer would be slightly more expensive than the star/star, the advantage lies with the former, as it retains all the operating advantages associated with a primary delta winding.

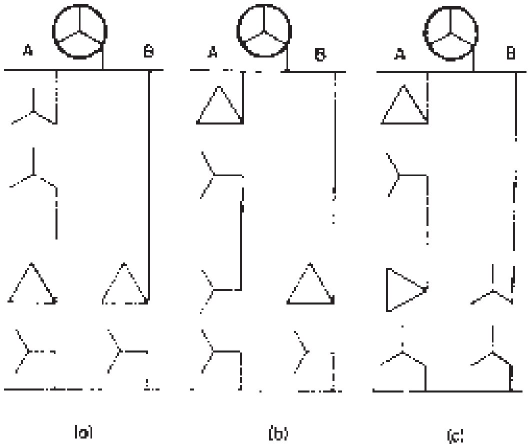


Figure 6.49 Connections permitting parallel operation

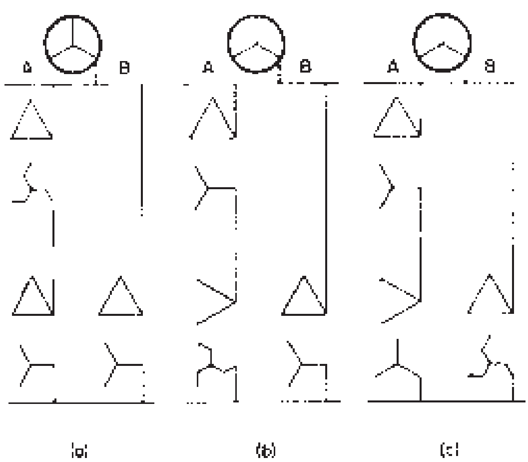


Figure 6.50 Alternative connections permitting parallel operation

The phasor diagram in *Figure 6.51* shows the relative voltage differences which would be measured between the secondary terminals of the two transformers, (2) and (3), assuming their neutral points were temporarily connected together for the purpose of taking voltmeter readings, and that all three transformers were delta/star connected as in *Figure 6.48*.

With properly chosen connections, as shown in *Figures 6.49* and *6.50*, the loads carried by the two parallel circuits A and B will, of course, be in inverse proportion to their respective sum total ohmic impedances.

Thus, when laying out a network supplied through the intermediary of transformers, the primary and secondary connections of the latter, at the different

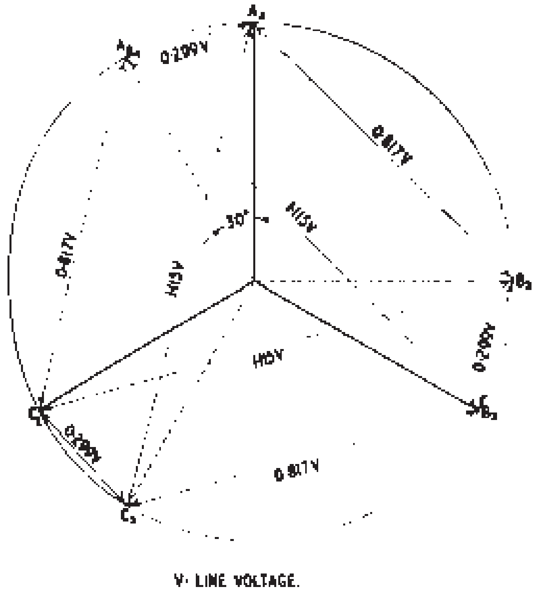


Figure 6.51 Phasor diagram of LV voltages corresponding to *Figure 6.48*

transforming centres, should be chosen with a view to subsequent possible network interconnections, as well as from the other more usual considerations governing this question.

6.5 TRANSIENT PHENOMENA OCCURRING IN TRANSFORMERS

Transient phenomena have probably provided transformer design engineers with their most interesting and stimulating challenge. For many years the very elusiveness of the subject coupled with the difficulties often met with in reproducing in the laboratory or test room the identical conditions to those which occur in practice undoubtedly provided the most significant aspect of that challenge. Until the advent of computers quantitative calculations were often very difficult since, under extremely abnormal conditions (for instance, when dealing with voltages at lightning frequencies and with supersaturation of magnetic circuits), the qualities of resistance, inductance and capacitance undergo very material temporary apparent changes compared with their values under normal conditions. A considerable amount of connected investigation has been carried out on transient phenomena of different kinds, by many brilliant investigators, and it is largely to these that we owe our present knowledge of transients. A number of individual papers have been presented before technical engineering institutions in the UK, the USA and Europe, and these have formed valuable additions to the literature of the subject. We cannot hope, in a volume of this nature, to cover anything approaching the whole field of the subject, but we have here endeavoured to present a brief survey of the chief disturbances to which transformers are particularly liable.

The transients to which transformers are mainly subjected are:

- Impact of high-voltage and high-frequency waves arising from various causes, including switching in.
- System switching transients with slower wavefronts than the above.
- Switching inrush currents.
- Short-circuit currents.

It is not intended to discuss specifically the results of faulty operations, such as paralleling out of phase or the opening on load of a system isolator link, as the resulting transients would be of the nature of one or more of those mentioned above.

Impact of high-voltage and high-frequency waves

Transformer windings may be subject to the sudden impact of high-frequency waves arising from switching operations, atmospheric lightning discharges, load rejections, insulator flashovers and short-circuits, and, in fact, from almost any change in the electrostatic and electromagnetic conditions of the circuits involved. An appreciable number of transformer failures occurred in the past, particularly in the earlier days of transformer design, due to the failure of interturn insulation, principally of those end coils connected to the line terminals, though similar insulation failures have also occurred at other places within the windings, notably at points at which there is a change in the winding characteristics. The failures which have occurred on the line-end coils have been due chiefly to the concentration of voltage arising on those coils as a result of the relative values and distribution of the inductance and capacitance between the turns of the coils.

In the early stages when these breakdowns occurred, considerable discussion took place on the relative merits of external protection in the form of choke coils and reinforced insulation of the end coils, but actual experience with external choke coils showed that in many cases their provision did not eliminate the necessity for reinforcement of the end coils, while, on the other hand, added reinforcement of the end coils was itself occasionally still subject to failure, and more frequent breakdown of the interturn insulation occurred beyond the reinforcement. For many years there was in use in the UK a British Standard, BS 422, which provided recommendations for the extent of reinforcement of end turns of higher voltage windings. Now external protection is provided by means of coordinating gaps or surge diverters coupled with the use of insulation coordination (see Section 6 of this chapter) and winding design has developed to a stage at which more effective measures are available than reinforcement of end turns. This development followed on from a fuller understanding of the response of windings to high-frequency transients and a recognition of the part played by capacitances at these high frequencies.

Lightning impulses

The following description of the effect of lightning impulses on transformer windings is based on material contained in a book *Power Transformers for High Voltage Transmission with Special Reference to their Design* by Duncan McDonald (now the late Sir Duncan McDonald), formerly Chief Designer, Transformer Department, Bruce Peebles, published by Bruce Peebles and Company Limited.

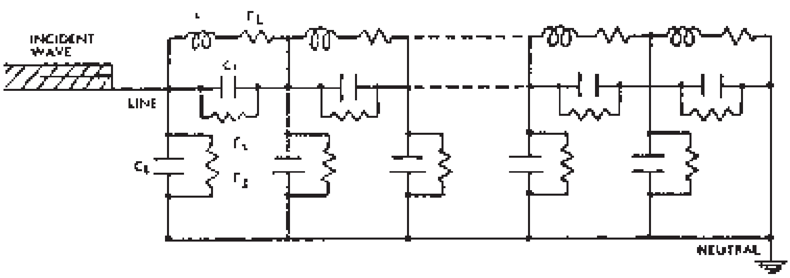


Figure 6.52 Equivalent circuit of transformer for simplified uniform winding.
The circuit parameters, uniformly distributed, are:

L = Inductance
C_S = Series (Turn-to-Turn) Capacitance
C_g = Shunt (Turn-to-Earth) Capacitance
r_L = Loss Component of Inductance (Winding Resistance)
r_S = Loss Component of Series Capacitance
r_g = Loss Component of Shunt Capacitance

In assessing its surge behaviour the transformer may be represented by an equivalent network possessing capacitance, inductance and resistance elements as shown in *Figure 6.52*. The voltage response of the transformer, the space distribution of potential through its windings at any instant of time, is a function of the magnitude and disposition of these circuit elements and of the nature of the incident voltage. In practice impulse voltages are characterised by a rapid rise to their crest value followed by a relatively slow decline to zero – by a front of high and a tail of low equivalent frequency. The steeper the front and the flatter the tail of the wave, the more severe its effect on the windings and for this reason, coupled with the analytical convenience and clearer understanding of the principles involved, it is convenient to regard the incident impulse voltage as a unit function wave having a front of infinite and a tail of zero equivalent frequency. The orthodox explanation of the transient behaviour of the windings is based on the time response of the circuit elements to these equivalent frequencies.

At the instant of incidence of the impulse the capacitance elements alone react to the front of the wave establishing an *initial distribution* of potential which is usually non-uniform, *Figure 6.53(a)*. At the end of the phenomenon, during the tail of the wave, the resistance elements govern the response establishing a *final distribution* which is usually uniform, *Figure 6.53(a)*. The transitional behaviour between the initial and final extremes takes the form of damped transference of electrostatic and electromagnetic energy during which complex oscillations are usually developed, *Figure 6.53(b)*. It can be seen that all parts of the winding may be severely stressed at different instants in time; initially, concentrations of voltage may appear at the line end of the winding; during the transitional period, concentrations may appear at the neutral end while voltages to earth considerably in excess of the incident impulse may develop in the main body of the winding.

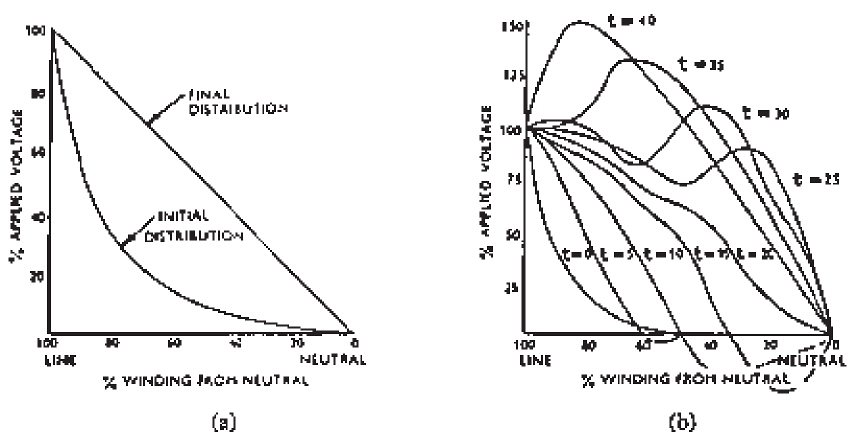


Figure 6.53 Transient voltage response of transformer winding.
(a) Initial and final distribution of impulse voltage.
(b) Transitional time-space distribution of impulse voltage.

Generally, under steady-state conditions, equal voltages are induced between turns and consequently, ideally, equal amounts of insulation are required between turns. To utilise this uniformly disposed insulation to best advantage, the voltages appearing between turns throughout the winding under impulse conditions should also be equal. To approach this ideal, in which oscillation voltages are completely eliminated, the initial distribution, like the final, must also be uniform. Unfortunately, for many years, the basic theories and practice always showed that uniform windings, with a uniform final distribution, inherently exhibited a grossly non-uniform initial distribution. Faced with this paradox, the designer has concentrated in determining by what artifice he might improve the initial distribution while striving to maintain winding uniformity.

The initial voltage distribution

It will be recalled that the initial distribution is determined wholly by the equivalent capacitance network. Consequently two circuit elements are available for controlling and improving the initial response – the shunt capacitance C_g and the series capacitance C_s. When a unit function wave is applied to the line terminal of a winding whose equivalent network is shown in *Figure 6.54*, the initial distribution of impulse voltage is determined from the differential equation of the capacitance network, *Figure 6.54(a)*. This equation may (for a uniform winding of length L, of uniform interturn capacitance C_s, of uniform turn-to-earth capacitance C_g) be expressed in terms of the instantaneous voltage to earth e_x at any point x (measured from the neutral terminal) as:

$$\frac{\partial^2 e_x}{\partial x^2} - \frac{C_g}{L.C_s}.e_x = 0$$

or, more conveniently:

$$\frac{\partial^2 e_x}{\partial x^2} - \frac{\alpha^2}{L}.e_x = 0$$

$$\text{where } \alpha = \sqrt{\frac{C_g}{C_s}} = \frac{\text{Shunt capacitance}}{\text{Series capacitance}} \tag{6.46}$$

Solution of equation (6.46) may be found in the form:

$$e_x = A.e^{\frac{\alpha x}{L}} + B.e^{\frac{-\alpha x}{L}} \tag{6.47}$$

where the constants of integration A and B are defined by substituting the boundary conditions. In particular, if the winding neutral is solidly earthed $e_x = 0$ when $x = 0$ and from equation (6.47):

$$0 = A + B$$

$$\text{and } e_x = A\left(e^{\frac{\alpha x}{L}} - e^{\frac{-\alpha x}{L}}\right. \tag{6.48}$$

In addition, $e_x = E$, the incident surge, when $x = L$ and, from equation (6.47):

$$E = A(e^{\alpha} - e^{-\alpha})$$

$$\text{whence } A = \frac{E}{(e^{\alpha} - e^{-\alpha})}$$

Substituting this value of A in equation (6.48) it is seen that:

$$e_x = \frac{E\left(e^{\frac{\alpha x}{L}} - e^{\frac{-\alpha x}{L}}\right.}{(e^{\alpha} - e^{-\alpha})}$$

$$= \frac{E \sinh \frac{\alpha x}{L}}{\sinh\ \alpha} \tag{6.49}$$

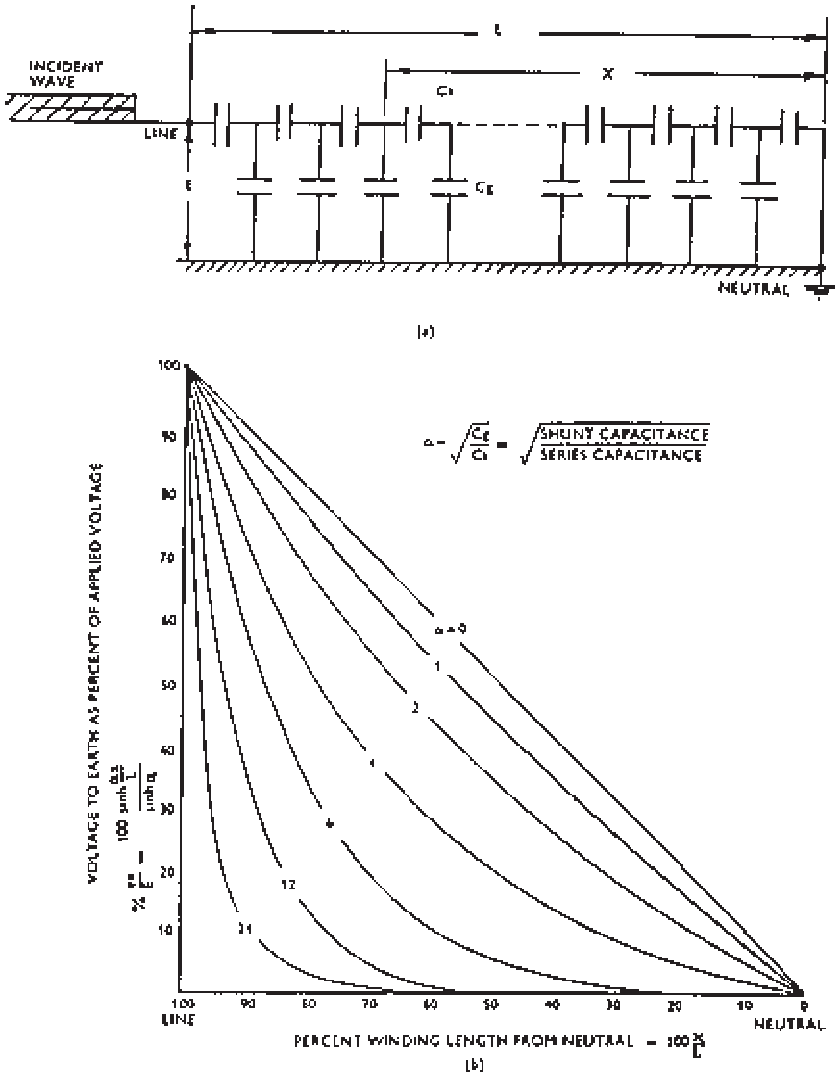


Figure 6.54 Initial distribution of impulse voltage in a uniform winding with earthed neutral.
(a) Equivalent capacitance circuit of winding.
(b) Curves of initial distribution of impulse voltage corresponding to various values of factor α.

Figure 6.54(b), which is prepared from equation (6.49), illustrates the variation of the initial distribution with α. It will be seen that when $\alpha = 0$ (when the shunt capacitance is zero, or the series capacitance infinite) the initial distribution is uniform and coincident with the final distribution; it will also be seen that as α increases the non-uniformity is aggravated. Clearly the distribution may be improved by decreasing the shunt capacitance (or nullifying it partially or wholly by electrostatic shields) and/or by increasing the series capacitance. The former is not very practicable and it is therefore the latter approach which has formed the main strategy for improving the response of transformer windings to lightning surges. Section 4 of Chapter 4 describes the methods which have been developed for increasing the series capacitance for practical windings.

The use of interleaving, which is now one of the most common methods of increasing series capacitance, in fact enables near uniform initial distributions to be obtained thus achieving the ideal of utilising the same uniform interturn insulation structure for both impulse and steady-state withstand. It should be stressed, however, that winding design is a matter of economics and not necessarily one of achieving ideals. Interleaving is an expensive method of winding and where acceptable stress distributions can be obtained without recourse to this method, say by the use of shields between end sections, designers will always prefer to do this. As unit ratings get larger there will be a tendency for C_g to get smaller relative to C_s anyway due to increase in physical size and increased clearances. In addition, the volts per turn will be greater in a larger unit so that the total number of turns, and hence number of turns per section, will be reduced. The next most critical area after the line-end interturn stress is usually the stress between the first two sections. A reduction in the number of turns per section will help to reduce this. These factors usually mean that impulse stress in a large high-voltage transformer is less than that in one of lesser rating but having the same HV voltage. In the smaller rated unit interleaving might be essential, whereas for the larger unit it will probably be possible to avoid this.

The final voltage distribution

The form of the final voltage distribution can be calculated in a similar manner to that for the initial distribution. For an incident wave with an infinite tail the capacitance and inductance elements of *Figure 6.52* appear respectively as open- and short-circuits and the resulting final distribution is governed wholly by the resistive elements. It will be seen that these resistive elements form a network identical to that of the capacitance network, *Figure 6.54(a)*, if C_s is replaced by $\frac{r_L \cdot r_s}{(r_L + r_s)}$ and C_g by r_g.

The differential equation for this network may therefore be written:

$$\frac{\partial^2 e_x}{\partial x^2} - \frac{r_L \cdot r_s}{r_g(r_L + r_s)L} \cdot e_x = 0$$

or more conveniently:

$$\frac{\partial^2 e_x}{\partial x^2} - \frac{\beta^2 e_x}{L} = 0$$

where $\beta = \sqrt{\frac{r_L \cdot r_s}{r_g(r_L + r_s)}}$ (6.50)

The solution of this equation, which is of the same form as equation (6.46), is clearly given by:

$$e_x = \frac{E \ \sinh \frac{\beta x}{L}}{\sinh \ \beta} \tag{6.51}$$

Since, in practice, r_s and r_g are very large compared with r_L, $\frac{r_L \cdot r_s}{r_L + r_s}$ tends to the value r_L and to a close approximation $\beta = \sqrt{\frac{r_L}{r_s}}$; this, in turn, is a very small quantity and it is therefore permissible to write $\sinh \frac{\beta x}{L} = \frac{\beta x}{L}$ and $\sinh \beta = \beta$. The final distribution is therefore given by

$$e_x = \frac{Ex}{L} \tag{6.52}$$

which is a uniform distribution of potential from line to earth.

Part winding resonances

As in any network consisting of inductances and capacitances, transformer windings are capable of oscillatory response to certain incident disturbances. When the disturbance has the appropriate properties severe dielectric stresses and, on occasions, failure can result.

In the discussion above relating to lightning impulses the incident disturbance is a once-only occurrence. The oscillatory circuits receive a single burst of energy and return by free oscillations at their natural frequencies to a steady state. Since in most cases the maximum voltage developed in the transformer windings occurs during the first one or two oscillations, the natural frequency and damping of the oscillatory circuits are of only secondary importance. In contrast, however, certain switching transients may consist of an initial peak voltage followed by an oscillatory component. If the frequency of this oscillation coincides with a natural frequency of the windings a resonance can develop which can take several cycles to reach its maximum amplitude. The value of this maximum amplitude is dependent on the damping of both the incident transient and of the windings themselves but it can on occasions be greater than the voltage resulting from a lightning impulse. It should be recognised that, unlike the case of designing in resistance to lightning impulses, the solution to resonance problems cannot be achieved by transformer manufacturers acting in isolation. Resonance always requires a passive structure, namely the transformer windings, *and* an active component represented by the various sources of oscillating voltages in the electrical system.

Resonances became recognised as a cause of dielectric failures in the early 1970s and a number of technical papers dealing with the subject were published over the next decade. The majority of these described specific incidents which had led to the failure of EHV transformers and although the mechanism of failure was ascribed to resonance phenomena the papers generally provided little information concerning the source and the nature of the initiating disturbance. In 1979 CIGRE set up a Working Group to deal with resonance problems and to report on the state of the art, including the provision of a description of the response of transformers to oscillating voltages and making a survey of the possible sources of oscillating voltages in electrical systems. The Working Group's findings were presented at the August/September 1984 session [6.6] and the following notes represent a summary of the salient points from their report. Only power transformers above 110 kV were considered and furnace and other special transformers were excluded. The Working Group also noted that their findings were in line with those of an American IEEE working group dealing with the same subject.

The report described studies carried out on a 405/115/21 kV, 300 MVA substation transformer having tappings of $\pm 13 \times 4.675$ kV per step on the HV winding. The arrangement is shown in *Figure 6.55*. The application of a step voltage on an arbitrarily chosen terminal of the transformer will cause the 'network' to oscillate. In principle, since the step function contains all frequencies, each natural frequency inherent in the network will be excited. The values of the frequencies and their related amplitudes depend on the parameters of the network and the boundary conditions. The total number of natural frequencies is given by the number n of free nodes. The values of the amplitudes are also a function of the location, i.e. of the ordering number j of a node. Because of the presence of resistances the oscillations are more or less damped, so finally the response at an arbitrary chosen node j to a step voltage U_S is (disregarding slight phase shifts) given by:

$$u_j(t) = U_s \times \left(A_{j00} + \sum_1^n A_{ij} \times e^{-\alpha_i t} \times \cos \omega_i t \right. \tag{6.53}$$

where A_{j00} describes the final steady-state voltage distribution
α is the damping constant

The response to a standard 1.2/50 full wave (*Figure 6.55(a)*) is similar to the response (6.53) to a step voltage. *Figure 6.55(b)* shows the voltage generated at the free oscillating end of the tapped winding (node m) under the given boundary conditions. From the oscillogram (b) it can be seen that there is a dominant natural frequency f_{i^*} of about 40 kHz, the related amplitude $A_{i^*,m}$ has a value of about 0.2 per unit. Application of a steady-state sine wave (*Figure 6.55(c)*) with an amplitude U_R (1 per unit, i.e. $420 \times \sqrt{2}/\sqrt{3}$) and a frequency f_{i^*} causes resonance and, according to oscillogram (d), a voltage with a maximum peak of $A_{Ri^*,m}$ of $3.85 \times U_R$ is generated at node m. The amplitude is limited to this value due to the inner damping of the transformer δ.

The report gives two methods of determining the degree of this internal damping. The first is to vary the frequency of the applied voltage and to make a second measurement, for instance at $0.9 \times f_{i^*}$. *Figure 6.56* shows a plot of maximum peak amplitude against frequency. From a measured second peak of 1.04 per unit a ratio of $1.04/3.85 = 0.27$ is derived and plotting this on the

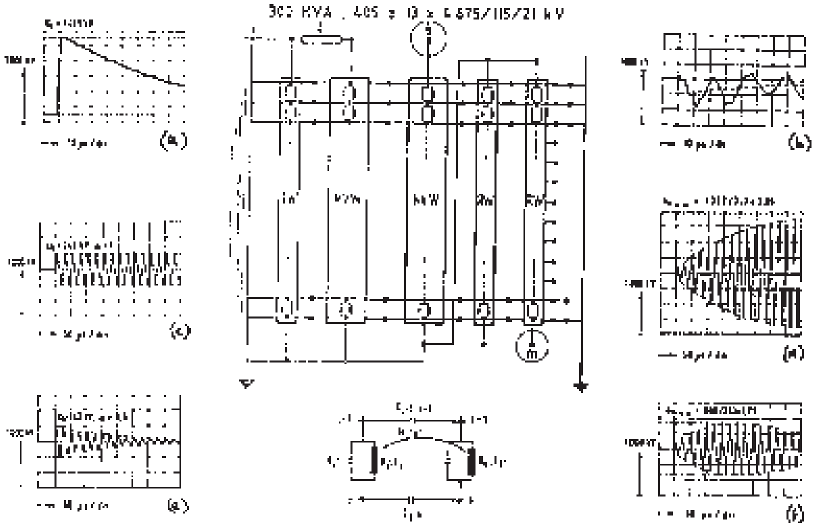


Figure 6.55 Equivalent network and response to aperiodic and oscillating voltages

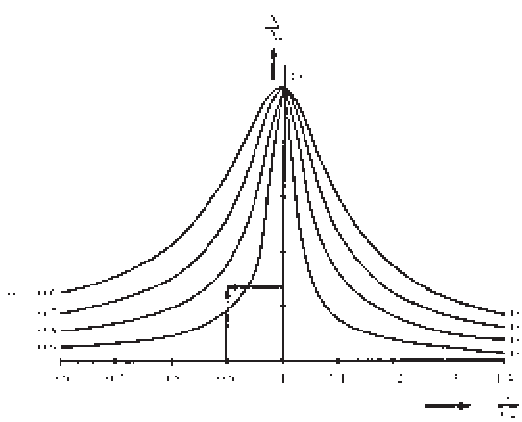


Figure 6.56 Influence of frequency and inner damping on the resonance amplitude ($\Delta = 1$)

curve of *Figure 6.56* gives a value for δ of 0.85, which is stated by the report to accord with the value which can be estimated from the impulse response.

The second method makes use of another mathematical relationship which can be used to determine the ratio:

$$\nu_{\max} = \frac{A_{Ri^*,m}}{A_{i^*,m}} \tag{6.54}$$

Values of ν_{max} are shown in *Figure 6.57* plotted for varying values of inner damping δ and external damping, i.e. the damping of the applied oscillatory voltage, Δ. For a value of ν_{max} of $3.85/0.2 = 19.25$ and $\Delta = 1$ (i.e. no external damping) it can again be seen that this gives a value of $\delta = 0.85$. *Figure 6.57* also permits the time, expressed as number of cycles τ at which the maximum amplitude occurs to be determined.

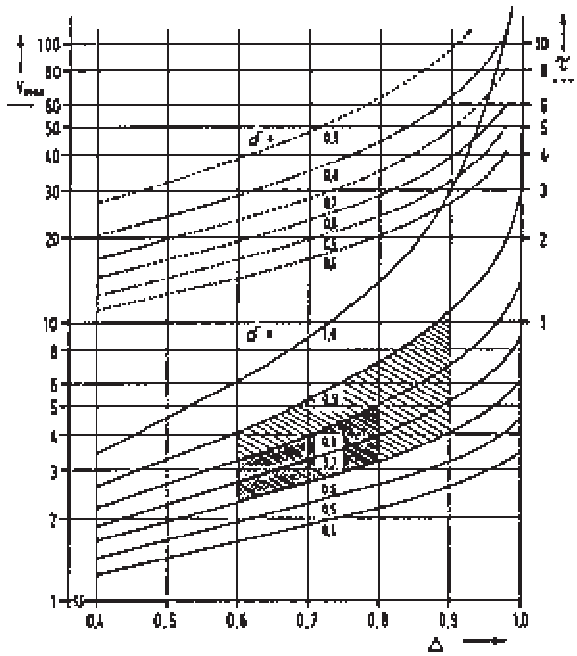


Figure 6.57 V_{max} and τ as a function of damping

Formula (6.54) also enables a comparison to be made of the voltage stresses in the case of resonance with those generated during impulse testing, especially if a natural frequency is dominating the impulse voltage response. Comparing oscillograms (*b*) and (*d*) reveals that the voltage generated during undamped resonance conditions is significantly higher than that under impulse test conditions. In order that this stress should not be exceeded by a resonance excitation of the same amplitude (i.e. 1 per unit) external damping Δ must be less than 0.9. Hence, from the curve of *Figure 6.57* $\nu_{max} = 8.7$. In this case the resonance voltage would be:

$$
\begin{aligned}
U_{R\,\max,m} &= U_R \times \nu_{\max} \times A_{i^*,m} \\
&= 1.74 \times U_R \\
&= 597\ \text{kV}
\end{aligned}
$$

which is in good agreement with oscillogram (f).

Another way of describing the resonance response is the comparison with the voltage under rated conditions. This relationship is quantified by the so called *q-factor*.

$$q_{i,j} = \frac{A_{Ri,j}}{r_j} \tag{6.55}$$

where r_j is the actual turns ratio of the node j.

For the example for which $r_m = 0.2$, a q-factor of $q_{i^*,m} = 19.25$ can be calculated. In this case either $\nu_{\max}$ or the q-factor permit the estimation of the maximum stresses developed under resonance condition at node m. However, as the dominating natural frequency of the regulating winding also influences the other windings it might be inferred that a resonance identified on one arbitrary node on the tapping winding might be indicative of other high stresses in other windings. *Figure 6.58* shows the calculated spatial distribution of the amplitudes $A_{i^*,j}$ throughout the HV winding. Although the q-factors for voltages to earth are rather moderate or even zero, high q-factors result between certain parts of the winding. From the gradients of the spatial amplitude distribution q-factors of up to 22 can be calculated and such values have indeed been reported.

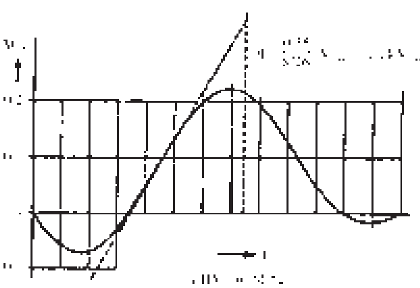


Figure 6.58 Distribution of A_i*, j along the HV winding

In summary, the Working Group came to the following conclusions as regards resonances within transformer windings:

- There is a close interdependence between impulse voltage response and resonance response.
- Amplitudes of harmonics can therefore to a certain degree be influenced by controlling the initial voltage distribution of a standard impulse wave for individual windings.
- There must be an awareness of the fact that transferred oscillations from other windings cannot be suppressed and may cause severe stresses.
- Internal damping is a decisive factor on the resonance response.

- q-factors may be misleading and should not be used in assessing transformer behaviour.

Determination of resonance response

The Working Group considered that a very detailed analysis was necessary to get precise information about the resonance of a particular transformer. Three different approaches are possible – calculation, measurement or a combination of the two. The calculable number of harmonics depends on the degree of subdivision of the equivalent network. To get sufficient information about the spatial amplitude distribution demands a large number of elements. Elaborate computer programs have to be used but the accuracy of the results still depends on the validity of the parameters inserted. From *Figure 6.56* it can be seen that a deviation from the resonance frequency of only a few per cent, considerably less than the margin of error in many instances, can affect the apparent amplitude by a large amount. In addition, at the present time there are no exact methods available for determining damping factors, the computation has to be based on empirical values and is therefore of limited accuracy. On the other hand to obtain a full assessment of the resonant response from measurements is very laborious, costly and even risky. There is the problem of making tappings on inner windings, and measurements taken out of the tank are inaccurate due to the difference in the permittivities of air and oil. Hence the compromise solution of performing a calculation and checking this by means of measurements taken at easily accessible points may prove to be the best option. Even this approach will be costly and should be adopted only if it is considered that a problem may exist.

Sources of oscillating voltages in networks

The Working Group also reported their conclusions concerning the sources of oscillations in networks. They found that their existence stems from one of three possible sources:

- Lightning.
- Faults.
- Switching.

Oscillations created by lightning need only be considered if this causes a switching operation or triggers a fault. Faults comprise single-phase to earth faults and two- or three-phase short-circuits with or without earth fault involvement. Switching may be initiated by the operator or automatically by the system protection.

The Working Group investigated 21 categories of incidents including remote and close-up faults, clearance of faults, reclosing onto faults, energisation of a transformer terminated line, de-energisation of an unloaded and loaded transformer, with and without pre-strikes or re-ignitions as appropriate. Their analysis revealed that in only three of these categories was there a likelihood of oscillations which might coincide with a natural frequency of the transformer. These were:

- Polyphase close-up faults on a single line.
- Energisation of a short transformer-terminated line from a strong bus.
- Repetitive re-ignitions during the de-energisation of a transformer loaded with a reactive load.

Close-up faults

These are defined as occurring at a distance of less than 15 km from the transformer, while the line itself is considerably longer. The transformer is likely to be struck by a dangerous oscillatory component only in those cases where one line is connected to the transformer (*Figure 6.59*) and a two- or three-phase fault occurs at the critical distance l, given by:

$$l = \frac{c}{4 \times f_i} \tag{6.56}$$

where c is the velocity of the travelling wave, which is about 300 km/ms for overhead lines and 150 km/ms for cables.

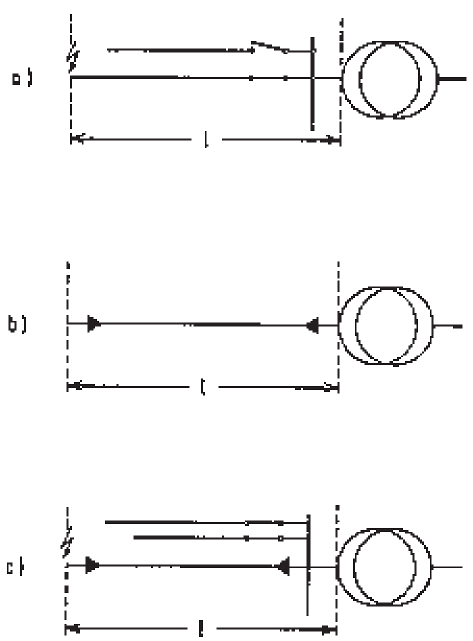


Figure 6.59 Close fault

Energisation of a transformer-terminated line

Switching in a short line through a circuit breaker fed from a strong busbar (*Figure 6.60*) creates standing waves which can be within the critical frequency range. Their frequency can be calculated from equation (6.56), where l corresponds to the length of the line.

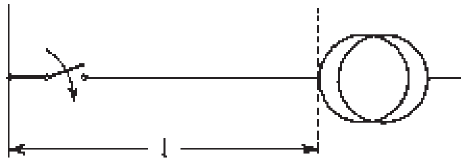


Figure 6.60 Energisation of transformer-terminated line

Repetitive re-ignitions

Breaking of small inductive currents ($\leq$ 1 kA), in particular the interruption of magnetising currents of transformers, may cause oscillations, but these are in the kHz range and strongly damped, therefore these do not create a risk of resonance. The interruption of reactive loaded transformer currents can cause repetitive re-ignitions at nearly constant time intervals. If the repetition frequency coincides with one of the lower natural frequencies of the transformer, resonance may result. A typical configuration for which this can happen is the case of an unloaded three-phase transformer with a reactor connected to the teriary winding.

Very fast transients

The majority of switching transients occurring on the system will have slower wavefronts and lower peak voltages than those resulting from lightning strikes and will therefore present a less severe threat to the insulation of the transformer high-voltage windings. The exceptions are certain transients which can arise as a result of switching operations and fault conditions in gas-insulated substations (GIS). These are known as very fast transient overvoltages (VFTOs). The geometry and dielectric of GIS (metallic sheath, coaxial structure and short dielectric distances) lend themselves well to the generation and propagation of VFTOs. Studies of the characteristics of VFTOs have indicated that typically these might have rise times of 20 ns and amplitudes of 1.5 per unit. In the worst condition a rise time of 10 ns and an amplitude of 2.5 per unit is possible. The steep-fronted section of the wave is often followed by an oscillatory component in the frequency range 1–10 MHz, the precise value being dependent on the travelling wave characteristics of the GIS system.

The VFTOs arriving at a transformer winding are more difficult to predict since magnitude and front time depends on the transformer parameters and the precise nature and length of the winding connection to the GIS. In the worst case the front time will be only slightly increased and the amplitude increased by possibly 30%.

When the VFTOs reach the transformer windings two problems can arise. Their very much higher frequency compared with standard impulse waves results in high inter-section stresses which are usually concentrated in the sections near to the line end. These stresses cannot be controlled by interleaving in the same way as can lightning impulse stresses. The second problem is the production of part-winding resonance resulting from the oscillatory wavetail of the VFTO. This can create oscillatory voltages within the end sections of the transformer windings, producing inter-section stresses many times greater than those resulting from lightning impulses.

In attempting to predict the response of transformer windings to VFTOs it is necessary to represent the winding structure in a similar way to that employed in performing calculations of impulse voltage distribution, in that capacitances predominate; however, it is no longer sufficient to consider a simple network having constant values of series and shunt capacitance, C_s and C_g respectively. In their paper presented to the 1992 CIGRE Summer Meeting, Cornick and others [6.7] used multiconductor transmission line theory to produce a turn-by-turn mathematical model of a 40 MVA, 220 kV partially interleaved winding. *Figure 6.61* shows the type of network considered, in which the capacitance of each turn is taken into account and, in order to predict the resonant frequencies, they also take into account the inductance network. Though laborious, the method lends itself well to computer calculation and, because it is the end sections which are known to be critical, computing time can be reduced by restricting the solution to the end, say the first four, sections of the winding. The authors compared their predicted inter-section and inter-turn voltages with measurements made on the actual winding following application of the output from a recurrent surge generator producing front-chopped impulses. These had a prospective front time of 1.2 μs chopped at that time. Voltage collapse time was 230 ns, relatively slow for a VFTO. *Figure 6.62* shows the arrangement of the winding end sections and the applied, predicted and measured inter-section voltage between the end two sections. The resonance frequency predicted by calculation was 2.12 MHz and that obtained by measurement 2.22 MHz, considered by the authors to represent good agreement.

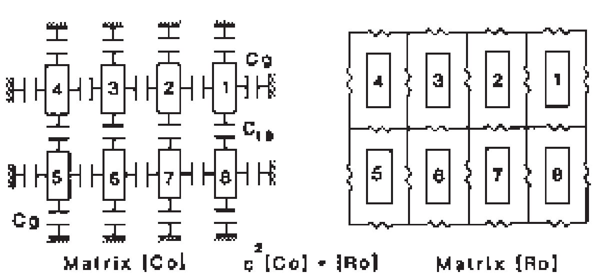


Figure 6.61 Capitance and reluctance networks

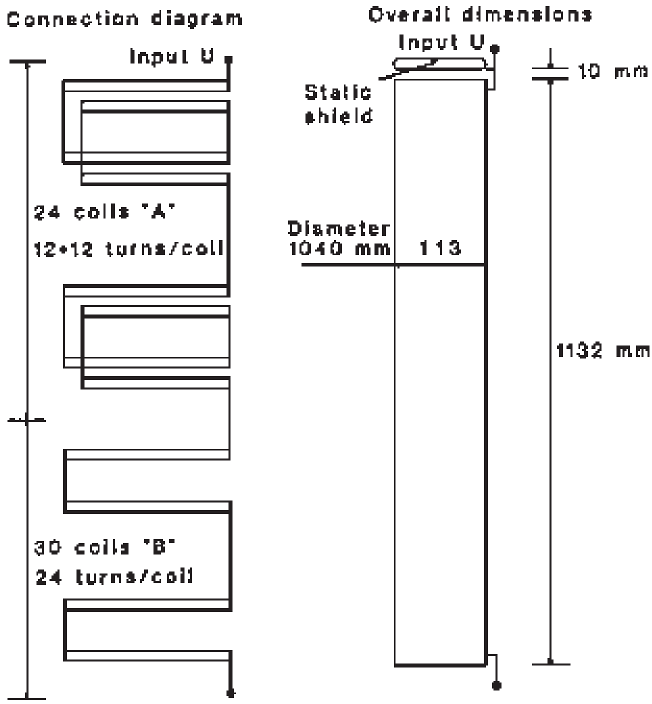


Figure 6.62 220 kV winding under test

Apart from noting the high level of the inter-section voltages observed, the above paper makes little general recommendation regarding the need for protection when connecting transformers directly to GIS, or the form which any protection might take. The authors do note, however, that the use of inductances, suitably damped, in series with the transformer windings might be justified in specific cases.

Switching in-rush currents

It is often noticed when switching in a transformer on no-load that the ammeter registers an initial current rush (which, however, rapidly dies down) greatly in excess of the normal no-load current and sometimes even greater than the normal full-load current of the transformer. In the latter case it may seem at first glance that there is a fault in the transformer. Upon considering the problem fully, however, and bearing in mind the characteristics of iron-cored apparatus, the true explanation of the transient current rush will become clear. The initial value of the current taken on no-load by the transformer at the instant of switching in is principally determined by the point of the voltage wave at which switching in occurs, but it is also partly dependent on the magnitude and polarity of the residual magnetism which may be left in the core after previously switching out. There are six limiting conditions to consider, namely:

(a) switching in at zero voltage – no residual magnetism;
(b) switching in at zero voltage – with maximum residual magnetism having a polarity opposite to that to which the flux would normally attain under equivalent normal voltage conditions;
(c) switching in at zero voltage – with maximum residual magnetism having the same polarity as that to which the flux would normally attain under equivalent normal voltage conditions;
(d) switching in at maximum voltage – no residual magnetism;
(e) switching in at maximum voltage – with maximum residual magnetism having a polarity opposite to that to which the flux would normally attain under equivalent normal voltage conditions;
(f) switching in at maximum voltage – with maximum residual magnetism having the same polarity as that to which the flux would normally attain under equivalent normal voltage conditions.

(a) Switching in at zero voltage – no residual magnetism

Under normal conditions the magnetic flux in the core, being 90° out of phase with the voltage, reaches its peak value when the voltage passes through zero. Due to this phase displacement it is necessary for the flux to vary from a maximum in one direction to a maximum in the opposite direction in order to produce one half cycle of the required back e.m.f. in the primary winding, so that a total flux is embraced during the half cycle corresponding to twice the maximum flux density.

At the instant of switching in, there being no residual magnetism in the core, the flux must start from zero, and to maintain the first half cycle of the voltage wave it must reach a value corresponding approximately to twice the normal maximum flux density.

This condition, together with the succeeding voltage and flux density waves, is shown in *Figure 6.63* and it will be seen that the rate of change of flux (upon which the magnitudes of the induced voltages depend) is nearly the same, throughout each cycle, as the normal flux density which is symmetrically placed with regard to the zero axis and which corresponds to the steady working conditions. The maximum values of the flux density, upon which the magnitude of the no-load current depends, vary gradually from a figure initially approaching twice the normal peak value in one direction only, down to the normal peak value disposed symmetrically on each side of the zero axis. As the magnitude of the no-load current is dependent upon the flux density, it follows that the current waves also will initially be unsymmetrical, and that they will gradually settle down to the steady conditions. While, however, in the case of the flux density the transient value cannot exceed twice the normal, the transient current reaches a value very many times the normal no-load current and can exceed the full-load current.

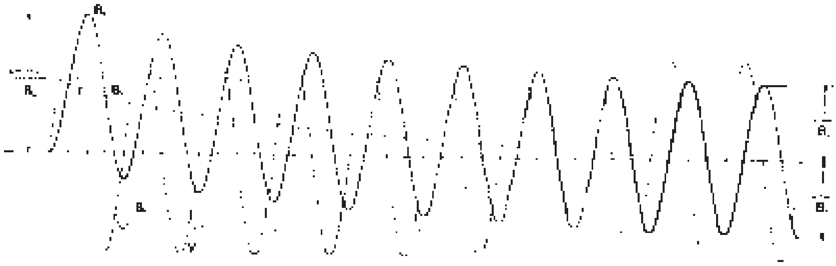


Figure 6.63 Transient flux density conditions when switching in a transformer at the instant $V = 0$. No residual magnetism. Dotted lines represent the normal steady flux density B_n and the transient component B

The reason for this current in-rush is to be found in the characteristic shape of the B/H curve of transformer core steel, which is shown in *Figure 6.64*, and from this it will be seen that the no-load current at twice the normal flux density is increased out of all proportion as compared with the current under steady conditions.

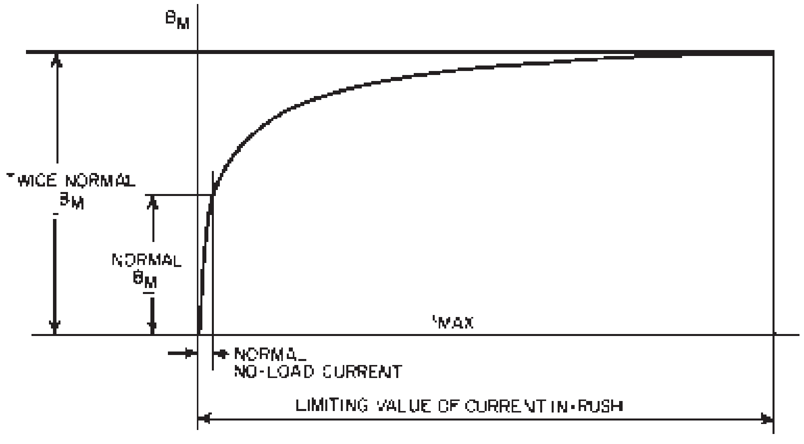


Figure 6.64 Typical B/H curve showing relationship between maximum flux density and no-load current

Figure 6.65 illustrates this current in-rush phenomenon, and the total current may be considered to consist of the normal no-load current and a drooping characteristic transient current superimposed upon it. Due to the initial high saturation in the core, the current waves may be extremely peaked and contain prominent third harmonics.

In practice, the transient flux does not actually reach a value corresponding to twice the normal flux density, as the voltage drop, due to the heavy current

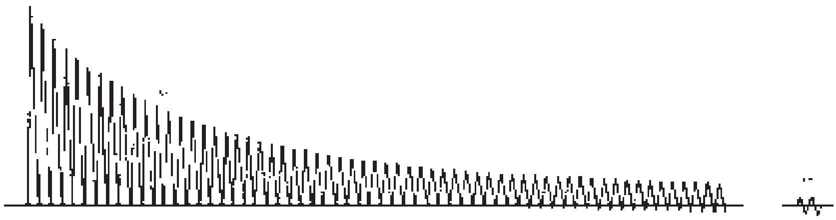


Figure 6.65 Typical transient current in-rush when switching in a transformer at the instant $V = 0$. i_n = normal no-load current, i_t switching current in-rush

in-rush flowing through the resistance of the entire primary circuit during the flux variation from zero to twice the maximum, is greater than the drop occurring with the normal flux distribution. Consequently a somewhat smaller back e.m.f. is to be generated by the varying flux, so that the latter does not reach a value corresponding to $2B_{max}$, but remains below this figure, the more so the higher the resistance of the primary circuit.

(b) Switching in at zero voltage – with maximum residual magnetism having a polarity opposite to that to which the flux would normally attain under equivalent normal voltage conditions

If there is residual magnetism in the core at the instant of switching in and the residual magnetism possesses an opposite polarity to that which the varying flux would normally have, the phenomena described under (a) will be accentuated. That is, instead of the flux wave starting at zero it will start at a value corresponding to the polarity and magnitude of the residual magnetism in the core, and in the first cycle the flux will reach a maximum higher than outlined in (a) by the amount of residual magnetism. The theoretical limit is a flux which corresponds to a value approaching three times the normal maximum flux density, and at this value the initial current in-rush will be still greater.

Figure 6.66 illustrates the resulting transient flux/time distribution, while the current in-rush will be similar to that shown in *Figure 6.65*, except that the maximum values will be much higher and the in-rush current will take a longer time to reach steady conditions. In this case also the drop in voltage, due to the resistance of the primary circuit, operates to reduce the maximum flux density and consequently the current in-rush, but to a greater extent than in the case of (a).

(c) Switching in at zero voltage – with maximum residual magnetism having the same polarity as that to which the flux would normally attain under equivalent normal voltage conditions

The converse of (b), where the residual magnetism possesses the same polarity as that which the changing flux would normally attain, results in a diminution

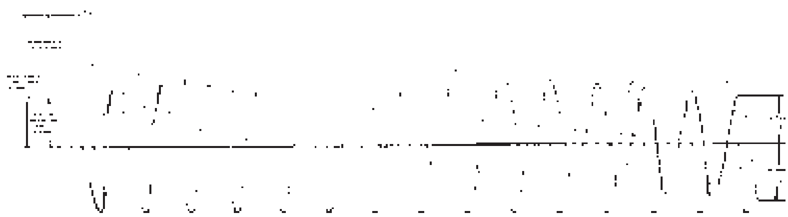


Figure 6.66 Transient flux density conditions when switching in a transformer at the instant $V = 0$ and with residual magnetism in the core and opposite to the normal flux density. Dotted lines represent the normal steady flux B_n and the transient component B

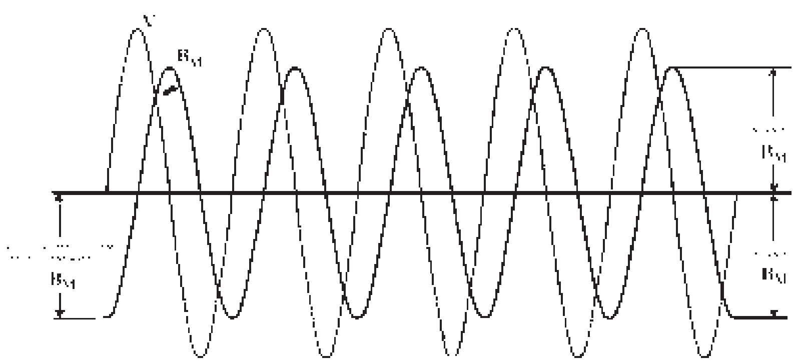


Figure 6.67 Flux density conditions when switching in a transformer at the instant $V = 0$ and with residual magnetism in the core equal to and of the same polarity as the normal flux density. No transient condition

of the initial maximum values of the flux, and consequently of the current in-rush.

If the value of the residual magnetism corresponds to maximum flux density the flux will follow its normal course and the no-load current in-rush will be avoided. *Figure 6.67* illustrates the flux/time distribution. If, however, the residual magnetism corresponds to a flux density lower than the maximum, the initial flux waves are unsymmetrically disposed about the zero axis, the more so the lower the value of the residual magnetism. *Figure 6.68* illustrates this, and a current in-rush occurs according to the maximum value of the flux.

(d) Switching in at maximum voltage – no residual magnetism

In this case at the instant of switching in, the flux should be zero, due to its 90° phase displacement from the voltage, and as we have assumed there is no residual magnetism in the core, the desired conditions are obtained which

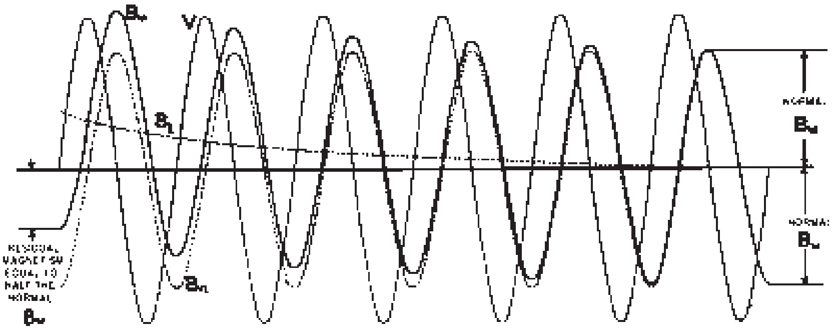


Figure 6.68 Flux density conditions when switching in a transformer at the instant $V = 0$ and with residual magnetism in the core equal to half the normal flux density and of the same polarity as the normal flux density. Dotted lines represent the normal steady flux B_n and the transient component B

produce the normal steady time distribution of the flux. That is, at the instant of switching in the flux starts from zero, rises to the normal maximum in one direction, falls to zero, rises to the normal maximum in the opposite direction and again reaches zero, the wave being symmetrically disposed about the zero axis. The no-load current, therefore, pursues its normal course and does not exceed the magnitude of the normal no-load current.

(e) Switching in at maximum voltage – with maximum residual magnetism having a polarity opposite to that to which the flux would normally attain under equivalent normal voltage conditions

In this case the residual magnetism introduces the transient components, so that the initial flux waves are unsymmetrically disposed about the zero axis, high initial maximum flux values are attained, and in the case where the residual magnetism has the same value as corresponds to the normal maximum flux density the current in-rush will have a value corresponding approximately to twice the normal maximum flux density. This is shown in *Figure 6.69.*

(f) Switching in at maximum voltage – with maximum residual magnetism having the same polarity as that to which the flux would normally attain under equivalent normal voltage conditions

This is the converse of the foregoing case, and the initial flux waves will again be unsymmetrically disposed about the zero axis. For the same value of residual magnetism the total maximum flux would be the same as in case (e), but both flux and current waves would initially be disposed on the opposite side of the zero axis. *Figure 6.70* illustrates this case.

The foregoing remarks are strictly applicable to single-phase transformers operating as such, but the principles can also be applied to polyphase

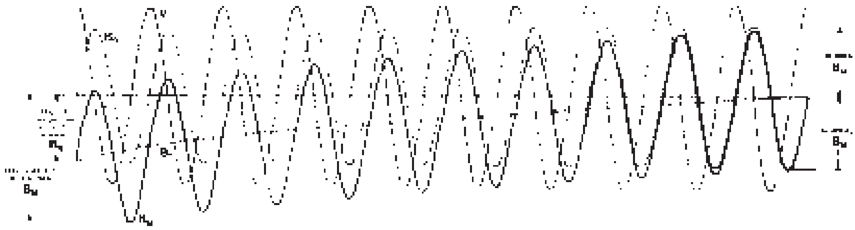


Figure 6.69 Transient flux density conditions when switching in a transformer at $V = V_{max}$ and with residual magnetism in the core equal to but in the opposite direction to the normally increasing flux density. Dotted lines represent the normal steady flux B_n and the transient component B_t

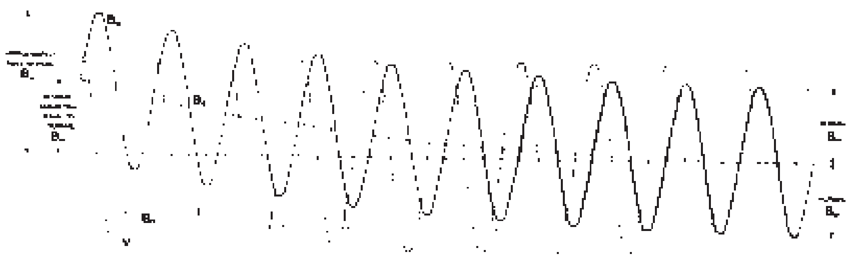


Figure 6.70 Transient flux distribution conditions when switching in a transformer at $V = V_{max}$ and with residual magnetism in the core equal to and in the same direction as the normally increasing flux density. Dotted lines represent the normal steady flux B_n and the transient component B_t

transformers or banks so long as one considers the normal magnetic relationship between the different phases. That is, curves have been given which relate to one phase only, but the principles apply equally well to polyphase transformers, providing each phase is treated in conjunction with the remaining ones.

A single instance will suffice to show what is meant, and for this purpose consider a three-phase core-type star/star-connected transformer switched in under the same conditions as (b) which is illustrated in *Figure 6.66. Figure 6.71* shows the normal main flux space and time distribution at intervals of 30°, and the number of lines in the cores indicate the relative flux density in each. Due to the usual three-phase relationship, the transformer can only be switched in when any *one* phase, say A, is at zero voltage, so that the remaining two phases B and C will each give a voltage at the instant of switching in equal to 86.6% of the maximum of each phase, one being positive and the other negative. Similarly, if the transformer has previously been switched out so that the residual magnetism in phase A of the core has a value corresponding to the maximum flux density and a polarity opposite to that which the flux would normally attain to under equivalent normal voltage

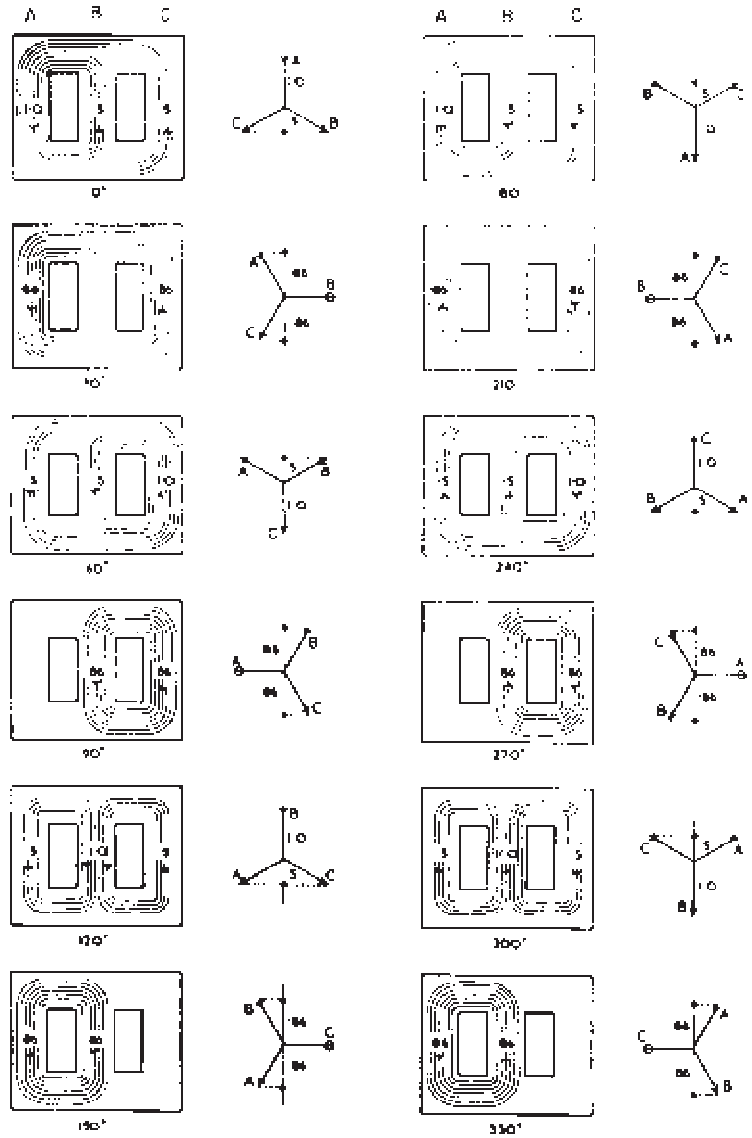


Figure 6.71 Flux space and time distribution at 30° intervals in a three-phase core-type transformer with star/star-connected windings

conditions, the residual magnetism in each phase B and C will have a value corresponding to half the normal flux density in each phase, and a polarity opposite to the residual magnetism in phase A. The current in-rushes in the three phases will therefore not be equal, but they will be modified by the flux conditions, which are shown in *Figure 6.72*. It is only necessary to refer to

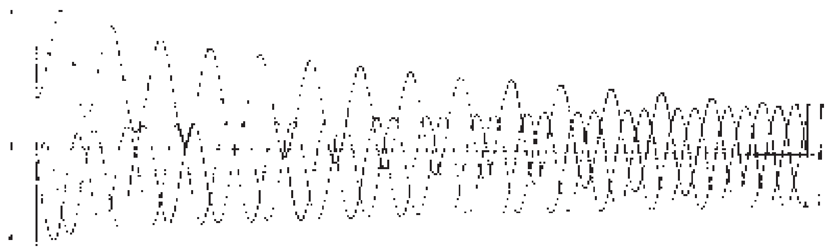


Figure 6.72 Transient flux density conditions when switching in a three-phase core-type transformer with star/star-connected windings at the instant $V_a = 0$; $V_b = 0.866V_{\max}$ and $V_c = 0.866V_{\max}$ and with residual magnetism in phase A equal to twice the normal flux density and in phases B and C equal to half the normal flux density. Dotted lines represent the transient components B_{At}, B_{Bt} and B_{Ct}

the B/H curve and hysteresis loop to obtain an approximation of the current value corresponding to each value of flux density.

The flux waves have been drawn sinusoidal in order to present the illustrations in the clearest manner, but the actual shape of the flux and current waves will be determined by the connections of the transformer windings and the type of magnetic circuit. In a three-phase core-type transformer with star/star-connected windings the normal flux wave may contain small third harmonics, and may therefore be flat topped, while the no-load current will be a sine wave. With a delta-connected winding on either primary or secondary side the normal flux wave will be sine shaped, while the no-load current may contain third harmonics and be peaked.

Figures 6.73 and *6.74* show the method of obtaining the non-sinusoidal wave shapes of flux and no-load current from the hysteresis loop of the core material when the no-load current and flux respectively are sine waves. In the initial transient stages the saturation of the cores will accentuate the higher harmonics so that in-rush current will have much higher peak values than can be deduced from ammeter readings. The B/H curve and hysteresis loops at various maximum flux densities would have to be available if more accurate theoretical determinations of the current values were to be made, but even then further difficulties would arise from the unequal form factors of the current waves in the three phases. These would be particularly marked in star/star-connected transformers and, due to the tendency to balance out the currents, the neutral point would be deflected and the phase voltages unbalanced.

It is also worthy of note that transformers with butt-type yokes do not retain residual magnetism so much as if the yokes and cores are interleaved. In-rush current may therefore be less with butt yoke transformers, though the disadvantages of this form of construction for ordinary power transformers far outweigh any advantage which might be gained in respect of a minimised current in-rush.

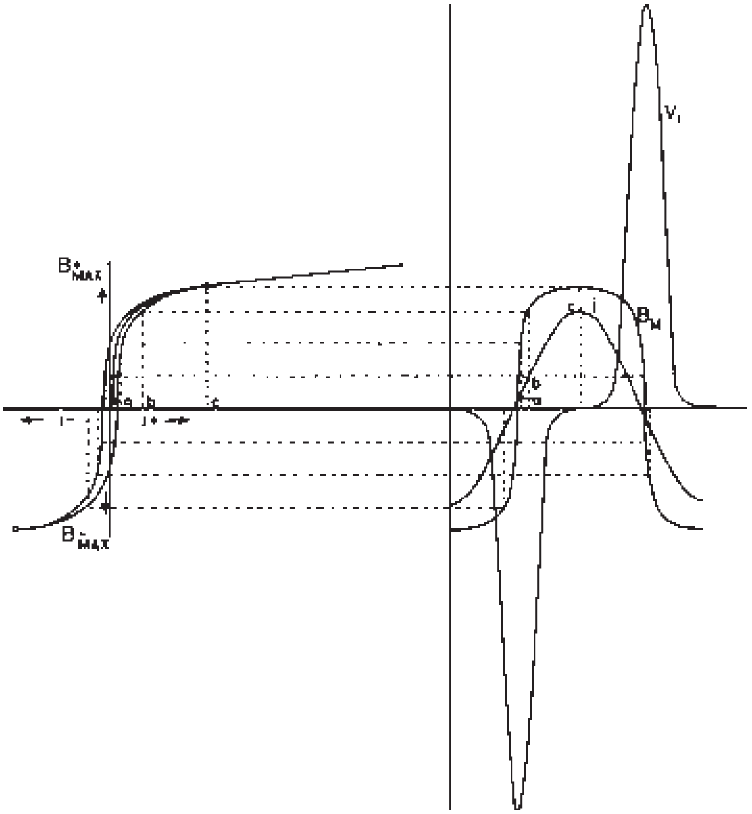


Figure 6.73 Construction for determining the non-sinusoidal waveform of flux density with a sine wave of no-load current. Note: induced voltage wave determined by differentiation of the flux wave

In passing it might be mentioned that these heavy current in-rushes were not experienced in the early days of transformer design on account of the relatively low flux densities which were then employed. The loss characteristic of transformer steel has improved considerably so that much higher flux densities are now utilised and the prevalence of heavy current in-rushes with modern transformers is due to this. These in-rushes are higher the lower the frequency for which the transformer is designed, as the lower the frequency the higher can the flux density be, which will still keep the iron loss to a reasonable figure.

For ordinary power transformers it has been suggested that residual magnetism may be greatly minimised if the load on the transformer is switched off before the primary circuit is opened. In this case when the transformer is finally switched out of circuit the only current flowing will be the normal no-load current which will be lagging behind the applied voltage by an angle usually between 70° and 90°. As it is generally found that a circuit breaker opens a circuit at or near zero

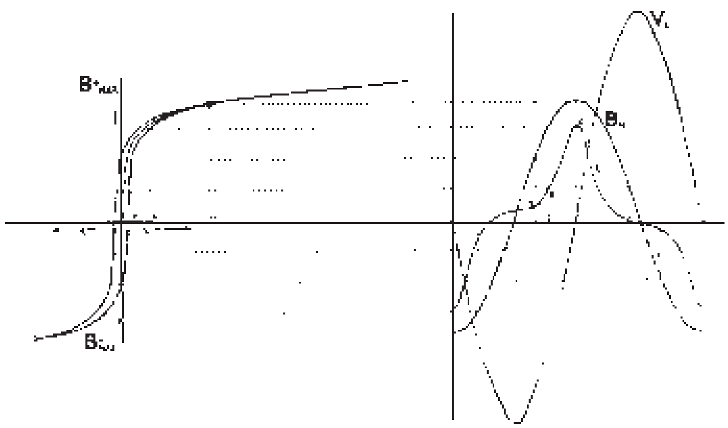


Figure 6.74 Construction for determining the non-sinusoidal waveform of no-load current with sine waves of flux and induced voltage

current, this will correspond to a point at or near the maximum point on the voltage wave so that the flux in the core will be nearly zero. If the transformer is switched out of circuit on load, zero current will, in the case of a non-inductive load, correspond nearly to zero voltage, so that the residual magnetism left in the core would be a maximum; but the more inductive the load, the less likelihood is there of switching out at zero voltage.

Theoretically the residual magnetism may almost be eliminated by gradually reducing the applied voltage before switching the transformer out of circuit, while a further possible method would be to provide some kind of contact mechanism which would ensure the switch opening the circuit at maximum voltage. It should be remembered, however, that in any case with polyphase transformers it is not possible to switch out all phases at the maximum voltage, and consequently this last method would, at the best, only result in zero magnetism in one phase and something between zero and the maximum in the remaining phases. Both of the last two methods are objectionable, however, in so far as they involve additional equipment.

It has also been suggested at various times that switching in current inrushes may be minimised by slowly closing the switch in the exciting circuit. The idea underlying this suggestion is that as the switch contacts approach one another, a point will be reached just prior to actual closing at which a spark will bridge the contacts of one phase at the maximum peak voltage. At this instant the normally varying flux will have zero value and consequently current inrushes will be avoided. This effect could, of course, only occur with one phase, and consequently the method could theoretically only be applied with perfect success to single-phase transformers. In the case of polyphase transformers, the remaining phases will each have a voltage at some value between zero and the maximum, and therefore abnormal flux distribution occurs in these phases, which will produce current in-rushes similar to those previously described. When considering this method, however, the fact should not be lost sight of that arcing at the switch contacts is liable to produce high-frequency voltage oscillations, the more so the more slowly the switch is closed. As this type of disturbance is generally very liable to produce a breakdown in the transformer windings, the method of slowly switching in for the purpose of avoiding current in-rushes is not one which can easily be recommended.

At one time circuit breakers controlling transformers were sometimes fitted with buffer resistors and auxiliary contacts so that the resistors were connected in series with the transformer when switching in, being subsequently short-circuited upon completion of the switching operation. These buffer resistors are, however, no longer employed but as a matter of academic interest *Figure 6.75* illustrates the effect of a buffer resistor on the transient switching in current in-rush of a 20 kVA transformer, the resistor having such a value that it takes 5% of the normal supply voltage at no-load.

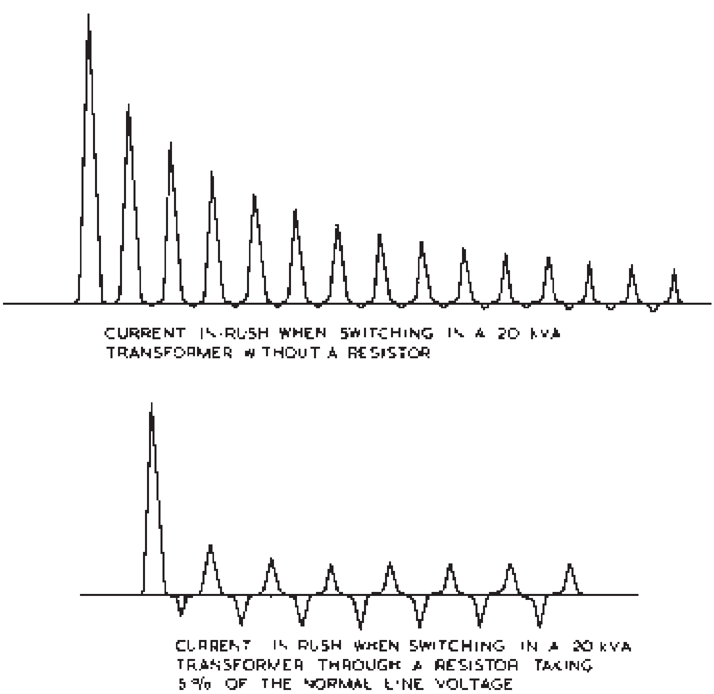


Figure 6.75 Current in-rush when switching in a 20 kVA transformer

An objection to these current in-rushes is the mechanical forces which are exerted between coils at the instant of switching in. While these certainly die down more or less rapidly, the conductors are strained to some extent and the insulation between individual conductors may become compressed in places, while in other places the normal mechanical pressure due to the winding process may be released, so that the mechanical rigidity of the coils as a whole becomes entirely altered. That is, in some parts adjacent conductors may be slack, while in others they may be compressed tightly, and with repeated switching-in operations there may be a risk of failure of the insulation between turns of the windings.

Cases have been known in which a transformer switched in under particularly adverse conditions has moved in its tank, and this introduces the possibility of damage to connections between coils and connections from coils to terminals, resulting in open-circuits in the windings concerned.

Among the minor disadvantages are the tripping of main switches, blowing of fuses, and the operation of relays, but while these are often annoying, they are not serious.

Short-circuit currents

It has already been shown that abnormal currents may occur in the primary windings under certain adverse conditions when switching in a transformer on no-load, but much heavier currents may flow in both primary and secondary windings when a transformer momentarily supplies its heaviest load: that is, when a short-circuit occurs across the secondary terminals. We thus have four distinct current conditions to which a transformer may be subjected, these being:

(a) transient switching no-load current in-rush;
(b) steady no-load current;
(c) steady normal load current;
(d) transient short-circuit current.

The currents which represent a danger to the windings are the transient in-rushes only, viz. (a) and (d), and of these two the latter is the one against which special precaution must be taken, as the resulting currents set up severe mechanical stresses in the windings.

If a conductor carries current a magnetic field is set up round the conductor in the form of concentric circles, the density of the field at any point being directly proportional to the current in the conductor and inversely proportional to the distance between the conductor and the point considered. If two conductors both carrying current are in close proximity to each other they will each be subjected to the influence of the magnetic field surrounding the other, and in the case of adjacent conductors carrying currents in the same direction the magnetic fields will produce a force of attraction between the two conductors, while with currents flowing in opposite directions the magnetic fields mutually repel each other and a repulsion force is set up between the conductors. For a given current and spacing between the two conductors the value of the forces is the same, irrespective of whether they are attractive or repulsive.

If, now, the above principles are applied to transformer coils it will be seen that any one coil, either primary or secondary, carries current so that the currents in opposite sides flow in opposite directions, and repulsion forces are thus set up between opposite sides so that the coil tends to expand radially outwards in just the same way as does a revolving ring or other structure due to centrifugal force. The coil thus tends to assume a circular shape under the influence of short-circuit stresses, and therefore it is obvious that a coil which is originally circular is fundamentally the best shape, and is one which is least liable to distortion under fault conditions. From this point of view the advantages of the circular core type of construction are obvious.

In a coil composed of a number of wires arranged in a number of layers, each having a number of turns per layer, such as may be the case with HV windings, the wires situated in the same sides of the coil carry current in the same direction, and therefore attract one another and tend to maintain the homogeneity of the coil.

In addition to the radial forces set up in the individual windings tending to force the coils into a circular shape, other repulsion forces exist between primary and secondary windings, as these windings carry currents flowing in opposite directions. The directions of these repulsion forces are shown in *Figure 6.76* for circular and rectangular coils under the conditions of:

(i) coincident electrical centres;
(ii) non-coincident centres.

When the electrical centres coincide it will be seen that if the coils are of the same dimensions, repulsion forces normal to the coil surfaces only exist, but if the electrical centres do not coincide, a component at right angles to the force normal to the coil surfaces is introduced which tends to make the coils slide past one another. A similar component at right angles to the normal component is introduced, even if the electrical centres are non-coincident and the dimensions of the coils are different. In this case the system consisting of the primary and secondary coils is balanced as a whole, but adjacent sides of primary and secondary coils are liable to distortion on account of the sliding components introduced. In actual practice, both with core-type and shell-type transformers, the sliding component of the mechanical forces between primary and secondary coils is the one which has been responsible for many failures under external short-circuit conditions, particularly of some of the older transformers having low impedances. In passing it should be remembered that often it is not possible to preserve the coincidence of electrical centres at all ratios when transformers are fitted with voltage adjusting tappings.

The value of the current flowing under external short-circuit conditions is inversely proportional to the impedance of the entire circuit up to the actual fault, and, so far as the transformer itself is concerned, the most onerous condition which it has to withstand is a short-circuit across the secondary terminals. The question of how the transformer impedance is affected by matters of design is dealt with elsewhere in this book, and it is only necessary to point

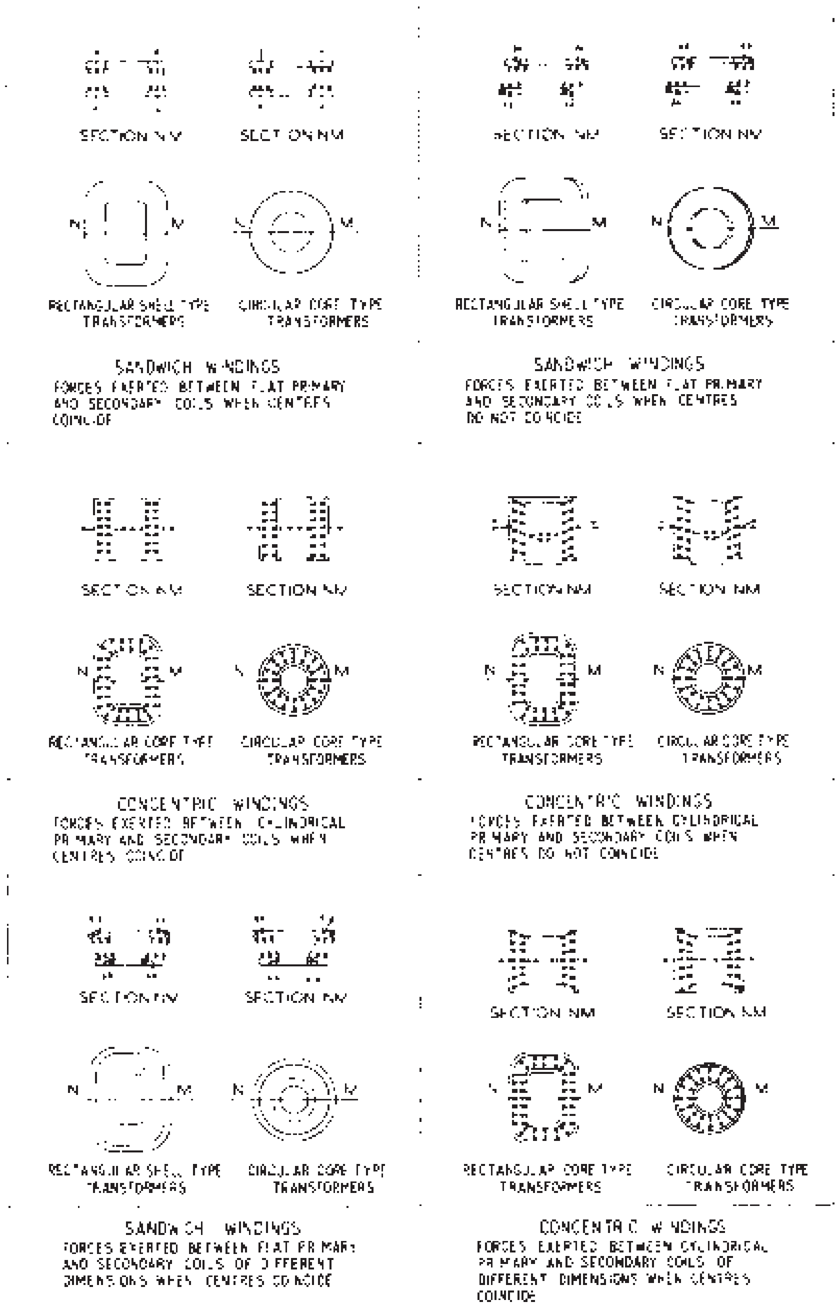


Figure 6.76 Mechanical forces on transformer coils

out here that as the impedance voltage is that voltage required to circulate *full-load* current in the transformer windings, the short-circuit current bears the same relation to the normal full-load current as does the normal full-line voltage to the impedance voltage, the latter being expressed in terms of the full-line voltage. Expressed in equation form, the connection between short-circuit current and impedance voltage is as follows:

$$I_{SC} = I_{FL}\frac{100}{V_z} \tag{6.57}$$

where I_{SC} = primary or secondary short-circuit current
I_{FL} = primary or secondary full-load current
V_z = percentage impedance voltage

It must be remembered that the short-circuit current derived from the above equation presumes maintenance of the full-line voltage under fault conditions, but in fact the line voltage is generally maintained for the first few cycles only after the first instant of short-circuit, and then only on the larger systems having sufficient MVA of generating plant behind the fault. Therefore, at the first instant of short-circuit the current reaches a value given by equation (6.57) but as the line voltage drops the value of the short-circuit current similarly falls until the transformer is automatically switched out of circuit.

The initial value of the short-circuit current in-rush may be further modified by the normal conditions existing at the instant of short-circuit, and in the worst case the initial value of the short-circuit current reaches twice the amount given by equation (6.57) by what has been termed the 'doubling effect'. This doubling effect occurs when the actual short-circuit is made at the instant when the voltage of the circuit is zero, and we will consider the two extreme cases when the short-circuit occurs at the instant (a) when the voltage is passing through its maximum value, and (b) when the voltage is passing through zero. In *Figure 6.77* V represents the voltage wave, B_M the flux wave, and I_{FL} the wave of normal full-load current. If a short-circuit takes place at the instant marked I in the diagram, the flux leading the voltage by 90° is zero, and as on short-circuit the resulting current is in phase with the flux or nearly so, the short-circuit current should have a similar phase relationship. At the instant I the short-circuit current should therefore be zero, and if no current existed in the circuit at this instant the short-circuit current would pursue its normal course, reaching an initial maximum value corresponding to equation (6.57), and it would be disposed symmetrically on either side of the zero axis, gradually and symmetrically dying down until the transformer was tripped out of circuit. This condition is shown by the current wave I_{SC} in *Figure 6.77*. On account of the presence of the normal full-load current which has a definite value at the instant I, the short-circuit current must initially start from that point and the resulting wave will be somewhat unsymmetrical, depending upon the ratio between the full-load and short-circuit currents and upon their relative power factors. This wave is shown at I''_{SC} in *Figure 6.77*.

If, on the other hand, the short-circuit occurs at the instant marked II in *Figure 6.78*, the voltage is zero and the flux has a negative maximum value, so that the initial short-circuit current should also be at or near its negative maximum value. This cannot occur, as the short-circuit current cannot *instantly* attain the value corresponding to the position and value of the flux wave, but instead it must start from a value corresponding in sign and magnitude to the current already in the circuit at the particular instant, viz. the normal full-load current at the instant II. During the first cycle immediately following the short-circuit the full voltage is generally active in producing abnormal short-circuit currents, and in order to maintain this voltage during the first half cycle, the short-circuit current must vary from a maximum negative to a maximum positive value, that is the total change is twice that occurring when a short-circuit takes place at maximum voltage and zero flux. This abnormal current wave, therefore, commences from the value of the full-load current in the circuit at the instant II, and from this point rises to a value approaching twice that obtained with a symmetrical short-circuit, as shown at I_{SC}'' in *Figure 6.78*. This explains the so-called ‘doubling effect’, though, as a rule, the short-circuit current does not reach the full double value on account of resistance voltage drops. This highly abnormal wave is, of course, unsymmetrical, but dies down rapidly, giving ultimately the same symmetrical current distribution as when a short-circuit takes place at the instant corresponding to maximum voltage.

The mechanical stresses set up in transformer windings vary as the square of the current flowing, and it will be seen, therefore, that the doubling effect may have serious consequences. For instance, in a transformer having an impedance of 5% the initial stresses under short-circuit conditions would be 400 times as great as those in the transformer under normal full-load conditions when making the short-circuit at maximum voltage, but when making the short-circuit at zero voltage the resulting stresses in the windings would be approximately 1600 times as great as those under normal full-load conditions, on account of the doubling effect.

In practice these high mechanical stresses have been responsible for damage to HV end coils of core-type transformers with concentrically disposed windings, though in such transformers the radial bursting tendency on the outer windings is not usually high enough to reach the elastic limit of the conductors. Similarly, the compressive stress on the inner windings is resisted by the mechanical rigidity inherent in such windings. With rectangular shell-type transformers employing flat rectangular coils arranged in sandwiched fashion, severe distortion and subsequent rupture of the ends of the coils projecting beyond the core has occurred from the same cause. With low-reactance transformers particularly, the HV end coils and also the coil clamping structure have been distorted, but as the forces which come into play have become more and more appreciated, transformer reactance has been increased and the coil clamping structure better designed and more adequately braced. Such coil clamps have been applied to compress the coils in an axial direction and

Figure 6.77 Short circuit at instant $V = V_{max}$

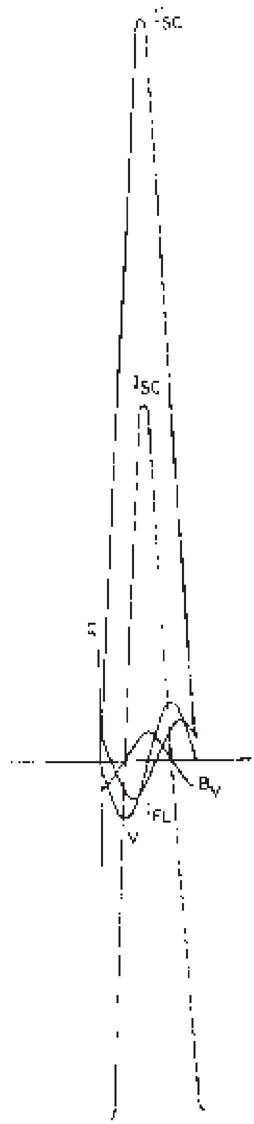


Figure 6.78 Short circuit at instant $V =$ zero

to restrain them from moving under short-circuit conditions. Except in very special cases, radial coil supports are not necessary, though there is more justification for their use with rectangular type of coils. In the core-type transformer the coils are generally circular, and as this is inherently the best possible shape, the conductors are best able to stand the short-circuit stresses.

While on short-circuit the phenomenon most to be feared is the mechanical stresses to which the windings and structure are subjected, and it must be remembered as somewhat of a paradox that this is so on account of the rapidity with which modern circuit breakers automatically disconnect such a fault from the supply. If for any reason the automatic means provided did not operate, the transformer would rapidly become overheated, and it would exhibit all the appearances associated with severe overloads. In a very short space of time short-circuits between turns would take place and the windings would become destroyed.

The reader should refer to Section 8 of Chapter 4 for more detailed information regarding electromagnetic forces in transformer windings.

6.6 TRANSFORMER PROTECTION

The subject of transformer protection falls naturally under two main headings. These are:

- Protection of the transformer against the effects of faults occurring on any part of the system.
- Protection of the system against the effects of faults arising in the transformer.

Protection of the transformer against faults occurring in the system

Considering first the means to be adopted for protecting the transformer itself against the effects of system faults, three distinct types of disturbances (apart from overloads) have to be provided for. These are:

- Short-circuits.
- High-voltage, high-frequency disturbances including lightning.
- Pure earth faults.

To this list could be added ferroresonance, which can occur under certain conditions in any system containing capacitance and inductance elements such as those associated respectively with cables and transformers. The problem usually arises when some external system disturbance causes a transformer to go into saturation thus greatly changing its inductance. This may lead to excess voltages and currents arising on the system which can cause damage to transformers and other plant. Although certain protective equipment may operate under ferroresonance conditions, ferroresonance is not normally regarded as a 'fault' in the normal sense of the word, rather as a condition to be avoided by careful system design. The non-linearity of core steel is a property which exists and cannot be eliminated. Whilst the design of transformers to operate at low flux densities might reduce the likelihood of core saturation, this would lead to very uneconomic designs and it is generally considered that it would have very little effect on the conditions which can lead to ferroresonance.

Short-circuits

System-short circuits may occur across any two or even three lines, or, if the neutral point is solidly earthed, between any one line and the earthed neutral. As pointed out in Section 5 of this chapter, the effect of a system short-circuit is to produce overcurrents, the magnitude of which are dependent on the short-circuit level of the system feeding the fault, the voltage which has been short-circuited, the impedance of the circuit up to the fault and the impedance of the fault itself.

The short-circuit currents produce very high mechanical stresses in the equipment through which they flow, these stresses being proportional to the square of the currents. The magnitude of these short-circuit currents can be limited by increasing the system impedance, usually incorporating this into the supply transformers. Unfortunately, increasing system impedance increases the regulation and this is not usually acceptable because of its effect on system performance and operation. On EHV and HV systems close control of system voltage is required in order to control power and VAr flows. On HV and MV systems there are close statutory limits on voltage variation at consumers' supply terminals which are necessary to ensure that the consumers' equipment will function correctly, particularly the starting of motor drives. Although on the EHV and HV systems the transmission authorities are able to make use of on-load tapchangers on transformers and other devices such as VAr compensators to control system voltages, it is desirable from the transformer practical and economic viewpoint that the extent of tapping ranges is limited, for the reasons explained in Chapter 4, and on MV systems tappings are usually only selectable off-circuit, so that no means of continuous voltage control is available. Consequently the system designer is normally striving to achieve minimum regulation by keeping supply impedance as low as possible, limited only by the fault interruption capability of the available switchgear. Whereas some years ago the capability of the supply transformers to withstand the resulting short-circuit currents also provided an important constraint on selection of the system fault level, nowadays transformer manufacturers must be prepared to supply a transformer which is capable of withstanding whatever fault level the system designer decides is necessary, so that modern transformers designed to comply with the current issue of IEC 76 are capable of withstanding, without damage while in service, the electromagnetic forces arising under short-circuit conditions, as determined by the asymmetrical peak value of the current in the windings, which is normally taken as 2.55 times the short-circuit current (see Section 7 of Chapter 4).

In recent times the widespread adoption of solid-state 'soft-start' equipment for 415 V motor drives has generally reduced motor starting currents so that regulation of medium voltage systems may no longer be quite so critical to the system designer. This might enable the smaller distribution transformers providing 415 V supplies to have higher impedances and consequently lower short-circuit withstand capability. In reality, however, this is unlikely to have much impact on distribution transformer specifications and designs since once low impedance and a high level of short-circuit withstand strength has been shown to be possible this will tend to dictate accepted design practices and cost savings resulting from a reduction in this will prove to be minimal.

High-voltage, high-frequency disturbances

High-voltage, high-frequency surges may arise in the system due to lightning, external flashover on overhead lines, switching operations and to the effects of atmospheric disturbances. These surges principally take the form of travelling waves having high amplitudes and steep wavefronts, and often successive surges may follow rapidly upon one another. On account of their high amplitudes the surges, upon reaching the windings of a transformer, pose a significant threat to the winding insulation. The effects of these surge voltages may be minimised by designing the windings to withstand the application of a specified surge test voltage and then ensuring that this test value is not exceeded in service by the provision of suitable surge protection installed adjacent to the transformer terminals.

All types of surge protection aim at attaining the same results, namely that of shunting surges from lines to earth or line to line to prevent their reaching the transformer. Protection may take the form of a rod gap, known as a coordinating gap, connected across the transformer bushings and designed to flash over at a given voltage level, or alternatively surge arresters may be used. Until quite recently surge arresters employed several spark gaps in series with a non-linear resistor material, normally silicon carbide, and, although this type is still used in significant quantities on rural distribution networks at 33 kV and below, elsewhere these have now been almost entirely superseded by the gapless metal oxide variety. The arresters are connected from each line to earth, or they may be occasionally connected from line to line. When a high-voltage surge reaches the arrester the metal oxide becomes conducting or the spark gaps break down and the disturbance is discharged through the device by reason of the fact that at the high voltage involved the arrester resistance is low. As the surge voltage falls the arrester resistance automatically increases and prevents the flow of power current to earth or between lines. An arrester of this type is therefore entirely automatic in action and self-extinguishing.

The internal surge impedance of a transformer winding is not a constant single valued quantity but has a range of values corresponding to the frequencies of the incident surge waveform. Changes in the surge impedance due to oscillation and decay of the surge voltages within the windings do not appreciably affect the terminal conditions. Moreover, the transformer terminal impedance is so high when compared with the line surge impedance that its assigned value, so long as it is of the right order, has little influence upon the shape of the resulting surge waveform given. The wave diagrams in this section show the variation of voltage and current with time at the transformer terminals and not the phenomena occurring throughout the windings subsequent to the application of the surge waves to the terminals. Studies of the latter are given in Section 5 of this chapter.

Consider, first, what happens when rectangular finite voltage and current waves reach a transformer from an overhead line, there being no protective apparatus installed to intercept the disturbance. The amplitudes of the waves in the overhead line and at the transformer terminals depend upon the respective values of their surge impedance, which is given by the formula:

$$Z = \sqrt{(L/C)}$$

where $Z =$ surge impedance in ohms
$L =$ inductance in henrys
$C =$ capacitance in farads

of the circuit concerned.

L and *C* may be taken for any convenient length of circuit.

When any travelling waves of voltage and current pass from a circuit of a certain surge impedance to a circuit of a different surge impedance, such waves in their passage to the second circuit undergo changes in amplitudes. The oncoming incident waves when reaching the transition point between the two circuits are, if the surge impedances of the two circuits are different, split up into two portions, one being transmitted into the second circuit, and the other reflected into the first. The transmitted waves always have the same sign as the incident waves, but the reflected waves may have the same or opposite sign to the incident waves depending upon the ratio of the two surge impedances. This applies both to the voltage and the current waves.

If the incident waves are of finite length, the reflected waves travel back into the first circuit alone, and they are only transient waves in that circuit. If, on the other hand, the incident waves are of infinite length, the reflected waves in their passage backwards along the first circuit combine with the tails of the incident waves, so that the resultant waves in the first circuit are a combination of the two respective incident and reflected waves.

Given the amplitudes of the incident voltage and current waves and the surge impedances of the two circuits, the transmitted and reflected waves may be calculated by means of the formulae given in *Table 6.6*. The table gives formulae for determining the conditions when the incident waves are finite in length, and they are based on the assumption that no distortion of the shape occurs, due to losses in the circuit.

Figures 6.79 and *6.80* show the incident, transmitted, and reflected voltage and current waves respectively, assuming the incident voltage wave to have an amplitude of 20 000 V, and the incident current wave an amplitude equal to $20\,000/Z_1 = 57.1$ A, as Z_1 is assumed to equal 350 Ω. The transmitted and reflected waves are constructed from the formulae given on the diagrams (distortion being ignored), and it will be seen that a voltage wave arrives at the transformer terminals having an amplitude considerably higher than that of the original incident wave. It is due to this sudden increase of voltage at the transformer terminals that so many failures of the insulation on the end

Table 6.6 Reflection of rectangular travelling waves at a transition point. No protective device

V = voltage I = current	Distortion due to dielectric and copper losses is ignored	i = incident waves r = reflected waves t = transmitted waves

Z_1 and Z_2 = surge impedances of circuit in *Figure 6.80*

$$\text{Current and voltage reflection factor} = \frac{Z_2 - Z_1}{Z_1 + Z_2} = n_r$$

$$\text{Voltage transmission factor} = \frac{2Z_2}{Z_1 + Z_2} = n_{tv}$$

$$\text{Current transmission factor} = \frac{2Z_1}{Z_1 + Z_2} = n_{tc}$$

Also

$$\frac{V_t}{V_i} = \frac{2Z_2}{Z_1 + Z_2};\ \frac{V_t}{V_r} = \frac{2Z_2}{Z_2 - Z_1};\ \frac{V_r}{V_i} = \frac{Z_2 - Z_1}{Z_2 + Z_1};$$

$$\frac{I_t}{I_i} = \frac{2Z_1}{Z_1 + Z_2};\ \frac{I_t}{I_r} = \frac{2Z_1}{Z_2 - Z_1};\ \frac{I_r}{I_i} = \frac{Z_2 - Z_1}{Z_1 + Z_2};$$

Then

	$Z_2 > Z_1$		$Z_2 < Z_1$	
	Voltage	*Current*	*Voltage*	*Current*
Incident wave	V_i	I_i	V_i	I_i
Transmitted wave	$n_{tv}V_i$	$n_{tc}I_i$	$n_{tv}V_i$	$n_{tc}I_i$
Reflected wave	n_rV_i	$-n_rI_i$	n_rV_i	$-n_rI_i$

For $Z_2 > Z_1$ the reflected voltage waves is positive
For $Z_2 > Z_1$ the reflected current wave is negative
For $Z_2 < Z_1$ the reflected voltage wave is negative
For $Z_2 < Z_1$ the reflected current wave is positive

Note: $\dfrac{2Z_2}{Z_1 + Z_2} - \dfrac{Z_2 - Z_1}{Z_1 + Z_2} = 1;\ \dfrac{2Z_1}{Z_1 + Z_2} + \dfrac{Z_2 - Z_1}{Z_1 + Z_2} = 1$

turns of windings have occurred in the past, as the increased voltage may be concentrated, at the first instant, across the first few turns of the winding only, though ultimately voltage is distributed evenly throughout the whole winding. The transmitted current wave is correspondingly smaller in amplitude than the incident current wave and, as such, is usually of no particular danger.

These diagrams show clearly that where the surge impedance of the second circuit is higher than that of the first, in comparison with the incident waves, the transmitted voltage wave is increased and the transmitted current wave is decreased, while the reflected waves have such signs and amplitudes as to satisfy the equations

$$V_t = V_i + V_r$$

$$I_t = I_i + I_r$$

That is, both transmitted voltage and current waves are equal to the sum of the respective incident and reflected waves.

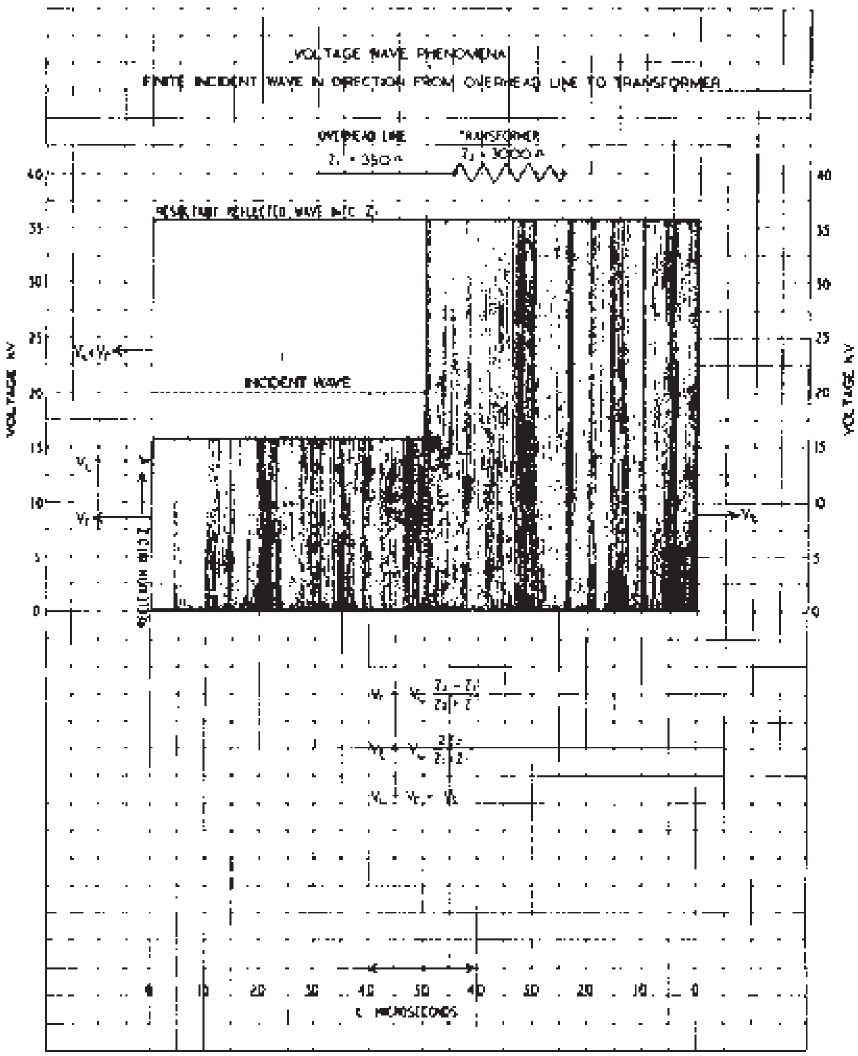


Figure 6.79 Diagram showing incident, transmitted and reflected voltage waves assuming an amplitude of 20 kV for the incident wave

During the time corresponding to the lengths of the incident waves, the total voltage and current in the first circuit is equal to the sum of their respective incident and reflected waves, but after that period the reflected waves alone exist in the circuit.

From the preceding formulae and diagrams, when surges pass from one circuit to another the phenomena can be summarised as follows.

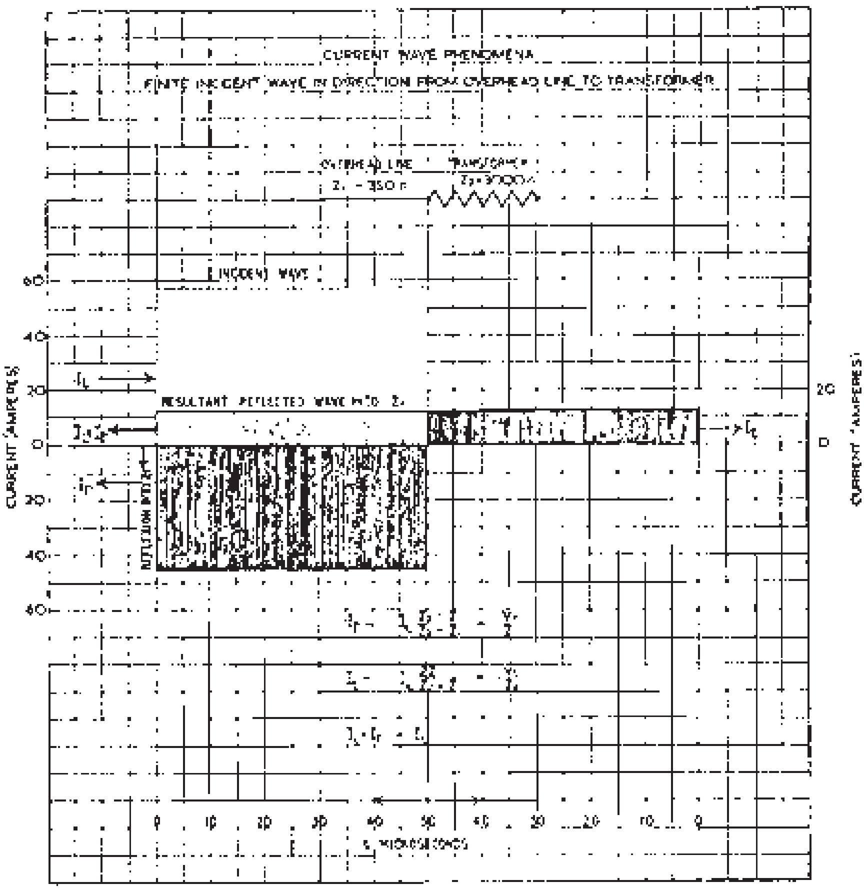


Figure 6.80 Diagram showing incident, transmitted and reflected current waves, assuming an amplitude of 57.1 A for the incident wave

When a voltage wave passes from one circuit to another of higher surge impedance, both reflected and transmitted waves have the same sign as the incident wave, while the transmitted voltage wave is equal in amplitude to the sum of the incident and reflected waves. For the same circuit conditions the transmitted current wave possesses the same sign as the incident current wave, but the reflected current wave has the opposite sign. The transmitted current wave is equal in amplitude to the sum of the incident and reflected waves.

At the transition point itself the total amplitudes of the voltage and current waves are always equal to the sum of the respective incident and reflected waves, bearing in mind, of course, the relative signs, and if the incident waves are infinite in length the same amplitudes extend throughout the whole of the circuit in which the incident waves arise. If, on the other hand, the incident waves are of finite lengths, the amplitudes of the resultant waves in the major part of the first circuit will be equal to the amplitudes of the reflected waves only.

The amplitudes of the transmitted and reflected waves are solely dependent on the ratio of the surge impedances of the two circuits.

The preceding notes have indicated that transmitted waves passing to a second circuit do so with rectangular fronts. That is, apart from any deformation of the waves which may occur due to losses in the circuits, the fronts of the transmitted waves are not modified in any way. If the second circuit is composed of inductive windings, such a rectangular fronted voltage wave represents a distinct danger to the insulation of the transformer. It becomes desirable, therefore, to modify the shape of the waveform from the steep rectangular form to a more gradual sloping one, and this can be achieved by the use of suitable surge diverters.

Surge protection of transformers*

Modern practice of surge protection of transformers is aimed at preventing excessive voltage surges from reaching the transformer as a unit, that is not only the HV and LV windings but also the bushings, where flashover and insulation breakdown will result in serious damage and system disconnections. In the UK surge protection is implemented by the addition of rod gaps or surge arresters adjacent to the transformer to shunt the surges to earth. These attenuate the surge magnitudes seen by the windings and their resulting insulation stresses to levels which can be withstood by suitably proportioned insulation distribution without causing resonant instability and dangerous oscillations within the windings.

Bushing flashover would generally protect the windings but this is not tolerable in practice for several reasons, notably the likelihood of damaging the bushing. The breakdown characteristic is most unfavourable and after initial breakdown to earth, via the bushing surface, tank and tank earth connection, the low impedance path to earth will allow a power-frequency current to flow if the system neutral is earthed or if two bushings flash over simultaneously. This current will cause protective schemes to operate, leading to system disconnections even when the bushings are undamaged.

The desired characteristic is one where the path to earth presents a high impedance to normal supply frequency voltages but which falls to a low impedance under high-voltage transient conditions, followed by a rapid recovery to the original impedance levels as the voltage falls again.

The two methods commonly adopted to obtain surge protection are:

(a) co-ordinating rod gaps, and
(b) surge arresters.

* Reproduced by kind permission of the CEGB.

Both methods have advantages and disadvantages but are applicable on systems operating at voltages down to 3.3 kV which are reasonably insulated and where the cost of surge protection of these types can be justified for system reliability.

Screened coordinating rod gaps

Coordinating rod gaps have been fitted in the UK on bushings for many years in order to protect the windings of HV transformers from external overvoltages. A disadvantage of coordinating rod gaps is the difference between the positive and negative polarity voltage protection levels, which in the case of 400 kV winding protection may be of the order of 300 kV for 100 μs wavefronts.

A further disadvantage is that for switching surges with wavefronts exceeding 100 μs there is a rapid increase in the operating voltage level with positive surges. On the assumption that a particular protective level at 100 μs wavefront is adequate to protect the transformer winding, the 40% voltage withstand increase for wavefronts between 100 and 1000 μs for the positive wave could result in the withstand strength of the transformer winding being exceeded in the case of switching surges with long fronts. Such fronts may be encountered when switching transformer feeders where surges with wavefronts of several hundred microseconds have been measured during switching operations.

Screened coordinating gaps for fitment to 132, 275 and 400 kV transformer bushings have been developed by CERL whereby the polarity differential is considerably reduced such that the 99.7% probability of sparkover to wavefronts between (a) 1 to 10 μs, (b) 10 to 200 μs can be maintained at not greater than the specified (a) lightning, (b) switching surge withstand levels of the winding, and with a 95% probability of sparkover for wavefronts up to 500 μs.

The screened coordinating gap comprises, as in the standard coordinating gap, a horizontal gap between two rods or two loops, but the HV rod or loop is screened by a vertical toroid at right angles to the rod or loop and positioned so that the radiused rod or loop termination is in the same plane as the surface of the toroid facing the earth electrode. *Figure 6.81* illustrates the arrangement of a screened coordinating gap electrode for use on a 275 kV system.

Protection with surge arresters

When a travelling wave on a transmission line causes an insulator flashover any earth fault which may be established on the system after the surge has discharged may cause the relay protective gear to operate, disconnecting the line from the supply. To avoid this the voltage flashover level of the line can be increased by means of larger insulators but this can only be done within limits because the higher the line insulator flashover voltage then the higher the value of the impulse wave transmitted to the transformer. Therefore some

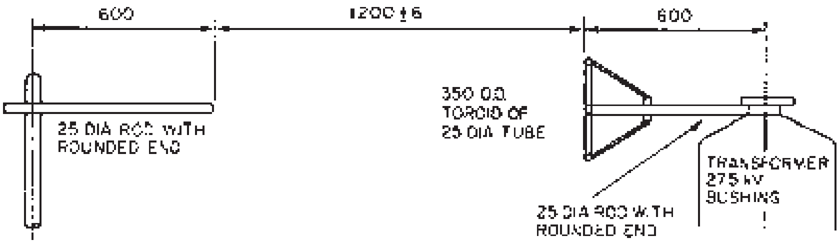


Figure 6.81 Screened coordinating gap electrode for use on a 275 kV system

compromise has to be made between the risk of a line flashover and possible damage to equipment and thus it is necessary to know the impulse voltage strength of the transformers to be protected. This has led to the system of insulation coordination as set out in IEC 71 (BS 5622) *Guide for Insulation co-ordination*. This is a two-part document; Part 1 covers terms, definitions, principles and rules; Part 2 is the application guide.

Quoting from the 1976 issue of Part 1: 'Insulation co-ordination comprises the selection of electric strength of equipment and its application, in relation to the voltages which can appear on the system for which the equipment is intended and taking into account the characteristics of available protective devices, so as to reduce to an economically and operationally acceptable level the probability that the resulting voltage stresses imposed on the equipment will cause damage to equipment insulation or affect continuity of service.'

Determination of electric strength is carried out by means of dielectric tests. The test level is related to the *highest voltage for equipment*, U_m, which is defined as the highest r.m.s. phase-to-phase voltage for which the equipment is designed in respect of its insulation as set out in the relevant equipment standards, which for power transformers is IEC 76 (BS 171). Overvoltages to which equipment and systems might be subjected are related to the *phase-to-earth per unit overvoltage (p.u.)* which is defined as the ratio of the peak values of a phase-to-earth overvoltage and the phase-to-earth voltage corresponding to the highest voltage for equipment, that is $U_m\sqrt{2}/\sqrt{3}$. For the purpose of IEC 71, the standardised values of Highest Voltage for Equipment are divided into three ranges determined by the overvoltage conditions prevailing on the systems within each of these ranges and the response of the equipment to these overvoltages:

- Range A: above 1 kV and less than 52 kV.
- Range B: from 52 kV to less than 300 kV.
- Range C: 300 kV and above.

Specified voltage tests are then related to the value of Highest Voltage for Equipment and the range within which this voltage falls. For ranges A and B the performance under power-frequency operating voltage, temporary overvoltages and switching overvoltages is checked by a short duration power-frequency test – generally referred to as the one minute test – and performance under lightning overvoltages is checked by a lightning impulse test. For equipment in range C the performance under power-frequency operating voltage and temporary overvoltages on the one hand, and under switching overvoltages on the other, is checked by different tests. For the former condition, IEC 71 expresses the intention that in the future the test will become a long duration power-frequency test – for transformers the Method 2 overpotential test of IEC 76 (see Section 2 of Chapter 5) but accepts that at the present time the one minute test is an acceptable alternative. For the latter condition performance is checked by means of a switching impulse test and performance under lightning impulses is checked by a lightning impulse test.

The IEC 71 recommended test voltages for ranges A and B are given in *Tables 6.7, 6.8* and *6.9*. No value for switching overvoltage tests are listed since, as stated above, the one minute test is considered an adequate test for this condition. The choice between list 1 and list 2 for lightning impulse withstand voltage for range A is made by considering the degree of exposure to lightning and switching overvoltages, the type of system neutral earthing and, if appropriate, the type of overvoltage protective device used. For example, industrial installations not connected to overhead lines and with their neutrals either solidly earthed or earthed through a low impedance may use list 1 impulse withstand levels. For range B, unlike range A, there is a number of alternative lightning impulse withstand and power-frequency withstand levels available. Selection of the appropriate power-frequency withstand level is related to the *earth fault factor* for the system and the plant location within that system. Earth fault factor is defined as 'the ratio of the highest r.m.s. phase-to-earth power-frequency voltage on a sound phase during a fault to earth (affecting one or more phases at any point) to the r.m.s. phase-to-earth power-frequency voltage which would be obtained at the location without the fault'. The earth fault factor is related to the earthing conditions of the system as viewed from the selected location. It is equal to the product of $\sqrt{3}$ times the 'factor of earthing' or 'coefficient of earthing' which has been used in the past. The earth fault factor can be calculated from the symmetrical component parameters of the system R_0, X_0, and X_1, where:

R_0 is the zero phase sequence resistance

X_0 is the zero phase sequence reactance

X_1 is the positive phase sequence reactance

subtransient reactance values being used for any rotating machines.

(i) *For a solidly earthed system* for which $\dfrac{R_0}{X_1} < 1$ and $\dfrac{X_0}{X_1} < 3$ the earth fault factor will not exceed 1.4.

Table 6.7 Standard insulation levels for 1 kV $<$ U_m $<$ 52 kV
Series I (based on current practice in most European and several other countries)

Highest voltage for equipment U_m (r.m.s.)	*Rated lightning impulse withstand voltage (peak)*		*Rated power-frequency short duration withstand voltage (r.m.s.)*
	List 1	*List 2*	
kV	*kV*	*kV*	*kV*
3.6	20	40	10
7.2	40	60	20
12	60	75	28
17.5	75	95	38
24	95	125	50
36	145	170	70

Table 6.8 Standard insulation levels for 1 kV $<$ U_m $<$ 52 kV
Series II (based on current practice in the United States of America, Canada and some countries)

Highest voltage for equipment U_m (r.m.s.)	*Rated lightning impulse withstand voltage (peak)*		*Rated power-frequency short duration withstand voltage (r.m.s.)*
	500 kVA and below	*Above 500 kVA*	
kV	*kV*	*kV*	*kV*
4.40	60	75	19
13.20 13.97 14.52	95	110	34
26.4	150		50
36.5	200		70

Note. Test values listed are specific to full insulation levels of transformers, but are representative of other equipment in common usage in US and Canadian standards as well. Particular apparatus standards should be referred to for exact values. Reduced insulation levels may be applied where justified by the degree of protection.

Table 6.9 Standard insulation levels for 52 kV $\leq U_m$ $<$ 300 kV

1	2	3	4
Highest voltage for equipmet U_m (r.m.s)	Base for p.u values $\frac{U\sqrt{2}}{\sqrt{3}}$ (peak)	Rated lightning impulse withstand voltage (peak)	Rated power-frequency short duration withstand voltage(r.m.s)
kV	kV	kV	kV
123	24.5	250	95
52	59	225	140
72.5	100	450	185
145	118	550	230
170	139	6 50	275
245	200	750	325
		850	360
		950	395
		1050	460

(ii) *For a non-effectively earthed system* for which $\dfrac{R_0}{X_1} > 1$ and $\dfrac{X_0}{X_1} > 3$ the earth fault factor will be $\sqrt{3}$, i.e. 1.7.

(iii) *For a system earthed via an arc suppression coil* the earth fault factor will be 1.9.

The higher the earth fault factor, the higher should be the rated power-frequency one minute withstand voltage. Lightning impulse withstand voltage is tied to power-frequency withstand voltage so that once the latter has been determined the former is automatically fixed.

Part 2 of IEC 71, however, warns that there can be situations for systems with voltages in ranges A and B where expected surge voltages might be higher in proportion to power-frequency overvoltages than might normally be expected and it identifies particularly equipment connected to wood-pole overhead lines with unearthed cross-arms. Conversely, there will also be situations where the magnitude of lightning surges will be likely to be lower. These include substations connected to overhead lines which are protected by protective earth wires or to overhead lines connected via at least 1 km of cable having an earthed metallic sheath.

For voltages in range C the ability to withstand switching surges is not adequately tested by the power-frequency overvoltage test, so it is necessary to carry out a separate switching surge test. *Table 6.10* gives the range of switching impulse and lightning impulse withstand levels related to the highest voltage for equipment recommended for rated voltages of 300 kV and above and it can be seen that there are a number of options for each voltage class. For equipment in this voltage range the economic savings to be gained from a careful matching of the insulation level to the degree of exposure to surges is most apparent. It will be evident, for example, that a 420 kV transformer designed for lightning impulse testing at 1300 kV, a figure generally specified by European purchasers where protection by surge arresters is to be employed, will be less costly than a similar unit but designed for a 1425 kV lightning impulse level as specified in the UK where protection is to be by coordinating rod gaps.

IEC 71, Part 2, identifies two methods of coordination of insulation level in respect of switching and lightning overvoltages. The first of these is termed the 'conventional method' and the second is a statistical approach.

Using the conventional method, insulation level is selected in such a way as to obtain an acceptable margin between maximum overvoltage likely to be experienced and the minimum insulation strength. The margin is to cover for all uncertainties in the design and manufacturing process; those of identifying the worst condition to be withstood and those of achieving the required ability to withstand this. No attempt is made to place a quantitative value on the degree of risk that the latter may not always be greater than the former. The document recommends that safety factors of 1.15 and 1.25 respectively should be adopted between the rated switching and lightning overvoltage withstand levels of the equipment and the appropriate impulse protective levels of the

Table 6.10 Standard insulation levels for $U_m \geq 300$ kV

1	2	3	4	5	6
Highest voltage for equipment U_m(r.m.s)	Base for p.u values $U_m\frac{\sqrt{2}}{\sqrt{3}}$ (peak)	Rated switching impulse withstand voltage (peak)		Ratio between rated lighting and switching impulse withstand voltages	Reted lightnig impulse withstand voltage (peak)
kV	kV	p.u	kV		kV
				1.13	850
		3.06	750		
				1.27	950
300	245			1.12	
		3.47	850		
		2.86			
				1.24	1050
362	296			1.11	
		3.21	950		
		2.76			
				1.24	1175
420	343			1.12	
		3.06	1050	1.24	1300
		2.45		1.11	
525	429				
				1.36	
		2.74	1175	1.21	1425
				1.10	
				1.32	
		2.08	1300	1.19	1550
				1.09	
				1.38	
765	625	2.28	1425	1.26	1800
				1.16	
		2.48	1550	1.26	1950
				1.47	2100
				1.55	2400

surge arrester employed as a means of ensuring that the margins will always be adequate.

The statistical method attempts to quantify the risk of failure and thus avoid the use of arbitrary safety factors. The approach is of value in the case of equipment such as post insulators (defined in IEC 71, Part 1, as *self-restoring insulation*, that is insulation which completely recovers its insulating properties after a disruptive discharge caused by the application of a test voltage) but is not so easily applied to something as complex as a transformer. The principle is to derive a frequency distribution for the overvoltages to be expected at the point of installation and a probability distribution that a given overvoltage will cause failure of insulation. While this latter distribution can be relatively readily be established by, say, carrying out a large number of impulse tests on a post insulator, it cannot be so easily defined for the non-self-restoring insulation of a transformer. The insulation strength may then be selected in such a way that the two curves do not overlap, or, adopting a more practical economic approach, overlap only by a known small amount. The area of overlap thus corresponds to a known risk of failure. The evaluation process can be simplified by assuming that the distributions of the overvoltages and the failure probability of insulation are Gaussian with known standard deviations. IEC 71, Part 1, defines quantities representative of single fixed points on these distributions so that on this basis the distributions are themselves defined. *The statistical switching (lightning) overvoltage* is defined as the switching (lightning) overvoltage applied to equipment as a result of an event of one specific type on the system (line energisation, reclosing, fault occurrence, lightning discharge, etc.), the peak value of which has a probability of being exceeded which is equal to the specified reference probability. IEC 71 proposes that the reference probability should be 2%. *The statistical switching (lightning) impulse withstand voltage* is defined as the peak value of a switching (lightning) impulse test voltage at which insulation exhibits under specified conditions a probability of withstand equal to a specified reference probability. IEC 71 proposes that the reference probability should be 90%. *Figure 6.82* gives a graphical explanation of the method. *Figure 6.82(a)* shows frequency distributions of overvoltage and insulation strength, where the statistical overvoltage is U_s and the statistical withstand voltage U_w. In *Figure 6.82(b)*, the overvoltage distribution and the electric strength distribution are superimposed for three values 1.0, 1.2 and 1.4 of the statistical safety factor γ taken as equal to the ratio U_s/U_w. The correlation between the statistical safety factor γ and the risk of failure R is given in *Figure 6.82(c)*.

Selection of appropriate protective characteristics

While the use of screened coordinating gaps on the transformer bushing can provide an acceptable level of protection for transformers in countries such as the UK which have a relatively low incidence of lightning, their use in locations where lightning is very frequent would not afford the degree of protection attainable by the use of surge arresters. For many system designers, therefore, the use of surge arresters is regarded as the standard practice.

Some guidance on selection of surge arresters is given in IEC 71, Part 2; however, there are a number of documents which deal specifically with surge arrester characteristics and selection. For clarity these are listed below, all are parts of the IEC 99 (BS EN 60099) series:

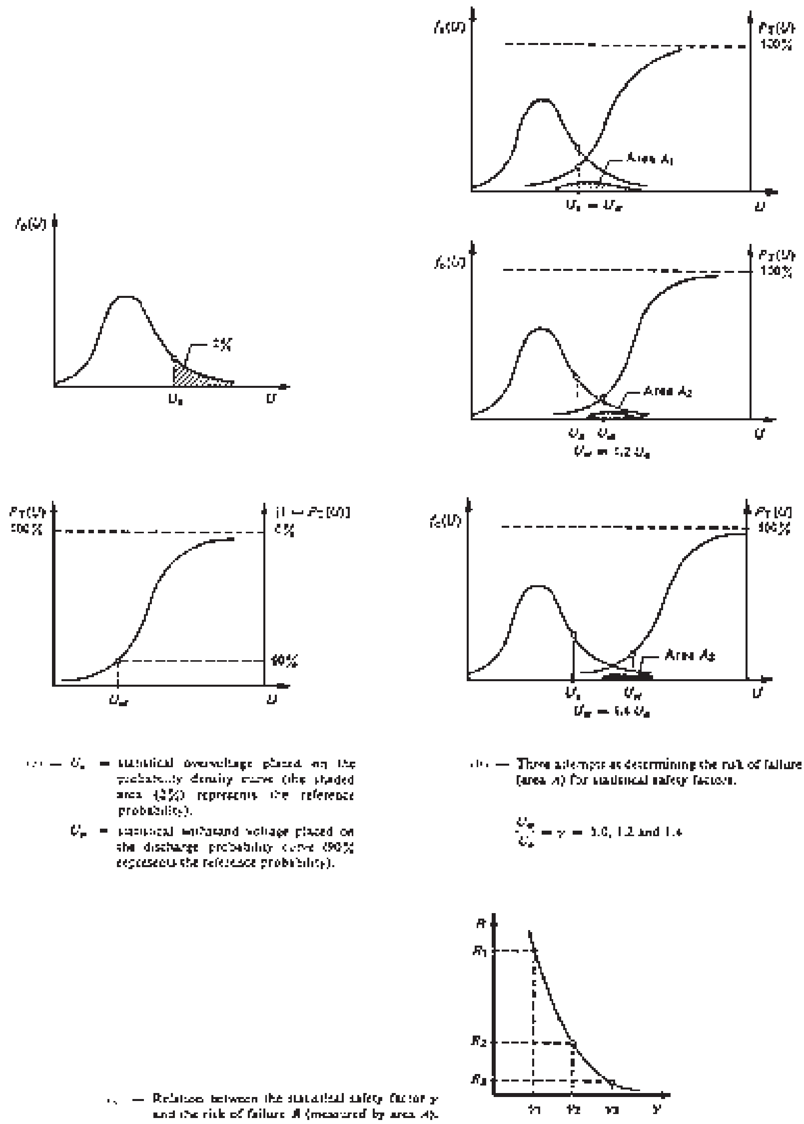


Figure 6.82 Simplified statistical method

Part 1: Non-linear resistor type gapped surge arresters for a.c. systems

Part 4: Metal-oxide surge arresters without gaps for a.c. systems

Part 5: Selection and application recommendations

Part 3: Artificial pollution testing of surge arresters is not likely to be of interest to transformer engineers.

These documents are lengthy and very comprehensive and in a work such as this it is only possible to give an outline of the general principles involved. Prospective users are therefore advised to consult the appropriate standard specification before specifying surge arresters.

Selection of gapped silicon carbide arresters

As indicated above, the superior performance of metal oxide arresters has meant that the use of silicon carbide non-linear resistor-type surge arresters with series spark gaps nowadays tends to be restricted to equipment in voltage range A. The main risk for transformers in such systems arises from induced and direct lightning strokes to the connected overhead line. In the case of cable-connected transformers only overvoltages due to faults and switching surges can occur. The basic characteristics of this type of arrester are their rated voltage, their sparkover voltages for lightning and switching surges, their nominal discharge currents and their residual voltages at these currents. Also relevant is the continuous operating voltage, long duration discharge class, pressure relief class and pollution withstand capability.

Rated voltage must be adequate to withstand temporary overvoltages resulting from earth faults on one phase causing a voltage rise on a healthy phase at a time when the arrester may be called upon to operate on this healthy phase.

IEC 99, Part 5, recommends an iterative procedure for the selection of surge arresters as shown in *Figure 6.83*. This is as follows:

- Determine the necessary continuous operating voltage of the arrester with respect to the highest system operating voltage.
- Determine the necessary value for the rated voltage of the arrester bearing in mind the temporary overvoltages as identified above.
- Estimate the magnitude and probability of the expected lightning discharge currents through the arrester (see below) and the transmission line discharge requirements and select nominal discharge current and the line discharge class of the arrester (not relevant for range A).
- Select the pressure relief class of the arrester with respect to the expected fault current.
- Select a surge arrester which fulfils the above requirements.
- Determine the necessary rated switching impulse withstand voltage of the transformer taking into account the switching overvoltages (not necessary to consider switching overvoltages for range A).
- Determine the necessary rated lightning impulse voltage considering
  - the representative impinging lightning overvoltage surge as it is determined by the lightning performance of the overhead line;
  - the substation layout;

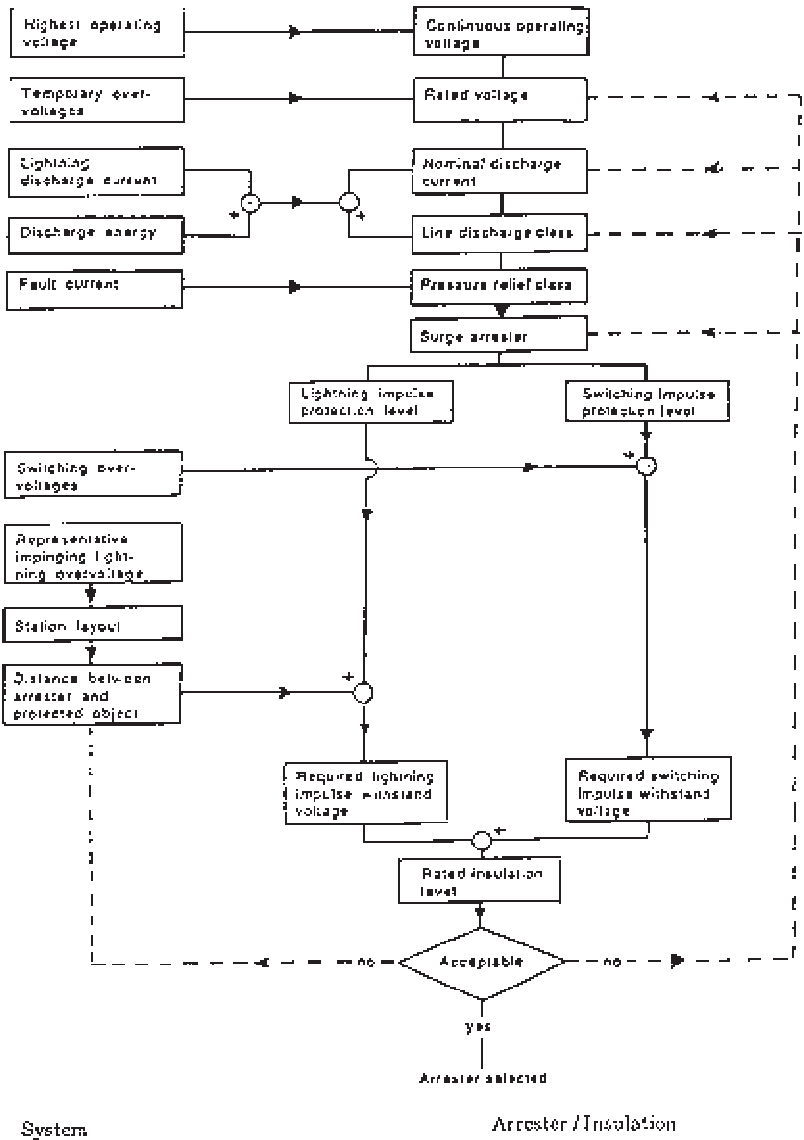


Figure 6.83 Flow diagram for the selection of surge arresters

– the distance between the surge arrester and transformer;

– the rated insulation level of the transformer in accordance with IEC 71.

Determination of lightning discharge currents

Generally arrester currents resulting from lightning strokes are lower than the current in the stroke itself. If a line is struck directly, travelling waves are set up in both directions from the point of the strike. Line insulators will probably flash over thus providing parallel paths to ground. More than one conductor may be struck so that two or more surge arresters operate to share the current. Only in the case of a direct strike close to the terminal arrester where no flashover occurs before operation of the arrester will the arrester be required to carry the full current of the lightning discharge. The probability of this occurring can be greatly reduced by the use of shielding for the line and/or the substation of the type described above. When a lightning strike occurs to a shield wire the current flows to ground through the line support structures, poles or towers, which carry the shield wire. This will raise the potential of the top of the support structure which may result in a flashover to the line. This is known as a back-flashover. The incidence of back-flashovers can be reduced by correct selection of the insulation level for the line and ensuring that the resistance of the support structure earth connections is kept to a minimum.

Bearing in mind the above factors, the importance of the transformer and degree of protection required, IEC 99, Part 5, recommends that 5 kA arresters are normally adequate for distribution systems of voltage range A. 10 kA arresters may, however, be used for important installations or in areas of high lightning incidence.

Selection of metal oxide arresters

Metal oxide arresters are now the preferred means of protection for systems in voltage ranges B and C but may, of course, also be used for voltage range A. Their main advantage is the lack of series gaps which means that they have a very much faster response time. For example, a lightning strike within one span of a terminal tower can result in a rate of rise exceeding 1200 kV/μs. With a gapped arrester a delay due to the gaps of, say, 0.5 μs will result in a peak voltage of 600 kV being 'let through' to the transformer. The response time of the gapless arrester is of the order of 10–15 nanoseconds and therefore no such problem exists. Basic characteristics of this type of arrester are the continuous operating voltage, the rated voltage, the nominal discharge current and the residual voltages at nominal discharge current, at switching impulse current and steep front current. For given continuous operating and rated voltages different types of arresters and, therefore, different protection levels exist. Careful attention must be given to ascertaining the correct continuous operating voltage for this type of arrester in view of the high degree of current/voltage non-linearity of the material and the fact that this has a negative temperature coefficient of resistance up to voltages in the order of 10% above rated voltage which could lead to thermal runaway if the continuous operating voltage and/or the rated voltage were underestimated. In selection of arresters of this type it is also necessary to consider requirements with regard to line discharge class, pressure relief class and pollution withstand capability. The selection procedure is thus similar to that described for gapped arresters. As regards current rating: for voltage range A, 5 or 10 kA rated arresters may be used according to the same criteria as discussed above for gapped arresters; for voltage range B, IEC 99, Part 5, recommends that 10 kA arresters are normally adequate, and for voltage range C, 10 kA arresters are considered adequate up to 420 kV, thereafter 20 kA arresters should be used.

Connection of surge arresters

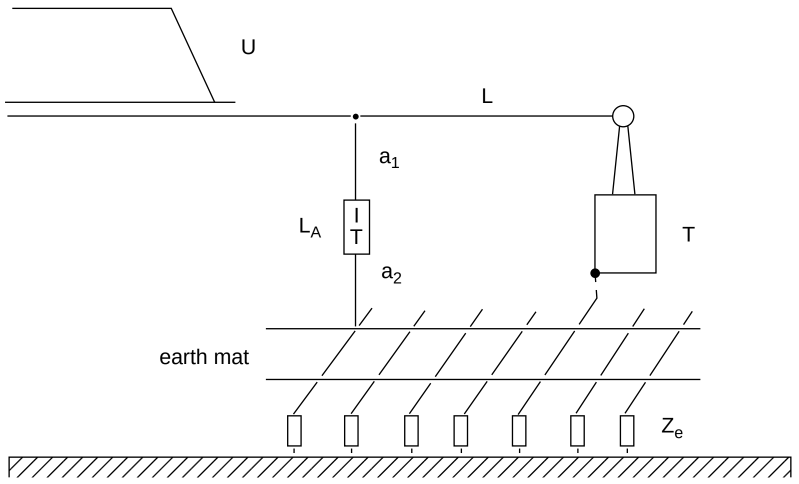
Mention has already been made of the desirability of connecting the surge arrester as close as possible to the equipment it is intended to protect. It is also important that the neutral end should have a low resistance connection to earth of adequate cross-sectional area. At currents of 10 kA or more, any resistance in these connections will mean a significant additional voltage is seen at the transformer terminals over and above the nominal protection level of the arrester. *Figure 6.84(a)* shows a typical installation adjacent the HV terminal of a substation transformer. The lengths l, a_1 and a_2 must be kept as short as possible. In the case of a small distribution transformer, possibly pole mounted, where there is no earth mat, the installation should take the form shown in *Figure 6.84(b)*.

Surge arrester operation and construction

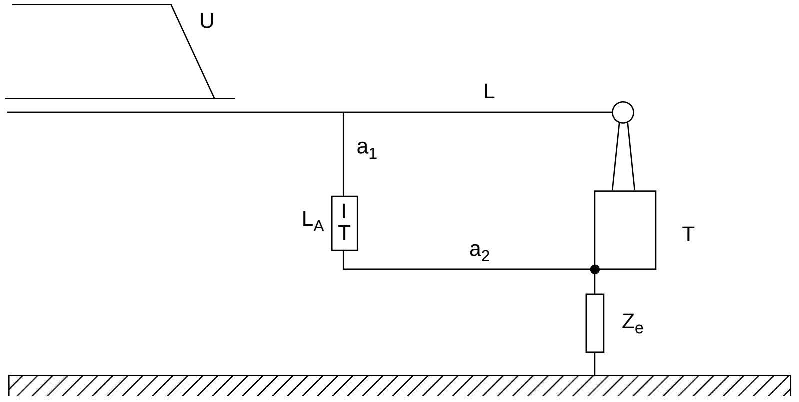
(a) Gapped silicon carbide surge arresters

A typical gapped surge arrester consists of a series of non-linear resistor discs separated by spark gaps. The resistor unit is made from a material having a silicon carbide base in a clay bond. The size of grit used, method of mixing, moisture content, and firing temperature play important parts in determining the characteristics of the final product and all are very carefully controlled. The finished material is a semiconductor, and its voltage/current characteristic is a curve with a pronounced knee point beyond which the curve is fairly linear typically as shown in the curve, *Figure 6.85*. The material has a negative temperature coefficient of resistance. At constant voltage the current increases by about 0.6% per °C. To maintain equilibrium the dissipation of heat must be adequate. Its specific heat is 0.84 watt seconds per gram per °C between 20 and 300°C.

Figure 6.86 shows a cross-sectional drawing of a typical gapped silicon carbide-type station class surge arrester. The ROTARC gaps provide the means of preventing power follow-through current following diversion of the surge. The extra ‘space’ to accommodate the necessary quantity of spark gaps means that an efficient, fast acting pressure relief system must be used to avoid the undesired explosion of the porcelain housing due to the passage of system short-circuit current following arrester failure. The presence of moisture, at this time, due to housing seal failure means that even higher internal pressures can be developed during the passage of system short-circuit current. This is of course due to the considerable expansion of water when changing to steam.



(a)



(b)

Figure 6.84 Schematic diagram for the surge arrester connection to the protected object. (a) Installations with earth-mat (substations) and (b) Installations without earth-mat (distribution systems)

l	:	distance between the high-voltage terminal of the protection equipment and the connection point of the arrester high-voltage conductor
a_1	:	length of the arrester high-voltage conductor
a_2	:	length of the arrester earth conductor
L_A	:	length of the arrester
Z_e	:	earthing impedance
T	:	protected object
U	:	impinging overvoltage surge

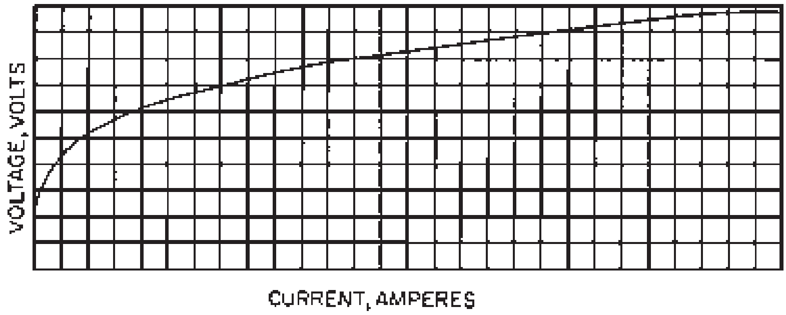


Figure 6.85 Typical surge diverter voltage/current characteristic for gapped silicon carbide surge arrester

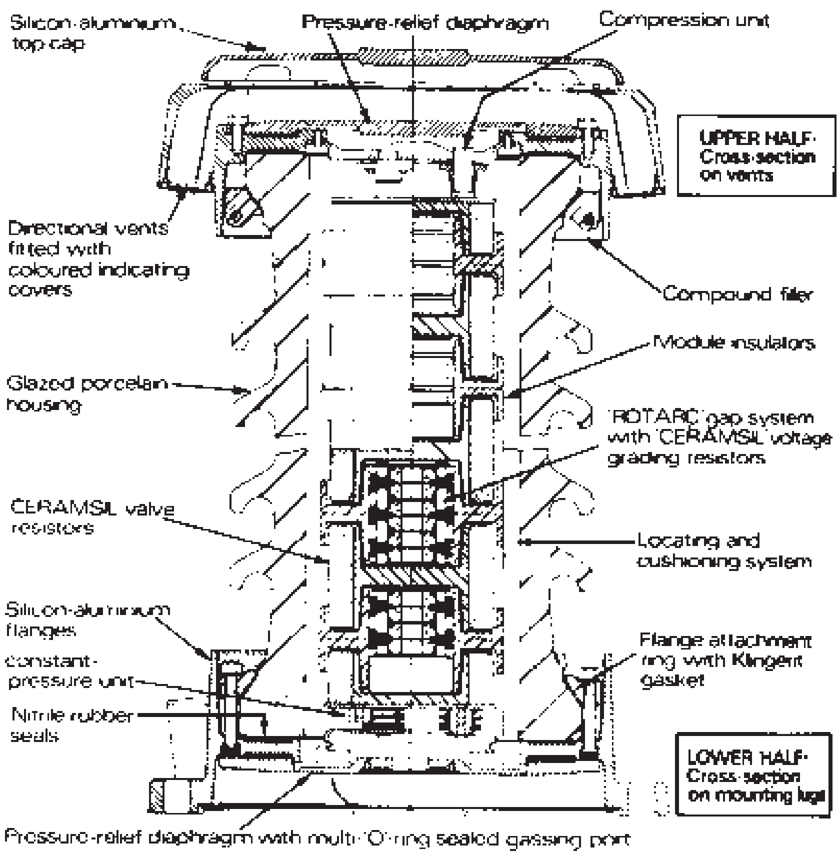


Figure 6.86 Cross-sectional drawing of a typical station-class surge arrester (Bowthorpe EMP Ltd)

In a gapped silicon carbide surge arrester the spark gap serves the purpose of interrupting the system follow-through current after a surge has discharged. The multi-gap design is chosen because it is more sensitive to voltage variation and more effective in arc quenching. The electrodes are symmetrical, giving many of the advantages of a sphere gap, which is independent of polarity effect and quick in response to breakdown voltage. Uniform voltage grading across the gaps is attained either by direct resistance grading or by equalising the capacitance values between the gaps. In a typical distribution class surge arrester, specially selected and graded mica discs are inserted between each pair of electrodes and, as they are very thin and have a high dielectric constant, the capacitance is relatively high, hence the stray capacitance to earth is relatively small. This further improves the uniformity of voltage grading across the gaps. The mica used has a small loss angle, almost independent of frequency, and the change in dielectric constant when subjected to impulse voltages is therefore negligible. The thin outer edge of each mica disc points towards the gap and under impulse conditions the concentration of charge around this mica is high, so that the resulting displacement current provides electrons which irradiate the gap, thus alleviating the darkness effect and improving the consistency of flashover.

Under impulse conditions the arrester gaps are required to flash over at the lowest possible voltage and to interrupt the system follow-through current at the first current zero after the surge has discharged. These two requirements are somewhat conflicting since both the impulse voltage breakdown and the current interrupting characteristics of the gaps increase with the number of gaps in series. Also the more non-linear discs employed in series the smaller is the system follow-through current and thus fewer gaps are required to interrupt this current. In contrast to this principle there is the fact that the surge voltage across the arrester stack will be higher under surge conditions. Thus, some compromise must be made; if too many discs or gaps are incorporated in the arrester then adequate protection may not be provided, while too few may result in destruction during operation under surge discharge conditions.

(b) Metal oxide surge arresters

A typical metal oxide surge arrester consists of a number of non-linear resistor discs arranged in series. The discs are sometimes spaced by metallic spacers in order to make the non-linear resistor assembly of comparable height to the required housing length. The housing may be porcelain or more recently a polymeric-type material. The gapless metal oxide surge arrester has fewer components and is therefore of much simpler construction than the older gapped silicon carbide type.

It is extremely important to select the correct rated voltage, due to the highly non-linear characteristic (see *Figure 6.87*). For example, at voltages

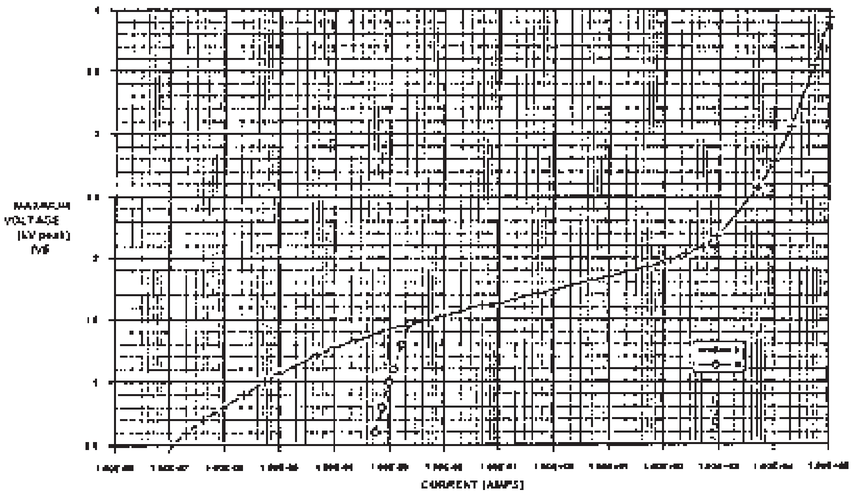


Figure 6.87 Current/voltage characteristic for gapless metal oxide surge arrester (Bowthorpe EMP Ltd)
Note: This curve is constructed from measurements taken with various forms of voltage/current stimulation, i.e. 2 μs current pulses, 8/20 μs current current pulses and 4/10 μs current pulses.

in the order of rated voltage a 10% increase in voltage can cause a 300% increase in current.

To avoid premature failure, the selected rated voltage must take into account all temporary overvoltages existing at the site where the surge arrester is installed.

(i) Porcelain housed gapless metal oxide surge arresters

Figure 6.88 shows a sectional arrangement of a gapless metal oxide surge arrester in a porcelain housing. It is evident that this is very much simpler than that shown in *Figure 6.85*. The peripheral air space, necessary for pressure-relief operation, can be a source of internal ionisation under polluted conditions which can cause premature failure of the surge arrester.

(ii) Polymeric-housed gapless metal oxide surge arresters

Figure 6.89 shows a sectional arrangement of a gapless metal oxide arrester in a polymeric housing. The use of the gapless construction makes possible another major step forward in the design of surge arresters. This is the use of polymeric housings in place of porcelain. This material not only permits a construction totally free of internal voids, which is thus impervious to moisture ingress, but also avoids the tendency to shatter associated with porcelain, hence eliminating the risk of disintegration under fault conditions and making unnecessary

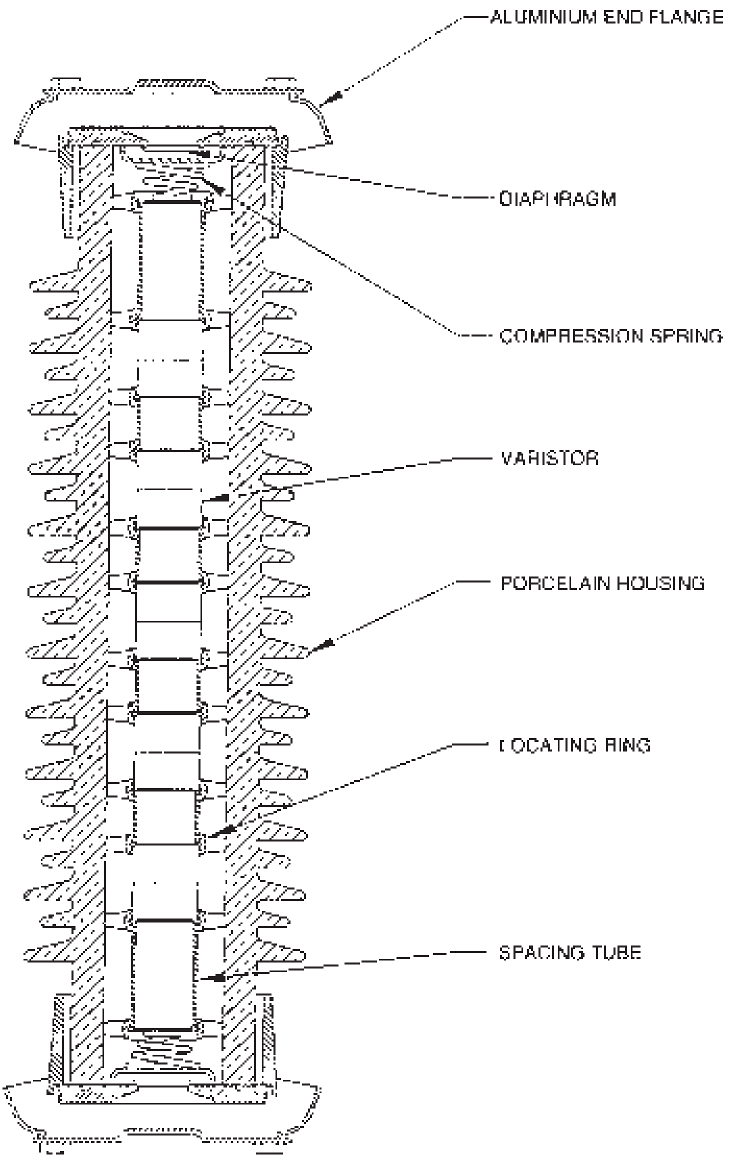


Figure 6.88 Gapless metal oxide arrester in porcelain housing (Bowthorpe EMP Ltd)

the incorporation of any pressure relief arrangement. The polymeric material is, of course, less expensive than porcelain and also very much lighter in weight. For example, a 10 kA, 150 kV rated voltage arrester weighs only around 85 kg. This greatly simplifies the installation arrangement as well as easing site handling at the time of installation.

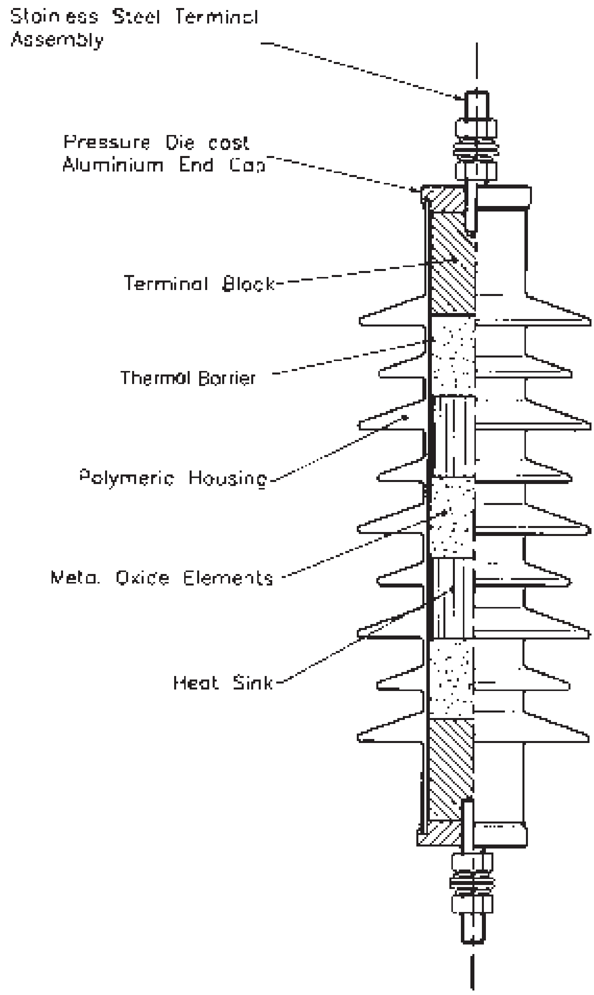


Figure 6.89 Cross section of EG/HE Series gapless metal oxide arrester detailing the major features of arrester design (Bowthorpe EMP Ltd)

An installation of gapless arresters in polymeric housings protecting a 11 kV pole mounted distribution transformer is shown in *Figure 6.90* while *Figure 6.91* shows a set of 300 kV, 20 kA polymeric-housed arresters providing the protection for the transformers of a large EHV substation.

Earth faults

Earth faults have different effects according to whether the neutral point of the system is earthed or isolated. In the first case, an earth fault represents

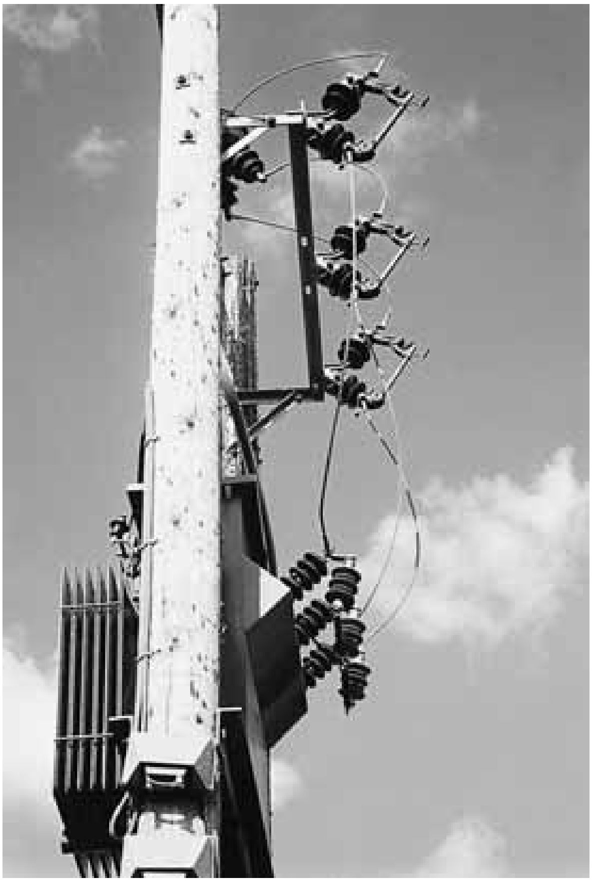


Figure 6.90 Installation of gapless metal oxide surge arresters with polymeric housings to protect 11 kV distribution transformer (Bowthorpe EMP Ltd)

a short-circuit across one phase, and the same remarks regarding protection apply as outlined for the protection against short-circuit stresses. In the other case, where the neutral point is isolated, there are two conditions to consider: first, when the earth is a sustained one, and second, when it takes the form of the so-called arcing ground. In the first of these two cases the voltage of the two sound lines is raised to full line voltage above earth, and after the initial surge the insulation stresses become steady, although increased by $\sqrt{3}$ above normal service conditions. The protection for the first condition is earthing of the neutral point, as explained elsewhere. In the second case, where the earth fault is unstable, such as at the breakdown of an overhead line insulator, high-frequency waves are propagated along the line in both directions, and to protect the transformer against the effects of these waves some form of surge arrester gear may be installed in front of the transformer as outlined earlier in

Figure 6.91 300 kV polymeric housed surge arresters installed on the Statnet system in Norway (Bowthorpe EMP Ltd)

this section. Alternatively the neutral point may be earthed, thereby converting the earth fault into a short-circuit across one phase.

Protecting the system against faults in the transformer

Consider next the means to be adopted for protecting the system against the effects of faults arising in the transformer; the principal faults which occur are breakdowns to earth either of the windings or terminals, faults between phases generally on the HV side, and short-circuits between turns, usually of the HV windings.

The protection of transformers, in common with the protection of other electrical plant, is an area in which there has been a great deal of change in recent years, brought about by the development of digital solid-state relays. The use of microelectronics makes possible the provision of high-reliability, rugged, compact and inexpensive relays having accurate tailor-made characteristics to suit almost any situation, so that the bulky and delicate electromagnetic devices on which protective gear has relied for so many years are becoming consigned to history.

However, the principles and objectives of transformer protection have not changed. It is simply the case that the protection engineer now has available relays which come much closer to meeting all his requirements and they will do so at a price which enables a degree of sophistication to be applied to the protection of a 500 kVA transformer which might hitherto have only been considered economically justified for one rated 30 MVA or more.

There are many thousands of electromagnetic relays in service and their life and reliability is such that they will continue to be so for a good many years. The following description of transformer protection principles will therefore consider initially those 'traditional' schemes based on electromagnetic relays before considering briefly how these have been developed to make use of the latest technology.

Breakdowns to earth may occur due to failure of the major insulation of transformers or of bushing insulators, these failures being due to the absence of any external surge protective apparatus or upon the failure of such apparatus to operate. When such a breakdown occurs it is essential that the transformer is isolated from the supply with as little delay as possible.

For small transformers, single overload and earth leakage devices will provide the necessary degree of protection to ensure that the transformer is disconnected automatically from the circuit.

On larger transformers forming parts of important transmission or distribution networks, it is necessary to employ some form of automatic discriminative protective equipment. This will remove from the circuit only the faulty apparatus leaving the sound apparatus intact, while the disconnection is performed in the shortest space of time and the resulting disturbance to the system is reduced to a minimum. The automatic protective gear systems which are most commonly used are described in the following sections.

Comprehensive details of various forms of protective systems for generators, generator/transformer combinations, transformers, feeders and busbars are given in *The J & P Switchgear Book* (Butterworths).

In considering the problems of protection across a power transformer, note should first be made of what is known as a differential rough balance scheme, as shown in *Figure 6.92*. This scheme can be applied where existing overcurrent and restricted earth-fault protection has become inadequate but provision of a separate differential scheme is considered unjustified. By using overcurrent relays and current transformers, lower fault settings and faster operating times can be obtained for internal faults, with the necessary discrimination under external fault conditions.

The taps on interposing transformers are adjusted so that an inherent out-of-balance exists between the secondary currents of the two sets of current

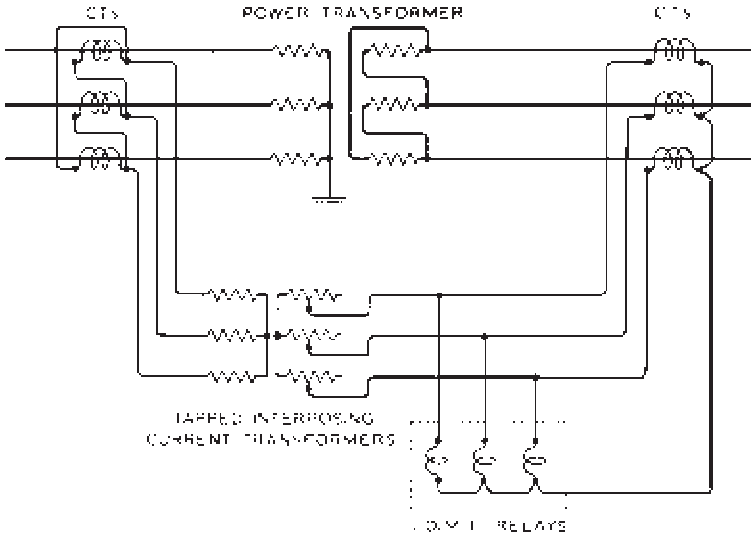


Figure 6.92 Differential rough balance protection scheme (GEC Measurements)

transformers but is insufficient to operate the overcurrent relays under normal load conditions. With an overcurrent or external fault the out-of-balance current increases to operate the relay and choice of time and current settings of the IDMT relays permit grading with the rest of the system.

The scheme functions as a normal differential system for internal faults but is not as fast or sensitive as the more conventional schemes. It is, however, an inexpensive method of providing differential protection where IDMT relays already exist.

Circulating current protection

Figure 6.93 shows an explanatory diagram illustrating the principle of the circulating current system. Current transformers (which have similar characteristics and ratios) are connected on both sides of the machine winding and a relay is connected across the pilot wires between the two current transformers. Under healthy or through-fault conditions, the current distribution is as shown at (a), no current flowing in the relay winding. Should a fault occur as shown at (b), the conditions of balance are upset and current flows in the relay winding to cause operation. It will be noted that at (b) the fault is shown at a point between the two current transformers (the location of these determine the extent of the protected zone). If the fault had occured beyond, say, the right-hand current transformer, then operation would *not* occur as the fault current would then flow through *both* current transformers thus maintaining the balance, as shown at (*a*).

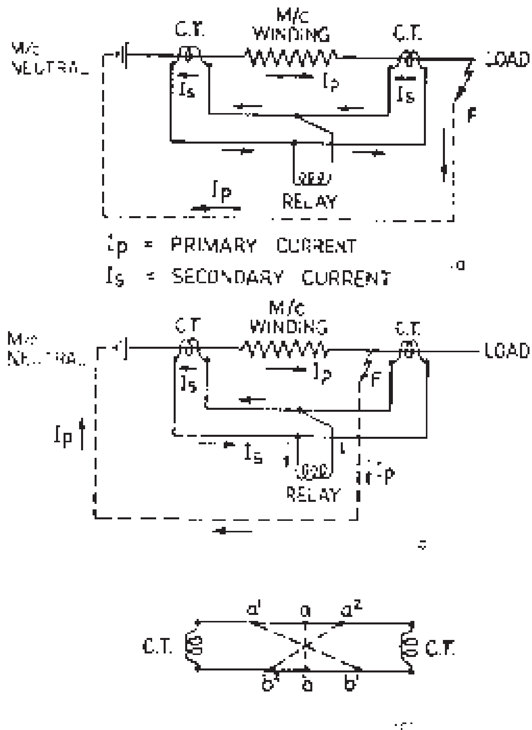


Figure 6.93 Explanatory diagram to illustrate principle of circulating current protection. (a) Healthy condition or external fault; (b) internal fault condition; (c) illustrating equipotential points

In order that the symmetry of the burden on the current transformers shall not be upset and thus cause an out-of-balance current to pass through the relay, causing operation when not intended, it is essential that the relay be connected to the pilot wires at points of equipotential. This is illustrated at (*c*) in *Figure 6.93*, such equipotential points being those as a and b, a^1 and b^1, etc. In practice it is rarely possible to connect the relay to the actual physical mid-point in the run of the pilots and it is usual to make the connection to convenient points at the switchgear and to insert balancing resistances in the shorter length of pilot wire. The resistances should be adjustable so that accurate balance can be obtained when testing before commissioning the plant.

Some complications arise when circulating current protection is applied to a power transformer because a phase shift may be introduced which can vary with different primary/secondary connections and there will be a magnitude difference between the load current entering the primary and that leaving the secondary.

Correction for a phase shift is made by connecting the current transformers on one side of the power transformer in such a way that the resultant currents fed into the pilot cables are displaced in phase from the individual phase currents by an angle equal to the phase shift between the primary and secondary currents of the power transformer. This phase displacement of the current transformer secondary currents must also be in the same direction as that between the primary and secondary main currents.

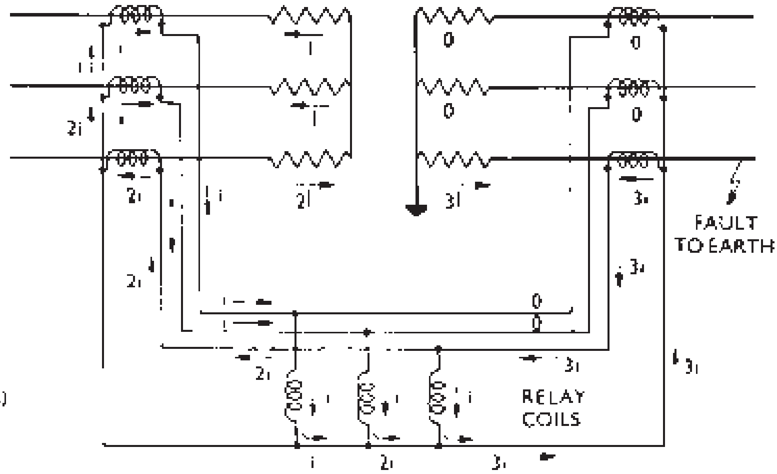
The most familiar form of power transformer connection is that of delta/star, the phase shift between the primary and secondary sides being 30°. This is compensated by connecting the current transformers associated with the delta winding in star and those associated with the star winding in delta.

In order that the secondary currents from the two groups of current transformers may have the same magnitude, the secondary ratings must differ, those of the star-connected current transformers being 5 A and those of the delta-connected group being 2.89 A, i.e. $5/\sqrt{3}$.

If the power transformer is connected delta/delta, there is no phase shift between primary and secondary line currents. Similarly, there is no phase shift in the case of star/star-connected power transformers, but phase correction is applied at *both* sets of current transformers, the reason being that only by this means can the protective system be stable under external earth fault conditions. Thus, both sets of current transformers will be delta connected so that the secondary currents in the pilots from each set will be displaced in phase by 30° from the line currents but both will coincide, a necessary requirement of circulating current protection. It is obvious that similarity in phase could be achieved if both sets of current transformers are connected in star, but it can be shown that, in this case, the protective system would be stable on through-faults between phases but *not* for earth faults. This is demonstrated numerically in *Figure 6.94*, noting that at (*a*) the secondary currents entering and leaving the pilots are not the same at both ends and therefore do not sum up to zero at the relays, whereas at (*b*) the reverse is true and no current appears in the relay coils. The 2:1:1 current distribution shown in *Figure 6.94* on the unearthed side of the transformer pertains only to such a transformer with a closed-delta tertiary winding. This winding is not shown in the diagram. Its function is to provide a short-circuit path for the flow of harmonic components in the magnetising current. The distribution applies also when the core is a three-phase type as opposed to shell type.

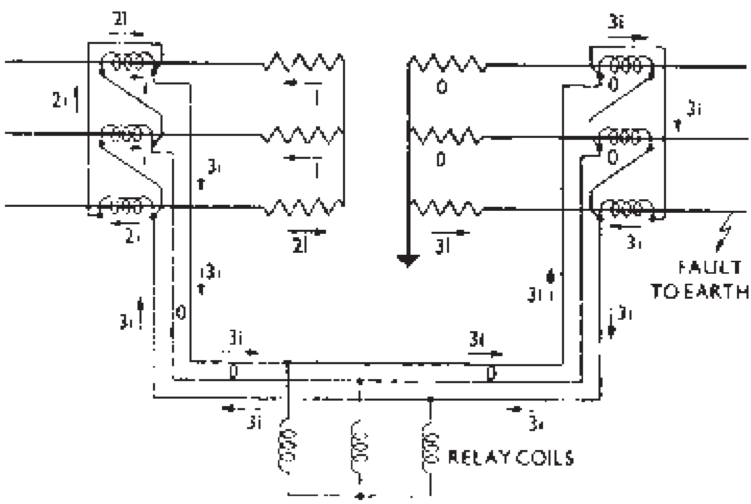
The switching in of a power transformer causes a transient surge of magnetising current to flow in the primary winding, a current which has no balancing counterpart in the secondary circuit. Because of this a ‘spill’ current will appear in the relay windings for the duration of the surge and will, if of sufficient magnitude, lead to isolation of the circuit. This unwanted operation can be avoided by adding time delay to the protection but, as the in-rush current persists for some cycles, such delay may render protection ineffective under true fault conditions. A better solution may lie in the use of harmonic restraint, and relays of this type are shown in *Figures 6.98* to *6.100*.

Figure 6.95 is a demonstration diagram of connections of a three-phase, delta/star-connected transformer equipped with circulating current protection



(a)

SHOWING OPERATION WHEN PROTECTIVE C.T's ARE CONNECTED IN STAR AND AN EARTH-FAULT OCCURS EXTERNAL TO THE POWER TRANSFORMER. THE RATIO OF WHICH IS ASSUMED TO BE UNITY



(b)

SHOWING STABILITY WHEN PROTECTIVE C T's ARE CONNECTED IN DELTA AND AN EARTH-FAULT OCCURS EXTERNAL TO THE POWER TRANSFORMER.

Figure 6.94 Showing stable and unstable conditions on through-earth faults, with circulating current protection applied to a star/star transformer, due to methods of connecting current transformers

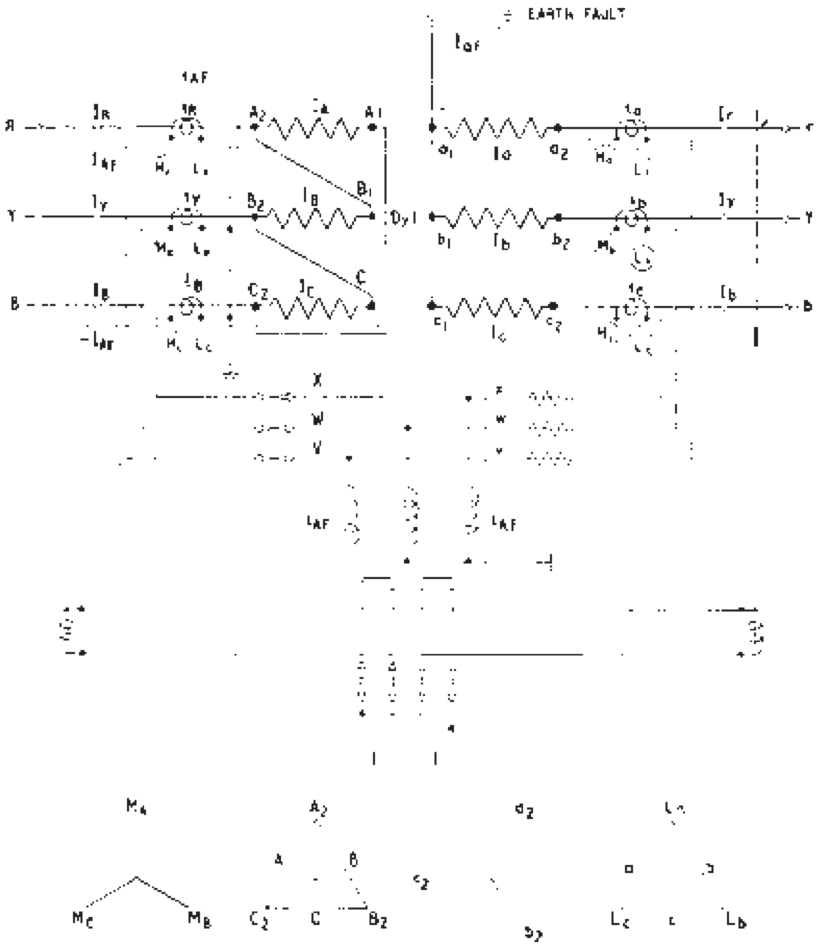


Figure 6.95 Circulating current protection for a three-phase delta/star-connected transformer, showing operation under internal earth fault conditions

and shows the distribution of the short-circuit fault currents arising from a winding fault to earth on the star-connected winding, when the neutral point of the latter is solidly earthed. The current phasor diagrams drawn for a one-to-one ratio, corresponding to the conditions of *Figure 6.95*, are given in *Figure 6.96* in which the phasors have the following significance.

Figure 6.96(a)

I_A, I_B, I_C are the normal balanced load currents in the primary delta-connected power transformer windings.

I_R, I_Y, I_B are the normal balanced load currents in the primary main lines.

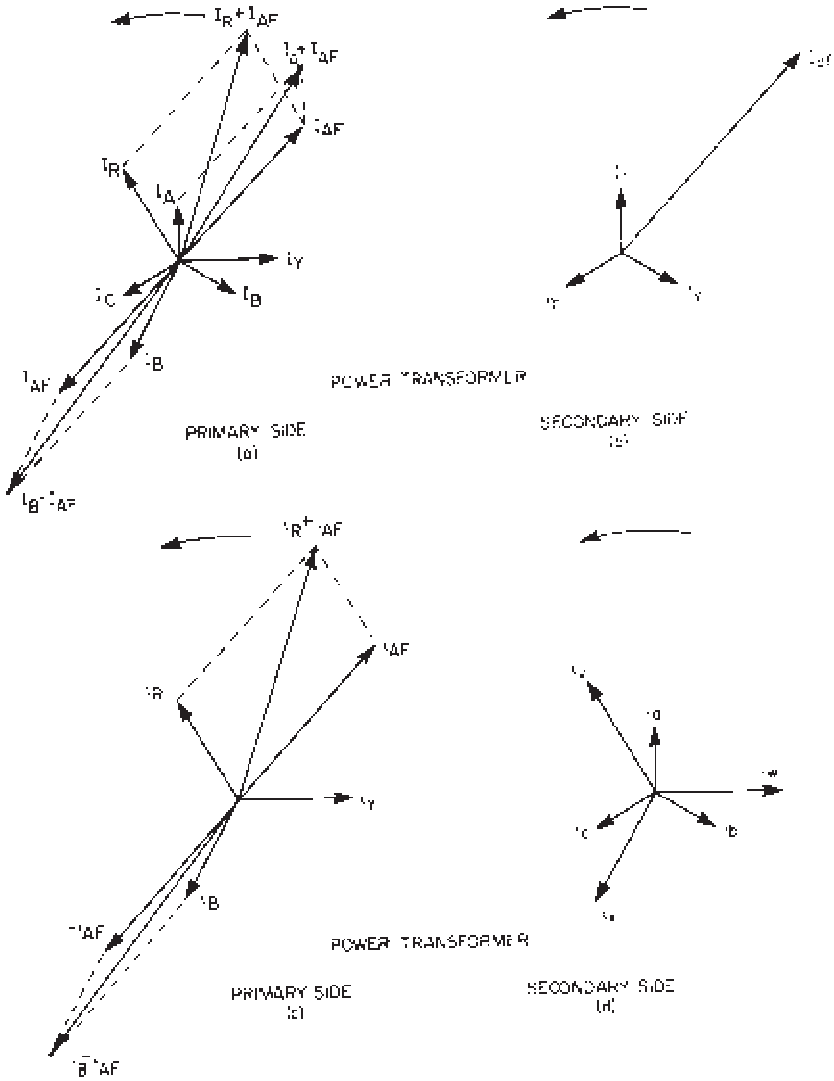


Figure 6.96 Current phasor diagrams corresponding to the conditions of *Figure 6.95*

I_{AF} is the short-circuit fault current in the power transformer primary winding A_2A_1 and in the line R corresponding to the fault current I_{af}, set up in the short-circuited portion of the power transformer secondary winding over a_2a_1. Its magnitude is such that the ampere-turns given by I_{AF} multiplied by the total number of turns in the primary winding A_2A_1 equal the ampere-turns given by the fault current I_{af} in the short-circuited portion of the secondary winding a_2a_1 multiplied by the number of secondary turns short-circuited.

The phase angle ϕ_p of I_{AF} with respect to the normal voltage across A_2A_1 is given by the expression $\cos^{-1}(R_p/Z_p)$ where R_p is the resistance of the primary winding A_2A_1 plus the resistance of the short-circuited portion of the secondary winding a_2a_1 and Z_p is the impedance of the short-circuited portion of the secondary windings a_2a_1 with respect to the whole of the primary windings A_2A_1, all quantities being referred to the primary side. $-I_{AF}$ is the short-circuit fault current in the line B, and is I_{AF} in the line R, but flowing in the reverse direction to I_{AF} with respect to the line R.

$I_A + I_{AF}$ is the total current in the winding A_2A_1, i.e. the phasor sum of the load current and the fault current in the winding.

$I_R + I_{AF}$ is the total current in the line R, i.e. the phasor sum of the load current and the fault current in the line.

$I_B - I_{AF}$ is the total current in the main line B, i.e. the phasor sum of the load current and the fault current in the line.

Figure 6.96(b)

I_r, I_y, I_b, are the normal balanced load currents in the secondary star-connected power transformer windings and in the secondary main lines.

I_{af} is the short-circuit fault current in that part of the power transformer secondary winding a_2a_1 between the earthed neutral and the winding earth fault. Its magnitude and phase angle ϕ_s, with respect to the normal voltage across the winding a_2a_1, are determined by the impedance of the short-circuited portion of the secondary winding a_2a_1 with respect to the whole of the primary winding A_2A_1, and by the resistance R_{af} of the short-circuited portion of a_2a_1. The magnitude of I_{af} is given by the expression V_{af}/Z_{af}, where V_{af} is the normal voltage across the short-circuited portion of the winding a_2a_1 and Z_{af} is the impedance referred to earlier in terms of the secondary side of the transformer. The phase angle ϕ_s, with respect to the normal voltage across a_2a_1, is $\cos^{-1}(R_{af}/Z_{af})$.

Figure 6.96(c)

i_R, i_Y, i_B are the normal balanced currents in the star-connected secondary windings of the current transformers and in the lines connected thereto on the primary side of the power transformer. They are the currents due to the normal balanced load currents in the primary power lines R, Y, B.

i_{AF} is the fault current in the current transformer secondary winding over M_AL_A and in the line V connected to it, and corresponds to the current I_{AF} in the primary power line R.

$-i_{AF}$ is the fault current transformer secondary winding M_CL_C and in the line X connected to it, and corresponds to the current $-I_{AF}$ in the primary power line B.

$i_R + i_{AF}$ is the total current in the current transformer secondary winding M_AL_A and in the line V connected to it, i.e. the phasor sum of the currents due to the load current and the fault current in the primary power line R.

$i_B - i_{AF}$ is the load current in the current transformer secondary winding $M_C L_C$ and in the line X connected to it, i.e. the phasor sum of the current due to the load current and the fault current in the primary power line B.

The relative angular displacements between the currents of *Figure 6.96(c)* are the same as those of *Figure 6.96(a)*.

Figure 6.96(d)

i_a, i_b, i_c, are the normal balanced currents in the delta-connected secondary windings of the current transformers on the secondary side of the power transformer. They are the currents due to the normal balanced load currents in the secondary power lines r, y, b.

i_v, i_w, i_x are the normal balanced currents in the lines to the delta-connected secondary windings of the current transformers on the secondary side of the power transformer. They are the line currents corresponding to the currents in the current transformer secondary windings which are due to the normal balanced load currents in the secondary power lines r, y, b.

This diagram bears no fault current phasors, showing that no fault currents flow through the current transformers on the secondary side of the power transformers.

The currents which flow through the protective relays are thus the fault currents i_{AF} and $-i_{AF}$ of *Figure 6.96(c)*, the magnitudes of which depend, for a given power transformer, upon the amount of the power transformer winding short-circuited and its position with respect to the whole winding on the other side of the power transformer.

So far no mention has been made of the problem which arises when a power transformer is provided with facilities for tap changing. It has been noted that for stability under healthy or though-fault conditions, identical outputs from each group of current transformers are an essential feature of circulating-current protection. It is clearly impossible for the current transformers to be matched at all tap positions unless these (the CTs) are also correspondingly tapped. This solution is generally impracticable if only because of the nature of the task of changing current transformer tappings each time a tap change is made on the power transformer. The latter function is often automatic so that it would then be necessary to make the tap changes on the current transformers automatic and simultaneous. Because of this and the normal inequalities which occur between current transformers, many schemes for the protection of transformers have been devised in which steps have been taken to eliminate the difficulties and some of these schemes will be noted later. Tap changing and current transformer inequalities can be largely avoided by using a circulating-current scheme which employs a biased differential relay, indicated typically in *Figure 6.100*.

In each pole of this relay, there are, in addition to the operating coil, two bias or restraining windings. Under through-fault conditions, when operation is *not* required, no current should flow through the operating coil but, because of imperfect matching of the current transformers, and the effects due to tap changing, some spill current may flow in the operating coil. This, however, will not cause operation unless the ratio of operating to bias current for which the relay is set is exceeded and the restraint or bias which is applied automatically increases as the through-fault current increases, thus enabling sensitive settings to be obtained with a high degree of stability.

To understand the operation of the bias coils, consider the protective system firstly under through-fault conditions (i.e. a fault outside the protected zone), and then under internal fault conditions.

(a) Through-fault conditions. If a three-phase short circuit occurred on the feeder side of the system beyond the circuit breaker the current circulating in the pilot wires would pass through the whole of the relay bias coils, and any out-of-balance current which might occur due to discrepancies in the ratios of the protective current transformers would flow through the relay operating coil. Under these conditions the biasing torque predominates, so preventing relay operation.

(b) Internal fault conditions. Imagine now a three-phase fault at the power transformer terminals on the star-connected side and that the power flow is as shown in *Figure 6.97*. Fault current flows through the three current transformers designated A on the delta-connected side of the power transformer but not through the set B on the star side. Therefore, the current transformer secondary currents circulate via the pilot wires, through *one-half* of the bias coils and the operating coils back to the current transformer neutral connection. Under these conditions the relay operating torque predominates. The protective system operates correctly when the transformer is fed from either or both directions and for all types of faults.

High-speed protection of power transformers by biased differential harmonic restraint

For many years the GEC Type DMH relay has provided differential protection for two-winding or three-winding power transformers with a high degree of stability against through-faults and is immune to the heavy magnetising current in-rush that flows when a transformer is first energised. The relay is available in two forms:

(a) for use with line current transformers with ratios matched to the load current to give zero differential current under healthy conditions;

(b) with tapped interposing transformers for use with standard line current transformers of any ratio.

In this relay the preponderance of second harmonic appearing in the in-rush current is detected and is used to restrain its action, thus discriminating between a fault and the normal magnetising current in-rush. The relay employs rectifier bridge comparators in each phase which feed their outputs through transistor amplifiers to sensitive polarised relays, resulting in:

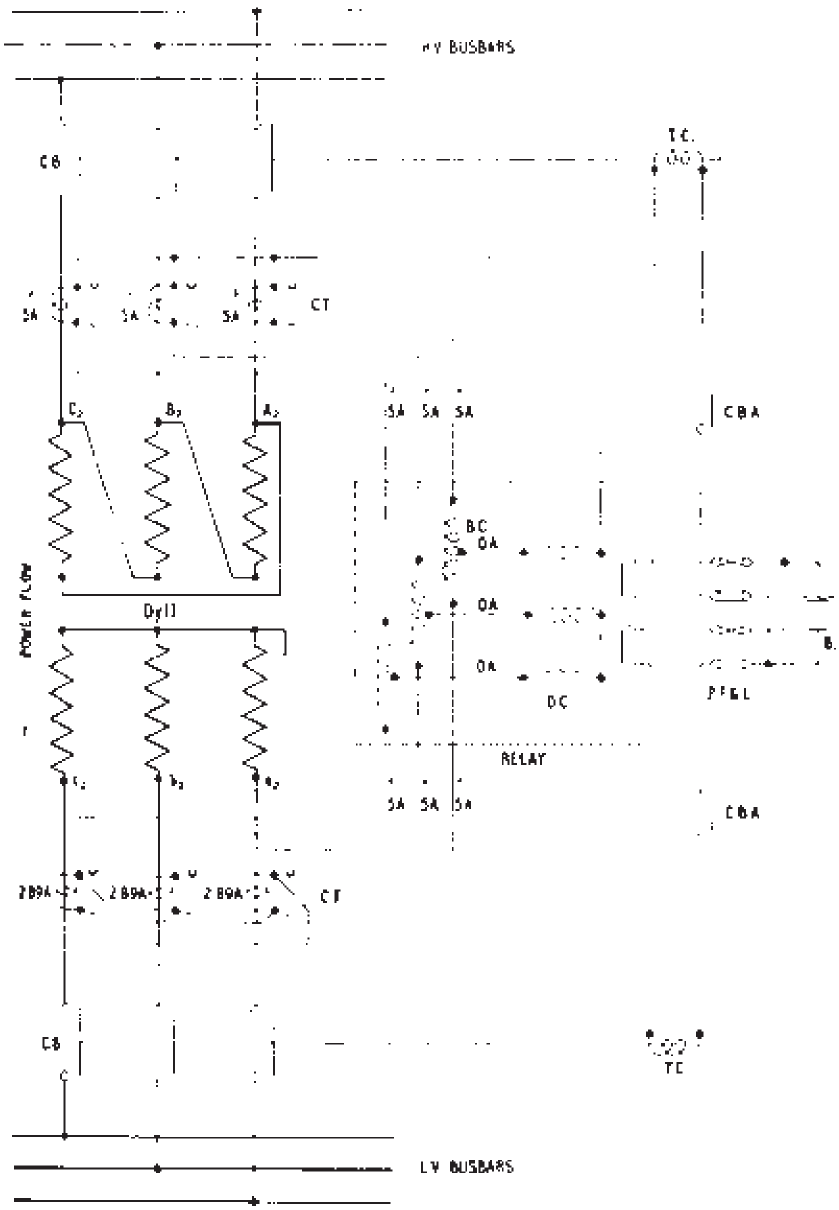


Figure 6.97 Biased differential protection applied to a delta/star-connected three-phase transformer

C.B. circuit breaker;	C.T. protective current transformer;
T.C. trip coil;	C.B.A. circuit breaker auxiliary switch;
B.C. bias coil;	O.C. operating coil;
P.F. & L. protector fuse and link;	B. battery.

(i) an operating current which is a function of the differential current;

(ii) a restraining current, the value of which depends on the second harmonic of the differential current;

(iii) a bias current which is a function of the through-current and stabilises the relay against heavy through-faults.

The relay is provided with an instantaneous overcurrent unit in each phase to protect against faults heavy enough to saturate the line-current transformers, under which conditions the harmonics generated would tend to restrain the main unit. These overcurrent units have a fixed setting of eight times the current-transformer secondary rating and are fed from saturable current transformers to prevent operation on peak in-rush current which may momentarily exceed this value.

The operation of the main unit is briefly as follows:

Under through-current conditions, current is passed by the two restraint rectifier bridges through the polarised relay in the non-operating direction. In conditions of internal fault there will be a difference between primary and secondary current, and the difference flows in the operating circuit so that the operating rectifier passes a current to the polarised relay in the operative direction. Operation depends on the relative magnitude of the total restraint and differential currents, and the ratio of these currents to cause operation is controlled by a shunt resistor across the restraint rectifiers. Under magnetising in-rush conditions, the second-harmonic component is extracted by the tuned circuit and the current is passed to the relay in the non-operating condition.

In addition to the second-harmonic component, the in-rush current contains a third-harmonic component, its proportion being large but less than the second. No restraint against the third harmonic is provided as there would be danger that the relay might be delayed in operating under heavy internal fault conditions, due to the current transformer saturation producing third harmonics in the secondary waveform.

Figures 6.98 and *6.99* show typical application diagrams for three-phase two-winding, and three-phase three-winding transformers.

Duo-Bias differential transformer protection

Another development, basically of the conventional current-balance scheme already discussed but using a special relay compensated to override the complications associated with transformer protection, is that by Reyrolle Protection. This is shown in *Figure 6.100*. It is a diagram of their 'Duo-Bias' relay scheme applied to a single phase, and functioning under various conditions as follows:

Under load or through-fault conditions, the current transformer secondary currents circulate through the primary winding of the bias transformer, the rectified output of which is applied to a bias winding on a transductor via a shunt resistor. Out-of-balance current flows from the centre tap on the primary

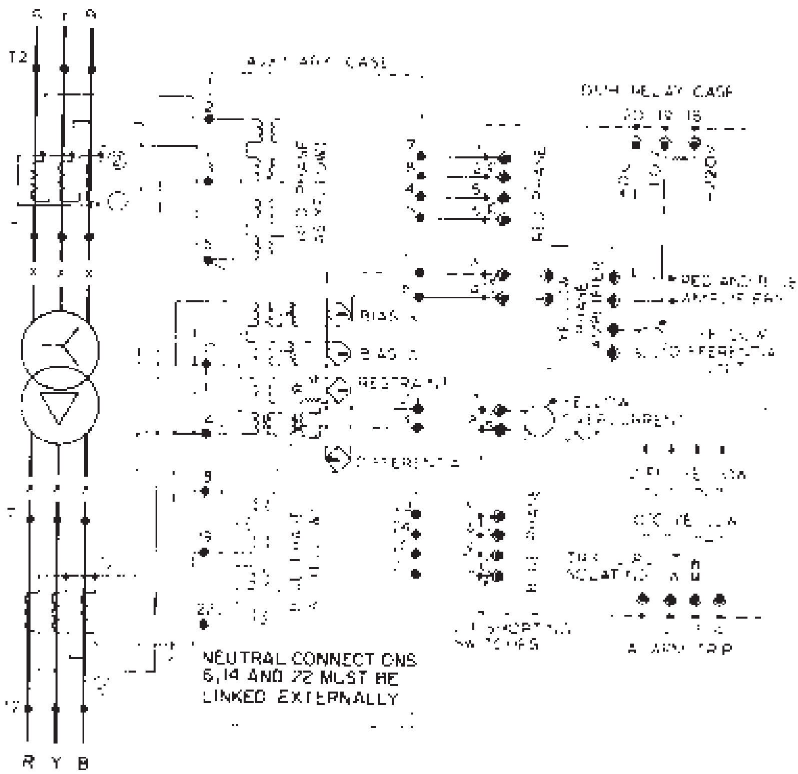


Figure 6.98 Typical application of GEC Type DMH biased differential harmonic restraint relay for a three-phase, two-winding transformer (GEC Measurements)

winding of the bias transformer, energising the transductor input winding and the harmonic-bias unit.

The input and output windings of the transductor are inductively linked but there is no inductive linking between these and the bias windings. So long as the transformer being protected is sound the transductor bias winding is energised by full-wave rectified current which is proportional to the load or through-fault current, and this bias current saturates the transductor. Out-of-balance currents in the transductor input winding, produced by power transformer tap changing or current transformer mismatch, superimpose an alternating m.m.f. on the DC bias m.m.f., as shown in *Figure 6.101* but the resulting change in working flux density is small and the output to the relay negligible.

The tappings on the shunt resistor are used for adjusting the relationship between the bias transformer primary current and the input to the transductor bias winding. This resistor also serves to suppress the ripple in the bias m.m.f.

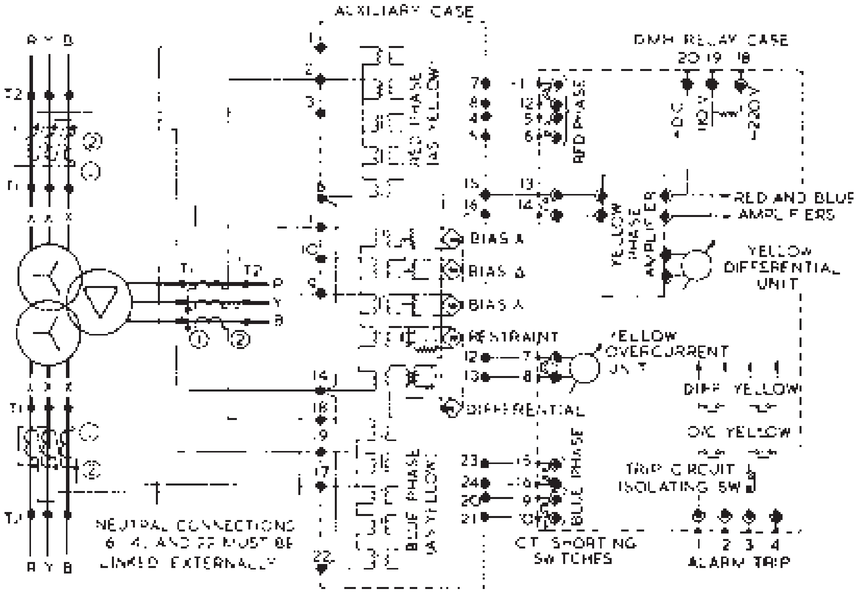


Figure 6.99 Typical application of GEC Type DMH biased differential harmonic restraint relay for a three-phase, three-winding transformer (GEC Measurements)

due to ripple in the bias current, because it provides a low-impedance non-inductive shunt path across the highly inductive bias winding for the AC content of the bias current.

If the power transformer develops a fault, the operating m.m.f. produced by the secondary fault current in the transductor input winding exceeds the bias m.m.f., resulting in a large change in working flux density which produces a correspondingly large voltage across the relay winding, and the resultant current operates the relay. Operation of the relay cannot occur unless the operating m.m.f. exceeds the bias m.m.f., and as the m.m.f. is proportional to the load or through-fault current, the required operating m.m.f. (and hence the operating current) is also proportional to the load or through-fault current.

The harmonic bias unit shown in *Figure 6.100* is a simple tuned circuit which responds to the second-harmonic component of the magnetising current. When magnetising in-rush current flows through the relay operating circuit the rectified output of the harmonic bias unit is injected into the transductor bias winding and restrains the relay.

Transformer differential relays generally have a basic setting which is the fault current required to operate them with no through-current in the differential system and internal fault current fed from only one set of current transformers. In the case of the Duo-Bias relay, this is 20% of the relay rating. The actual value of the fault current at which the differential relay will operate is thus the basic setting value under no-load conditions but when

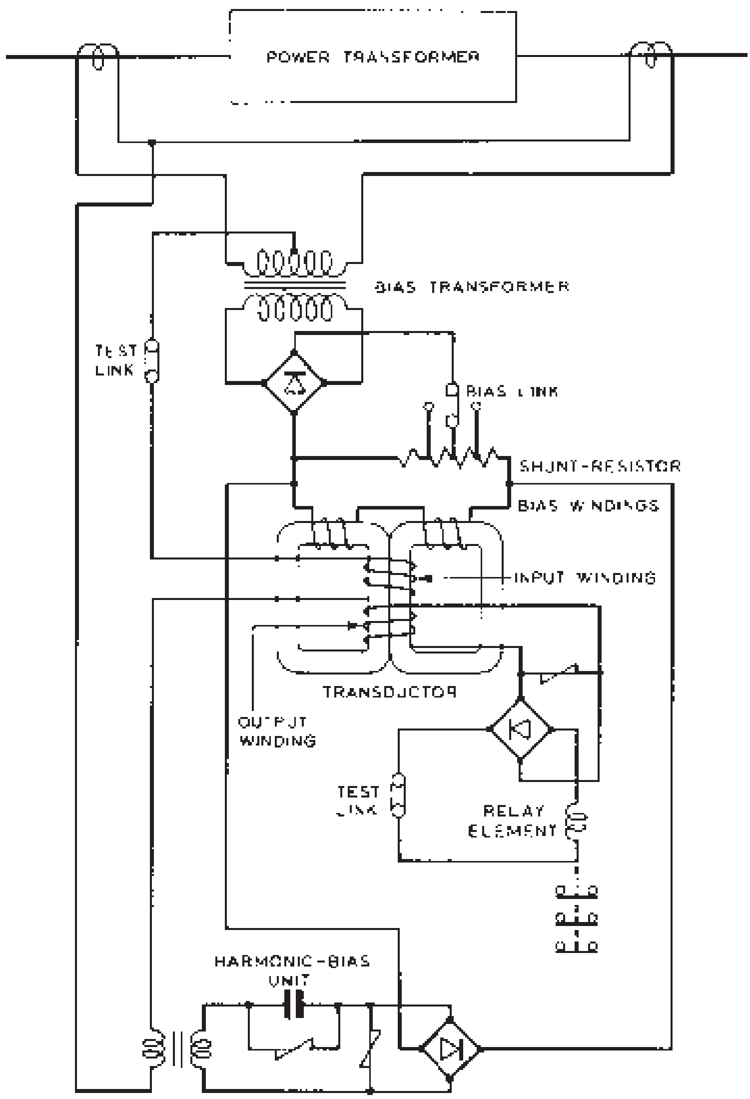


Figure 6.100 Duo-Bias transformer protection, single-phase diagram (NEI-Reyrolle Protection)

load current is flowing the setting will be higher, depending upon the amount of load and the bias setting in use. With an internal earth fault in which the current is limited by a neutral-earthing resistor, the load current might well be little affected by the fault and, therefore, when considering such a condition, the effect of load current on the setting should be taken into account.

Figure 6.102 shows a diagram for a three-phase assembly of Duo-Bias relays applied to the protection of a two-winding transformer. When applied

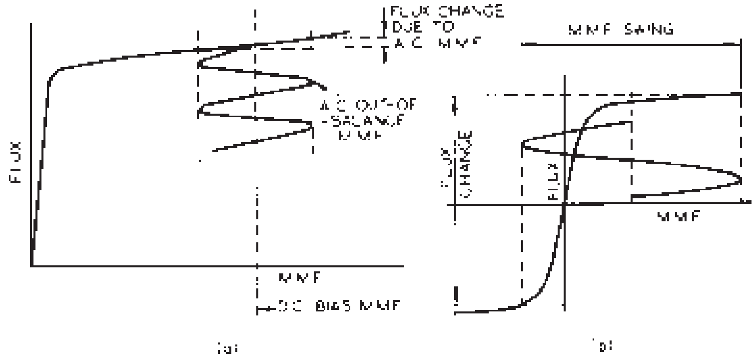


Figure 6.101 Fluxes due to operating and biasing ampere-turns (NEI-Reyrolle Protection)

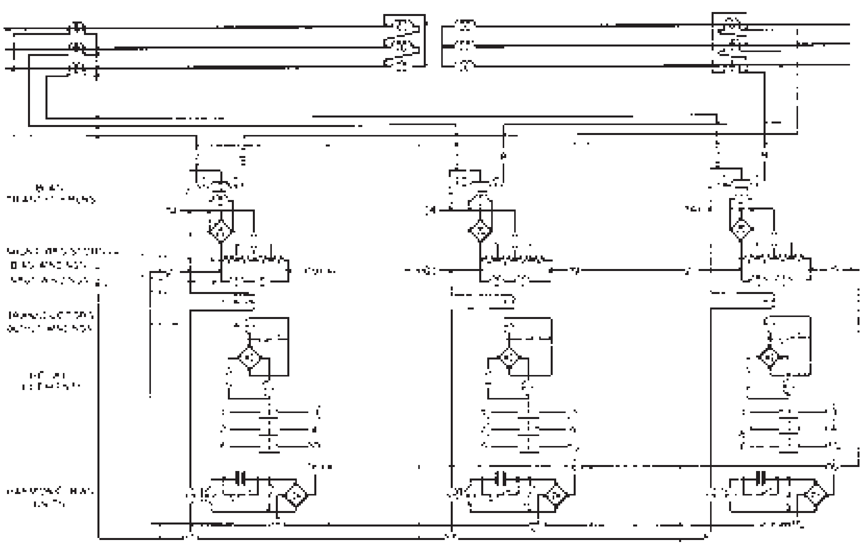


Figure 6.102 Duo-Bias protection for a two-winding transformer (Reyrolle Protection)

to a three-winding transformer, the relay is identical except for a change of tapping on the primary winding of the bias transformer. Further details of this type of protection are given in *The J & P Switchgear Book* (Butterworths).

Opposed-voltage protection

The essential difference between this and the circulating current scheme is that under normal conditions no current circulates in the pilot wires, the e.m.f.s generated at either end of the pilots being balanced against each other. This is basically the well-known ‘opposed-voltage’ scheme, a typical arrangement of which is shown in *Figure 6.103*. This particular scheme is known as ‘Translay’ and was developed originally by Metropolitan-Vickers Electrical Co. Ltd (now GEC Measurements).

The two diagrams illustrate the operation of the protection for through-fault conditions, and for internal fault conditions. This scheme is also more fully described in *The J & P Switchgear Book*, which refers particularly to feeder protection, but in general applies as well to transformers.

Overcurrent and earth leakage protection

As indicated earlier, it is not always economical to fit circulating current protection for the smaller sizes of power transformers up to, say, 1000 kVA (and in some cases larger than this). Adequate protection can be provided by means of simple overcurrent and earth fault relays, the latter preferably of the restricted form on the LV side.

A typical diagram is shown in *Figure 6.104* where it will be seen that the HV side comprises three overcurrent and one earth leakage relays, while the LV arrangement is similar with the addition of a neutral current transformer if the power transformer neutral is earthed. With this type of protection no balancing of current transformers on the primary and secondary sides of the power transformer is necessary, and hence similar characteristics and definite ratios are unnecessary. Further, the earth leakage relays are instantaneous in operation, and earth fault settings as low as 20% can usually be obtained without difficulty. Line to line faults are dealt with by the overcurrent relays, which operate with a time lag and are graded with the overcurrent relays on other parts of the system.

For unearthed windings (delta or star) the apparatus would consist of a three-pole overcurrent relay of the inverse, definite minimum, time lag type and a single pole instantaneous earth leakage relay with or without series resistor depending on the type of relay. This is shown at the left-hand side of *Figure 6.104* and by the full lines at the right-hand side: this is the overcurrent and plain earth leakage system of protection.

If the power transformer neutral point is earthed, as shown dotted at the right-hand side of *Figure 6.104*, an additional current transformer is provided in the neutral connection with its secondary winding in parallel with the three line current transformers; this protection is known as the overcurrent and restricted earth leakage system. With an external earth fault (say to the right of the current transformers on the star-connected side of the power transformer), current flows in one of the line current transformers and in the neutral current transformer and the polarities are so arranged that current circulates between the two secondaries. The earth leakage relay is thus connected across equipotential points; no current flows in it, and it does not operate. With an internal earth fault, fault current flows either in the neutral current transformer only, or in opposition in the line and neutral current transformers; the relay is then energised and operates.

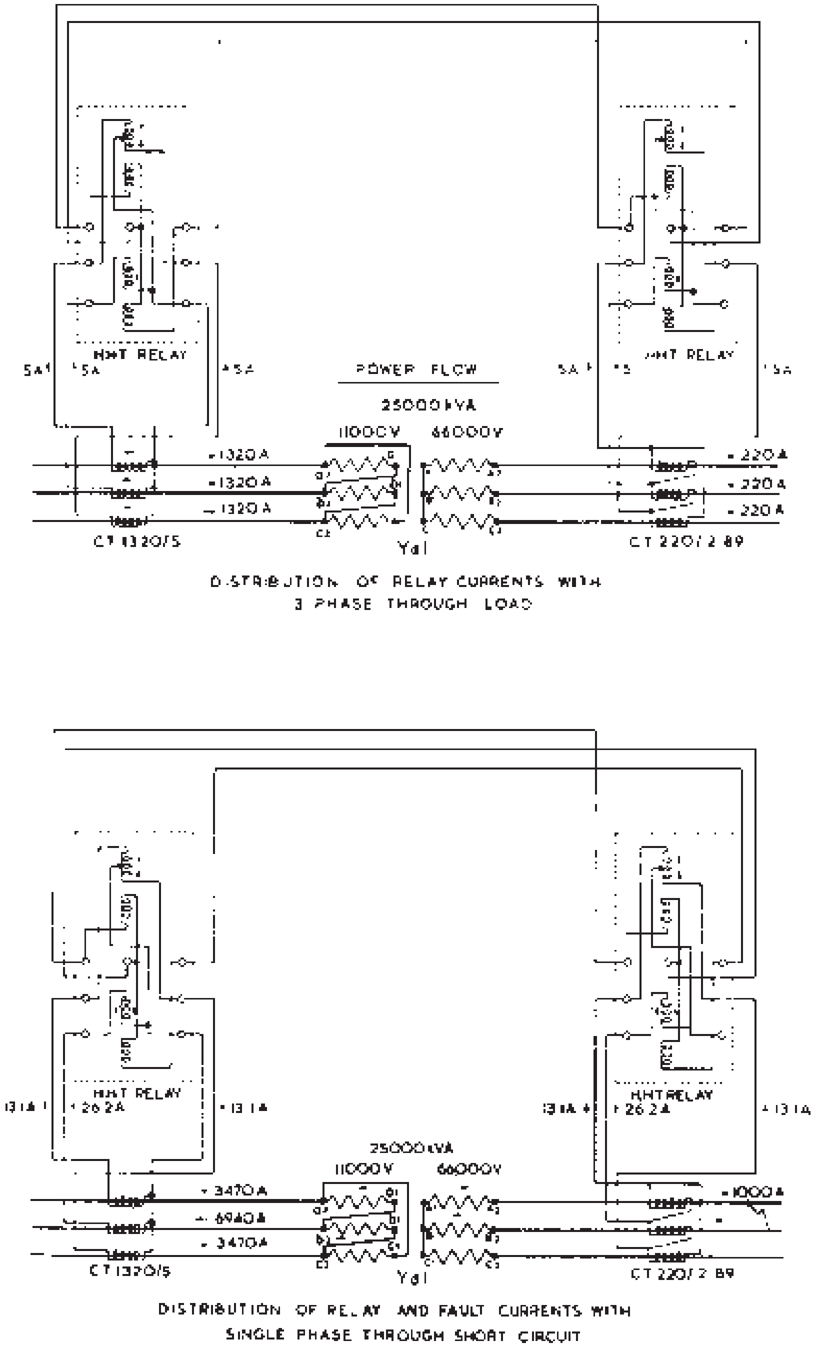


Figure 6.103 Translay protection applied to a transformer feeder (GEC Measurements)

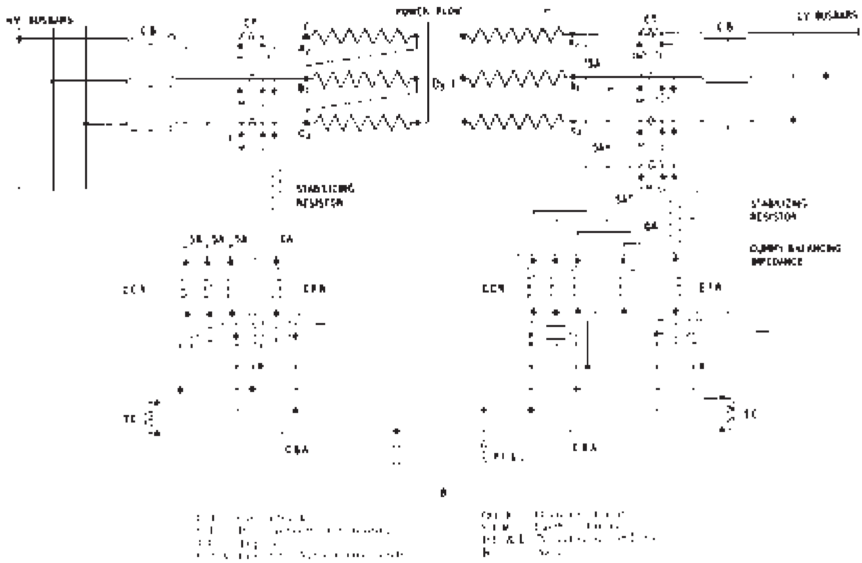


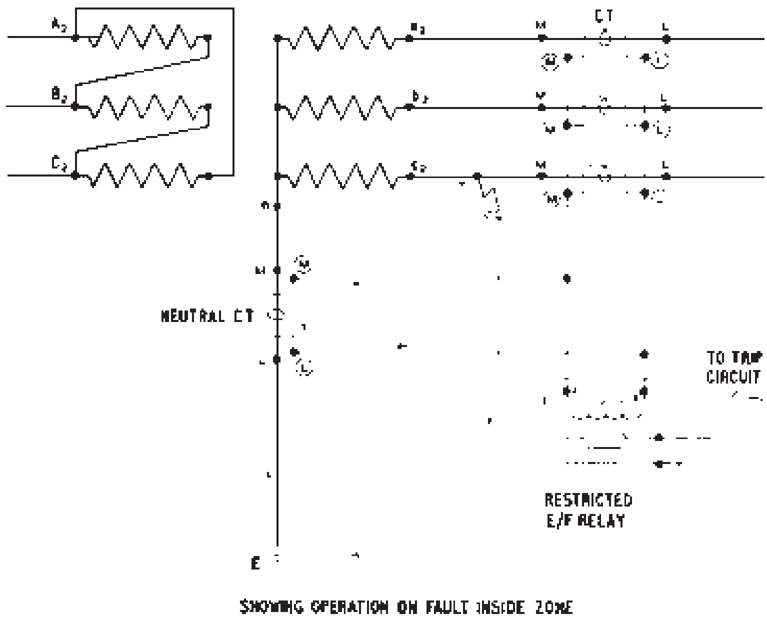
Figure 6.104 Overcurrent and unrestricted earth fault protection of a three-phase delta/star-connected transformer

To balance the line and neutral current transformers with external earth faults, a dummy balancing impedance equal to the impedance of one of the overcurrent elements is connected in series with the neutral current transformer as shown in *Figure 6.104* so that the burdens of the line and neutral current transformers are equalised. *Figure 6.105* shows in diagrammatic form the current distribution for restricted earth fault protection for faults inside and external to the protected zone.

Dealing next with the question of protection against interturn faults within the transformer, it has already been stated that such faults are more likely to occur in the HV windings and therefore it is only necessary as a rule to install protective gear on the HV side. When, however, the LV side of the transformer is designed for a voltage which is higher than normal, the degree of susceptibility of the windings to interturn insulation failure is comparable to that of HV windings, bearing in mind, of course, the influence of the type of circuit, i.e. overhead lines, underground cables, or merely short connecting leads, to which the windings are connected.

Restricted earth fault protection: high-impedance principle

The current balance scheme will only protect a transformer against earth faults within the area between the current transformers, hence the title ‘restricted earth fault protection’. The major difficulty experienced with the scheme is that of retaining stability on through-faults when unequal saturation of the current transformers occurs during the first few cycles after the fault zero.



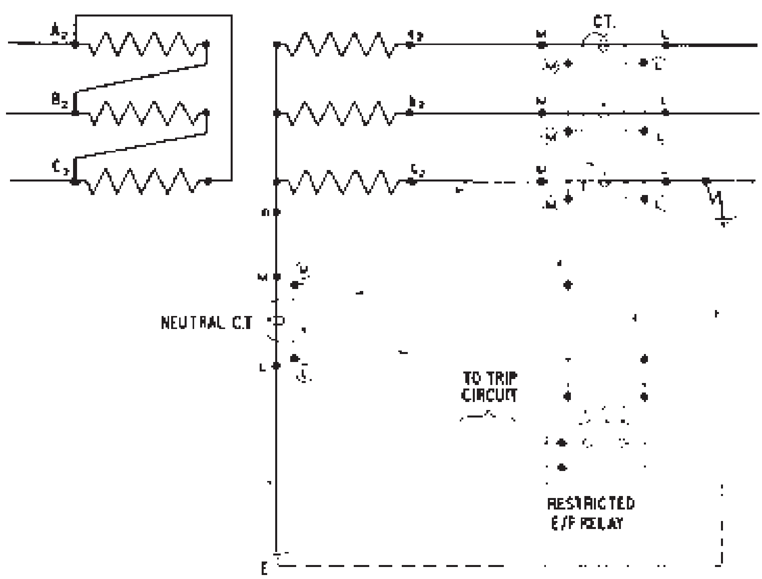


Figure 6.105 Diagrams showing restricted earth fault protection for transformers

This is overcome by using a high-impedance relay, which has a high-value stabilising resistor in its circuit, such as the Reyrolle Protection type 4B3 relay illustrated in *Figure 6.106*. The relay element is AC energised via a full-wave rectifier in series with the setting resistors R_1 to R_7. The non-linear resistors M_1 and M_2 limit the peak output voltages of the current transformers and protect both the relay components and the current transformers. The capacitor C together with the resistors R_1 to R_7 form a low-pass filter which ensures that the primary fault setting of the scheme at harmonic frequencies will be greater than the setting at the fundamental frequency.

Figure 6.107 shows the diagrammatic representation of a high-impedance restricted earth fault current balance scheme used with a three-phase, two-winding transformer. The performance of the relays can be calculated with certainty for both stability and fault setting, and the voltage setting adjusted by means of the links across the resistors which are marked in volts on the face of the relay.

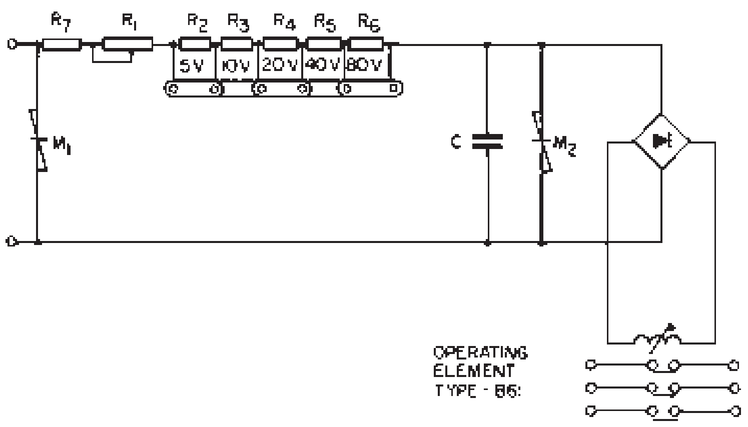


Figure 6.106 Circuit diagram of high impedance relay Reyrolle Protection Type 4B3 relay (NEI-Reyrolle Protection)

The stability of the scheme depends on the voltage setting being greater than the maximum voltage which can appear across the relay under a given through-fault condition. Assuming the worst case condition that one CT is fully saturated, making its excitation impedance negligible, then the maximum voltage $V_{\max}$ is given by:

$$V_{\max} = \frac{I}{N}(R_{CT} + R_L)$$

where I is the maximum steady-state through-fault current
N is the current transformer turns ratio
R_{CT} is the current transformer secondary winding resistance
R_L is the pilot loop resistance

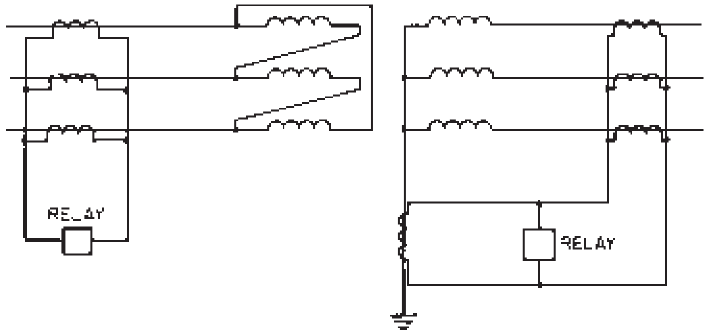


Figure 6.107 High impedance restricted earth fault protection scheme applied to a three-phase, two-winding transformer (Reyrolle Protection)

The fault setting is calculated in the usual manner taking the excitation currents of the current transformers in parallel with the relay:

$$\text{Primary fault setting} = N(I_0 + I_1 + I_2 + I_3)$$

where N is the current transformer turns ratio
I_0 is the relay operating current
I_1, I_2, I_3 are the current transformer excitation currents

This scheme is unaffected by load, external fault and magnetising in-rush currents. It will protect a winding which has a solidly earthed neutral but not if it is earthed through a resistance.

Replacement of electromagnetic relays

As explained earlier in this section, the types of electromagnetic relays described have been the basic means of providing protection for electrical plant and equipment for more than 60 years. With the electronic revolution of the 1980s these are gradually being replaced by more sophisticated types of relays, initially utilising transistor circuitry, a few small microprocessors and more recently these have totally changed to microprocessor technology. These modern devices continue to perform the same tasks, taking signals from current and voltage transformers in the circuits being protected, but these signals, instead of causing a disc to rotate or an armature to be attracted, are processed by amplifiers, comparators or digital processors in order to produce the necessary trip signal to the controlling circuit breaker. The principles of protection remain unchanged, but the following description of modern biased differential protection relays gives an indication of the effects which recent developments have had on the equipment involved.

The present-day GEC Measurements equivalent of the DMH relay is the MBCH shown in *Figure 6.108*. This is from their Midos range and was introduced in the mid-1980s. *Figure 6.109* shows the functional block diagram,

Figure 6.108 Modern Static differential protection relay (GEC Measurements)

from which it will be seen that the philosophy of operation is basically similar to that of the DMH. The outputs from each bias restraint transformer T3 to T5, proportional to the primary line currents, are rectified and summed to produce a bias restraint voltage. Any resulting difference current is circulated through transformers T1 and T2. The output from T1 is rectified and combined with the bias voltage to produce a signal which is applied to the amplitude comparator. The comparator output is in the form of pulses which vary in width depending on the amplitude of the combined bias and difference voltages. Where the measurements of the interval between these pulses

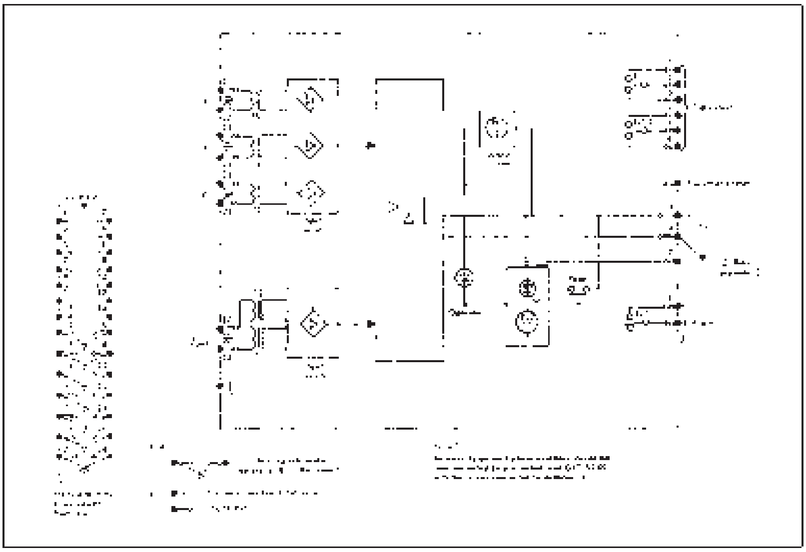


Figure 6.109 Block diagram: biased differential protection relay type MBCH 13 with three biased inputs (GEC Measurements)

indicate less than a preset time, an internal fault is indicated and a trip signal is initiated after a short delay, the magnitude of which is set by the bias. If, during this delay, the instantaneous value of differential current falls below the threshold and remains below for longer than a further preset time, as it would during transformer magnetising in-rush conditions, the trip timer is reset and operation of the relay blocked.

An unrestrained high-set circuit, which monitors the differential current, will override the amplitude comparator circuit and operate the relay output element when the difference current is above the high-set setting.

Even under normal operating conditions, unbalanced currents, spill current, may appear. The magnitude of the spill current depends largely on the effect of tap changing. During through-faults the level of spill current will rise as function of the fault current level. In order to avoid unwanted operation due to spill current and yet maintain high sensitivity for internal faults, when the difference current may be relatively small, the variable percentage bias restraint characteristic shown in *Figure 6.110* is used. The setting I_s is defined as the minimum current, fed into one of the bias inputs and the differential circuit to cause operation. This is adjustable between 10 and 50% of rated current.

The initial bias slope is 20% from zero to rated current. This ensures sensitivity to faults while allowing a 15% current transformer ratio mismatch when the power transformer is at the limit of its tapping range, plus 5% for CT ratio error. Above rated current, extra errors may be gradually introduced as a result of CT saturation. The bias slope is therefore increased to 80% to compensate for this.

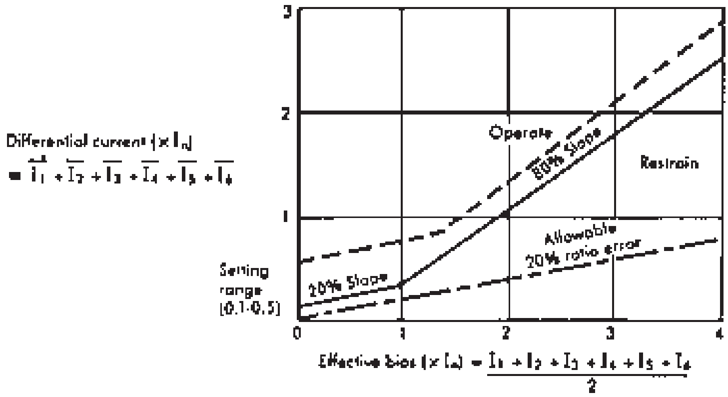


Figure 6.110 Typical percentage bias characteristic (GEC Measurements)

At the inception of a through-fault the bias is increased to more than 100%. It then falls exponentially to the steady-state characteristic shown in *Figure 6.110*. The transient bias matches the transient differential currents that result from CT saturation during through-faults, so ensuring stability. However, during internal faults this transient bias is suppressed to ensure that no additional delay in operation is caused.

The most significant change in operating philosophy made possible by the use of more elaborate electronic circuitry is the method of providing restraint during magnetising in-rush conditions. The relay makes use of the fact that the magnetising in-rush current waveform is characterised by a period during each cycle when little or no current flows, as shown in *Figure 6.111*. By measuring this characteristic zero period, the relay is able to determine whether the difference current is due to magnetising in-rush current or to genuine fault current and thereby inhibit operation only during the in-rush condition. This technique enables operating times to be speeded up even during periods of significant line CT saturation.

The relay can also discriminate against increases in magnetising current which can occur under conditions of sudden loss of load from the system. Such sudden loss of load may cause a 10 to 20% increase in voltage at the input terminals of the transformer until such time as tapchangers or other system voltage control equipment is able to respond. This might briefly lead the transformer into saturation with a resultant large increase in exciting current which will be seen only by the input line CTs. However, exciting currents resulting from saturation have a waveshape, as shown in *Figure 6.112*, which also has a period during each cycle for which the current remains close to or at zero. By detecting this in a similar manner to that used to identify magnetising in-rush current, the relay is able to remain inoperative to this over excitation current. It should be noted that where large and potentially damaging over excitation currents can occur, for example following tripping of the EHV side

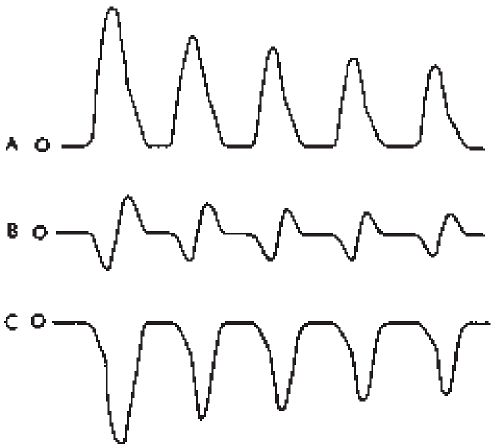


Figure 6.111 Typical magnetising in-rush waveforms (GEC Measurements)

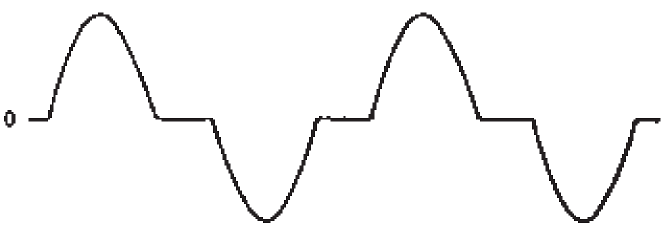


Figure 6.112 Magnetising current with transformer overfluxed (GEC Measurements)

of a large generator transformer while it remains connected to the generator on the LV side, separate overfluxing protection should be installed. This will be discussed further in Section 1 of Chapter 7.

The relay also incorporates an unrestrained instantaneous high-set feature to provide very fast clearance of heavy internal faults. This instantaneous feature has an auto-ranging setting, normally low at normal load throughput, but rising to a higher value under heavy through-fault conditions. This will not trip on magnetising in-rush current provided the first peak of this does not exceed 12 times the rated r.m.s current.

Figure 6.113 shows a typical application using three MBCH 12 relays to protect a delta/star-connected transformer and using an additional restricted earth fault relay connected into the differential circuitry, in association with a current transformer connected into the transformer neutral. Supplementing the differential protection by a restricted earth fault relay in this way can be beneficial, especially when the transformer neutral is earthed via a current-limiting resistor which limits earth fault current to a maximum of about normal full-load current.

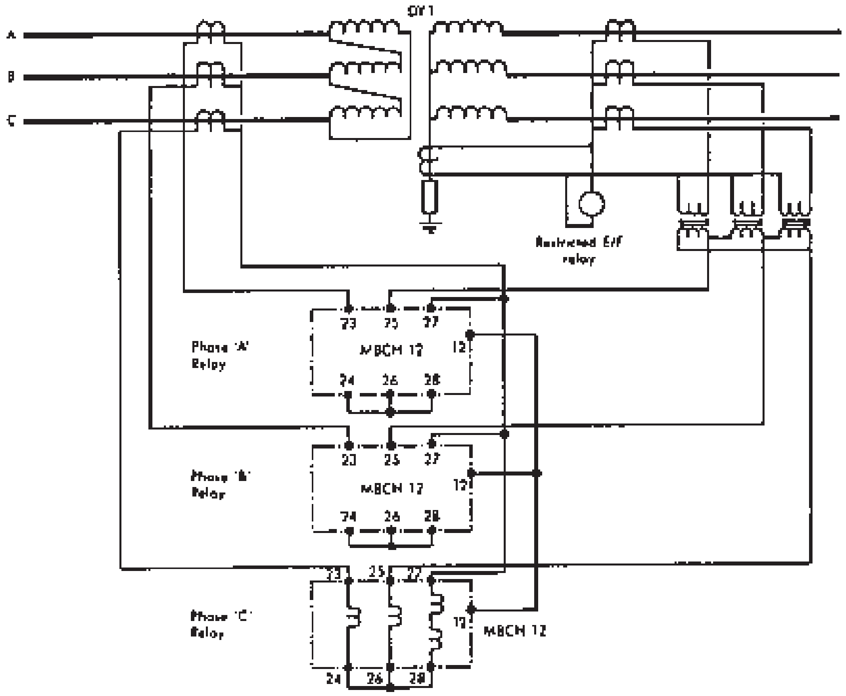


Figure 6.113 Typical connection diagram for MBCH 12 relays protecting a DY 1 transformer with integral restricted earth fault relay (GEC Measurements)

The GEC Measurements' logical successor to the Midos range of protection relays is their 'K Range' introduced in the mid-1990s. These are truly microprocessor based which makes possible the facility for 'communication' between the relay and computer-based SCADA systems concerned with plant monitoring, thus greatly reducing the extent of operator involvement. For transformer-biased differential protection the appropriate relay is the KBCH. Settings can be input into the K Range relays by means of a keypad on the relay face and these are displayed by a liquid crystal display. Where the relay power supply is non-secure, relays are available which derive their energy from the fault current to provide for circuit breaker tripping. The greatly increased amount of information which can be output from the relay if used in conjunction with a central data logging computer includes, for example, a post-incident log which can be of great assistance in fault investigation and diagnosis.

The gas- and oil-actuated relay

The gas- and oil-actuated (Buchholz) relay has been used extensively in the UK for disconnecting a transformer from the supply upon the occurrence of an interturn fault or any other internal failure which generates gases in sufficient quantities to operate the device and to actuate the controlling circuit breaker.

The modern transformer is a very reliable piece of electrical equipment and however infrequent breakdowns may be, they must be guarded against and all possible steps taken to maintain continuity of supply. Any means of indicating the development of a fault within the transformer, particularly in the incipient stages, may avoid major breakdowns and sudden failure of the power supply.

The gas-operated relay is designed for this particular duty and depends for its operation on the fact that most internal faults within the transformer generate gases (see also Section 7 of this chapter). The service record over many years shows clearly that the relay is extremely sensitive in operation and that it is possible to detect faults in their incipient stages, thus minimising damage and saving valuable time in effecting the necessary repairs. The gas-operated relay can only be fitted to transformers having conservator vessels, and is installed in the pipeline between the transformer and its conservator tank. The relay comprises an oil-tight container fitted with two internal elements which operate mercury switches connected to external alarm and tripping circuits. Normally, the device is full of oil and the elements, due to their buoyancy, rotate on their supports until they engage their respective stops. An incipient fault within the transformer generates small bubbles of gas which, in passing upwards towards the conservator, become trapped in the housing of the relay, thereby causing the oil level to fall. The upper element rotates as the oil level within the relay falls, and when sufficient oil has been displaced the mercury switch contacts close, thus completing the external alarm circuit.

In the event of a serious fault within the transformer, the gas generation is more violent and the oil displaced by the gas bubbles flows through the connecting pipe to the conservator. This abnormal flow of oil causes the lower element to be deflected, thus actuating the contacts of the second mercury switch and completing the tripping circuit of the transformer circuit breaker, so disconnecting the transformer from the supply.

Gas within the device can be collected from a small valve at the top of the relay for analysis and from the results obtained an approximate diagnosis of the trouble may be formed. Some of the faults against which the relay will give protection are:

1. core-bolt insulation failure;
2. short-circuited core laminations;
3. bad electrical contacts;
4. local overheating;
5. loss of oil due to leakage;
6. ingress of air into the oil system.

These would normally initiate an audible or visible alarm via the upper element, while the following more serious faults would trip the transformer from the supply:

(a) short-circuit between phases;
(b) winding earth fault;
(c) winding short-circuit;
(d) puncture of bushings.

Typical values of the oil velocity required to operate the lower element under oil surge conditions and the volume of gas required to operate the upper alarm element are given in *Table 6.11*.

Table 6.11

Internal diameter relay pipe (mm (in))	*Oil velocity (m/s)*	*Gas volume (mm^3)*
25 (1.0)	1.2	260×10^3
51 (2.0)	1.2	260×10^3
76 (3.0)	1.4	260×10^3

A view of a dismantled double-element relay is shown in *Figure 6.114* and the recommended arrangement for mounting the relay is shown in *Figure 6.115*. It is essential when designing the transformer tank that all gas rising from the transformer shall pass into the relay pipe and not collect in stray pockets, for otherwise an accumulation of gas would delay the operation of the alarm float. For testing purposes, a test valve is provided on the relay for connection to a source of air supply. A suitable testing equipment comprises a small air vessel with a pressure gauge and a suitable length of rubber tubing. The air chamber is filled to a pressure of approximately 42 g/mm^2. Slow release of the air to the relay operates the upper float while quick release causes the tripping float to operate.

When transformers are to be installed in countries subject to earthquake tremors, mining blasting effects or traction applications, a relay having magnetically operated reed switches instead of mercury type should be specified.

Interturn failures

All types of coils are liable to interturn insulation failure, and the order of susceptibility may be given as crossover, continuous-disc and spiral coils. A purely interturn fault is distinguished by localised burning of the conductors of the coil affected, and often by extensive charring of the interturn insulation of the coil; distortion of the conductors is not a feature of a true interturn insulation fault. Severe coil distortion is direct and positive evidence of an external short-circuit across the whole or a major portion of the winding.

It is generally the case that an initial interturn insulation failure does not draw sufficient current from the line to operate an ordinary overload circuit breaker or even more sensitive balanced protective gear. The transformer will, in fact, only be disconnected from the line automatically when the fault has extended to such a degree as to embrace a considerable portion of the affected

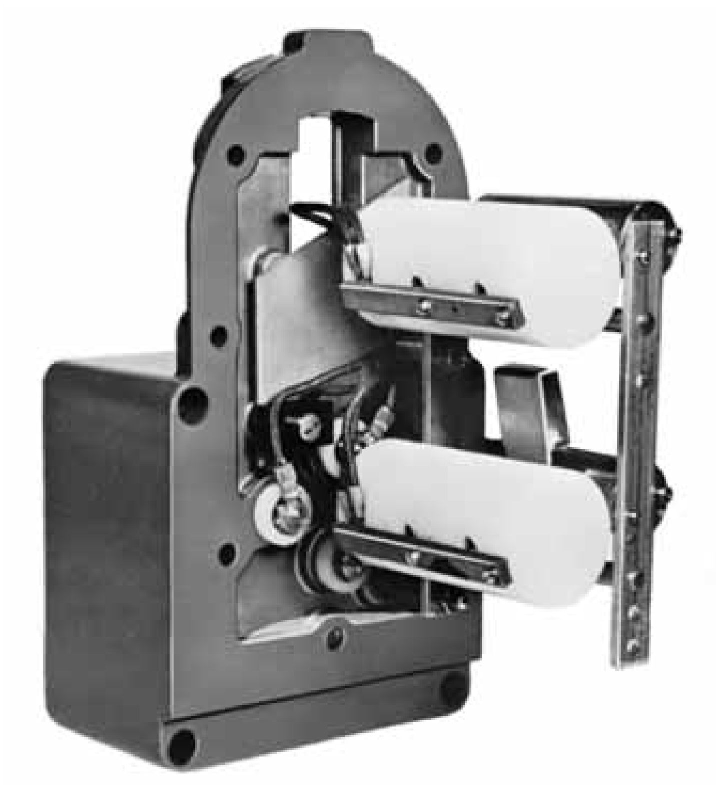


Figure 6.114 Gas- and oil-actuated relay dismantled to show the position of the elements and test jet (Weir Electrical Instruments)

winding. This may take one of the forms shown in *Figure 6.116* in which the fault is confined strictly to the winding at (*a*), while at (*b*) it burns through to earth in the incipient stage of the failure.

If the fault occurs on the primary winding the short-circuited turn acts as an autotransformer load on the winding, and the reactance is that between the short-circuited turns and the whole of the affected phase winding. If the fault takes place on the secondary winding the short-circuited turns act as an ordinary double winding load, and the reactance is that between the short-circuited turns and the whole of the corresponding primary phase winding.

The following example gives an idea of the relative order of magnitudes of the quantities involved.

Tests were carried out on a typical step-down 250 kVA, 50 Hz, three-phase, core-type transformer. The design data were as follows: HV phase voltage, 2800 V; LV phase voltage, 237 V; Volts per turn, 7.38; turns per HV phase winding, 380; turns per LV phase winding, 32; normal impedance, 3.25%; normal reactance, 3.08%; axial length of each HV and LV phase winding, 16.4 in. The HV winding on each phase consisted of a total of 380 turns and

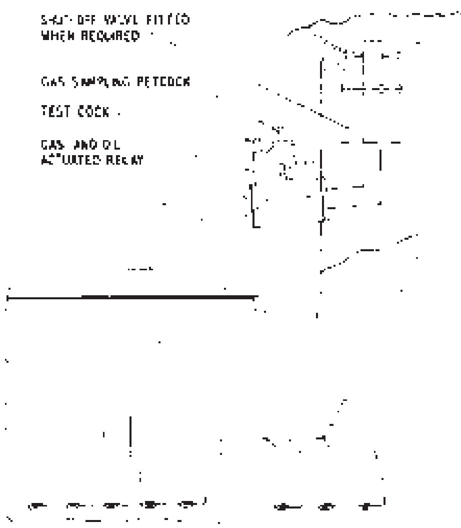


Figure 6.115 Arrangement for mounting the gas- and oil-actuated relay

tapping points were obtained at 28 intervals of 16 turns and two intervals of 12 turns. Both ends of each tapping point were brought out for testing so that they could be short-circuited. Impedance tests were made, first short-circuiting one tapping section only at a time, starting at the top and working down the core limb, taking each consecutive interval in turn and, subsequently, short-circuiting different series and parallel groups of tappings up to eight in number, at various positions throughout the entire length of the limb. This made it possible to plot impedances, primary line currents and currents in short-circuited winding sections against the relative position of the short-circuited turns in the complete winding and the number of winding sections short-circuited. Tests were also made, applying voltage to the HV winding and to the LV winding, to simulate the conditions of a fault on the primary or on the secondary winding. In all cases the current in the short-circuit was the normal full-load current of the HV winding, namely, 29.8A.

Figures 6.117 to *6.119* give some of the results of this particular series of tests. They are fairly self-explanatory and show how the position and number of the short-circuited turns affect the primary current drawn from the line. The illustrations apply to the case where the fault occurs on one phase of the primary windings, which, for this series of tests, were star connected.

It will be seen from these curves that when relatively few turns are short-circuited, on the one hand extremely large currents flow in the short-circuited

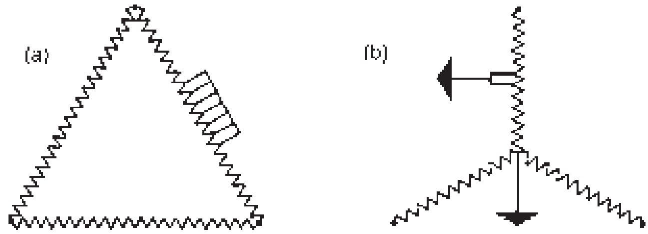


Figure 6.116 Interturn insulation failures. (a) Winding insulated from earth; (b) winding neutral point earthed

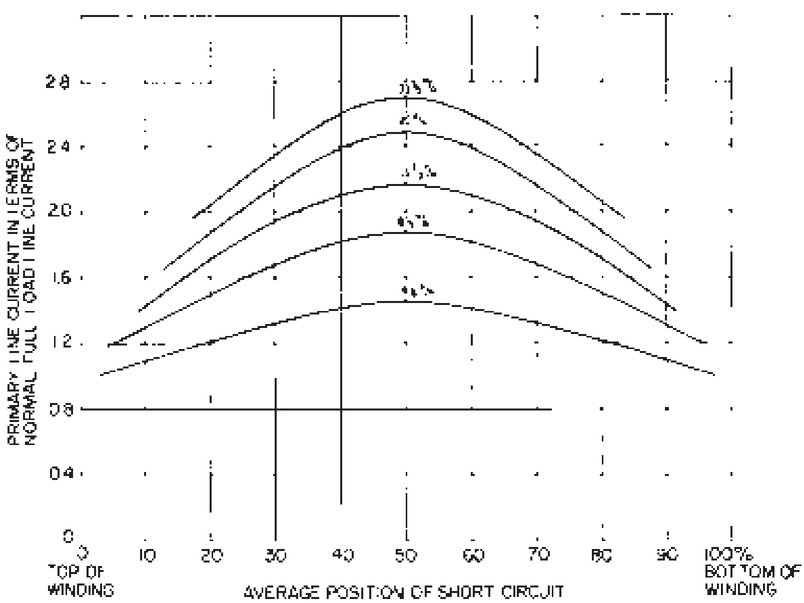


Figure 6.117 Curves showing the relationship between primary line current and average position of short-circuited turns in a typical three-phase, core-type transformer

turns, while *relatively* small currents are drawn from the primary lines, and at first glance these appear to be opposing facts. They are easily reconciled, however, when it is pointed out that the high currents in the few short-circuited turns are due to the low impedances between those turns and the primary winding, while the smallness of the current drawn from the primary lines is due to the high ratio of total primary turns to short-circuited turns. As the number of turns short-circuited increases, the impedance increases (up to a point) and the current in the short-circuit decreases, while the ratio of turns cited above decreases and more current is drawn from the primary lines.

It will be noted that, bearing in mind the numbers of turns short-circuited, the impedances shown by *Figure 6.118* really are very high relative to the

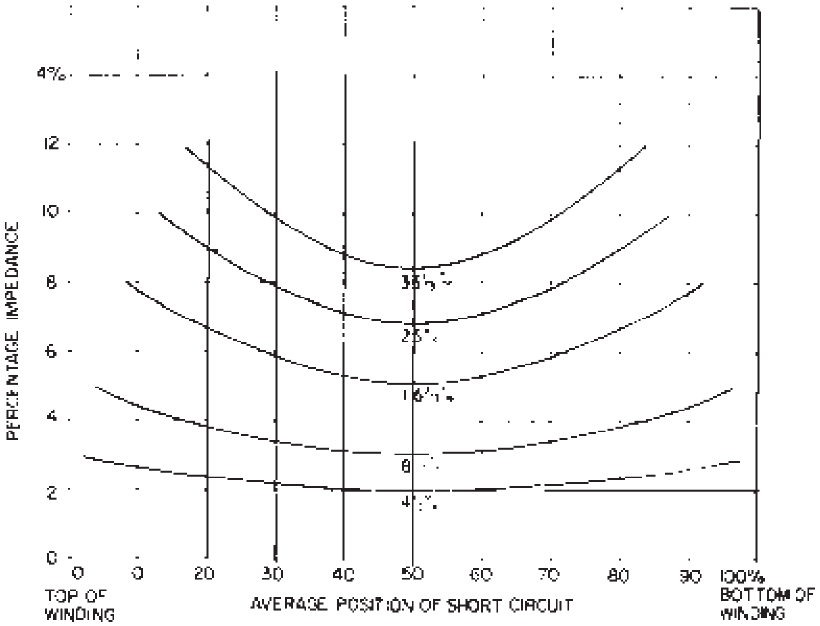


Figure 6.118 Curves showing the relationship between the percentage impedance and average position of short-circuited turns in a typical three-phase, core-type transformer

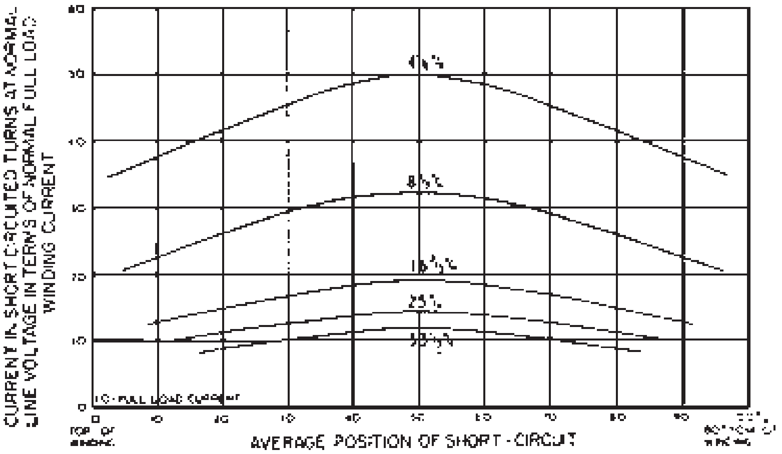


Figure 6.119 Curves showing the relationship between the current in the short-circuited turns and the average position of the short-circuited turns in a typical three-phase, core-type transformer

normal transformer impedance, and this is accounted for by the relatively high reactance produced by the dissymmetry between the primary winding and the short-circuited turns.

It is to be borne in mind that the minimum number of turns short-circuited in these tests was 16, and that they were all in series. In the usual interturn fault, first one turn, then a second turn and so on are short-circuited in parallel, in which case impedances are lower than those shown in *Figure 6.118*, short-circuit currents are higher, and primary line currents are lower. The usual result of this is thus: severe local burning out of the faulty turns, small primary line currents, but no untoward distortion of the windings.

The following major conclusions may be drawn from the data obtained from the tests, bearing in mind that the maximum portion of winding short-circuited was limited to one-third of the total winding on one limb.

For a given number of turns short-circuited the impedance is a minimum when the axial centre of the turns coincides with the axial centre of the winding, and the line current is then a maximum for that number of turns; the *variation* of impedance throughout the length of the winding increases with the number of turns short-circuited. Impedances increase with the number of turns short-circuited, and the increases are greatest when the short-circuited turns are at the ends of the winding. For a given number of turns short-circuited, the current in the short-circuited turns is highest when the axial centre of the turns coincides with the axial centre of the winding; the short-circuit current decreases with increasing number of turns. The primary line current increases with an increase in the number of turns short-circuited as for a given increase of the latter the impedance increase is proportionately less, so that the resulting ampere-turns in the short-circuit are greater. The turns in the whole winding are constant, and therefore the line current increases proportionately to the short-circuit ampere-turns.

The characteristics disclosed by the curves apply generally to single-phase and polyphase transformers however the windings may be connected and for faults on the primary or secondary winding. Currents and impedances are of the same order of magnitude for similar interturn faults on either winding of a given transformer.

Line currents and phase voltages become unbalanced to a degree depending upon the extent of the winding fault and the transformer connections.

The curves illustrate clearly the reason why an initial breakdown of inter-turn insulation, involving a few turns only, fails to operate automatic protective gear, and they demonstrate that the supply can be interrupted only when sufficient turns are embraced by the fault to provide sufficient primary current to operate the protective equipment.

6.7 MAINTENANCE IN SERVICE

The subject of transformer maintenance has received only cursory attention in previous editions of this book. Perhaps this is not surprising. Transformers generally have no moving parts and there is nothing to wear out, so that there is little to be maintained. Indeed, many small transformers, particularly those installed in distribution networks, once commissioned remain in service for many years with minimal attention. These are literally examples of the 'fit and forget' philosophy. However, most transformers will operate more reliably if given some attention, and the larger the transformer and the more important its role, the greater is the justification for regular and relatively frequent attention.

The following section will identify the benefits to be gained from a regular maintenance regime and describes the procedures which can be carried out in order to achieve maximum reliability. It will deal almost exclusively with oil-filled transformers. There is very little maintenance which can be carried out on a dry-type transformer with the exception of keeping it clean and dry.

The objects in maintaining any item of plant are:

- to obtain the maximum practicable operating efficiency;
- to obtain optimum life;
- to minimise the risk of premature and unexpected failure.

In the case of a power transformer, there is very little that the operator can do which will affect operating efficiency except to ensure that the cooling equipment is functioning correctly. Obtaining optimum life and minimising risk of unexpected failure are therefore the principal objectives of transformer maintenance. Although to some extent interlinked, these are separate activities but both involve obtaining a close awareness of the transformer condition which, with the present state of the art of condition monitoring, comes principally from close monitoring of the condition of the transformer oil. Much of this section, therefore, concerns the sampling and testing of transformer oil and the information which can be obtained from this activity. It assumes an understanding of the properties of mineral oil in conjunction with cellulose insulation discussed in Section 5 of Chapter 3. Reference should also be made to BS 5730 *British Standard Code of practice for maintenance of insulating oil*. This is based on IEC 422 which is used in many countries world wide. It should be emphasised also that the content of this section is intended as a starting point. Any suggestions that it makes are not meant as a substitute for any instructions issued by the plant manufacturer, or any special requirements of the user. The object is simply to draw attention to the factors which have a bearing on the life of the transformer and its likely service reliability.

Oil sampling procedures

Monitoring of transformer oil – the taking of oil samples, which is the essential prerequisite to any maintenance – can be carried out with the minimum of plant shutdown, or even, if necessary, while the plant remains on load. Sampling of oil is a fairly common activity on the part of electrical maintenance staff. It might, therefore, appear superfluous in a volume such as this to attempt to give instruction on the taking of oil samples. Clearly, a textbook is not the best medium for the provision of such practical instruction. However, the oil sample is such an important source of information as to the transformer condition that it is essential that extreme care is taken in obtaining it in order to ensure that the information gained is not misleading and it is therefore worthwhile emphasising the most important aspects of the sampling procedure. Reference should also be made to BS 5263 *Method for sampling liquid dielectrics*. This is based on IEC publication 475 which has the same title.

In the UK the procedure is to allow the oil to drain, preferably from a valve provided solely for the purpose of taking an oil sample, into a sample bottle. In some countries, notably parts of Europe, the oil is drawn into a large purpose-made syringe. In the UK it is also practice to position the sampling valve about one metre above the tank base so that the oil drawn off is truly representative of the bulk oil in the transformer. *Figure 6.120* shows an oil sampling valve as specified by CEGB.

On initially opening the sampling valve a few litres of oil should be drawn and discarded in order to flush the valve and ensure that no contamination from around the valve is allowed to enter the sample bottle. It is usually convenient to attach a short length of flexible pipe to the valve to enable the oil to be more easily directed into a bucket for this purpose. Once this steady flushing flow has been established the valve should not be disturbed until taking of the sample is completed so as to avoid the risk of disturbing any debris from around the valve and allowing this to enter the sample. The sample bottle should then be filled to about half way, the bottle rinsed using this oil which should then be discarded before filling the bottle with the sample. The sample should be allowed to flow into the bottle down the side of the glass to minimise aeration of the sample and filling should continue until the bottle overflows, which helps to dispel any air bubbles. A small amount of the sample should then be poured off so as to leave some space for expansion. The bottle should then be tightly stoppered.

Immediately the sample has been taken the sample bottle should be inverted and held up to enable the contents to be visually examined. Any air bubbles will rise. Any bubbles which fall are bubbles of free water and there is little point in carrying out any electrical tests on a sample which contains free water. The sample should therefore be discarded and a further sample taken to establish whether the water has entered the sample inadvertently or whether this is truly representative of the transformer bulk oil. Although it is possible that the transformer will have been taken out of service for the oil sampling to take place, it is desirable that the sample is taken as soon as practicable after shutdown to obtain the best possible representation of the bulk of the oil to ascertain its general condition and to avoid the possibility that foreign materials and water, which tend to sink to the bottom, may settle and not be obtained in the sample. It is also important that the transformer oil temperature

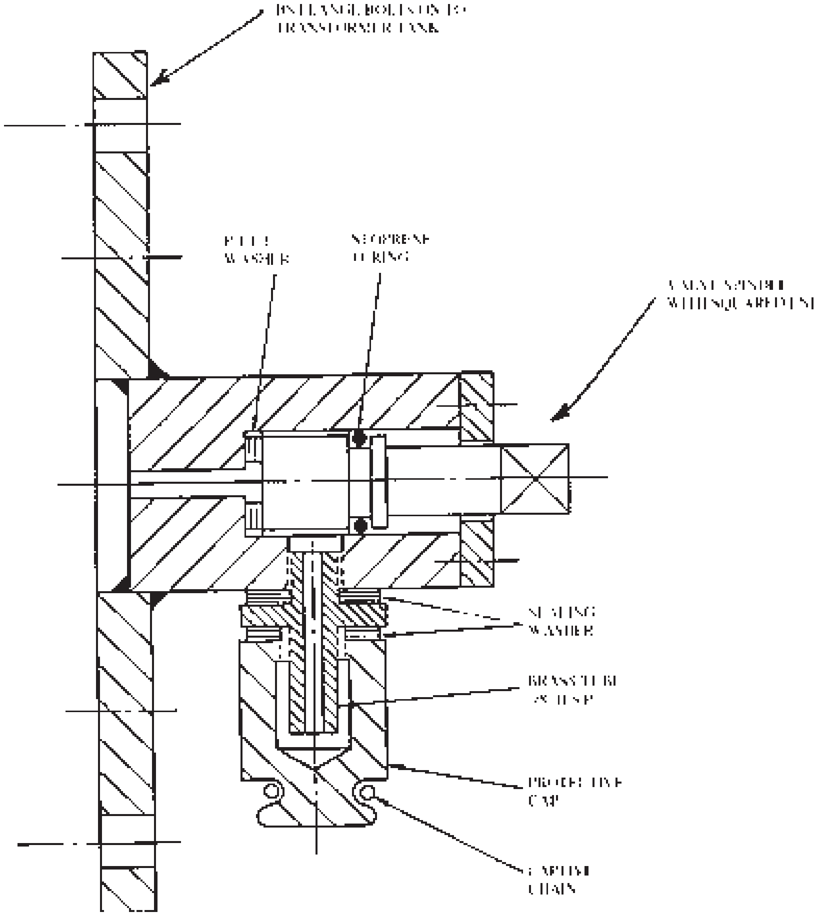


Figure 6.120 Typical oil sampling device

should be recorded at the time of taking the sample. Finally the sample should be clearly identified with the transformer details and the date of sampling.

Oil in storage

Although not strictly part of transformer maintenance procedure, it is appropriate at this time to make some comment concerning maintenance of oil in store. Oil may be stored in bulk tanks, or more usually it is stored in drums as delivered from the refinery. Bulk oil storage tanks will be fitted with a breather usually of the silica gel type. It is important that the desiccant in this should be frequently checked and maintained in a dry state. Oil stored in drums will also breathe via the bungs on the covers. To ensure that water cannot collect on the covers, to be breathed in when the contents are cooled, drums should be stored in the horizontal position with the bungs at the 3 and 9 o'clock positions. Ideally the drums should be stored indoors where temperature cycling will be minimised. If they must be stored out of doors they must be at least protected from extremes of temperature and shielded from direct sunlight. The storage period should be minimised and a system adopted which ensures that the first received is the first to be used. Even with these precautions oil in drums will have a higher water content than oil stored in bulk and this is the reason why BS 148 allows new oil delivered in drums to have a higher water content than oil delivered in bulk.

It is possible that it may be required to sample oil from store to establish its water content. This is, in fact, more important if the oil is to be used in switchgear than if it is for topping up a transformer. As explained in Section 5 of Chapter 3, transformer insulation has a high capacity for water and even a moderately large transformer with 1 or 2% water in its insulation will contain several litres of water in total. If the transformer is topped up by adding, say, 50 litres of oil from a drum having a water content of 40 ppm, the maximum permitted for delivery in drums, the total amount of water added to the transformer is:

$$\frac{40 \times 50}{10^6} \times 1000 = 2 \quad \text{cubic centimetres}$$

which is insignificant compared with the quantity of water already in the insulation and even if the oil in the drum had twice its permitted level this would still have no significant impact. This fact should not, of course, lead to slackness in storage procedures since laxity can soon lead to a serious deterioration in discipline and ultimately to accidents.

If it is required to take a sample from a bulk storage tank then the procedure is similar to that employed for a transformer. If a sample is to be taken from a drum then a glass pipette or 'thief' is used. This is of a length to enable it to reach to the bottom of the drum. *Figure 6.121* shows such a device being used to take a sample from a drum of oil. Before insertion into the drum the thief must be scrupulously clean, particularly on the outside since this could otherwise introduce contamination into the drum contents which would not be seen in the sample. To ensure that this is the case it may be wiped using a lint-free cloth of welded polypropylene or similar material. Ordinary rag or paper towelling which will shed fibres is not permitted. The thief should initially be inserted to a level to allow it to be approximately half filled and this oil used to rinse the inside. This oil is then discarded and the procedure repeated to obtain sufficient oil to rinse the sample bottle. After this the thief may be inserted to extract the sample. Once the outside of the thief has become 'wet' with the oil even greater care is necessary to ensure that it does not pick up airborne contamination. To take the sample it should be inserted with the top end closed with the thumb until it reaches the bottom of the drum. The top is then uncovered, thus admitting the sample from the bottom of the drum where any free water or contaminants are likely to be found. The sample bottle can then be filled using the same procedure as when sampling from the transformer.

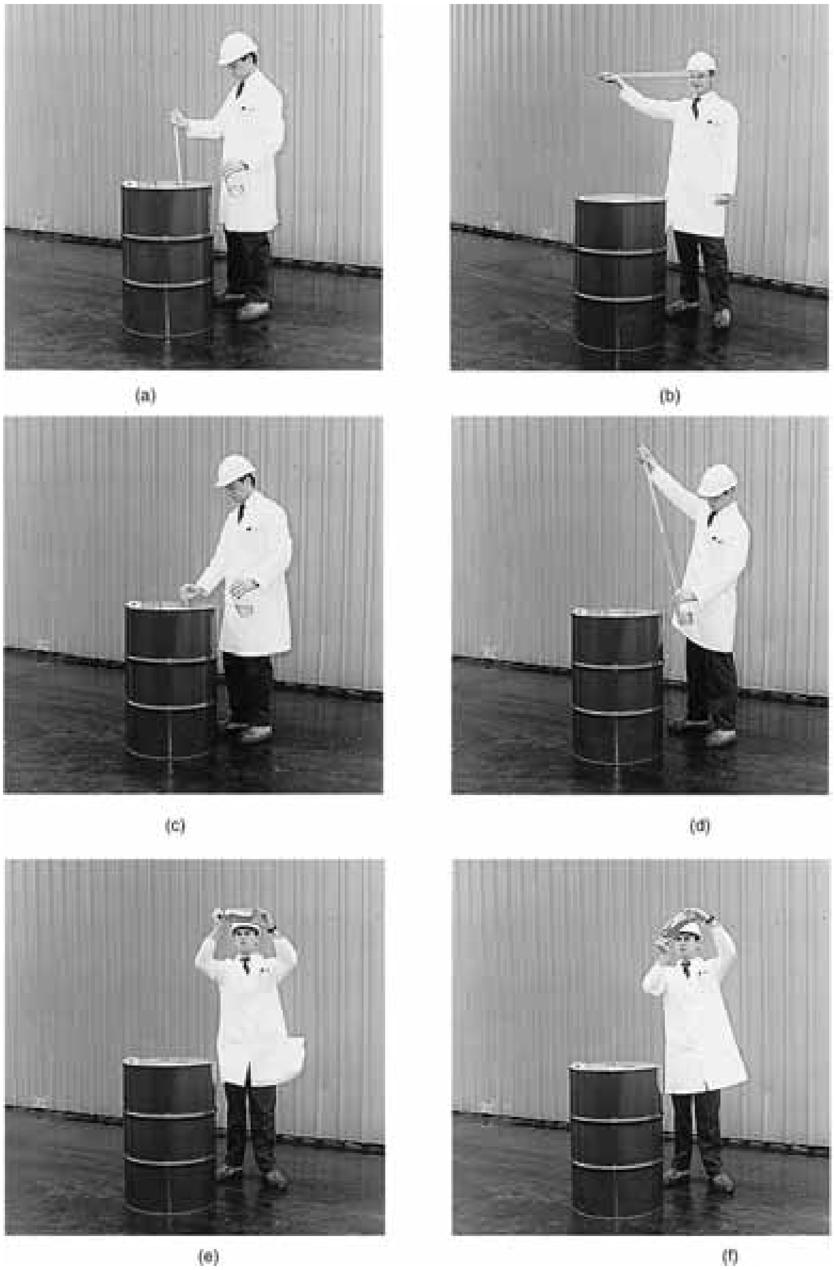


Figure 6.121 'Thief' being used to sample oil in drums (Carless Refining & Marketing Ltd)

When to take samples

The British Standard 5730 gives a varying frequency of testing related to the category of importance of the unit. For most transformers it is recommended that a sample be taken for electric strength and water content after filling or refilling, followed by a sample after one year. Subsequent to this, samples should be drawn from important transformers every two years and from transformers of lesser importance every four or six years.

These proposals should be viewed in a very flexible manner. Clearly, it is sensible to sample after filling or refilling. Beyond that, there is merit in sampling annually and tabulating the results, or plotting these graphically until a trend can be established, following this, the decision can be taken to sample more or less frequently as appropriate. CEGB had a policy of sampling generator transformers every three months. A nickel smelter in a remote part of Indonesia is known to take samples from critically important furnace transformers on a monthly basis. Obviously there will be some smaller distribution units, which, once installed, would only be sampled at a frequency to coincide with other maintenance schedules perhaps at five or six yearly intervals.

What are samples tested for

Whenever a sample is taken initially it should be examined for odour, appearance and colour and if this is a sampling carried out after filling of refilling, then it would be sensible to carry out an electrical strength test. If this sample gives any cause for suspicion that the water content is high, i.e. if there is free water present or if the oil should fail the electrical strength test, then it is desirable to determine the actual water content by carrying out a Karl Fischer test. This is described in BS 6725 (IEC 814) *Method for determination of water in liquid dielectrics by automatic coulometric Karl Fischer titration*.

As indicated in Section 5 of Chapter 3 acceptable water content depends on the age of the transformer, its voltage class and its strategic importance. Although it is always desirable that water content be maintained as low as practicable, the upper bounds of acceptability might be around 40–50 ppm at 80°C in a 132 kV transformer after some years in service. A value above this would not necessarily mean that the oil should be processed. As explained earlier, the quantity of water absorbed in the paper is quite large and it would be a slow process to attempt to remove it by drying the oil. The main priority is to find out how the level got to be so high. Has the breather charge been left in need of renewal for some considerable time? Has a valve been wrongly set so that the transformer has been open to atmosphere with the breather bypassed? For a water-cooled transformer, is there a leak of water into oil? Clearly, more frequent sampling should be introduced to ensure that any corrective measures have been successful in dealing with the situation.

Should the oil's odour or colour suggest that it may have become significantly oxidised, then an acidity check is called for. BS 5730 suggests that, except for the most important transformers, an acidity level of below 0.3 mgKOH/g is satisfactory assuming no other characteristic is unsatisfactory. Between 0.3 and 0.5 mgKOH/g it is suggested that more frequent testing should take place to ensure that the acidity does not exceed the 0.5 mgKOH/g level. Above this level the BS suggests that the oil should be replaced.

In replacing the oil, the contamination of the new oil by residual used oil in the transformer becomes a more serious risk in respect of subsequent deterioration the higher the acidity of the old oil is allowed to become. When replacing oil which is very acid it is important to allow the drained down core and windings to stand for a few hours to allow as much as possible of the old oil to drain off, and then to flush the transformer out as thoroughly as possible with clean oil before refilling.

By far the most worthwhile test of the oil sample for all important transformers is to carry out a dissolved gas analysis. The levels of hydrocarbon gases should be recorded and compared with previous values for the transformer. Any unexplained step changes should be investigated.

It may well be the case that for an older transformer which has spent a significant proportion of its life highly loaded, the gas ratios along with the previous records simply show steadily increasing levels of the lower temperature gases, methane, hydrogen and possibly some ethane indicating possible mild overheating. If this is the case and there are no sudden changes in the general trends, and provided all other characteristics of the oil are satisfactory, then no action is necessary.

Dissolved gas analysis

Introduction

Dissolved gas analysis (d.g.a.) is the most valuable and important tool available to the maintenance engineer concerned about the condition and life expectancy of transformers. Some authorities make excessive claims for its efficacy. It has its limitations. In the UK its use was pioneered from the early 1970s by CEGB in cooperation with a large transformer manufacturer. During that time some spectacular successes were achieved which saved thousands of pounds in avoidance of catastrophic failures and lost generation costs. There were also notable occasions when generator transformer failures occurred which were not predicted. It is worthwhile therefore considering the process in some depth and examining what it can achieve and what it cannot do.

The generation of gas in oil-filled equipment by disruptive discharges (sparks and arcs) and severe overheating results from the chemical reactions which occur as a result of such faults. The resultant effect of the high thermal and disruptive discharge conditions are due to the severity of the fault and the presence of other materials such as solid insulation. Solid and liquid materials are also produced, but it is the gaseous products that are of the most concern and interest. The analytical and interpretative techniques that are used differentiate between those which are due to air contamination, oxidation and partial discharge, and those from more severe thermal and electrical faults which can destroy insulation and result in costly and severe damage to the equipment.

Background

The identification and significance of gases in electrical equipment was first used to distinguish between combustible and non-combustible gases produced in transformers as long ago as the 1920s. This was carried out by applying a light to the gas collected from the sample or vent tap of the Buchholz relay.

Initially the procedure aimed to detect the presence of hydrogen, which meant that there was a 'real' fault within the transformer. Over the next 30 years the procedure was refined to enable hydrogen, acetylene and carbon monoxide to be detected, which enabled some indication of the nature of the fault to be deduced. In particular, the presence of acetylene meant that very high temperatures existed, and carbon monoxide was taken as an indication that solid insulation was involved.

The development of chromatography, mass spectrometry and infrared analytical techniques in the period 1955–1965 led to their use for analysing gases from Buchholz relays, and ultimately the realisation that by extracting these gases from an oil sample, their presence could be detected and interpreted long before the oil was saturated and the fault had developed to the stage at which free gas could be collected in the Buchholz relay.

This development coincided with the expansions of the electricity supply systems and the use of higher voltages which was taking place in several countries, including the UK, leading to increased failure rates. Analysis of gases coupled with inspection of the failed equipment led to further study of the gas evolution processes and to the appreciation of certain gas ratios as being indicative of different fault temperatures.

Theory of gas evolution

The composition of the gas produced in a fault is decided by many factors. In addition the gases which are seen in any sample taken for analysis are further influenced by factors other than those relating to the fault. The previous history of the transformer, the loading regime, the amount of insulation that it contains and the dryness of this insulation as well as the precise location of the fault are just some of these. Nevertheless, it is possible to relate certain patterns of gas evolution to temperatures existing at the fault and from a knowledge of these, along with a careful assessment of all other relevant factors, to obtain some appreciation of the nature and seriousness of the fault.

The immediate effect of the breakdown of the hydrocarbon molecules as a result of the energy of the fault is to create free radicals as indicated in *Figure 6.122*. These subsequently recombine to produce the low molecular weight hydrocarbon gases. It is this recombination process which is largely determined by the temperature, but also influenced by other conditions.

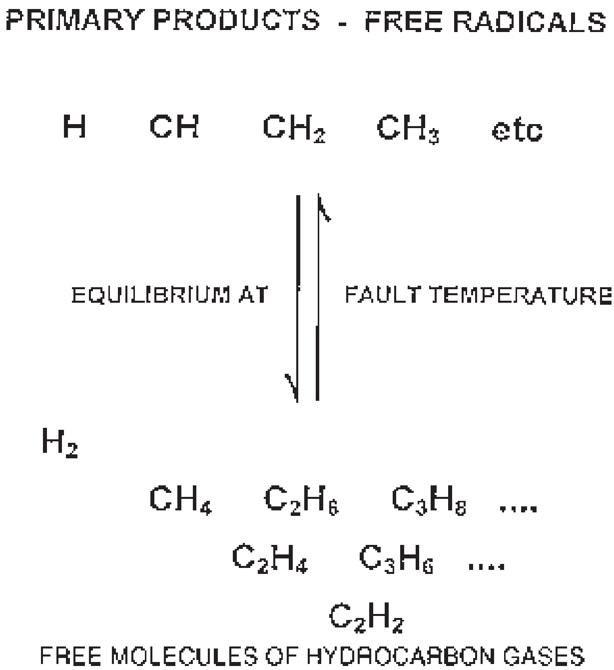


Figure 6.122 Free radicals resulting from the heating of mineral oil

The result is that the pattern of gases appearing in the oil has a form as shown in the chart of *Figure 6.123*. For the lowest temperature faults both methane and hydrogen will be generated, with the methane being predominant. As the temperature of the fault increases ethane starts to be evolved, methane is reduced, so that the ethane/methane ratio becomes predominant. At still higher temperatures the rate of ethane evolution is reduced and ethylene production commences and soon outweighs the proportion of ethane. Finally, at very high temperatures acetylene puts in an appearance and as the temperature increases still further it becomes the most predominant gas. It will be noted that no temperature scale is indicated along the axis of *Figure 6.123*, but the diagram has been subdivided into types of fault. The area indicated as including normal operating temperatures goes up to about 140°C, hot spots extend to around 250°C, and high-temperature thermal faults to about 1000°C. Peak ethylene evolution occurs at about 700°C.

A curve which frequently appears in articles dealing with the subject of dissolved gas analysis is shown in *Figure 6.124*. This shows the partial pressures exerted by the hydrocarbon gases in oil plotted on a logarithmic scale as the temperature increases and was initially published in the *Journal of the Institute of Petroleum* in a paper by W.D. Halstead in 1973 [6.8]. While this might provide a more scientifically accurate statement of the composition of the gases with temperature, since this can be shown to be proportional to

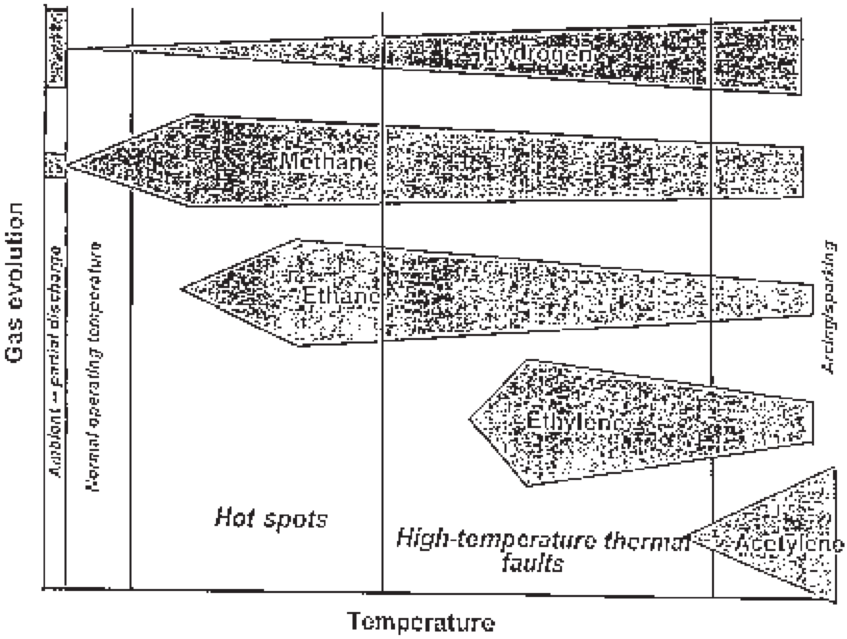


Figure 6.123 Chart of hydrocarbon gas evolution in mineral oil against temperature.

the partial pressure exerted by the gas, *Figure 6.123* conveys a more easily comprehensible picture of what is happening.

It is evident from *Figure 6.123* that the ratios of the evolved gases change at various points along the temperature scale. The ratios mentioned above were:

$$1\ \frac{\text{Methane}}{\text{Hydrogen}} \quad 2\ \frac{\text{Ethylene}}{\text{Methane}} \quad 3\ \frac{\text{Ethylene}}{\text{Ethane}} \quad 4\ \frac{\text{Acetylene}}{\text{Ethylene}}$$

These are the ones which were proposed by Messrs I. Davies and P. Burton of CEGB in 1972. For each of the ratios, if they have a value of less than unity they are given the code zero. If they are greater than unity they are given the code one. It is then possible to compile a table, shown as *Table 6.12,* which relates each likely combination of codes to a position along the temperature scale.

In 1974, after a detailed study of dissolved gas data and associated transformer faults, Mr R.R. Rogers of CEGB proposed some refinement of the ratios into bands according to their magnitudes. These are given in *Tables 6.13* and *6.14*. These have become known as Rogers ratios and are still widely used as a means of attempting to identify fault conditions from dissolved gas analysis.

Other authorities use other ratios, for example the compilers of British Standard 5800 *Guide for the interpretation of the analysis of gases in transformers*

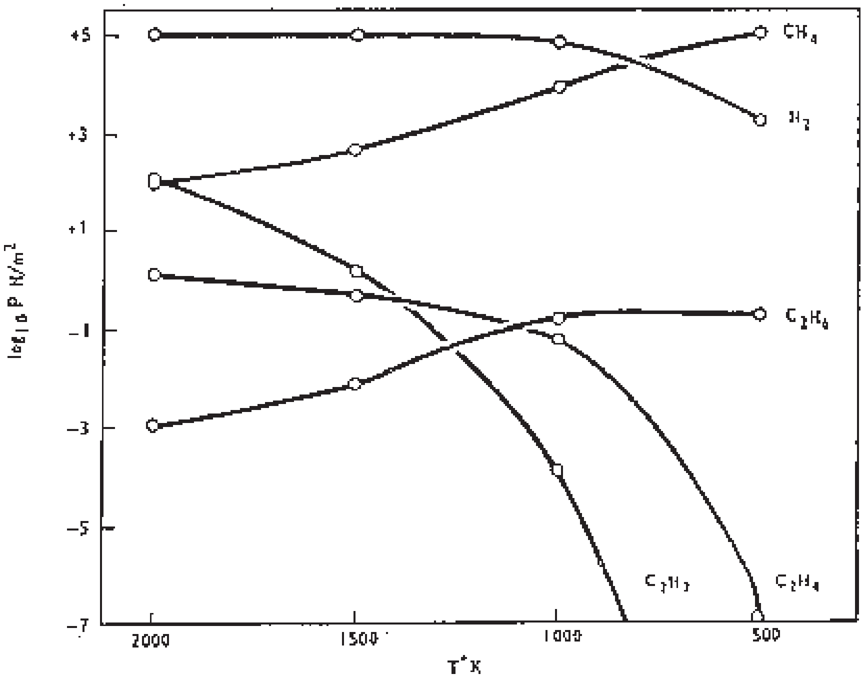


Figure 6.124 Equilibrium pressures in the system C(solid) H_2, CH_4, C_2H_4, C_2H_2, C_2H_6 total system pressure $1 \times 10^{+5}$ N/m^2

and other oil-filled electrical equipment in service (this is identical to IEC 599) believe that the diagnostic process can be simplified by the use of only three ratios, omitting that for ethane to methane. This document aims to indicate the temperatures reached, rather than categorising the faults. It then gives what it calls typical faults which would give rise to the temperatures experienced. This is reproduced as *Table 6.15*.

In none of the foregoing has mention been made of carbon monoxide and carbon dioxide levels. There is now a view that attempting to draw conclusions from the level of carbon monoxide and carbon dioxide can be very misleading. It was once considered that the only source of carbon monoxide was from overheating of cellulose (i.e. paper) insulation. However, it is now recognised that both carbon dioxide and carbon monoxide can also arise from normal oxidation of the oil, in relative proportions which differ widely in different transformers, so unless there is a very marked change in a long-established pattern of carbon monoxide and carbon dioxide evolution it is considered that it is more reliable to ignore these gases. It is further argued that serious insulation degradation only occurs in conjunction with significant overheating of metal surfaces, so such conditions will be detected by the presence of the other gases.

Table 6.12 Diagnostic interpretation of gas ratios proposed by Burton & Davies of CEGB in 1972

$\frac{CH_4}{H_2}$	$\frac{C_2H_6}{CH_4}$	$\frac{C_2H_4}{C_2H_6}$	$\frac{C_2H_2}{C_2H_4}$	*Diagnosis*
0	0	0	0	If $\frac{CH_4}{H_2} \simeq$ or $< 0.1 \longrightarrow$ Partial discharge otherwise − normal deterioration
1	0	0	0	Slight overheating − below 150°C (?)
1	1	0	0	Slight overheading − 150−200°C (?)
0	1	0	0	Slight overheading − 200−300°C (?)
0	0	1	0	General conductor overheading
1	0	1	0	Circulating currents and/or overheated joints
0	0	0	1	Flashover without power follow-through
0	1	0	1	Tapchanger selector breaking current
0	0	1	1	Arc with power follow-through − or persistent sparking

Table 6.13 Codes for gas ratios proposed by R.R. Rogers of CEGB in 1974

Gas Ratio	*Range*		*Code*
$\frac{CH_4}{H_2}$	Not greater than 0.1	($\leq$ 0.1)	5
	Between 0.1 and 1.0	($>$ 0.1, $<$ 1)	0
	Between 1.0 and 3.0	($\geq$ 1, $<$ 3)	1
	Not less than 3.0	($\geq$ 3)	2
$\frac{C_2H_6}{CH_4}$	Less than 1.0	($<$ 1)	0
	Not less than 1.0	($\geq$ 1)	1
$\frac{C_2H_4}{C_2H_6}$	Less than 1.0	($<$ 1)	0
	Between 1.0 and 3.0	($\geq$ 1, $<$ 3)	1
	Not less than 3.0	($\geq$ 3)	2
$\frac{C_2H_2}{C_2H_4}$	Less than 0.5	($<$ 0.5)	0
	Between 0.5 and 3.0	($\geq$ 0.5, $<$ 3)	1
	Not less than 3.0	($\geq$ 3)	2

Table 6.14 Diagnostic chart for Rogers codes listed in Table 6.13

$\frac{CH_4}{H_2}$	$\frac{C_2H_6}{CH_4}$	$\frac{C_2H_4}{C_2H_6}$	$\frac{C_2H_2}{C_2H_4}$	*Diagnosis*
0	0	0	0	Normal deterioration
5	0	0	0	Partial discharge
1/2	0	0	0	Slight overheating − below 150°C (?)
1/2	1	0	0	overheating − 150−200°C (?)
0	1	0	0	overheating − 200−300°C (?)
0	0	1	0	General conductor overheating
1	0	1	0	Winding circulating current, overheated joints
1	0	2	0	Core and tank circulating currents
0	0	0	1	Flashover without power follow through
0	0	1/2	1/2	Arc with power follow through
0	0	2	2	Continuous sparking to floating potential
5	0	0	1/2	Partial discharge with tracking (note CO)

Table 6.15 Fault diagnosis table reproduced from BS 5800 (IEC 559)

		Code of range of ratios			
		$\frac{C_2H_2}{C_2H_4}$	$\frac{CH_4}{H_2}$	$\frac{C_2H_4}{C_2H_6}$	
	Ratios of characteristic gases				
	< 0.1	0	1	0	
	$0.1-1$	1	0	0	
	$1-3$	1	2	1	
	> 3	2	2	2	
Case No.	Characteristic fault				Typical examples
0	No fault	0	0	0	Normal ageing
1	Partial discharges of low energy density	0 but not significant	1	0	Discharges in gas-filled cavities resulting from incomplete impregnation, or supersaturation or cavitation or high humidity
2	Partial discharges of high energy density	1	1	0	As above, but leading to tracking or perforation of solid insulation
3	Discharges of low energy (see Note 1)	$1 \rightarrow 2$	0	$1 \rightarrow 2$	Continuous sparking in oil between bad connections of different potential or to floating potential. Breakdown of oil between solid materials
4	Discharges of high energy	1	0	2	Discharges with power follow-through. Arcing − breakdown of oil between windings or coils or between coils to earth. Selector breaking current
5	Thermal fault of low temperature $< 150°C$ (see Note 2)	0	0	1	General insulated conductor overheating
6	Thermal fault of low temperature range $150°C-300°C$ (see Note 3)	0	2	0	Local overheating of the core due to concentrations of flux. Increasing hot spot temperatures; varying from small hot spots in core, shorting links in core, overheating of copper due to eddy currents, bad contacts/joints (pyrolitic carbon formation) up to core and tank circulating currents
7	Thermal fault of medium temperature range $300°C-700°C$	0	2	1	
8	Thermal fault of high temperature $> 700°C$ (see Note 4)	0	2	2	

In addition to the above, more recent research has achieved some success in detecting and measuring other products of cellulose degradation so that investigation of low-temperature overheating has been directed in this quarter. More details of this technique are given below.

Diagnosis in practice

There are those persons and organisations who see dissolved gas analysis as the answer to all transformer operating problems. This is not the case. There are occasions when it can create as many problems as it resolves.

The first word of caution is to avoid drawing any conclusions on the basis of a single sample, and by single sample is meant a sample taken at a particular point in time, because the first thing an operator must do on carrying out an analysis which suggests that a fault exists is to take a second sample and repeat the analysis. On the assumption that the repeat sample confirms the initial diagnosis, the next step is to look at the previous history of the transformer. When was the last sample taken and what was the result? Which gases have changed since that sample and to what extent?

If the transformer has been in service for a long time with no significant change in loading pattern and there is a long history from past sampling of only steadily changing gas levels, then a sudden step change should be taken seriously. Even then it is necessary to proceed with caution. Could the gases have diffused from the diverter-switch compartment of an on-load tapchanger? Has someone topped up the transformer recently using contaminated oil?

Only when all these questions have been asked and appropriate answers obtained should it be accepted that a fault exists. Following the receipt of such confirmation the next step is to consider an increased sampling frequency. If the procedure was as identified above of taking a second confirmatory sample as soon as the initial suspicion was raised, then it is likely that by the time definite confirmation of a fault has been obtained, some indication of the rate of gas evolution will have been gained, since there is likely to have been at least a day or two time lag between these two samples. The increased sampling frequency will clearly depend on both the rate of evolution and the type of fault. If the fault indicated is only modest overheating, then it is not so important to achieve rapid response than if a very high temperature, perhaps indicated by the presence of acetylene, is indicated.

When the presence of a fault has been definitely confirmed, and its development perhaps been monitored for several weeks, there comes a time when a decision must be made as to how to proceed further. Perhaps it will be decided to drain the oil and enter the tank for a visual examination. Perhaps it will be considered that dissolved gas levels are approaching saturation and danger of free gas production is a possibility. In this situation, processing of the oil, either on-line or by briefly taking the transformer out of service, is an option which may be considered.

The other important aspect to be recognised is that some hydrocarbon gases are present in the oil of most power transformers. Those which have been in service for some years and have been operated for considerable periods at or near to rated load can have levels of many tens, maybe even a hundred or more parts per million of some gases and still be healthy. Because of this, and because of the many other variable factors involved, as identified above, it is not generally possible to obtain an indication of the condition of a particular transformer, or of its life expectancy, simply by carrying out a dissolved gas analysis. The most reliable indications are those obtained when a d.g.a. history has been maintained and a step change in an established pattern is suddenly observed. Typical is the case of a large 400 kV generator transformer which had operated satisfactorily for 10 years or so. A routine three-monthly sample then revealed a sudden increase, by a factor of two or three, in ethane and ethylene levels with acetylene, which had previously been showing only 1 or 2 ppm, increased to around 10 ppm. After a repeat sample had confirmed the figures it was decided to take the transformer out of service and drain down the oil in order to gain access to the tank. Following an internal inspection it was found that a flexible connection on a main 400 kV line lead had worked loose. Since this connection was covered by about 15 mm radial thickness of paper insulation, finding the source of the problem was not easy. However, the flexible joint was repaired, the lead reinsulated and the transformer returned to service without further problems.

It is appropriate at this stage to consider some case histories in more detail.

The first of these is an example of one of the early successes achieved by CEGB. After some weeks of site commissioning runs on a large generator, its 22/400 kV generator transformer dissolved gas levels were found to be excessively high for a new transformer. These are shown in the graph, *Figure 6.125*. The actual dissolved gas figures are set out in *Table 6.16*. *Table 6.16* also gives the gas ratios as they were calculated at the time and the Rogers, 1974, ratios for comparison. It will be seen that the original ratios vary between 1010 and 0010, with the former being the most prevalent. Interpretation using *Table 6.12* would give the diagnosis ‘circulating currents and/or overheated joints’ or possibly ‘general conductor overheating’. Rogers ratios are predominantly 1020 and occasionally 0020. These would be interpreted from *Table 6.14* as ‘core and tank circulating currents’. Rogers did not envisage a 0020 pattern.

The transformer was de-tanked on site using the turbine hall crane and from a visual examination it soon became clear that the problem was associated with the core-frame and core-frame to tank insulation. The insulation had become damaged during shipment so that arcing was taking place between sections of the frame and also between frame and tank permitting circulating currents to flow through the frames and the tank. This was a relatively common problem with very large transformers at one time because of the very modest test requirements for the core insulation. The problem was eliminated by specification of higher test levels for this insulation (see Section 1 of Chapter 5). Additional insulation was inserted at the locations where arcing had been taking place, the core and coils were replaced within the tank and the transformer returned to service. *Figure 6.126* shows a graph of d.g.a. figures following the return to service and it can be seen that these are virtually nil, confirming that the repair had been successful.

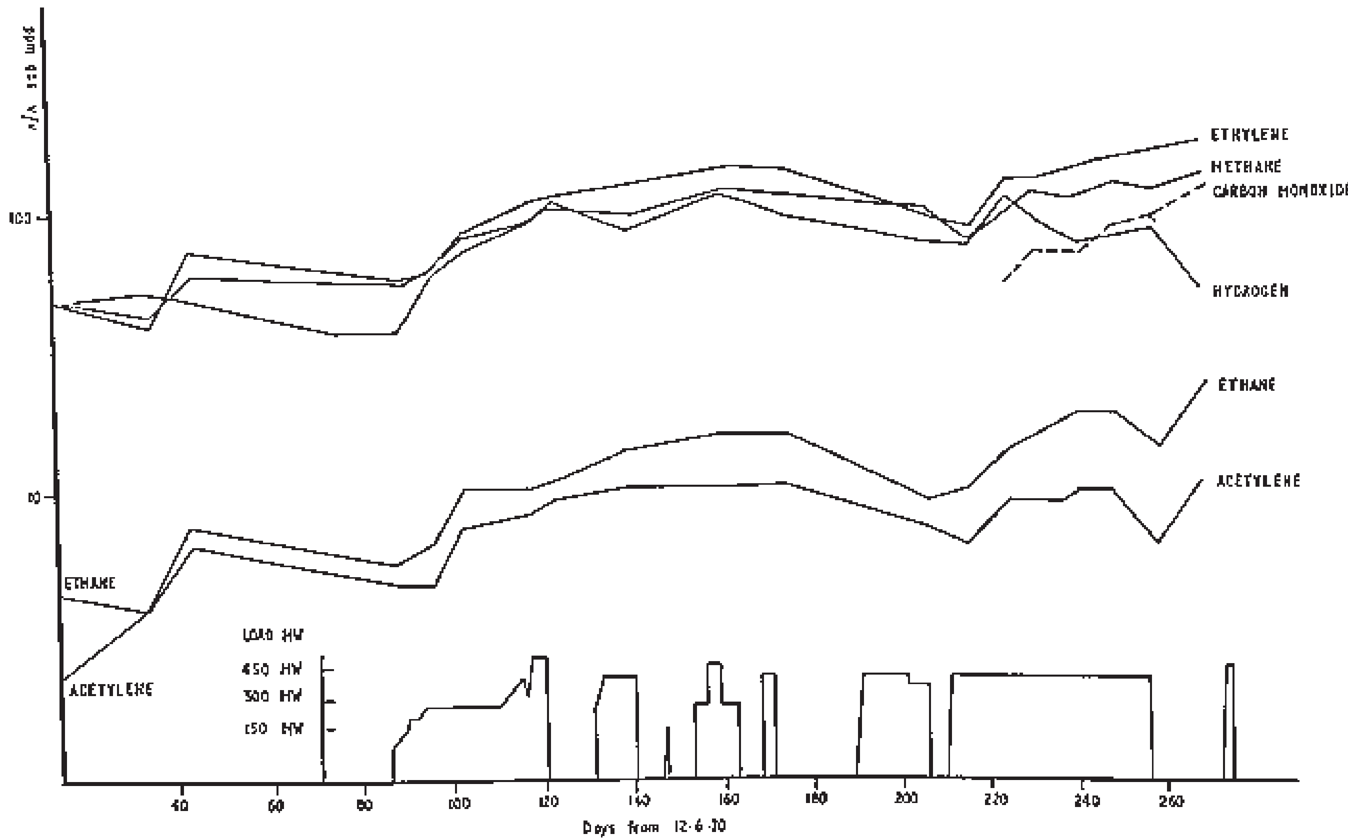


Figure 6.125 Generator transformer no. 1 dissolved gas levels on initial commissioning

Table 6.16 Levels of dissolved hydrocarbon gases (parts per million) in generator transformer 1 oil samples against time of sampling and values of gas ratios as were calculated at the time and as Roger ratios

time(days)	hydrogen	methane	ethane	ethylene	acetylene	1970 ratios				Rogers 1974 ratios			
	H_2	CH_4	C_2H_6	C_2H_4	C_2H_2	CH_4/H_2	C_2H_6/CH_4	C_2H_4/C_2H_6	C_2H_2/C_2H_4	CH_4/H_2	C_2H_6/CH_4	C_2H_4/C_2H_6	C_2H_2/C_2H_4
initial	50	50	4.5	50	5	1	0	1	0	0	0	2	0
30	40	53	4	40	4	1	0	1	0	1	0	2	0
42	60	50	8	73	7	0	0	1	0	0	0	2	0
86	57	39	6	59	5	0	0	1	0	0	0	2	0
96	65	60	7	62	5	0	0	1	0	0	0	2	0
102	81	71	10	88	8	0	0	1	0	0	0	2	0
117	92	95	10	120	9	1	0	1	0	1	0	2	0
122	115	105	12	130	10	0	0	1	0	0	0	2	0
138	85	100	14	140	11	1	0	1	0	1	0	2	0
160	120	125	18	148	11	1	0	1	0	1	0	2	0
173	95	120	18	145	11	1	0	1	0	1	0	2	0
205	75	102	9	95	8	1	0	1	0	1	0	2	0
215	73	78	10	87	7	1	0	1	0	1	0	2	0
222	112	97	14	125	9	0	0	1	0	0	0	2	0
228	93	115	15	126	9	1	0	1	0	1	0	2	0
239	74	113	20	148	10	1	0	1	0	1	0	2	0
247	80	127	20	160	10	1	0	1	0	1	0	2	0
258	84	120	15	178	7	1	0	1	0	1	0	2	0
269	50	140	23	185	11	1	0	1	0	1	0	2	0

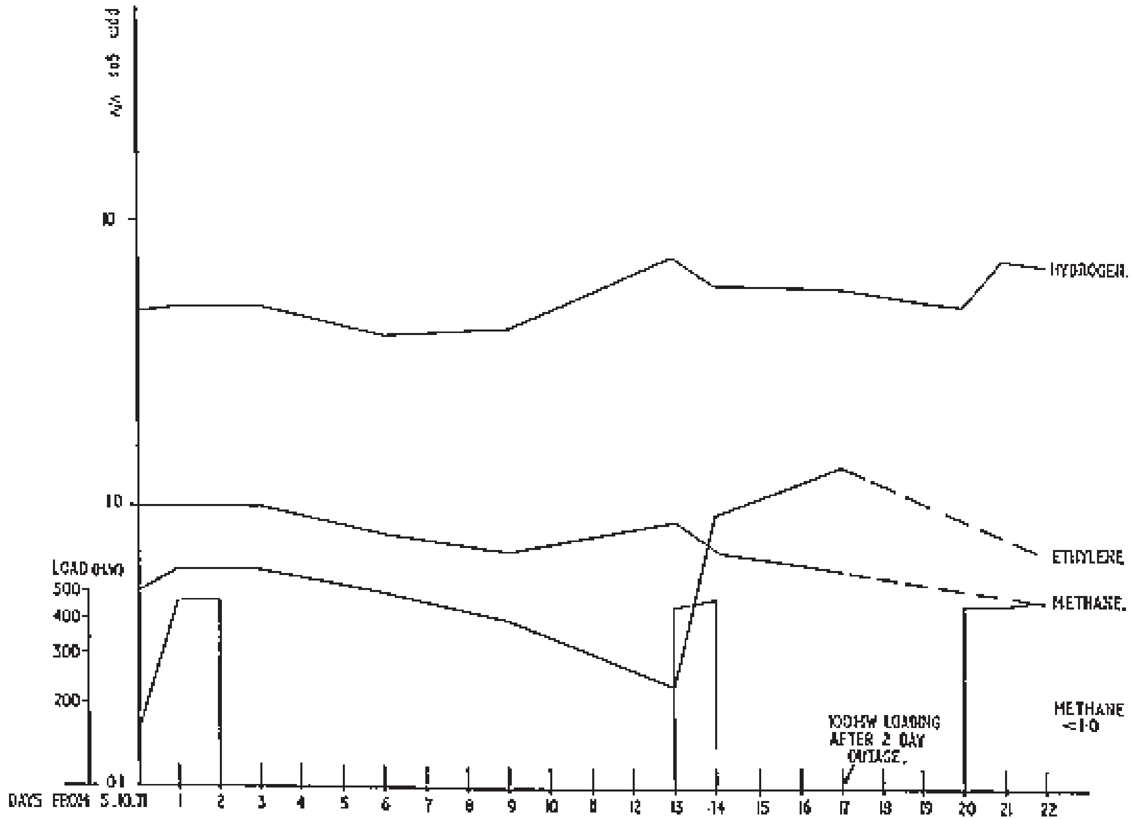


Figure 6.126 Case study no. 1 Generator transformer no. 1 dissolved gas levels after repair

The second case study might be considered less of a success in that it did not enable a fault to be pinpointed and repairs made. This is partly because there were a number of relatively minor faults taking place concurrently and partly because operations and maintenance staff had carried out a number of degassifications of the oil. Maintenance staff can sometimes be faced with a dilemma when transformer dissolved gas levels are increasing. The concern is that these might reach a level at which free gas will be released leading to Buchholz relay operation. To avoid this the strategy is to treat the oil in order to lower dissolved gas levels. This procedure unfortunately greatly confuses efforts at fault diagnosis, since although gas-in-oil levels are reduced, the gas in the insulation remains at a high level. This then diffuses into the oil until an equilibrium is reached, thus increasing gas-in-oil levels, but at rates which are not related to the fault. When attempting to obtain a diagnosis, therefore, it is always preferable not to treat the oil.

The transformer was a 19.5/300 kV generator transformer and the dissolved gas levels first gave cause for concern when the transformer had been in service for about six years and continued for a further period of some 14 years until it was finally removed from service for scrap following Buchholz relay operation. *Table 6.17* gives the dissolved gas levels over this 14 year period and indicates the timing of oil treatments. Rogers ratios are also included. During the final three years of service the generator voltage was restricted to 18.7 kV due to machine problems and it will be noted that during this period dissolved gas levels were seen to stabilise. Throughout the period in service the generator AVR was known to exhibit a control problem which resulted in generator voltage frequently exceeding 19.5 kV. It was considered that some of the transformer problems were due to overfluxing resulting from these periods of overvoltage and this was probably confirmed by the reduction in gas evolution following the reduction in machine operating voltage. It will be seen that there is no clear pattern to the Rogers ratios. Because of the complex gas evolution history of this transformer and the large amount of monitoring data which had been amassed it was decided that it might well be instructive to dismantle it for as detailed an inspection as possible before totally scrapping it. The inspection revealed that there had been several faults, some of which had probably developed earlier than others and some which probably owed their origin to the overfluxing. Among the faults identified were:

- Arcing of winding clamping-pressure adjusting screws.
- Arcing of a connection to a winding stress shield.
- Burning of core plates at their edges consistent with severe circulating currents.
- Indication of overheating of core frames and adjacent core frame insulation.

It was considered possible that these latter two faults owed some of their existence to the overfluxing incidents.

Table 6.17 Case study no. 2. Dissolved gas levels and Rogers ratios for generator transformer over period 1969–1983. Shaded bands indicate data from samples taken immediately after degassification of oil

Year	Hydrogen	Methane	Ethane	Ethylene	Acetylene	CH4/H2	C2H6/CH4	C2H4/C2H6	C2H2/C2H4
1969	120	105	15	21	16	0	0	1	1
	91	134	35	21	21	1	0	0	1
	106	119	20	21	21	1	0	1	1
	92	164	46	19	26	1	0	0	1
1970	18	17	6	0	6	0	0	0	1
	62	60	16	11	20	0	0	0	0
	76	106	25	11	25	1	0	0	1
1971	62	76	16	11	20	1	0	0	1
	107	76	17	11	25	0	0	0	1
	62	165	30	11	35	1	0	0	1
	107	194	41	20	30	1	0	0	2
	107	194	41	30	35	1	0	0	1
1972	107	208	57	30	40	1	0	0	1
	107	179	51	21	30	1	0	0	1
1973	62	194	81	31	40	2	0	0	1
	19	17	6	2	6	0	0	0	1
	49	46	6	10	11	0	0	1	2
	77	91	21	10	26	1	0	0	1
1974	93	81	21	10	26	0	0	1	1
	77	91	21	21	26	1	0	1	1
1975	77	91	21	21	20	1	0	1	1
	77	91	21	21	26	1	0	1	1
	62	91	26	31	20	1	0	1	1
	77	106	26	41	26	1	0	1	1
	93	91	21	41	30	0	0	1	1
	77	91	21	31	25	1	0	1	1
1976	93	91	21	42	25	0	0	1	1
	77	77	17	22	25	1	0	1	1
	50	34	8	22	15	0	0	0	1
1977	66	35	8	12	20	0	0	2	0
	110	77	38	32	38	0	0	2	0
	154	137	28	120	48	0	0	2	0
	97	122	28	130	54	1	0	2	0
	139	136	28	110	44	0	0	2	0
1978	109	108	22	90	30	0	0	2	1
	66	108	28	90	39	1	0	2	1
	154	37	22	71	49	0	0	1	0
	2	4	2	13	6	1	0	2	1
	79	33	8	22	30	0	0	1	0
1979	79	47	7	22	30	0	0	1	1
	94	62	12	22	44	0	0	1	1
	122	77	17	42	44	0	0	2	1
1980	79	78	17	42	39	0	0	2	1
	153	106	22	81	54	0	0	2	1
	226	120	26	90	70	0	0	2	1
	211	106	26	90	65	0	0	2	1
	137	107	26	80	65	0	0	1	1
	167	91	22	70	65	0	0	1	1
1981	95	90	26	70	54	0	0	1	1
	109	76	22	50	45	0	0	1	1
	94	76	22	50	54	0	0	1	1
	65	61	16	40	50	0	0	1	1
1982	80	61	22	40	50	0	0	1	1
	65	61	16	30	35	0	0	1	1
	95	61	22	30	45	0	0	1	1
	81	61	16	29	45	0	0	1	1
1983	66	61	16	29	40	0	0	1	1
	95	61	16	29	45	0	0	1	1
	151	105	21	99	40	0	0	2	1

This latter case study demonstrates some of the difficulties which can be experienced on some occasions when attempting to draw meaningful conclusions from d.g.a. results. Dissolved gas analysis can, at best, serve to alert an operator to the existence of a problem. There can then often be many additional problems such as whether to take the unit out of service in an effort to locate the fault by means of an in-tank inspection and, even if this decision has been taken, should the fault be buried deep within windings it will not be located from such an inspection. The next problem is then whether to go further and take the unit completely out of commission for dismantling. Most operators will, rightly, fight shy of this decision.

Gas monitors

Very occasionally it will be the case that a serious fault will be detected of a considerable magnitude. Often, despite the seriousness, there will be pressures to retain the transformer in service, perhaps until an approaching outage, or perhaps until a spare unit can be brought from another location. In these circumstances very frequent sampling will be called for and it is possible that it will be economic to install an on-line gas monitor. Such equipment can be connected into the oil circuit and arranged to take and analyse samples at, say, hourly intervals. An alarm level, either for a particular gas, or for total gas content in the sample, can be set to indicate at a remote location should this alarm level be exceeded.

One such device was developed by CEGB in conjunction with Signal Instruments of Camberley, Surrey. For some years it continued to be manufactured and marketed by Signal Instruments, although being quite costly and not, therefore, justifiable except in special circumstances, there was a very limited market so that production was discontinued in the early 1990s. It is possible, however, that the recent dramatic reduction in the cost of programmable logic controllers might result in it making its reappearance in solid-state form at some time in the future.

A more economical on-line device is the Hydran continuous gas monitor which was also developed in conjunction with CEGB. This operates on the principle that hydrogen is produced whenever there is a fault (see *Figure 6.123*). It is therefore designed only to detect the presence of hydrogen and can be set to alarm as soon as this is found in a continuous sample.

The disadvantage of this device is that it simply alarms at the presence of a particular gas. As should be evident from the above, it is not so much the presence of gas, or gases, which are indicative of a fault so much as a sudden change in the status quo. It is understood that the most modern versions of the Hydran can, in fact, be set to ignore a steady situation and only raise the alarm should a step change occur.

Certainly there are occasions when it can be beneficial to monitor a transformer with some such device which is able to warn of a very rapidly developing fault. Whenever a manual system of sampling is instituted there is a limit to the frequency at which this can be carried out. It is impractical to operate a system of taking routine samples more frequently than, say, every two or three months and a lot can happen in this interval. It is understood that the National Grid Company now specifies that all new transformers supplied for the UK 400 and 275 kV grid systems are provided with provision for installation of on-line dissolved gas monitoring devices.

Another proposal worthy of consideration and requiring the facility for easy connection of an on-line gas monitor is that all newly commissioned EHV transformers should be monitored on-line for the first three months of service.

Degradation of cellulose

Although by the late 1970s considerable progress and many successes had been achieved in CEGB using the dissolved gas analysis techniques described, one or two major catastrophic failures which had not been predicted had occurred and these underlined one of the weaknesses of the dissolved gas analysis approach. One of the problems is that at very low levels of overheating, which are nonetheless serious enough to result in significant shortening of life expectancy, the volumes of hydrocarbon gases produced are so low that it is difficult to measure their concentration in the oil with any accuracy.

It was therefore felt that a more precise and sensitive method of detecting paper degradation was required. It was against this background that the work described below was initiated. The information is taken from a paper presented to CIGRE at its August/September meeting in 1984 by Messrs P. J. Burton, J. Graham, A. C. Hall, J. A. Laver and A. J. Oliver of CEGB [6.9]. The method developed is based on the analysis of the oil for compounds that are produced exclusively by thermal degradation of paper at temperatures as low as 110°C. The intention was that the procedure should be used in conjunction with dissolved gas analysis rather than independently. That is, reliance should be placed on normal d.g.a. techniques to raise the alarm that a possible fault condition exists, but the new technique should then be applied to obtain more information regarding the nature and magnitude of the fault.

Oil samples are taken as for the d.g.a. procedure but are then mixed with methanol. A certain quantity of the compounds sought then become dissolved in the methanol at concentrations determined by the equilibrium levels with the oil (a similar process to the oil/water/paper equilibrium situation previously described). The methanol and its solutes are then injected into a High Performance Liquid Chromatograph (HPLC) for separation and measurement of the individual compounds. A typical chromatogram is shown in *Figure 6.127*.

The main reason for using the methanol extraction stage is to avoid those constituents of the oil which would crowd the chromatograph making the detection of the compounds being investigated more difficult.

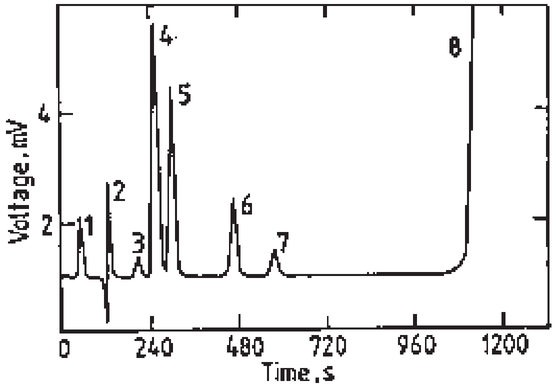


Figure 6.127 Liquid chromatogram showing separation of paper degradation products extracted from oil

Column C_{18} alkane bonded to silica	Peaks
Particle size: 10 μm	1 2furoic acid
Length 300 mm	2 solvent front
Mobile phase: 20% methanol in water to 100% methanol	3 5hydroxy methyl 2furfuraldehyde
Flow rate : 0.025 ml/s	4 2furfuryl alcohol
Detector : UV216 nm	5 2furfuraldehyde
Sample : 15μl methanol extract	6 2acetyl furan
	7 5methyl2furfuraldehyde
	8 oil compounds soluble in methanol

The paper degradation products identified are also listed in *Figure 6.127*. Of these compounds, 2-furfuraldehyde is the most common product detected from transformers in service.

Following the development of this method many samples of oil from transformers in service have been analysed for fufuraldehyde. In one particular 22/400 kV generator transformer, it was noted that the dissolved ethane and methane concentrations were increasing fairly rapidly indicating that an overheating fault existed having a temperature within the range 150–200°C. The furfuraldehyde concentration also increased over the same period of 16 weeks from about 0.7 to 1.7 mg/l suggesting that paper as well as oil was being overheated. The transformer eventually failed.

Investigations into the failure revealed that the A and B phase windings were loose, probably as a result of a fault on the transmission system and that the transformer tripped due to an interturn fault on the B phase LV winding. Paper insulation had been overheated confirming the conclusions drawn from the furfuraldehyde measurements.

Confidence is now growing in the use of this method of detecting paper degradation. However, there are also problems similar to those identified with d.g.a. There is no such thing as a norm for furfuraldehyde level in a healthy transformer, so that it is not possible, as some authorities might have hoped, to carry out general measurements of furfuraldehyde levels throughout transformer populations to identify those for which the insulation is prematurely ageing. There is no reliable way of differentiating between a large mass of paper which is just slightly degraded and a localised area for which degradation is seriously advanced. It is also the case that if a short-term overload causes overheating and significant ageing, with associated furfuraldehyde production, and then this is followed by a period of normal loading without overheating, the furfuraldehyde will be absorbed into the mass of the paper, so that the levels in the oil will appear little different from normal. Once again, as in the case of d.g.a., it is observation over a period and the detection of step changes which can be regarded as indicative of a fault condition.

Dissolved gas analysis during works testing

It should be recognised, of course, that the value of d.g.a. as a diagnostic tool need not be restricted to transformers that are in service. D.g.a. can serve a very useful function during works testing.

Utilities are becoming increasingly conscious of the fact that a few hours in works-testing is a very limited time in which to demonstrate that a large transformer will be suitable for 30 or more years' satisfactory service (see also Section 3 of Chapter 5). In addition, specifications are tending to allow higher operating temperatures and, although these in theory still allow margins above the average values which can be measured on test for hot spots, the customer has no guarantees that there will not be hot spots which exceed this allowance. There is also a tendency for transformer manufacturers to shorten the overall times for temperature rise tests by reducing the cooling of a forced-cooled unit during the initial phase of the test, thereby reducing further the likelihood of some faults being brought to light. As a counter to this many users are specifying that the temperature rise test or, perhaps more correctly, load-current run should be continued for 24 hours. On this timescale it is possible to obtain meaningful d.g.a. figures from oil samples taken before and after this load-current run.

It is not normally considered practicable to set any acceptance/rejection level on d.g.a. figures but analysis of the oil samples will not only clearly show the presence of any more significant fault, but can also be expected to reveal the presence of modest overheating of the insulation which would affect the transformer's overall life expectancy.

Of course, one criticism of a short-circuit temperature rise test is that the core flux density is low and consequently leakage fluxes which could give rise to overheating in service will be very much reduced. The CEGB response to this was to specify a prolonged overvoltage run, equivalent to about 8.3% overfluxing for three hours. This was considered long enough to produce detectable gas levels in the oil should there be any significant overheating resulting from leakage fluxes.

Many manufacturers, of course, recognise the benefits of identifying incipient faults during works testing rather than having these possibly damage their reputations by coming to light in service and so advocate the use of d.g.a. as an aid to assessing performance during works tests. The two case studies which follow were described in a paper presented to the IEEE Power Engineering Society summer meeting in July 1981 by the Westinghouse Electric Corporation [6.10]. Both units tested were of the shell type.

The first case was a three-phase transformer with on-load tapchanger. *Table 6.18* shows d.g.a. results at the end of the factory temperature rise test. It is assumed that an oil sample would also have been tested before the temperature rise test but no figures are given. Being a new transformer newly filled and processed it must be assumed that the initial gas levels were very low. Even without taking ratios it is clear from the ethylene level that severe overheating is taking place. In addition, the presence of any acetylene in a new transformer should always be regarded as indicative of a fault. The paper reports that investigation revealed the overheating to be due to the effect of leakage fluxes. After taking corrective measures a repeat of the temperature rise test showed that the problem had been resolved.

Table 6.18 Dissolved gas analysis used during works testing: case study no. 1 from paper presented at IEEE Summer Meeting, 1981

	CH_4	C_2H_6	C_2H_4	C_2H_2	H_2	CO	CO_2
After temperature test	184	32	243	10	101	61	298
After correction	0	0	0	0	0	35	168

Diagnosis: stray flux heating in steelwork

The second reported case was that of a furnace transformer with a very high LV rated current. The LV leads and connections were made from large section copper bar with bolted joints. *Table 6.19* shows the d.g.a. results following the temperature rise test. Hydrocarbon gas levels are, in reality, quite modest. It is very unusual to find no hydrogen present at all; however, once again, in a newly processed transformer none of the gas levels should be expected to exceed a few parts per million. Certainly the methane and ethane figures must be taken seriously, but the very low ethylene suggests that on this occasion any overheating is quite modest. The paper reports that the tightness of all bolted joints was checked and although none were found to be loose, it proved possible to tighten some by a further quarter to half turn. A thorough inspection of the transformer revealed no other fault. That the source of the problem had indeed been found was proved by repeating the temperature rise test without the production of any hydrocarbon gases.

Table 6.19 Dissolved gas analysis during works testing: case study no. 2 from paper presented at IEEE Summer Meeting, 1981

	CH_4	C_2H_6	C_2H_4	C_2H_2	H_2	CO	CO_2
After temperature test	57	40	4	0	0	72	203
After correction	0	0	0	0	0	55	168

Diagnosis: overheating bolted joints in LV lead

Establishment of norms

Most authorities experienced in the use of d.g.a. for hydrocarbon gases and for cellulose degradation products are emphatic in the view that it is not possible to identify 'norms' for healthy transformers for the reasons given above and that it is change in the status quo which is the clearest indication of a transformer fault. However, many transformer users feel that there ought to be norms and there are authorities who have endeavoured to provide these. The American IEEE in their codes for interpretation of dissolved gas levels make reference to norms.

In the UK the organisation EA Technology's Dr M.K. Domun has studied and collated oil analysis data from around 500 transformers, mainly of 132 kV, for many years and as a result of this work has published figures in a paper presented to an IEE Conference on Dielectric Materials, Measurements and Applications in September 1992 [6.11] as 'optimal values' for transformers which have been on load for a lengthy period and which are considered to be in a 'healthy' condition. These are listed in *Table 6.20*.

Table 6.20 M.K. Domun's norms for dissolved gas levels in system transformers

Hydrogen	20 ppm
Methane	10 ppm
Ethane	10 ppm
Ethylene	10 ppm
Acetylene	1 ppm
Carbon dioxide	5000 ppm
Carbon monoxide	100 ppm
Acidity	0.08 mgKOH/g
Moisture	25 ppm (no temperature quoted)
Electric strength	27 kV
Furfuraldehyde	2 mg/l

Dr Domun stresses that there is a wide variation between individual units and says that the above figures were chosen on the basis of the 50% rule, i.e. at least 50% of the samples conform to the values of these parameters.

CEGB experience is of large generator transformers which are operated at high loadings for long periods, unlike the system transformers studied by Dr Domun, and many of these are operating satisfactorily with hydrocarbon gas levels considerably higher than the values given in *Table 6.20*.

Other monitoring systems

Put into the simplest terms it can be said that transformers have three basic failure modes:

- They can suffer insulation failure leading to electrical breakdown between internal parts.
- They can fail due to severe internal overheating.
- They can suffer mechanical failure due to their inability to withstand the effects of a close-up external fault.

It is the first two of these modes which are truly 'faults' for which dissolved gas analysis can be of assistance in providing an indication of incipient breakdown before this has reached the catastrophic stage. But it is the third which represents 'end of life' failure. When paper insulation is severely degraded it loses its mechanical strength but nevertheless much of the dielectric strength of the paper/oil combination is retained so that in a transformer of which the insulation has aged to the extent of approaching the end of its useful life, there is no immediate failure and the transformer will continue to operate satisfactorily until it receives a 'shock' mechanical loading due to some external factor such as a system fault relatively close to its terminals. Ideally a user would like to replace his transformer just before it is due to fail in this way. If he replaces it several years before it is due to fail he has not obtained maximum use and there will be an economic 'cost'. If he defers replacement until failure has actually occurred he is involved in the high costs of an unscheduled outage and the need to find a replacement on an urgent basis, and possibly even some consequential damage costs.

Consideration of this problem has engaged researchers for some years; to find a system of knowing just when insulation has reached the point when it no longer has sufficient strength to meet the mechanical demands placed upon it. It was hoped at the early stages of developing furfuraldehyde assessment that this might be linked to the absolute level of paper degradation and thus provide the means that were sought, but there are problems in attempting to derive absolute indications from furfuraldehyde in exactly the same way as there are from the hydrocarbon gases. Transformers vary so considerably in their relative insulation volumes, oil content, water content and acidity as well as loading patterns, and all these factors influence furfuraldehyde levels. In addition, the degradation of a fairly small localised area of insulation in the vicinity of a hot spot can be just as terminal as degradation of far greater extent in a design which has seen extensive service but which does not have significant hot spots The former, however, will generate a far smaller quantity of furfuraldehyde making it much more likely to go undetected. As indicated in Chapter 3, the properties of paper insulation depend on those of the long chain cellulose molecules of which it is made up. Deterioration of its mechanical properties is brought about by decomposition of these long chain molecules, and early researchers used tensile strength as a measure of remanent life. Current practice is to measure degree of polymerisation (DP) which is an indication of the number 'links' in the long chain cellulose molecules. This starts at about 1100–1200 for new material but drops rapidly during the drying and processing stage of the transformer to around 850–900 which might be taken as a typical starting point for a new transformer. End of life is reached when DP has dropped to about 250 and the paper loses its remaining strength suddenly at about half of its original value.

There have been suggestions that by entering the transformer and taking samples of the insulation for measurement of DP, the remanent life of the insulation could be estimated. The problem, of course, is that any insulation which is sufficiently accessible to sample will not be representative of the more critical insulation in the vicinity of the hot spot. One way of overcoming this would be to place an insulation sample in the hottest oil at the time of commissioning the transformer and to further heat this by means of a heater coil supplied from a current transformer placed in one of the winding leads in the same way as for a thermal image winding temperature indicator (see Section 8 of Chapter 4). The difficulty is that the hot-spot temperature cannot be determined with sufficient accuracy to make this exercise worthwhile. The problem remains, therefore, that determination of imminent end of life must be based on little more than guesswork.

Another approach thought by a number of researchers to have promise is based on the detection of movement within the windings in response to impressed low-voltage impulses. As insulation ages shrinkage occurs so that, while windings are initially in a state of axial compression due to the manufacturing clamping forces, as end of life is approached the effect of shrinkage will create a degree of slackness. The slackness, of itself, can accelerate the onset of failure of a transformer already weakened by the low mechanical strength of its insulation, since it will permit winding displacement and, as explained in Section 7 of Chapter 4, the axial forces on the transformer windings under high through-fault currents are increased if there is already some initial displacement. Most of the methods employed require the transformer to be taken entirely off-line so as to avoid the presence of an external circuit making the difficult task of detection of the impulse currents and the small changes in them even more difficult. Other systems have attempted to detect winding vibration produced by the impulses, using acoustic sensors. Another technique is based on the fact that the slight change in winding inductance and capacitance values will result in changes to natural resonance frequencies. The difficulty with all of these efforts is in relating the measured parameters to transformer condition and the risk of failure. Accurate measurement of the selected parameter is itself difficult enough but making this final step is many times more so and it is unlikely that such methods will achieve meaningful results in the foreseeable future so that meanwhile the guesswork must continue.

Failures and their causes

In the foregoing paragraphs there has been a general discussion of the mechanisms of transformer failure. Previous editions of this volume have included a more specific catalogue of the ways in which transformers have failed in service. Such an approach was reasonable in the earliest editions, since transformer design and manufacture was developing rapidly and those involved in the process were going through a phase of gaining a large amount of experience with regard to what could be done and what could not. Hopefully, more than 70 years after the publication of the first edition, this experience has been fully assimilated, failure rates have been reduced significantly and to simply include a list of failures which have occurred over the past 20 years is likely to teach very little. Designs have changed and a transformer built today will have many different features from one made 20 years ago, although it might appear superficially the same. For example, in earlier editions failure of core-bolt insulation was identified as a common fault. For a purchaser to use this knowledge at the present time to specify the quality of core-bolt insulation, or even to insist that bolted cores should be avoided, would be superfluous, since small and medium-sized transformers have used boltless cores for many years and core bolts are now avoided in even the largest cores.

This is not to say that failures will cease to happen. Relatively recently, in the early 1970s, CEGB noted disturbingly high failure rates in large generator transformers. (This has also been discussed in Section 3 of Chapter 5.) There were a number of reasons for this but significant among these was the large step increase in unit sizes as generator ratings were rapidly increased in the UK from around 120 MW to 500 and 660 MW. Failure rates were reduced once more in the 1980s by a combination of more extensive testing, improved QA during manufacture, moving to single-phase units rather than three phase, which had the effect of removing the severe limitations which the latter had imposed on transport weights, thus reducing the loadings imposed on the basic materials, and also by adopting a procedure whereby designs which had been proven by service were repeated, rather than accepting a process of almost continual innovation.

This latter strategy was controversial, since limiting innovation can be construed as preventing manufacturers using their skills to increase their competitiveness. However, the same accusation can be levelled at the practice referred to earlier of listing previous failures and their causes, since there is an inference that if such a way of doing something has caused a failure in the past, then this should always be avoided in the future regardless of the availability of improved materials and better methods of performing design calculations, and this can lead to very restrictive thinking. It can also result in purchasers' specifications becoming very proscriptive. This is a criticism which was often made of the UK Electricity Supply Industries' Specification BEBS T2 (1966), and indeed this document identifies many design and construction features which it considers unacceptable, usually because they have caused failure at some time in the past.

Now the move is towards specifications which allow manufacturers to utilise their own design skills. But if they are to be given this freedom, specifications must also call for adequate testing and they must also tell manufacturers exactly how the transformer is to be operated. Section 1 of Chapter 8 deals with the specification of technical requirements and it is hoped that this will enable prospective purchasers to identify all those operational features which have a bearing on how a transformer should be designed and manufactured. The reasons why these particular features are relevant should, of course, be apparent from elsewhere within the pages of this book.

Clearly, not all transformer failures are the fault of the designer or manufacturer. Operation and maintenance must also have an impact as it is hoped will be appreciated from a study of the earlier part of this chapter. Although maintenance requirements are few, users must regularly monitor the condition of their transformer and, if they seek high reliability, they must ensure that three fundamental requirements are observed:

- breather systems must be adequately maintained so that water content is kept at the lowest practicable level;
- the transformer must be adequately cooled at all times, any overloading maintained within permitted limits and action taken on any indications of possible overheating;
- the transformer must not be subjected to excessive overvoltages.

One of the most detailed international studies of transformer failures was carried out by a CIGRE Working Group in 1978. It was reported in *Electra* number 88, dated May 1983 [6.12]. Input was received from 13 countries relating to all types of transformers having HV voltages from 72 to 765 kV. The analysis took account of more than 1000 failures occurring between 1968 and 1978, relating to a total population of more than 47 000 unit years. The transformers varied from 'just entered service' to 'aged 20 years'. Nearly half were aged between 10 and 20 years. They were categorised into power station transformers, substation transformers and autotransformers and were further subdivided into those with on-load tapchangers (OLTC) and those without. The main purpose of the survey was to establish reliability figures, but those responding to the questionnaires were also asked to categorise the reasons for failure. The overall failure rate was concluded to be 2% and the breakdown into voltage classes showed that the figure was higher, up to 3%, for the 300–700 kV voltage class. Figures for the greater than 700 kV class were left out of the main report since too few statistics were reported. These were covered in an appendix in which it was reported that the failure rate was about 7%.

Figure 6.128(a), reproduced from the report, shows the causes of failure for the largest group, covering over 31 000 unit years. These are substation transformers with on-load tapchangers, and the pattern is similar for other groups. The histogram gives the presumed cause of failure, the component involved and the type of failure. The quantities also indicate the outage time involved, classified as either less than one day, 1–30 days or greater than 30 days. The most significant features to emerge are that the on-load tapchanger was the component most frequently involved, perhaps not too surprising since this is the only component of the transformer which has moving parts; with winding faults less than half as frequent but still the second most likely component to fail. For all groups the magnetic circuit has the lowest reported failure rate, this despite the fact that the statistics refer to transformers in service between 1968 and 1978 when the use of bolted cores was standard practice. Although design and manufacturing errors were reported as by far the most likely cause of failure, it should be noted that incorrect maintenance figures quite prominently in this list of causes. (It must be remembered that this information has been provided by the transformer operators.)

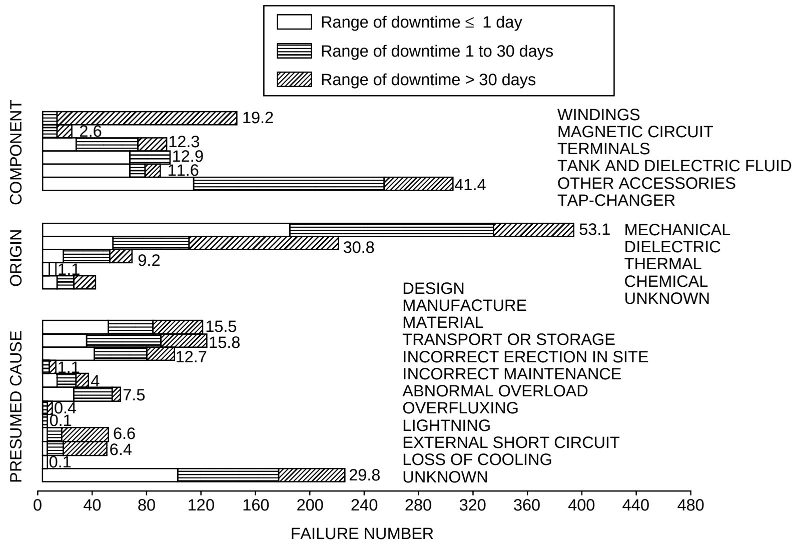


Figure 6.128a Substation transformers. Failures with forced and scheduled outage. Units with on-load tapchanger. Population: 31031 Unit-years

Figure 6.128(b) gives the reported data for the equivalent group of power station transformers, namely those with on-load tapchangers. This is a very much smaller group, covering only just over 2300 unit years so the figures must be correspondingly less reliable. The largely similar pattern is nevertheless evident, except that terminals now become the most likely component to fail, equally with windings. This probably reflects the fact that power

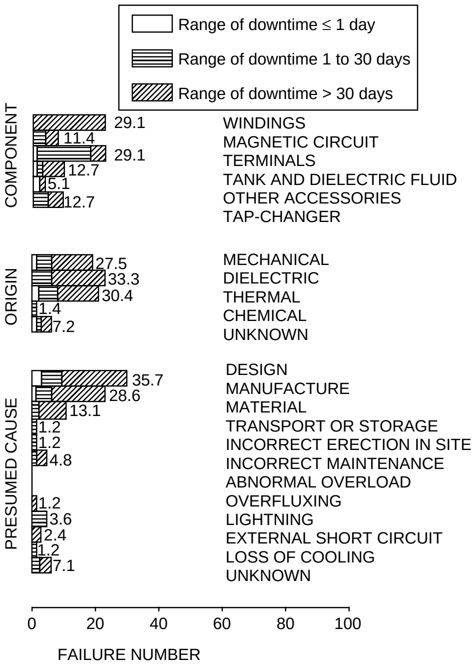


Figure 6.128b Power station transformers. Failures with forced and scheduled outage. Units with on-load tapchanger. Population: 2335 Unit-years

station transformers tend to run more fully loaded so that components such as terminals will be more highly stressed. What is surprising is that terminal failures almost invariably resulted in outages exceeding one day and a significant proportion of outages exceeded 30 days so these must have been more serious than simply requiring changing of a bushing. This does emphasise the importance of paying proper attention to the selection and installation of these components and of ensuring that connections are correctly made and checked during maintenance. The very much lower ranking of tapchanger-related faults probably reflects the fact that on generator transformers these operate on manual control and perform far fewer operations than those of substation transformers which are under automatic control.

6.8 OPERATION UNDER ABNORMAL CONDITIONS

By definition, according to IEC 76, 'normal' service conditions for a power transformer are at an altitude of not greater than 1000 m above sea level, within an ambient temperature range of −25 to +40°C, subjected to a wave shape which is approximately sinusoidal, a three-phase supply which is approximately symmetrical and within an environment which does not require special provision on account of pollution and is not exposed to seismic disturbance. The inference, then, is that ‘abnormal’ means any conditions which fall outside these boundaries. Some ‘abnormalities’ are, however, more likely to be encountered in practice than others and, in this section, abnormal will be taken to mean certain operating conditions which differ from those identified on the transformer nameplate, namely:

- at other than rated power;
- at ambient temperatures which may not conform to the averages set out in IEC 76;
- at other than rated frequency;
- at other than rated voltage;
- at unbalanced loading.

It is also increasingly common for transformers to be operated with wave shapes which are not sinusoidal because of the large amount of equipment now installed which utilises thyristors or other semiconductor devices which generate high levels of harmonics. Although such high levels of harmonics constitute abnormal operating conditions in accordance with the above definition, the problem is one which is particularly associated with rectifier transformers and is therefore considered in Section 12 of Chapter 7 which covers these in detail. Seismic withstand requirements are now also occasionally included in specifications for transformers supplying strategically essential systems, for example emergency reactor cooling supplies for nuclear power stations. Transformers are normally built with a high degree of ruggedness in order to withstand forces occurring on short-circuit, as explained in Section 7 of Chapter 4, so compliance with seismic requirements mainly involves firmly anchoring the unit down and bracing the core to withstand the lateral seismic forces. No generally accepted rules have, as yet, emerged for the provision of measures to cater for these forces and it is not therefore proposed to discuss this subject in greater detail.

The first two of the conditions listed above are the ones which are most frequently encountered in practice and they are, of course, interrelated. Transformers are rarely required to operate continuously at near constant load and in the short to medium term ambients may differ significantly from the annual averages on which IEC 76 ratings are based. Generally users recognise that it is uneconomic to rate a transformer on the basis of the peak loading which only occurs for limited periods each day and, in addition, in temperate climates where lighting and heating loads cause winter loading peaks to be very much higher than those arising during the summer months, it is usually considered desirable to expect to obtain a degree of overloading capability during periods of low ambient temperature. Hence it is necessary to find a means of assessing the extent to which recurring loads over and above the IEC rating might be permitted and of converting a cyclic loading pattern into an equivalent continuous rating, or the extent of overload which a temporary reduction in ambient might allow.

Operation at other than rated load or other than IEC ambients

Operation at other than rated load will result in hot-spot temperature rises differing from those corresponding to rated conditions and, as explained in Section 5 of Chapter 4, rated temperature rise is based on a hot-spot temperature of 98°C with a 20°C ambient. This hot-spot temperature is considered to result in a rate of ageing which will provide a satisfactory life expectancy. It has already been stressed in the earlier chapter, and it is worth stressing again, that there is no 'correct' value of hot-spot temperature. The value of 98°C has been selected as a result of testing in laboratory conditions and any attempt to draw too significant a conclusion as to true life expectancy from such laboratory testing must be avoided because of the many other factors which also ultimately affect service life. Consequently other values of hot-spot temperature must be equally tenable and other ratings besides the IEC rating must be equally permissible, particularly if it is anticipated that these ratings will not be required to be delivered continuously and if it is recognised that 20°C may not always be representative of many ambients in which IEC rated transformers are required to operate. The question then is to decide what variation from 98°C should be permitted.

To do this it is necessary to revisit the conclusions concerning insulation ageing which were discussed in Section 5 of Chapter 4. These were that for those periods for which the hot-spot temperature is above that corresponding to normal ageing, insulation life is being used up at faster than the rate corresponding to normal life expectancy. In order to obtain normal life expectancy, therefore, there must be balancing periods during which insulation life is being used up less rapidly. Expressed in quantitative terms the time required for insulation to reach its end of life condition is given by the Arrhenius law of chemical reaction rate:

$$L = e^{\alpha+\frac{\beta}{T}}$$

where L = the time for the reaction to reach a given stage, but which might in this case be defined as end of life
T = the absolute temperature
and α and β are constants.

Within a limited range of temperatures this can be approximated to the simpler Montsinger relationship:

$$L = e^{-p\theta}$$

where p is a constant
θ = the temperature in degrees Celsius.

Investigators have not always agreed on the criteria for which L is representative of end of life, but for the purposes of this evaluation this is not relevant and of more significance is the *rate of ageing*. This is the inverse of the lifetime, that is:

$$\nu = Me^{p\theta}$$

where M is a constant which is dependent on many factors but principally moisture content of the insulation and availability of oxygen. Additionally the presence of certain additives such as those used for the production of thermally upgraded paper (see Section 4 of Chapter 3) can have a significant effect on its value. Most important, however, is the fact that the coefficient of temperature variation p can be generally regarded as a constant over the temperature range 80–140°C and it is widely agreed that its value is such that the rate of ageing doubles for every 6 K increase in temperature for most of the materials currently used in transformer insulation.

Relative ageing rate

If 98°C is then taken as the temperature at which normal ageing rate occurs, then the relative ageing rate at any other temperature θ_h is given by the expression:

$$V = \frac{\text{ageing rate at } \theta_h}{\text{ageing rate at } 98^\circ C}$$
$$= 2^{(\theta_h - 98)/6} \qquad (6.58)$$

This expression may be rewritten in terms of a power of 10 to give:

$$V = 10^{(\theta_h - 98)/19.93} \qquad (6.59)$$

This is represented in *Figure 6.129* and by *Table 6.21*.

Example. 10 hours at 104°C and 14 hours at 86°C would use $(10 \times 2) + (14 \times 0.25) = 23.5$ hours life used in 24 hours operation.

Table 6.21

θ_c	*Relative rate of using life*
80	0.125
86	0.25
92	0.5
98	1.0
104	2.0
110	4.0
116	8.0
122	16.0
128	32.0
134	64.0
140	128.0

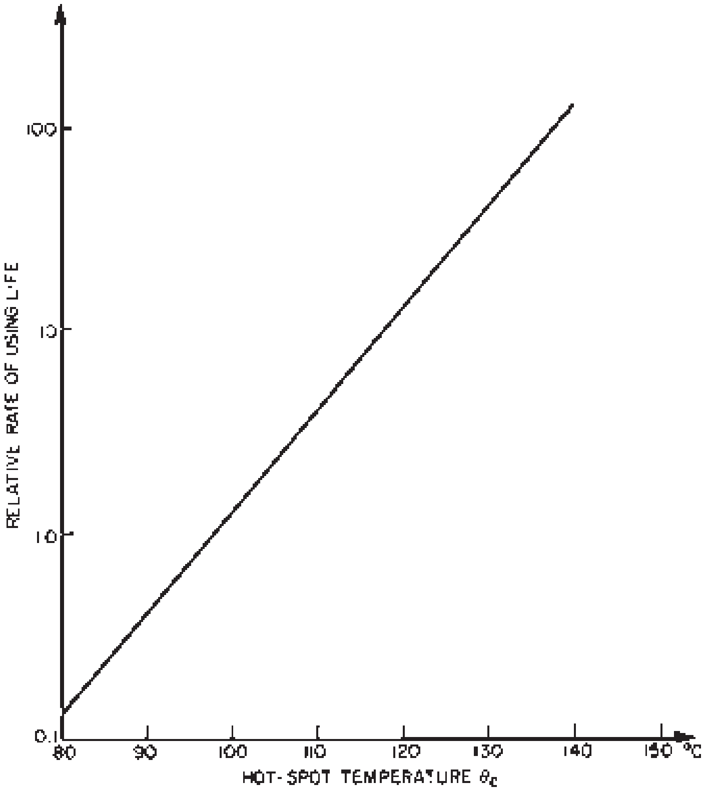


Figure 6.129 Life line

Equivalent life loss in a 24 hour period

It may be required to find the time t hours per day for which the transformer may be operated with a given hot-spot temperature θ_h, with the complement to 24 hours corresponding to a sufficiently low temperature for negligible life loss; then the hours of life loss are given by tV and for tV to equal 24:

$$t = \frac{24}{V} = 24 \times 10^{(98-\theta_h)/19.93} \tag{6.60}$$

Equation (6.60) gives the number of hours per day of operation at any given value of θ_h that will use one day's life per day. *Table 6.22* gives values of t for various values of θ_h.

It can happen that it is required, for limited periods of time, to operate at higher temperatures than those associated with normal daily cyclic loading and accept the more rapid use of life for those periods, for instance the loss of a unit in a group. If a daily loss of life 2, 5, 10 ... times the normal value is assumed, the corresponding 'hot-spot' temperatures will be 6, 14 and 20°C higher than given in *Table 6.22*, but θ_h must not exceed 140°C.

Table 6.22

Hours per day	θ_c
24	98
16	101.5
12	104
8	107.5
6	110
4	113.5
3	116
2	119.5
1.5	122
1.0	125.5
0.75	128
0.5	131.5

As a general rule, the transformer will be loaded in such a way that daily operation with use of life higher than normal will not extend over periods of time which are an appreciable proportion of normal expected life duration. In these conditions it will not be necessary to keep a record of the successive loads on the unit.

Determination of hot-spot temperature for other than rated load

In all of the foregoing discussion load capability has been related to hot-spot temperature. The effect on hot-spot temperature at rated load of variation in ambient is simple to deduce; one degree increase or reduction in ambient will result, respectively, in one degree increase or reduction in hot-spot temperature. The question which is less simple to answer is, how does hot-spot temperature vary with variation in load at constant ambient? To consider the answer to this it is necessary to examine the thermal characteristics of a transformer, which were discussed in Section 5 of Chapter 4.

Hot-spot temperature is made up of the following components:

- Ambient temperature.
- Top oil temperature rise.
- Average gradient.
- Difference between average and maximum gradient of the windings.

In IEC 76 the last two terms are on occasions taken together to represent maximum gradient. Maximum gradient is then greater than average gradient by the ‘hot-spot factor’. This factor is considered to vary between 1.1 for distribution transformers to 1.3 for medium-sized power transformers. The last term thus varies between 0.1 and 0.3 times the average gradient.

Effect of load on oil temperature rise

Mean oil rise is determined by the dissipation capability of the cooling surface and the heat to be dissipated. The heat to be dissipated depends on the losses.

At an overload k times rated load the losses will be increased to:

$$\mathrm{Fe} + k^2\mathrm{Cu}$$

where Fe and Cu are the rated no-load and load losses respectively.

As the excess temperature of the cooling surface above its surroundings increases, cooling efficiency will tend to be increased, that is the oil temperature will increase less than pro rata with the increased losses to be dissipated. This relationship may be expressed in the form:

$$\frac{\theta_{o2}}{\theta_{o1}} = \left(\frac{\text{increased losses}}{\text{rated losses}}\right)^x$$

where θ_o is the oil temperature rise, with suffixes 1 and 2, respectively, indicating the rated and the overload conditions.

IEC 76, Part 2, which deals with temperature rise, gives values for the index x which are considered to be valid within a band of $\pm 20\%$ of the rated power, these are:

0.8 for distribution transformers having natural cooling with a maximum rating of 2500 kVA.
0.9 for larger transformers with ON.. cooling.
1.0 for transformers with OF.. or OD.. cooling.

The inference to be drawn from the above values is that with OF.. and OD.. cooling, the coolers are already working at a high level of efficiency so that increasing their temperature with respect to the surroundings cannot improve the cooler efficiency further.

Effect of load on winding gradients

The heat transfer between windings and oil is considered to improve in the case of ON.. and OF.. transformers for increased losses, that is the increased heat to be dissipated probably increases the oil flow rate, so that the winding gradient also increases less than pro rata with heat to be dissipated, which is, of course, proportional to overload factor squared. IEC 76, Part 2, gives the following values:

$$\frac{\Delta\theta_{wo2}}{\Delta\theta_{wo1}} = k^y$$

where $\Delta\theta_{wo}$ is the winding/oil differential temperature, or gradient, with additional suffixes 1 and 2, respectively, to indicate the rated and overload conditions. The index y is then:

1.6 for ON.. and OF.. cooled transformers.
2.0 for OD.. cooled transformers.

IEC 76, Part 2, places limits on the accuracy of the above as within a band of $\pm 10\%$ of the current at which the gradient is measured; however, it does state that this limitation, and that placed on the formula for extrapolation for oil temperature indicated above, should be applied where the procedure is used for the evaluation of test results subject to guarantee. In other circumstances the method may give useful results over wider ranges.

Example 1. The above method may be used to estimate the hot-spot temperature of a 30/60 MVA, 132/33 kV ONAN/ODAF transformer when operated at, say, 70 MVA. The transformer has losses of 28 kW at no-load and load losses of 374 kW on minimum tapping at 60 MVA. On temperature rise test the top oil rise was 57.8°C and the rise by resistance was LV, 69.2°C, HV, 68.7°C on minimum tapping. The effect of changes in ambient can also be included. Let us assume that the ambient temperature is 10°C.

The transformer temperature rise test certificate should indicate the value of the mean oil rise and the winding average gradients. If this information is not available, for example if no temperature rise test was carried out, these values will have to be estimated. Top oil rise at 60 MVA can be measured by a thermometer placed in the top tank pocket. Oil temperature rise on return from the cooler can be similarly measured at the tank oil inlet. Mean oil temperature rise is the average of these two figures. Let us assume that either from the test certificate or by measurement, mean oil rise is found to be 49.8°C. Then,

$$\begin{aligned}\text{LV winding gradient} &= 69.2 - 49.8 = 19.4^\circ\text{C, and}\\ \text{HV winding gradient} &= 68.7 - 49.8 = 18.9^\circ\text{C.}\end{aligned}$$

At 70 MVA, the overload factor is $70/60 = 1.167$.

$$\begin{aligned}\text{New top oil rise} &= 57.8\left(\frac{28 + 1.167^2 \times 374}{28 + 374}\right.\\ &= 77.3^\circ\text{C}\end{aligned}$$

The critical gradient is the LV winding = 19.4°C, at 1.167 times rated load this will become:

$$19.4 \times 1.167^2 = 26.4$$

hence, hot-spot temperature $= 10 + 77.3 + 1.3 \times 26.4 = 121.6^\circ\text{C}$.

By reference to *Table 6.22* it can be seen that this overload may be carried for up to one and a half hours per day with the remainder of the time at a load which is low enough to cause minimal loss of life. Alternatively, provided this daily overload is only imposed for a matter of a few weeks, normal load may be carried for the remainder of the day with only negligible loss of life.

Normally a transformer such as the one in the above example would have pumps and fans controlled from a winding temperature indicator which would mean that these would not be switched in until a fairly high winding temperature was reached; however, if the overload is anticipated, pumps and fans can, with advantage, be switched in immediately. This will delay the time taken to reach maximum hot-spot temperature and, although cooler losses will be incurred, these will to some extent be offset by the lower transformer load loss resulting from the reduction in winding copper temperature.

During any period of overloading there will be a time delay before the maximum hot-spot temperature is reached. This will have two components:

- The time for the windings to reach equilibrium with the oil at the new level of gradient.
- The time taken for the complete transformer to reach equilibrium with its surroundings.

The first of these, the winding time constant, is likely to be of the order of minutes, say between 5 and 20 minutes, and it is normally neglected. The second, the transformer oil time constant, or simply transformer time constant, will be a great deal longer, probably between one and three hours. The hot-spot temperature variation for a daily loading duty of the form indicated in *Figure 6.130* will be as shown, with an exponential increase

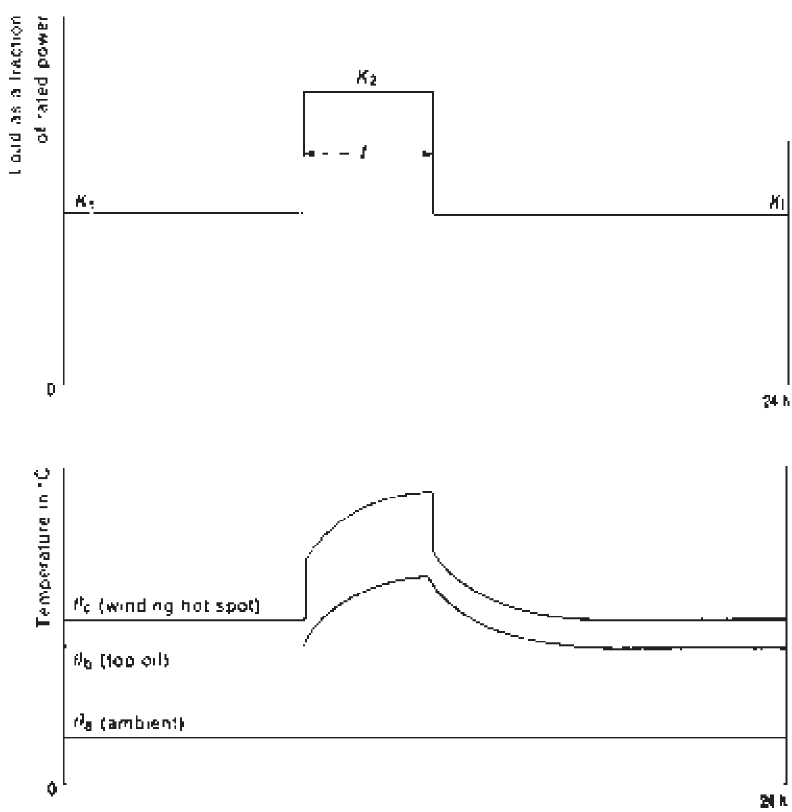


Figure 6.130 Simplified load diagram for cyclic daily duty

at the commencement of the overloading and a similar decay at the end of the overload period. In terms of use of life the areas under these exponential curves are equal, so the times spent in the heating and cooling phases will partly cancel out and may therefore be ignored. This will not be entirely true, however, because rate of ageing is proportional to 2 (or 10) raised to a power of temperature (see equations 6.58 and 6.59 above). Ignoring the time delays results in the introduction of a small factor of pessimism which is no bad thing. Recognition of the time delay can be particularly beneficial, however, where the overload would take the final hot-spot temperature above 140°C. By definition, for an overloading period equal to the time constant for the oil, the rise in top oil temperature at the end of this period will be approximately 63% of its ultimate value. If the time constant for the oil is two hours and its ultimate rise, say, 45°C, 63% of this is only 28.4°C, some 16.6°C lower, and this will not be reached until after two hours.

IEC loading guide for oil-filled transformers

The principles outlined above have been used as a basis for compiling loading guides for oil-immersed transformers, for example IEC 354 *Loading guide for oil immersed transformers*. While the use of such guides can greatly simplify the process of assessing loading capability, it is always beneficial to have a good understanding of the theory involved. As well as aiding an appreciation of the precise effect on the transformer of operating at other than rated load, it is clearly preferable to be able to perform a calculation for a particular transformer using loss values and gradients specific to that transformer than to rely on guides which must of necessity make many assumptions. It will be seen from the example worked above that if a transformer has high maximum gradients, say approaching 30°C, which is not untypical of many OD..-type transformers (IEC 354, 1991, assumes 29°C), then its ability to carry overloads will be considerably less than that of a transformer having maximum gradients of, say, 25°C or less, since the effect of overloading for OD.. transformers is to increase gradients in accordance with a square law. For an overload of 25%, $1.25^2 \times 30 = 46.8$°C, whereas $1.25^2 \times 25 = 39.06$, so an OD.. transformer having the lower maximum gradient will have a rate of using life of less than half that of the transformer with the higher gradient at an overload of 25%.

It should also be noted that a transformer with a low ratio of load loss to no-load loss will also be capable of slightly greater overloading than one for which this ratio is higher, since it is only the load loss which will increase under overload, and this in proportion to the overload squared. Loading guides must assume a typical value for the ratio of the load to no-load loss. IEC 354 assumes a ratio of 5 for ONAN distribution transformers and 6 for all other types. Just how widely actual transformers can vary in practice will be apparent from the example of the 30/60 MVA transformer used in the overload calculation above. The figures are for an actual transformer and it can be seen that the ratio is $374/28 = 13.4$ to 1. Variation of this ratio has less an effect on top oil temperature, and hence hot-spot temperature, than does variation in gradient.

If the transformer in the above example is assumed to have the same total losses, i.e. 402 kW, but split so that the ratio is the IEC assumed value, i.e. 57.4 and 344.6 kW, respectively, and the top oil rise recalculated for a load of 70 MVA, it will be found that this equates to 75.7°C, only 1.6°C lower.

Continuous loading at alternative ambients in accordance with IEC 354

Table 6.23, reproduced from IEC 354, gives factors for continuous loadings which will result in a hot-spot temperature of 98°C for varying ambient temperatures and for each type of cooling, thus enabling the continuous loading capability for any ambient temperature to be calculated.

Table 6.23 Acceptable load factor for continuous duty K_{24} at different ambient temperatures (ON, OF and OD cooling)

Ambient temperature °C			−25	−20	−10	0	10	20	30	40
Hot-spot temperature rise K			123	118	108	98	88	78	68	58
K_{24}	Distribution	ONAN	1,37	1,33	1,25	1,17	1,09	1,00	0,91	0,81
	Power transformer	ON	1,33	1,30	1,22	1,15	1,08	1,00	0,92	0.82
		OF	1,31	1,28	1,21	1,14	1,08	1,00	0,92	0,83
		OD	1,24	1,22	1,17	1,11	1,06	1,00	0,94	0,87

Cyclic loading in accordance with IEC 354

IEC 354 may also be used to give an indication of permissible daily loading cycles. Loading patterns are deemed to consist of a simplified daily cycle having the form shown in *Figure 6.130*, above. Symbols used in the Guide have the following meanings:

K_1 = initial load power as a fraction of rated power
K_2 = permissible load power as a fraction of rated power (usually greater than unity)

t = duration of K_2, in hours

θ_A = temperature of cooling medium, air or water

$$K_1 = \frac{S_1}{S_r} \text{ and } K_2 = \frac{S_2}{S_r}$$

where S_1 = initial load power
S_2 = permissible load power
and S_r = rated power

The values of K_1, K_2 and t must be selected to obtain as close a match as possible between the actual load cycle and the overload basic cycle of *Figure 6.130*. This can be done on an area for area basis as shown in

Figure 6.131, reproduced from IEC 354. For the not uncommon case where there are two peaks of nearly equal amplitude but different duration, the value of t is determined for the peak of longer duration and the value of K_1 is selected to correspond to the average of the remaining load as shown in the example of *Figure 6.132*. Where the peaks are in close succession, the value of t is made long enough to enclose both peaks and K_1 is selected to correspond to the average of the remaining load, as shown in *Figure 6.133*.

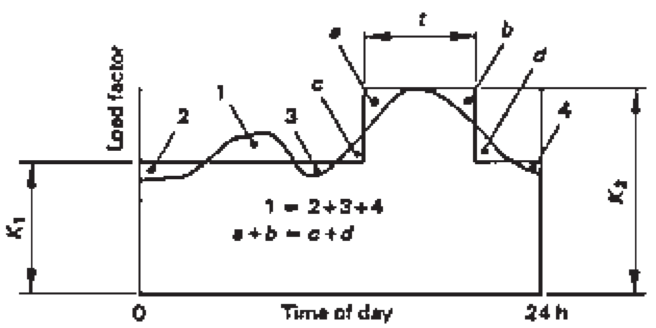


Figure 6.131 Load cycle with one peak

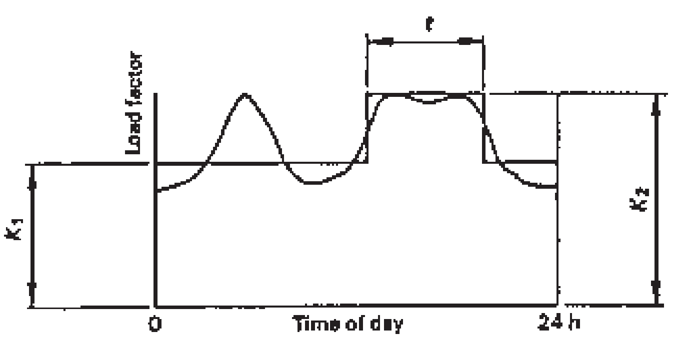


Figure 6.132 Load cycle with two peaks of equal amplitude and different duration

A series of loading curves for varying ambients, of which *Figure 6.134* is a typical example, are then provided to enable permissible cyclic loading to be deduced. The Guide lists the thermal characteristics which have been assumed in drawing up the curves and recommends that for normal cyclic loading the load current should not exceed 1.5 times rated current and the hot-spot temperature should not exceed 140°C. For large power transformers (over 100 MVA) it recommends that these should not exceed 1.3 times rated current and 120°C, respectively. For all transformers it recommends that top

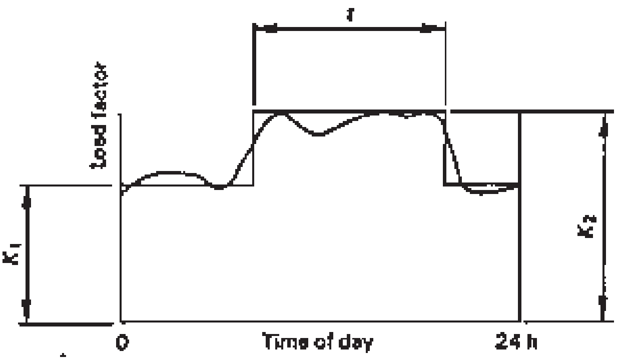


Figure 6.133 Load cycle with peaks in close succession

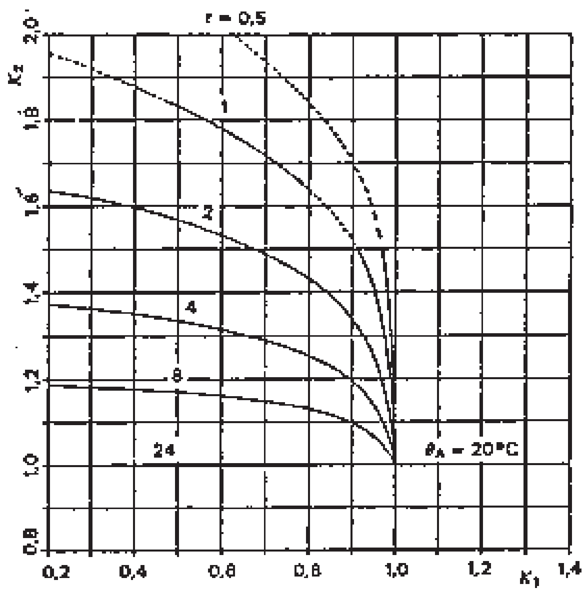


Figure 6.134 Permissible cyclic loading duties for ONAN distribution transformers for normal loss of life at 20°C ambient

oil temperature should not exceed 105°C. The following examples show how the tables may be used.

Example 2. A 2 MVA ONAN distribution transformer has an initial load of 1 MVA. To find the permissible load for 2 h at an ambient temperature of 20°C, assuming constant voltage, we have:

$$\theta_A = 20^{\circ}\text{C} \quad K_1 = 0.5 \quad t = 2\ \text{h}$$

Figure 6.134 gives $K_2 = 1.56$, but the Guide limit is 1.5. Therefore the permissible load for 2 h is 3 MVA (then returning to 1 MVA).

Example 3. With $\theta_A = 20°C$, an ONAN distribution transformer is required to carry 1750 kVA for 8 h and 1000 kVA for the remaining 16 h each day. To find the optimum rating required to meet this duty, assuming constant voltage, we have:

$$\frac{K_2}{K_1} = \frac{1750}{1000} = 1.75$$

On the curve of *Figure 6.134*, first plot the line $K_2/K_1 = 1.75$ (*Figure 6.135*), then at the point where this intersects the curve for $t = 8$, the values of K_1 and K_2 are $K_2 = 1.15$ and $K_1 = 0.66$ so that the rated power is:

$$S_r = \frac{1750}{1.15} = \frac{1000}{0.66} = 1520 \text{ kVA}$$

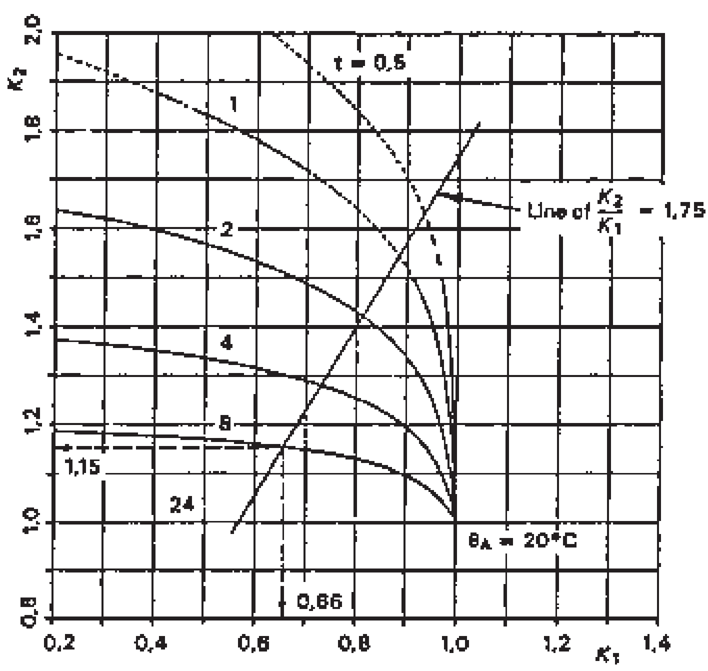


Figure 6.135 Illustration of *Example 3*

Emergency cyclic loading

Example 3 above enables the best rating of transformer to be selected to meet a known cyclic duty. On occasions it may be necessary to overload a transformer on a cyclic basis when it was not originally intended to be so loaded, even though some shortening of life might be entailed. IEC 354 terms this 'Emergency cyclic loading' and provides a series of tables covering all cooling types for a range of loading duties. *Table 6.24*, which is table 27 of the Guide, provides information relating to emergency loading of OD medium and large power transformers for 2 hours.

Table 6.24 OD medium and large power transformers: $t = 2$ h. Permissible duties and corresponding daily loss of life (In 'normal' days)

To determine whether a daily load diagram characterised by particular values of K_1 and K_2 is permissible and to evaluate the daily loss of life entailed, proceed as follows:

Ambient temperature	40 °C	30 °C	20 °C	10 °C	0 °C	–10 °C	–20 °C	–25 °C
Daily loss of life: Multiply the value given in the table below by the factor given here, then round off the result	10	3.2	1	0.32	0.1	0.032	0.01	0.0055
Hot-spot temperature: Add the hot-spot temperature rise given in the table to the ambient temperature. If the resulting hot-spot temperature exceeds the limit stated in table 1, the duty is not permissible.								

K_2 \ K_1	0.25	0.50	0.70	0.80	0.90	1.00	1.10	1.20	1.30	1.40	1.50
0.7	0.000 31	0.001 33	0.008 36								
0.8	0.001 42	0.002 44	0.009 47	0.032 48							
0.9	0.002 54	0.004 56	0.014 59	0.040 60	0.163 62						
1.0	0.010 68	0.015 70	0.032 72	0.067 74	0.209 76	1.00 78					
1.1	0.048 83	0.070 85	0.122 87	0.192 89	0.398 91	1.33 93	7.42 95				
1.2	0.278 99	0.395 101	0.639 104	0.894 105	1.41 107	2.93 109	10.4 112	66.7 114			
1.3	1.93 117	2.70 119	4.22 122	5.66 123	8.09 125	12.9 127	26.6 130	97.7 132	726 135		
1.4	15.9 136	22.0 138	33.7 141	44.3 143	61.1 144	89.6 147	145 149	297 152	1120 154	9550 157	
1.5	156 157	213 159	321 162	418 163	566 165	805 167	1210 170	1990 172	4070 175	+ 178	+ 181
1.6	1800 179	2450 181	3650 184	+ +	+ +	+ +	+ +	+ +	+ +	+ +	+ +

Example 4. What is the daily loss of life and the hot-spot temperature when the 30/60 MVA transformer of *Example 1* above is loaded at 70 MVA for 2 hours in an ambient of 10°C?

$$K_1 = 1.0 \quad K_2 = 1.167 \quad \theta_A = 10^\circ\mathrm{C} \quad t = 2\ h$$

Table 6.24 shows that $V = 2.4$, $\Delta\theta_h = 103.7$ for an ambient temperature of 20°C. (By linear interpolation between $K_2 = 1.1$ and $K_2 = 1.2$, which is reasonable for hot-spot temperature, somewhat optimistic for V.) Taking account of the actual ambient temperature of 10°C we have:

$$\text{Loss of life} = 2.4 \times 0.32 = 0.77 \text{ 'normal' days}$$

$$\theta_h = 103.7 + 10 = 113.7^\circ\mathrm{C}$$

The above hot-spot temperature is a little lower than the figure of 121.6 calculated in *Example 1* which corresponds to exactly one day's loss of life per day.

It will be noted that there is a reference in *Table 6.24* to a table 1 which gives a value of maximum permissible hot-spot temperature. This is, of course, table 1 of IEC 354. For completeness this is reproduced as *Table 6.25*; however, the reader should refer to IEC 354 for a full explanation of its position in relation to maximum hot-spot temperature.

Table 6.25 Current and temperature limits applicable to loading beyond nameplate rating

Types of loading		Distribution transformers	Medium power transformers	Large power transformers
Normal cyclic loading				
Current	(p.u.)	1,5	1,5	1,3
Hot-spot temperature and metallic parts in contact with insulating material	(°C)	140	140	120
Top-oil temperature	(°C)	105	105	105
Long-time emergency cyclic loading				
Current	(p.u.)	1,8	1,5	1,3
Hot-spot temperature and metallic parts in contact with insulating material	(°C)	150	140	130
Top-oil temperature	(°C)	115	115	115
Short-time emergency loading				
Current	(p.u.)	2,0	1,8	1,5
Hot-spot temperature and metallic parts in contact with insulating material	(°C)	*	160	160
Top-oil temperature	(°C)	*	115	115

*None given.

The above examples give some indication of the information which is available in IEC 354 and the way in which it can be used to determine the loading capability of an oil-filled transformer. For a fuller explanation of overloading principles for all sizes of transformers and types of cooling reference should be made to the document itself.

Limitations on overloading

Although in the previous paragraphs emphasis has been placed on the arbitrary nature of 98°C as a hot-spot temperature for 'normal' rating in normal ambients and the flexibility built into the rating of transformers designed on this basis, before concluding it is appropriate to add a few words of caution.

Care should be taken, when increasing the load on any transformer, that any associated cables and switchgear are adequately rated for such increases and that any transformer ancillary equipment, e.g. tapchangers, bushings, etc., do not impose any limitation. The voltage regulation will also increase when the load on a transformer is increased.

The mineral oil in the transformer should comply with BS 148 and should be maintained at least in accordance with BS 5730. Consideration should be given to closer monitoring of the oil in accordance with the procedures outlined in Section 7 of this chapter.

For normal cyclic duty, the current should not exceed 1.5 times rated value. Hot-spot temperature should never exceed 140°C. For emergency duty, currents in excess of 1.5 times rated value are permissible provided that the 140°C hot-spot temperature is not exceeded, that the fittings and associated equipment are capable of carrying the overload and that the oil temperature does not exceed 115°C. The limit of 115°C for the oil temperature has been set bearing in mind that the oil may overflow at oil temperatures above normal. Depending on the provision made for oil expansion on a particular transformer, the oil may overflow at temperatures lower than 115°C.

IEC 354:1991 states that for certain emergency conditions the hot-spot temperature may be allowed to reach 160°C. The question then is what constitutes such an emergency. It should be noted that when the hot-spot temperature reaches 140–160°C, gas bubbles may develop which could hazard the electrical strength of the transformer. It is clearly most undesirable to add to an existing emergency, possibly caused by the failure of a transformer, by creating conditions which might lead to the failure of a second unit.

Operation at other than rated voltage and frequency

Considering initially variation from rated frequency, it can be stated that it is not usually possible to operate a transformer at any frequency appreciably lower than that for which it was designed unless the voltage and consequently the output are correspondingly reduced. The reason for this is evident if the expression connecting voltage, frequency and magnetic flux given in Section 1 of Chapter 1, equation (1.4), is recalled. This is:

$$E/N = 4.44 B_m A f \times 10^{-6}$$

where E/N = volts per turn, which is the same in both windings
B_m = maximum value of flux density in the core, tesla
A = nett cross-sectional area of the core, mm^2
f = frequency of supply, Hz

Since, for a particular transformer A and N are fixed, the only variables are E, B_m and f, and of these B_m is likely to have been set at the highest practicable value by the transformer manufacturer. We are therefore left with E and f as the only permissible variables when considering using a transformer on a frequency lower than that for which it was designed. The balance of the equation must be maintained under all conditions, and therefore any reduction in frequency f will necessitate precisely the same proportionate reduction in the voltage E if the flux density B_m is not to be exceeded and the transformer core not to become overheated. The lower the frequency the higher the flux density in the core, but as this increase is relatively small over the range of the most common commercial frequencies its influence on the output is very slight, and therefore the reduction in voltage and output can be taken as being the same as the reduction in frequency.

Operation at higher than rated frequency but at design voltage is less likely to be problematical. Firstly, the danger of saturation of the core is no longer a threat since increased frequency means a reduction in flux density. There will be some increase in winding eddy-current loss which will probably increase as the square of the frequency. The impact of this will depend on the magnitude of the eddy-current losses at rated frequency but for transformers smaller than 1 or 2 MVA and frequencies within about 20% of rated frequency, this will probably be acceptable. Changes in hysteresis and eddy-current components of core loss, both of which increase with frequency, will probably be balanced by the reduction in flux density as can be seen by reference to the expressions for these quantities which were given in Section 2 of Chapter 3. These were equations (3.1) and (3.2) respectively:

$$\text{Hysteresis loss, } W_h = k_1 f B_{\max}^n \text{ watts/kg}$$

$$\text{and Eddy current loss, } W_e = k_2 f^2 t^2 B_{\text{eff}}^2/\rho \text{ watts/kg}$$

where k_1 and k_2 are constants for the material
f is frequency, Hz
t is thickness of the material, mm
ρ is the resistivity of the material
$B_{\max}$ is maximum flux density, T
B_{eff} is the flux density corresponding to the r.m.s. value of the applied voltage
n is the 'Steinmetz exponent' which is a function of the material

Considering next the question of using a transformer on voltages different from the normal rated voltage, it can be stated very definitely that on no account should transformers be operated on voltages appreciably higher than rated voltage. This is inadmissible not only from the point of view of electrical clearances but also from that of flux density, as will be clear from equation (1.4) which was recalled earlier. It should be noted, while considering this aspect of operation at higher than rated voltage, that many specifications state that the system voltage may be capable of increasing by 10% above its rated value. It is important that in this circumstance the designer must limit the design flux density to such a value as will ensure that saturation is not approached at the overvoltage condition. This usually means that the nominal flux density must not exceed 1.7 tesla at any point in the core. If the transformer has an on-load tapchanger under automatic control and there is any possibility that this might be driven to minimum tap position while system volts are high, then the design flux density must be selected so as to ensure that saturation is not approached under this fault condition, which might require that this be kept as low as 1.55 tesla.

Operation with unbalanced loading

In considering the question of unbalanced loading it is easiest to treat the subject from the extreme standpoint of the supply to one single-phase load only, as any unbalanced three-phase load can be split up into a balanced three-phase load and one or two single-phase loads. As the conditions arising from the balanced three-phase load are those which would normally occur, it is only a question of superposing those arising from the single-phase load upon the normal conditions to obtain the sum total effects. For the purpose of this study it is only necessary to consider the more usual connections adopted for supplying three-phase loads. The value of current distribution is based upon the assumption that the single-phase currents are not sufficient to distort the voltage phasor diagrams for the transformers or transformer banks. This assumption would approximate very closely to the truth in all cases where the primary and secondary currents in each phase are balanced. In those cases, however, where the primary current on the loaded phase or phases has to return through phases unloaded on the secondary side, the distortion may be considerable, even with relatively small loads; this feature is very pronounced where three-phase shell-type transformers and banks of single-phase transformers are employed. *Figures 6.136, 6.137* and *6.138* show the current distribution on the primary and secondary sides of three- to three-phase transformers or banks with different arrangements of single-phase loading and different transformer connections. These diagrams may briefly be explained as follows.

(a) Star/star; single-phase load across two lines

With this method of single-phase loading the primary load current has a free path through the two primary windings corresponding to the loaded secondary phases, and through the two line wires to the source of supply. There is, therefore, no choking effect, and the voltage drops in the transformer windings are those due only to the normal impedance of the transformer. The transformer neutral points are relatively stable, and the voltage of the open phase is practically the same as at no-load. The secondary neutral point can be earthed without affecting the conditions.

The above remarks apply equally to all types of transformers.

ASSUMED LINE VOLTAGE RATIOS 1:1
ASSUMED SINGLE PHASE LOADS OF 100 A AT UNITY POWER FACTOR

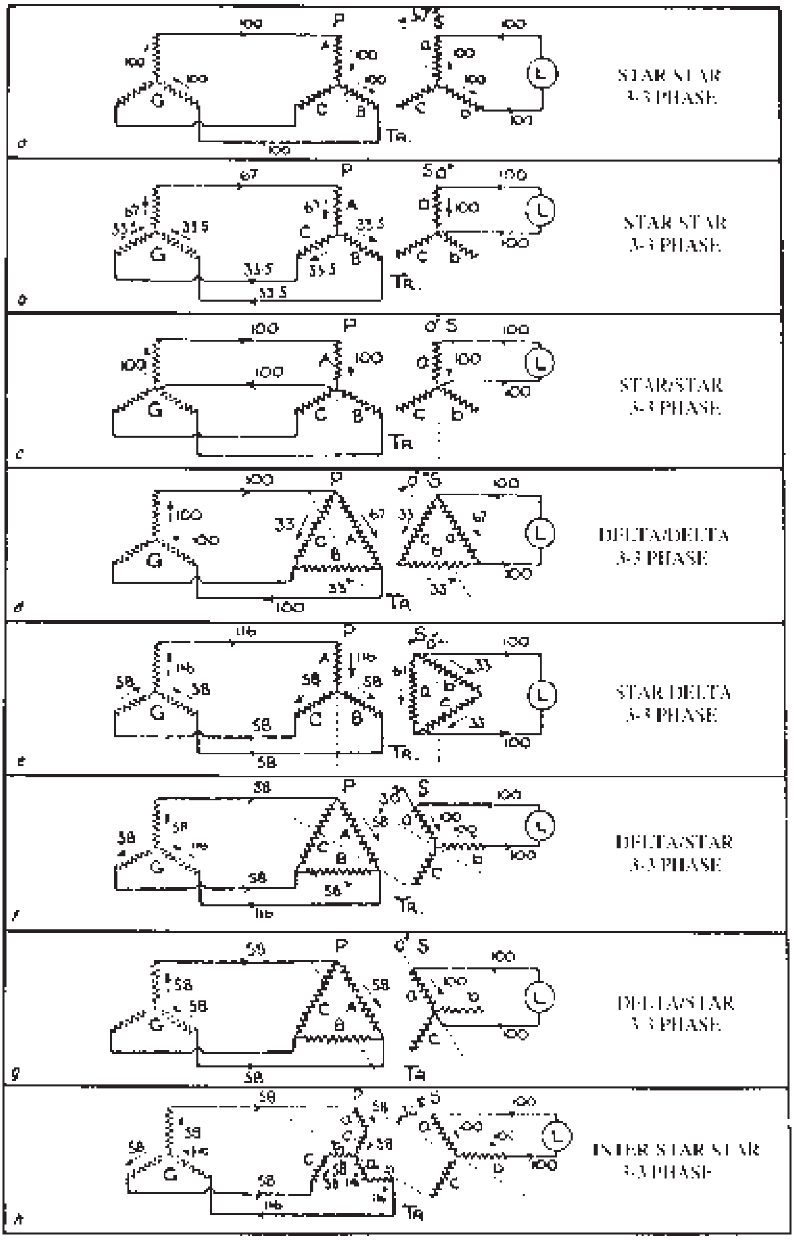


Figure 6.136 Current distribution due to a single-phase load on polyphase transformers or transformer groups. Note: in all cases the dotted lines indicate the phase angle of the single-phase load currents

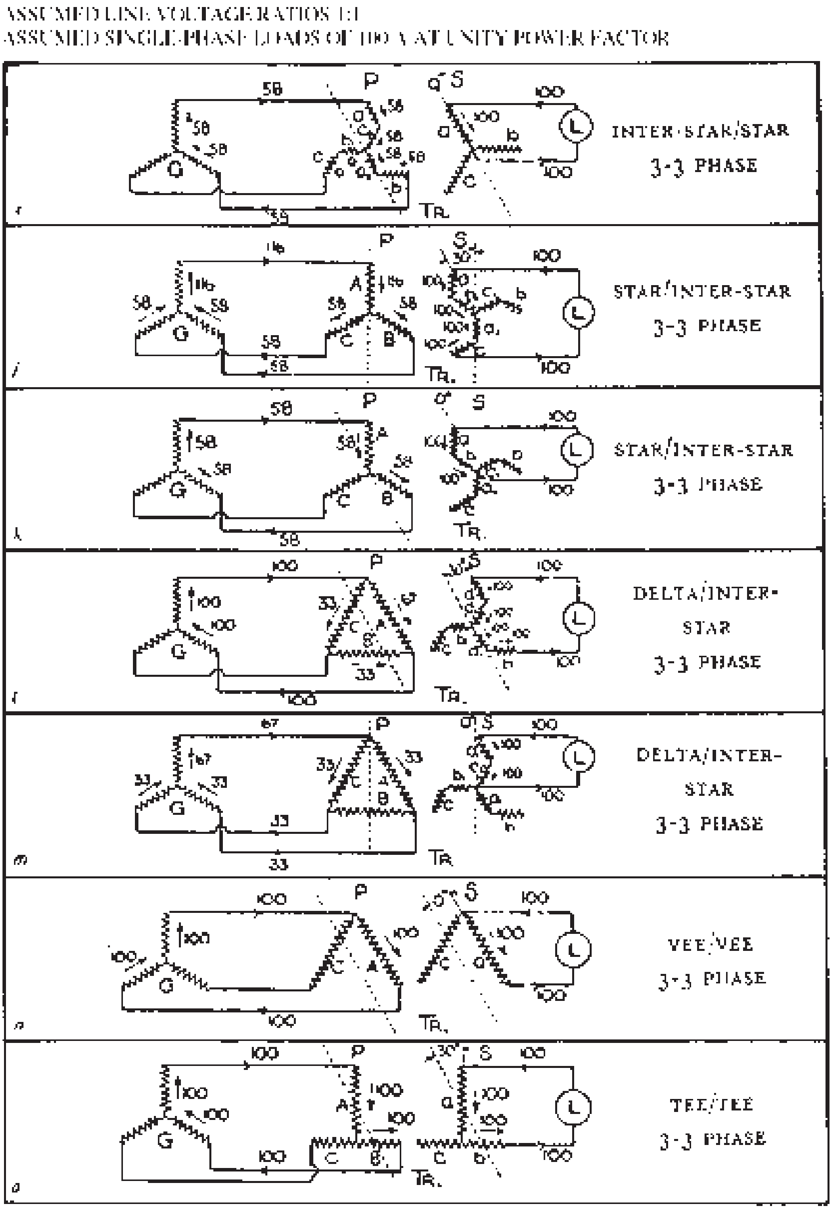


Figure 6.137 Current distribution due to single-phase load on polyphase transformer groups. Note: in all cases the dotted lines indicate the phase angle of the single-phase load currents

(b) Star/star; Single-phase load from one line to neutral

With this method of single-phase loading the primary load current corresponding to the current in the loaded secondary must find a return path through the other two primary phases, and as load currents are not flowing in the secondary windings of these two phases, the load currents in the primaries act as magnetising currents to the two phases, so that their voltages considerably increase while the voltage of the loaded phase decreases. The neutral point, therefore, is considerably displaced. The current distribution shown on the primary side is approximate only, as this will vary with each individual design.

The above remarks apply strictly to three-phase shell-type transformers and to three-phase banks of single-phase transformers, but three-phase core-type transformers can, on account of their interlinked magnetic circuits, supply considerable unbalanced loads without very severe displacement of the neutral point.

(c) Star/star with generator and transformer primary neutrals joined; single-phase load from one line to neutral

In this case the connection between the generator and transformer neutral points provides the return path for the primary load current, and so far as this is concerned, the other two phases are short-circuited. There is therefore no choking effect, and the voltage drops in the transformer windings are those on the one phase only, due to the normal impedance of the transformer. The transformer neutral points are relatively stable, and the voltages of the above phases are practically the same as at no-load. The secondary neutral point can be earthed without affecting the conditions.

The above remarks apply equally to all types of transformers.

(d) Delta/delta; single-phase load across two lines

With this connection the loaded phase carries two-thirds of the total current, while the remainder flows through the other two phases, which are in series with each other and in parallel with the loaded phase. On the primary side all three windings carry load currents in the same proportion as the secondary windings, and two of the line wires only convey current to and from the generator. There is no abnormal choking effect, and the voltage drops are due to the normal impedance of the transformer only. The type of transformer does not affect the general deductions.

(e) Star/delta; single-phase load across two lines

On the delta side the distribution of current in the transformer windings is exactly the same as in the previous case, that is, two-thirds in the loaded phase and one-third in each of the other two. On the primary side the corresponding load currents are split up in the same proportions as on the secondary, and in value they are equal to the secondary currents of the different phases multiplied by $\sqrt{3}$ and multiplied or divided by the ratio of transformation, according to whether the transformer is a step-up or step-down. The primary neutral point is stable.

The above remarks apply equally to all types of transformers.

(f) Delta/star; single-phase load across two lines

Single-phase loading across lines of this connection gives a current distribution somewhat similar to that of (a), except that the currents in the two primary windings are $1/\sqrt{3}$ times those occurring with the star primary, while all the three lines to the generating source carry currents in the proportions shown instead of two lines only carrying currents as in the case of the star primary. There is no choking effect, and the voltage drops in the windings are due only to the normal impedance of the transformer. The transformer secondary neutral point is relatively stable and may be earthed. The voltage of the open phase is practically the same as at no-load.

The above remarks apply equally to all types of transformers.

(g) Delta/star; single-phase load from line to neutral

With this connection and single-phase loading the neutral, primary and secondary windings on one phase only carry load current, and on the primary side this is conveyed to and from the generating source over two of the lines only. There is no choking effect, and the voltage drops in the transformer windings are those corresponding only to the normal impedance of the transformer. The secondary neutral point is stable and may be earthed without affecting the conditions. The voltages of the open phase are practically the same as at no-load. The type of transformer construction does not affect the general deductions.

(h) Interconnected star/star; single-phase load across two lines

With this connection and method of loading, all the primary windings take a share of the load, and although in phase C there is no current in the secondary winding, the load currents in the two halves of the primary windings of that phase flow in opposite directions, so that their magnetic effects cancel. There is no choking effect, and the voltage drops in the transformer windings are those due to the normal impedance of the transformer only. With three-phase shell-type transformers and three-phase banks of single-phase transformers the secondary neutral is not stable and should not be earthed unless the flux density is sufficiently low to permit this. With three-phase core-type transformers, however, the neutral is stable and could be earthed. The voltage of the open phase is practically that occurring at no-load.

(i) Interconnected star/star; single-phase load from one line to neutral

With this connection and method of loading a partial choking effect occurs, due to the passage of load current in each half of the primary windings corresponding to the unloaded secondary windings. The voltage of the two phases in question, therefore, becomes increased on account of the high saturation in the cores and the voltage of the windings corresponding to the loaded phase drops. Both primary and secondary neutrals are therefore unstable and should not be earthed. The above remarks apply strictly to three-phase shell-type transformers and to three-phase banks of single-phase transformers. With three-phase core-type transformers the deflection of the neutral point is not so marked, and considerable out-of-balance loads can be supplied without any excessive deflections of the neutral points.

(j) Star/interconnected star; single-phase load across two lines

With this connection and method of loading the secondary windings on all three limbs carry load currents, and therefore all the primary windings carry corresponding balancing load currents. The current distribution is clearly shown on the diagram, from which it will be seen there is no choking effect, and the transformer neutral points are stable if three-phase core-type transformers are used, and so may be earthed. On the secondary side the voltage of the open phase is practically the same as at no-load. The voltage drops in the transformer windings are those due only to the normal impedance of the transformer.

(k) Star/interconnected star; single-phase load from one line to neutral

With this method of loading there is similarly no choking effect, as the primary windings corresponding to the loaded secondaries carry balancing load currents which flow simply through two of the line wires to the generating source. The voltage drops in the transformer windings are those due only to the normal impedance of the transformer, and the voltages of the above phases are practically the same as at no-load. The secondary neutral is stable and can be earthed. The primary neutral can only be earthed, however, if the transformer unit is of the three-phase core type of construction.

(l) Delta/interconnected star; single-phase load across two lines

With this connection and loading the general effect is similar to the star/interconnected-star connection. That is, there is no choking effect, as the primary windings corresponding to the loaded secondaries take balancing load currents, although the primary current distribution is slightly different from that occurring with a star primary. The voltage drops in the transformer windings are those due only to the normal impedance of the transformer, while the voltage of the open phase is practically the same as at no-load. The secondary neutral is stable and can be earthed.

(m) Delta/interconnected star; single-phase load from one line to neutral

With this connection and method of loading the results are similar to those obtained with the star/interconnected-star, that is the primary windings corresponding to the loaded secondaries carry balancing load currents so that there is no choking effect. The voltage drops in the transformer windings are those due only to the normal impedance of the transformer, while the voltages of the open phases are practically the same as at no-load. The secondary neutral point is stable and can be earthed.

(n) Vee/vee

With this connection and method of loading there is clearly no choking effect, as this is simply a question of supplying a single-phase transformer across any two lines of a three-phase generator. The voltage drops are comparable to those normally occurring, and the voltages of the open phases are practically the same as at no-load. The connection is, however, electrostatically unbalanced, and should be used only in emergency.

(o) Tee/tee; single-phase load across two lines, embracing the teaser and half the main windings

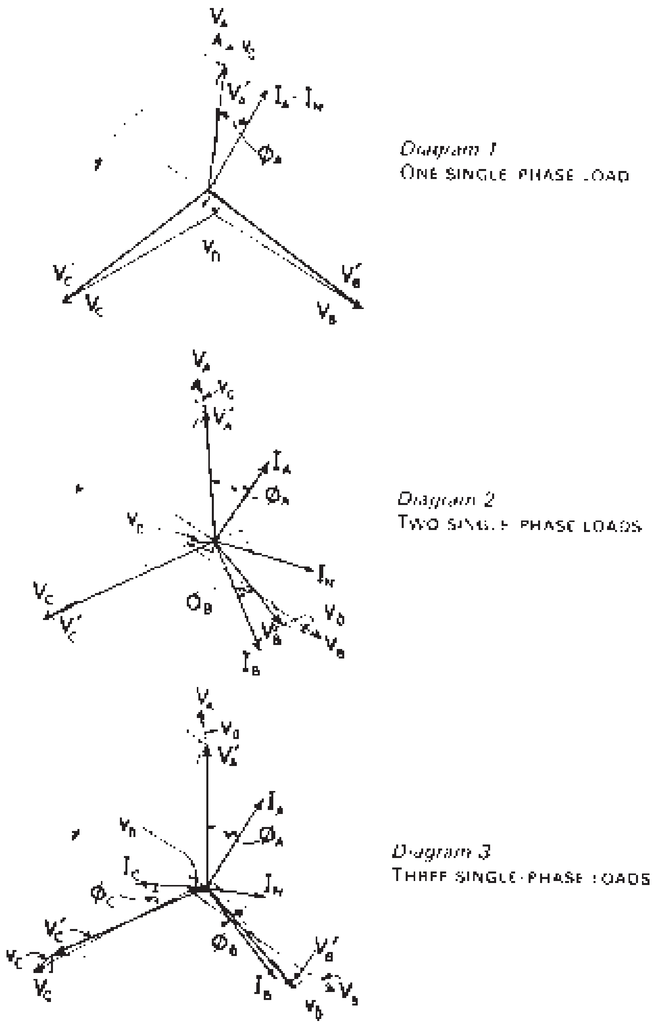
With this connection and method of loading there is no choking effect, as the balancing load current in the corresponding primary windings has a perfectly free path through those windings and the two line wires to the generating source. The voltage drops in the windings are those due only to the normal impedance of the transformer, and the voltages of the open phases are practically the same as at no-load. The neutral points are stable and may be earthed.

It should always be remembered that it is impossible to preserve the current balance on the primary side of a polyphase transformer or bank and in the line wires and source of supply when supplying an unbalanced polyphase load or a pure single-phase load. In most cases the voltage balance is maintained to a reasonable degree, and the voltage drops are only greater than those occurring with a balanced load on account of the greater phase differences between the voltages and the unbalanced polyphase currents or the pure single-phase currents. The voltage drops become accentuated, of course, by the reactance of the circuit when the power factors are low.

Figure 6.138 shows the phasor diagrams for typical unbalanced loading conditions on a delta/star three-phase step-down transformer where one, two and three separate single-phase loads are connected from lines to neutral. Voltage drops include transformer and cable or line drops. The triangles constructed on V'_A, V'_B and V'_C show the resistive and reactive components of the total voltages across the respective loads. In diagram 1 the current I_N in the neutral is the same as the load current I_A; in diagram 2 the neutral current I_N is the phasor sum of the load currents I_A and I_B, while in diagram 3, I_N is the phasor sum of I_A, I_B and I_C.

6.9 THE INFLUENCE OF TRANSFORMER CONNECTIONS UPON THIRD-HARMONIC VOLTAGES AND CURRENTS

It is the purpose of this section, firstly, to state the fundamental principles of third-harmonic voltages and currents in symmetrical three-phase systems;



V_A, V_B, V_C = balanced no-load line to neutral voltages
I_A, I_B, I_C = line load currents
I_N = neutral load current
V_A', V_B', V_C' = load line to neutral voltages at receiving end
v_a, v_b, v_c, v_n = impedance voltage drops in each phase and in the neutral at receiving end
ϕ_A, ϕ_B, ϕ_C = load angles of lag at receiving end

Figure 6.138 Phasor diagrams showing unbalanced loadings on a delta/star, 3-phase, step-down transformer secondly, to indicate their origin in respect of transformers; thirdly, to marshal the facts and present them in tabular form; and finally, to indicate their undesirable features.

No new theories are introduced, but facts, often understood in a more or less vague sort of way, are hopefully crystallised and presented in a clear manner.

The treatment is confined to three-phase transformers with double windings, as the principles, once clearly understood, are easily applicable to polyphase auto-transformers.

Principles of third harmonics in symmetrical three-phase systems

The two forms of connections of three-phase systems behave differently as regards third-harmonic voltages and currents and so need to be considered separately.

(a) Star

In any star-connected system of conductors it is a basic law that the instantaneous sum of the currents flowing to and from the common junction or star point is zero.

In a symmetrical three-phase, three-wire star-connected system, the currents and voltages of each phase at fundamental frequency are spaced 120° apart. At any instant the instantaneous current in the most heavily loaded phase is equal and opposite in direction to the sum of the currents in the other two phases, and at fundamental frequency this balance is maintained throughout the cycle. At third-harmonic frequency, however, currents flowing in each phase would be $3 \times 120 = 360°$ apart, that is in phase with one another and flowing in the same relative direction in the phases at the same instant. The sum of the currents in the star connection would therefore not be zero, and consequently in a symmetrical three-phase, three-wire star-connected system third-harmonic currents cannot exist.

If, however, a connection is taken from the neutral point in such a manner that it completes the circuit of each phase independently (though through a common connection), a current at three times the fundamental frequency can circulate through each phase winding and through the lines and the fourth wire from the neutral point. The fourth wire acting as a drain for third-harmonic currents preserves the current balance of the system; it has, of course, no effect on the currents at fundamental frequency, as these are already balanced.

Third-harmonic voltages, on the other hand, can exist in each phase of a symmetrical three-phase, three-wire star-connected system, that is from each line to earth,* but they cannot appear in the voltages between lines. The third-harmonic voltages in each phase are in phase with one another, so that there is one third-harmonic phasor only, and the neutral point of the star is located at the end of this phasor. The potential of the neutral point is consequently not

* With unearthed neutral, or from each line to neutral with earthed neutral.

zero, but oscillates round the zero point at triple frequency and third-harmonic voltage. *Figure 6.139* illustrates this and also shows how the third-harmonic voltages to earth cancel out, so far as the voltages between lines are concerned, leaving the line terminal voltages free from their influence.

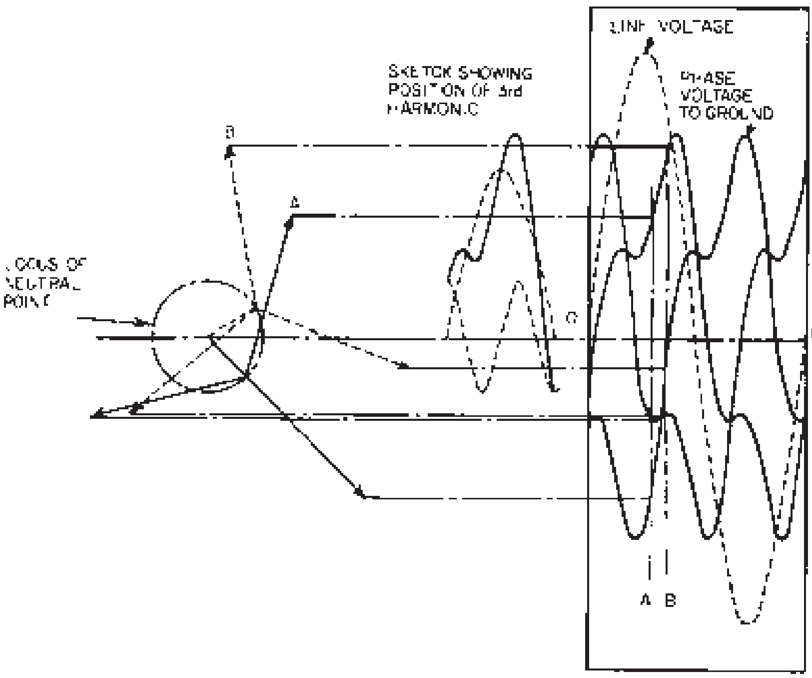


Figure 6.139 Phenomenon of ‘oscillating neutral’ in a symmetrical 3-phase, 3-wire star-connected system with unearthed neutral

When a connection is taken from the neutral point in such a manner as to allow third-harmonic currents to flow, the third-harmonic voltages to neutral are expended in forcing the currents round the circuits. It will be seen subsequently that according to the characteristics of the circuit in which these currents flow, the third-harmonic voltages may be suppressed totally or only partially.

(b) Delta

In any delta-connected system of conductors the resultant fundamental voltage round the delta is zero. That is, the addition of the voltage phasors at fundamental frequency which are spaced $360^\circ/m$ (where m = number of phases) apart forms a regular closed polygon.

In a symmetrical three-phase delta-connected system third-harmonic voltages tending to occur in each phase would be spaced 360° apart, and so would be in phase with each other and act in the closed delta circuit as a single-phase voltage of third-harmonic frequency. Such a voltage could not actually exist in a closed delta system, so that third-harmonic currents circulate round the delta without appearing in the lines and the third-harmonic voltages are suppressed.

In discussing the third-harmonic aspect of various combinations of star and delta connections for three-phase transformer operation, we therefore have the following bases to work upon:

1. With a three-wire star connection, third-harmonic voltages may exist between lines and neutral or earth, but not between lines.
2. With a three-wire connection, third-harmonic currents cannot exist.
3. With a four-wire star connection, third-harmonic voltages from lines to neutral or earth are suppressed partially or completely according to the impedance of the third-harmonic circuit.
4. With a four-wire star connection, third-harmonic currents may flow through the phases and through the line wires and fourth wire from the neutral.
5. With a three-wire delta connection, third-harmonic voltages in the phases and hence between the lines are suppressed.
6. With a three-wire delta connection, third-harmonic current may flow round the closed delta, but not in the lines.

Origin of third-harmonic voltages and currents in transformers

It should be understood that this discussion is quite distinct and apart from higher harmonic functions of the source of supply, and it is limited to those which are inherent in the magnetic and electric circuits of the transformer. The two circuits being closely interlinked, it is a natural sequel that the higher harmonic phenomena occurring in both should be interdependent.

There are two characteristics in the behaviour of sheet-steel transformer laminations when under the influence of an alternating electromagnetic field, which produce an appreciable distortion in the waveform (from the standard sine wave) of certain alternating functions. These functions are no-load current, flux and induced voltages, any distortion of which is due to the varying permeability of the core steel plates and to cyclic magnetic hysteresis. For the purpose of this section, the range of the phenomena involved is more briefly and cogently explained by means of diagrams with short explanations than by lengthy dissertation and tedious mathematical equations. *Figures 6.140* to *6.146* inclusive, together with the following remarks, aim at attaining this end. *Figure 6.140* shows a typical *B/H* curve with hysteresis loop for cold-rolled steel; the hysteresis loop illustrates the general shapes that would occur in practice.

Figure 6.141 shows the waveform relation between the no-load current, flux and induced e.m.f. when the e.m.f. is a sine wave and when hysteresis is absent. From a study of these curves it will be seen that the current is a true

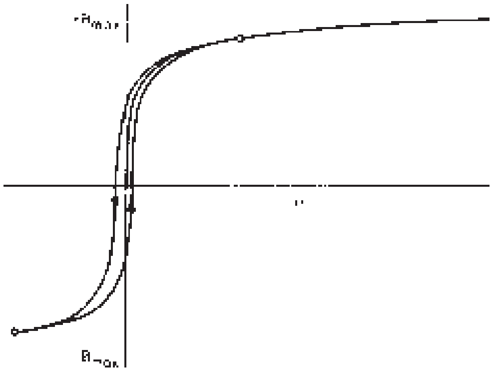


Figure 6.140 Typical B/H curve and hysteresis loop for cold-rolled steel

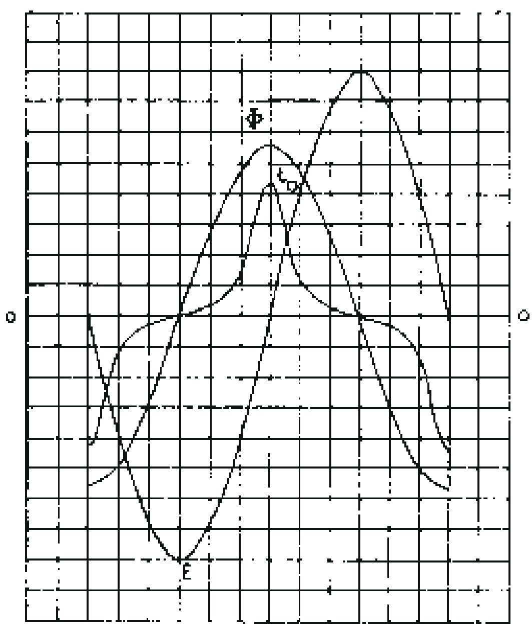


Figure 6.141 No-load current, flux, and induced voltage waves, with a sine wave of applied voltage.

$$i_0 = 100 \sin\theta - 54.7 \sin\theta + 31.5 \sin 5\theta + \ldots$$

magnetising current, being in phase with the flux, its peaked form showing the presence of a prominent third harmonic. It will also be noted that this wave is symmetrical about the horizontal axis, and each half wave about a vertical axis. The flux must, of course, be sinusoidal on account of the assumption of a sine wave-induced e.m.f.

Figure 6.142 is similar to *Figure 6.141* with the exception that hysteresis is taken into account. In this case the current is not a true magnetising current on account of the hysteresis component which is introduced, which makes the no-load current lead the flux by a certain angle θ, the hysteretic angle of advance. This figure also shows that for the same maximum flux the maximum values of the true magnetising and no-load current are the same, but that when taking hysteresis into account the no-load current becomes unsymmetrical about a vertical axis passing through its peak. It will, however, be seen by comparing *Figures 6.141* and *6.142* that the third-harmonic component is contained almost entirely in the true magnetising current, and very little, if any, in the current component due to hysteresis, thus indicating that third-harmonic currents are produced as a result of the varying permeability of the core steel, and only in a very minor degree by magnetic hysteresis.

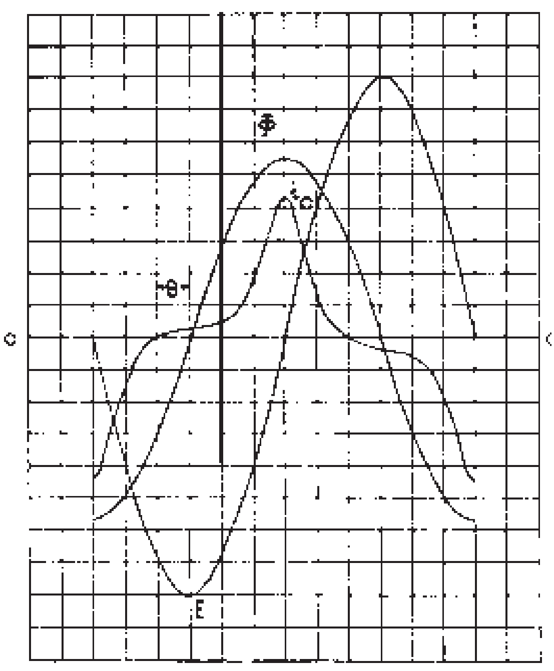


Figure 6.142 No-load current, flux and induced voltage waves, with a sine wave of applied voltage; hysteresis effects included

Figure 6.143 shows the waveform relation between the no-load current, flux and induced e.m.f. when the current is a sine wave and when hysteresis is absent. As in the case of *Figure 6.141*, the current is a true magnetising current and in phase with the flux. The flux wave is flat topped, which indicates the presence of a third harmonic in phase with the fundamental, the harmonic having a negative maximum coincident with the positive maximum of the

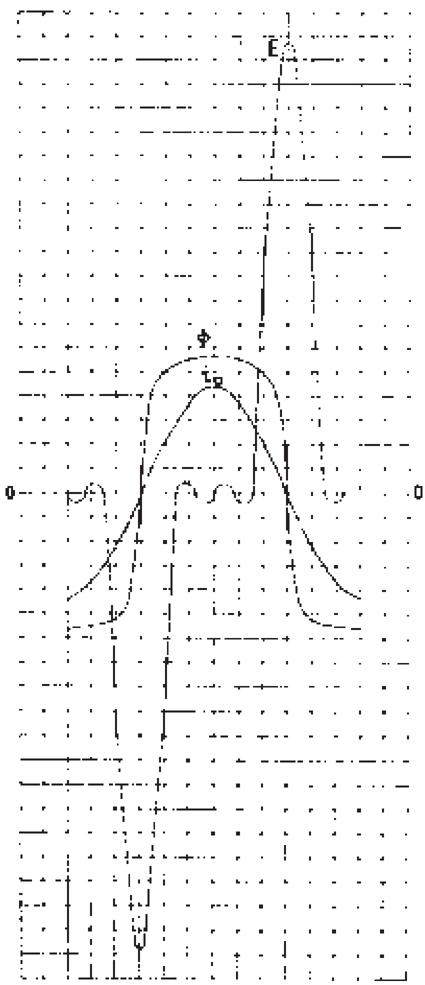


Figure 6.143 No-load current, flux and induced voltage waves, with a sine wave of no-load current; hysteresis effects excluded.

$$m = 100 \sin \theta + 22.9 \sin 3\theta + 5.65 \sin 5\theta + \ldots$$

$$E = 100 \cos \theta + 69.0 \cos 3\theta + 28.4 \cos 5\theta + \ldots$$

fundamental, and so producing a flat-topped resultant wave. It will be noticed that the flux wave is symmetrical about the horizontal axis, and each half-wave about a vertical axis. The induced e.m.f. is, of course, affected by the departure of the shape of the flux wave from the sine, a flat-topped flux wave producing a highly peaked wave of induced e.m.f. (as shown in the figure), in which also appears a prominent third harmonic. In the case of the voltage wave the third harmonic is in opposition to the fundamental, the positive maximum of fundamental and harmonic waves occurring at the same instant, so that the resultant voltage wave becomes peaked.

Figure 6.144 is similar to *Figure 6.143* with the exception that hysteresis is taken into account. In this case the no-load current leads the flux, thereby producing the hysteretic angle of advance θ as in the case of *Figure 6.142*. The flux wave is somewhat more flat topped, and while still symmetrical about the horizontal axis, each half-wave is unsymmetrical about a vertical axis passing through its peak.

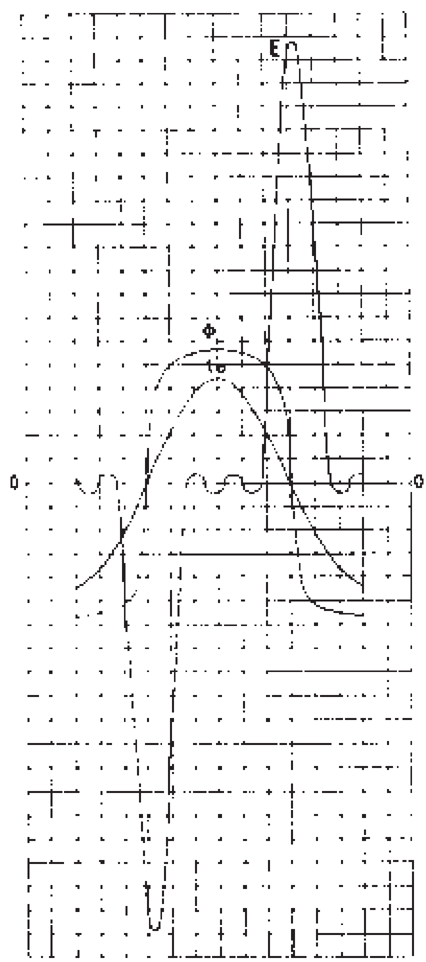


Figure 6.144 No-load current, flux and induced voltage waves with a sine wave of no-load current, hysteresis effects included.

$$\Phi m = 100 \sin \theta + 22.9 \sin 3\theta + 5.65 \sin 5\theta + \ldots$$

$$E = 100 \cos \theta + 69.0 \cos 3\theta + 28.4 \cos 5\theta + \ldots$$

The induced voltage waves of *Figures 6.143* and *6.144* do not take into account harmonics above the fifth, and this accounts for the ripples on the zero axis.

Hysteresis does not alter the maximum value of the flux wave, though it increases its dissymmetry; the wider the hysteresis loop the greater the dissymmetry of the flux wave.

Figures 6.145 and *6.146* show the analysis up to the fifth harmonic of the magnetising current wave, i_0, *Figure 6.141*, and the induced voltage wave *E*, *Figure 6.143*; in each case waves are given showing the sum of the fundamental and third harmonic, and indicating the degree of the error involved in ignoring harmonics beyond the third. In order to obtain some idea at a glance of the approximate phase of the third harmonic relative to the fundamental in a composite wave. *Figure 6.147* shows the shape of the resultant waves obtained when combining the fundamental and third harmonic alone with different positions of the harmonic.

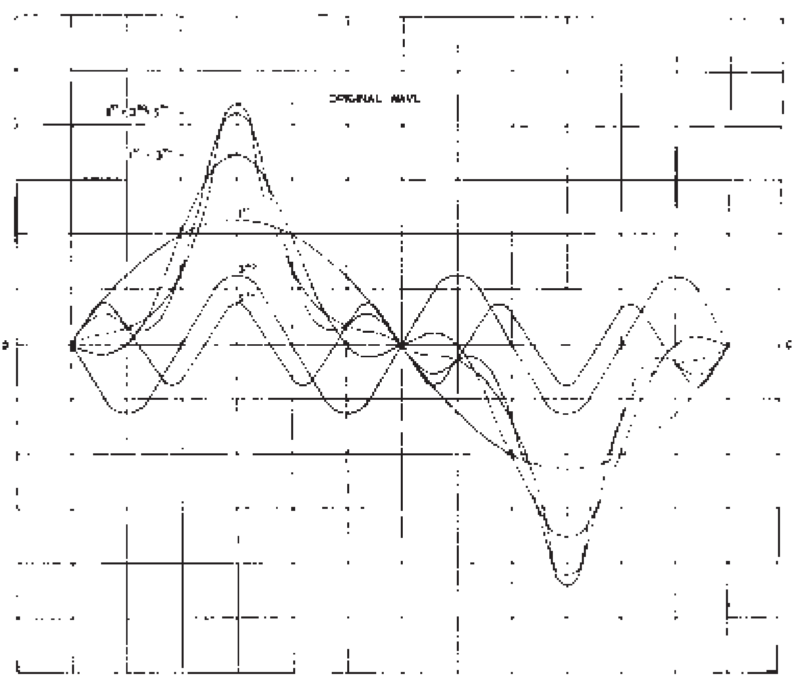


Figure 6.145 Harmonic analysis of peaked no-load current wave of *Figure 6.141*

$i_0 = 100 \sin \theta + 31.5 \sin 5\theta + \ldots$

From the foregoing discussion on the origin of third harmonics the following conclusions are to be drawn:

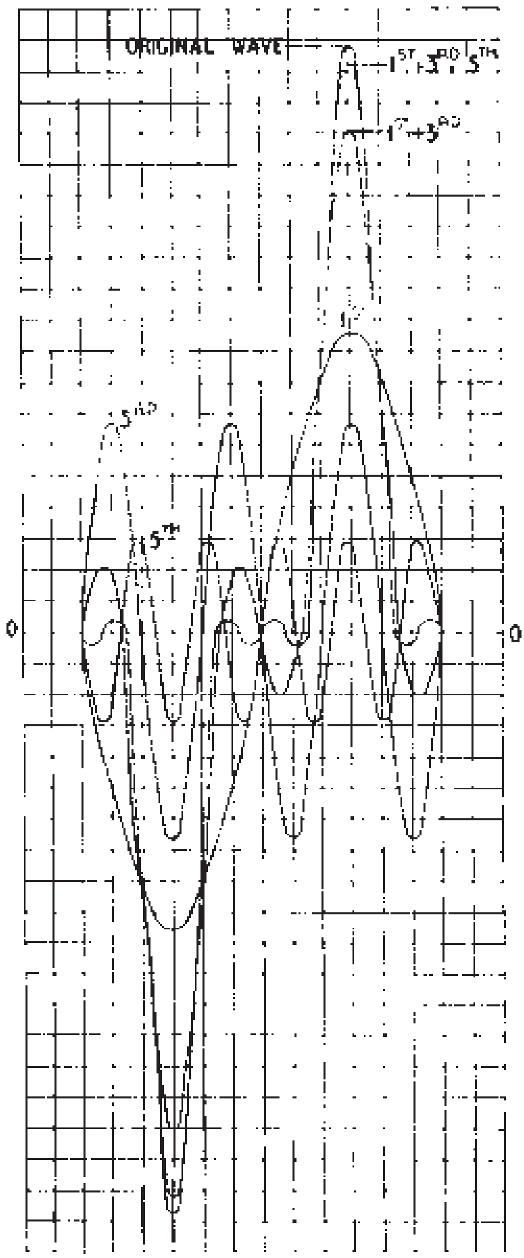


Figure 6.146 Harmonic analysis of peaked induced voltage wave of *Figure 6.143*

$E = 100\cos\theta + 69\cos\theta = 28.4\cos 5\theta + \ldots$

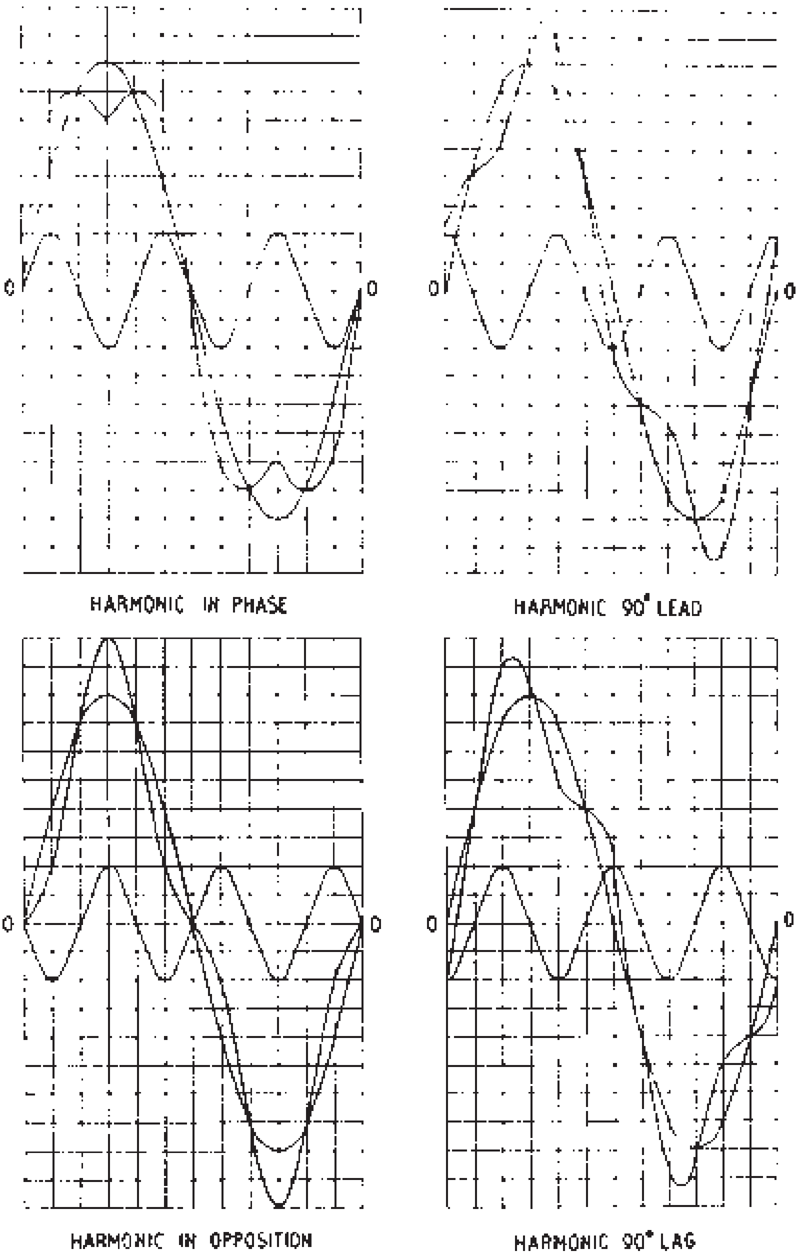


Figure 6.147 Combinations of fundamental and third-harmonic waves

1. With a sine wave of flux, and consequently induced voltages, the no-load current contains a prominent third harmonic which produces a peakiness in the wave. The third harmonic is introduced mainly into the true magnetising current component through the variation in the permeability of the sheet steel and only in a very small degree into the hysteresis component of the current by the cyclic hysteresis.
2. With a sine wave of no-load current the flux and consequently the induced voltages contain prominent third harmonics which produce a flat-topped flux wave and peaked induced voltage waves.

Table 6.26 summarises the above conclusions: (a) for constant B_{max}; (b) for constant E r.m.s.

Table 6-26 Wave shape relationship between flux, induced voltage and no-load current

CONSTANT $B_{MAX.}$						
FLUX			INDUCED VOLTAGE		NO LOAD CURRENT	
WAVE SHAPE	FORM FACTOR COMPARD TO SINE WAVE	IRON LOSS COMPARED TO THAT WITH SINE WAVE FLUX	WAVE SHAPE	FORM FACTOR COMPARD TO SINE WAVE	WAVE SHAPE	FORM FACTOR COMPARD TO SINE WAVE
SINE (RMS b, MAX a)	SAME	SAME	SINE (RMS b′, MAX a′)	SAME	PEAKED THIRD HARMONIC IN OPPOSITION (RMS <b″, MAX a″)	GREATER
FLAT THIRD HARMONIC IN PHASE (RMS >b, MAX a)	LESS	LESS	PEAKED THIRD HARMONIC IN OPPOSITION (RMS >b′, MAX >a′)	GREATER	SINE (RMS b″, MAX a″)	SAME
SINE (RMS b, MAX a)	SAME	SAME	SINE (RMS b′, MAX a′)	SAME	PEAKED THIRD HARMONIC IN OPPOSITON (RMS b″, MAX a″)	GREATER
FLAT THIRD HARMONIC IN PHASE (RMS <b, MAX <a)	LESS	LESS	PEAKED THIRD HARMONIC IN OPPOSITION (RMS b′, MAX >a′)	GREATER	SINE (RMS b″, MAX a″)	SAME

Undesirable features of third harmonics

These are summarised under two headings as follows:

Due to third-harmonic currents

(a) Overheating of transformer windings and of load.
(b) Telephone and discriminative protective gear magnetic disturbances.
(c) Increased iron loss in transformers.

Due to third-harmonic voltages

(d) Increased transformer insulation stresses.
(e) Electrostatic charging of adjacent lines and telephone cables.
(f) Possible resonance at third-harmonic frequency of transformer windings and line capacitance.

These disadvantages may briefly be referred to as follows:

(a) In practice, overheating of the transformer windings and load due to the circulation of third-harmonic current rarely occurs, as care is taken to design the transformer so that the flux density in the core is not so high as to increase the third-harmonic component of the no-load current unduly. Apart from the question of design, a transformer might, of course, have a higher voltage impressed upon it than that for which it was originally designed, but in this case the increased heating from the iron loss due to the resulting higher flux density would be much more serious than the increased heating in the transformer windings due to larger values of the third-harmonic circulating current. These remarks hold good, irrespective of whether the transformer windings are delta connected or star connected with a fourth wire system.

The only case where the circulation of the third-harmonic currents is likely to become really serious in practice is where the transformer primary windings are connected in interconnected star, the generator and transformer neutrals being joined together.

(b) It is well known that harmonic currents circulating in lines paralleling telephone wires or through the earth where a telephone earth return is adopted produce disturbances in the telephone circuit. This is only of practical importance in transmission or distribution lines of some length (as distinct from short connections to load), and then as a rule it only occurs with the star connection using a fourth wire, which may be one of the cable cores or the earth.

Similar interference may take place in the pilot cores of discriminative protective gear systems, and unless special precautions are taken relays may operate incorrectly.

The remedy consists either of using a delta-connected transformer winding or omitting the fourth wire and earthing at one point of the circuit only.

(c) In the case of a three-phase bank of single-phase transformers using a star/star connection, it has been proved experimentally that a fourth wire connection on the primary side between the transformer bank and generator neutrals (which allows the circulation of third-harmonic currents) results in increasing the iron loss of the transformers to 120% of that obtained with the neutrals disconnected. This figure varies according to the design of the transformers and the impedance of the primary circuit. The conditions are similar for three-phase shell-type transformers.

Under certain conditions, the third-harmonic component of the phase voltage of star/star-connected three-phase shell-type transformers or banks of single-phase transformers may be amplified by the line capacitances. This occurs when the HV neutral is earthed, so that third-harmonic currents may flow through the transformer windings, returning through the earth and the capacitances of the line wires to earth. The amplification occurs only when the capacitance of the circuit is small as compared to its inductance, in which case the third-harmonic currents will lead the third-harmonic voltages almost by 90°, and they will be in phase with the third-harmonic component of the magnetic fluxes in the transformer cores. The third-harmonic component of the fluxes therefore increases, which in turn produces an increase in the third-harmonic voltages, and a further increase of the third-harmonic capacitance currents. This process continues until the transformer cores become saturated, at which stage it will be found the induced voltages are considerably higher and more peaked than the normal voltages, and the iron loss of the transformer is correspondingly greater. In practice, the iron loss has been found to reach three times the normal iron loss of the transformer, and apparatus has failed in consequence.

This phenomenon does not occur with three-phase core-type transformers on account of the absence of third harmonics.

(d) It has been pointed out previously that with the three-wire star connection and isolated neutral a voltage occurs from the neutral point to earth having a frequency of three times the fundamental, so that while measurements between the lines and from lines to neutral indicate no abnormality, a measurement from neutral to earth with a sufficiently low reading voltmeter would indicate the magnitude of the third harmonic. In practice, with single-phase transformers the third-harmonic voltages may reach a magnitude of 60% of the fundamental, and this is a measure of the additional stress on the transformer windings to earth. While due to the larger margin of safety it may not be of great importance in the case of distribution transformers, it will have considerable influence on the reliability of transformers at higher voltages.

(e) Due also to the conditions outlined in (d), star-connected banks of single-phase transformers connected to an overhead line or underground cable, and operated with an earthed or unearthed neutral, may result in an electrostatic charging at third-harmonic frequency of adjacent power and telephone cables. This produces abnormal induced voltages to earth if the adjacent circuits are not earthed, the whole of the circuit being raised to an indefinite potential above earth even though the voltages between lines remain normal. The insulation to earth, therefore, becomes unduly stressed, and the life of the apparatus probably reduced.

(f) A further danger due to the conditions outlined under (e) is the possible resonance which may occur at third-harmonic frequency of the transformer windings with the line capacitance. This can happen if the transformer neutral is earthed or unearthed, and the phenomenon occurs perhaps more frequently than is usually appreciated, but due to the present-day complicated networks and the resulting large damping constants, the magnitude of the quantities is such as often to render the disturbances innocuous.

Further notes on third harmonics with the star/star connection

It is generally appreciated that three-phase shell-type transformers and three-phase groups of single-phase transformers should not have their windings connected star/star on account of the third-harmonic voltages which may be generated in the transformers at the normal flux densities usually employed. It is, however, not so equally well known that under certain operating conditions the star/star connection of the type of transformers referred to above may produce serious overheating in the iron circuit in addition to augmented stresses in the dielectrics. The conditions referred to are when the secondary neutral of the transformer or group is earthed, the connecting lines having certain relative values of electrostatic capacitance.

Consider a three-phase step-up group of single-phase transformers having their windings star/star connected, each transformer of such a group having a flux density in the core of approximately 1.65 tesla.

With isolated neutrals on both sides, no third-harmonic currents can flow, and consequently the magnetic fluxes and induced voltages would contain large third-harmonic components, the flux waves being flat topped and the induced voltage waves peaked. The magnetising current waves would be sinusoidal. At the flux density stated, the flux waves would have a third-harmonic component approximately equal in amplitude to 20% of that of the fundamental, and the resulting induced voltage waves would have third-harmonic components of amplitudes of approximately 60% of that of their fundamentals. With isolated neutrals the third-harmonic components of the voltage waves would be measurable from each neutral to earth by an electrostatic voltmeter. Their *effects* would be manifested when measuring the voltages from each line terminal to the neutral point by an ordinary moving iron or similar voltmeter. There would be no trace of them when measuring between line terminals on account of their opposition in the two windings which are in series between any two line terminals so far as third harmonics are concerned.

With isolated neutrals the only drawback to the third-harmonic voltage components is the increased dielectric stress in the transformer insulation.

It should be borne in mind that so far as third harmonics of either voltage or current are concerned the transformer windings of each phase are really in parallel and the harmonics in each winding have the same time phase position. When such transformers are connected to transmission or distribution lines on open circuit, the parts which are effective so far as third harmonics are concerned can be represented as shown in *Figure 6.148(a)* where we have three circuits in parallel, each consisting of one limb of the transformer with the capacitance to earth of the corresponding line, this parallel circuit being in series with the capacitance between earth and the neutral point of the transformer. By replacing the three parallel circuits by a simple equivalent circuit consisting of a resistance, inductance and capacitance, *Figure 6.148(a)* can be simplified to that shown in *Figure 6.148(b)*. The inductance is that of the three phases of the transformer in parallel, and the voltage across these is the third-harmonic voltage generated in each secondary phase of the transformer. As the

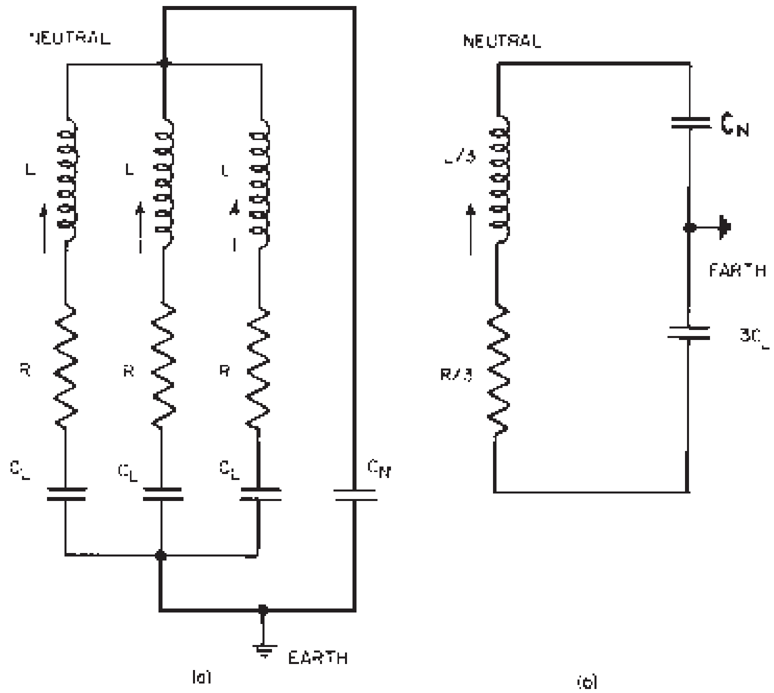


Figure 6.148 Third-harmonic distribution of inductance, resistance and capacitance in an unearthed neutral 3-phase circuit consisting of the secondaries of a 3-phase group of single-phase transformers supplying an open-ended transmission line

third-harmonic voltages are generated in the transformer windings on account of the varying permeability of the magnetic cores, the inductance shown in *Figure 6.148(b)* can be looked upon as being a triple-frequency generator supplying a voltage equal to the third-harmonic voltage of each phase across the two capacitors in series. The capacitor $3C_L$ is equal to three times the capacitance to earth of each line while the capacitor C_N represents the capacitance from the neutral point to earth. By comparison the latter capacitor is infinitely small, so that as a voltage applied across series capacitors divides up in inverse proportion to their capacitances, practically the whole of the third-harmonic voltage appears across the capacitor formed between the transformer neutral point and earth. This explains why, in star/star-connected banks having isolated neutrals, the third-harmonic voltage can be measured from the neutral point to earth by means of an electrostatic voltmeter.

Now consider the conditions when the secondary neutral point is earthed, the secondary windings being connected to a transmission or distribution line on open-circuit. This line, whether overhead or underground, will have certain values of capacitance from each wire to earth, and so far as third harmonics are concerned the circuit is as shown diagrammatically in *Figure 6.149(a)*. It will be seen that the only difference between this figure and *Figure 6.148(a)* is that the capacitor C_N between the neutral point and earth has been short-circuited. The effect of doing this may, under certain conditions, produce undesirable results. The compound circuit shown in *Figure 6.149(a)* may be replaced by that shown in *Figure 6.149(b)*, where resistance, inductance and capacitance are respectively the single equivalents of the three shown in parallel in *Figure 6.149(a)*, and from this diagram it will be seen that all the third-harmonic voltage is concentrated from each line to earth. Under this condition the third-harmonic component cannot be measured directly, but its effects are manifested when measuring from each line terminal to earth by an ordinary moving-iron or similar instrument.

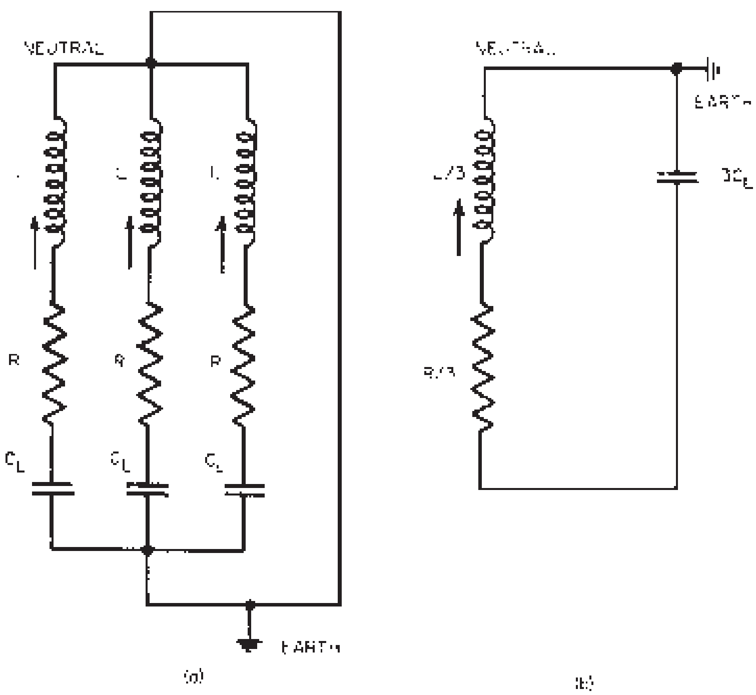


Figure 6.149 Third-harmonic distribution of inductance, resistance and capacitance in an earthed neutral 3-phase circuit consisting of the secondaries of a 3-phase group of single-phase transformers supplying an open-ended transmission line

The chief difference between the conditions illustrated in *Figures 6.148(a)* and *6.149(a)* is that where in the first case no appreciable third-harmonic current could flow on account of the small capacitance between the neutral point and earth, in the second case triple-frequency currents can flow through the transformer windings completing their circuit through the capacitances formed between the lines and earth. We thus see that the conditions are apparently favourable for the elimination of the third-harmonic voltages induced in the transformer windings on account of the varying permeability of the magnetic cores.

This, however, is not all the story, for in order that the third-harmonic voltages induced in the transformer windings shall be eliminated, the third-harmonic currents must have a certain phase relationship with regard to the fundamental sine waves of magnetising currents which flow in the primary windings. In practice the third-harmonic currents flowing in such a circuit as shown in *Figure 6.149(a)* may or may not have the desired phase relationship, for the following reasons.

The circuit shown in *Figure 6.149(b)* is a simple series circuit of inductance L resistance R and capacitance C, the impedance of which is given by the equation,

$$Z = \sqrt{R^2 + \left(2\pi f L - \frac{1}{2\pi f C}\right)^2}$$

The resistance R is the combined resistance of the three circuits in parallel shown in *Figure 6.149(a)*, namely, the transformer windings which are earthed, the lines, and the earth. The capacitance C is the combined capacitance of the three lines to earth in parallel, as the capacitance of the transformer windings to earth is so small that it can be ignored. The inductance L is the combined inductance of the three transformer windings in parallel which are earthed, the inductance between the lines and earth being ignored on account of their being very small. The inductance of the transformer windings corresponds to open-circuit conditions, as the triple-frequency currents are confined to the secondary windings only, on account of the connections adopted.

For a circuit of this description the power factor is given by the expression,

$$\cos\phi = \frac{R}{Z} = \frac{R}{\sqrt{R^2 + \left(2\pi f L - \frac{1}{2\pi f C}\right)^2}}$$

and the angle of lead or lag of the current with respect to the applied voltage is

$$\phi = \tan^{-1}\left(\frac{2\pi f L - 1/2\pi f C}{R}\right) \tag{6.61}$$

If the value of $2\pi f L$ is greater than that of $1/2\pi f C$ the angle ϕ is lagging, and if smaller the angle ϕ is leading.

There are three extreme conditions to consider:

1. when C is very large compared with L;
2. when L is very large compared with C;
3. when L and C are equal.

If C is large compared with L the impedance of the combined circuit is relatively low, so that the line capacitances to earth form, more or less, a short-circuit to the third-harmonic voltage components induced in the transformer secondary windings. Under this condition the resulting third-harmonic currents will be lagging with respect to the third-harmonic voltage components. The third-harmonic currents will act with the fundamental waves of primary magnetising current to magnetise the core, and the resulting total ampere-turns will more or less eliminate the third-harmonic components of the flux waves, bringing the latter nearer to the sine shape. This will correspondingly reduce the third-harmonic voltage components, making the induced voltage waves also more sinusoidal. The reduction in third-harmonic voltage components will have a reflex action upon the third-harmonic currents circulating through the transformer secondary windings and the line capacitances, and a balance between third-harmonic voltages and currents will be reached when the third-harmonic voltage components are reduced to such an extent as to cause no further appreciable flow of secondary third-harmonic currents.

In the extreme case where the line capacitances are so large as to make the capacitive reactance practically zero, almost the full values of lagging third-harmonic currents flow in the secondary windings to eliminate practically the whole of the third-harmonic voltages, so that from the third-harmonic point of view this condition would be equivalent to delta-connected secondary transformer windings. *Figure 6.150* shows the different current, flux and induced voltage wave phenomena involved, assuming that $C_L > L_L$.

The diagrams of *Figure 6.150* show the phase relationship of all the functions involved, but they do not show the actual third-harmonic flux and voltage-reduction phenomena. The composite diagram of *Figure 6.150* shows clearly that the third-harmonic secondary current is in opposition to the third-harmonic flux component, and the result is a reduction in amplitude of the latter. As a consequence the induced voltage waves become more nearly sinusoidal, and ultimately they approach the true sine wave to an extent depending upon the value of the capacitance reactance of the secondary circuit.

When, however, the inductance of the transformer windings is high compared with the line capacitances to ground, the third-harmonic components of the voltage waves become intensified. In this case the inductive reactance is very high compared with the capacitive reactance, so that the third-harmonic voltage components impressed across the line capacitances produce third-harmonic secondary currents which lead the third-harmonic secondary voltages.

The angle of lead is given by equation (6.61) and in the extreme case where the capacitance is very small the third-harmonic current will lead the third-harmonic voltage almost by 90°. The resulting third-harmonic ampere-turns of the secondary winding act together with the fundamental exciting ampere-turns in the primary, and as the two currents are in phase with one another their effect is the same as that produced by a primary exciting current equal to the sum of the fundamental primary and third-harmonic secondary currents. The

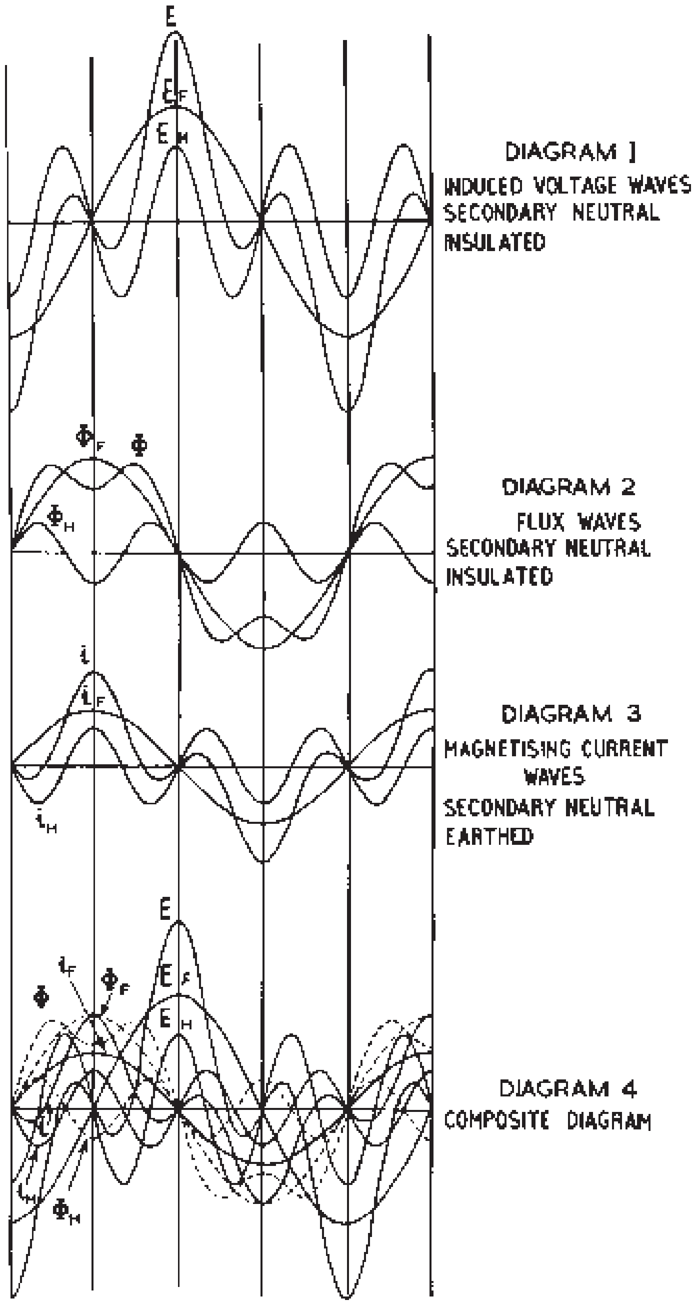


Figure 6.150 Induced voltage, flux and magnetising current waves in a 3-phase star/star-connected group of single-phase transformers with secondary neutral solidly earthed and supplying an open-ended line such that $C_L > L_L$

sum of two such currents in phase is a dimpled current wave, and compared with the fundamental sine wave of exciting current the r.m.s. value of the composite current wave is higher, though more important than this is the fact that such a current wave produces a very flat-topped flux wave. In other words, the third-harmonic components of the flux waves are intensified, and on this account the third-harmonic voltage components of the induced voltage waves are also intensified.

Higher third-harmonic voltage waves react upon the secondary circuit to produce larger third-harmonic currents, which in turn increase the third-harmonic flux waves, and again the third-harmonic voltage waves. This process of intensification continues until a further increase of magnetising current produces no appreciable increase of third-harmonic flux, so that the ultimate induced voltages become limited only by the saturation characteristics of the magnetic circuit. It should be noted that the third-harmonic currents circulate in the secondary windings only, as the connections on the primary side do not permit the transfer of such currents.

Figure 6.151 shows the phase relationship of the different current, flux and induced voltage waves involved, assuming the third-harmonic currents lead the third-harmonic voltage components by 90°. The diagrams of this figure do not show the actual amplification phenomena. The composite diagram shows very clearly that the third-harmonic secondary current is in phase with the third-harmonic flux component, and the result is an amplification of the latter. Therefore, the induced voltage waves become more highly peaked and ultimately reach exceedingly high values, producing excessive dielectric stresses, high iron losses, and severe overheating.

Cases have occurred of transformer failures due to this third-harmonic effect, and one case is known where, on no-load, the transformer oil reached a temperature rise of 53°C in six hours, the temperature still rising after that time at the rate of 3°C per hour.

In the resonant condition where the capacitive and inductive reactances are equal, the flow of third-harmonic current is limited only by the resistance of the secondary circuit. The third-harmonic currents would be in phase with the third-harmonic voltage components, and being of extremely high values they would produce exceedingly high voltages from each line to earth and across the transformer windings. The transformer core would reach even a higher degree of saturation than that indicated in the previous case, and the transformers would be subjected to excessive dielectric and thermal stresses. *Figure 6.152* shows the wave phenomena apart from the amplification due to resonance.

The resonant condition fortunately, however, is one that may be seldom met, but the other two cases are likely to occur on any system employing star/star-connected transformers with earthed secondary neutral, and unless some provision can be made for allowing the circulation of third-harmonic currents under permissible conditions three-phase shell-type transformers or three-phase groups of single-phase transformers should not so be connected.

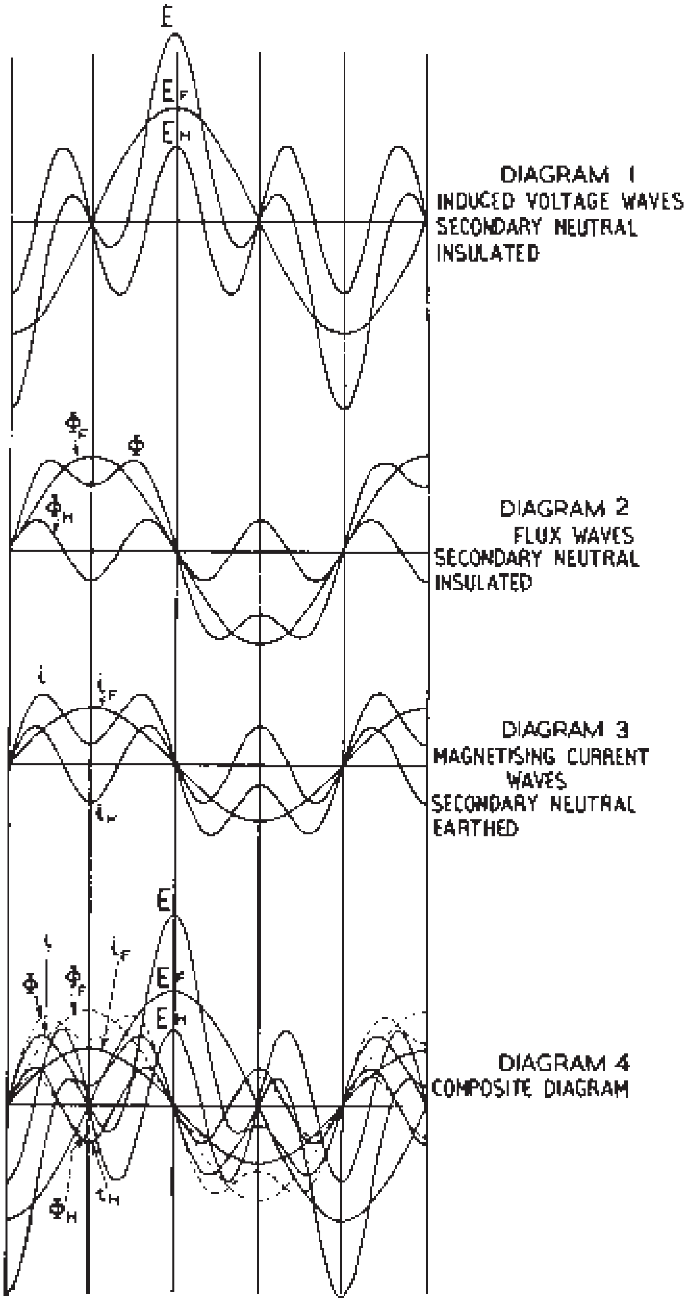


Figure 6.151 Induced voltage, flux and magnetising current waves in a 3-phase star/star-connected group of single-phase transformers with secondary neutral solidly earthed and supplying an open-ended line such that $L_L > C_L$

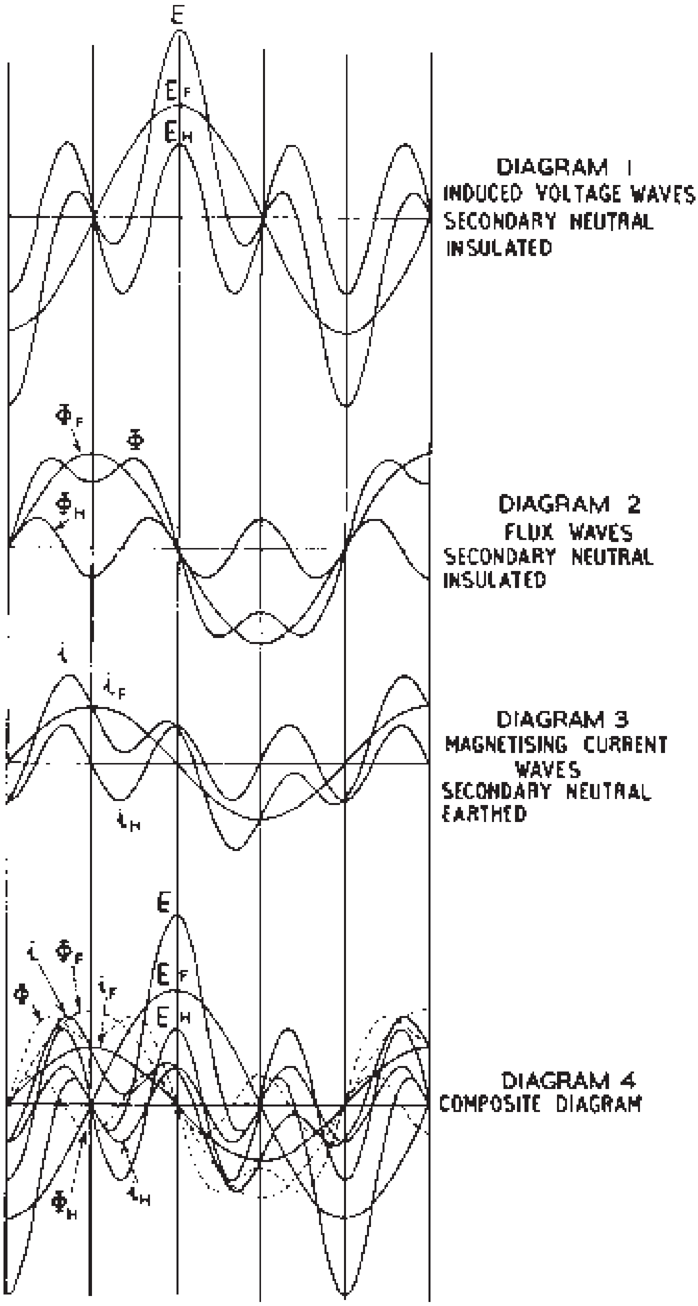


Figure 6.152 Induced voltage, flux and magnetising current waves in a 3-phase star/star-connected group of single-phase transformers with secondary neutral solidly earthed and supplying an open-ended line such that $C_C = L_L$

With three-phase core-type transformers there is still theoretically the same disadvantage, but as in such transformers the third-harmonic voltage components do not exceed about 5% of the fundamental, the dangers are proportionately reduced. However, at high transmission voltages even a 5% third-harmonic voltage component may be serious in star/star-connected three-phase core-type transformers when the neutral point is earthed, and it is therefore best to avoid this connection entirely if neutral points have to be earthed.

Precisely the same reasoning applies to three-phase transformers or groups having interconnected-star/star windings if it is desired to earth the neutral point on the star-connected side. With this connection the third-harmonic voltages are eliminated by opposition on the interconnected-star side only, but they are present on the star-connected side in just the same way as if the windings were star/star connected, their average magnitudes being of the order 5% for three-phase core-type transformers and 50–60% in three-phase shell-type and three-phase groups of single-phase transformers.

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7 Special features of transformers for particular purposes

Previous chapters have examined those features which are common to the majority of power transformers. This chapter takes a closer look at specific classes of transformer to identify the special aspects which are required for each particular application.

7.1 GENERATOR TRANSFORMERS

Required characteristics

It is appropriate to commence this examination of specific transformer types by considering generator transformers and in this context these are taken to mean those step-up transformers directly connected to generator output terminals in large generating stations. The break-up of the state monopoly and privatisation of electricity supply arrangements in the UK since 1990 have lead to an increase in the number of individual combined heat and power, wind power and other installations of embedded generation having ratings ranging from a few hundred kW to a few MW and connected to the local distribution network at 3.3 or 11 kV. It is generally uneconomic to make any special provision in the design of generator transformers for these small installations and usually normal distribution transformer design practices are acceptable, although it may be necessary to incorporate on-load tapchangers to ensure the generator output can be passed into the local network.

Most large modern generators are designed for operation at voltages between about 11 and 30 kV. The generator designer aims to use as high a voltage as practicable so as to limit the stator current necessary to achieve the required output. Increase of the machine voltage significantly beyond the minimum necessary requires more insulation on the generator stator windings, thus increasing its size and cost. Hence machines of around 150 MW generally operate at 11 kV and have line currents of around 9260 A at 0.85 power factor, while those at 660 MW, in the UK, usually operate at 23.5 kV with line currents of about 19 000 A at 0.85 power factor. Since the generation is usually located away from the load centres, for economic transmission it is necessary to greatly reduce these output currents, so at most power stations the generator output voltage is immediately stepped up by means of a generator transformer, and nowadays power stations are designed on the unit principle, so that each generator will have its own dedicated step-up transformer. In the case of combined cycle gas turbine (CCGT) plants this can mean having four step-up transformers, three associated with the gas turbines (each rated about 150 MW) and one with the steam turbine (rated about 250 MW) on a single unit. All four of these transformers may be connected together via isolators at 400 kV and switched by a single 400 kV circuit breaker to the 400 kV transmission system.

Generator transformers thus frequently have a wide voltage ratio, maybe 11/420 kV in the case of the above-mentioned 150 MW unit. The rating must be sufficient to allow the generator to export its full megawatt output at 0.85 power-factor lagging or 0.95 power-factor leading or, alternatively, half of full megawatt output at 0.7 power-factor leading, so that for a generator output of 150 MW, the transformer rating will need to be 150/0.85, which is approximately 176 MVA, and for 660 MW it must be 660/0.85 which is approximately 776 MVA.

In the UK some of the first CEGB 660 MW generators were designed to deliver full output at 0.8 power factor which, after subtracting the power requirements absorbed by the unit auxiliaries, led to a maximum output power of 800 MVA, so that for the sake of standardisation the CEGB generator transformer rating was generally fixed at that level.

The important criteria which influence the generator transformer design are as follows:

- The HV volts are high – often, in the UK, 400 kV nominal.
- The LV current is high – about 19 000 A for an 800 MVA, 23.5 kV transformer.
- The impedance must be lower than that resulting from the simplest design for this rating – a figure of about 16% is generally specified over a wide range of ratings and variation with tap position must be kept to a minimum to simplify the system design and operation.
- An on-load tapchanger is required to allow for variation of the HV system volts and generator power factor. LV volts will generally remain within $\pm 5\%$ under the control of the generator automatic voltage regulator (AVR). It should be noted that there is an alternative view prevailing among some utilities who see on-load tapchangers as a source of unreliability in an area where high availability and load factor is paramount. These utilities prefer

to have a very limited range of off-circuit taps on the generator transformer, say ± 2.5 and $\pm 5\%$, and control unit voltage and power factor entirely by means of the generator AVR. This approach, however, requires a very much larger and more costly AVR, and the holders of this viewpoint tend to be in the minority.

- The transport weight must be within the limits laid down by the appropriate transport authorities and the available transport vehicles.
- Transport height must meet the maximum limit permitted by the need to pass under any road bridges on the route to site or to the port of loading onto a vessel, if the transformer is to be transported by sea.
- Reliability and availability must be as high as possible, since without the generator transformer, unit output cannot be made available to the transmission network.

There are also a number of other criteria which although less important will also have a bearing on the design. These are:

- Because of the high load factor, both load and no-load losses must be as low as possible.
- In view of the direct connection to the EHV transmission system, a high impulse strength is required.
- Noise level must be kept below a specified level.
- Very little overload capability is necessary since generator output cannot normally be increased, although most gas turbine generators achieve maximum output with an inlet-air temperature of 0°C so that generator transformers associated with these often have a designated rating at 0°C which is a few percent higher than the IEC 76 rating. Many fossil-fuelled steam turbines are capable of about 4% increase in output at 0°C with some loss of efficiency by bypassing part of the feed-heater train so that generator transformers for these units are required to match this output.

Load rejection

Generator transformers may be subjected to sudden load rejection due to operation of the electrical protection on the generator. This can lead to the application of a sudden overvoltage to the terminals connected to the generator. Very little documentary evidence is in existence concerning the likely magnitude of the overvoltage since monitored full-load rejections on generators are not the type of tests which are carried out every day. CEGB carried out some testing in the 1970s and concluded that the likely magnitude was of the order of 135% of normal voltage and this might persist for up to one minute. As a result of this testing the CEGB specification for generator transformers contained a clause requiring that this level and time of overvoltage should be withstood without damage. Manufacturers of generator transformers maintained that before the overvoltage had reached this level the core would become saturated and would thus draw a very large magnetising current at a very low power factor which would have the effect of pulling the generator voltage down. The feeling was that the end result would be a magnitude of about 125% volts persisting for something less than one minute. IEC 76, Part 1, specifies that generator transformers subject to load rejection should withstand 140% volts for 5 seconds. This is probably pessimistically high but for an optimistically short duration.

General design features

The extensive list of required characteristics given above places considerable constraints on the design of the generator transformer. For even quite modestly rated generator transformers in the UK, where transport is invariably by road, the most limiting factor is that of transport weight coupled with travelling height. For a transformer of 400 kV, the high voltage requires large internal clearances which means increasing size and, as can be seen from the expression for leakage reactance – equation (2.1) in Chapter 2 – increased HV to LV clearance has the effect of increasing the reactance, and hence the impedance. This tendency to increase reactance would normally be offset by an increase in the axial length of the winding but, for a large generator transformer, even when measures are adopted such as reduced yoke depth for the core, necessitating outer return limbs resulting in a five-limb core, the stage is soon reached where further increases cannot be obtained because of the limit on transport height.

A significant reduction in leakage reactance for given physical dimensions can be obtained by adopting an arrangement of windings known as 'split concentric'. This is shown in *Figure 7.1(a)*. The HV winding has been split into two sections, with one placed on either side of the LV winding. This is not too inconvenient for a transformer with graded HV insulation, since the inner HV winding is at lower voltage and can therefore be insulated from the earthed core without undue difficulty. The reason why this arrangement reduces leakage reactance can be seen from *Figures 7.1(b)* and *(c)*, which give plots of leakage flux both for simple-concentric and split-concentric arrangements having the same total m.m.f. It can be shown that the leakage reactance is proportional to the area below the leakage flux curve, which is significantly less in the split-concentric design. The price to be paid for this method of reducing the leakage reactance which, in reality, means significantly reducing the physical size for a given rating, is the complexity involved in the increased number of windings, increased number of leads, and increased sets of interwinding insulation. For simplicity, the tapping winding has not been shown in *Figure 7.1(c)*. With this split-concentric arrangement, it is usual to locate the taps in a separate winding below the inner HV winding. As taps are added or removed, the ratio of the HV split is effectively varied and this has the effect of producing relatively large changes in leakage reactance. This undesirable feature is a further disadvantage of this form of construction.

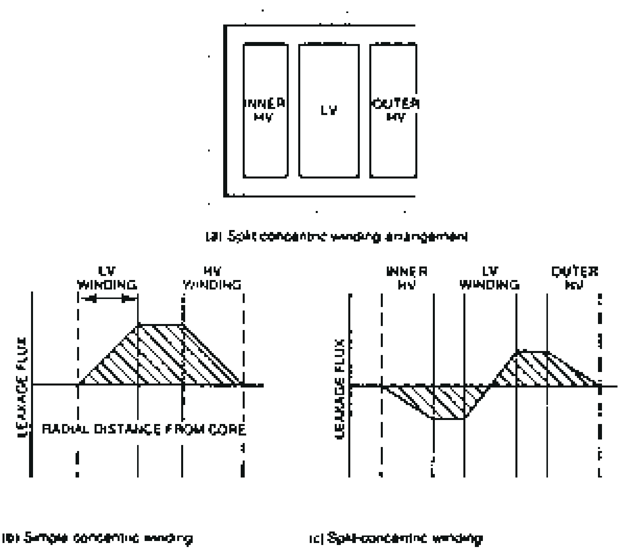


Figure 7.1 Split-concentric winding arrangement

Throughout the 1960s, at the time of building most of the CEGB 500 MW units, the split-concentric arrangement was the most common form adopted for 570 and 600 MVA three-phase generator transformers. This enabled these transformers to be transported as three-phase units within limits of about 240 tonnes transport weight and 4.87 m travelling height, albeit most of them had very high flux densities, a nominal 1.8 tesla, and relatively high losses in order to keep the material content to the minimum. It was still necessary to resort to reduced yoke depths and five-limb cores to meet the maximum height limit. The use of aluminium tanks was another measure employed, and, in the case of one manufacturer, a very sophisticated lightweight steel tank having a girder frame and stressed-skin construction was used. In fact, a transformer of 735 MVA, three phase, was transported within these height and weight limits to Hartlepool power station, although its HV winding was only 275 kV. However, at the time of the adoption of the 660 MW unit size for the Drax power station (now owned by National Power) at the end of the 1960s, it was decided to make the transition to single-phase units. These have many advantages and will be described in greater detail in the following section.

Single-phase generator transformers

With the adoption of single-phase construction, transport weight for 800 MVA and probably even larger transformers ceases to impose such a major constraint on the transformer designer. Travelling height continues to impose some restriction, but the designer is usually able to deal with this without undue difficulty, and as will become clear, single-phase construction provides even more scope than does three phase for reduced yoke depths.

It is now normal practice to design for a nominal flux density at nominal voltage of 1.7 tesla since this offers a better margin of safety below saturation than the figure of 1.8 tesla previously allowed and it was CEGB practice, in addition, to specify that this should not exceed 1.9 tesla at any point in the core under any operating condition. When originally framed, this specification clause was intended to allow for some local increase in flux density in the region of core bolt holes. Now that boltless cores are normally used this reason is eliminated, but since it can never be assumed that the distribution of flux will always be uniform at all points in the core, some margin is nevertheless desirable. As indicated above, the generator AVR will normally ensure that the voltage applied to the LV terminals will remain within the range of ±5% of nominal so it may appear that variation in flux density due to possible variation of applied voltage will likewise not be very great. However, it is necessary to consider the operating situation.

In order that the machine can export maximum rated VArs at 0.85 power factor lag under all normal conditions of the 400 kV transmission network, i.e. at a voltage of up to 5% high and a frequency down to 49.5 Hz in the UK, it will be necessary for its excitation to be increased to such a level as to overcome the regulation within the transformer at this condition and still have a high enough voltage at the HV terminals to match that of the 400 kV network at its highest normal voltage condition of 420 kV. Regulation within the transformer at a load of a times full-load current may be calculated by reference to equation (1.7) of Chapter 1:

$$\text{percentage regulation} = a(V_R \cos\phi + V_X \sin\phi) + \frac{a^2}{200}(V_X \cos\phi - V_R \sin\phi)^2$$

For a large generator transformer V_R will be so small as to be negligible, so this expression may be rewritten:

$$\text{percentage regulation} = aV_X \sin\phi + a^2 \frac{(V_X \cos\phi)^2}{200}$$

Taking V_X equal to 16%, the regulation at full load ($a = 1$) may thus be calculated at 9.35%. Overall, therefore, under these conditions the generator output voltage must be increased by $(9.35 + 5) = 14.35\%$ above nominal in order to export the required VArs. This voltage applied to the generator transformer would represent too great an increase above normal and to avoid the need for this it is normal practice to specify an open-circuit HV voltage for the generator transformer of 432 kV, i.e. 8% above nominal. The generator would thus only be required to increase its voltage by $(14.35 - 8) = 6.35\%$ in order to produce the required voltage at the transformer HV terminals. Thus the transformer flux density would be increased by this amount plus any increase resulting from possible reduced frequency of the network, i.e. it could be as low as 49.5 Hz, or 1% low. Total overall increase in flux density is thus

$(6.35 + 1) = 7.35\%$. This would result in a nominal flux density under this condition of $1.0735 \times 1.7 = 1.825$ tesla.

It will be noted that in the above discussion no allowance has been made for tappings on the transformer HV winding. In reality, however, flexibility of operation will be assisted by the use of these. Typically, in the UK, a 400 kV generator transformer might have tappings on the HV winding of $+6.67\%$ to -13.33% in 18 steps of 1.11%. (Some of the first 800 MVA generator transformers were provided with HV tappings at $+2$ to -18% in 18 steps but these were found to be somewhat limiting in VAr exporting capability under some conditions at some locations on the system.) Normally these would be used for control of VAr import and export so that the 6.35% increase in output voltage called for in the above example could be achieved by tapping up by the appropriate amount on the transformer tapchanger and would normally be done in this way. As mentioned above, by so doing, the necessary continuous rating of the generator excitation system is greatly reduced.

Figure 7.2 shows various arrangements of core and windings that can be adopted for single-phase transformers. In *Figure 7.2(a)*, the core has one wound limb and two return yokes. Alternatively, both limbs could be wound, as shown in *Figure 7.2(b)*, but this increases the cost of the windings and also the overall height, since the yoke must be full depth. It would be possible to reduce the yoke depth by providing two return yokes as in *Figure 7.2(c)* but this adds further complexity and is therefore rarely advantageous. Some manufacturers reduce the yoke depth still further by using four return yokes *(Figure 7.2 (d))*. *Figure 7.3* shows the core and windings of a single-phase 267 MVA 23.5/432 kV generator transformer having one limb wound and with two return yokes. This has a transport weight of 185 t and a travelling height of 4.89 m.

A further benefit of single-phase construction is that should a failure occur, it is very likely to affect one phase only, so only that phase need be replaced and, being more easily transported, spare single-phase units can be kept at strategic central locations which can then serve a number of power stations. This led to the concept of interchangeable single-phase generator transformers which were developed for the majority of the CEGB 660 MW units. For this the electrical characteristics of impedance and voltage ratio must be closely matched on all tap positions and, of course, the physical sizes and arrangements of connections for HV and LV windings must be compatible. Each single-phase unit must have its own on-load tapchanger, driven from a single drive mechanism mounted at the end of the bank. Tapchangers must thus be compatible in that all must drive in the same sense and all must have the same number of turns for a tap change. The tap changers must be located so that the drive shafts will align. The location of inlet and outlet cooling oil pipes must correspond on all units. *Figure 7.4* shows the arrangement of an 800 MVA bank of single-phase units and details all the items which must align to provide complete interchangeability.

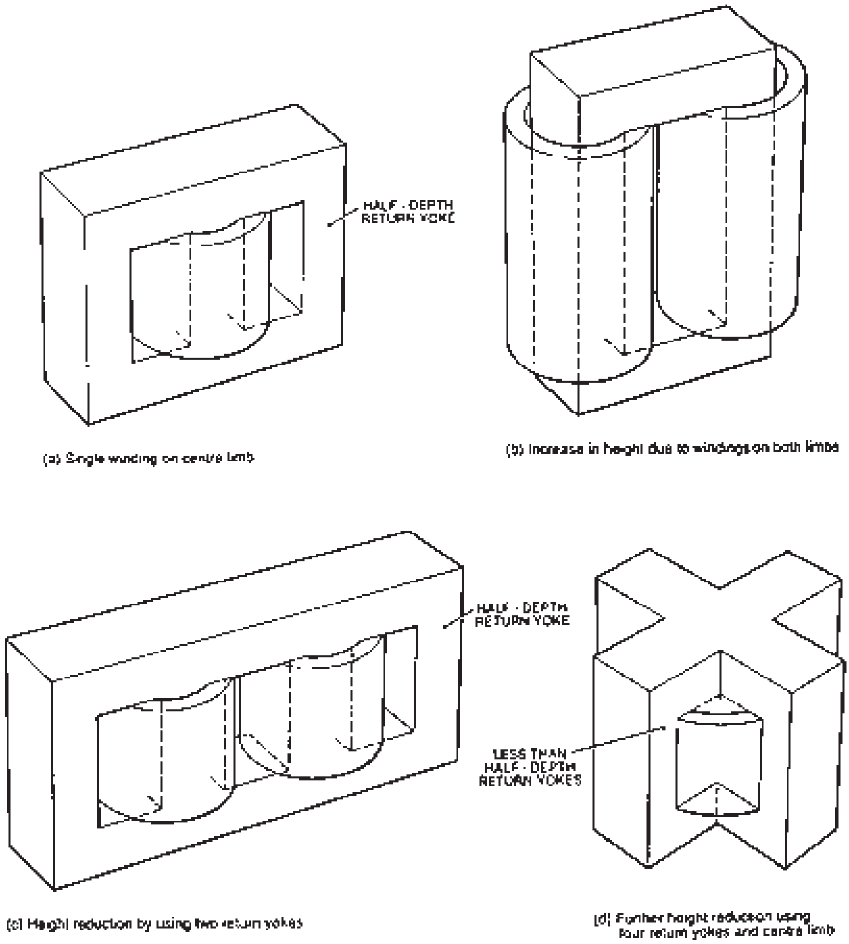


Figure 7.2 Core and windings for single-phase transformers

Both ends of each winding of a single-phase unit are brought out of the tank so that the HV neutral has to be connected externally, as well as the LV delta. The former is arranged by bringing the earthy end of each HV winding to a bushing terminal mounted on the top of the tapchangers. These can then be solidly connected together by means of a length of copper bar, of adequate cross-sectional area for the HV current at full rating and which is taken via any neutral current transformer and connected to the station earth.

On the early CEGB single-phase banks, the LV delta was connected by means of an oil-filled delta box which spanned the three tanks. This can be identified in *Figure 7.4*. It was split internally into three sections by means of barrier boards so that the oil circuits of the three tanks were kept separate. It was recognised that phase-to-phase faults were possible within the delta

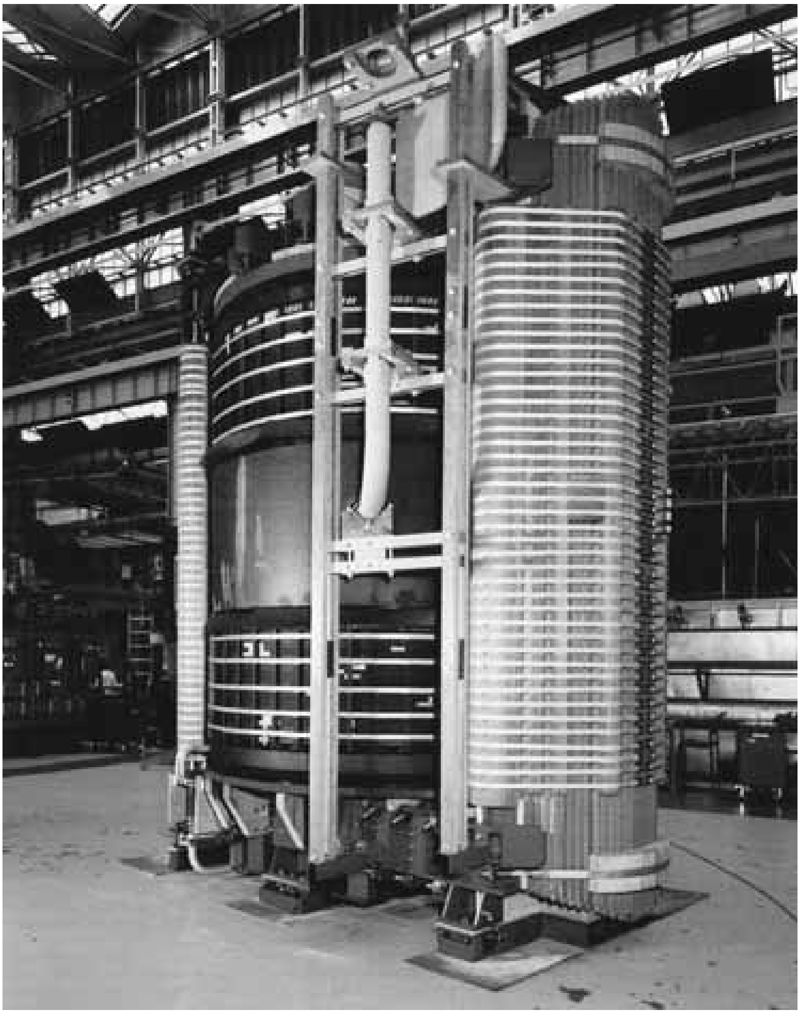


Figure 7.3 Core and windings of single phase 267 MVA, 432/23.5 kV generator transformer. View of HV side (GEC Alsthom)

box and that greater security could be obtained by the use of an external air-insulated phase-isolated delta which was, in fact, an extension of the generator main connections. This was subsequently adopted as the standard arrangement, so that the LV connections to each single-phase unit are made via a pair of bushings mounted on a pocket on the side of the transformer tank. The use of air-insulated phase-isolated delta connections has the added advantage that it enables the oil circuits of the three phases to be kept entirely separate, so that, in the event of a fault on one phase, there will be no contamination of the oil in the other phases.

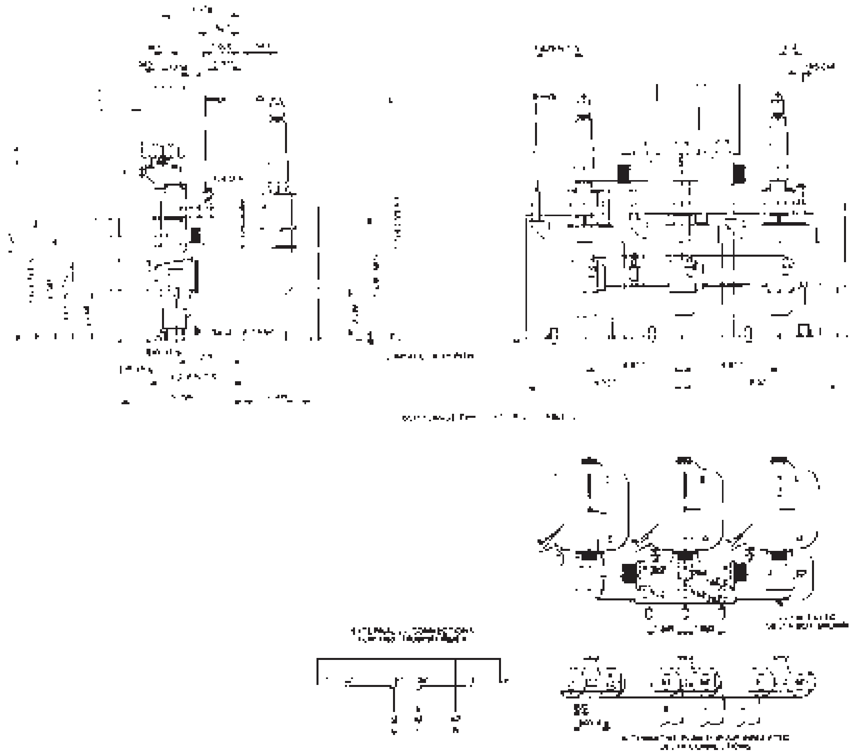


Figure 7.4 Details of 800 MVA bank of single-phase transformers showing requirements for interchangeability

The HV connections may be via air bushings or SF_6-insulated metal-clad trunking. The interface is therefore the mounting flange on the tank cover, as can be seen from *Figure 7.4*.

Figure 7.5 shows an 800 MVA generator transformer bank installed at the Drax power station before erection of the acoustic enclosure.

Commissioning

The procedure for commissioning generator transformers is similar to that adopted for other transformers and generally as described in Section 4 of Chapter 5, but one aspect deserving of some extra attention arises from the very high currents which are normally associated with generator transformer LV windings and connections. These can lead to additional stray fluxes in the vicinity of LV terminals and busbars which can give rise to severe local overheating. It is most important to ensure that there are no closed conducting paths encircling individual phase conductors and that any cladding surrounding LV busbars and connections does not form closed paths permitting circulating currents. Such structures must, of course, be solidly bonded to earth but care

Figure 7.5 800 MVA generator transformer bank at Drax power station (GEC Alsthom)

needs to be taken to ensure that the bonding is at one single point only for each individual section of the structure.

It is also important to pay particular attention to the connections between the LV bushings of the transformer and its external busbar connections from the generator. Nowadays generator busbars are generally of phase-isolated construction with aluminium conductors and an external aluminium sheath. To allow for relative movement between the transformer and the busbars these are connected by means of bolted flexible links, or connectors, bridging between two sets of palms, one on the busbars and a similar set on the transformer bushings. In the UK these flexible links consist of woven copper braided connectors; in some countries foil laminates are preferred. Woven braid has the advantage that it allows relative movement in three perpendicular directions, whereas a laminate only allows movement in two directions. Users of laminates consider that braids can become abraded and ultimately disintegrate due to vibration and work hardening of the copper. CEGB experience was that braids are superior to laminates provided the connection is carefully designed to allow sufficient flexibility in the braids and to ensure that none of them are overloaded in terms of current density.

Current sharing is a very important aspect and, to provide this, particularly for currents in excess of 10 000 A it is desirable that the connection palms are arranged as close as possible to a circular configuration as explained in the earlier section describing high-current bushings (Section 8 of Chapter 4). The four sides of a square represent a satisfactory approximation to this at 10 000 A, but this needs to be octagonal at 14 000 A. Such arrangements ensure that all the current paths through the connectors have equal reactance, which is more important in determining equal current sharing than equal resistance. It is nevertheless important to obtain a low contact resistance for each joint. This is obtained by ensuring that these have adequate contact surface area – generally this needs to be five or six times the conductor cross-sectional area, surfaces must be clean and flat and adequate contact pressure must be maintained. The design of and practical aspects associated with the making of heavy current joints is outside the scope of this book and those seeking further information should consult works such as *Copper for Busbars* [7.1] or *Modern Power Station Practice* [7.2].

On a completely new installation the turbogenerator will need to have an initial proving run and this usually involves running it for 72 hours at continuous full load. The opportunity should be taken during this run to monitor temperatures around the generator transformer, particularly in the vicinity of the LV busbars and connections. The usual procedure is to use temperature monitoring ‘stickers’ attached to terminal palms and braided flexible connectors which are inside enclosures and thus cannot be approached when the unit is in operation. Temperatures on the outer surfaces of enclosures and other such accessible locations may be monitored while the unit is in operation by means of a contact thermometer or using infrared thermal imaging equipment. It is usual to specify that the temperature of terminal palms should not exceed

90°C for plain copper or 110°C if both palm and connector is silver plated. The temperature of external cladding should not exceed 80°C in those locations where an operator could make accidental contact with it from ground level.

Performance and reliability

The generator transformer is the one transformer on a power station for which no standby is provided. It must be available for the generator output to be connected to the transmission network. For a large high-efficiency generating unit in the UK, high reliability is required. If its output is not available, this results in loss of earnings for the generating company and necessitates the running of less efficient plant which is likely to be more costly to the Electricity Pool.

It is difficult to set down design rules for high reliability. Design experience may identify features which might detract from reliability and studies are occasionally carried out such as that by CIGRE reported in Section 7 of Chapter 6, but it is difficult to apply lessons which may be learned from these and be sure that every potential source of trouble has been avoided. Large generator transformers are produced in relatively small numbers, so there are no long production runs which can be used to eliminate teething troubles. One factor which can aid reliability therefore is to repeat tried and proven design practices wherever possible, even over many years, thus reducing the occasions on which teething troubles might occur.

Another design rule for high reliability is to 'keep it simple'. This is not always easy for an item as complex as a large generator transformer but, nevertheless, as explained above, a degree of simplification was achieved by the change from three-phase to single-phase units. This also meant that there was no longer the same emphasis on keeping sizes and weights to an absolute minimum and so there was a consequent relaxation of another of the pressures which threatened reliability.

A further option which must be considered is that of adopting a more onerous testing regime than that included in IEC 76. This has been discussed in Section 3 of Chapter 5. This was part of the strategy adopted by CEGB in the 1980s and is considered to have been instrumental in improving the reliability obtained from large generator transformers.

The final factor to be considered is the level of monitoring and maintenance to be applied. For large generator transformers oil samples for dissolved gas analysis should be taken at least at three-monthly intervals. Dryness of the oil must be maintained at levels in the region of 0.1% and action taken as discussed in Section 7 of Chapter 6 on any step changes in dissolved gas levels.

7.2 OTHER POWER STATION TRANSFORMERS

Station transformers

The station transformer generally supplies the power station auxiliary system for starting up the boiler/turbine generator unit or gas turbine/generator and for supplying those loads which are not specifically associated with the generating unit, for example lighting supplies, cranes, workshops and other services. In addition, in order to provide a diversity of supplies to certain plant, the station switchboard is used as a source of supply for certain large drives which are provided on a multiple basis for each unit, for example the gas circulators of a nuclear reactor and the circulating water pumps for the main condensers of a steam turbine generator. A minimum of two station transformers will normally be provided in order to provide diversity of supplies with all units shut down. In a four-unit station each transformer will probably have the capability of starting up two units simultaneously while also supplying a proportion of the power station load. The station transformer will usually therefore have a larger rating than that of the unit transformer. The station transformer is usually the first major connection to be made with the transmission system for a power station under construction, providing supplies for the commissioning of the plant.

The design criteria to be met by the station transformer are as follows:

- In the UK the HV connection is usually from the 132 network; however, it is possible to use the 275 or 400 kV systems.
- The LV is almost invariably 11 kV nominal on modern main generating stations.
- Impedance must be such that it can be paralleled with the unit transformer at 11 kV to allow changeover from station to unit supplies and vice versa without loss of continuity and without exceeding the permissible fault level for the unit and station switchgear – this usually means that it is about 15%.
- An on-load tapchanger is required to maintain 11 kV system volts constant as load is varied and as grid voltage varies.
- Operating load factor is low, i.e. for much of its life the station transformer will run at half-load or less. Load losses can therefore be relatively high, but fixed losses should be as low as possible.

General design features

The station transformer is almost invariably star/star connected, since both HV and LV windings must provide a neutral for connection to earth. For a four-unit fossil-fuelled or nuclear station its rating will be of the order of 50–60 MVA. If supplied from the 275 or 400 kV system, this represents a rather small rating for either voltage class so that special care must be taken in the design of the HV winding. This will have a large number of turns having a relatively small wire size. A disc winding having a large number of turns per section must be used which will require particular attention to the distribution of impulse voltage. An interleaved winding arrangement will almost certainly be necessary.

At combined cycle gas turbine stations where the station auxiliaries loading is considerably less than the values mentioned above, so that, even at 132 kV,

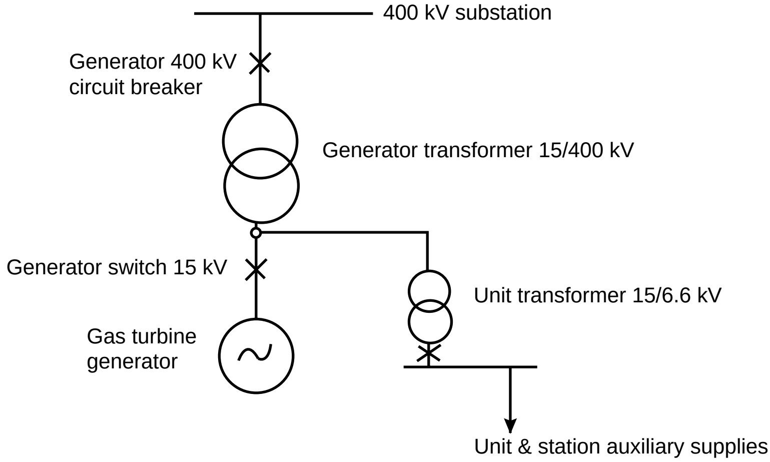


Figure 7.6 Arrangements for deriving auxiliary supplies employing a generator switch

the design of a ‘conventional’ station transformer would be very difficult and certainly uneconomic, it is common to employ a generator switch scheme as shown in *Figure 7.6*. With this type of arrangement a switch or circuit breaker is provided on the low-voltage side of the generator transformer so that the generator can be disconnected when not operating. A tapping off the LV side of the generator transformer can then be used to provide station supplies and, when the unit is in operation, this will also double as a unit supply. Generator circuit breakers and even generator switches are costly and a full discussion of the merits and demerits of the generator switch scheme is beyond the scope of a volume dealing with transformers, but at least a transformer and its associated connections are saved, and a transformer which would be fairly difficult technically at that.

Until the late 1970s, a star/star-connected station transformer would automatically have been provided with a delta-connected tertiary for the elimination of third harmonic. However, as auxiliary systems and the transformers feeding them became larger, fault levels increased and it became clear these could be effectively reduced and third harmonic remain at acceptable levels if a three-limb transformer without a tertiary winding was used. The thinking behind its omission from the station transformers for the CEGB’s Littlebrook ‘D’ power station designed in the 1970s is described in Chapter 2.

If the tertiary is omitted, zero-sequence impedance will be greatly increased and it is necessary to be sure that, in the event of an 11 kV system line-to-earth fault, there will be sufficient fault current to enable the protection to operate. Works testing of the Littlebrook station transformer showed that the actual value of zero-sequence impedance was low enough to meet the auxiliary system protection requirements. It was also necessary to ensure that the absence of a tertiary would not give rise to excessive third-harmonic currents

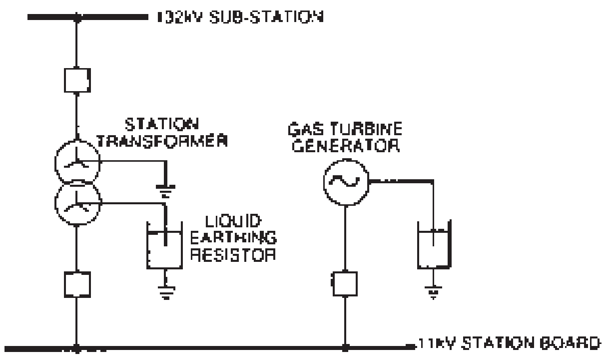


Figure 7.7 Connection of gas turbine neutral in parallel with station transformer neutral

circulating in the system neutral. Such currents flow whenever the system has more than one neutral earthed as, for example, in the system shown in *Figure 7.7* where an auxiliary gas turbine generator with its neutral earthed is operated in parallel with the station transformer supply, thus setting up a complete loop for circulating currents. The impedance of this loop to third-harmonic currents can be increased by connecting a third-harmonic suppresser in series with the gas turbine earth connection. This is an iron-cored reactor whose design flux density is carefully chosen to be fully saturated at 50 Hz, thus having a low impedance at normal supply frequency, whereas at 150 Hz it operates below the knee point and, being unsaturated, has a high impedance, effectively equal to the magnetising reactance. In order to ensure that protection problems are not encountered when deciding to omit the tertiary from a star/star transformer it is good practice to specify that the zero-sequence impedance should fall within a band from, say, 0.9 to 6 times the positive-sequence value.

Mention has been made above of the use of an on-load tapchanger on the station transformer as a means of compensating for grid voltage variation and for regulation within the transformer itself. This has an important bearing on the design of the station transformer.

In order to ensure that the 11 kV station board voltage remains at an adequate value under full-load conditions, the open-circuit ratio of the station transformer is usually selected to give a low voltage somewhat above nominal. A figure of 11.8 kV is typical.

Under normal operating conditions the UK transmission system, voltage may be permitted to rise to a level 10% above nominal. On the 400 kV system this condition is deemed to persist for no longer than 15 minutes. For the 132 and 275 kV systems, the condition may exist continuously.

Should the station transformer HV volts rise above nominal, the operator may tap up on the tapchanger, i.e. increase the number of turns in the HV winding. If the HV voltage were to fall, he would operate the tapchanger in the opposite direction, which would reduce the HV turns: both these operations maintain the flux density constant.

The operator can also use the tapchanger to boost the LV system voltage, either to compensate for regulation or because a safe margin is required, say, to start an electric boiler feed pump. The tapchanger would increase the volts/turn and this would thus increase the flux density. The use of the on-load tapchanger in this way to control the LV system voltage is discussed more fully in Section 6 of Chapter 4.

The station transformer will probably have been provided with a tapping range of ±10% to match the possible supply voltage variation. On the limit, it is possible for a voltage which is 10% high to be applied to the −10% tapping. This is an overvoltage factor of 22% and would result in an increase in flux density of this amount. To avoid saturation, it is desirable that the operating flux density should never exceed about 1.9 tesla; this results in a specified nominal flux density of 1.55 tesla at nominal volts for all station transformers, a value considerably lower than that specified for other transformers, for example a generator transformer as discussed above.

Unit transformers

The unit transformer is teed off from the main connections of the generator to the generator transformer. It is energised only when the generator is in service, except where a generator switch scheme is used as described above, and supplies loads which are essential to the operation of the unit.

The design criteria to be met by the unit transformer are as follows:

- The HV voltage is relatively low, being equal to the generator output voltage, i.e. usually between 11 and 23.5 kV.
- The LV voltage is usually 11 kV nominal, although on some combined cycle gas turbine stations 6.6 kV is used to supply the unit auxiliaries.
- Impedance must be such as to enable it to be paralleled with the station transformer at 11 kV (or 6.6 kV, as appropriate) without exceeding the permissible fault level – usually this will be about 15%.
- Since the HV voltage is maintained within ±5% of nominal by the action of the generator AVR, on-load tap changing is not needed. This also enables a design flux density of 1.7 tesla to be used as for the generator transformer.
- As in the case of the generator transformer, operating load factor is high, so that load losses and no-load losses should both be as low as is economically practicable. (Except in some nuclear stations, where two fully rated unit transformers are provided per unit for system security purposes.)
- Paralleling of unit and station transformers during changeover of station and unit supplies can result in a large circulating current between station and unit switchboards (see *Figure 7.8* and below). This generally adds to the unit transformer load current, and subtracts from that of the station transformer.

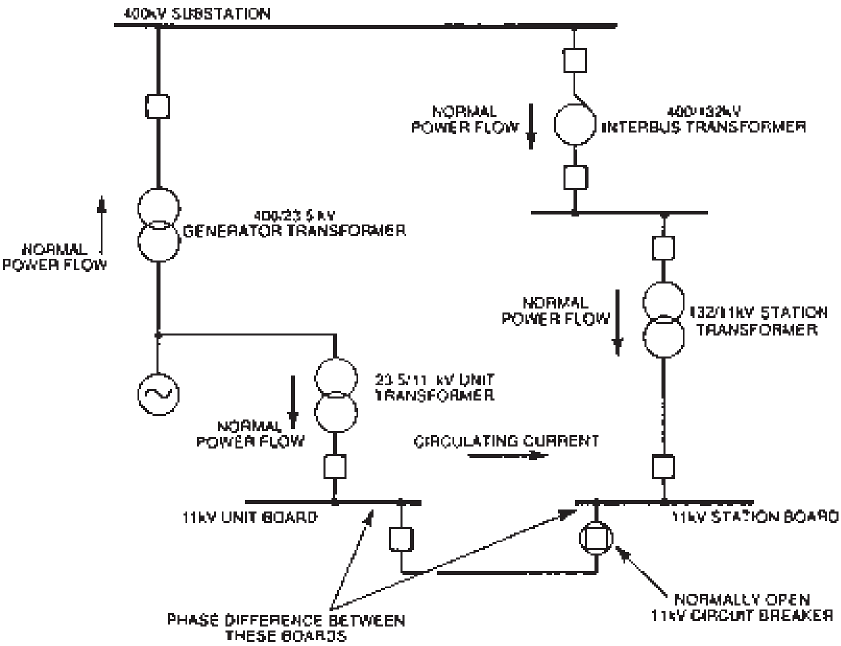


Figure 7.8 Paralleling of station and unit transformers

The unit transformer must therefore be capable of withstanding the resultant short-time overload.

General design features

The above design criteria result in a transformer which will probably have a fairly close voltage ratio, say 23.5/11.8 kV in the case of a unit transformer associated with a large 660 MW generator. The low voltage (11.8 kV) winding must have a neutral to provide for an earth on the unit auxiliaries system, so the connections will probably be delta/star. The open-circuit voltage ratio of 23.5/11.8 kV is equivalent to 23.5/11 kV at full-load 0.8 power factor. Off-circuit taps on the HV winding of ±7.5% in six steps of 2.5% will probably be provided to enable fine trimming of the system to be carried out during commissioning. For the reasons explained in Section 6 of Chapter 4, these are nowadays often varied by means of links under the oil rather than using an off-circuit switch which was the previous practice.

Unit transformers on combined cycle gas turbine stations, if used, will often have quite low ratings, perhaps no more than a few MVA, since these employ few unit auxiliaries. These may well be very similar to large distribution transformers. However, on coal-fired or nuclear stations, the need to provide supplies for electric boiler feed pumps, circulating water pumps and/or gas circulators plus many other lower rated auxiliaries, means that ratings of from 20 to 50 MVA are common. Such a relatively large rating and modest voltage can lead to some design and manufacturing problems. Both HV and LV currents are relatively high, so that windings have a small number of turns of fairly large cross-section conductor. The large cross-section means that stray loss will be high, probably necessitating the use of continuously transposed conductor for HV and LV windings. The number of HV turns will be relatively few, so that it will be difficult to build in the necessary strength to resist outward bursting forces under short-circuit (see Section 7 of Chapter 4). In order to improve the bursting strength it is desirable to employ a disc winding but if a disc winding is used there will be a very small number of large-section turns per section which will not make this an easy winding to produce. These manufacturing difficulties will probably make a unit transformer of this type as costly as one having a similar rating but higher HV voltage, and the level of QA appropriate during manufacture will be greater than that normally associated with other types of transformers of similar voltage class.

The changeover of unit and station supplies normally only requires that these transformers be paralleled for a few seconds. This is long enough for the operator to be sure that one circuit breaker has closed before the other is opened. During this time, however, a circulating current can flow which is dependent on the combined phase shift through the unit, generator and station transformers, plus any phase shift through interbus transformers, if generator and station transformers are not connected to the same section of the transmission system (*Figure 7.8*). This can result in the unit transformer seeing a current equivalent to up to two and a half times full load. Should the operator take longer than expected to carry out this switching, the unit transformer windings will rapidly overheat. Such a delay is regarded as a fault occurrence, which will only take place fairly infrequently, if at all. It is considered that parallel operation for a time as long as two minutes is more likely to occur than a short-circuit of the transformer and so the limiting temperature is set lower than the temperature permitted on short-circuit. The latter is set at 250°C by IEC 76 and so the CEGB considered it appropriate that a figure of 180°C should not be exceeded after a period of two minutes' parallel operation.

7.3 TRANSMISSION TRANSFORMERS AND AUTOTRANSFORMERS

Transmission transformers are used to provide bulk supplies and to interconnect the separate EHV transmission systems. In the UK they will have nominal HV voltages of 400, 275 or 132 kV. Both double wound and auto-connected types are used and these are usually of three-phase construction having three-limb or five-limb cores and dual ONAN/ODAF cooling. The ONAN rating is usually 50% of the ODAF rating. Tappings are provided on the HV winding of double wound transformers. On autotransformers tappings, if provided, will generally be at the line end of the lower voltage winding. However, because of the high cost of line-end tapchangers, some transmission autotransformers do not have on-load tapchangers.

To ensure security of supply, transmission transformers are installed in two, three or four transformer substations, such that, in the event of one transformer being unavailable for whatever reason, the load can be carried by the remaining transformers. This might, on occasions involve some modest degree of overloading within the limits permitted in IEC 354. For larger more important transformers, the overload capability will generally be made a requirement of the specification so that this can be accurately determined at the time of the transformer design.

Autotransformers and the HV windings of double wound transformers are, in the UK, almost exclusively star connected, with the HV neutral solidly earthed and thus employing non-uniform insulation. All other windings have uniform insulation. In the UK the 66 kV system is in phase with the 400, 275 and 132 kV systems, so that double wound transformers stepping down to 66 kV from any of these voltages will be star/star connected. All autotransformers and the majority of star/star-connected double wound transformers have delta-connected tertiary windings. Autotransformer tertiary windings are usually rated 13 kV and are brought out to external bushing terminals to enable these to be connected to 60 MVAr reactive compensation equipment. Earthing of this 13 kV system is provided by means of an interconnected-star earthing transformer (see Section 7 of this chapter). The ratings of the main windings are not increased to allow for the loading of the tertiary winding. Should these transformers not be required to supply reactive compensation equipment, then two connections from the phases, forming one corner of the delta, are brought out for linking externally to close the delta, and for connection to earth via protection current transformers. Any decision to omit the tertiary winding from a star/star-connected transmission transformer would only be taken following careful consideration of the anticipated third-harmonic current in the neutral, the third-harmonic voltage at the secondary terminals and the resultant zero-sequence impedance to ensure that all of these were within the prescribed values for the particular installation.

The maximum permitted value of nominal core flux density varies according to the rated HV voltage. Because the upper voltage limit on the 400 kV system under normal operating conditions is restricted to +5%, autotransformers and double wound transformers with this primary voltage are allowed to operate at up to 1.7 tesla nominal flux density. The 275 kV system voltage can rise to +10% above nominal so for 275 kV transformers the flux density is limited to a nominal 1.6 tesla. At 132 kV the transformer tapchanger can be used to boost the voltage of the lower voltage system as explained in Section 6 of Chapter 4, so the nominal flux density needs to be low enough to ensure that saturation will not be reached at the highest system volts applied to the lowest likely tap position. For 132 kV transformers flux density is thus restricted to a nominal value of 1.55 tesla.

7.4 TRANSFORMERS FOR HVDC CONVERTERS

With the increasing number, worldwide, of HVDC interconnections between high-voltage transmission networks such as, for example, that between the UK and France, the use of HVDC converter transformers is becoming more widespread. HVDC links may simply be back-to-back schemes used for the interconnection of AC systems having incompatible characteristics, which usually means having different frequencies, or they may be used for EHV transmission over long distances.

In the former case the DC voltage need not be very high and can be optimised to suit the economics of the converter station. Since 25–30% of these substation costs are determined by the cost of the converter transformers, transformer design considerations have an important bearing on the overall design of the interconnection. In the case of long distance transmission, where the requirements of the transmission line represent a significant factor in the economic equation, it is often the case that the highest technically feasible voltage is selected for the DC system. In both cases, however, system interconnections are usually made at those points on the AC systems having the highest voltage level, so that the 'AC windings' of converter transformers are normally of 400 kV or higher.

Since all the windings of any transformer normally operate on AC, it is not very specific to refer to the AC windings of converter transformers. The windings which are directly connected to the AC system are normally termed the *line windings*. The windings connected to the converter are termed the *valve windings*. The other parameter unique to converter transformers is the *commutating reactance* which can usually be taken as the transformer reactance.

Winding connections

The generation of harmonics is an undesirable feature of any converter equipment and in order to minimise these, 12-pulse converters are normally used. *Figure 7.9* shows a typical arrangement in which two converters are connected in series on one pole. Each converter has one valve winding connected in delta and the other in star, so that their AC voltages are displaced by 30° electrically. It is usual to arrange that both star- and delta-connected valve windings have a common star-connected primary line winding, although a number of alternatives are possible:

- One three-phase transformer having one line (primary) and two valve (secondary) windings.
- Two three-phase transformers each having one line and one valve winding.
- Three single-phase transformers each with one line and two valve windings.
- Six single-phase transformers each with one line and one valve winding.

Since system interconnections frequently have fairly large ratings, converter transformers are almost invariably also fairly large. Transport limitations

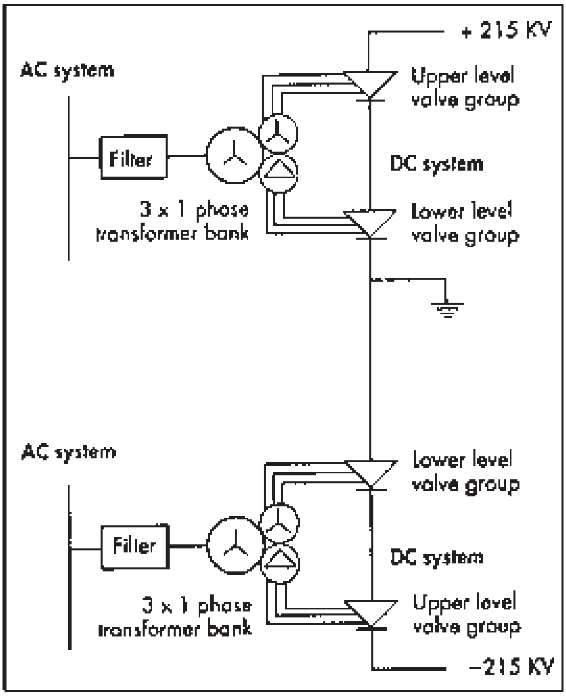


Figure 7.9 AC/DC system schematic

require that these must frequently be subdivided and the use of single-phase units is the most usual form of subdivision with the third of the options identified above being adopted as the most economic. *Figure 7.10* shows the core and windings of a single-phase transformer with two wound limbs. One limb has a line winding plus a star valve winding, and the other a line winding plus a delta valve winding. The two line windings are connected in parallel and each has a tapping winding contained in a separate outer layer and controlled by an on-load tapchanger. A reduced depth yoke is used in order to reduce transport height so that the core has external reduced section outer return limbs. *Figure 7.11(a)* shows the arrangement of the windings in section and *Figure 7.11(b)* the connections for the three-phase bank.

Insulation design

It is in the area of insulation design that HVDC converter transformers differ most significantly from conventional transformers designed solely to withstand AC voltage stresses. The valve windings experience a DC bias voltage which is a function of the DC system voltage and this is superimposed on the AC voltage distribution. The DC voltage experiences a polarity reversal when the direction of power flow is reversed. To further complicate this situation, the behaviour of insulating materials, paper, pressboard and oil, differs greatly in its response to DC stress than it does to AC stress. Oil is weakest dielectrically

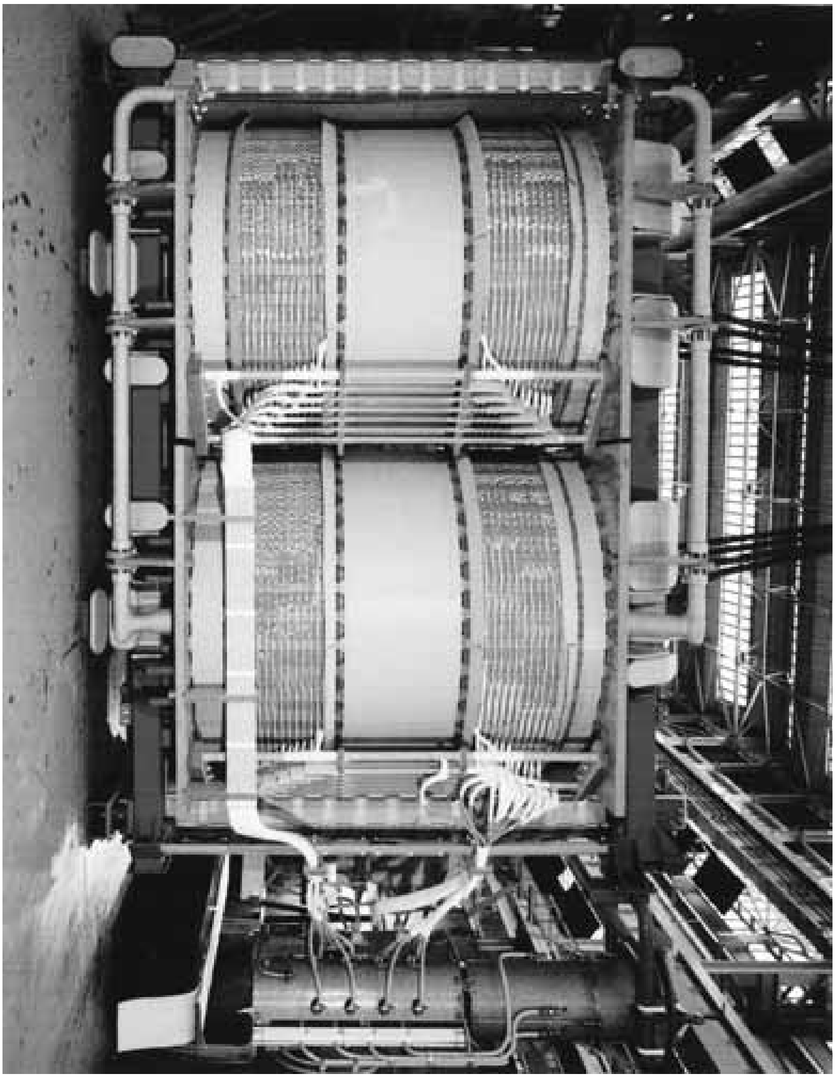


Figure 7.10 Core and windings of a 234 MVA converter transformer for Chandrapur, India. The transformer has a primary rated voltage of $400/\sqrt{3}$ kV, 50 Hz, and supplies a DC system having a rated voltage of ± 215 kV. The tapping range is ± 27 to -6 % and the transformer has OFAF cooling (GEC Alsthom)

so that areas subject to high levels of DC stress must be suitably barriered and the barriers must be shaped to limit the stress levels at the oil/pressboard interface.

In a system subjected to AC stresses the voltage distribution is determined by the material dimensions and dielectric constants. For a composite

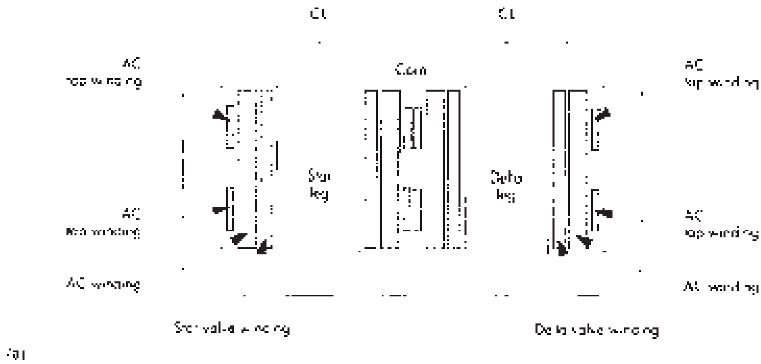


Figure 7.11(a) Section through core and windings of HVDC converter transformer (GEC Alsthom)

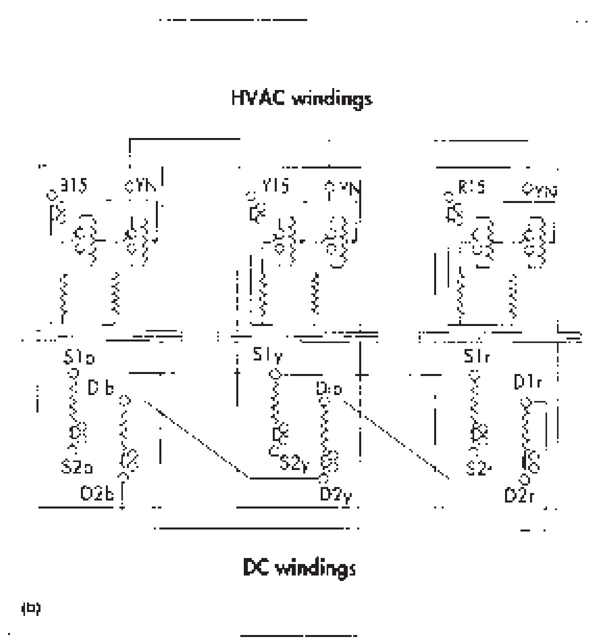


Figure 7.11(b) Three phase bank connections (GEC Alsthom)

insulation structure such as that formed by oil and pressboard, the stress in each component is in inverse proportion to the dielectric constant, so that the oil, having a lower dielectric constant than pressboard, will be subjected to the higher stress. In the case of a system subjected to a DC stress the distribution is determined by the material dimensions and their resistivity. Pressboard has the higher resistivity and is thus subjected to the highest stress. Generally this is beneficial since the pressboard also has the highest electrical strength.

However, unlike the situation for AC conditions, which do not usually create any special problems, very careful consideration must be given to the design of pressboard/oil interfaces and insulation discontinuities. The situation is, of course, made more difficult from a design viewpoint by the fact that a combination of AC and DC stresses occur in practice.

Further factors add to the complexity of the insulation design problems. For AC stressing purposes the oil and pressboard dielectric constants may be regarded as fixed with respect to level of stress and varying only very slightly with temperature. On the other hand the resistivities of different materials are very much dependent on moisture content, temperature and applied electrical stress. When the DC voltage is applied, a capacitative charging voltage distribution appears initially, changing to the final resistivity governed distribution over a period which might be anything from a few minutes to as long as an hour. This DC distribution will have superimposed upon it the AC distribution. Calculation of the resultant voltage distribution is thus a very complex procedure requiring that the stress levels be known in order to determine the resistivity, which, in turn, needs to be known in order to determine the stress levels. This used to demand that a lengthy iterative process be employed. Nowadays the use of computer programs based on finite element modelling (FEM) techniques has simplified the process considerably.

The design of the high-voltage leads and their connections to the DC bushings is another area requiring particular attention because of the combination of AC and DC stresses as well as the polarity reversal condition. This usually involves the use of a number of pressboard cylinders as well as preformed pressboard insulation structures which often provide support as well as an insulation function.

Insulation conditioning

Because of the effect of moisture on the resistivity of insulation material, it is necessary to obtain and maintain a high level of dryness in the insulation of HVDC transformers. This is equally important in service as it is in the factory at the time of testing. In addition, a very high level of cleanliness must be observed involving extensive filtering of the oil. Any particulate contamination of the oil, whether in the form of cellulose fibres or metallic particles, can migrate under the influence of the DC stress field so that as they come into contact with electrodes or solid insulation materials they can cause corona discharges or even breakdown. Oil circulation in service is generally maintained continuously regardless of load so as to ensure that the temperature distribution remains as even as possible thus ensuring that the DC stress distribution is not distorted due to thermal effects on resistivity.

Harmonics

Brief mention has already been made of the problems of harmonics and the need to reduce their effect on the system to which the converter is connected.

This is achieved by the use of filters connected as shown in *Figure 7.9*. The harmonics cannot, however, be eliminated from within the converter windings and it is important to allow for the effects of these in the design of the transformer. The harmonics add considerably to the stray losses in the transformer windings, core and structural steelwork, and due allowance must be made for their effects, not only in carrying out the thermal design but also when testing, to ensure that adequate cooling provision has been made. The harmonics arise because of the circuitry and the mode of operation. *Figure 7.12(a)* shows the conventional idealised waveform, which itself has a high harmonic content, in practice the leading and trailing edges of the current pulses are parts of a sine wave, *Figure 7.12(b)* when rectifying and *Figure 7.12(c)* when inverting. The harmonic content is made greater by transient overshoot creating oscillations at the turn-off points of the current pulses.

Commutating reactance and short-circuit current

Fault current in the case of converter transformers is likely to contain a very much greater DC component than is the case for normal transformers. Fault current is dependent on the impedance of the valves but also the winding DC resistance, which in all probability will be very low. Furthermore, unlike in the case of faults in conventional AC circuits for which the DC component decays very rapidly, for converter circuits the high DC component will continue until the protection operates. The resulting electromagnetic forces can therefore be very significant, and great importance is placed on high mechanical strength of windings and support structures for busbars and connections. One method of limiting short-circuit forces is to design converter transformers to have a higher impedance than would normally be associated with a similar rating of conventional transformers. High impedance, however, always results in high regulation, which system designers will seek to avoid, and as experience is accumulated with the design and operation of converter transformers the trend is towards lower impedances and closer design and manufacturing tolerances. For converter transformers the tapchangers, which are used in addition to the control of valve firing angle to control the power flow, will often have up to 50% greater range than for conventional AC power transformers, so that the need to limit the variation of impedance with tap position becomes an important consideration in determining the winding configuration.

Tapping windings and tapchangers

The extent of the tap winding and its location such as to minimise impedance variation results in a high voltage being developed across it under impulse conditions, placing demands on the winding insulation design as well as the impulse withstand capability of the tapchanger itself. In addition, the operation of the thyristor valves results in AC-side current waveforms with a steeper rate of rise than that occurring under normal sinusoidal conditions. This places more severe demands on the switching capability of the tapchanger.

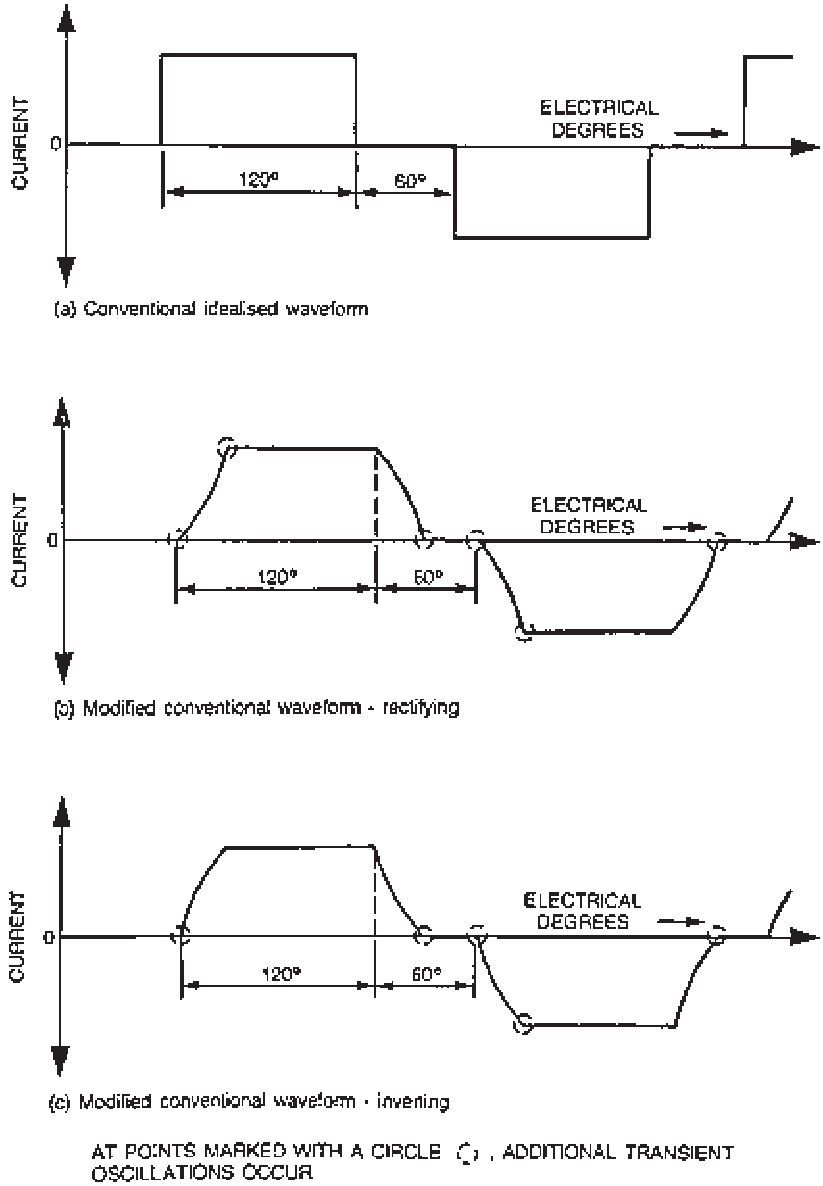


Figure 7.12 Valve winding current waveforms

The increased dielectric and switching requirements placed on the tapchanger result in it being larger than that required for a conventional transformer of similar rating and voltage class. *Figure 7.11(b)* shows the arrangement of tapchanger connections used for the single-phase converter transformer of *Figure 7.10*. A separate tapchanger is used for each half line winding. There are no current sharing problems since the line winding currents are determined by their respective delta- or star-connected valve windings.

Bushings and connections

The converter valve stack is normally housed within a building to provide weather protection, and connections must be made to this from the transformer which is outdoors. This is normally done by taking the valve winding bushings directly through the wall of the valve hall so that the bushings are usually mounted horizontally on the side of the transformer. This arrangement prevents the connections from transmitting high-frequency radio interference. Another alternative would be the use of gas-insulated busbars. The use of e.r.i.p. bushings avoids the danger of oil leaks causing contamination of the valve hall, see *Figure 7.13*.

The design of bushings for DC operation presents particular problems which do not arise on AC systems. The external insulator surface is very vulnerable to atmospheric deposits (another advantage in housing this indoors) and requires a special design with a long creepage distance. The high harmonic content of the current waveform gives rise to high dielectric losses. As explained above, because of the DC voltage stresses, internally within the transformer the design of the interface with the valve winding lead requires very careful consideration. Finally, the length of the external portion of the bushing coupled with the fact that this is mounted horizontally creates large cantilever forces which must be taken into account in its design.

Testing

The testing of converter transformers must take account of the special operating requirements. AC dielectric testing follows the normal pattern of lightning and switching impulse tests applied to the line winding, which by electromagnetic and capacitative action will also be transferred to the valve winding, followed by induced overvoltage tests which will, of course, stress both line and valve windings. Additional testing is required to demonstrate that the valve winding and its insulation structure is able to withstand the imposed DC voltage stresses. Any DC overvoltage test must be applied for a sufficiently long duration to enable the steady voltage distribution to become established. When the final voltage distribution is reached a polarity reversal test is carried out by switching off the test equipment and then applying the same level of voltage with reversed polarity, which again is applied for a period long enough to enable the final steady-state distribution to be reached.

Load-loss measurements cannot be made with harmonics present and specifications for HVDC converter transformers call for loss guarantees related to standard testing procedures under normal sinusoidal conditions to be demonstrated on test. Temperature rise tests are carried out on short-circuit with the supplied losses increased to take account of the anticipated harmonic losses. This is done by increasing the stray losses derived under sinusoidal conditions

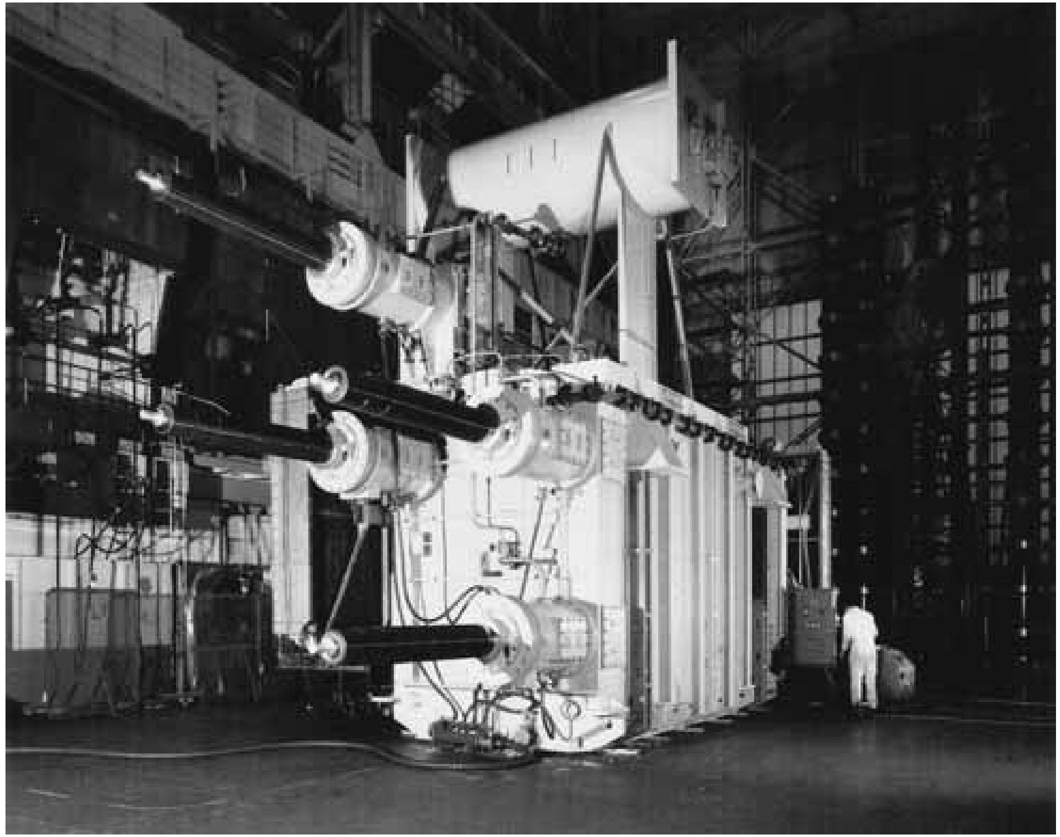


Figure 7.13 Transformer of Figure 7.10 undergoing works tests
(GEC Alsthom)

by an arbitrary factor. Hence:

$$P_c = P_1 + F_h(P_1 - I^2R) \tag{7.1}$$

where P_c = load loss for converter operation
P_1 = load loss under sinusoidal conditions including stray losses
F_h = harmonic loss multiplier
I = sinusoidal rated current
R = DC resistance of the transformer referred to the winding being considered

Typically a value of 0.75 may be assumed for F_h.

7.5 PHASE SHIFTING TRANSFORMERS AND QUADRATURE BOOSTERS

To control the power flow in an interconnected network it is sometimes necessary to use a phase shifting transformer. For example, in the network shown in *Figure 7.14(a)* there are two routes for the flow of load current passing from substation A to substation B. If no external influences are brought to bear then the load would divide between the two alternative routes in inverse proportion to their impedances, or, expressed algebraically:

$$i_1 = i\frac{z_2}{z_1 + z_2}$$

and

$$i_2 = i\frac{z_1}{z_1 + z_2}$$

where i is the total load current flowing between A and B and i_1, i_2, z_1, z_2 are the currents and impedances respectively in the lines as denoted by the appropriate suffixes.

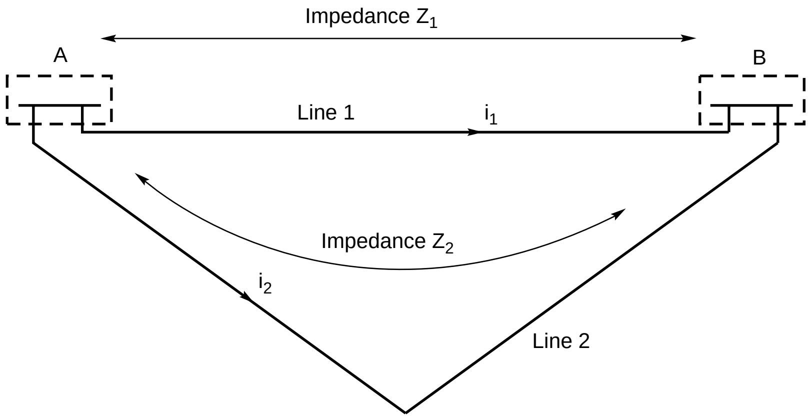
However, if it is required that the load current should split in some proportion other than the inverse of the route impedances – perhaps the rating of line 1 is twice that of line 2 but its impedance only 75% of the line 2 impedance – then it is necessary to increase the current in line 1 by some quantity i_x and reduce that in line 2 by the same amount, so that

$$i'_1 = i\frac{z_2}{z_1 + z_2} + i_x$$

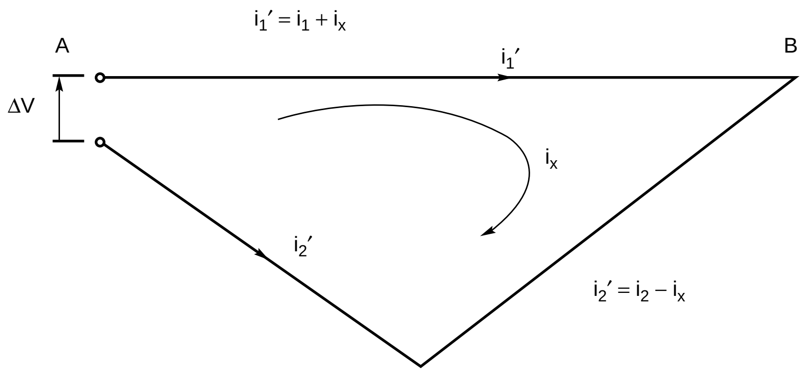
and

$$i'_2 = i\frac{z_1}{z_1 + z_2} - i_x$$

where the new currents, i'_1 and i'_2 are in the required proportion, in this case $i'_1/i'_2 = 2$.



(a) Flow of load current from A to B determined by line impedances



(b) Additional imposed voltage, ΔV, at substation A gives rise to circulating current, i_X

Figure 7.14

As will be seen from *Figure 7.14(b)* the current i_x may now be regarded as a circulating current flowing around the system superimposed on the load currents determined by the line impedances. To cause this current to circulate requires a driving voltage ΔV such that

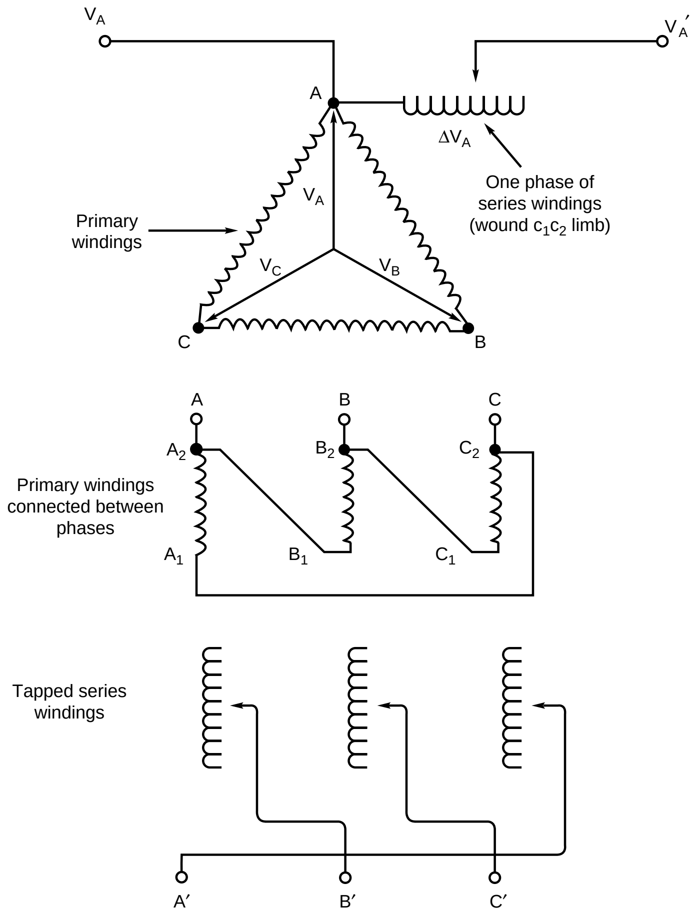
$$i_x = \frac{\Delta V}{z_1 + z_2}$$

and since the impedance $(z_1 + z_2)$ is largely reactive, the voltage ΔV will need to be approximately in quadrature with the line current. This quadrature voltage can be provided by the installation in the system of a suitably connected transformer. The most appropriate location for this transformer depends on the voltage profile around the system; it might be necessary to provide $\Delta V/2$ at each of the substations. The transformer, or transformers, provide the necessary phase shift, or quadrature voltage, around the system to drive the required equivalent circulating current. They are thus known as phase shifting transformers or quadrature booster transformers.

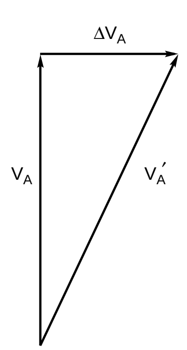
In order to provide a voltage in quadrature with the line voltage the phase shifting transformer has its primary windings, or shunt windings, connected between phases of the transmission line. By interconnecting the phases as shown in *Figure 7.15* the transformer secondaries, or series windings, will have their output voltages at 90° to the primary phase voltages. The series windings need only consist of regulating windings with on-load tapchangers so that the amount of phase shift can be varied to suit load transfer requirements. In *Figure 7.15(a)* the tappings are arranged in linear fashion so that the phase shift has variable magnitude but is always in the same sense (*Figure 7.15(b)*). If the tappings are connected in a buck/boost arrangement as shown in *Figure 7.15(c)* then the phase shift may be positive or negative (*Figure 7.15(d)*).

The arrangement shown in *Figure 7.15(c)* represents a workable quadrature booster configuration; however, it has disadvantages. The series winding is totally exposed to the transmission network conditions and, since most system interconnections operate at voltages of at least 400 or 500 kV, this represents a particularly onerous duty for a regulating winding and tapchanger, both of which would require insulating for up to $500/\sqrt{3}$ kV to earth as well as meeting the appropriate lightning and switching impulse withstand requirements. The most common arrangement of quadrature booster is therefore as shown in *Figure 7.16*. This consists of two separate components having separate three-phase cores. For all but the smallest units these will be housed in two separate tanks and, since by their very nature system interconnectors tend to have ratings of several hundred MVA, this means that separate tanks are normally provided. The advantage of this arrangement is that by isolating the regulating winding from the system this can operate at a somewhat lower voltage to earth as well as only needing to withstand surges transferred from the line rather than directly on its terminals. The voltage ratio of the open-delta/delta connected series transformer can also be selected to enable the unit to be optimised to match the voltage and current capability of the available tapchanger.

For the purpose of illustration it is possible to put some typical values on the booster arrangement of *Figure 7.16*. This might be required to provide a phase shifting capability of $\pm 18°$ on a 400 kV transmission line having a current rating of 1200 A. The tangent of 18° is 0.325 so that the series winding must produce a maximum quadrature output of $0.325 \times 400/\sqrt{3} = 75$ kV. With a rated current of 1200 A, the series unit will have a three-phase rating of $3 \times 75 \times 1200 = 270$ MVA. (Note that this unit has its output winding in open

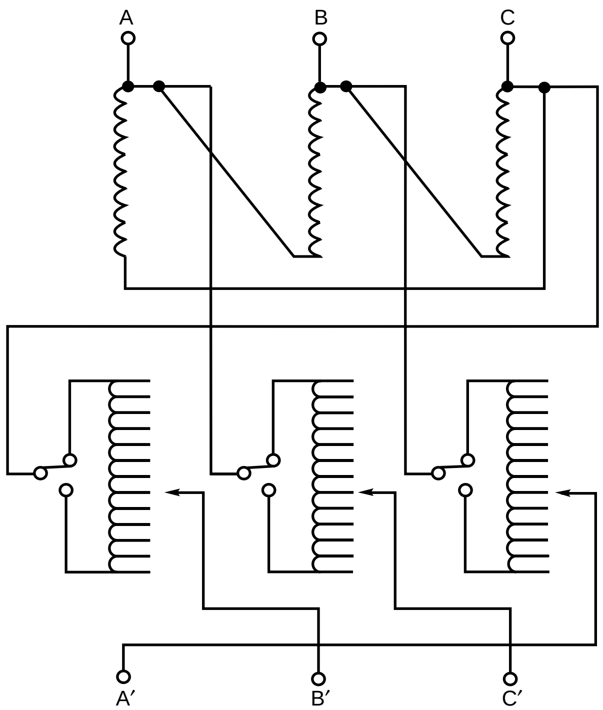


(a) Basic connections of quadrature booster
upper diagram shows arrangement in its functional form while
physical configuration is shown in lower diagram

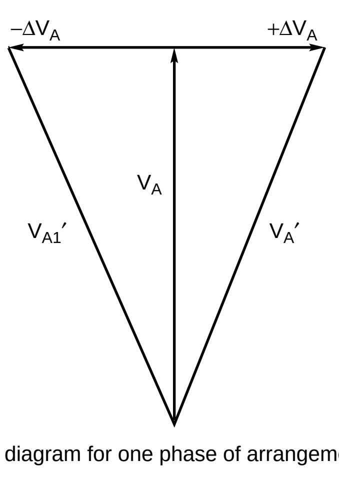


(b) Phasor diagram for one phase of booster in diagram (a)

Figure 7.15 Arrangements of quadrature booster



(c) Workable arrangement of quadrature booster with tapped winding connected in buck/boost



(d) Phasor diagram for one phase of arrangement in diagram (c)

Figure 7.15 (*continued*)

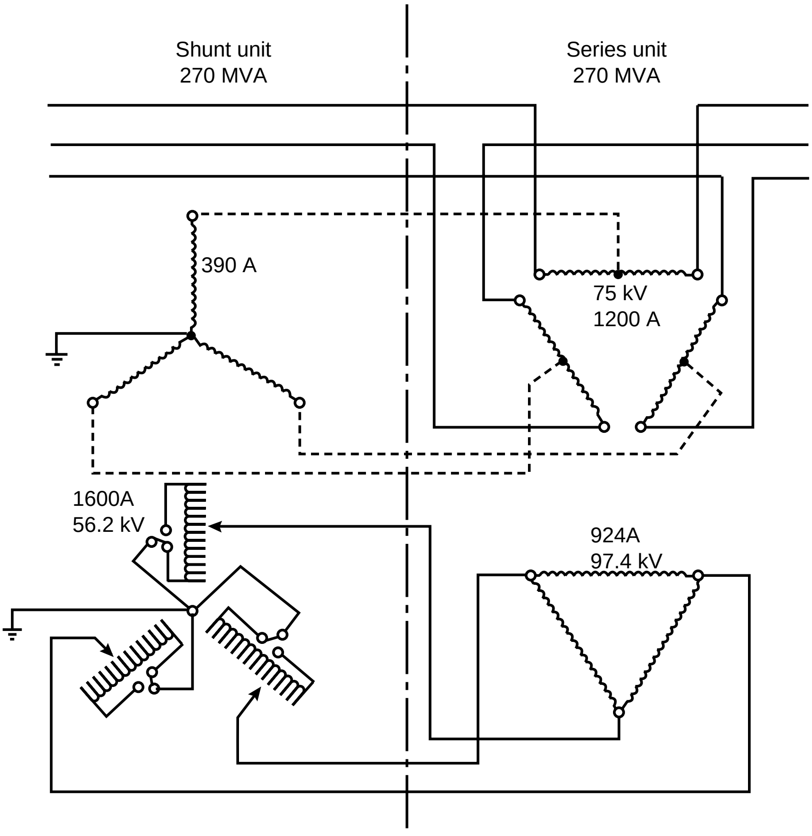


Figure 7.16 Arrangement of 400 kV, 1200 A booster to provide a phase shift of $\pm 18°$

delta so that 75 kV and 1200 A are the respective phase voltage and current. The three-phase unit thus has a rating of three times the product of these phase quantities, and no $\sqrt{3}$ factor is involved.) A typical current rating of tapchanger which might be considered for such a unit is 1600 A. If maximum use is to be made of tapchanger current capability, the open-delta/delta series transformer must have a voltage ratio such as to produce this line current from the delta winding, i.e. the delta winding must have a phase current of $1600/\sqrt{3} = 924$ A and hence a phase voltage of 97.4 kV. Connecting the regulating windings in star means that each phase must have a total all-taps-in voltage of $97.4/\sqrt{3} = 56.2$ kV. This represents the maximum voltage across the range for the tapchanger and based on an 18-step, 19-position, tapchanger is equivalent to 3120 volts per step. These values are just about on the limit of the capability of a commercial 1600 A tapchanger. The rating of the shunt transformer will be $3 \times 56.2 \times 1600 = 270$ MVA, and the combined rating of the complete unit will be 540 MVA. At full output for the series winding the shunt winding will draw a current of $(270/\sqrt{3} \times 10^6)/400\,000 = 390$ A from the 400 kV system.

It should be noted that the figure of 18° phase shift assumed for the above example is an open-circuit value and would be reduced at full load due to regulation. The impedance of the series unit adds to the system impedance to determine the fault level on the system and thus must be set to meet system requirements. The impedance of the shunt unit will vary considerably between the all-taps-in and the all-taps-out condition, but it has very little effect on the system fault level and so the lower it can be made the less will be the effect of its variation on the overall impedance variation of the unit. The fault infeed for faults on the interconnections between shunt and series units is effectively limited only by the supply system impedance plus their respective impedances acting in parallel. This will therefore be very high and the design should be such as to make the likelihood of phase-to-phase faults on these connections as low as possible. If the units are in separate tanks one way of achieving this is by enclosing the connections in gas-insulated bus ducting. Alternatively oil-filled phase-isolated trunking may be used. The series transformer, in particular, requires a very large number of very high-voltage connections and if some of these are gas insulated or enclosed in oil-filled trunking this enables the terminal spacing to be reduced and thus reduces the overall space required on the tank for connections.

Testing

Testing large quadrature boosters presents particularly difficult problems for manufacturers. Shunt and series units need to be erected in the test bay which generally means that the available space is stretched to the limit. The large number of interconnections, particularly those across phases, means that lightning impulse voltage distribution and the transfer of surge voltages between windings are difficult to predict with accuracy so that the manufacturer will wish to have confirmation of his design calculations at the earliest opportunity. It is likely, therefore, that he will wish to connect up the units in air in order to carry out RSO measurements before these are installed in their tanks. When the units have been installed in their tanks and filled with oil the RSO measurements will be repeated. To provide access to those interconnections which are enclosed, it may be necessary to install additional temporary bushings. It will also be necessary to have access to these interconnections in order to make resistance measurements for the temperature rise tests.

To carry out the temperature rise test a short-circuit may be applied to each of the open-delta phases of the series transformer and a supply connected to the regulating windings on the shunt transformer which must be at the all-taps-in position. A current can then be circulated through both transformers of sufficient magnitude to generate full-load losses, i.e. no-load plus load losses in each of the two transformers. Because of the differing requirements between shunt and series transformers as regards impedance and insulation requirements it is unlikely that their core sizes will be the same and so their no-load losses will differ. This means that supplying all the losses as copper losses in this way will result in some inaccuracy in the measured top oil temperature rises. Loss distribution on test will, however, be within a few per cent of the correct figures so that the measured top oil rises can be corrected in accordance with the IEC 76-2 procedure with very little error.

For the induced overvoltage test the booster can be supplied with the test generator connected to the regulating winding in the same way as for the temperature rise test. Alternatively it is possible to provide an additional winding on the shunt transformer which is used solely for this purpose. Lightning impulse and switching surge tests may be applied to all winding terminals as a test of the dielectric integrity of the individual windings but in addition it is usual to apply an impulse and switching surge test to both output winding terminals (i.e. source and load terminals) of the series transformer connected together as a simulation of service conditions. *Figure 7.17* shows a large quadrature booster erected for test in the factory.

7.6 SYSTEM TRANSFORMERS

In the UK the term system transformer is normally used to describe that class of transformer which provides the first stage of distribution beyond the stepping down to 33 kV, or occasionally 66 kV, of the bulk supply from the transmission system operating at 132 kV or above. That is, it is the transformer used to make the transformation from 33 or 66 kV to 11 kV.

These transformers are unique in that they are not strictly designed to IEC 76 temperature rises but are tailored to meet a particular duty. They were widely introduced in the early 1960s, although the concept had been around for somewhat longer, and were designed with the intention of minimising use of material and manufacturing costs as well as more precisely matching the operational requirements of what were at that time the area electricity boards (now regional electricity companies). For this reason, at the time of their introduction, they were known as ‘integrated system transformers’, usually abbreviated to ISTs. Now they are generally termed CERs or ‘continuous emergency rated’ transformers, referring to the manner in which their rating is derived.

It was the practice of the distribution authorities in the 1960s, and it generally still is, to operate primary distribution transformers in pairs connected in parallel so that, should one of these fail, the remaining unit will carry the substation load until the failed transformer can be repaired or replaced so that supplies to the consumer will not be interrupted. Standard ratings for these transformers at that time were 10/14, 15/21 and 20/28 MVA. In each case the lower rating is achieved with ONAN cooling and the higher value by means of pumps and fans to provide an OFAF or ODAF rating. A 10 MVA transformer has an LV current at, say, 11 500 V of 502 A. At 14 MVA this is increased to 703 A. But the available 11 000 V switchgear had a standard current rating of 800 A, so when operating singly at its forced-cooled rating the transformer is

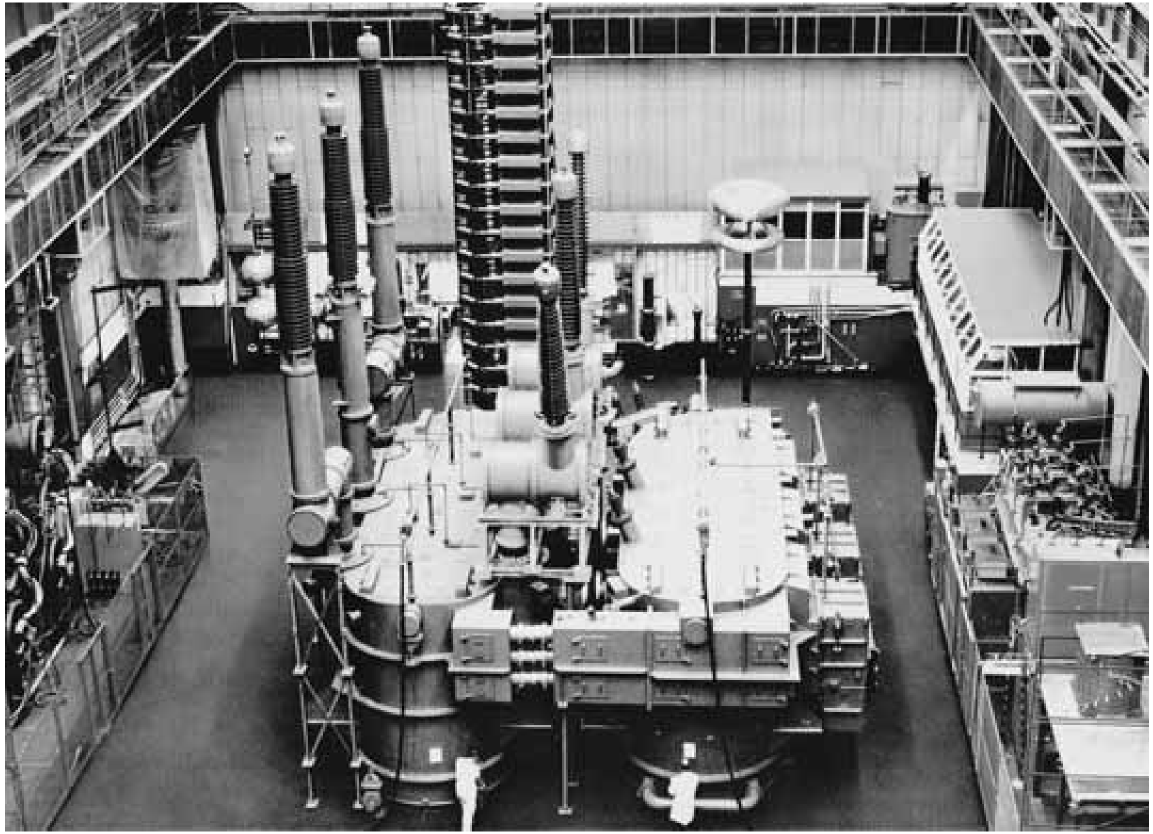


Figure 7.17 2000 MVA, 400/400 $\pm j80$ kV quadrature booster on final test

not able to match the full current capability of the switchgear and at its ONAN rating, as one of two transformers sharing the substation load equally, it would be quite sufficient for it to be able to carry 400 A, not 502 A. The transformer is considerably overdesigned at the ONAN condition and switchgear capacity is being wasted at the forced-cooled condition which was intended for the emergency ‘one transformer carrying the total substation load’ situation.

The requirement for the integrated system transformer was thus that it should have an emergency rating which was a close match to that of the substation 11 kV incoming switchgear when carrying the full load of the two-transformer substation. This rating need only be sustainable for possibly a week or two and may be achieved by the operation of pumps and fans. At all other times the rating should be half this emergency duty and must be achieved without the operation of any forced cooling equipment. The following ratings are those normally used at the present time:

7.5/15 MVA corresponding to 800 A switchgear
12/24 MVA corresponding to 1200 A switchgear
15/30 MVA corresponding to 1600 A switchgear
20/40 MVA corresponding to 2000 A switchgear

The LV currents for these ratings, for the forced-cooled condition and assuming an LV voltage of 11 500 V are, respectively, 753, 1205, 1506 and 2008 A, from which it will be seen that the 12/24 and 20/40 MVA match the switchgear ratings better than do those of 7.5/15 and 15/30 MVA. In fact 8/16 and 16/32 MVA are a better match for 800 and 1600 A respectively. The reasons for this are not clear but it is probably the case that at sometime someone’s desire to use round numbers got the better of simple logic. It remains to be seen whether a new series of CER transformer ratings will be introduced having values which match the ISO 3 preferred R10 series of switchgear current ratings of 630, 800, 1000, 1250, 1600, 2000, 2500 A, etc. currently in use.

When the integrated system transformer was first introduced the intention was that there should be a high degree of standardisation to enable a flow line type of production to be used thereby assisting the objective of minimising costs. In the event, this aspect of the original concept has been somewhat lost, so that designs tend to be tailored to suit the requirements of each particular application, i.e. tapping range, voltage ratio, impedance values, terminal connections, etc. are varied as each installation demands. Logically there is therefore no reason why a new series of transformer ratings having ODAF rated powers of 12.5, 16, 20, 25, 32, 40 MVA, etc., which have LV current ratings to match present-day switchgear, should not be introduced.

In line with the fact that the CER transformer ODAF rating is regarded as an emergency rating, the permitted ODAF temperature rises are related to an ambient temperature of 5°C, and a hot-spot temperature of 115°C is permitted. In fact, some specifications now allow a hot-spot temperature of 125°C at the emergency ODAF rating. By reference to *Table 6.21* (Section 8 of Chapter 6) it will be seen that the first of these two values corresponds approximately to rate of use of life of 8 times normal and the second, using some interpolation, to about 23 times normal. Although it will appear that the latter rate, in particular, is exceedingly high even if occurring for only one or two weeks in the transformer lifetime, it should be recognised that substation loading is likely to be cyclic of the form shown in *Figure 7.18* where the time at maximum load is unlikely to be more than 10 hours per day and may possibly be only six to eight hours. Ten hours daily for 14 days at 125°C will thus use up $(10/24 \times 14 \times 23) = 134$ extra days of life, i.e. about five months of life. This is not going to be noticed in a lifetime of 30 years plus, and is probably a fairly small price to pay for the economies gained from rating the transformer in this way.

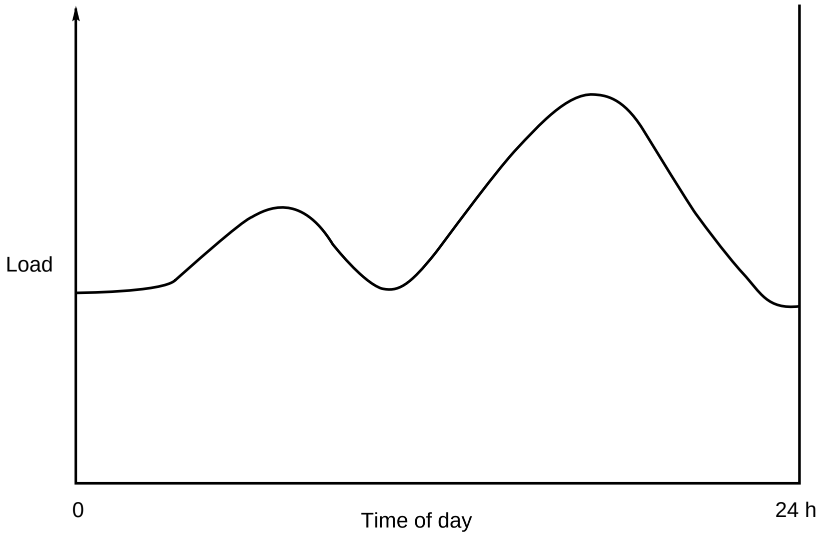


Figure 7.18 Typical daily load cycle

In reality, there is another factor which will reduce the degree of ageing that the CER transformer will be likely to suffer in such an emergency. Because system loading is always tending to increase, substations must be periodically reinforced by the installation of additional transformers. The loss of one transformer will only result in the remaining unit being required to carry the full rated load of two should this emergency occur at about the time the substation is due for reinforcement. At any other time the load per transformer will be less.

However, there is also one note of caution. In the UK maximum system loading tends to occur during the winter months when ambients are generally lowest. This is the reason why the permitted hot-spot temperature is quoted at an ambient temperature of 5°C. If a CER transformer is called upon to perform an emergency duty during the summer months, the hot-spot temperature must be carefully monitored to ensure that this does not exceed the design figure of 115 or 125°C as appropriate. For each 10°C that the ambient temperature exceeds 5°C it will be necessary to reduce the maximum rated load by about 7%. It must be remembered that a CER transformer has *no* overload capability beyond its emergency rating and it is designed for operation at one ambient of 5°C maximum and not a variable one as set out in IEC 76. *Figure 7.19(a)* shows the core and windings of a 12/24 MVA 33/11.5 kV CER transformer and *Figure 7.19(b)* shows a typical CER installation.

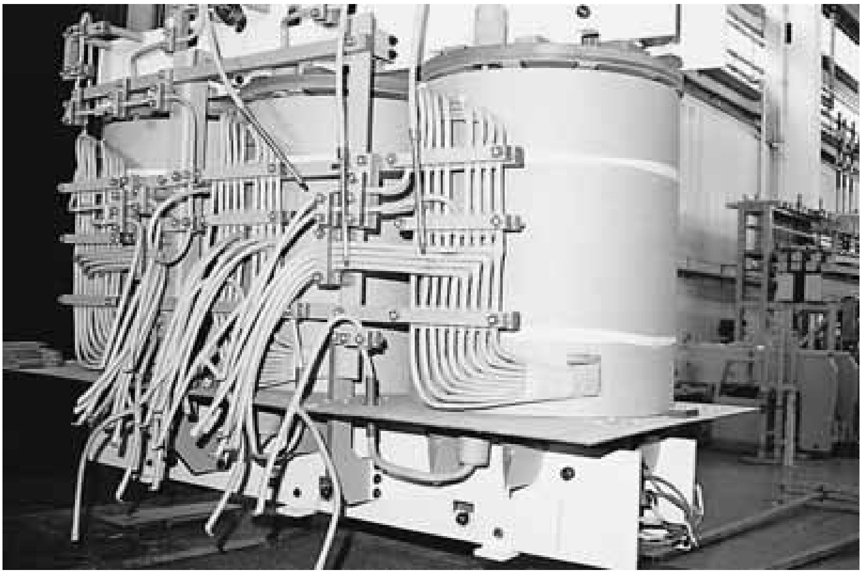


Figure 7.19(a) Core and windings of 12/24 MVA, 66/11 kV, three-phase, 50 Hz CER system transformer (ABB Power T&D Ltd)

Testing of CER transformers

It will have been noted that in the foregoing description of the CER transformer that the rating is based on achieving compliance with a specified *hot-spot* temperature rise, this despite the fact that, as explained in Section 5 of Chapter 4, hot-spot temperature cannot be measured. It is thus difficult to ensure by testing that the manufacturer has complied with the specification as regards achieving the specified hot-spot temperature.

CER specifications usually approach this problem in two alternative ways. The first involves very extensive monitoring on temperature rise test by the use of fibre-optic probes or similar devices placed in what are adjudged by the designer as being the critical locations. In discussing this as an option it must be recognised that, as stated above, when the concept of CER transformers was first developed it was intended that a high degree of standardisation of

Figure 7.19(b) Two three-phase 12/24 MVA, 33/11 kV, 50 Hz continuously emergency rated system transformers fitted with single compartment high-speed tapchangers, installed on site (ABB Power T&D Ltd)

CER transformers should be adopted with possibly several hundred identical units being built. In these circumstances elaborate monitoring of a prototype on temperature rise test is an economic proposition (even though, at that time, fibre-optic equipment was not available as a means of dealing with the voltage problems). When designs are far from standardised then more conventional methods have to be adopted, which means the second alternative approach.

It is not too difficult to take measurements of top oil temperature where it emerges from the windings rather than at the tank outlet to the coolers where it is likely to have mixed with cooler oil which has not passed through the windings. Once again, nowadays fibre-optic probes can be of assistance, the merit is that only a small number of locations, not actually within the windings, require to be monitored. If this is done it is possible to obtain a reasonably accurate estimate of mean oil temperature in each winding (because the inlet oil temperature to the windings is fairly easy to establish) and from this, and a measurement of the temperature rise by resistance of the individual windings, it is possible to obtain a fairly accurate average gradient for each. It is still necessary, having established the average gradient, to make an estimate of the maximum gradient. This needs the designer's knowledge of the design, but, since the hot-spot factor derived in this manner, i.e. based on a gradient derived from a fairly accurate knowledge of the oil temperature within the windings, is only likely to be two or three degrees, even a large percentage error in this will not greatly affect the accuracy of the estimate of hot-spot temperature. Hence, by one means or another, compliance with guarantees can be fairly clearly demonstrated.

For the ONAN condition top oil temperature rise and winding temperature rise should be measured in the conventional manner and these should comply with IEC 76.

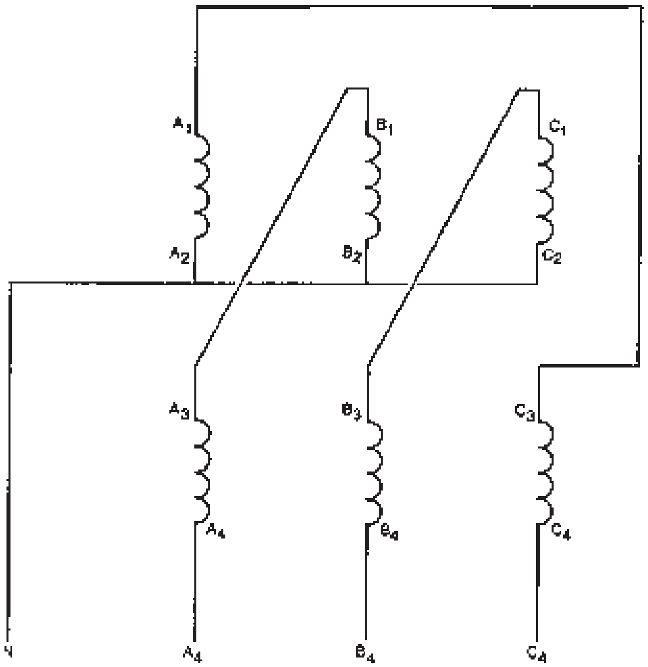
7.7 INTERCONNECTED-STAR EARTHING TRANSFORMERS

On a number of occasions in the preceding chapters, for example in Section 2 of Chapter 6, mention has been made of the use of interconnected-star earthing transformers to provide a neutral point for connection to earth on a system which would otherwise not have one. This requirement commonly arises at a grid bulk supply point where transformers stepping down to 66 or 33 kV from the 132 kV or higher voltage system will need to have one winding connected in delta and, since the HV must be the star-connected winding to enable non-uniform insulation to be used, the delta winding must be the LV. Transformers for stepping down from the 66 or 33 to 11 kV are normally required to be connected in delta on their higher voltage, i.e. 66 or 33 kV, windings in order to provide a neutral for earthing purposes on the 11 kV side, as well as ensuring that the 11 kV system has the required zero phase shift relative to the 400 kV system reference. Hence the 66 or 33 kV system is without a neutral. The situation also arises where a 13 kV delta-connected tertiary is provided on a star/star or star auto-connected transmission transformer for connection to a shunt reactor for VAr absorption.

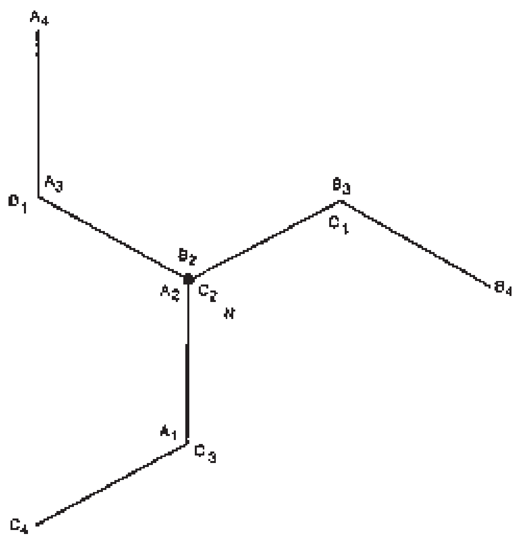
This section examines a little more closely the technical requirements and constructional features of interconnected-star earthing transformers which are used in these situations.

An interconnected-star earthing transformer is a conventional three-phase oil-filled transformer except that it requires only a primary winding in order to provide the required neutral point. *Figure 7.20* shows a phasor diagram and connection diagram of such a transformer. Each ‘half-phase’ is effectively a complete winding for construction purposes so that the transformer is built as if it were a double wound transformer. Core frame size, flux density and number of turns necessary will probably mean that 66 and 33 kV earthing transformers at least will need to have disc windings throughout, although it is possible that at 13 kV helical windings may be used. Particularly at 66 or 33 kV there will be a need to consider lightning impulse strength. Each winding end will constitute a discontinuity from the point of view of surge impedance and will probably require some form of stress control. In the case of disc windings at 66 or 33 kV a shield between end sections or a dummy strand as described in Section 4 of Chapter 4 will probably be used.

Under normal conditions the steady-state voltage applied to earthing transformers is the LV voltage of the step-down transformer with which they are associated. This voltage is likely to have a maximum value of 10% above the



(a) Arrangement of windings



(b) Phasor diagram

Figure 7.20 Interconnected-star earthing transformer system nominal voltage so that a flux density of 1.7 tesla may be permitted for the earthing transformer without the risk of saturation. It is not usual to provide the transformer with tappings. However, it is common practice to provide an auxiliary winding, usually a star-connected 415 V winding, to provide a three-phase and neutral supply for substation services. Generally the rating of this auxiliary winding is up to about 200 kVA. The rating of the earthing transformer is, however, determined by the current it is required to carry in the neutral for 30 seconds (the short-time rated current) in the event of an HV line-to-earth fault, and not the rating of any auxiliary winding.

As explained in Section 2 of Chapter 6 it is normal practice to select the impedance of the system earth connection to such a value as will result in the flow of rated full-load current for the supply transformer in the earthing transformer HV neutral in the event of a line-to-earth fault on the HV system, which itself has negligible impedance. It is usual to place a minimum value on this fault current which varies according to the HV system voltage. Values of minimum rated short-time currents are listed in *Table 7.1*. At the end of 30 seconds the maximum temperature of the copper must not exceed 250°C. The starting temperature is taken as maximum ambient, 40°C, plus any temperature rise resulting from operation at the continuous maximum rating of the auxiliary winding. The calculation is performed in the same manner as when determining the temperature rise of a transformer on short-circuit described in Section 7 of Chapter 4. Expression (4.3) is used except that the time must be increased to 30 s. The same assumption is made that, for time for which the fault current flows, all the heat is stored in the copper. Although this will be slightly less true in the case of a 30 s fault compared with one for 2 s, it is nevertheless introducing a small degree of pessimism which is no bad thing. The transformer will also be required to withstand the mechanical forces resulting from carrying the short-time fault current and these two requirements usually result in a transformer which is considerably more generously proportioned than would be determined by any requirement to supply the auxiliary loading alone.

Table 7.1 Minimum rated short time current through the neutral of interconnected-star earthing transformers in relation to voltage of delta-connected winding of main transformer

Lower voltage of main transformer (kV)	6.6	11	22	33	66
Rated short time current (amps) for 30 seconds	1320	1050	750	750	750

An important factor in determining the HV system single-phase to earth fault current is the zero-sequence impedance of the earthing transformer. This is calculated in the same way as the positive-sequence value between half-phases treating these as if they were separate windings and using the expression (2.1) given in Chapter 2. It is usual to quote a minimum value for this, i.e. with no negative tolerance and a 20% plus tolerance and it is also necessary to convert this into a value in ohms per phase rather than in percentage terms, the reason being that the earthing transformer does not have a true continuous rating against which to relate a percentage impedance and it is the ohmic value of impedance which dictates the system earth fault current. If the earthing transformer is provided with a secondary or auxiliary winding, the impedance between the interconnected-star winding and the auxiliary winding is normally between 4 and 6% based on the auxiliary winding rating and is calculated in the normal manner.

Earthing transformers for 66 and 33 kV generally have HV bushings for line and neutral terminations of the 66 or 33 kV windings. Air connections of copper bar or tube can then be brought across from the LV terminals of the main transformer and the neutral bushing is usually connected in a similar manner, via any protective current transformers, to a liquid or metal element neutral earthing resistor. The 415 V auxiliary winding will probably be brought out via a weatherproof fuse-switch unit incorporating a bolted neutral link arranged for glanding and terminating a 4-core cable to take the auxiliary supply to its associated distribution board. *Figure 7.21* shows 33 kV earthing transformer with a 415 V auxiliary output and the associated 132/33 kV bulk supplies transformer is discernible in the background.

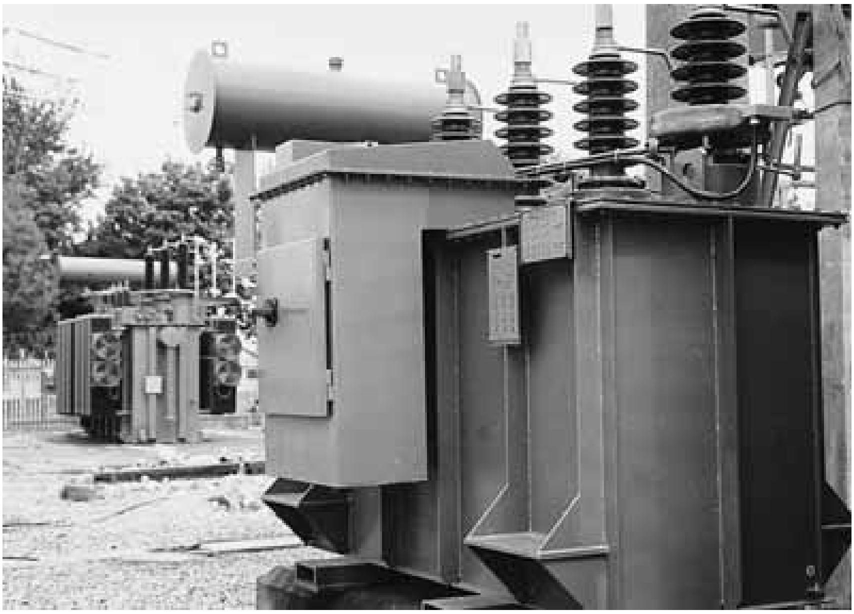


Figure 7.21 A 33 kV interconnected-star earthing transformer with a 415 V auxiliary winding during site installation. The transformer is positioned on a raised concrete plinth in order to provide the necessary clearance to the live 33 kV connections (TCM Tamini)

7.8 DISTRIBUTION TRANSFORMERS

Distribution transformers are normally considered to be those transformers which provide the transformation from 11 kV and lower voltages down to the level of the final distribution network. In the UK this was, until January 1995, 415 V three-phase and 240 V phase to neutral. Now it is nominally 400 V three-phase and 230 V between phase and neutral. Of course, these are nominal voltages to be applied at consumers' terminals and there are tolerances to take account of light loading conditions and regulation at times of peak load. Prior to January 1995, most distribution transformers were designed for a secondary open-circuit voltage on principal tapping of 433 V and it remains to be seen whether this situation will change in the long term. At the present time, however, transformer voltage ratios have not changed, although it is possible that some adjustment of transformer off-circuit tappings might have been made at some points of the distribution network. Throughout the following section, therefore, in making reference to distribution transformer low-voltage windings and systems, these will be termed 415 V or 0.415 kV. Except where specifically indicated to the contrary this should be taken as a nominal description of the winding or system voltage class and not necessarily the rated voltage of the winding or system in question.

Distribution transformers are by far the most numerous and varied types of transformers used on the electricity supply network. There are around 500 000 distribution transformers on the UK public electricity supply system operated by the Regional Electricity Companies (RECs) and a similar number installed in industrial installations. They range in size from about 15 kVA, 3.3/0.415 kV to 12.5 MVA, 11/3.3 kV, although most are less than 2000 kVA, the average rating being around 800 kVA. The vast majority are free breathing oil-filled to BS 148, but they may be hermetically sealed oil-filled, dry type, or, occasionally, where there is a potential fire hazard, fire resistant fluids notably silicone fluid, synthetic ester or high molecular weight hydrocarbons which have a fire point in excess of 300°C may be specified.

This section will first discuss oil-filled units in some detail and later highlight those aspects which are different for dry-type transformers. Synthetic liquids have been discussed in Chapter 3. As far as the constructional features of transformers using these are concerned, there are no significant differences compared with oil-filled units apart from the need to ensure that all the materials used are compatible with the dielectric fluid. Most insulating materials, including kraft paper and pressboard, are satisfactory on this score; if there are problems it is usually with gaskets and other similar synthetic materials.

Design considerations

Distribution transformers are very likely to be made in a different factory from larger transformers. Being smaller and lighter they do not require the same specialised handling and lifting equipment as larger transformers. Impregnation under very high vacuum and vapour-phase drying equipment is not generally required. At the very small end of the range, manufacturing methods are closer to those used in mass production industries. There are many more manufacturers who make small transformers than those at the larger end of the scale. The industry is very competitive, margins are small and turnround times are rapid. As a result the main consideration in the design of the active part is to achieve the best use of materials and to minimise costs, and a 1000 or 2000 kVA transformer built in 1996 would, on reasonably close examination, appear quite different from one made as recently as, say, 20 years earlier.

Cores

Simplicity of design and construction is the keynote throughout in relation to distribution transformers. Simplification has been brought about in the methods of cutting and building cores, notably by the reduction in the number of individual plates required per lay by the use of single plates for the yokes (notched yokes) rather than the two half-yoke plates as would generally be used for a larger transformer. Nonetheless all joints are still mitred and low-loss high-permeability materials are widely used. Cores are built without the top yoke in place and, when the yoke is fitted, this is done in a single operation rather than by laboriously slotting in individual packets of plates. Core frames have been greatly simplified so that these have become little more than plain mild steel 'U' section channels drilled in the appropriate places, and occasionally some manufacturers may use timber for the core frames. These have the advantage that there are no problems with clearances from leads, for example, to be considered in the design of the unit but they are not so convenient in other respects, for example it is not so easy to make fixings to them for lead supports or to support an off-circuit tapchanger. Timber frames are now generally considered by most manufacturers to be less cost effective than steel channels and are now generally tending to be phased out. It is, of course, hardly necessary to state that distribution transformer cores are invariably of a totally boltless construction. Wound cores, in which the core material is threaded in short lengths through the windings to form a coil (*Figure 7.22*), are common for smaller ratings up to several tens of kVA.

One occasion on which more sophisticated designs are widely used in distribution transformers is in relation to the use of the step-lapped core construction described in Section 2 of Chapter 4. While this form of construction might occasionally be used in some large transformers, it is to be regarded as the norm for most distribution transformer cores. There are a number of reasons for this:

- Joints form a greater proportion of the total iron circuit in the case of a small distribution transformer core compared to that of a large power transformer and so measures to reduce losses at the joints will show a greater benefit.
- Building a small core is so much easier than it is for a large core, so that the more sophisticated construction does not present such an obstacle in manufacture.

Figure 7.22 Wound core for single-phase 11/0.250 kV, 50 kVA, polemounted transformer. Although not discernible in the photograph, each loop of core steel has an overlapped joint at the upper end. As an indication of its physical size, the core limb is about 10 cm square (Allenwest Brentford)

- Distribution transformers tend to operate at poor load factors. Although this means that the magnitude of the load loss is not too important, iron loss is present all the time and it is therefore desirable to minimise its impact.
- The competitive nature of the industry, discussed above, gives an incentive to provide low losses and noise levels, both of which are improved by using the step-lap construction.

Distribution transformer cores also represent the only occasion for which the use of amorphous steel has been seriously considered in the UK (and quite widely adopted in other countries, notably the USA). As indicated in Section 2 of Chapter 3, the dimensions of the material currently available is one factor which prevents its use in larger transformers, but nevertheless some of the reasons discussed above for the adoption of the step-lap form of construction, namely the relative ease of building small cores and the importance of minimising iron losses as well as the competitive commercial situation also provide strong incentives for innovation in core design among distribution transformer manufacturers.

Windings

Foil windings are frequently used as low-voltage windings. In this form of construction the winding turn, of copper or aluminium foil, occupies the full width of the layer. This is wound around a plain mandrel, with intermediate layers of paper insulation, to form the required total number of turns for the winding. Strips of the conductor material are welded or brazed along the edge of the foil at the start and finish to form the winding leads as shown in *Figure 7.23*. Any slight bulge that this creates in the section of the winding is of no consequence. This arrangement represents a very cost-effective method of manufacturing low-voltage windings and also enables a transformer to be built which has a high degree of electromagnetic balance and hence good mechanical short-circuit strength. Diamond dotted presspaper (see Section 4 of Chapter 3) is frequently used as interlayer insulation for these windings which also gives them added mechanical strength. The diamond dotted pattern enables the dry-out process to be carried out more easily than would be the case if the resin bonding material were applied uniformly to the whole surface of the presspaper sheet. Foil windings are produced in this way for use in oil-filled transformers; however, the same construction using class F materials can be used in air-insulated transformers or as the low-voltage windings of cast resin transformers.

Distribution transformers frequently use other types of winding construction not found in larger transformers in addition to the foil windings described above. Because of the small frame sizes resulting from low kVA ratings, the volts per turn is usually very low so that for a high-voltage winding a considerable number of turns will be required. The current is, however, also low and the turn cross-section, as a result, is small. Winding wires are frequently circular in section and enamel covered. Circular cross-section wire cannot be wound into continuous disc windings so multilayer spiral windings are common. These will normally have one or more wraps of paper between layers to give the winding stability and to provide insulation for the voltage between layers. One problem with this arrangement is that when drying out the winding the only route for removal of moisture is via the winding ends so that the dry-out process must allow sufficient time under temperature and some degree of vacuum to allow the moisture to migrate axially along the length of

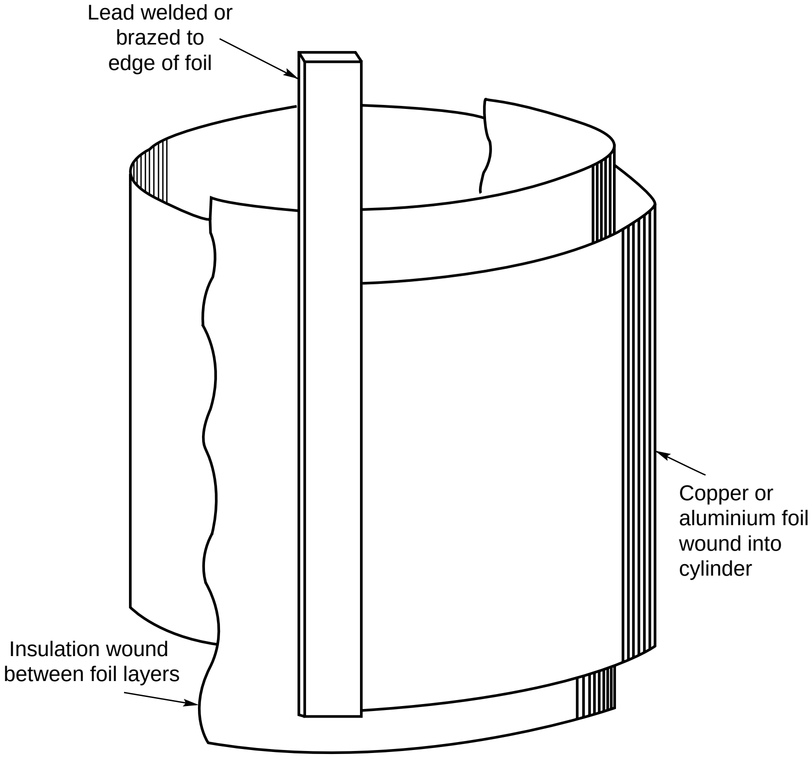


Figure 7.23(a) Construction of foil winding

the layers. Frequently the dry-out time for this type of winding might appear disproportionately long for a small transformer.

Another alternative for high-voltage windings is the use of 'crossover' coils. This form of construction is shown in *Figure 7.24* which shows an individual coil. Each section of the winding, or coil, is itself a small multilayer spiral winding having a relatively short axial length. A complete HV winding will then be made up of perhaps 6 or 8 coils arranged axially along the length of the winding and connected in series as shown in the photograph of a complete transformer, *Figure 7.25*. Crossover coils are easier to dry out than full length multilayer windings since they have a short axial length and, by subdividing the winding into a number of sections, the volts within each section are only a fraction of the phase volts, thus distributing this evenly along the leg. For this reason this form of construction is likely to be used for the higher voltage class of HV winding, for example at 22 or 33 kV, where a simple layer construction would not provide the necessary clearance distances.

Continuous disc windings are, of course, used for any high-voltage winding which has a large enough current to justify the use of a rectangular conductor. At 11 kV, this probably means a rating of about 750 kVA, three phase and

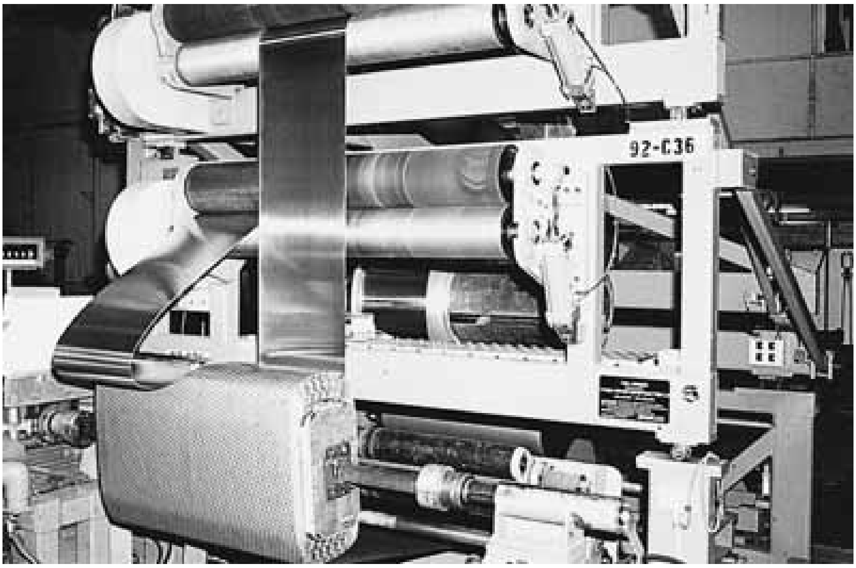


Figure 7.23(b) Foil winding in manufacture. Two widths of foil are being wound in axial dimension with diamond dotted presspaper insulation between layers (Whiteleys Ltd)

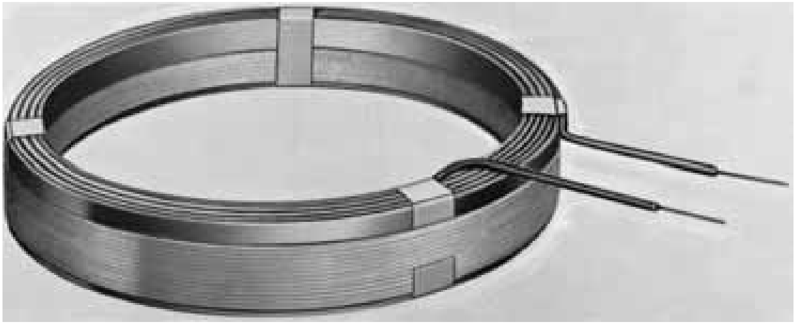


Figure 7.24 Crossover coil

above would have a disc wound HV winding. At 3.3 kV disc windings will probably be used for ratings of 250 kVA, three phase and above. Because of their intrinsically greater mechanical strength, disc windings would be preferred for any transformer known to have a duty for frequent starting of large motors or other such frequent current surges.

Pressure for much of the innovation introduced into distribution transformers has come from the competition within this sector of the industry. Although many of the materials and practices used have some application or spin-off for larger sized units, others can be used only because they are tolerable when

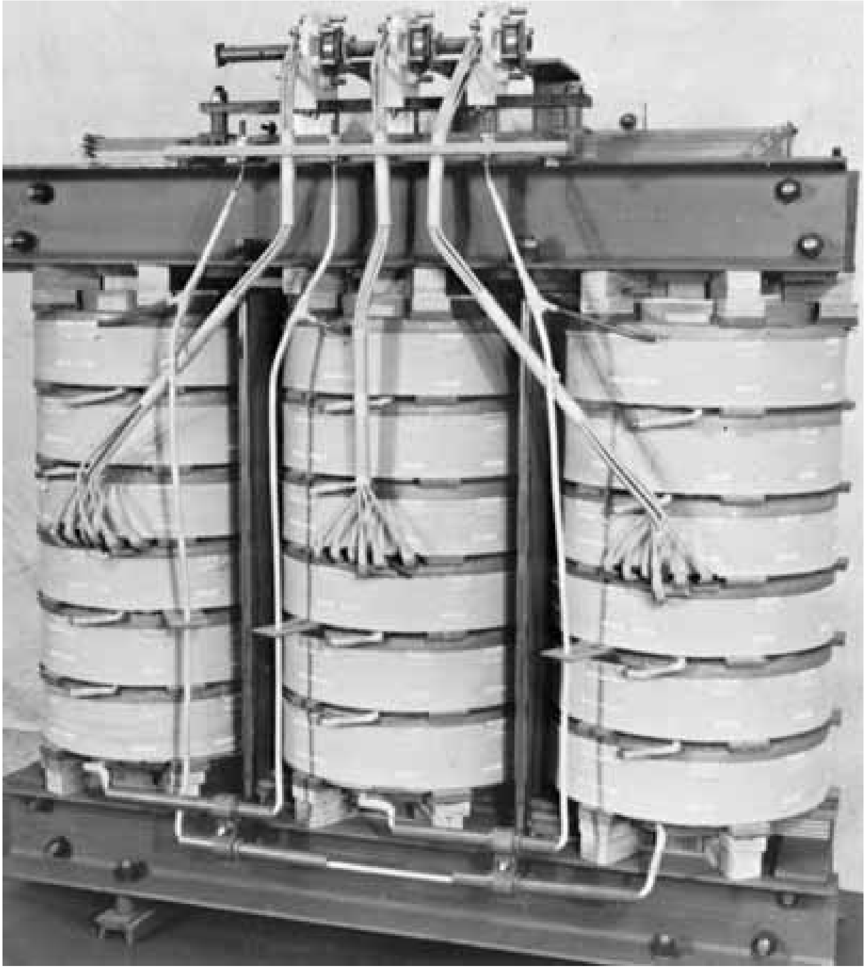


Figure 7.25 Three-phase 750 kVA, 11 000/433 V, 50 Hz transformer with a mitred core. HV windings in delta, LV in star. Crossover HV coils; spiral LV coils. HV windings fitted with tappings brought up to an externally operated tap selector (ABB Power T&D Ltd)

currents are small and short-circuit forces, for example, are modest. One such case is in the use of winding arrangements which are square in planform as shown in *Figure 7.26*. By adopting this arrangement the core limb can have a square cross-section so there is no need to cut a large range of plate widths, and the core with its three-phase set of windings is more compact so a smaller tank can be used. This is only permissible because small units with modest short-circuit forces do not need the high mechanical strength provided by the use of windings which are circular in section.

Figure 7.26 400 kVA transformer with square-section core and coils. This transformer has a core of amorphous steel (see also Figure 3.8) but the technique can be used to simplify core construction and improve space-factor for any type of transformer where the unit is small enough to limit the short-circuit forces to a modest enought level (GEC Alsthom)

Leads and tappings

Most distribution transformers will be provided with off-circuit tappings, generally at ±2.5 and ±5% on the HV winding, selectable by means of a padlockable switch on the outside of the tank operable only when the transformer is isolated. A typical off-circuit tapping selector switch is shown in *Figure 7.27*. This enables the user, probably no more than once or twice at the time the transformer is commissioned, to select very conveniently the most appropriate LV voltage for its location on the system. At these low-current ratings off-circuit switches are not subject to any of the problems of pyrolytic carbon deposits, described in Section 6 of Chapter 4, which beset the high-current applications and which, as a result, lead to a preference for tap changing by the use of off-circuit links on these very much larger units.

Multilayer windings and crossover coils are not as convenient as disc windings as regards the ability to make tapping connections from the outside face of the coil. It is common practice to make a tapping connection within a layer so that the lead is brought out along the surface of the layer and with possibly an additional layer of presspaper insulation above and below it to provide insulation as it crosses the adjacent turns within the layer. The tapping connections can be seen emerging from the ends of the central crossover coils in *Figure 7.25*.

Figure 7.27 Three-phase 11–33 kV HV off-circuit tap selector (ABB Power T&D Ltd)

Simplification of the arrangement and method of forming leads internal to the tank has been made possible by the use of round wire rather than flat copper bar for these wherever possible. Round wire or bar, being stiffer, usually requires fewer supporting cleats and since it can be bent with equal ease in all planes it can usually be taken from point to point in a single formed length, whereas flat bar might require several specially formed bends and joints in order to follow a complex route. Joints external to windings are generally formed by crimping and are nowadays rarely brazed. Crimping has the advantage that it avoids the need to bring a blowtorch into the close proximity of windings with its associated risk of fire or, at the very least, overheating of insulation. Crimped joints are also made very much more quickly than brazed or sweated joints, leading to cost savings.

Widespread use is also made of preformed insulation sections, for example flexible crêped paper tubes threaded onto leads to provide external insulation for these, and corrugated pressboard to form interwinding ducts.

Tanks

Because of the relatively large numbers made, some flow-line production can be introduced into tank manufacture for the smaller units, notably the 3.3/0.415 kV pole-mounted types. This requires that tanks should be standardised, which means that the fittings provided and the location of these must also be standardised. Internal surfaces, as well as the steel core frames, are usually left unpainted. Although this goes against the principle of preventing oil coming into contact with the catalytic action of the steel, manufacturers claim that with modern oils, for the conditions of operation encountered in sealed distribution transformers (see below) this does not lead to unacceptable levels of oxidation.

Provision of a silica gel breather for most small distribution transformers would result in an unacceptably high maintenance liability. These transformers are therefore frequently hermetically sealed, with a cushion of dry air above the oil to allow for expansion and contraction. This limited amount of air in contact with the oil is then considered to present only a modest tendency towards oxidation. Sealing of the transformers prevents the moisture arising from insulation degradation from escaping, but again this amounts to far less of a threat to insulation quality than would be the case if the transformers were left to breathe freely without a silica gel breather or if a breather, having been provided, was not maintained in a dry condition.

Larger distribution transformers, say those of 1 or 2 MVA and greater, would probably benefit from having silica gel breathers fitted provided that these were well maintained, in which case tank internals should be painted to prevent contact between the oil and mild steel components. As the units become larger, the use of a conservator tank to reduce the surface area of contact between oil and air, and the fitting of a Buchholz relay, must be considered, although the precise rating at which these measures become economically justified is a decision for the user.

Installation

When used for 415 V local distribution purposes, ground-mounted distribution transformers with ratings from about 315 kVA are frequently supplied as part of a complete packaged substation unit. That is 11 kV ring-main units, transformer isolating switch or circuit breaker and protection equipment, transformer and 415 V distribution panel are all included in a single package usually mounted on a skid base and ready to be placed on a prepared foundation. This has the advantage that the connections from the HV switchgear to the transformer and from transformer to 415 V distribution panel are all internal and factory made. *Figure 7.28(a)* shows a typical arrangement of packaged substation and the electrical connections of this are shown in *Figure 7.28(b)*. 11 kV cables are terminated to each side of the ring-main unit and the 11 kV tee-off connections from this are taken directly through internal 11 kV bushings into the transformer tank. On the 415 V side busbars emerge for direct connection onto the outgoing fuseways.

Nowadays the switchgear for packaged substations almost invariably consists of SF_6-insulated sealed-for-life maintenance-free units, with protection for the transformer and LV busbar zone provided by fuses for transformer ratings up to about 1.5 MVA, and above this by circuit breakers. At least one UK manufacturer has produced a protection device which uses the action of a fusible element to trigger an SF_6 rotating-arc interrupter to give one-shot discriminating protection for the transformer in the event of a fault either

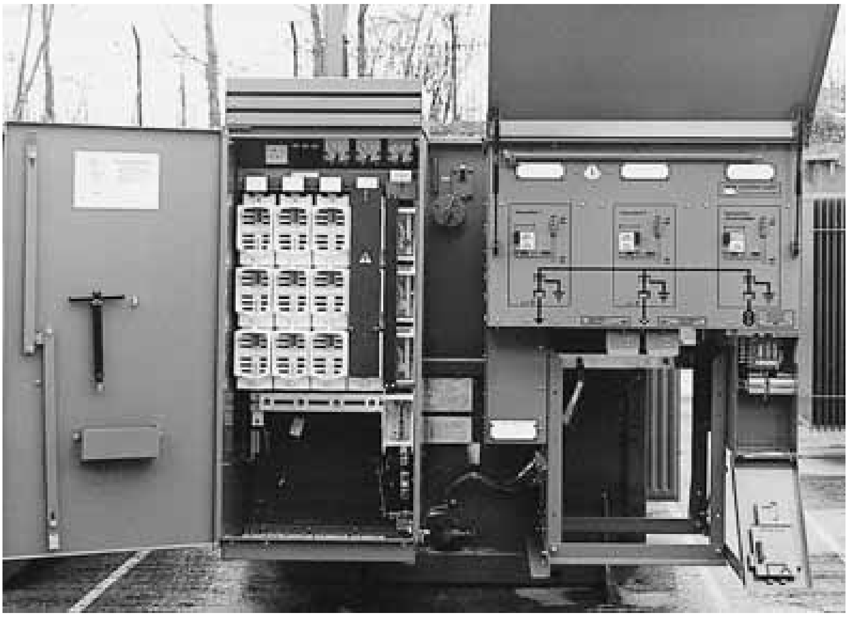


Figure 7.28(a) Packaged substation having 11 kV switchgear consisting of two ring-main units and circuit breaker feeding transformer on right of photograph and 415 V feeder pillar for outgoing circuits on left, all mounted directly onto tank of 11/0.415 kV skid-mounted transformer. Incoming 415 V disconnector is on right-hand side of feeder pillar (Merlin Gernin)

internally or on the 415 V busbars. The fusible element provides the basis for the time-graded discrimination and the whole unit is enclosed in a sealed-for-life SF_6 module. It is a fairly simple step to progress from this arrangement to one in which the module is housed within the transformer tank to produce a 'self-protecting transformer'. Such an arrangement is shown in *Figure 7.29*.

Dry-type and cast resin transformers

Dry-type transformers, particularly those using cast resin insulation, are now widely used in locations where the fire risk associated with the use of mineral oil is considered to be unacceptable, for example in offices, shopping complexes, apartment buildings, hospitals and the like. The background to this development and the factors requiring to be considered in installing cast resin transformers within buildings have been discussed at some length in Section 1 of Chapter 6. This section describes the special features of cast resin transformers themselves.

Complete encapsulation of the windings of a power transformer in cast resin is an illogical step to take, because, as explained on a number of occasions elsewhere in these pages, one of the main requirements in designing

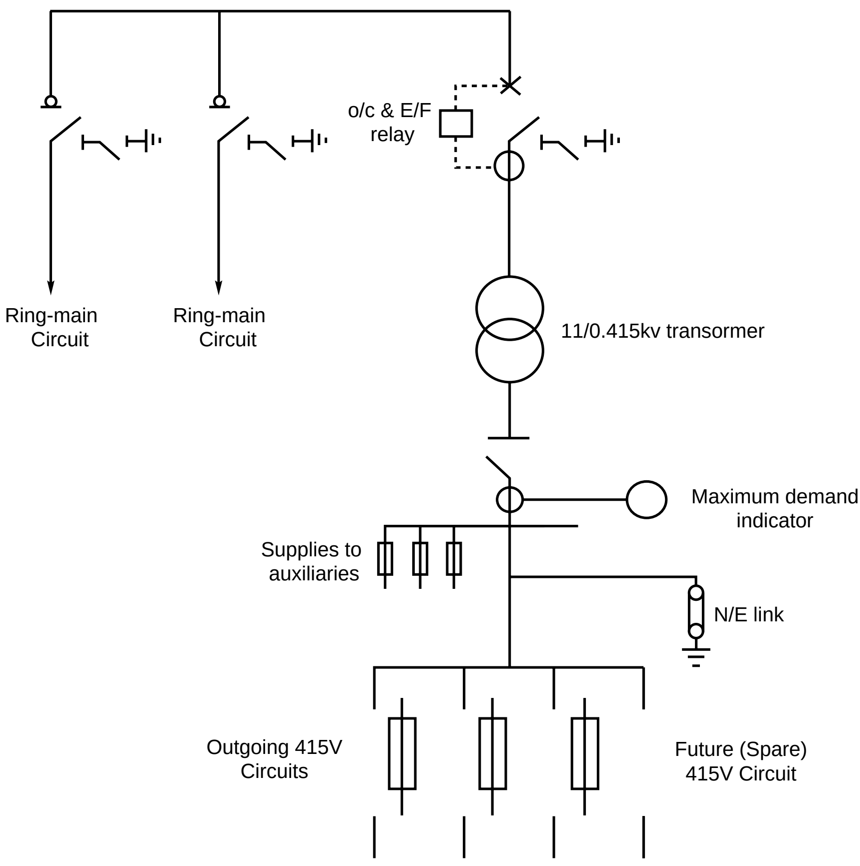


Figure 7.28(b) Electrical arrangement of packaged 11 kV/415 V substation shown in *Figure 7.28(a)*

transformer windings is to provide a means of dissipating the heat generated by the flow of load current. Air is a very much poorer cooling medium than mineral oil anyway, without the additional thermal barrier created by the resin. All air-cooled transformers are therefore less efficient thermally than their oil-filled counterparts and cast resin are poorer than most. Hence they will be physically larger and more costly even without the added costs of the resin encapsulation process. In addition, the absence of a large volume of oil with its high thermal inertia means that cast resin-insulated transformers have shorter thermal time constants which limit their overload carrying capability.

The incentive to develop an economic design of cast resin transformer was provided by the outlawing of polychlorinated biphenyls (PCBs) in the late 1970s on the grounds of their unacceptable environmental impact. Alternative non-flammable liquid dielectrics have all tended to have had some disadvantages, with the result that users have come to recognise the merits of

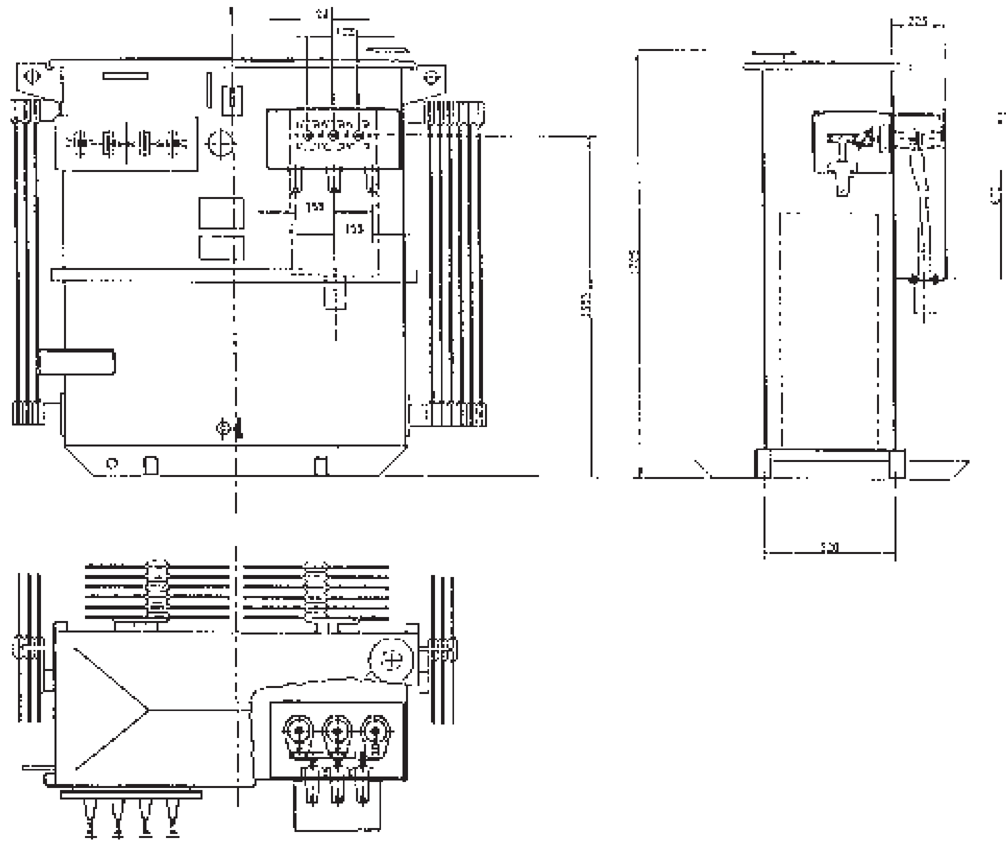


Figure 7.29 800 kVA unit substation transformer with integral HV protection (Merlin Gerin)

eliminating the liquid dielectric entirely. Nevertheless, cast resin does not represent an automatic choice of insulation system for a power transformer. Cast resin transformers are expensive in terms of first cost. They are less energy efficient than their liquid-filled equivalents. In their early days there were suggestions that their reliability was poor and even that their fire resistance left something to be desired. In recent times, however, their qualities of ruggedness, reliability and excellent dielectric strength have come to be recognised as outweighing their disadvantages and their use has become widespread in situations where these properties are most strongly valued.

Resin-encapsulated windings

Cores and frames of cast resin transformers are very similar, if a little larger, to those of oil-filled distribution transformers. It is in the design of the windings that cast resin transformers are unique. 415 V low-voltage windings are usually foil wound, as described above for oil-filled transformers, and are non-encapsulated, although they are frequently given a coating of the same resin material as that used for the high-voltage winding in order to provide them with an equivalent level of protection from the environment.

It is the high-voltage winding which is truly resin encapsulated. Apart from the problem of heat dissipation, the other problem arising from resin encapsulation is the creation of internal voids or minute surface cracking of the resin. Voids can arise due to less than perfect encapsulation or they can be created due to differential thermal expansion between winding conductors and the resin, which may also lead to surface cracking. Surprisingly, the resin has a greater coefficient of expansion than the conductors. The coefficient of expansion of aluminium is a closer match to that of resin than is copper, and aluminium is therefore the preferred winding material. This may be either wire or foil.

If wire is used this will normally be round in section, with a thin covering of insulation. This will probably be randomly wound to the required build-up in diameter, either over a plain mandrel or one which is notched at intervals so that the turns progress from one end of the winding to the other to provide an approximately linear voltage distribution along the axial length of the winding.

If the winding is wound from foil, then a number of narrow foil-wound sections will be connected in series in a similar manner to the method of connecting crossover coils described earlier. Each foil-wound section will be machine wound with two layers of melamine film between foils to provide the interturn insulation; two layers being used to avoid the possibility of any minute punctures in the film coinciding and creating turn-to-turn faults. The melamine film is exceedingly flimsy and the foil must be free from any edge defects which could cut through the film, and a very high level of cleanliness is necessary during the foil winding process to ensure that no particles are trapped between foil and film which could also lead to breakdown by puncturing the film. The winding process usually takes place within an enclosed winding machine which is pressurised with air to above the pressure of the winding room and dry filtered air is blown across the surfaces of the foil and films at the point within the machine where these are brought together. After winding, the foil sections must be kept in a carefully controlled ambient temperature to ensure that the winding tension remains within close limits so as to ensure that there is no relative axial movement of foils and film.

The encapsulation process involves placing the wire or foil-wound sections within steel moulds into which the resin may be admitted under high vacuum. Resin, hardener and fillers, that is the material which gives the resin its bulk, are mixed immediately prior to being admitted to the mould. To ensure that the filler material is fully mixed, part quantity can be fully mixed with the resin and the remainder fully mixed with the hardener before the two are then mixed together. The windings are located within the moulds by means of axial strips of resin material of the same quality as that used for encapsulation. These are placed between the winding and the outer mould so that the resin covering the inner surface of the winding, which will be subjected to the HV to LV test voltage, will be totally seamless. It is important that the resin should penetrate fully the interstices between the conductors if the winding is of the wire-wound type. In some processes this is assisted by initially admitting low viscosity resin into the mould. This is then followed by the encapsulation resin which displaces it except in any difficult to penetrate places, which, of course, was the purpose of the low-viscosity resin.

The resin hardening process is endothermic, that is it generates heat. In order to ensure freedom from stress within the cured resin to minimise the likelihood of resin cracking, it is necessary to carefully control the temperature of the curing process by cooling as and when required. Achieving the precise temperature/time relationship is critical to the integrity of the encapsulated winding so that this process is usually done under microprocessor control.

It is usual to provide cast resin transformers with off-circuit tappings on the HV winding at ± 2.5 and $\pm 5\%$ of open-circuit voltage. These are selected by means of bolted links on the face of the HV winding. The windings are mounted concentrically over the core limb with shaped resilient end blocks, usually of silicone rubber, providing axial location and radial spacing. The HV delta connection is made by means of copper bars taking the most direct route between winding terminals.

Installation

The complete unit is normally mounted on rollers so that it can be easily moved around for installation and is fitted within a sheet-steel ventilated enclosure. Since cast resin transformers are frequently associated with a 415 V distribution switchboard, the enclosure can be made an integral part of this, with the transformer LV busbars connected directly to the switchboard incoming circuit breaker or switch fuse. The HV supply cable may be glanded and terminated within the enclosure with cable tails taken directly to the winding terminals. If the cable comes from below, so that the cable tails pass in front of the face of the HV coil, the transformer manufacturer will specify a minimum clearance between these and the coil face. Some users may prefer to keep the cable termination external to the transformer enclosure and mount a cable box on the outside with through bushings taking the connections into the enclosure so that these may be linked across to the winding terminals. *Figure 7.30* shows a cast resin transformer core and windings and *Figure 6.3* (Chapter 6) shows how such a transformer can be incorporated in a 415 V switchboard.

Figure 7.30 11 kV/433 V cast resin transformer (Merlin Gerin)

Problems with cast resin transformers

Despite the problems associated with cast resin which have been briefly mentioned already, the history of cast resin transformers has been remarkably successful and catastrophic failures have been few.

The possibility of voids and of resin cracking is one problem which has been identified. One measure which can help to resist cracking is the incorporation into the resin of some reinforcement, such as, for example, glass fibre. This may be distributed uniformly within the resin as an additional filler, or it may be included simply at strategic locations where the tendency to crack is considered to be the greatest. In addition small quantities of plasticisers can be added to the resin to give it some resilience. The presence of voids or cracks can be detected by partial discharge testing and the only certain indication of the absence of these is that the winding remains discharge free, that is indistinguishable from background, at twice normal volts. The creation of cracks, or voids, is aggravated by thermal stresses. Stresses induced by differential thermal expansion will be greatest at high temperature, but the resin is more brittle, and therefore more likely to crack, at low temperature. Thermal shock, such as that induced by the sudden application of full load to a cold transformer or mechanical shocks received during shipment in low temperatures may be particularly damaging in this respect. Specified tests for proving the quality of cast resin such as, for example, those listed in the CENELEC standard HD 464 S1, *Dry-type transformers*, are usually based on cycling the windings through extremes of temperature. Details of HD 464 S1 testing will be discussed below.

Another concern attached to cast resin was that although it might not self-ignite, if a cast resin transformer was engulfed in a fire, resins were generally considered to be the type of materials which would burn to produce more heat and/or generate copious quantities of toxic fumes. The fire properties of the resin are, however, largely determined by the type of filler used. Fillers are usually mainly silica, but it is possible to add quantities of other materials to the silica which greatly improve the fire performance. This is also a property which can be tested and it is nowadays the usual practice for manufacturers to submit a prototype winding to a fire resistance type test such as that included in the above-mentioned standard and further described below.

Cast resin transformers are also considered to have poor overload capability due to their short thermal time constants referred to above and also because of the combined effects of poor cooling of the conductors and the limitations imposed on operating temperature due to the need to limit thermal stresses. Manufacturers have, however, improved overload performance over the years by changes in the constitution of the resin. The plasticisers mentioned above assist overload capability by improving the cracking resistance, and the thermal conductivity of the resin can also be influenced by use of a suitable filler. If it is required to subject a cast resin transformer to cyclic rating which takes it above its nameplate continuous rating the manufacturer should be consulted. It must not be assumed that standard loading guides are applicable to cast resin transformers. Forced circulation of the cooling air will, of course, improve the heat transfer from the windings so that it is possible to obtain a dual rated cast resin transformer which achieves its higher forced-cooled rating by means of fans, usually mounted off the lower core frames, and directing air over the windings.

Another possible difficulty with cast resin transformers is that, because of the high cost of moulds, there is a strong incentive for manufacturers to produce a limited range of standard designs, so that if alternative impedances, non-standard ratings or non-standard losses are required, then these cannot be obtained in cast resin. For the vast majority of applications, however, where a standard unit can be used, this will not present a problem.

Testing of cast resin transformers

Most of the testing carried out on cast resin transformers is exactly as would be carried out on an oil-filled distribution transformer. They can be impulse tested, if required, and if the transformer is to be installed within an enclosure, the impulse test should be carried out with the transformer in its enclosure. Similarly, if a temperature rise test is to be carried out, then this should be done with the transformer installed within the enclosure and, as indicated in Chapter 5, it is desirable that the temperature rise test on any dry-type transformer should be done using one of the methods involving excitation of the core at normal voltage. Short-circuit testing is also possible, though unusual, but if carried out, the duration will probably be shorter than the full IEC 76-5 time of 2 seconds, reflecting the poorer thermal capability of cast resin. A shorter time is permissible for equipment connected to the tail end of the distribution system in view of the shorter fault clearance times which apply in this case.

The most important tests on cast resin transformers, however, are those which the manufacturer carries out in order to prove his resin encapsulation system. These will normally be done when a new system is developed, or changes made to manufacturing procedures, and not on the transformers of a particular contract; however, it is important that any potential user of a cast resin transformer should satisfy himself of the relevance of the encapsulation type tests to the resin system being offered. These consist of thermal or climatic proving tests, environmental tests and fire resistance tests and are set out in HD 464 S1, identified above.

Two climatic classes are identified in the above document; class C1 requires operation at ambient temperatures down to $-5°C$ with transport and storage at temperatures down to $-25°C$. Class C2 requires operation, transport and storage down to $-25°C$. After placing the transformer in a climatic chamber set at the appropriate conditions for 12 hours, the condition of the transformer is assessed by subjecting it to 75% of the standard dielectric test level and measuring partial discharge. The transformer is considered satisfactory provided that this is less than 20 pC.

The thermal shock test of class C2 involves immersion in water alternately at boiling point and then containing ice. Each immersion is to last for 2 hours to allow the coils to reach the temperature of the immersion medium throughout, with three immersions in total at each temperature. Again the proof of a successful test is the ability to meet the specified partial discharge requirement.

Environmental tests involve subjecting the cast resin windings to high humidity. These include 6 hours in a climatic chamber at a relative humidity greater than 93%; within 5 minutes of the end of the 6 hour period the transformer is to be held at a voltage of $1.1U_m$ for 15 minutes during which no flashover is to occur. In addition the transformer may be immersed in water for 24 hours and the voltage test applied within 5 minutes of its removal from the water; no flashover is to occur. A further test involves placing in a climatic chamber at 50°C and 90% relative humidity for 144 hours, at the end of which the transformer is subjected to the standard dielectric tests at 75% of the normal specified test levels. No flashover or breakdown is to occur.

An indication of the ability of cast resin to withstand very adverse environmental conditions (and the relative ease with which the above HD 464 S1 environmental requirements should be withstood) can be gained from the 'damp heat test' which was devised by the CEGB in the late 1970s for single-phase cast resin generator voltage transformers of 33 kV class. In this test the transformer is placed in a climatic chamber which is maintained as near as possible at 100% relative humidity for a period of four hours. The transformers are physically small enough to have reached temperature equilibrium with the chamber at the end of this period. At the end of the 4 hours the temperature of the chamber is raised by approximately 3°C while maintaining the relative humidity at 100%. The transformer is thus cooler than its surroundings and its surface quickly becomes wet with condensation. In this condition a voltage of 1.2 times rated voltage is to be applied to the transformer for 1 hour, followed by a final 5 minutes at 1.9 times rated voltage; no breakdown, surface tracking or external flashover is to occur.

Flammability of cast resin transformers

The metal parts of a cast resin transformer, such as aluminium and steel, account for around 89% of its total weight. The insulating materials amount to only about 11%. Of this, less than half can be considered flammable because about two-thirds of the resin compound is silicon dioxide filler – quartz powder – and much of the insulation material of the LV winding is glass based. Hence not more than 5–6% of the total weight of the transformer comprises flammable substances which could supply energy in the event of the transformer being engulfed in a fire. Nevertheless manufacturers are keen to demonstrate the low fire risk associated with their cast resin transformers by testing, and HD 464 S1 sets out details of a flammability test.

Tests for determining flammability are difficult to frame and to interpret because standardised test conditions often bear no relationship to real circumstances. However, two conditions must be met for stable self-sustaining combustion; the temperature of the material must be raised to the fire point (defined in Chapter 3) – in the case of cast resins used in transformers this is usually about 450°C – and the combustion must produce an adequate supply of heat to sustain itself. The HD 464 S1 test is derived from the testing procedure established for electric cables, and in addition to seeking to test whether the material will add to the heat of a fire, it also aims to test whether the materials will release toxic products as a result of the fire. The test involves heating the transformer windings in a chamber by burning alcohol and by providing additional electric heating. The quantity of alcohol is arranged to burn for about 15 minutes and the electric heating is maintained for a further 25 minutes. During the test the temperature in the chamber must not exceed 420°C and this must start to fall immediately the combustion of the alcohol is completed. All of the products of combustion are analysed and the presence of any toxic compounds assessed.

Class C dry-type transformers

Class C dry-type transformers are those based on glass fibre-reinforced boards, aromatic polyamide paper conductor insulation and similar materials capable of operating at temperatures up to around 220°C. These are described in Chapter 3. They have now been somewhat eclipsed by cast resin encapsulated types. However, they do have some advantages over cast resin; they are a little more compact and thus lighter, they generally have lower losses and are up to 20% cheaper than cast resin, and, most significantly, they have better overload and short-circuit withstand capability. Although they are not capable of withstanding the same extreme environmental conditions as cast resin, present day dry types are greatly superior in this respect to those of the 1960s when they were initially introduced. At that time, the conductor insulation or 'paper' covering was largely asbestos based in order to be able to achieve the required temperature withstand capability. Even when properly impregnated, this material was inclined to absorb moisture, which greatly reduced its insulation properties. It was therefore very important to ensure that transformer windings were properly dried out before energising, and even while in service it was important to ensure that transformers were given a good dry environment. The availability of aromatic polyamide paper from the mid-1970s greatly improved this situation.

The construction of class C dry-type transformers is very similar to oil-filled units. They may have conventional helically wound LV windings or these may be foil wound. For all but the lowest ratings the HV winding conductor will be rectangular in section so that HV windings may generally be disc wound. Disc windings are to be preferred to the multilayer helical type, since the former arrangement gives a uniform distribution of the phase voltage throughout the length of the winding thus ensuring that the electrical stresses are minimised. As previously mentioned, air is a poorer cooling medium than oil and in order to ensure adequate cooling air flow through the windings vertical ducts should be a minimum of 10 mm wide and horizontal ducts a minimum of 6 mm. *Figure 7.31* shows the core and windings of a typical class C dry-type transformer.

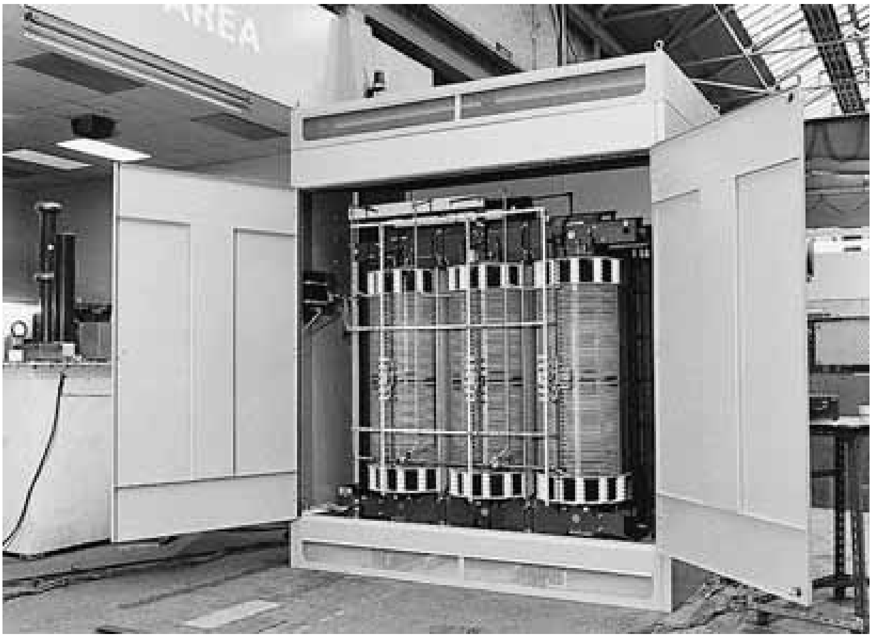


Figure 7.31 Core and windings of a three-phase class 220 dry-type transformer in its enclosure (Brush Transformers Ltd)

The modern aromatic polyamide papers are far less inclined to absorb moisture than the earlier asbestos-based materials. They will absorb about 1% moisture for each 10% relative humidity, so that at 95% RH they will contain 8–10% water. However, even at this level of moisture content their electrical properties will be very little impaired. *Table 7.2* gives the electrical properties of NOMEX®* Paper Type 410, 0.25 mm thick, at varying levels of relative humidity.

Table 7.2 Variation of electrical properties of NOMEX® paper type 410-0.25 mm with variation in relative humidity

Relative humidity per cent	Dielectric strength* kV/mm	Dielectic constant** at 1000 Hz	Dissipation factor*** at 1000 Hz	Volume resistivity Ω-m
Oven dry	37.8	2.3	0.013	6×10^{14}
50	35.4	2.6	0.014	2×10^{14}
95	33.8	3.1	0.025	2×10^{12}

*ASTM D-149, 50.8 mm electrodes
**ASTM D-150, 25.4 mm electrodes
***ASTM D-257

* Du Pont's registered trademark for its aramid paper.

Such a good resistance to humidity might create the impression that varnish impregnation of a winding having aromatic polyamide insulation is unimportant. This is far from the case and it is necessary to properly vacuum impregnate the windings with a silicone varnish if partial discharges, which will ultimately lead to breakdown, are to be avoided. The object of the impregnation should be to ensure that the insulation structure is free from voids, particularly in the areas of high electrical stress, for example at the ends of windings in the close vicinity of conductors, or between the open ends of layers, if a layer type winding is used. The dielectric constant of the aromatic polyamide is between 1.5 and 3.5, depending on the density of the material. The figure for air is, of course, near to unity. In any composite insulation structure, i.e. aromatic polyamide with air-filled voids, the electrical stress in each component material will divide in inverse proportion to their dielectric constants, so that the stress in the voids may be between 1.5 and 3.5 times that in the solid insulation and the reason why these can become a source of partial discharge is thus quite clear.

Installation of class C dry types

The method of installing class C dry-type transformers is very similar to that used for cast resin transformers. The transformer core and windings will normally be mounted on rollers and housed in a sheet-steel ventilated enclosure incorporated into the LV switchboard with its LV busbars connected directly to the switchboard incoming circuit breaker. It is not so convenient to provide moulded HV connections directly onto the winding as is the case with cast resin and, in addition, the paper insulated windings are more easily damaged than those of a cast resin transformer so it is best to avoid carrying out any unnecessary work in the close vicinity. It is desirable, therefore, that the HV supply cable is not terminated internally within the enclosure but connected into an externally mounted cable box. Adequate access to the enclosure should be provided, however, to enable the windings to be cleaned and inspected about once per year. This should preferably be a vacuum cleaning rather than by blowing out dust deposits – a procedure which may embed foreign material in undesirable locations.

Fire resistance

As in the case of a cast resin transformer, a class C dry type contains very little insulation material, probably no more than 3–4% of its weight, so the quantity of combustion products resulting from being engulfed in a fire will be very small. The manufacturers of NOMEX® claim that it does not melt or support combustion. At high temperature, it will degrade and give off gases which are composed of combinations of its constituent oxygen, carbon, hydrogen and nitrogen in concentrations which are dependent on the conditions, such as temperature, availability of oxygen and other materials present. *Table 7.3*

Table 7.3 Combustion gases from NOMEX® aramid

	Off-gases, mg/g sample Burning at 900–1000°C	
	Excess air	Deficient air
CO_2	2100	1900
CO	$<$ 10	100
C_2H_4	–	$<$ 1
C_2H_2	$<$ 0.5	1
CH_4	–	$<$ 2
N_2O	–	4
HCN	$<$ 2	8
NH_3	2	–
H_2O	10	–

gives details of the products of combustion from NOMEX® aramid paper at 900–1000°C for the cases of both excess and insufficient air.

7.9 SCOTT- AND LE BLANC-CONNECTED TRANSFORMERS

Scott- and Le Blanc-connected transformers were once widely used as a means of interconnecting three-phase and two-phase systems. Nowadays the use of three-phase systems is so universal that the requirement for such connections no longer exists. They can also be used to reduce the extent of phase unbalance when single-phase loads are supplied from three-phase supplies which means that the possibility exists that they might still occasionally be encountered in this mode of operation. Earlier editions of this work included a much more detailed treatment but the following brief descriptions are provided for completeness and to provide some coverage of all aspects of transformer design and operation.

The Scott connection

The Scott connection is one means of making the three-phase to two-phase transformation and utilises two single-phase transformers connected to the three-phase system and to one another to achieve this. In *Figure 7.32*, if A, B and C represent the three terminals of a three-phase system and N represents the neutral point, the primary windings of three single-phase transformers forming a delta-connected three-phase bank may be represented by the lines AB, BC and CA. If it is desired to arrange the primary windings in star, the corresponding lines on the diagram are AN, BN and CN. If, in the diagram, AN is continued to the point S, the line AS is perpendicular to the line BC, and it is evident that it would be possible to form a three-phase bank using only two single-phase transformers, their respective primary windings being represented in phasor terms by the lines AS and BC. With this connection it is possible to

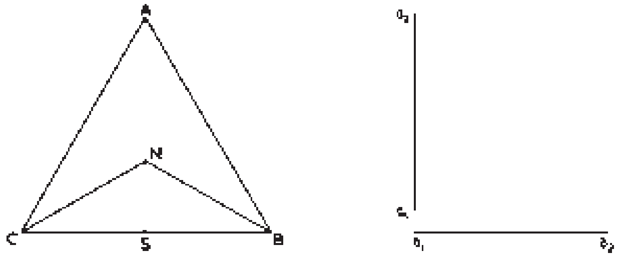


Figure 7.32 Phasor derivation of the Scott connection

form a three- to three-phase bank consisting only of two single-phase transformers. At the same time it is also possible, by giving each transformer a single secondary winding, to form a three- to two-phase bank. These secondary windings are represented in the diagram by the lines a_1a_2 and b_1b_2.

The simplest form of Scott group utilises two single-phase transformers having primary turns in the ratio AS to BC. Both have the same number of secondary turns dictated by the required secondary phase voltage. The primary of the transformer having the larger number of turns, i.e. equivalent to BC, also has its primary winding centre tapped and the connection brought out for connection to one primary pole of the other transformer.

The first transformer is known as the 'main' transformer and the other is known as the 'teaser', and the ratio of primary turns on teaser to main transformer can be deduced from an examination of *Figure 7.32*. ABC is an equilateral triangle for which the ratio of the length of perpendicular AS to side AB is equal to $\sqrt{3}/2{:}1$, i.e. 0.866:1. Each secondary winding is simply a single-phase winding, and the voltage across it and the current in it are precisely as would be expected for any single-phase transformer. On the three-phase side, if the line voltage is V, then:

$$\text{voltage across main transformer} = V$$

$$\text{and voltage across teaser transformer} = 0.866\ V$$

$$\text{current in main transformer } \frac{1000 \times \text{kVA}}{\sqrt{3}V}$$

$$\text{current in teaser transformer } \frac{1000 \times \text{kVA}}{\sqrt{3}V}$$

where the required group output is stated in kVA.

By multiplying the voltage across each transformer by its current, the equivalent size of each is obtained. In the case of the main transformer, this is equal to 0.577 times the group output; and in the case of the teaser transformer, 0.5 times the group output. Therefore, in a Scott-connected group, the two-phase windings are equivalent to the windings of two ordinary single-phase windings of the same output, but on the three-phase side the winding of the main transformer is increased in size by 15.5% above what would be required in a single-phase transformer of the same output. Assuming that the primary and secondary windings of an ordinary single-phase transformer each occupies about the same space, then, for a Scott-connected group, the main transformer will need to be about 7.75% larger than a single-phase transformer providing the same output, but the teaser transformer size will not be increased.

Figure 7.33 shows the arrangement of windings and connections for the Scott group for which the neutral point on the three-phase side is brought out for connection to earth if required. As will be apparent from examination of the geometry of the equilateral triangle ABC of *Figure 7.32*, the position of the neutral divides the primary winding turns of the teaser transformer in the ratio of 2:1.

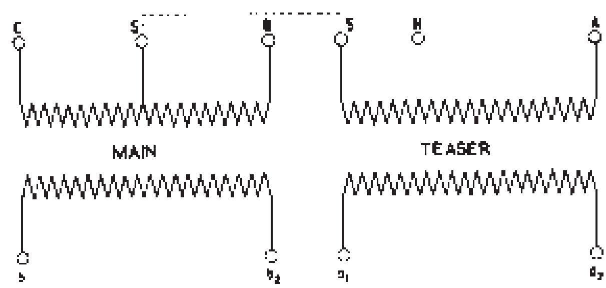


Figure 7.33 Connections for non-interchangeable Scott group

Interchangeable groups

When the Scott connection was in common use it was often considered inconvenient that the pair of transformers constituting the Scott group were not interchangeable and because the cost of making them so was quite modest, this was commonly done. It is only necessary to provide each primary winding with the full number of turns with the centre point of each brought out to an external terminal. Each primary must then have a tapping brought out at 86.6% of the total turns, and, if a neutral connection is required, a tapping must be brought out at the appropriate position on each primary for this purpose. A diagram of connections for such a group is shown in *Figure 7.34*. Although it might appear that a large number of connections are required, it should be remembered that these transformers would normally only be used at 415 V or lower and with ratings of only a few kVA, so that the size of the leads and terminals, and consequently their cost, will not be great.

Three-phase to single-phase

In *Figure 7.35* the current distribution in a Scott group is shown for three different conditions. *Figure 7.35(a)* shows the current distribution when the

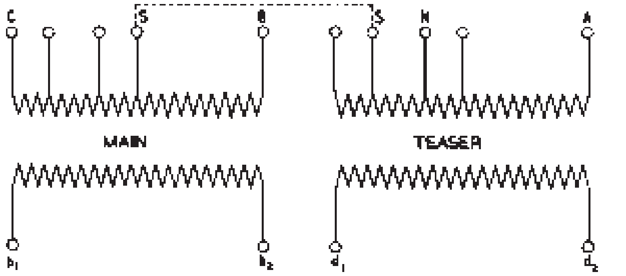


Figure 7.34 Connections for interchangeable Scott group

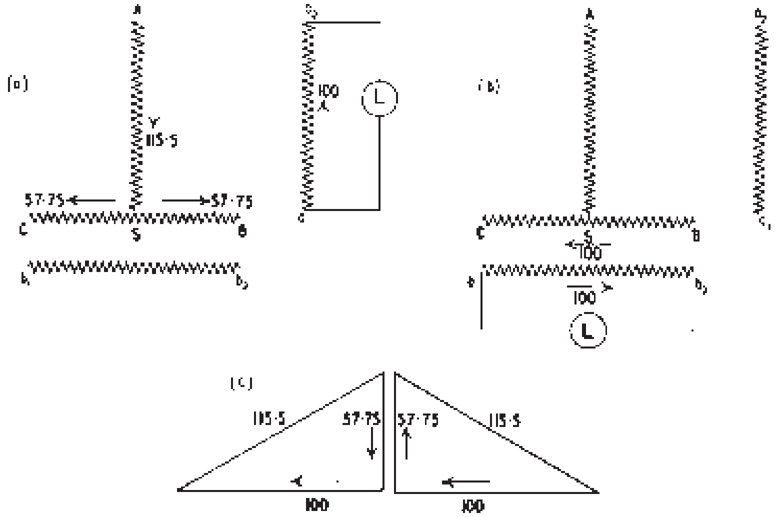


Figure 7.35 Loadings of Scott-connected groups

teaser transformer only is loaded; *Figure 7.35(b)* shows the corresponding distribution when the secondary of the main transformer only is loaded; *Figure 7.35(c)* is a phasor diagram of currents showing a combination of the conditions in the first two figures for the main transformer only.

Referring to *Figure 7.35(a)* it can be seen that the current in the teaser windings on the three-phase side divides into two equal parts on passing to the main transformer, these two parts being in opposite directions. If the two halves of the primary winding on the main transformer are wound in such a way that there is a minimum magnetic leakage between them, these two currents will balance one another, and the main transformer will offer very little impedance to the flow of current even though its secondary is open-circuit. If, however, the coupling between these two halves is loose, the main transformer will appear as a choke to the current of the teaser transformer. It can be seen that the Scott connection will operate as a fairly effective means of supplying a single-phase load from a three-phase supply provided the main transformer is wound with its primary halves closely coupled. This is best achieved by winding them as two concentric windings on the same limb of the core. With this arrangement the single-phase load is distributed between the three phases of the supply equally in two phases with double the current in the third phase. When used in this way no load is applied to the secondary of the main transformer.

The Le Blanc connection

The alternative connection to the Scott for transforming from a three-phase to a two-phase supply is the Le Blanc connection. Although this latter connection has been accepted by engineers from the end of the nineteenth century it has not gained the same popularity as the Scott connection and is by no means so well known.

Figure 7.36 shows the combined voltage phasor diagrams of the Scott and Le Blanc connections and it will be seen that the phase displacement obtained by both methods is identical and that the connections are interchangeable. It follows therefore that transformers having these connections will operate satisfactorily in parallel with each other if the normal requirements of voltage ratio and impedance are met.

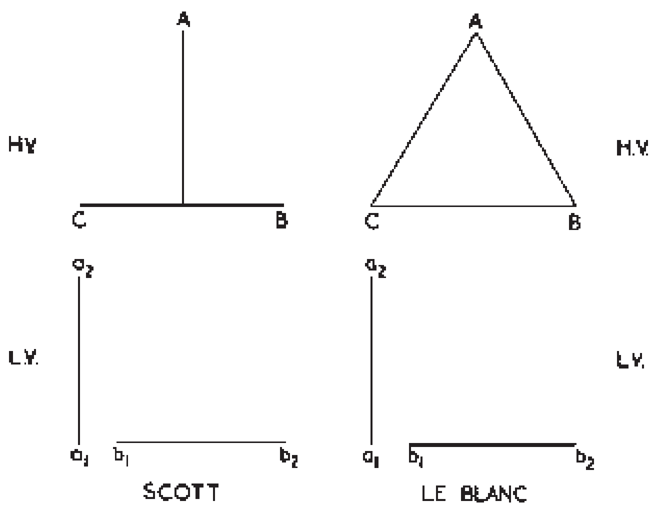


Figure 7.36 Phasor diagrams illustrating interchangeability of Scott and Le Blanc connections

The primary of the Le Blanc-connected transformer shown in *Figure 7.36* is connected in three-phase delta which is the normal interphase connection in the case of a step-down unit supplied from an HV source. Where the primary three-phase winding is connected in delta the inherent advantage of this winding for the suppression of third-harmonic voltages will be apparent. For fuller details of this aspect reference should be made to Chapter 2. Where the three-phase side is the secondary, i.e. when the transformer is operating two- to three-phase it would be more convenient to use a star connection on the three-phase side.

A core of the three-limb, three-phase design is employed for the construction of a Le Blanc-connected transformer compared with two single-phase cores for the Scott-connected transformer. In addition to a somewhat simpler standard core arrangement the Le Blanc transformer is less costly to manufacture due to the fact that for a given rating less active materials are required for its construction. The fact that a three-phase core, and hence a single tank, can be employed to house the Le Blanc transformer means that the unit is more economical in floor space than the Scott transformer, particularly if compared with the arrangement of two separate single-phase cores each in its own tank.

From the phasor and connection diagrams of *Figure 7.37*, which is drawn to show the arrangement of windings for a three- to two-phase Le Blanc transformer, it will be seen that the HV primary is identical with that of any delta-connected winding and is constructed as such. The voltage of the output winding is established across the four two-phase terminals a_1a_2 and b_1b_2 and the LV turns are so designed that the voltage phasor a_1a_2 is equal to b_1b_2. From the geometry of the phasor diagram the quadrature relationship between a_1a_2 and b_1b_2 will immediately be apparent.

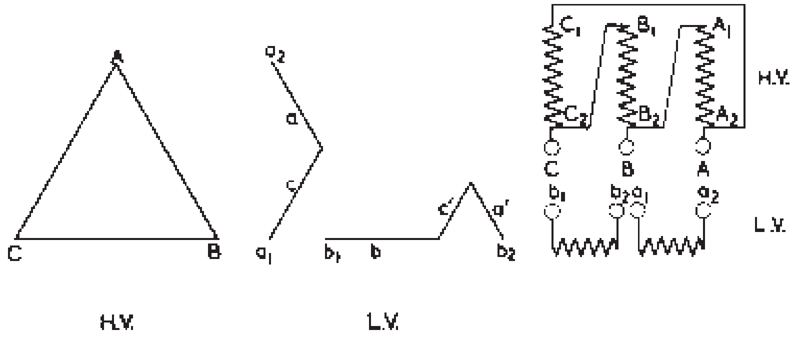


Figure 7.37 Phasor and connection diagrams of a Le Blanc-connected transformer

The phase relationship between the winding sections a and c which comprise one phase of the two-phase output is 120 apart so that each section a and c must have 57.7% of the number of turns required to develop the specified phase voltage a_1a_2. Further, the winding sections a and c must have $\sqrt{3}$ times the number of turns of winding sections a′ and c′, resulting in winding sections a′ and c′ having 33.3% of the number of turns corresponding to the phase voltage b_1b_2. It follows that winding section b must have 66.6% of the number of turns corresponding to the phase voltage b_1b_2. These fixed relationships of number of turns between the winding sections a, a′, b, c and c′ follow from the basic voltage phasor diagram.

When transforming from a three-phase HV supply to an LV two-phase output quite definite limitations are therefore imposed upon the design of the secondary winding of a Le Blanc-connected transformer due to the fact that only whole numbers can be employed for the winding turns, while at the same time certain fixed ratios of turns must be maintained between sections of windings. These conditions are accentuated by an LV winding having comparatively few turns. In addition to these considerations of voltages of the various sections of the two-phase side, the ampere-turns of each phase of the primary winding are balanced by the phasor sum of the ampere-turns of the components of the secondary windings of the two-phase winding on the same phase.

The Le Blanc connection can be arranged for either two-phase three-wire or four-wire output windings, and will transform from three- to two-phase or vice versa with the three-phase side connected in either star or delta. The former is invariably employed for three-phase LV secondary windings and the latter for HV three-phase primary windings.

When supplying a balanced three-phase load from a star-connected secondary the regulation of the Le Blanc transformer will be comparable with that of a three-phase star/star-connected transformer and if it is required to load the transformer windings between line and neutral, and so cause appreciable unbalanced loading, a tertiary delta-connected winding should be provided.

The phasor and winding diagrams shown in *Figure 7.38* illustrate the modification necessary to the two-phase side of a Le Blanc transformer when the mid-points are required to be available on the two-phase winding. Compared with the arrangement of the windings of *Figure 7.37* it will be seen that each winding section a, a′, b, c and c′ of the diagram is subdivided into halves and interconnected to provide the mid-points at a_2 and b_2 of *Figure 7.38*.

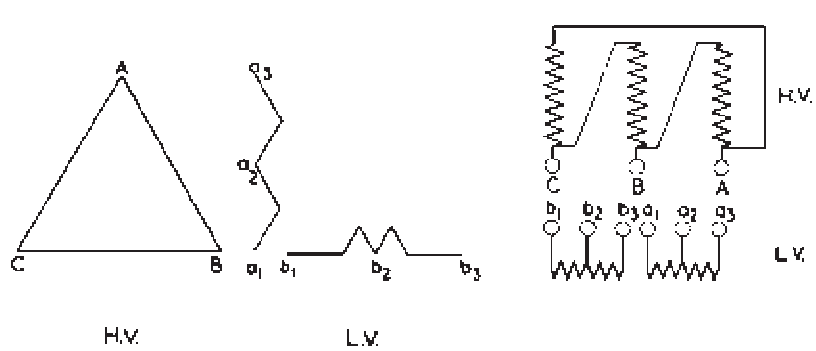


Figure 7.38 Phasor and connection diagrams of a Le Blanc-connected transformer when mid-points are required on the two-phase windings

7.10 RECTIFIER TRANSFORMERS

The requirement for DC power supplies is nowadays relatively uncommon. The advent of inexpensive and rugged thyristor drives has meant that AC three-phase motors can now be used for traction as well as for all types of hoists, winders, rolling mills and the like which might hitherto have relied on DC-derived Ward Leonard supplies. Telephone exchanges now operate with solid-state digital controls drawing currents of only a few amps so that large batteries of Planté cells are no longer necessary. The exceptions are certain process plants, aluminium smelters, electrolytic gas production plants, electroplating plants and uninterruptible power supplies (UPSs) systems and there are still some locations, such as power stations, both fossil fuelled and nuclear, where the provision of a large battery represents the ultimate guarantee of supply security for essential plant such as turbine barring gear, lubricating and jacking oil supplies, or post-trip reactor cooling systems. Most power stations will also have batteries for control and operation of HV switchgear.

For large plants such as aluminium smelters, rectifier transformer ratings may be as large as 20 to 60 MVA, taking a supply at 33 kV and providing a low-voltage output to the rectifiers at between 500 and 1000 V. LV currents may therefore be as high as 10–30 kA and the LV conductors will need to have a substantial cross-section. This usually means that in order to bring out the large cross-section LV leads, the low-voltage winding must be made the outer winding rather than occupying its usual position next to the core and it will probably consist of a number of parallel disc-wound sections arranged axially with their ends connected directly to vertical copper busbar risers.

For power station battery supplies, the rectifier transformers will be very much smaller and of more conventional construction with the low-voltage winding next to the core. They will probably be supplied at 3.3 kV or 415 V with output voltages of 220 or 110 V.

Regardless of their rating, the feature which singles out rectifier transformers for special attention is the problem of harmonic currents created by the thyristor rectifiers and fed back into the supply system. The problem has two aspects: the additional heating which these produce within the transformer, and the waveform distortion which is created on the supply network.

In the case of the first of these, the important requirement is that they should be taken into consideration when designing the cooling for the transformer and also when carrying out any temperature rise test. Ideally the temperature rise test should be carried out with the transformer coupled to its rectifier, although this might not be practicable in the case of the larger rectifier transformers. This is one of the recommendations of BS 4417:1981 *Specification for semiconductor rectifier equipments* which sets out the particular requirements of rectifier transformers.

It is the second aspect, however, which can be the most serious, particularly for the very large rectifier loads, and especially if the loads from a

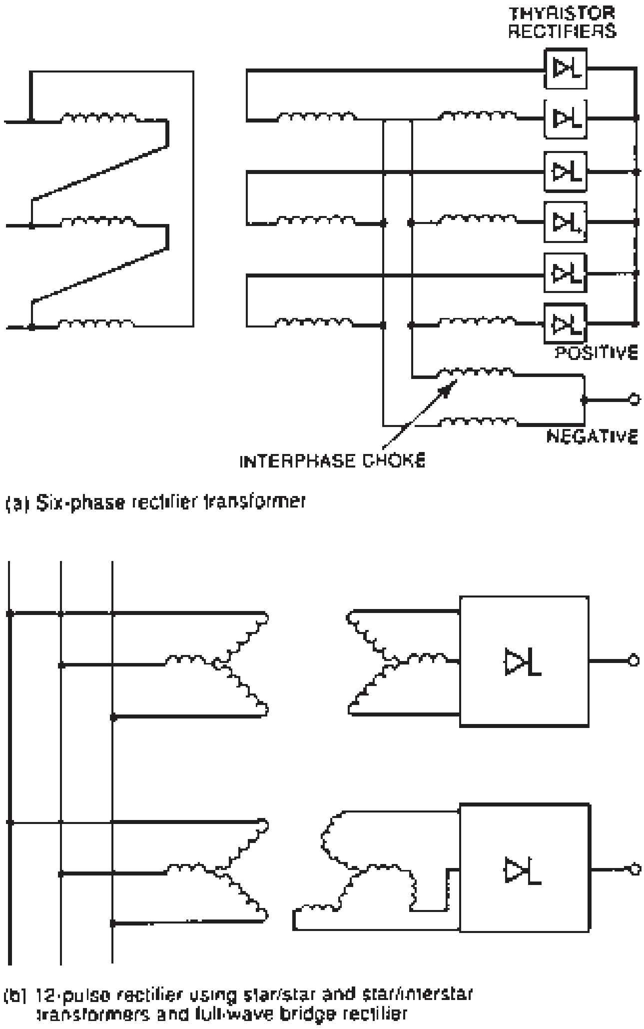


Figure 7.39 'Six-phase' rectifier transformer and rectifier transformer bank of delta/star and interstar/star transformers

number of parallel rectifiers are all drawing harmonics in phase with each other. Many rectifier transformers employ a 'six-phase' delta/star/star connection arrangement as shown in *Figure 7.39(a)* and this of itself helps to reduce harmonic distortion by elimination of even harmonics. However, an improved arrangement can be obtained by doubling the number of supply transformers and providing half of these with an interconnected-star secondary winding (*Figure 7.39(b)*). This has the object of displacing half the rectifier load, and its associated harmonic currents, by 30° so as to reduce the resultant magnitude of any given harmonic current drawn from the supply. *Figure 7.40* shows a large rectifier transformer with two sets of star connected secondaries installed on a common core to provide double six-phase outputs. See also *Figure 4.121*. Although control of the harmonics generated by most medium-sized rectifiers is unlikely to represent a major problem for the system, the problem is nevertheless an increasing one due to the very large growth in the use of thyristor drives and there is considerable literature on the subject, for example, Electricity Association Engineering Recommendation G.5/3 [7.3] and in the technical press [7.4].

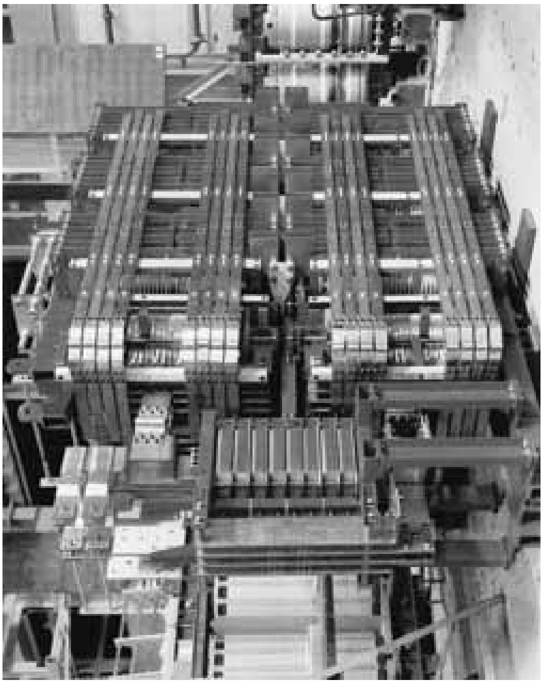


Figure 7.40 Core and windings for 5590 kW, 130 V DC, 43 kA rectifier tranformer. This unit is connected with 2 × 6 phase double star valve windings and has a centre yoke (GEC Alsthom)

In addition to the heating produced by harmonics, certain connection arrangements of rectifiers fed from polyphase transformers can lead to the transformers being subjected to a DC component of current in their secondary windings. This is another reason why, if possible, any temperature rise test should be carried out, in conjunction with the associated rectifier.

Many smaller rectifier transformers operating from 3.3 kV and below are of the dry-type, class C, variety so that they can be installed indoors in a cubicle adjacent to the rectifier. Smaller units may well be installed within the same cubicle as the thyristor equipment, in which case, in order to avoid the generation of too much heat within the cubicle, a transformer of the lower temperature rise insulation class F could be used with its temperature rise limits specified as for class E materials.

7.11 AC ARC FURNACE TRANSFORMERS

This section deals with the special features of transformers used for the provision of supplies to alternating current electric arc furnaces. Although, to the author's knowledge, there are no direct current electric arc furnaces in the UK in the mid-1990s, there are some in Europe and a few in Japan. Direct current furnaces have a higher efficiency and feed back less disturbance into the supply system.

Arc furnaces utilise the heating effect of an electric arc to melt the contents of the furnace. They are characterised by very high currents, perhaps up to 200 kA, at relatively modest voltages, between, say, about 200 and 1000 V. Because of the power required by the furnace, which might be between 10 and 100 MVA and occasionally even up to 200 MVA or higher, and the nature of the load, the transformers will need to take their supply from a strong HV system. In the UK it has been found appropriate to provide a supply to furnaces of up to around 120 MVA at 33 or 66 kV derived from a supply which is usually dedicated solely to supplying a number of arc furnaces and having a direct connection to a grid bulk supply point so that the disturbances created on the network will be maintained at an acceptable level. For furnaces rated at 60 MVA and above the bulk supply point needs to be associated at least with the 275 kV system. The relatively modest 33 or 66 kV HV voltage for the furnace transformer has the benefit of making the insulation level of the HV windings and the tapchangers considerably lower and therefore less expensive than they might otherwise have been.

In some less developed countries it is occasionally possible that a hydroelectric scheme might supply a smetler, or a number of smelters and little more. In such locations the arc furnace transformers may operate directly from the hydro transmission voltage of, say, 220 kV but it is more likely there will be some intermediate voltage, possibly 33 kV provided specifically for supplying the arc furnace transformers so as to simplify the design of these. It should be noted that wherever bulk supplies transformers are associated with the furnace transformers, these bulk supplies transformers will be subjected to similar adverse loading conditions to those imposed on the furnace transformers themselves, so that many of the design considerations regarding furnace transformers described below will, to a considerable extent, also apply to the associated bulk supplies transformers.

The principle of the AC arc furnace is shown in *Figure 7.41*. The load cycles of furnaces vary widely, depending on their size and the metallurgical requirements. Many furnaces have load cycles falling within the range 3–8 hours. The first part of the cycle consists of the melt-down period when the solid charge is melted and the main energy input is required. The latter part of the

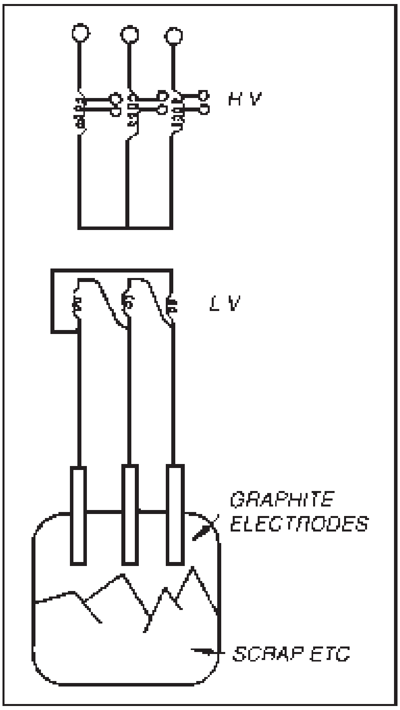


Figure 7.41 Principle of the arc furnace

cycle is the refining period; in this the energy supplied has only to make good the heat losses. The melt-down period is characterised by heavy current fluctuations caused by arc instability and movement of the charge (*Figure 7.42*). In the refining period fluctuations are much smaller because all the charge is molten. The severity of the current fluctuations during the melt-down period is governed to varying extents by the electromagnetic design of the furnace and its transformer and by the type of charge. Individual current excursions several times larger than the furnace nameplate rating are possible. The fineness of the charge has an important bearing on these fluctuations. For example, finely shredded steel scrap causes much smaller fluctuations than does a charge consisting of large irregular pieces. The main causes of the fluctuations are the movement of the arcs due to the changing electromagnetic-field conditions, and in some cases their extinction and restriking, and also by the short-circuiting of the graphite electrodes by movement of parts of the charge.

Deciding on the continuous rating of the furnace transformer requires a detailed study of the operating cycle. Although in arriving at a suitable rating the effects of the current surges which occur during the first part of the loading cycle must not be overlooked, advantage may be taken of the two distinct phases of the cycle so that it is possible to utilise some overload capacity to meet the peak loadings which occur during the melt-down phase on the basis

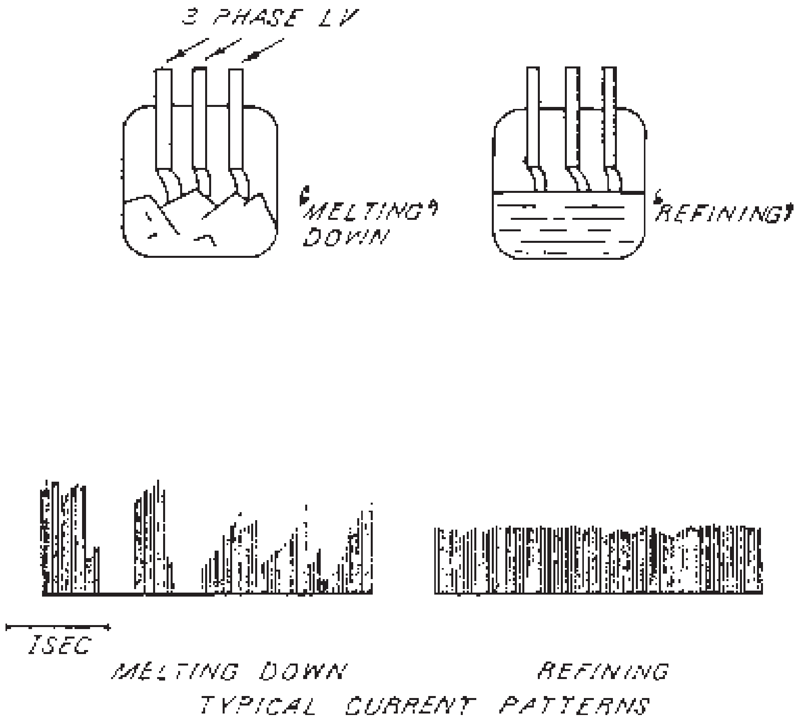


Figure 7.42 Typical current fluctuation

that these will be balanced by the reduced loading during the refining stage. At the beginning of the melt cycle the instantaneous loading of the transformer may be up to twice its continuous rating.

Because of the high currents required from the LV windings, the constructional problems of furnace transformers are similar to those of large rectifier transformers described in the previous section, except that they are compounded by the rapidly fluctuating nature of the load. The LV turn cross-section needs to be very large and the number of turns required is few. The phase current can be reduced by a factor of $\sqrt{3}$ by connecting this winding in delta. In order to bring out the leads, the LV must be the outer winding and it becomes impracticable to produce plain helical outer windings having a large cross-section and a small number of turns; the helix angle would be very large, making it difficult to obtain good electromagnetic balance, wasting a large amount of space at each end of the winding; and the winding itself would possess very little 'capstan effect' to resist the outward bursting forces experienced during current surges and short-circuits.

A high degree of short-circuit strength is particularly important in a furnace transformer in view of the nature of the load. Designing the transformer to have a fairly high impedance assists in limiting the magnitude of the current surges and minimises their effects on the supply network; however, too high a value reduces the furnace short-circuit power which increases its cycle time. The combined impedance of transformer and furnace may be as high as 50% on rating and the major portion of this will be provided by the transformer. Nevertheless the windings will be repeatedly subjected to severe mechanical shocks during the melt-down period so that their bracing and structural supports must be exceedingly robust. All winding spacers and end support blocks must be positively keyed in position to ensure that the constant buffeting that they receive does not cause them to become loosened. Radial support for the windings must be provided by substantial pressboard or s.r.b.p. cylinders; the winding conductors themselves will probably be of silver-bearing copper, work hardened by the winding process to provide maximum strength and rigidity. Core frames must also be of substantial section, usually having extended and reinforced coil support plates which in turn support heavy laminated-wood winding end platforms in order to provide maximum rigidity and to withstand axial short-circuit forces with the minimum of deflection. Tie bars connecting top and bottom yokes will probably be provided beneath the inner winding so as to be well out of the way of stray fluxes created by the high currents in the LV winding.

To enable the requirements of good electromagnetic balance and high mechanical strength to be met, the LV winding is usually constructed from a number of parallel disc pairs. For example, if the winding is required to have 16 turns of 100 strands in parallel, then this may be formed by stacking, say, 50 disc pairs – pairs because both start and finish must be at the outer surface – axially along the winding length. Each disc pair will then contain 16 turns wound with two strands in parallel. If the strand size is, say, 15×5 mm, this will have a cross-section of approximately 72 mm^2, allowing for radiused corners, then 100 parallel strands provides a total conductor cross-section of 7200 mm^2. A current density of 3.2 A/mm^2 gives a total current-carrying capacity of 23.04 kA which for a winding voltage of 1000 V, delta connected, is equivalent to a three-phase rating of about 40 MVA.

The other characteristic of the arc furnace which compounds the transformer designer’s problems is that the voltage drop in the furnace varies greatly during the changing stages of the melt. To strike the arc and maintain it at the initial melt-down stage requires a very much greater voltage than that necessary during the refining stage when obtaining equilibrium requires an accurate control of the furnace current. Close control of LV voltage is therefore important and, in view of the very high current in this winding, this must be achieved by means of tappings on the HV winding.

Again, in order to maintain optimum electromagnetic balance of the transformer windings so as to minimise out-of-balance forces, these tappings will best be contained in a separate layer which will probably be of the multi-start helical type placed inside the HV winding. This arrangement has the benefit of enabling optimum balance to be maintained regardless of the number of tappings in circuit and also allows the tapping leads to be easily taken from the top and bottom ends of the winding. In this location the radial short-circuit forces will be directed inwards towards the core so that a helical arrangement has adequate mechanical strength.

As explained in Section 6 of Chapter 4, control of LV voltage by means of HV tappings leads to variation of flux density and, in view of the wide range of voltage variation necessary, there will be considerable flux density variation. Using a modern grain-oriented steel, it will be necessary to design for a maximum nominal flux density of 1.9 tesla under any supply voltage conditions, which may mean up to 10% high, so that, at nominal supply voltage, a limiting flux density of about 1.72 tesla must be assumed. If this flux density equates to maximum LV output voltage, then in order to provide a minimum voltage of, say, 50% of this, the lowest flux density will need to be as low as 0.86 tesla.

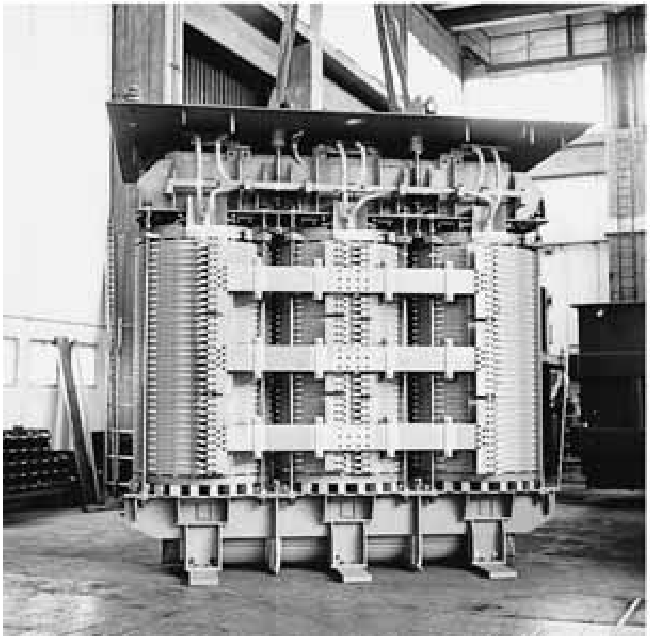
In addition, in order to produce the required degree of current control, a large number of very small tapping steps must be provided. This presents practical problems; there are limits to the number of tappings which can be provided in a multi-start arrangement beneath the HV winding, and also most commercial tapchangers have a maximum of about 18 steps, 19 positions, anyway.

One solution is to provide two transformers; a regulating transformer and a step-down transformer. The former will probably be auto-connected. It will operate at a nominally constant flux density, allowing only a 10% margin for supply voltage variation, and will be controlled by a line-end tapchanger to provide, say, eight tapping steps from 100 to 50% of the supply voltage. The line-end tapchanger will not need to be particularly special provided the supply voltage is no more than 66 kV, in fact, any tapchanger designed for 66 kV delta-connected operation will be suitable. The output from the regulating transformer will then supply the tapped HV winding of the step-down transformer via a second tapchanger which will provide the intermediate fine tapping steps. The number of these steps will depend only on the maximum number of steps that this tapchanger can accommodate and the number of tapping leads that it is considered economic to bring out from beneath the HV winding. Since this transformer will be subjected to a widely varying supply voltage from the regulating transformer, it will operate at a widely varying flux density.

Notwithstanding the above comments concerning tapchanger requirements, it should not be overlooked that the duty of the tapchangers associated with arc furnace transformers is a very demanding one, both in terms of tapchanging duty and number of operations, which will be considerably greater than that of the tapchanger of a normal system transformer. The tapchanger must be very conservatively rated therefore to ensure that it is capable of repeated operation at any condition of load or overload and it needs to be frequently maintained to ensure that it remains capable of this duty.

Figure 7.43 shows the core and windings of an 85 MVA, 34.5/1.2–0.78 kV AC electric arc furnace transformer having a tapchanger at the line end of each

(a) HV side



(b) LV side

Figure 7.43 Core and windings of 85 MVA 34.5/1.2-0.78 kV electric arc furnace transformer (TCM Tamini) phase. The HV winding, which is the tapped winding, is next to the core and the leads to the helically interleaved tapping windings can be seen emerging at the bottom of each leg from beneath the LV windings.

7.12 TRACTION TRANSFORMERS

Traction transformers are used to provide single-phase supplies for train overhead catenary pick-up systems and, since the late 1950s in the UK, these have operated at a nominal voltage of 25 kV AC. These transformers have ratings which vary between about 5 and 18 MVA and were initially ONAN cooled with impedances of between 8% for the smallest units up to 12% for the largest. Later units were provided with mixed cooling, typically ONAN/OFAN/OFAF to give ratings as, for example, 18/20.5/26.5 MVA. In addition, all sizes of transformers are required to have the capability to provide a cyclic output of 133.3% of rated load in an ambient temperature of 30°C for 8 hours followed by 16 hours at 60% load. This is to cater for the situation of an outage of an adjacent unit. The transformers normally take their supply from two phases of the 132 or 275 kV transmission networks and feeder stations are located adjacent to the rail tracks at 40 or 50 km intervals.

This section describes the design and constructional features of the transformers used to provide traction supplies in the UK, but the general principles are applicable to transformers used to provide these supplies in many parts of the world.

The duty of traction supplies transformers is a particularly onerous one in that, although their loading may be only intermittent, they are subjected to rapid and repeated load current fluctuations taking them from zero to twice full-load current and with an incidence of system short-circuits which may be as high as 250 per year of varying magnitude up to full fault current. In terms of the electromechanical stresses applied to the transformer windings, this duty is very similar to that described for arc furnace transformers in the previous section and hence the constructional features of the windings and their clamping arrangements are also very similar to those of arc furnace transformers.

Traction transformers, from the earliest times of the use of AC supplies, have had to withstand the additional duty resulting from the high harmonic content of the load current. This is a problem common to all transformers supplying rectifier loads and has been described in the earlier sections covering HVDC converters as well as ordinary rectifier transformers.

With the most recent AC traction systems utilising Insulated Gate Bi-polar Transistor (IGBT) drive mechanisms, the nature of the harmonics problem has become somewhat different. The IGBT system is switched at a high frequency, 4 kHz in some systems used in the UK, so that the harmonic frequencies appearing are in the 70th to 80th range. These harmonics unfortunately excite particularly severe harmonic voltages on the catenary system, typically 5 kV at 4 kHz, so the LV windings of the traction supplies transformers must be designed to withstand these voltages superimposed onto their normal working voltage.

LV system voltage

The 25 kV system voltage must comply with the requirements of the European Standard, EN 60850. This sets down the following voltage requirements:

Nominal voltage	25 000 V r.m.s.
Highest permanent voltage	27 500 V r.m.s.
Highest non-permanent voltage	29 000 V r.m.s. (this is the maximum voltage which may be present for up to 5 minutes)
Lowest permanent voltage	19 000 V r.m.s.
Lowest non-permanent voltage	17 500 V r.m.s. (this is the minimum voltage which may be present for a maximum of 10 minutes)

This represents the voltage range which must be available at the locomotive and for efficient operation the no-load voltage must be maintained as close to the upper limit as possible. The drop in supply voltage is dependent upon load, the transformer impedance, the load power factor and the voltage drop in the overhead catenary system. The incoming grid supply voltage is permitted to vary between ±10% of its nominal value but at any given bulk supply point the variation will normally be no more than ±3% of the average value prevailing at that particular supply point. It would be possible to provide an on-load tapchanger to compensate for the regulation in the transformer and overhead catenary system, but recognising that this regulation will occur every time a locomotive draws a large load current in the supply section associated with a particular transformer, it is clear that a tapchanger operation frequency would be very much greater than that normally experienced in a tapchanger associated with a supply network and it has been suggested that based on this usage, the life of a tapchanger could be expected to amount to no longer than a few weeks. The transformers are therefore usually provided with off-circuit taps only, which enable the open-circuit voltage ratio to be optimised to suit the voltage normally occurring at the grid supply point to which the transformer is to be connected. These are usually for a range of 0–12.5% in 2.5% steps on the LV winding. Experience suggests that after selecting the most suitable tapping when the transformer is put into service, it will remain at this setting unless any major changes are made to the local supply network.

The transformers operate with one pole of the LV winding connected to the rail and solidly bonded to earth. The other pole is thus nominally at a voltage of 25 kV to earth and the insulation requirement equates to that of a three-phase system having a nominal voltage of 44 kV. Such a system has a phase voltage of 25.4 kV to earth and dielectric test levels are those for a system having a highest voltage for equipment of 52 kV. For several years traction transformers were designed with this insulation level for the LV winding; however, recently consideration, in particular, of the superimposed harmonic voltages on the LV has led to the increasing of the insulation level one step higher to that of a system having a highest voltage for equipment of 72.5 kV.

Rating and impedance

Selection of the most suitable rating for a particular installation is not easy considering the rapidly fluctuating nature of the load and the additional heating effects of harmonics. *Figure 7.44* shows a typical load-current-demand curve and illustrates the difficulty of relating this to a continuous current rating. The procedure generally adopted is to equate the load-demand cycle to a series of half hourly maximum demand values. If an existing comparable installation is available, these can be obtained from actual meter readings. If no comparable existing installation is available, then estimated values must be used. Because the heating effect of the load peaks is proportional to the square of the load, and in order to provide some allowance for the effect of the harmonic currents, it is then considered that the rating of transformer to be used is selected by multiplying the mean half hourly maximum demand value by a factor of between 1.2 and 1.3. The precise value of the factor used will probably be that which results in the selection of an existing standard rating, but clearly it is preferable to err on the conservative side in arriving at this.

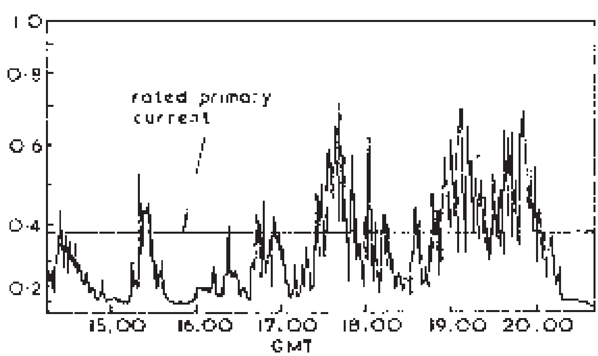


Figure 7.44 Typical traction load-current-demand curve

The values of impedance quoted above are those which have been used throughout the 1970s and 1980s and are set so as to limit the fault current in the event of a system short-circuit to 6 kA. Operating experience up to this time suggests that this is the maximum fault current which can be tolerated returning in the rails without causing interference with signalling circuits. The other effect of impedance is, of course, to cause regulation and, as explained above, it is desirable to obtain as high a voltage as possible at the locomotives, so that, particularly in view of the fact that on-load tapchangers cannot be used, the lowest possible impedance is to be preferred. As more modern signalling systems are installed which are not susceptible to interference by fault current in the rails, it will be possible to reduce the transformer impedance to a value which restricts the fault current to 12 kA, the fault capability of the switchgear on the locomotives.

Impulse withstand

Since the transformers are connected to two phases on the HV side, the HV windings may be subjected to impulse voltages applied to either terminal individually, or to both terminals simultaneously. It has been recognised for some years that when delta-connected three-phase windings are subjected to simultaneous impulse voltages on two line terminals the effect is to produce a doubling of the magnitude of the incident waves at the centre point of the winding. A single-phase traction supply transformer connected across two phases is entirely equivalent to a delta-connected three-phase unit and can be expected to show exactly the same response. To demonstrate the traction supply transformer's ability to withstand this condition it is usual to specify that they shall be impulse tested by carrying out a full series of shots applied to both HV terminals connected together as well to each terminal individually.

Some supply authorities outside the UK do not subject traction-supply transformers to this double terminal impulse test, but studies in the UK in the 1960s and 1970s of the incidence of lightning strikes on overhead transmission networks showed that in more than one-third of the lightning faults more than one phase of the 132 kV system was involved. For the 275 and 400 kV systems the proportions involving more than one phase were very much less, around 5 and 3%, respectively, but these figures would appear to justify the test at least for 132 kV transformers.

Construction

Cores may be of two-limbs-wound or single-limb-wound construction. If the latter is used, outer 50% cross-section return limbs will be required. The choice is usually determined by factors such as primary current, impulse voltage distribution and whether tappings are specified. For example, at the lowest ratings, say, 5 MVA, a fairly small frame size will be required. The volts per turn will therefore be quite low, necessitating a fairly large number of turns, so that a continuous disc winding will have a large number of turns per section. A large number of turns per section will result in high intersection voltages under impulse conditions demanding that an interleaved winding arrangement is adopted, and adoption of an interleaved arrangement will result in the winding being an expensive one. If the winding is expensive, it is more economic to have one of these rather than two so a single-limb-wound arrangement is likely to be adopted. It must be recognised that the windings are effectively of the uniformly insulated type since both ends require to be insulated for line voltage to earth so that even if the cost of the extra strengthening

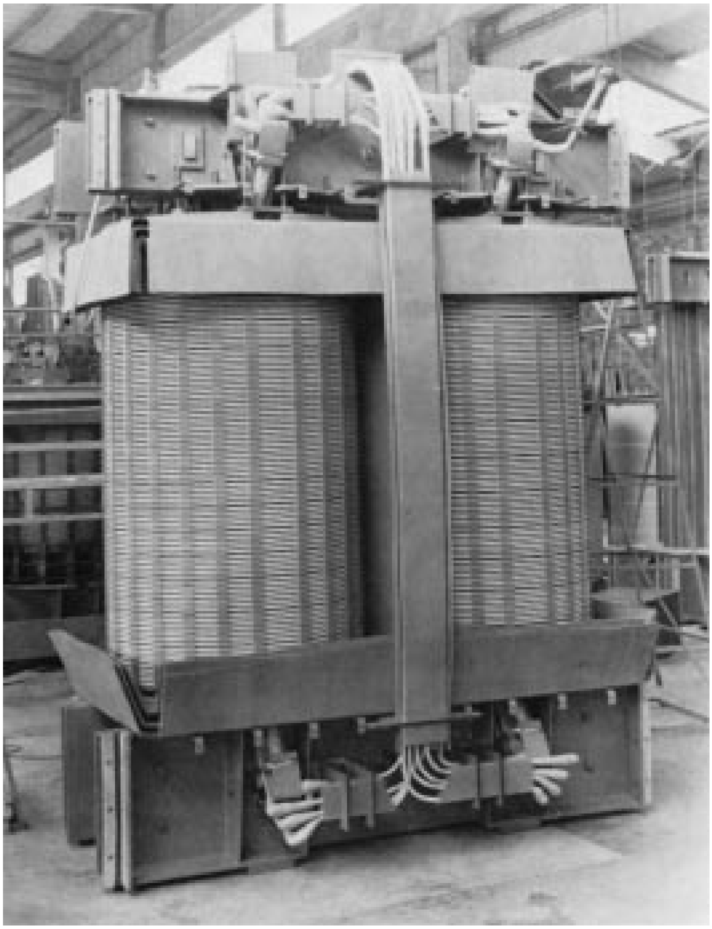


Figure 7.45 Core and windings of a single-phase 18 MVA, 132/25 kV, 50 Hz transformer for trackside supplies to an electrified railway system. The LV side is provided with tappings for a range of $+10\%$ to -20% (Allenwest Brentford Ltd.)

measures is discounted, they will still be more costly than non-uniformly insulated windings of the same voltage class.

If the two-limbs-wound construction is utilised then normally one pair of windings will be connected in series and the other in parallel. This ensures equal load sharing between the limbs. Even at 18 MVA the HV current is only 78.7 A. At a current density of 3 A/mm^2 the strand cross-section need only be about 26 mm^2, having uncovered dimensions of, say, 4×7 mm, which is quite small for winding into a stable winding. Certainly a conductor of half this cross-section should be avoided. Hence HV windings would probably be in series, with LVs in parallel.

The off-circuit tappings are likely to be accommodated in a separate layer beneath the LV winding and have a multi-start configuration. This ensures that electromagnetic balance is maintained for all tapping positions. The arrangement of windings radially from the core will be: LV tappings, LV, HV. There is no merit in having the HV line lead at the centre of the limb, so that the start and finish of the HV winding will be at the top and bottom of the limb. *Figure 7.45* shows a typical core and windings assembly.

7.13 GENERATOR NEUTRAL EARTHING TRANSFORMERS

The practice of earthing the neutral of large generators via a high resistance was developed in the USA in the 1950s with the object of restricting the stator earth fault current to a low value and thereby limiting the damage caused in the event of a fault. The aim, in selecting the value of resistance to be used is to arrange that its kW dissipation in the event of an earth fault on a generator line terminal is equal to the normal three-phase capacitative charging kVA of the combined generator windings and its connections. The equality between kW dissipation and charging kVA can be shown to give critical damping to the restriking transients generated by arcing ground faults. This value of resistance results in earth fault currents for a full phase to earth fault on the generator terminals of the order of 2–3 A but in the UK the CEGB adopted the continental European practice of using a slightly lower value of resistance to limit the current for an earth fault on the generator terminals to between 10 and 15 A. This value makes little difference to the critical damping at the point of the fault but simplifies the setting of the protection to avoid spurious operation due to third-harmonic currents in the neutral. On a 23.5 kV generator this requires a resistance of about 1400 Ω. If connected directly into the generator neutral a resistor of this value for such a low rated current would tend to be rather flimsy as well as expensive. The solution is to use a resistor of low ohmic value to load the secondary of a single-phase transformer whose primary is connected in series with the generator neutral earth connection.

When this system was first devised the practice was to use a low-cost standard single-phase oil-filled distribution transformer. Since that time generator ratings have increased considerably and the need for high security means it is no longer considered acceptable to use an oil-filled transformer located near to the generator neutral because of the perceived fire hazard and, although some utilities have used both synthetic liquid-filled and class H distribution units, once the principle of using other than an off-the-shelf oil-filled item is placed in question, it becomes logical to design a transformer which is purpose made for the duty.

The following section describes the special characteristics of generator neutral earthing transformers which have been developed at the present time. For a detailed description of the protection aspects the reader is referred to a specialist work dealing with generator protection, for example *The J & P Switchgear Book or Modern Power Station Practice* [7.2].

The generator neutral connection to the primary of an earthing transformer, or any other high-resistance neutral earthing device, must be kept as short as possible since this connection is unprotected. An earth fault on this connection would go undetected until a second fault occurred on the system and then a very large fault current would flow. Hence the desirability of locating the neutral earthing transformer immediately adjacent the generator neutral star point. In the mid-1970s, the CEGB decided that this was an ideal application for a cast resin transformer and therefore drew up a specification for such a device. When the system operating at generator voltage is healthy, the neutral is at earth potential, so a transformer connected between this neutral and earth is effectively de-energised. It only becomes energised at the instant of a fault and then its ability to function correctly must be beyond question. Such a duty is very demanding of any dielectric but as explained in Section 8 of this chapter, this is a duty for which cast resin is well suited. After extensive testing of a prototype cast resin transformer, the system was adopted for the earthing of the Dinorwig generators and this became the standard arrangement for subsequent stations.

For the neutral of a 23.5 kV, 660 MW generator a voltage ratio of 33/0.5 kV was selected. The primary voltage insulation level of 33 kV corresponds to that used for the generator busbars, thus maintaining the high security against earth faults. However, the main reason for selecting an HV voltage considerably higher than the rated voltage of the generator is to exclude any possibility of ferroresonance, that is resonance between the inductive reactance of the transformer and the capacitative reactance of the generator windings, occurring under fault conditions. This could give rise to large overvoltages in the event of a fault. Such a condition could be brought about on a non-resonating system by a change in the effective reactance of the transformer as a result of saturation in the core when the generator phase voltage is applied at the instant of a fault. Occurrence of a severe fault is likely to cause the generator AVR to drive to the field-forcing condition thus boosting the phase voltage to up to 1.4 times its rated value. To avoid the risk of saturation under this condition the transformer flux density at its ‘normal operating voltage’ must be well below the knee point for the core material. Normal operating voltage in the case of a 23.5 kV machine is $23.5/\sqrt{3}$ kV $= 13.6$ kV and if increased by a factor 1.4, this would become about 19 kV. A transformer having a nominal flux density of, say, 1.7 tesla at 33 kV would have a flux density of around 1 tesla at 19 kV and so a good margin exists below saturation.

In aiming at a minimum 10 A earth fault current under ‘normal’ phase voltage conditions a current of 14 A would result for the field-forcing situation, hence the maximum transformer rating must be $14 \times 33\,000 = 462$ kVA, single phase. However, since an earth fault of this magnitude would lead to rapid operation of the generator protection, this only need be a short-time rating. CEGB specified that this duty should apply for five minutes although the use by some utilities of ratings as short as 15 s has been suggested.

The transformer must also have a continuous rating and the required continuously rated current is that which is just too low to operate the protection, plus an allowance for third-harmonic currents which may flow continuously in the generator neutral. The aim is to protect as much of the generator windings as possible and so the minimum current for operation is made as low as possible. This is taken to be 5% of the nominal setting of 10 A, i.e. 0.5 A. Tests on 660 MW turbine generators suggest that the level of third-harmonic current in the neutral is about 1 A. The transformer continuous rating is thus $(0.5 + 1) \times 33\,000 = 49.5$ kVA. In practice a typical cast resin transformer able to meet the specified five minute duty has a continuous rating of 20–25% of its five minute rating, hence the continuous rating is accommodated naturally.

Practical arrangement

As stated above, the generator neutral earthing transformer needs to be located as close as possible to the generator neutral. For most large modern machines the neutral star point is formed in aluminium or copper busbar located underneath the neutral end of the generator winding, usually at the turbine hall basement level. It is housed in a sheet-aluminium enclosure which provides protection for personnel from the operating voltage as well as electromagnetic protection to the surrounding plant from the large flux generated by the high machine phase currents. The neutral earthing transformer in its enclosure, which usually also houses the resistor, is arranged to abut the neutral enclosure in such a way as to enable a short ‘jumper connection’ to be made from a palm on the generator neutral bar to one on the transformer line-end terminal via suitably located openings in the neutral enclosure and transformer enclosure. On generators 4, 5 and 6 at Drax power station, the transformer was made with long flexible connections to the secondary loading resistor and arranged so that it could be ‘racked forward’ towards the generator neutral bar once the transformer and resistor had been placed adjacent the neutral enclosure, thus enabling a very short connection indeed to be made between the neutral bar and the transformer. A generator neutral bar and its earthing connection is shown in *Figure 7.46*.

Loading resistor

The value of apparent resistance required in the generator neutral is

$$\frac{V}{I_f\sqrt{3}}\ \Omega$$

where V is the generator line voltage and I_f the specified stator fault current.

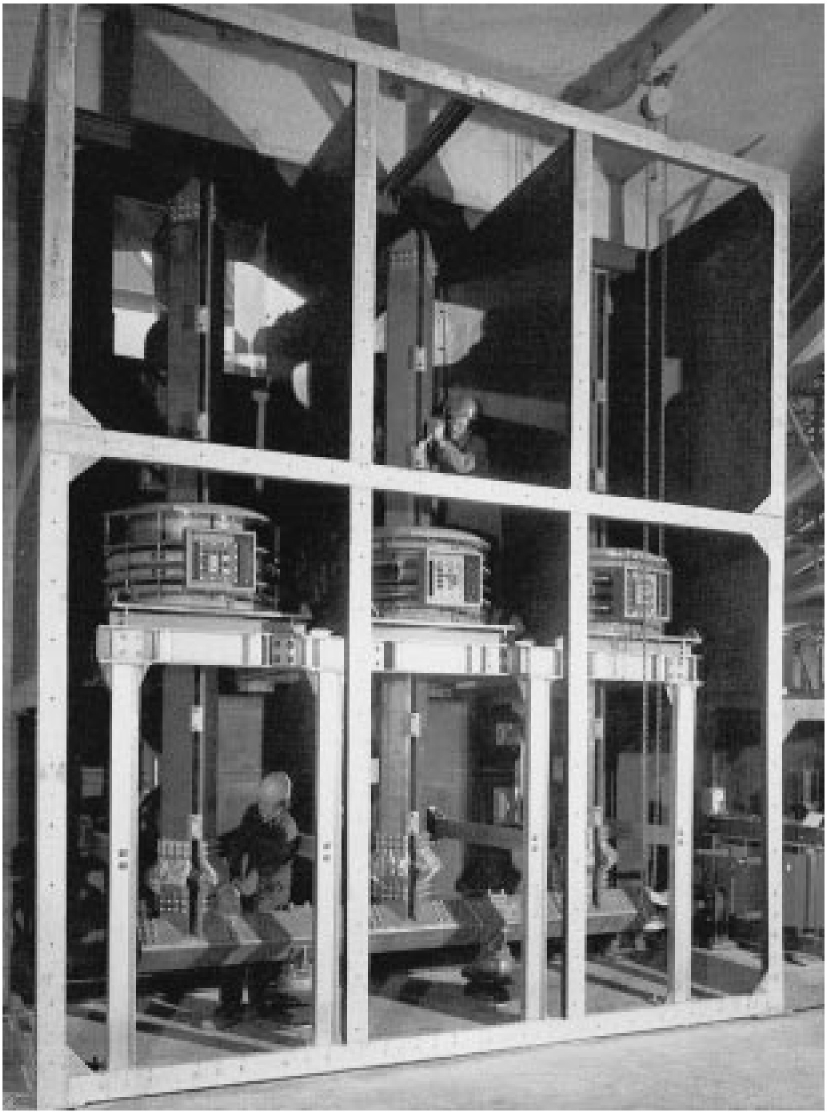


Figure 7.46 Arrangement of Dinorwig generator neutral star-bar with cast-resin insulated neutral earthing tranformer at lower right-hand side. Neutral current-transformers can be seen, one set on each vertical phase-conductor. Generator earth-fault CT is just discernible mounted over lower left-hand earthing transformer terminal (Emform Ltd)

When referred to the low-voltage side of the transformer, this becomes

$$\frac{1}{n^2}\frac{V}{I_f\sqrt{3}}$$

where n is the turns ratio of the transformer.

Inserting the values already given for a 660 MW, 23.5 kV generator gives a resistance value of about 0.3 Ω. Strictly speaking this is the total secondary resistance including that of the transformer, but since a transformer of the rating quoted above has an equivalent resistance of less than 0.01 Ω, this can be neglected within the accuracy required.

It is also necessary that the X/R ratio for a transformer/resistor combination does not exceed a value of about 2 in order to ensure that the power factor of arcing ground faults is as high as possible and that restriking transients are kept as low as possible.

In fact, a practical transformer meeting the other parameters specified above can be designed fairly easily to have a reactance of about 4% based on the rating of 462 kVA for the transformer of a 23.5 kV, 660 MW unit, which equates to 0.0025 Ω. This would give an X/R value of about 0.08, assuming the resistor to be non-inductive, and would allow the resistor to have considerable inductance before causing any embarrassment. The CEGB practice was to specify that the resistor should be non-inductive but this is simply erring on the side of caution and ensuring that there is no likelihood of the maximum X/R value being exceeded inadvertently. Generally, a non-inductive resistor would be flimsier than one which has some inductance because of the construction needed to give this characteristic. Economics might therefore dictate that the resistor is allowed to have some inductance: if so, it is important to know its magnitude and to ensure that the permissible X/R ratio is not exceeded. A typical form of construction of a low-inductive resistor element is shown in *Figure 7.47*.

The resistor rating can be calculated on the basis of I^2R, where I equals 924 A, equivalent to a primary current of 14 A, and R is equal to 0.3 Ω. This works out to about 260 kVA, which is the required five minute rating. This is not equal to the five minute rating of the transformer, since the latter has been based on a notional voltage of 33 kV rather than the actual applied voltage of 19 kV.

The resistor must also have a continuous rating. For the example quoted, this is 1.5 A in the transformer primary or 99 A in the secondary, giving about 3 kVA for a 0.3 Ω resistor. As with the transformer, a resistor which can meet the five minute rating easily satisfies the continuous rating.

Other parameters of the loading resistor are conventional for metal resistors of this type. It should be housed in a ventilated sheet-steel enclosure which provides protection against personnel access and accidental contact. This can be a common enclosure with the transformer, as indicated in *Figure 7.46*. However, if a common enclosure is used, there should be a metal barrier between resistor and transformer so that the transformer is protected from any

Figure 7.47 Typical low-inductive metallic resistor element used to form a bank of the appropriate resistance and current rating for neutral/earth connection (GEC Alsthom)

directly radiated heat from the resistor. The external temperature of the resistor enclosure after operation must not exceed about 80°C to avoid possible injury to anyone coming into contact with it.

7.14 TRANSFORMERS FOR ELECTROSTATIC PRECIPITATORS

Electrostatic precipitators are used to remove fine dust particles from gases, the most common example being the removal of minute particles of pulverised fuel ash from power station flue gases.

To do this the flue gas is passed horizontally through a strong electric field established between negatively charged wire mesh grids suspended centrally between vertical sets of positively charged metal plates. Plate spacing may be around 300 mm and the mesh opening about 150 mm. The positive plates are usually connected solidly to earth. The corona discharge created by the electric field causes the ash particles to become negatively charged as they enter the precipitator so that they migrate towards and are collected by the positively charged plates. These positive electrodes are periodically given a mechanical rap causing the collected particles to fall under gravity into hoppers placed beneath the electrode array.

Up to three precipitation stages in series are commonly employed and in a good precipitator collection efficiency can be better than 99.9%.

To establish the necessary field for the electrode spacing identified above, a voltage of around 60 kV DC would be necessary between mesh and plates. This is derived from a small transformer-rectifier unit designed specifically for this purpose. To obtain maximum extraction efficiency, the maximum possible voltage consistent with avoiding continuous flashover must be applied to the electrodes and this is generally achieved by means of an automatic voltage control system which gradually increases the LV supply to the transformer-rectifier until flashover is detected. When this occurs the control system winds back the input voltage to extinguish the arc and then repeats the process once more.

Precipitator transformers are single phase and produce an output voltage which is rectified and connected via a length of cable to the electrode array. The primary supply is usually taken from two phases of a 415 V three-phase system via a voltage regulator giving a 0–415 V output. This enables the HV output voltage to be continuously varied from zero volts up to the maximum rated value. Current into the load is normally about 1 A maximum so the transformer rating is no more than 50–60 kVA. The unusual feature of the transformer is that the load presented by the electrode array plus rectifier is capacitative so that the transformer operates at near to zero power factor lead and thus experiences negative regulation. To provide a terminal voltage of about 60 kV at full load requires a transformer open-circuit voltage of about 55 kV.

Because the normal operating mode of the electrostatic precipitator involves frequent short-circuiting due to electrode flashover, it is desirable that the supply system should have a high impedance in order to limit the magnitude of the short-circuit current. Small transformers with ratings of the order of a few tens of kVA will, however, normally have very low impedances, probably no more than 3 or 4%, and to raise this to the order of magnitude required, around 50% on rating, can be somewhat uneconomic. One way of doing this is to use a form of 'sandwich' construction, similar to that used in a shell-type transformer, whereby alternate sections of LV and HV windings are assembled axially onto the core with large axial 'gaps' between sections of the winding to create the required loose coupling. This leads to a fairly complex insulation structure in order to handle the relatively high voltage, however, and it is probably more economic to design for the highest practicable value of impedance which can be obtained, say around 10–15%, utilising conventional concentric LV/HV construction and then increase the overall supply impedance by means of a series-connected external choke. This type of 'conventional' construction will involve a helically wound LV using paper-covered rectangular section copper conductor with an HV winding consisting of crossover coils wound using enamel-covered circular cross-section wire.

The transformers are usually immersed in BS 148 mineral oil in a common tank with the rectifier and are frequently located at a high level within the precipitator structure in order to minimise the length of high-voltage connection between transformer and electrodes. Although precipitators are not housed in structures where fire hazard is likely to give rise to concern, it will be necessary to make provision for oil containment in the event of a serious leakage.

Testing

Transformers for electrostatic precipitators are of a very specialised nature and have tended to be developed in isolation from 'mainstream' transformers as defined in IEC 76. As a result, dielectric tests, for example, are not normally carried out in the manner that would be appropriate for a transformer falling into the category of highest voltage for equipment of 72.5 kV of IEC 76. Testing is normally as agreed between the transformer manufacturer and the designer of the precipitator equipment in conjunction with his customer. An induced overvoltage test is usually carried out at 1.5 times rated voltage for one minute rather than the figure of twice rated voltage for transformers with uniformly insulated high-voltage windings specified in Clause 11.2 of IEC 76-3. Lightning impulse withstand tests are rarely carried out, partly because the electrical location of the installation is not exposed to lightning surges so that there is not considered to be a need to simulate any operational condition, and partly because the specialist manufacturers who produce these transformers will probably not have the necessary impulse testing equipment. If an impulse test is specified it will probably be carried out at 250 kV for a transformer providing a 60 kV precipitator supply.

Since the transformer and rectifier are housed in a common tank, it is necessary to ensure that the top oil temperature rise due to the transformer does not exceed the value which can be tolerated by the rectifiers. It is necessary, therefore, to measure the precipitator transformer losses, not because efficiency guarantees are of great importance, but because a temperature rise test must be carried out. It is likely that a complete testing schedule will include a short-circuit temperature rise test on the transformer alone and also a further temperature rise test on the complete transformer and rectifier under simulated operating conditions.

The other important feature of the transformer is its ability to withstand the repeated short-circuits which occur in operation. It is usual, therefore, to include in the test programme a series of short-circuits at full output voltage. These will be carried out on the complete equipment including any external choke, in order to ensure that the current on short-circuit is a true representation of that experienced under service conditions.

7.15 SERIES REACTORS

Series reactors are not, of course, strictly within the family of transformers; however, many of them are oil immersed and use paper-insulated windings with copper conductors and may or may not have something approaching a steel core, so that they have many constructional features in common with transformers. They are sometimes referred to as current-limiting reactors and, as the name suggests, are used for the purpose of limiting fault currents or restricting the fault levels of transmission and distribution networks and works auxiliary systems, which include those of power stations. The usual reason for wishing to limit fault levels is to ensure that the system will remain within the fault capability of the system switchgear and, provided the requirements with regard to system regulation can be met, the use of current limiting reactors can often enable more economic fault ratings for switchgear to be employed. For the auxiliary systems of power stations, switchgear of high fault rating has been developed, primarily to make possible the direct-on-line starting of large drives, so the use of series reactors for these is the exception rather than the rule although in some instances these are installed between station and unit switchboards to limit fault levels when the unit and station transformers are paralleled for load transfer purposes.

There are four basic types of current limiting reactor. These are:

- Cast-in-concrete air cored.
- Oil-immersed gapped iron cored.
- Oil-immersed magnetically shielded coreless.
- Oil-immersed electromagnetically shielded coreless.

Ideally, current-limiting reactors should have no iron circuit because all iron circuits exhibit a non-linear saturating-type characteristic, so that, under the very overcurrent conditions which the reactor is required to protect against, there is a tendency for the reactance to be reduced. Hence, the prevalence of coreless reactors in this list.

The *cast-in-concrete* variety is therefore aimed at eliminating iron entirely and consists of a series of non-reinforced concrete posts supporting a helical copper conductor arrangement. The problems with these reactors result from the fact that they present extremely specialised manufacturing requirements, albeit that they are technically fairly crude. They tend to be sold in such small quantities that it is rarely worthwhile for a manufacturer to maintain the expertise required in their construction. The major problem is to cast the concrete posts with a sufficiently consistent quality that they can be guaranteed crack free, particularly since they are arranged in a circle of six, eight, or more, all of which must be made without defects to achieve an acceptable reactor.

As a result of the above problems it is likely that enquiries for cast-in-concrete reactors to most electrical plant manufacturers will be met with a totally blank reaction.

If cast-in-concrete reactors are employed care is needed in the design of the floor and the building to house the reactor to ensure that any reinforcing of concrete in these is not influenced or affected by the large magnetic field which the reactor produces in service. Personnel should also be aware of these fields and avoid having anything affected by magnetic fields in their possession when carrying out routine inspections even at some distance from the reactor.

The same does not apply in the case of *oil-filled reactors* whether with or without an iron core. Since these have a number of features in common with transformers, most transformer manufacturers are able to design and build them.

Reactors with gapped iron cores are most like transformers in their construction. In a three-phase reactor, a core of superficially similar appearance to a normal transformer core carries one winding on each limb, similar to a transformer winding. The core, however, differs from a transformer core in that 'gaps' are inserted into the axial length of the wound limbs by the insertion of distance pieces made from non-magnetic material – usually pressboard. These normally make up no more than about 1% of the iron path length but have the effect of reducing the 'normal' flux density of the device to a level such that, even at fault currents of 10 or 12 times normal full-load current, the core remains substantially unsaturated and the reactance is no more than 5–10% less than the value at normal full-load current. Such a device is shown diagrammatically in *Figure 7.48*.

Like transformers, reactors are subjected to large electromagnetic forces under fault conditions. Since each limb has only one winding, there can be no significant axial unbalance such as can be experienced in a transformer, so there will be no major end forces on winding supports. There remains an axial compressive force and an outward bursting force on the coils. The latter is resisted by the tensile strength of the copper which is usually well able to meet this but the winding must be adequately braced to prevent any tendency for it to unwind. Since reactor windings normally have fewer turns than transformer outer (HV) windings this aspect often requires more careful consideration than for a transformer (see Section 7 of Chapter 4).

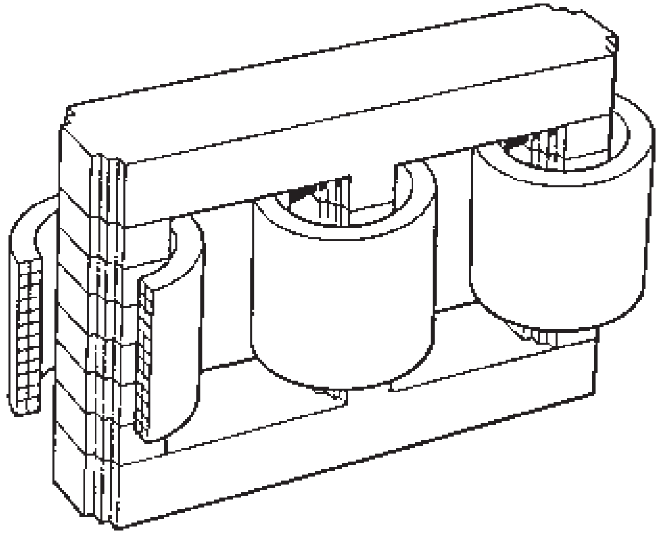


Figure 7.48 Gapped iron-core reactor

The axial compressive force can, after repeated overcurrent applications, result in a permanent compression of the winding insulation with the result that windings can become loose. This must be prevented by the application of sufficient axial pressure during works processing to ensure that all possible shrinkage is taken up at that time.

In a *magnetically shielded coreless reactor*, the magnetic shield is arranged to surround the coils in much the same way as the yokes of a conventional transformer core. The shield provides a return path for the coil flux thus preventing this from entering the tank, which would result in large losses and tank heating. The larger the cross-section of the shield the greater is the quantity of iron required, the larger is the tank and oil quantity, and the more costly the reactor. If the shield cross-section is reduced, the flux density under normal rated conditions increases and the tendency to saturate under short-circuit currents is greater, thus bringing about a greater impedance reduction. A wise precaution when purchasing such a reactor is to specify that the impedance under short-circuit conditions shall not be less than, say, 90% of the impedance at normal rated current. *Figure 7.49* shows the internal arrangement of a three-phase, 30 MVA, 11 kV, 16% magnetically shielded reactor.

In many respects the *electromagnetically shielded reactor* appears the most attractive in that it offers the advantage of constant impedance. In practice, this benefit is usually reflected in the cost. The arrangement of the shield for a single-phase reactor is shown in *Figure 7.50*. The shield, which may be of copper or aluminium, provides a path for currents which effectively eliminate the return flux at all points outside the shield. The flow of shield current does, of course, absorb power which appears as heating in the shield.

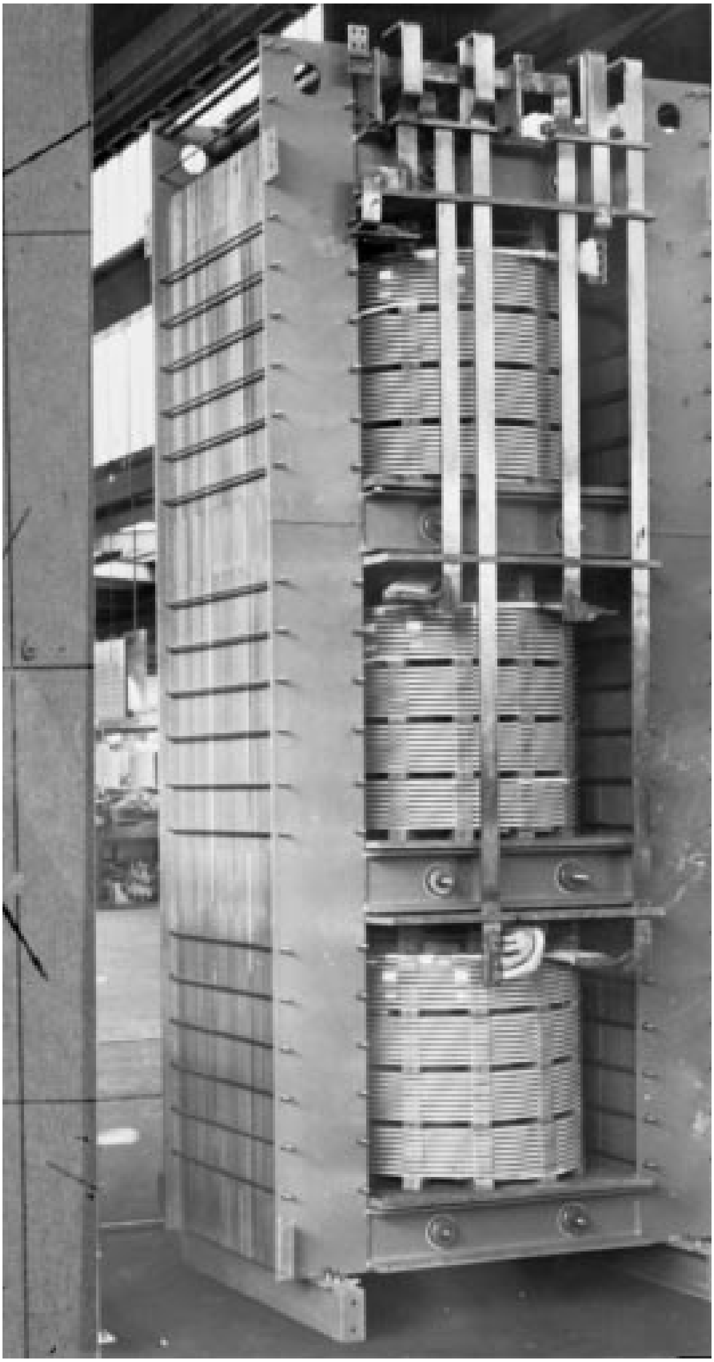


Figure 7.49 Magnetically shielded three-phase reactor 30 MVA, 11 kV, 16% $\times$ 50 Hz, shown out of its tank (ABB Power T&D Ltd)

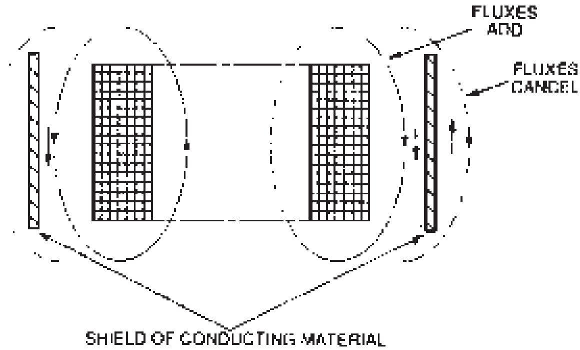


Figure 7.50 Electromagnetically shielded reactor

In addition to the balancing effect of the shield currents on flux outside the shield, there is some reduction of the flux within the coil, hence there is a reduction in its reactance. It can be shown, however, that this is independent of the current within the coil and is determined only by the inductance of the coil and the mutual inductance between coil and shield. As in the case of the magnetically shielded reactor, therefore, there is a need to strike an economic balance between physical size, as determined by the size of the shield, and the unwanted reduction of reactance produced by placing the shield too close to the reactor coil. In practice the effective reactance of the coil and shield combination is made about 90% of the coil reactance alone.

Testing of series reactors

Testing of all reactors can present problems to the manufacturer which are not encountered in the testing of transformers. To a certain extent this results from the fact that they are made in very much smaller quantities than transformers and so manufacturers do not equip themselves with the specialised test equipment necessary to deal with them.

Series reactors create two difficulties: one is concerned with proving the performance under short-circuit, the other with proving the adequacy of the interturn insulation.

Proving performance under short-circuit not only involves demonstrating that the reactor will withstand the fault currents which are very likely to be a similar magnitude to those in transformers but, for a magnetically shielded or gapped-cored reactor, also establishing the reactance reduction which occurs under short-circuit conditions.

It is rarely possible to measure the impedance at the full short-circuit level, so that the usual approach is to measure impedance at 50, 75 and 100% of rated current. For three-phase reactors, this is normally obtained from voltage and current measurements taken with the windings temporarily connected in star for the purposes of the test. A curve plotted from these values can then be extrapolated to the short-circuit level. Since this will involve considerable extrapolation (although the iron part of the circuit should operate below the knee point of the magnetising curve – even at the short-circuit current) it is usual, as a type test, to make an impedance measurement on one coil fully removed from the shield. This establishes an absolute minimum impedance which may be used as an asymptote for the extrapolated impedance curve. Alternatively, depending on the rating, it is possible that one unit might be taken to a specialised short-circuit testing station.

The normal method of proving the interturn insulation of a transformer is to carry out an induced overvoltage test during which a voltage of twice the normal interturn voltage is developed. Such a test would not be very effective for a series reactor since the 'normal' voltage between turns will be very small and even increasing this to twice its normal value is unlikely to give rise to any particularly searching stress.

The usual solution is to apply an impulse test to each line terminal in turn which will generate a more significant voltage between turns. The test level is usually the same as would be applied to the same voltage class of transformer. The usual practice is to apply two full-wave shots preceded and followed by a reduced (between 50 and 70%) full-wave application. Other tests are more straightforward and similar to the tests which would be carried out on a transformer, so that a full test series might consist of:

- Winding resistance.
- Oil samples.
- Loss measurement.
- Impedance measurement.
- Zero phase-sequence impedance.
- Noise level.
- Applied voltage test, including measurement of partial discharge.
- Impulse test.
- Oil samples (repeat).
- Insulation resistance.
- Magnetic circuit and associated insulation applied-voltage test.

References

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7.2 British Electricity International (1992) Vol. D, Chapter 4 'Generator main connections', pp. 287–324, Chapter 11 'Protection', pp. 868–947. *Modern Power Station Practice*, Third edition, Pergamon Press.

7.3 Electricity Association (1976) *Engineering Recommendation G.5/3, Limits for harmonics in the UK Electricity supply system*, 30 Millbank, London SW1P 4RD. (Under revision, October 1997.)

7.4 Corbyn, D. B. (1972) 'This business of harmonics', *Electronics and Power*, June, 219–223.

8 Transformer enquiries and tenders

No work of this magnitude would be complete without providing guidance in the procurement of transformers and emphasising to the reader and potential purchasers the need to ensure that there is a complete understanding between all parties from the outset, of the technical, commercial and legal requirements constituting any contract which may be established between them. Earlier editions included a chapter covering enquiries and tenders near to the beginning, following the chapters on fundamental principles. While there is some value in 'defining the problem' at the outset, moving the topic to near the end means that this chapter can serve as a résumé of the work as a whole with the advantage that the reader should have a clearer understanding of what is involved. In describing the process of issuing an enquiry it is assumed that the reader has a knowledge of what has gone before. Where important or more complex issues are involved, there is a cross-reference to the point in the text where the subject is discussed in detail. Elsewhere, the point of reference should be evident without the need for it to be specifically identified. For all of the technical issues raised the reader will be able to find a fuller explanation by referring to what has gone before.

8.1 TRANSFORMER ENQUIRIES

In the initial stage of an enquiry for a transformer there is nothing so important as a full and explicit statement of the total requirements that, from the user's point of view, have to be met and, from the manufacturer's standpoint have to be considered. This statement generally constitutes the *technical specification, guarantees and schedules*, which, together with the commercial and contractual conditions, will form the basis of a contract between the user and the supplier.

Frequently, enquiries are issued giving insufficient information concerning the relevant details, with the result that errors are made and delays are incurred in projects which could have been avoided if adequate consideration had been given to identifying the user's exact requirements at the outset.

There is a regrettable tendency at the present time, in the interests of obtaining the most economical designs and of permitting open competition, of issuing enquiries for 'transformers to BS 171' or 'to IEC 76', with the intention of allowing manufacturers to follow their 'standard' design practices and these enquiries include little more by way of technical requirements. For a good many years both the British and International Standards have themselves endeavoured to emphasise the inadequacy of this approach by providing appendices of information required with an enquiry or order. While following the guidance provided by these appendices should ensure that no vital information is omitted or no irretrievable disasters are likely to be uncovered when a new transformer arrives on site, it should be remembered that these documents only identify the most basic technical requirements. There is nothing set down in either BS 171 or IEC 76 which covers details such as how the transformer should be painted, for example − other than the basic requirement that it must be fit for purpose. But, then, how long does the paint finish have to last for it to be fit for purpose and how severe an environment does it have to survive? This is the type of information, not listed in the appendices to BS 171 and IEC 76, which the purchaser must provide if he wishes to ensure that he will obtain the transformer which most effectively, and in the long term most economically, meets all his needs.

Hence, it should be clear that if it is required that a manufacturer submit his most competitive tender, in response to any transformer enquiry, a fairly detailed specification defining minimum standards must be issued with that enquiry, otherwise a manufacturer may be justified in making his own assumptions with regard to minimum requirements in the interests of competitiveness.

Manufacturers do not have standard designs, except, perhaps, for the smallest distribution transformers. To attempt to do so would require that an enormous number of combinations of ratings, voltage ratios, impedances, connections, terminal arrangements, etc. would have to be covered, to say nothing of the variations of no-load losses and load losses required to cover the varying economic circumstances applying to different customers' duties and applications. Any new transformer contract thus will generally involve the generation of a new design and it is therefore just as easy to make this design fit the user's exact requirements as it is to try to second guess these by providing a 'standard' arrangement.

Minimum standards can and should, therefore, be identified by the purchaser without restricting a manufacturer's scope for using his expertise to provide reliable and competitive designs. It must be possible, however, to establish compliance with these minimum standards by means of simple checks or tests and not by attempting to dictate to a manufacturer how a transformer should be designed. In the case of the above example relating to paint finish, it is not restrictive of competition to specify the type of paint to be used, the minimum number of coats and the final paint thickness, but it could be restrictive to specify the precise process by which the paint is to be applied. There is no reason why the prospective user should not also specify that the paint finish should last for, say, eight years without attention to repainting, since this gives an indication of the quality required, although it is not practicable to enforce such a requirement contractually because manufacturers' contractual commitments, in the form of warranties, do not normally last for longer than the first year of service.

Technical specification

A technical specification has three objectives:

- To provide the tenderer, or manufacturer, with all that technical information necessary to carry out his design and which will vary from unit to unit, for example rating, voltage ratio, type of cooling, etc.
- To provide the tenderer, or manufacturer, with an indication of the strategic importance of the transformer and the value to be placed on reliability, maintainability and long service life.
- To provide the tenderer, or manufacturer, with information which will ensure that the transformer will satisfactorily interface with its associated plant and equipment and that installation and commissioning will proceed smoothly and without undue delays.

Clearly the first two objectives will have a significant bearing on the cost of the transformer and must be met by the enquiry document to enable the manufacturer to prepare his tender. The third will include many items which will have relatively little bearing on the overall cost and which could possibly be resolved during the engineering of the contract. However, it is good discipline to identify in the technical specification all those aspects which should be known at the time of initially drawing this up, since not only does this minimise the use of engineers' time during the contract stage and ensure that there are no unnecessary delays during the contract, but it also avoids the risk that these items might be overlooked during the detail engineering of the contract.

Preparation of the technical specification

The first step in the preparation of the technical specification is to draw up a checklist of important technical parameters. This checklist may well take the form of a *schedule of technical particulars* which can ultimately form part of the enquiry document. If the user is in the habit of buying transformers at fairly frequent intervals the form of this schedule can provide the basis for a standard company document. A typical schedule is shown in *Table 8.1* or, alternatively, the appendix listing information required with an enquiry and order in BS 171 or IEC 76 may be used as a starting point.

For some applications, for example for small distribution transformers for which the main technical parameters are very simply determined, it may be possible to complete the schedule of technical particulars directly and without any preliminary work; however, for most transformers, although the schedule identifies those particulars which need to be determined, the act of deciding the values of many of these will require a design study.

The result of the design study should be to produce a *Document of Design Intent*, or a document of 'needs'. This document will identify the basis on which, for example, the rating, impedance, voltage ratio and tapping range have been decided and will probably include, possibly as appendices, any calculations performed to derive these. It might possibly identify the need for closer tolerances on impedance variation than those set out in IEC 76 and, if this is the case, it will include a justification for this. It will probably examine a number of options for the other main parameters, for example the type of cooling, and give the reasons why a particular option has been adopted. In the case of a large, important transformer, for example for a generator transformer, it might identify the need for high reliability and availability, justifying the requirement for extra testing over and above that covered by IEC 76. It might also consider the case for the provision of a spare generator transformer and identify whether one is to be included at the outset.

When all the information for the schedule of technical particulars has been decided this can then be compiled for inclusion in the enquiry document. This schedule will provide a useful summary for tenderers and ultimately for the designer; however, this should be regarded as no more than a summary, so that the full set of technical requirements should also be set out in narrative form in order that, where necessary, any additional explanation of the requirements can be included.

Scope

The narrative part of the technical specification should commence with a descriptive outline of the overall scope of the works. For example, it might say:

> *This Specification details the requirements for the supply, delivery to site, off-loading onto prepared foundations, erection, preparation for service, commissioning and maintenance for the maintenance period of an ONAN-cooled oil-immersed three-phase double wound generator transformer for the connection of an 11 kV gas turbine generator to the 33 kV network. The transformer shall be supplied complete with the first filling of oil.*

Standards and conditions of service

The narrative should then identify the main International and National Standards which are to be applied and the extent to which these are to apply.

Table 8.1 Schedule of technical particulars for transformer

Description		*Examples*		
Type of transformer		*Outdoor oil-filled*	*Class 220 dry-type*	*Outdoor oil-filled*
Continuous maximum rating (CMR) at rated voltage	MVA	60	1.6	100
Number of phases		3	3	1
Continuous ONAN rating in case of mixed cooling	MVA	30	–	–
Voltage ratio at no-load, principal tap	kV	132/33	11/0.44	15/420/$\sqrt{3}$
Alternative voltage ratio at no-load (if required)	kV	–	–	11/420/$\sqrt{3}$
Continuous maximum rating at alternative voltage ratio	MVA	–	–	60
Frequency	Hz	50	50	50
Any special overload capability other than IEC 354		80 MVA at 5°C	–	–
Winding connections or connections of three-phase bank if single-phase	HV/LV	Star/delta	Delta/star	Star/delta
Details of any teriary winding required for connection to external load		None	None	None
Type of cooling		ONAN/ODAF	AN	ODAF
Auto or double wound		Double	Double	Double
System earthing conditions				
a) HV		Solid	Resistance	Solid
b) LV		Resistance	Solid	Resistance at generator neutral
Performance characteristics				
Operating conditions		HV voltage ± 10% on any tapping	HV voltage +6% to −10%	Rated output over range 0.95 p.f. lead to 0.85 p.f. lag with constant rated LV voltage applied and HV voltage in range ±10% on any tap position

Impedance voltage at CMR on principal tap	%	15	4.75	15 based on 300 MVA bank rating
Maximum impedance on any tap position	%	16.5	5.25	17 based on 300 MVA bank rating
Minimum impedance on any tap position	%	13	4.0	12.5 in 15 kV connection based on 300 MVA bank rating 13.5 in 11 kV connection based on 180 MVA bank rating
Short circuit capacity				
a) available at HV terminals	kA	31.5	20	53
b) available at LV terminals	kA	20	31.5	110 in 15 kV connection 85 in 11 kV connection
Condition for guaranteed load losses in case of dual rating		ODAF	–	100 MVA, 15 kV
Capitalisation rates to be applied to losses				
a) No-load loss	£/kW	1500	2200	1800
b) Load loss	£/kW	250	450	1800
c) Cooler loss	£/kW	250	–	1800

(*continued overleaf*)

Table 8.1 (*Continued*)

Description		*Examples*		
Type of transformer		*Outdoor oil-filled*	*Class 220 dry-type*	*Outdoor oil-filled*
Any limitations on zero-sequence impedance		Not less than 0.85 times positive sequence value	None	Not less than 0.85 times positive sequence value
Voltage control				
Method of variation of voltage ratio		On load	Off circuit	On load
Which winding is tapped		HV	HV	HV
Total range of variation, from:				
Plus per cent, to		10	5	5
minus per cent		20	5	15
Size of step	%	1.67	2.5	1.25
Whether automatic voltage control required		Yes	–	No
Terminations				
a) HV terminations required		Bushings	Cable box on outside of cubicle. Entry from below	Bushings
b) LV terminations required		Bushings	Direct to LV switchgear	Bushings for connection to phase-isolated busbars
c) HV neutral termination required		11 kV bushing	–	11 kV bushing
d) LV neutral termination required		–	Direct to LV switch gear	–

Accommodation required in turrets for current transformers				
a) HV		Yes–see schedule	–	Yes–see schedule
b) LV		No	–	No
Cooling				
Arrangement of coolers				
a) Tank attached		No	–	Yes
b) Separate free-standing		Yes	–	No
Number and rating of coolers per transformer		1 × 100%	–	3 × 50%
Average temperature of incoming cooling water	°C	–	–	–
Maximum temperature of incoming cooling water	°C	–	–	–
Maximum static head of water at plinth level	metres of water	–	–	–
Nature of water		–	–	–
General				
Maximum permissible sound power, transformer and cooler	dBA	80	–	95
Whether a noise enclosure is required from the outset		No	–	No
Whether antivibration pads are required		Yes, transformer only	–	Yes
Is first filling of oil required, if so state type		Yes, uninhibited	–	Yes, uninhibited
Type of oil preservation system required		Silica-gel breather	–	Refrigeration breather
Tank mounted or free-standing marshalling cubicle		Tank mounted	–	Tank mounted

Table 8.1 (*Continued*)

Description		*Examples*		
Testing requirements				
Standards applicable to testing		BS EN 60076-1 BS EN 60076-2 (Temperature rise) HD 398.3 (Insulation levels and dielectric tests)	HD 464	BS EN 60076-1 BS EN 60076-2 (temperature rise) HD 398.3 (insulation levels and dielectric tests)
Winding insulation class				
a) HV		Non-uniform	Uniform	Non-uniform
b) LV		Uniform	Uniform	Uniform
Rated withstand voltages: short duration power frequency/lightning impulse				
a) HV	kV	230/550	28/75	630/1425
b) LV	kV	70/170	3/–	38/95
Type testing requirements on first unit of contract		Temperature rise	Temperature rise	Temperature rise
Special testing requirements on first unit of contract		1) Lightning impulse including chopped waves 2) Zero-sequence impedance 3) Sound power level	–	1) Zero sequence impedance 2) Sound power level
Special testing requirements on all units		1) Measurement of partial discharge during short duration power frequency test 2) Oil samples to be taken for dissolved gas analysis	Measurement of partial discharge during short duration power frequency test	Additional dielectric testing and load current runs as for generator transformer – see text

This may be followed by a detailed description of the service conditions, for example:

The transformer shall be suitable for outdoor installation under the normal service ambient conditions set out in IEC 76 except as modified by the requirements with regard to rating set out below.

Special requirements

Before detailing the requirements concerning rating it is appropriate to identify any other special requirements, for example in the case of a generator transformer a high reliability and availability will be desirable. Although, as explained above, the best way of ensuring that this is obtained would be to specify more extensive testing of the type discussed in Section 3 of Chapter 5, it could be that for a fairly small generator transformer, as in this example, the extra cost of this could not be justified. Whether additional testing is included or not, it is worthwhile identifying the requirement for high reliability and availability and, by way of extra emphasis for this, the tenderer might be asked to identify in his tender those design features which he would incorporate for the purpose of obtaining high reliability. It will also be appropriate to include under this heading any requirement for the transformer to operate in parallel with an existing transformer.

Rating

The rating of the transformer required will be determined by the magnitude and the nature of the load. Since all except the smallest transformers are designed specifically for a particular contract, there is no reason why the rating specified should not be exactly that required, after making due allowance for any future load growth, where appropriate. There is no need to limit the specified rating to the preferred range of sizes, i.e. 1, 1.6, 2.5, 3.125, 5, 6.25, etc. An important point to be remembered, however, is that the IEC 76 rating is a purely notional quantity and is defined as the product of *open circuit voltage* times *full-load current*. This will be greater than the total MVA or kVA consumed by the load, which will be the product of nett busbar voltage after allowing for regulation within the transformer times full-load current.

Gas turbines usually provide their highest output at lower ambients than those of IEC 76, so, for a gas turbine generator transformer, it will be more important to ensure that these can be obtained than to identify an appropriate IEC 76 rating. Hence the rating requirement might typically be set out in the following manner:

The continuous rated power of the transformer shall be matched to the output of the associated gas turbine generator, which is as follows:

(a) 29 MVA at an LV terminal voltage of 11 kV and an ambient temperature of 0°C.

(b) 26.2 MVA at an LV terminal voltage of 11 kV and an ambient temperature of 10°C.

Under the above operating conditions the winding hot-spot temperature shall not exceed the value appropriate to continuous operation under the normal operating conditions and temperature rises of IEC 76. The Tenderer shall state in his tender the winding hot-spot temperature for operation at each of the above conditions. The Tenderer shall also state in his tender the equivalent IEC 76 rating of the transformer offered when operating under the normal IEC 76 ambient conditions. The above ratings shall be maintained on all tap positions.
The transformer is not required to have any specific overload capability other than that implied by virtue of its compliance with IEC 76.
The transformer will not be subjected to any unbalanced loading.

The reason for asking that the tenderer should also state a true IEC 76 rating is that this will assist in comparison of tenders, but more will be said later about the tender assessment process.

Rated voltage ratio

The voltage ratio to be specified is that applying on open-circuit, so that in the case of a step-down transformer, the secondary voltage specified must make due allowance for regulation, for example in the case of a transformer required to supply an 11 kV system, it is likely that the LV open-circuit voltage will need to be 11.5 kV. Ideally the Document of Design Intent should include a calculation of the open-circuit voltage required to ensure that the minimum voltage necessary at the terminals of the load can be obtained with minimum supply voltage at the HV winding terminals with the transformer fully loaded. The calculation should then be repeated for the condition with maximum supply voltage applied to the HV terminals and the transformer lightly loaded to ensure that an excessively high voltage does not appear at the load terminals. Ensuring that this does not occur might require the use of an on-load tapchanger on the transformer and these calculations will enable the required extent of the tapping range to be established.

Although in the example given above, the generator transformer has been described as having LV and HV voltages of 11 and 33 kV respectively, these are nominal values. In the case of the LV winding the actual, or rated, voltage may well be the same as the nominal voltage, but, in the case of the HV, the rated voltage will need to be higher than 33 kV because the generator, via its step-up transformer will be required to export MW and MVArs to a system which is normally at around 33 kV. The Document of Design Intent will similarly be required to include a calculation of the precise voltage required. (For an explanation of this see Section 1 of Chapter 7.) The tenderer must therefore be given the rated voltages for each winding. In this example the HV rated voltage will be taken to be 34.6 kV.

Flux density

It is also very important that the tenderer is given sufficient information to determine the nominal flux density for his design. Alternatively, it is often simpler to specify the maximum permissible nominal flux density to be used. This latter alternative might be considered by some as no longer an acceptable practice since it is tantamount to telling the tenderer how to design the transformer. As indicated in Sections 1, 2 and 3 of Chapter 7 and elsewhere, flux density is determined by the combination of applied voltage, tap position and frequency. The difficulty of ensuring that the designer is made aware of the most adverse condition which can occur in operation can be appreciated by considering the following typical clause which it would be necessary to include in a specification for the generator transformer used in the example.

In the UK the likely variation of 33 kV system voltage and frequency is given in the Distribution Code. At voltages of 132 kV and above the relevant document is the Grid Code. The following typical clause has been based on an interpretation of the Distribution Code current at the time of writing:

The HV nominal system voltage is 33 kV. It will normally be maintained within ±6% of this value but may occasionally and for short periods reach a level of plus 10% above nominal.

The nominal LV terminal voltage is 11 kV. This will be maintained by the action of the generator automatic voltage regulator within a band of ±5% of the nominal value.

The nominal system frequency is 50 Hz.

The transformers shall be capable of exporting full generator output to the 33 kV system and of operation without damage at the loadings indicated above, over the range of power factors from 0.85 lag to 0.95 lead and frequency 47 to 51 Hz under the following conditions:

(i) Frequency range 49.5 to 51 Hz:
at rated MVA and with rated applied voltages, continuously.

(ii) Frequency range 47 to 49.5 Hz:
the decrease in transformer throughput MVA shall not be more than pro rata with the change of frequency.

*Operation below 47 Hz down to 40 Hz during extreme emergency system conditions will be for periods not longer than 15 minutes at or about no-load with the voltage adjusted pro-rata with frequency.**

The simpler alternative to the above would be to specify that the nominal flux density should not exceed 1.7 tesla at rated voltage and frequency, but it must, of course, be recognised that this is transferring to the user the responsibility

* The requirement for operation below 47 Hz would normally only apply to a generator connected to the main transmission network and would probably not be a requirement for an embedded generator such as this unless it was required to have the capability for operation in an islanded mode.

for ensuring that at this nominal flux density there is no risk of saturation under any operating condition.

Insulation levels

The above detail concerning system voltage would also generally enable the tenderer to decide on the insulation levels required for the HV and LV windings, except that because both the HV and LV system voltages are less than 52 kV, Table II of IEC 76:Part 3, allows two alternative impulse withstand voltages for each. Clause 5.2 of that document states that choice between the alternative levels depends on the severity of overvoltage conditions to be expected on the system and on the importance of the particular installation. For a generator transformer this would normally be taken as having a high importance so that the higher impulse levels of 75 kV for the LV and 170 kV for the HV would be appropriate. The narrative part of the technical specification should make this clear. It is usual to quote insulation levels in terms of power frequency and impulse withstand tests so the wording of the appropriate clause would typically be:

The winding insulation levels shall be:

LV windings – power frequency 28 kV, lightning impulse 75 kV peak
HV windings – power frequency 70 kV, lightning impulse 170 kV peak.

This clause should also indicate whether it is required to make measurements of partial discharge during the induced overvoltage test and whether or not the lightning impulse withstand test is to include chopped waves. For a generator transformer, even one operating at the relatively modest voltages of 11/33 kV, specifying that each of these tests should be carried out would be a way of ensuring high reliability without incurring too much additional cost.

Tappings

The decision concerning the extent of tapping range required will depend on the likely variation in the supply voltage and the acceptable limits on output voltage taking into account regulation within the transformer over the load range from light load to full load. The influence of these factors on the extent of the tapping range has been mentioned above in relation to voltage ratio. The tappings will be provided on the HV winding unless there is a very good reason for doing otherwise, and they will normally be *full-power tappings*, that is the product of rated tapping power and rated tapping current will remain constant and equal to the rating of the transformer. Thus, for tappings having a lower rated tapping voltage than the rated voltage on principal tap, the rated tapping current will be greater than the rated current on principal tap, and for tappings having a higher rated tapping voltage, the rated tapping current will be less than the rated current on principal tap. IEC 76-1 suggests that some economy can be obtained by applying a cut-off to the tapping current at some tapping having a higher rated tapping voltage than the minimum rated tapping voltage. Any saving will, however, be minimal and it is rare for such arrangements to be employed.

Defining the tapping range requirements also provides the balance of the information required by the tenderer to enable him to establish a value for flux density. Typically, again considering the generator transformer of the above example, the specification might say:

> *Full power tappings shall be provided on the 34.6 kV winding for a variation of the no-load voltage over the range +4.44% to −15.54% in 18 steps of 1.11%.*

This wording provides sufficient information, taken in conjunction with that relating to power factor, applied voltage and frequency given above. It should be noted that the above arrangement of tappings does not provide round percentages at either end of the tapping range but the overall range is approximately 20% and the extreme taps are a whole number of steps removed from the principal tapping. An alternative way of specifying tappings, used in IEC 76 and much of Europe, is to quote the number of tappings in each direction and the size of step. The above arrangement would thus be described as 36.4 kV $+ 4 \times 1.11\%$, $-14 \times 1.11\%$.

System earthing and short-circuit levels

Even when a transformer has uniformly insulated windings throughout, as will be the case for the 11/33 kV generator transformer of the example, it is customary to provide details of the system earthing. This enables the tenderer to be assured that there will be no condition arising in service which might stress the transformer to a higher level than that for which it has been designed. This is relevant since, if the tenderer is ultimately given a contract to supply the transformer he will be required to provide a warranty of at least 12 months, possibly longer.

Similarly it is customary to provide information concerning system fault levels which will enable the tenderer to calculate the currents which the transformer will be required to withstand in the event of a short-circuit on either set of winding terminals with system volts applied to the other winding. IEC 76, Part 5, allows the impedance of the supply to be taken into account in calculating short-circuit current and gives values for supply impedance which may be assumed in the absence of any information provided by the user. The supply impedance is usually small compared to that of the transformer, however (see Section 7 of Chapter 4), and margins of safety are generous, so that the manufacturer is, in most cases, effectively ignoring the impedance of the supply.

If the transformer is required to withstand a short-circuit on its secondary terminals for longer than the two seconds implied by compliance with IEC 76, then this should be specified. Any other special requirements with regard to fault withstand capability should also be stated, for example if the transformer were required to provide power for frequent direct-on-line starting of large motors. It might be that the tenderer might be asked to supply evidence, either from test reports or calculations, of the transformer's ability to withstand short-circuit or frequent imposition of motor starting loads.

Load rejection

As explained in Section 1 of Chapter 7, generator transformers can be subjected to sudden load rejection leading to a short-term increase in the voltage applied to the LV terminals. Clause 8.3 of IEC 76, Part 1:1993, identifies this requirement for generator transformers and states that these shall be able to withstand 1.4 times rated volts for 5 seconds at the terminals to which the generator is connected. It is helpful to remind tenderers of this, in the case of an enquiry for generator transformers, by identifying that they may be subjected to sudden load rejection and to include any details of the resultant overvoltage requirement particularly if a more specific figure than that quoted in IEC 76 is available.

Impedance

As explained in Section 6 of Chapter 6 which deals with system faults and their effects on transformers, system designers are constantly striving to achieve the best compromise between the lowest level of impedance which will nevertheless limit fault currents to an acceptable magnitude and the highest level which can be tolerated without resulting in excessive system regulation. As a result they are invariably aiming to restrict manufacturers to the tightest possible tolerance limits on impedance values. Impedance tolerances can frequently be restricted to narrower limits than those set out in IEC 76, but there is usually a price to be paid. It is desirable therefore that close tolerances on impedance are only specified if there is a very good reason for doing so. A significant proportion of the variation in impedance is due to change of tap position. Although designing for a closer overall tolerance might be difficult or involve additional cost, it is sometimes possible to arrange that the impedance characteristic is of a shape which causes the least problems for the system designer. For an explanation of this the reader is referred to the discussion concerning variation of impedance with tap position contained in Section 6 of Chapter 4. If impedance and the variation thereof is so important that normal IEC 76 tolerances are not acceptable, then the best way of specifying this is by means of an envelope of acceptable values as shown in *Figure 8.1*.

Losses

If the transformer has any multiple rating arrangement, as, for example, as provided by ONAN/ODAF type cooling, or should the transformer have any special emergency rating in addition to its normal IEC 76 value, then it must

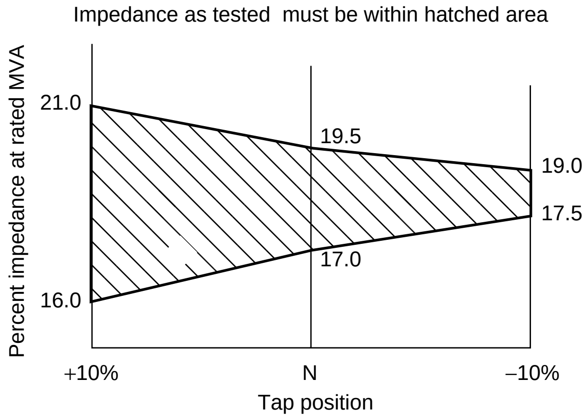

Figure 8.1 Typical impedance envelope as used to specify acceptable impedance variation with tap position

be made clear to the tenderer under which condition the losses are to be guaranteed. Referring once more to the generator transformer of the example, losses are most important at the gas turbine generator full-load condition. The tenderer should therefore be instructed that the losses are to be guaranteed at this loading. This is an appropriate place also to indicate to the tenderer the value to be placed on losses and whether these will be taken into account for tender assessment purposes. A suitable clause to be included in the specification for the generator transformer of the example would be:

The guaranteed losses of each transformer on principal tapping and at a winding temperature of 75°C shall be stated by the Tenderer. Load losses shall be guaranteed at the maximum rated power of 29 MVA. These guaranteed losses will be used as the basis for evaluation of tenders, for acceptance or rejection of the completed transformer or for variation of the Contract Price in accordance with the capitalised cost of losses specified in the Enquiry.

Sound power level and vibration

The tenderer should be advised of any noise constraints existing at the proposed site and whether any form of sound attenuating enclose is required for the transformer either initially or in the future. The tenderer should be asked to give guarantees of maximum sound power level when measured in accordance with BS EN 60551.

Transformer construction

The technical specification may also identify any constructional requirements which are considered important. This will include whether radiators may be tank mounted or whether a separate free-standing cooler bank is required. The manufacturer will probably ensure that there is an adequate number of removable covers for access to such items as winding temperature indicator current transformer connections and core and core-frame earth connections as he is likely to need access to these at the stage of installing the transformer in its tank. It is nevertheless worthwhile reiterating this requirement as well as specifying that these should be provided with lifting handles and be light enough in weight to be easily removed by one person. This usually means no heavier than 25 kg.

Consideration should be given as to whether it is required that the core and core-frame earth should be brought outside the tank to enable the insulation resistances to be periodically checked without lowering the oil. The cost of providing this feature is not large in relation to the overall cost of the transformer and the advantages of bringing out these connections on any transformer rated more than a few MVA is becoming increasingly recognised.

The section of the specification relating to construction should also identify whether a welded flange for the tank cover is acceptable. Such an arrangement has the benefit that the possibility of oil leaks is eliminated, but it has the disadvantage that, should it be necessary to gain full access to the tank for any reason (as distinct from the limited access which can be gained by removing an inspection cover), this will involve cutting of the weld and rewelding when any work is completed. Where such an arrangement is adopted, it is usual to specify that the design of the welded joint shall be suitable for opening, by grinding or otherwise, and subsequent rewelding on at least three occasions.

Cleaning and painting

Included under the heading of construction are the requirements concerning cleaning and painting. If the transformer is to be installed at a particularly hostile site, for example close to the sea, then this should be stated. Internal and external surfaces of all equipment other than that having machined mating surfaces should be shot blasted or cleaned by other similar process and the first protective paint coat applied on the same day without any outdoor exposure. External surfaces should then be suitably primed followed by two further coats of weather and oil resisting paint. These should be of contrasting colours so that full coverage can be easily established and specifying a minimum total thickness of 0.13–0.15 mm will ensure a good durable protection.

The internal surfaces of tanks, core frames and any vessels or chambers which are to contain oil should be sealed by means of a single coat of oil-resistant paint or varnish, the main objective of this being to prevent the catalytic action of the steel on the oil. As indicated in the section dealing with distribution transformers, this paint treatment is often omitted in the case of distribution transformers without, it is claimed by manufacturers, any deleterious effect on the long-term quality of the oil.

The advantage to be gained by galvanising any thin sheet-steel components, particularly panel-type radiators, prior to painting is becoming increasingly recognised. These should be hot-dip galvanised to the appropriate ISO Standard prior to the application of a paint finish in a similar manner to that described above for the other external surfaces. Without galvanising, any loss of paint which might occur after leaving the factory quickly results in rusting. This usually occurs in the crevices between the panels so that adequate preparation for repainting is virtually impossible with the result that, even if an attempt is made to repaint these, it is likely to be unsuccessful and the radiator life becomes seriously restricted. The only disadvantage of galvanising is that it is more difficult to achieve a good bond for the subsequent paint coating. Most manufactures of panel radiators are, however, able to carry out some artificial weathering or similar process which results in a greatly improved bond.

Oil

For any transformer manufactured in the UK it is likely that the initial filling of oil will be uninhibited naphthenic to BS 148 unless the purchaser has specified otherwise. If the transformer is manufactured outside the UK it will be necessary to specify the type of oil to be supplied. If the transformer is to be installed in the UK then the use of uninhibited naphthenic oil is to be preferred since this is least likely to create problems should it ever be necessary to request one of the UK oil suppliers to remove the oil from the transformer and take it for reprocessing.

Fittings

The technical specification should list the fittings to be supplied with the transformer. These should be selected from the following.

Conservator Most transformers used in the UK, with the exception of distribution transformers of around 1.6 MVA or less, are likely to benefit from the fitting of a conservator. Transformer breathing systems are discussed in Section 8 of Chapter 4. If a conservator is specified it should have a capacity of about 7.5% of the total cold oil volume within the transformer. A removable end cover should be provided to allow the interior to be cleaned out if necessary and the conservator should be provided with a sump to contain any solid deposits either by extending the feed pipe inside the conservator or by bringing this in through an end wall. The extension or wall entry should be such as to provide a minimum sump depth of 75 mm or one-tenth the diameter of the conservator, whichever is less.

It will be necessary to provide a means for filling the conservator which must be airtight and weatherproof when closed. An oil level gauge will be required. This may be simply a prismatic sight-glass or it may be of the type having a dial pointer which is magnetically coupled to an internal float operating within the vessel. If a sight glass is used it is advantageous for this to be angled downwards slightly to aid viewing from the transformer plinth level. Prismatic gauges are the most foolproof but the magnetically operated type can be arranged to provide remote indication of oil level by means of microswitches and/or transmitters/transducers. Whichever type of gauge is used it must have a mark corresponding to the 15°C oil level and may also be marked with, say, −10°C and +80°C levels.

For most transformers the conservator will also be fitted with a silica gel breather. For transformers of 275 kV and above a refrigeration breather may be fitted as an alternative.

A transformer having an on-load tapchanger will normally have a second small conservator for the diverter-switch oil. This frequently takes the form of a sectioned-off portion of the main conservator at one end of the main conservator.

Cooling equipment If tank-mounted radiators are permitted these should be detachable to allow replacement or repair in the event of a leak and these will thus require a butterfly-type isolating valve at each of the points of connection to the tank.

Where separate free-standing coolers have been specified these will need expansion devices in the inlet and outlet pipes to the transformer.

For a transformer having forced cooling, the extent of standby capacity should also be identified, for example if transformer is required to deliver full rated output with one oil pump and/or one fan out of action this should be clearly stated.

If the transformer is to be water cooled, the need for cooler standby capacity is more important since a water-cooled transformer has no naturally cooled capability and without standby a loss of cooling represents a loss of transformer. The Document of Design Intent should therefore make an assessment to decide the extent of standby required, usually this means whether this is to be two by 100% coolers or three by 50%. Alternatively the tenderer could be asked to provide alternative prices for each option so that this can be decided at the tender assessment stage. It will also be necessary to provide the tenderer with an analysis of the water quality to enable cooler tube and tube-plate material to be decided.

Consideration should also be given to the use of double tube, double tube-plate, coolers, particularly if the cooling water is at high head or is of a chemically highly aggressive nature.

Valves The number, size and location of all valves required for maintenance and operation of the transformer will need to be identified. These should comply with the appropriate national or international standard. British Standards 5150, 5153, 5154 and 5155 are the ones applying in the UK at the time of writing. It will avoid the risk of operating errors if valves are standardised to all have the same direction for operation. Clockwise to close is the convention usually adopted. Isolating and filter valves should preferably be of the wedge-gate variety. Up to 75 mm nominal bore these will be of copper alloy. For some applications, for example for the individual isolation of tank-mounted radiators, should it be necessary to remove these, as mentioned above, butterfly valves may be acceptable. When a radiator has been removed, unless it is replaced immediately the closed butterfly valve will be covered with a blanking plate as additional security. The necessary blanking plates should be included with any maintenance spares supplied with the transformer. If the transformer is to be provided with a separate free-standing cooler bank, consideration should be given as to whether it is required to provide isolating valves to enable this to be mounted at either end of the tank. Any valves which are open to the atmosphere should also be provided with blanking plates.

All valves should be padlockable in both the open and closed positions so as to avoid the risk of any unauthorised interference.

The following valves should be provided as a minimum:

Isolating valves

(a) On the conservator side of any gas- and oil-actuated relay.

(b) A valve for draining the conservator sump – usually 50 mm will be adequate.

(c) A valve at the lowest point of each main oil pipe – usually 50 mm will be adequate.

(d) A valve at the lowest point of any oil-filled chamber – usually 50 mm.

(e) A valve for draining the main tank. This should be 80 mm as a minimum, larger on large transformers.

As a cost-saving measure some users will accept the use of a screw-in plug for draining short pipes and small oil-filled chambers. These have the disadvantage that when loosened there is no control over the escaping oil and they are therefore best avoided.

Filter valves

(f) A filter valve is required at the top and bottom of the main tank, sensibly diagonally opposite each other, and in the top and bottom headers of any separate cooler bank. Filter valves will normally be 50 mm and should be fitted with adapters for flexible hoses and be complete with covers and gaskets.

Gas- and oil-actuated relays   A gas- and oil-actuated relay will be required in the oil feed pipe to each conservator, that is main conservator and any tapchanger diverter-switch conservator where provided. In the case of some small, single compartment tapchangers the conservator and gas- and oil-actuated relay are built into the tapchanger itself.

To ensure correct operation in the event of an oil surge, gas- and oil-actuated relays should be fitted into a straight run of pipework having a minimum length of about five times the internal diameter of the relay on the tank side of the relay and three times the internal diameter of the pipe on the conservator side of the relay. The pipe should be arranged at a rising angle of between 3 and 7° to the horizontal.

In order to assist with routine testing of the relay as well as the venting of it in the event of gas collection, separate pipes terminated in pet-cocks should be brought down to a suitable height above plinth level. The pet-cocks should be provided with end covers and be lockable in the closed position. The pipe for air injection should be provided with a suitable one-way valve, as close to the relay as possible, to prevent oil seepage down the pipe.

The tenderer should be given details of the requirements regarding type and duty of alarm and trip contacts to be provided on the gas- and oil-actuated relay.

Pressure relief device All transformer tanks should be provided with a pressure relief device to reduce the likelihood of tank rupture in the event of a severe internal fault. This must be provided with deflector pipework to ensure that any oil released is safely directed to within one metre of plinth level.

The tenderer should be given details of the requirements regarding type and duty of alarm and trip contacts, if any, to be provided on the pressure relief device. It is generally considered that alarm contacts only are required, since, although spurious operation of the device is unlikely, the number of trip sources should be restricted to a minimum to avoid unnecessary tripping and any internal event which operates the pressure relief device is almost certain to operate the Buchholz relay also, thus tripping the transformer by that means.

Winding or oil temperature indicators Requirements for winding temperature indicators should be set out. On less important transformers or those rated below about 5 MVA, some economy can be obtained by the use of oil temperature indication only. Otherwise winding temperature indication should be provided for each winding. It is desirable that winding temperature indicators should have a means of checking the operation and setting of the contacts, usually via a spring-loaded knurled knob, external to the indicator case. This should have wire and lead sealing facilities to prevent unauthorised interference. The indicators should be scaled from about 30°C to 150°C and have independently adjustable alarm and trip contacts. The range of adjustment for both sets of contacts should cover from about 80°C to full scale. If possible the enquiry document should advise the initial settings to be provided. Refer to Section 6 of Chapter 6 for recommended settings.

The tenderer should be given details of requirements regarding the type and duty of the alarm and trip contacts to be provided on the winding temperature indicators.

The winding temperature indicators should be provided with isolating and test links so that these may be checked for correct operation while the transformer is in service.

The tenderer should also be advised of any requirement for remote indication of winding temperature including details of the type of system to be used and the type of transmitter to be provided.

Other fittings In addition to the foregoing fittings, the following are likely to be required:

(a) A thermometer pocket mounted in the top cover in vicinity of the hottest oil.
(b) In the case of transformers having separate cooler banks, two further thermometer pockets, one in the outlet pipe to the cooler and one in the inlet pipe from the cooler. All thermometer pockets must be provided with captive weatherproof screwed caps.
(c) An oil sampling device mounted 1 m above plinth level.
(d) Jacking plates, haulage eyes and lifting lugs.
(e) An earthing connection point on the transformer tank and an additional such point on any separate cooler banks.

Terminations and accommodation for current transformers

This section of the specification should provide details of the terminations required. If air bushings are provided for either HV or LV terminations, any special requirements relating to terminal palms should be identified and any requirements concerning shed profile. If coordinating gaps are to be provided this should be made clear including details of type, and range of adjustment where appropriate and gap settings required on initial delivery to site.

If cable boxes are to be fitted then full details including number, type, size and rating of cables should be given, type of terminations to be used and whether cables will enter boxes from above or below. Requirements regarding gland plates should be identified. Ideally individual gland plates should be provided for each cable. The specification should also make clear who is to supply cable glands.

Any neutral termination arrangements should be described including details of physical arrangement of neutral connections and any neutral current transformers.

Full details of line current transformers should be provided. These should be accommodated in turrets mounted above the tank cover so that, should it be necessary for a current transformer to be removed at some time in the future, then this can be done without lowering the oil in the main tank below the top of the core. Terminal connections for current transformer secondaries should be provided in weatherproof terminal boxes on the outside of each turret.

Marshalling cubicle

The tenderer will normally be asked to include in his tender for the supply of a marshalling cubicle to which he should extend connections from all equipment mounted on the transformer. The specification should identify all items to be included in this cubicle and indicate whether this is to be separate free standing or whether a tank-mounted cubicle is acceptable.

Whether tank mounted or free standing, the cubicle should be of outdoor weatherproof construction with a cover designed to shed water and a front opening door or doors. No equipment in the cubicle should be mounted more than 1.8 m above plinth level for ease of operator access.

The marshalling cubicle should provide accommodation for the equipment listed below. Equipment for each common function should be grouped together and each item should be labelled to identify its function in accordance with the appropriate circuit diagram.

(a) Temperature indicators, test links and ammeters for winding temperature circuits.
(b) Interposing current transformers associated with the unit main protection system. Where these are not required to be installed initially, a space should be reserved for any future requirements.
(c) Control equipment for forced cooling, where appropriate, including local/remote and duty/standby selector switches, isolators, fuses, motor contactors and overload devices.
(d) Any transformers required for the provision of 110 V AC control supplies.
(e) Terminal blocks to accommodate all interconnecting multicore cabling associated with alarms and tripping equipment and current transformer secondary circuits. The provision of some spare multicore terminal blocks to allow for future extensions/modifications is advisable. For most purposes about 20 of these will be adequate. It is also worthwhile reserving the right to approval of the terminal blocks to be used or, provided the requirement is qualified by the use of the description 'or equivalent', a particular type reference may be quoted. It should be recognised, however, that the transformer manufacturer is unlikely to have a great deal of control over the type of terminal blocks used in proprietary equipment such as tapchanger drive and control cubicles.
(f) Sectionalised gland plates to accommodate all incoming and outgoing cables with sufficient allowance to meet any future additions.

All equipment must be mounted so that terminals are accessible for testing purposes but shrouded to prevent danger to operators.

Construction

It is important to recognise that the cubicle must withstand all weather conditions and provide protection for its contents against deterioration for many years. The cubicle must therefore be designed to shed water and should be free of features which may trap debris. The cover and sides of the cubicle should preferably not be pierced by fixings. All parts should have a non-corrodable finish and ferrous parts should be covered by the requirements for painting and weather protection discussed above.

The cubicle needs to be adequately ventilated to ensure free air circulation over all equipment and a heater should be fitted to prevent condensation.

Doors should be provided with fastenings having integral handles and padlocking facilities. A sensible size of padlock shackle needs to be accommodated, say 9 mm diameter. Doors must be adequately weatherproofed.

Lighting and socket outlet

The cubicle should be provided with internal lighting arranged to illuminate all the internal equipment as evenly as possible so that an operator can work during darkness and consideration should be given to the provision of a 240 V socket outlet to provide a power supply for any portable test equipment which it might be required to operate on the transformer plinth.

Lamps should be to BS EN 60064 extended life (2500 h), mounted in a heat resisting lampholder to BS 5042, Part 1 and controlled by a door-operated switch. The lamp should be suitably protected to avoid accidental breakage or touch.

If a socket outlet is to be provided this should be of an appropriate pattern, protected by RCD, and mounted on the outside of the cubicle.

It will be necessary for the purchaser to provide an incoming 240 V supply to the cubicle to supply the lighting, heating and socket outlet as well as a power supply which may be required for any forced cooling equipment.

Interconnecting cabling

The type and standard of interconnecting cabling required between equipment mounted on the transformer and the marshalling cubicle may be specified unless the transformer manufacturer is to be given a free hand in this. Preferably 600/1000 V armoured cable with stranded copper conductors in accordance with BS 5467, or equivalent, should be used and it is desirable that the enquiry document should make clear who is to install, gland and terminate this. This is normally done by the transformer manufacturer. It is usual to specify a minimum nominal conductor cross-sectional area of 2.5 mm^2 for the cable cores to ensure that these are mechanically adequate to withstand the duty to be imposed upon them, in particular the vibration generated by the transformer, although nowadays smaller cores are considered acceptable for transmission of signals to SCADA systems.

Testing

It is rare for any transformer, other than a small distribution transformer, to be tested simply to IEC 76 or BS 171, and, even when this is considered adequate, there are frequently options which need to be identified such as whether the rated lightning impulse withstand voltage for windings of U_m up to 36 kV should be to list 1 or list 2 of Table II of IEC 76-3 or, for values of U_m of 123 kV and over, which of the alternative power frequency and impulse withstand voltages, given in the same table, are to apply. Consequently it is desirable to carefully consider all the testing which will be required and to set this out clearly so that no misunderstandings or omissions will occur.

If any doubt exists as to the extent of testing which should be specified, reference should be made to Chapter 5.

It is also necessary to decide whether the option is to be retained to witness any or all of the tests. To provide for this option is likely to involve the manufacturer in some additional costs and might also limit his flexibility of operation at the testing stage, so it is likely that he will wish to include some allowance for this in the contract price. On the other hand, should any problem occur during testing, it can greatly assist constructive discussion and resolution of the problem or of any proposed remedial measures, to have been represented at its occurrence. This is particularly the case for testing which might to some extent be subjective in its interpretation, such as the measurement of partial discharges during an overpotential test, the examination of test records during a lightning impulse withstand test or the measurement of sound power.

Type testing

As indicated earlier, most transformers will be designed to meet a particular contract and are likely to differ from other designs previously manufactured and tested at least in respect of losses, impedance or tapping range, so that it is likely that some type testing will be required on any new contract. Type testing is considered at some length in Chapter 5; however, for the convenience of the reader the tests normally considered to be type tests are the following:

Temperature rise test.

Lightning impulse test including chopped waves and switching surge tests where appropriate.

Impedance on all tap positions – and may also include load loss on all tap positions.

Zero-sequence impedance.

Sound power level measurement.

Short-circuit tests.

Consideration should also be given to the strategic importance of the transformer to be purchased and to whether this might justify any additional or enhanced testing as discussed in Section 3 of Chapter 5. It should also be considered as to whether the taking of oil samples for dissolved gas analysis as part of works testing will be required. This procedure can greatly increase the confidence which can be obtained from works testing and is also discussed in Section 7 of Chapter 6. The appropriate times for the taking of samples are as follows:

Before the commencement of final works testing.
On completion of temperature rise tests.
On completion of impulse testing.
On completion of power-frequency dielectric testing.

Routine tests

Routine tests can be simply specified as being in accordance with IEC 76 or BS 171 as appropriate. If it is required that measurement of partial discharge is to be carried out during the short-duration power-frequency withstand test, this requirement should be identified and the method of carrying out the test indicated, including the acceptance criteria (see Chapter 5).

Tank vacuum and leakage tests

Most manufacturers will carry out a leakage test on a transformer tank since it will be inconvenient for them if the tank should leak either during works tests or on site during the maintenance period. For transformers which are to be vacuum filled on site it will be necessary for the tank to be designed to withstand full vacuum so that in order to ensure that there are no problems on site, a manufacturer must satisfy himself in the factory with regard to the tank vacuum capability. It is, however, preferable that these aspects are not left to chance and that the technical specification includes tests for tank vacuum capability, where appropriate, and for freedom from leakage. Tests for tank vacuum capability and leakage are detailed in Section 1 of Chapter 5.

8.2 ASSESSMENT OF TENDERS

Following the issue of the transformer enquiry, at a date nominated by the purchaser, a number of tenders will be received. These should be left unopened until the declared time has passed and then formally opened. The pricing information for each tenderer should be extracted and logged together with the relevant information for any options and prices for work deemed extra by the tenderer. The tenders should be kept by one person who is responsible, until the contract is placed, for keeping them confidential and ensuring they are kept locked away when not being worked on. If each of the tenders is technically fully compliant with the specification then deciding which tender to accept is simply a matter of deciding which has the lowest cost. It is rare, however, for the tender selection process to be such a simple one, so that a careful assessment will need to be carried out to determine which, if any, of the tenders should be accepted.

Tenders may have aspects for which they are not technically compliant. It may be that some of the tenderers wish to apply commercial conditions which could possibly result in additional costs. It is fairly certain that every tender will be for a different combination of no-load and load losses. If the programme timescale is short it is possible that a tenderer might not be able to meet the required delivery date. If all other aspects of this tender make it attractive it might be appropriate to consider the cost implications of delaying completion of the project or of rescheduling construction.

This section, however, is restricted to a description of the procedure for making a technical assessment of the received tenders, although clearly the final decision concerning the placing of a contract will involve selecting the most acceptable combination of commercial, technical and programme aspects.

Initial selection process

It can be quite common nowadays to receive as many as seven or eight tenders for even a fairly modest project. Making a detailed study of eight tenders can be quite a time-consuming process. The first step therefore is to reduce the number of tenders to be considered in detail to a shortlist of three or four. This will normally be done by an examination of the costs. For each tender the total cost can be calculated; this is the sum of the tender price plus the cost of the losses plus the cost of any special commercial aspects associated with the offer. Possibly, despite specifying a requirement for a five year guarantee, say, one of the tenderers might only be prepared to offer a one year guarantee period. Possibly one of the tenderers will be from overseas so that monitoring of the contract will be more costly, requiring some extra allowance to be made. Another might require a different schedule of stage payments, making the financing costs greater. *Table 8.2* shows a typical initial tabulated series of costs for six tenders taking account of such factors. It will be seen how the order of preference can be significantly affected by carrying out this exercise. Although on price alone tender A is the lowest, the extra cost of supplying the significantly higher losses during the operating life of the transformer make this less attractive overall and tender D, which on initial examination might appear considerably higher, appears to be the most attractive. The method of assessing the cost of the losses will be considered in the following section.

Table 8.2 Typical price and loss summary for transformer tenders

Tenderer		A	B	C	D	E	F
Price	£	435 000	478 300	495 700	473 600	498 200	520 000
No-load loss	kW	28	26	35	32	29	27
Load loss	kW	270	290	190	188	265	245
Cost of no-load loss	£	84 000	78 000	105 000	96 000	87 000	81 000
Cost of load loss	£	175 500	188 500	123 500	122 200	172 250	159 250
Totals	£	694 500	744 800	724 200	691 800	757 450	760 250

Having carried out this initial examination of the tenders to arrive at the position shown in *Table 8.2*, the next stage is to look at those which appear more attractive in a little more detail. Of those examples listed in the table, tenders A, C and D are worthy of consideration in greater depth.

Tenderers will frequently submit a tender letter in which they will highlight those aspects of their bid which they feel might require clarification. This letter might also identify aspects of the enquiry document which they did not consider to be entirely clear in its requirements and it will explain any assumptions which they felt it necessary to make. They will also probably include a detailed description of the transformer offered, including those aspects of their design and manufacturing processes, as well as their QA procedures, which they feel renders their bid worthy of extra commendation, and, of course, they should have completed the tender schedules included in the enquiry document. All of this material provides a great deal of information about the transformer offered and must be studied in detail.

In making this study the objective must be to obtain answers to the following questions:

- Are there any statements made in the covering letter, descriptive material or tender schedules which suggest that the equipment supplied will not be in accordance with the specification?
- Are the impedance values given in the tender schedules in accordance with those specified? Are the impedances on extreme tap positions, including any possible tolerances, within acceptable limits? If zero-sequence impedance is important, is the value offered acceptable?
- Has all the specified testing, in particular type testing, been included in the offer?
- Has the waiving of any type testing been claimed? If so, is the supporting evidence included and is it acceptable?
- Has the tenderer taken due account of any special requirements included in the specification, for example special overloading capability?
- Will the transformer fit in the site?
- Has the tenderer included for all the specified fittings, marshalling cubicle, valves, anti-vibration mountings, etc.?
- Does the pattern of terminations offered comply with the specified requirements with regard to, for example, bushing shed profile, palm configuration, type of cable boxes?
- Has the tenderer included all the special descriptive information requested in the enquiry document, for example the measures incorporated to allow for a high level of harmonics in the load, or to cater for frequent severe overloads?
- Does the offer meet any specified noise level requirements, including the effect of a noise attenuation enclosure where appropriate? If a noise enclosure will be required, has it been included in the tender price?
- Has the tenderer included for all the necessary site work, including delivery and site erection?

Occasionally the descriptive material provided by one tenderer can raise questions in relation to the other tenders, for example some of the tenderers might comment that a specified overload duty at 10°C will require an increase in the rating at normal IEC 76 ambient. This then raises the question as to whether a tenderer who has made no comments at all in relation to the specified overload duty has taken this into account in preparing his design. Similarly, it is sometimes the case that setting out the information provided by the tenderers in their completed schedules of technical particulars will highlight an anomaly in some of the data provided by one of the tenderers and raise the question as to whether his offer is in compliance with the specification.

In the example of the embedded generator mentioned in the previous section of this chapter, the transformer rating was specified at an ambient temperature of 10°C but it was proposed that tenderers should be asked to quote the rating of the transformers offered at normal IEC ambients. It would be expected that the reduction in rating resulting from the increase in ambient temperature from 10°C to an annual average of 20°C and a daily average of 30°C would be quite modest and very nearly the same for all tenders, but the one for which the reduction is least might be taken as an indication that this is the design which is least stressed thermally, and, as indicated elsewhere in this work, lowest thermal stress is likely to lead to longest life. Such considerations would only, of course, be relevant in differentiating between tenders which were very similar in other respects.

This careful scrutiny of the shortlisted tenders will probably result in the need to make some adjustments to the initial assessment of costs as given in the example of *Table 8.2*. It is quite common for tenderers not to include for type testing in their total tender sum, even though they will probably indicate the price of the tests themselves. It might be the case that one tenderer can meet the specified noise level without the use of a noise enclosure, while others cannot. The figures comprising *Table 8.2* for the three shortlisted tenderers can thus be amended as shown in *Table 8.3* so that a preferred tenderer will be identified.

Table 8.3 Amended price and loss summary after study of tender descriptive material

Tenderer		A	C	D
Price	£	435 000	495 700	473 600
No-load loss	kW	28	35	32
Load loss	kW	270	190	188
Cost of no-load loss	£	84 000	105 000	96 000
Cost of load loss	£	175 500	123 500	122 200
Extra for impulse type test	£	–	1500	–
Extra for temperature rise type test	£	–	1800	–
Extra for antivibration mountings	£	2500	–	–
Revised totals	£	697 000	727 500	691 800

Tender questionnaire

Often despite all the descriptive material provided as well as the information in the tender schedules, it will be the case that the purchaser does not have the confidence to place a contract with the preferred tenderer without some further investigation. In these circumstances it may be appropriate to issue a questionnaire to one, or more, preferred tenderers.

Sometimes, particularly in the case of tenders for smaller transformers of ratings up to perhaps a few tens of MVA where manufacturers are keen to limit their costs for the preparation of tenders, the extent of descriptive material may be very limited. In this case, unless there is definite evidence that some aspect of the specification will not be met, or description which has been specifically requested in the specification is not provided, it must be assumed that the tender is compliant. There is no need for questions to be raised simply because the tenderer has not written at great length about every one of the design features.

Frequently questions can arise because a manufacturer provides too much descriptive material and in the relatively short time that he has for the preparation of his tender he has not had chance to thoroughly check to ensure that no conflicting statements are included.

Although the response to questions can occasionally result in additional costs, questions should be phrased in such a way as to avoid inviting these, for example the tenderer should generally be asked to confirm that his offer includes the specified feature which is in doubt. After consideration of the response to the questionnaire the effect on the price comparison should be finally assessed before placing the contract. If two or more of the tenderers assessed prices are sufficiently close that the response to questions might change the order of preference, then questionnaires should be issued to all of these.

8.3 ECONOMICS OF OWNERSHIP AND OPERATION

When the purchase of a transformer is considered, as with most other items of plant or equipment, there are two aspects to be taken into account:

- The initial capital cost.
- The running cost – which in the case of a transformer is the cost of supplying the losses.

In the typical tender assessment exercise discussed in the preceding section, notional values were placed on each kilowatt of the guaranteed losses for the transformers tendered as a means of comparison of the tenders on a common basis. That is, a cost was assigned to the value of one kilowatt of no-load loss and also to the value of a kilowatt of load loss during the operating life of the transformer. In the example no-load loss was costed at a considerably higher value, £3000 per kW, than load loss at £650 per kW, and although there was no mention in the example of the type of transformer being considered, this could be the case for a typical transmission transformer operating in a multiple transformer substation in the part-loaded condition, so that in the event of losing one transformer in the substation, the remainder must be capable of carrying the total substation load without becoming overloaded. In addition, the daily load cycle has a daytime peak and a very much lower value at night. As a result the transformer spends much of the time at less than half load, and the average load losses are less than one-quarter of their magnitude at nominal rated power, which is the rating for which the load losses are quoted and guaranteed by the manufacturer.

While this illustration explains why the cost of the load losses is so much less than the no-load losses, it does not explain how their actual value is derived. To do this it is necessary to examine the subject a little further and assess the likely cost of a kilowatt of loss over the lifetime of the transformer.

The simplest method would be to calculate the total energy consumed in losses over, say, a 25 or 30 year life and cost this at today's energy price. This calculation can be worth carrying out if for no other reason than the fact that the answer can be quite surprising.

Typical cost of losses to industry

Even when taking such a simple approach, it is worthwhile attempting to carry out the calculation as carefully as possible, that is the load factor should be estimated as closely as possible and factors such as time of day rates and maximum demand charges need to be taken into account.

Example 1 Consider a typical small factory which has two 11/0.415 kV transformers. The factory operates for 50 weeks of the year and during this time the plant is running 10 hours per day, weekdays only. The transformers are energised 24 hours per day, 50 weeks of the year, to provide power for lighting but their only significant load is while the plant is running.

It is often the case that such a factory will be considering the purchase of an additional transformer at the time of extending the electrical system. Perhaps it is planned to supplement two existing transformers because the factory load has grown to considerably more than could be handled by one alone with the other out of service. The purchase might have been initiated by the installation of new plant which will mean that on completion the new installation will have three transformers normally carrying the equivalent of full load for two, i.e. each transformer will normally carry two-thirds full load.

The factory operates on a Seasonal Time of Day Tariff, supplied from the local Regional Electricity Company (REC).

The cost per year (of 351 days) for one kilowatt of iron loss is typically thus:

	£
Supply capacity charge, say	18
Maximum demand charge – winter p.m., say	40

Night units – 23.30 to 06.30, 7 hrs daily, $7 \times 351 = 2457$ units at, say, 2.5p/hr	61
Weekend units – 06.30 to 23.30, 17 hrs/day for 49 weekends, $17 \times 98 = 1666$ units at, say, 4.5p/hr	75
Evenings Mon. to Fri. – 20.00 to 23.30, 3.5 hrs/day $3.5 \times 253 = 885$ units at, say, 4.5p/hr	40
Days Nov. to Feb. – 06.30 to 20.00, 13.5 hrs/day $13.5 \times 86 = 1161$ units at, say, 6.5p/hr	75
Days rest of year – 06.30 to 20.00, 13.5 hrs/day $13.5 \times 167 = 2255$ units at, say 5p/hr	113
Total, per year	£422

Over a 25 year lifetime this would amount to a quite surprising £10 550 per kilowatt.

The cost of one kilowatt of copper loss can be calculated in a similar manner:

	£
Supply capacity charge (transformer at 66.6% load) – $0.443 \times$ £18	7.98
Maximum demand charge – $0.443 \times$ £40	17.72
Days Nov. to Feb., 10 hours per day during period 06.30 to 20.00 $0.443 \times 10 \times 86 = 381$ units at 6.5p	24.76
Days rest of year, 10 hours per day, same time of day $0.443 \times 10 \times 167 = 740$ units at 5p	37.00
Total, per year	£87.46

or approximately £2186 per kilowatt over a 25 year lifetime of the transformer.

Most accountants would not accept the above method of assessing lifetime cost, probably rightly so when a life of 25 years or more is expected, since costs incurred a long time ahead can be expected to have been eroded by inflation, or, alternatively to meet a commitment some years ahead cash can be set aside now which will accrue interest by the time the payment is due. An alternative viewpoint is that these losses will continue to have the same magnitude and the cost of energy will probably have increased roughly in line with inflation.

Generally the accountants' view prevails so that the cost of making provision for the lifetime cost of losses is expressed in terms of the sum which must be set aside now to pay for these. This can be calculated from the following expression:

$$C = \{a(1+b)^n + b - a\}/\{(1+b)^n - 1\} \tag{8.1}$$

where C is the cost per £ annual cost of losses
a is the rate of interest payable for loans at the date of purchase (expressed on a per unit basis)
b is the rate of interest obtainable on sinking funds (expressed on a per unit basis)
n estimated lifetime of the transformer in years

Typically, and for the purpose of illustrating this example, 'a' might be taken as 9% for a large organisation seeking a long-term loan and 'b' as 7%. For a value of 'n' equal to 25 years 'C' is then 0.1058

Hence the capitalised value of no-load loss is $422/0.1058 = £3988/\text{kW}$
and the capitalised value of load loss is $87.46/0.1058 = £827/\text{kW}$

These are the values for losses which it would be reasonable for an organisation such as the one described to use in its assessment of tenders for an additional transformer. The tenders and the assessment of them might typically be as in the following example.

Example 2 The following tenders have been received for a 1000 kVA 11/0.415 kV transformer:

Manufacturer	Tender price £	No-load loss kW	Load loss kW
A	9 000	2.3	15.25
B	12 460	1.2	12.9
C	9 500	1.8	14.0

Capitalising at £3988/kW for no-load loss and £827/kW for load loss gives the following assessed costs:

Manufacturer	A £	B £	C £
Capital cost	9 000	12 460	9 500
Cost of no-load loss	9 172	4 786	7 178
Cost of load loss	12 612	10 668	11 578
Totals	30 784	27 914	28 256

From this assessment, it can be seen that the lowest loss, highest priced option, offered by manufacturer B, provides the factory with the lowest lifetime cost. It should be noted, however, that the lifetime cost of a transformer from manufacturer C is only just over £340 greater than one from manufacturer B and buying this would save nearly £3000 now. It is therefore worthwhile carrying out a sensitivity check on the assumptions made. If the new transformer were only loaded to 60% of its capacity and not 66.6% as assumed, what effect would this have on the most economic option?

To check this is a fairly simple matter. Returning to the calculation above of the cost of load loss; substitution of a load factor of 0.60 instead of 0.666

would give a load loss factor of 0.36 instead of the figure of 0.443 used in the calculation. This would reduce the annual cost of 1 kW of load loss at nameplate rating to $(0.36 \times 87.46)/0.443 = £71.07/\text{kW}$. This in turn reduces the load loss capitalisation value to $71.07/0.1058 = £672/\text{kW}$.

Repeating the loss evaluation with this revised load loss capitalisation value gives the following figures:

Manufacturer	A	B	C
	£	£	£
Capital cost	9 000	12 460	9 500
Cost of no-load loss	9 172	4 786	7 178
Cost of load loss	10 248	8 669	9 408
Totals	28 420	25 915	26 086

and it can be seen that manufacturer B remains the most economic option. Provided the factory management are confident that the load factor on the new transformer is not likely to fall below about 0.60, they can justify the expenditure of the additional £3 000 initially.

Test discount rate

In the above example the lifetime cost of losses has been converted to an equivalent capital sum per kilowatt which will meet the lifetime costs. The purchaser may therefore either spend up to that additional sum at the outset for each kilowatt reduction in losses or alternatively set it aside to pay for the losses during the transformer lifetime. Both alternatives have the same weighting and there is therefore no constraint on the spending of extra capital initially, provided it will produce at least an equivalent saving in losses. The concept of test discount rates (t.d.r.) was originally applied to publicly owned utilities in the UK some years ago to control capital spending so as to ensure that extra expenditure was only incurred if it could produce real returns. The practice is still widely used by the now privatised utilities and the t.d.r. applied has varied between 5 and 10% over the years since its inception. The figure of 5% being normally used but this can be increased to 10% at times when cash is particularly tight. A 5% t.d.r. requires that any additional capital spent over and above that necessary for the basic scheme should show a return of 5%.

Applied to a capitalising rate of C per £ as derived in the example above, a t.d.r. of r% has the effect of multiplying the cost of losses by a factor k, where:

$$k = C/(C + r/100) \tag{8.2}$$

The effect of a 5% t.d.r. on the capitalised cost of losses in the above example is thus

$$k = 0.1058/(0.1058 + 0.05)$$

Hence $k = 0.679$

Cost of no-load loss thus becomes £2707/kW and cost of load loss £553/kW and it is now the case that greater initial expenditure to obtain lower losses will only be allowed if a real return can be obtained from that extra expenditure. Use of a t.d.r. greater than 5% reduces *k* and hence reduces the value placed on energy savings still further. If the management of the factory in the above example were to stipulate the use of a 5% t.d.r., the decision would clearly be in favour of saving money at the outset, as can be seen by repeating the above assessment process using these new loss values:

Manufacturer	A	B	C
	£	£	£
Capital cost	9 000	12 460	9 500
Cost of no-load loss	6 226	3 248	4 873
Cost of load loss	8 433	7 134	7 742
Totals	23 659	22 842	22 115

and there is now no doubt that the additional £3000 of expenditure over the cost of manufacturer C's tender cannot be justified.

The above example illustrates how the cost comparison process can be rationalised. It must be recognised, however, that the process is very greatly influenced by basic policy decisions such as the level of t.d.r. applied or whether any t.d.r. is applied at all. Thus, if a purchaser wishes to sway his assessment towards low first cost, he can do so and, conversely, if he wishes to invest more initially to provide energy efficient plant he can ensure that his procedures make this more likely.

Transformers for an electricity supply network

Although it is important to recognise that any system for assessment of losses such as that used in the above example can never be regarded as absolute, since no decision made today can take account of long-term changes in energy costs or of availability of investment capital, the industrial user of the example has the benefit of a known tariff structure and a fairly constant works system loading to enable him to make his estimates of the magnitude and cost of losses fairly easily. The operator of an electricity supply network is faced with a slightly more complex assessment process. For any new transformer installed on this network there will almost certainly be a daily cyclic variation in load as well as an annual summer/winter variation. In addition, there is the possibility of a load growth cycle resulting in the loading on a transformer after some years in service being greater than that applied on initial commissioning. All of these factors need to be taken into account in the loss capitalisation process.

In the UK, since privatisation, the distribution companies have been faced with the added complication of having to buy most of their energy from the energy market, thus encountering the added unpredictability of this system. The situation which existed previously was that they were simply required to pay the CEGB's Bulk Supply Tariff (BST) and were, in addition, provided with long-term predictions as to its likely magnitude. Whatever the actual method of payment, however, the cost of energy to the distribution companies has two main components and these remain, thus appearing as costs to be assigned to any source of losses within their network. These components represent a *capacity charge* and an *energy charge* and both are required to cover the marginal costs in meeting incremental increases in the demands of the system. In the days when the BST was in operation, these charges were identified as specific components of the BST. Now the distribution companies must rely on their own experience of energy trading and their own predictions of future trends in deciding the values to be placed upon them.

The capacity charge is a reflection of the long-term cost of providing the additional power (as distinct from simply energy) required to supply the additional losses. This will involve the cost of increasing the capacity of the distribution companies' own network as well as the cost of the additional generation and transmission plant which must be installed. The magnitude of the generation capacity charge is likely to be dependent on the requirement for the capacity at some specified critical time or times of the annual and daily load cycle, in the UK usually a weekday in December or January between the hours of 17.00 and 17.30 when the system loading is likely to be near to its highest.

The energy charge represents primarily the cost of the consumable element of supplying the losses, namely the additional fuel cost.

No-load losses are generally assumed to be constant and incur capacity and energy charges on this basis.

Load losses are, of course, variable according to the magnitude of the load squared. The daily and annual load loss factors are nowadays usually calculated by means of a computer program which can accurately reproduce the daily and annual patterns of load variation, making due allowance for the 'load squared' relationship.

It is also possible to allow some diversity for load losses. The diversity factor is defined as the sum of the load losses for all substations divided by the effective load losses taken from the supply. The value of the diversity factor will not differ greatly from unity. It is usually of the order 1.1–1.2.

All of these factors are then applicable to the value of load loss energy charge and the computer program can be arranged so that it has the necessary information concerning the critical times to enable it also to compute the load loss capacity charge.

The load growth cycle can be relatively easily accommodated and is best illustrated by means of an example.

Example 3 Typically a distribution network may consist of a number of 'two-transformer' substations in which two similar units share the load equally. The maximum peak load for this substation is limited by the capacity of the switchgear. Consider an 11 kV two-transformer substation having 1200 A switchgear, giving it a peak capacity of 23 MVA. In the event of a failure of one of the transformers, the other will be limited to 23 MVA.

Now suppose the annual rate of growth of load to be 7%. After six years the substation total load will have risen to 1.5 times the initial load, since $1.07^6 = 1.5$, but, if the load is not to exceed 23 MVA, then this must be the peak load at the time for reinforcement, and the initial load must thus be $23/1.5 = 15.3$ MVA, or 7.65 MVA per unit.

The load loss growth factor for the substation will, however, be equivalent to the r.m.s. load over the six year period which can be calculated by reference to *Figure 8.2*. The initial load on the substation is S and the load after n years is P, where

$$P = S(1+x)^n$$

x being the rate of load growth, expressed decimally.

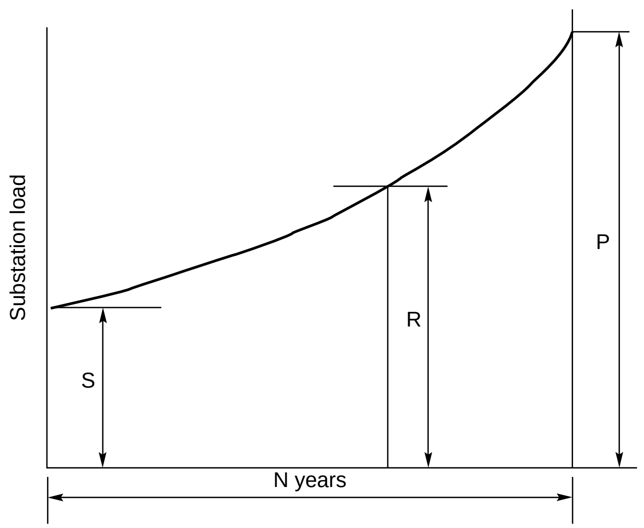

Figure 8.2 Calculation of r.m.s. load on a substation

The r.m.s. equivalent load is then

$$R = S\sqrt{\frac{(1+x)^{2n}-1}{2n\log_e(1+x)}}$$

$$= \frac{P}{(1+x)^n}\sqrt{\frac{(1+x)^{2n}-1}{2n\log_e(1+x)}}$$

Example 4 Using the values from above, $P = 23$ MVA, $S = 15.3$ MVA, $x = 0.07$, $n = 6$,

$$R = \frac{23}{1.5}\sqrt{\frac{1.07^{12} - 1}{12\log_e 1.07}}$$
$$= 23 \times 0.828$$
$$= 19.04 \text{ MVA}$$

This is the r.m.s. loading on the substation and the r.m.s. load on each transformer over the six year period is 9.5 MVA.

In the UK at the present time it is relatively uncommon to uprate a two-transformer substation with a third transformer due to the existing extent and interlinkage of the network. It is more usual to reinforce two two-transformer substations with a third substation or three two-transformer substations with a fourth substation. Still limiting the peak rating of one transformer to 23 MVA and based on a 7% annual growth rate, the r.m.s. loadings on the substations are:

two to three two-transformer substations	0.828
three to four two-transformer substations	0.865

In this situation it would probably be convenient to capitalise load losses for all purchases of transformers for this duty at an r.m.s. load factor of 0.85 times the appropriate factors resulting from daily and annual load cycles.

Capitalisation values

From the foregoing it is possible to calculate typical capitalisation values which might apply when purchasing transformers for the reinforcement of a distribution network. It must be stressed that the calculations are intended to illustrate how the process might be carried out and are not representative of the method or values used by any particular REC.

Example 5 No-load loss
Energy cost, 8760 hrs per year, say, 2.5p per unit = £219 per year.

Distribution companies might expect 40 years of life from a distribution transformer and could therefore capitalise these costs over 40 years. For this longer term basis it might, however, be appropriate to base the capitalisation on lower interest rates than those used in the earlier example. Inserting values of $a = 7\%$, $b = 5\%$ and $n = 40$ years in equation (8.1) gives the cost of capital as £0.0783 per £ of annual cost. Hence £219 per year is equivalent to a capital sum now of $219/0.0783 = £2796$.

A test discount rate of 5% might typically be applied to an investment of the type considered. Using this t.d.r. and the cost of capital C of £0.0783 per £ in equation (8.2) gives a discount factor of 0.632, so the nett energy cost is $£2796 \times 0.632 = £1767/\text{kW}$.

The total cost of no-load loss can then be computed as follows:

	£
Energy cost	1767
Capacity cost – paid to generation company	850
Capacity cost – own distribution system	260
	2877
Add 4% for additional system loss as a result of no-load loss	115
Total cost of no-load losses	£2992

Total cost of load loss is as follows:

	£
Energy cost – assuming nett load loss factor 0.2	354
Capacity cost $= \dfrac{850}{\text{Diversity factor}^2}$	
$= \dfrac{850}{(1.1 \times 1.15 \times 1.2)^2}$	369
(assuming diversities of 1.1, 1.15 and 1.2 respectively for each level of transformation above the new transformer)	
Capacity cost – own distribution system allowing for diversity	190
	913
Add 4% for system losses	37
Total cost of load losses	£950

Example 6 It is of interest to repeat the earlier assessment exercise carried out on the 1 MVA, 11/0.415 kV for the factory unit. The losses offered by the three manufacturers can be costed at £2992 for no-load loss and £950 for load loss to give the following assessed costs over the 40 years' anticipated lifetime:

Manufacturer	A	B	C
	£	£	£
Capital cost	9 000	12 460	9 500
Cost of no-load loss	6 882	3 590	5 386
Cost of load loss	14 487	12 255	13 300
Totals	30 369	28 305	28 186

It can be seen that the expensive low loss option is not the most attractive to the distribution company as it was for the factory, despite the fact that the loss savings will accrue for 40 years, and although the tenders from manufacturer B and C are very close in overall assessed costs, there is less incentive to repeat the sensitivity study as in the case of the factory transformer, since the option of having the lowest assessed cost is also very attractive on first cost.

Appendix 1
Transformer equivalent circuit

The calculations of a combined electrical system or circuit comprising transformers, transmission and distribution lines are often simplified by the use of the equivalent circuit diagram. The characteristics of a loaded transformer also can often be indicated more clearly by the same means. *Figure A1.1* shows the more general form of diagram of connections, and *Figure A1.2* the corresponding phasor diagram for a loaded transformer.

V_1	primary terminal voltage;
E_1	primary induced e.m.f.;
E_2	secondary induced e.m.f.;
V_2	secondary terminal voltage;
I_2	secondary load current;
I'_2	load component of total primary current;
I_1	total primary current (including I_0 and I'_2);
I_0	primary no-load current;
I_m	primary magnetising current;
I_c	primary core loss current;
R_1	primary reactance;
X_1	primary leakage reactance;
Z_1	primary impedance;
R_2	secondary resistance;
X_2	secondary leakage reactance;
Z_2	secondary impedance;
I_1R_1	primary resistance voltage drop;
I_1X_1	primary reactance voltage drop;
I_1Z_1	primary impedance voltage drop;

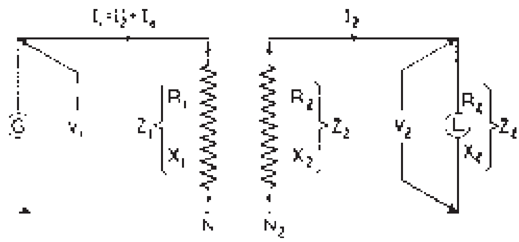

Figure A1.1 Circuit diagram

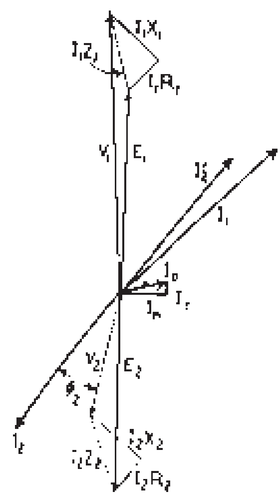

Figure A1.2 Phasor diagram of loaded transformers. Assumed turns ratio 1:1

I_2R_2	secondary resistance voltage drop;
I_2X_2	secondary reactance voltage drop;
I_2Z_2	secondary impedance voltage drop;
Rl	secondary load resistance;
Xl	secondary load reactance;
Zl	secondary load impedance;
N_1	primary turns;
N_2	secondary turns;
$\cos\phi_2$	secondary load power factor.

Figure A1.3 shows the equivalent circuit diagram corresponding to *Figure A1.1* and this applies to step-up and step-down transformers. This diagram enables the primary voltage V_1 necessary to maintain a given load voltage V_2 to be determined. Those characteristics of *Figure A1.3* which apply to the secondary circuit are shown as referred to the primary circuit by the turns ratio n. The admittance Y_0 (no-load current divided by the primary induced e.m.f.) is simply such as to represent the no-load characteristics of

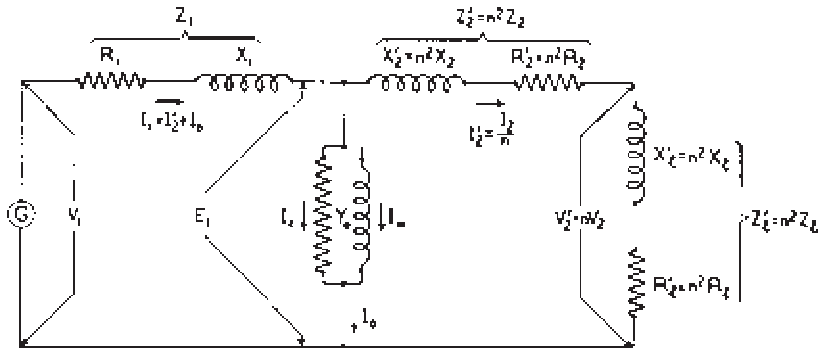

Figure A1.3 Equivalent circuit diagram for determining the primary voltage V_1

the transformer; that is, the resistance branch takes a current equal to the core-loss current, and the reactance branch takes a current equal to the true magnetising current. This method of treatment takes account of the efficiency of the transformer, and the copper losses appear as voltage drops. The phasor diagram corresponding to *Figure A1.3* is shown in *Figure A1.4*. E_1 is the e.m.f. across the admittance Y_0, and $V_1 - E_1$ is the voltage drop (which is not measurable) that is assumed to occur in the primary circuit if half the transformer reactance is allotted to the primary side of the transformer.

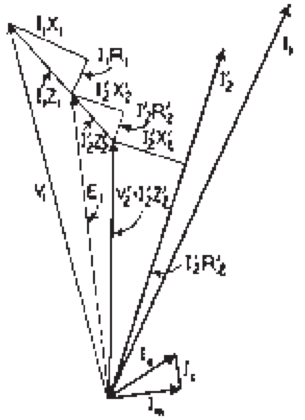

Figure A1.4 Phasor diagram of equivalent circuit shown in *Figure A1.3*

The required voltage V_1 can be calculated simply by multiplying the equivalent load current in the circuit by the total equivalent impedance of the circuit. In calculating the equivalent impedance, the individual equivalent ohmic resistances may be added arithmetically as also may be the equivalent ohmic reactances; including, of course, the equivalent load resistance and reactance;

the total equivalent impedance is then the phasor sum of the total equivalent resistances and reactances. This is illustrated in *Figure A1.5*. (This method neglects the very small phase displacements that exist between the individual ohmic impedances but the approximation is normally justified.)

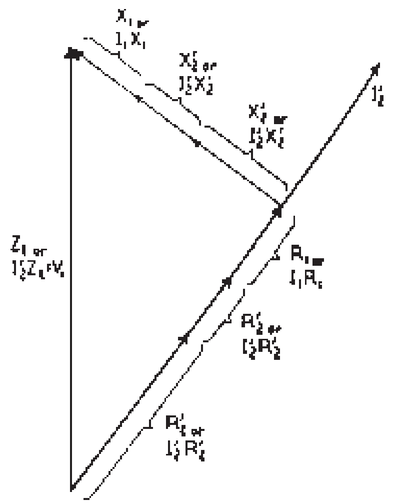

Figure A1.5 Resultant phasor diagram corresponding to *Figure A1.4*

Figure A1.6 is similar to *Figure A1.3* except that the notation is framed so as to enable the secondary load voltage V_2 at a given primary voltage V_1 to be determined. That is, the primary characteristics are referred to the secondary circuit by the turns ratio n.

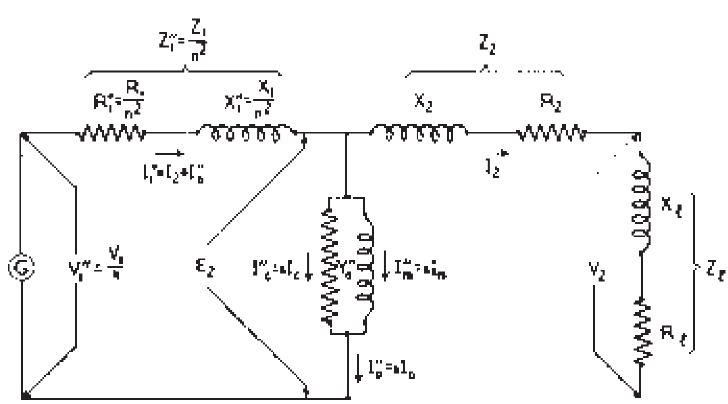

Figure A1.6 Equivalent circuit diagram for determining the secondary load voltage V_2

The phasor diagram corresponding to *Figure A1.6* is shown in *Figure A1.7* and the simplified phasor diagram for calculating the required voltage V_2 is shown in *Figure A1.8*. In constructing the latter diagram the very small phase displacements that exist between the individual ohmic impedances have again been neglected.

Example on Figure A1.3

Consider the case of a 200 kVA, 11 000/415 V, three-phase, delta/star, 50 Hz transformer.

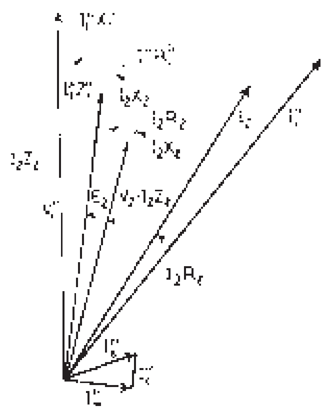

Figure A1.7 Phasor diagram of equivalent circuit shown in *Figure A1.6*

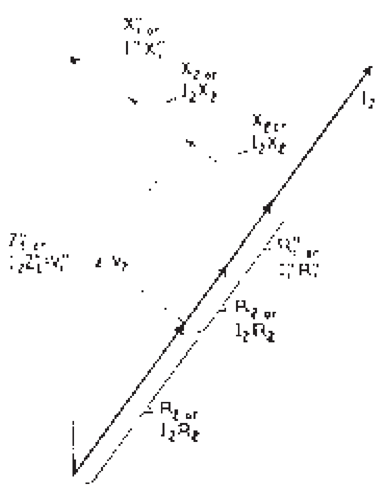

Figure A1.8 Resultant phasor diagram corresponding to *Figure A1.7*

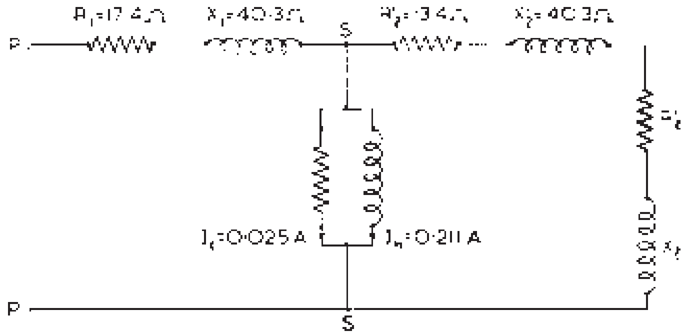

Figure A1.9 Equivalent circuit diagram for the given example

Tested phase voltage ratio $n = 11\,000\sqrt{3}/415 = 45.9$

and therefore $n^2 = 45.9^2 = 2110$

Tested core loss per phase $= 270$ watts

I_c per phase $= 270/11\,000 = 0.025$ A

Tested no-load current per phase $I_0 = 0.212$ A

I_n per phase $= \sqrt{(0.212^2 - 0.025^2)}$

$= 0.211$ A

Primary no-load power factor $\cos\phi_0 = 0.025/0.212 = 0.118$

and therefore $\phi_0 = 83.3^\circ$

Tested copper loss per phase $= 1130$ W $\left\{ \begin{array}{l} \text{Approximately 5\%} \\ \text{increase in losses on} \\ \text{calculated figure} \end{array} \right.$

Calculated copper loss per phase $= 1080$ W

Calculated primary resistance $= 16.6\ \Omega$

Actual primary resistance $R_1 = 16.6 \times 1.05$

$= 17.4\ \Omega$

Calculated secondary resistance $= 0.00606\ \Omega$

Actual secondary resistance $R_2 = 0.00606 \times 1.05\ \Omega$

$= 0.00637\ \Omega$

$R_2' = 0.00637 \times 2110\ \Omega$

$= 13.4\ \Omega$

Tested h.v. impedance per phase $= 524$ V at 6.06 A per phase therefore $Z'_e = 524/6.06 = 86.3\ \Omega$

and
$$X'_e = \sqrt{\{(Z'_e)^2 - (R_1 + R'_2)^2\}}$$
$$= \sqrt{\{86.3^2 - (17.4 + 13.4)^2\}}$$
$$= 80.6\ \Omega$$

Assuming the reactive voltage drop to be equal in the primary and secondary winding gives $X_1 = 40.3\ \Omega$, and $X'_2 = 40.3\ \Omega$.

The phase constants of the transformer derived from test figures are thus

$n = 45.9$	$\phi_0 = 83.2^\circ$
$n^2 = 2110$	$R_1 = 17.4\ \Omega$
$I_c = 0.025$ A	$R'_2 = 13.4\ \Omega$
$I_0 = 0.212$ A	$X_1 = 40.3\ \Omega$
$I_m = 0.211$ A	$X'_2 = 40.3\ \Omega$

(a) With an applied primary terminal voltage V_1 of 11 000 V it is required to find the secondary terminal voltage V_2 when the transformer supplies a secondary load of 200 kVA at a power factor $\cos\phi_2 = 0.8$ lagging.

All calculations are made on a phase to neutral basis.

It is necessary to start by assuming a value of V_2, say 288 V (i.e. assuming a 5% drop).

$$I_2 = 200\,000/(\sqrt{3} \times 228 \times \sqrt{3}) = 292\ \text{A}$$
$$I'_2 = 292/45.9 = 6.36\ \text{A}$$
$$R\ell = (V_2 \cos\phi_2)/I_2 = 228 \times 0.8/292 = 0.624\ \Omega$$
$$R\ell' = 0.624 \times 2110$$
$$= 1310\ \Omega$$
$$X_1 = (V_2 \sin\phi_2)/I_2$$
$$= 228 \times 0.6/292$$
$$= 0.468\ \Omega$$
$$X\ell' = 0.468 \times 2110$$
$$= 987\ \Omega$$

Resistance drop to SS $= I'_2(Rl' + R'_2) = 6.36(1310 + 13.4) = 8420$ V
Reactance drop to SS $= I'_2(Xl' + X'_2) = 6.36(987 + 40.3) = 6540$ V

$$\phi_{ss} = \tan^{-1} 6540/8420 = \tan^{-1} 0.776 = 37.8^\circ$$
$$I_1 = \sqrt{\{[I'_2 + I_0 \cos(\phi_0 - \phi_{ss})]^2 + [I_0 \sin(\phi_0 - \phi_{ss})]^2\}}$$

$$= \sqrt{\{[6.36 + 0.212\cos(83.2^\circ - 37.8^\circ)]^2 + [0.212\sin(83.2^\circ - 37.8^\circ)]^2\}}$$
$$= 6.51 \text{ A}$$

Primary line current $= 6.51 \times \sqrt{3} = 11.3$ A

$$\theta_1 = \tan^{-1}\frac{I_0\sin(\phi_0 - \phi_{ss})}{I_2' + I_0\cos(\phi_0 - \phi_{ss})}$$
$$= \tan^{-1}\frac{0.212\sin(83.2^\circ - 37.8^\circ)}{6.36 + 0.212\cos(83.2^\circ - 37.8^\circ)}$$
$$= \tan^{-1} 0.0232 = 1.3^\circ$$

Resistance drop to PP $= 8420 + I_1R_1 = 8420 + 6.51 \times 17.4 = 8530$ V
Reactance drop to PP $= 6540 + I_1X_1 = 6540 + 6.51 \times 40.3 = 6800$ V

$$V_1 = \sqrt{(8530^2 + 6800^2)} = 10\,910 \text{ V}$$

$$\text{Percentage regulation} = \frac{V_1 - V_2'}{V_1} \times 100$$
$$= \frac{10\,910 - 228 \times 45.9}{10\,910} \times 100 = 4.2\%$$

Thus, with $V_1 = 11\,000$ V

we have $V_2 = 11\,000\dfrac{100 - 4.2}{100} \times \dfrac{1}{45.9}$

i.e. $V_2 = 230$ V

Secondary terminal line voltage $= 230\sqrt{3} = 398$ V

$$(\phi_1 - \theta_1) = \tan^{-1} 6800/8530 = \tan^{-1} 0.798 = 38.6^\circ$$
$$\phi_1 = 38.6^\circ + 1.3^\circ = 39.9^\circ$$
$$\cos\phi_1 = 0.767$$

Power input $= V_1I_1\cos\phi_1 = 10\,910 \times 6.51 \times 0.767 = 54\,500$ watts
Power output $= V_2I_2\cos\phi_2 = 228 \times 292 \times 0.8 = 53\,300$ watts
therefore percentage efficiency $= (53\,300/54\,500)100 = 97.80\%$.
With $V_1 = 11\,000$ V and $V_2 = 230$ V,
the corrected value of $I_2 = 200\,000/(\sqrt{3} \times 230 \times \sqrt{3}) = 290$ A
and, the corrected value of $I_2' = 290/45.9 = 6.32$ A.
The corrected value of $R\ell' = 230 \times 0.8 \times 2110/290 = 1340\ \Omega$
and, the corrected value of $X\ell' = 230 \times 0.6 \times 2110/290 = 1000\ \Omega$.

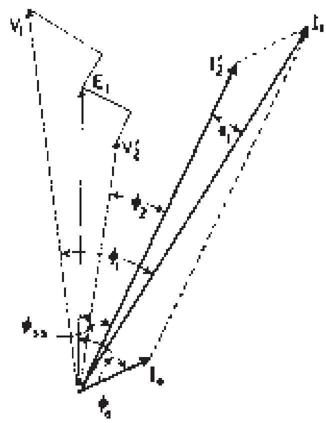

Figure A1.10 Phasor diagram

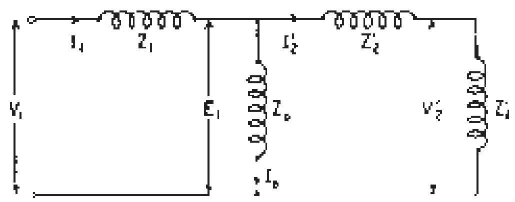

Figure A1.11 The general form of Figure A1.9

(*b*) Results can also be obtained by means of the symbolic method which allows for the very small phase displacements between the individual ohmic impedances. Consider the general form of *Figure A1.9* as shown in *Figure A1.11*:

It can be derived that

$$V_2' = \frac{V_1 Z\ell' Z_0}{(Z\ell' + Z_2')(Z_0 + Z_1) + Z_1 Z_0} \tag{A1.1}$$

$$I_1 = \frac{V_1(Z_0 + Z_2' + Z\ell')}{(Z\ell' + Z_2')(Z_0 + Z_1) + Z_1 Z_0} \tag{A1.2}$$

$$I_2' = \frac{V_1 Z_0}{(Z\ell' + Z_2')(Z_0 + Z_1) + Z_1 Z_0} \tag{A1.3}$$

In order to determine Z_0 it is first necessary to calculate E_1.

$$\begin{aligned} E_1 &= V_2 + I_2' Z_2' \\ &= 230 \times 45.9(0.8 + j0.6) + 6.32(13.4 + j40.3) \\ &= 8530 + j6590 = 10\,800 \text{ V} \end{aligned}$$

$$
\begin{aligned}
Z_0 &= E_1/I_0 = E_1/(I_c - jI_m) \\
&= \frac{E_1 I_c}{I_c^2 + I_m^2} + j\frac{E_1 I_m}{I_c^2 + I_m^2} \\
&= \frac{10\,800 \times 0.025}{0.025^2 + 0.211^2} + j\frac{10\,800 \times 0.211}{0.025^2 + 0.211^2} \\
&= 5990 + j50\,500\ \Omega
\end{aligned}
$$

Thus,

$$
\begin{aligned}
Z_1 &= 17.4 + j40.3\ \Omega \\
Z_2' &= 13.4 + j40.3\ \Omega \\
Z_0 &= 5990 + j50\,500\ \Omega \\
Z\ell' &= 1340 + j1000\ \Omega
\end{aligned}
$$

and $(Z\ell' + Z_2')(Z_0 + Z_1) + Z_1 Z_0 = (-46.3 + j75.6)10^6$.

Thus, substituting these values in equation (A1.1),

$$
\begin{aligned}
V_2' &= \frac{11\,000(1340 + j1000)(5990 + j50\,500)}{(-46.3 + j75.6)10^6} \\
&= 10\,540\ \overline{\backslash 1.6^\circ}\ \text{V} \\
V_2 &= 10\,540/45.9 = 230\ \text{V}
\end{aligned}
$$

and the secondary terminal line voltage $= 230\sqrt{3} = 398$ V.

Substituting in equation (A1.2),

$$
\begin{aligned}
I_1 &= \frac{11\,000(5990 + j50\,500 + 13.4 + j40.3 + 1340 + j1000)}{(-46.3 + j75.6)10^6} \\
&= 6.45\ \overline{\backslash 39.6^\circ}\ \text{A}
\end{aligned}
$$

Primary line current $= 6.45\sqrt{3}\overline{\backslash 39.6^\circ} = 11.2$ A

$$
\begin{aligned}
\cos\phi_1 &= \cos 39.6^\circ \\
&= 0.771 \\
\text{Power input} &= V_1 I_1 \cos\phi_1 \\
&= 11\,000 \times 6.45 \times 0.771 \\
&= 54\,600\ \text{watts}
\end{aligned}
$$

Substituting in equation (A1.3),

$$I_2' = \frac{11\,000(5990 + j50\,500)}{(-46.3 + j75.6)10^6} = 6.31\overline{\backslash 38.3^\circ}\text{A}$$

and $I_2 = 6.31 \times 45.9\ \overline{\backslash 38.3^\circ}\text{A} = 290\overline{\backslash 38.3^\circ}$ A

Power input $= V_2 I_2 \cos\phi_2 = 230 \times 290 \times 0.8 = 53\,300$ watts

Percentage efficiency $= (53\,300/54\,600)100 = 97.62\%$.

Thus it will be seen that the results obtained by the two methods of calculation show close agreement.

Appendix 2
Geometry of the transformer phasor diagram

The following diagrams and equations apply equally well to single-phase transformers and to the individual phases of polyphase transformers.

Specification data

V_1	primary terminal voltage
V_2	secondary terminal voltage
I'_2	load component of total primary current
I_1	total primary current
I_2	secondary load current
$n(= N_1/N_2 = E_1/E_2)$	turns ratio
$\cos\phi_2$	secondary load power factor

Test data

R_1	primary resistance
R_2	secondary resistance
$I'_2Z'_e$	total equivalent impedance voltage drop (referred to the primary side)
$I_2Z''_e$	total equivalent impedance voltage drop (referred to the secondary side)
I_0	primary no-load current
I''_0	secondary no-load current
P_f	iron loss

For the phasor diagram see *Figure A2.1*. Voltage drops due to no-load current are ignored.

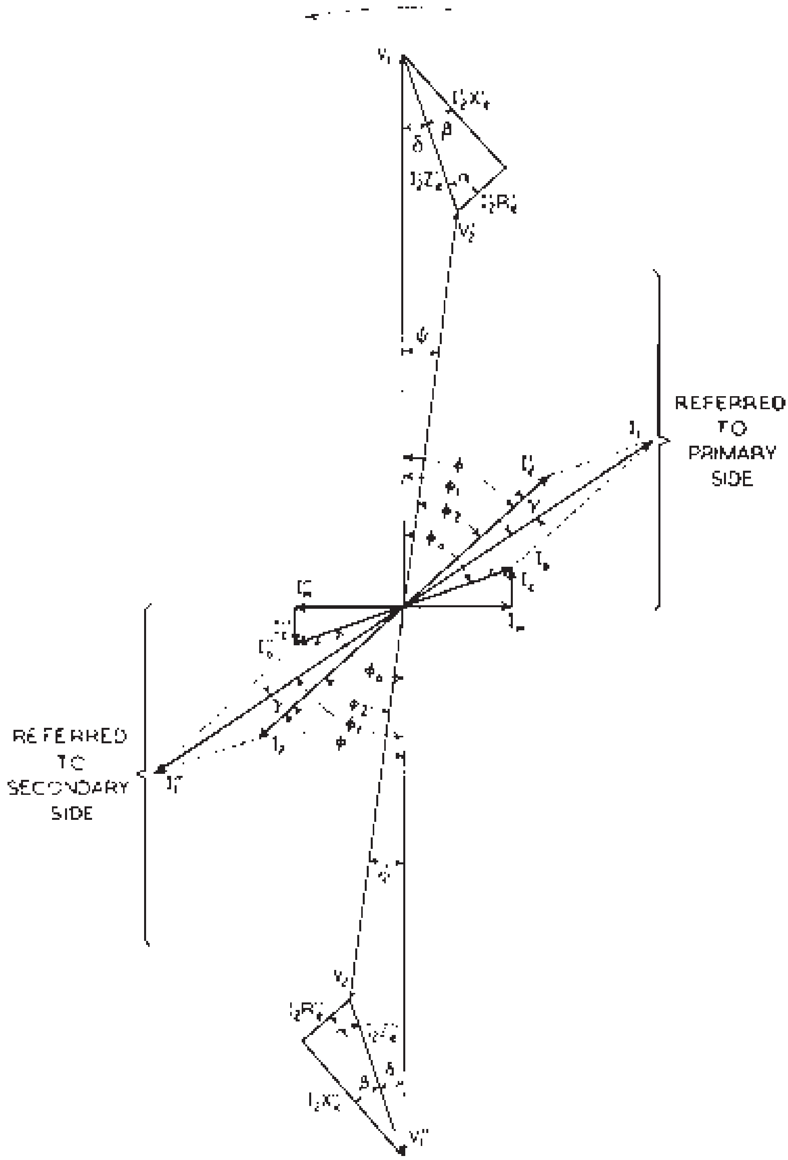

Figure A2.1 Phasor diagram for no-load and for load conditions

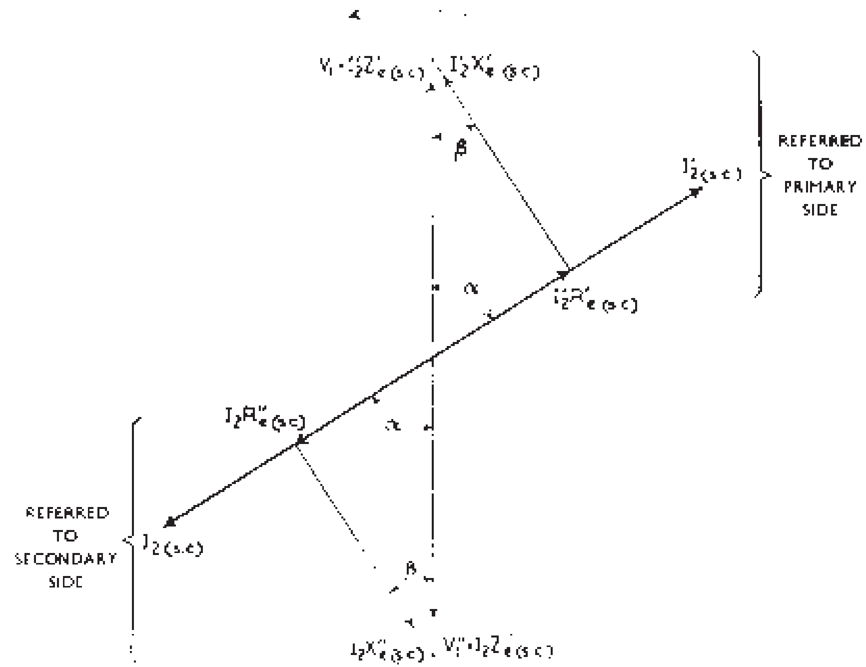

Figure A2.2 Phasor diagram for short-circuit conditions

Table A2.1

Characteristics referred to	Primary side	Secondary side
No-load (Figure A2.1)		
(1) Primary terminal voltage	V_1	$V_1'' = V_1/n$
(2) Secondary terminal voltage	$V_2' = nV_2$	V_2
(3) Primary no-load current	I_0	$I_0'' = nI_0$
(4) Primary core loss current	$I_c = P_f/V_1$	$I_c'' = nI_c = P_f/V_1''$
(5) Primary magnetising current	$I_m = \sqrt{I_0^2 - I_c^2}$	$I_m'' = nI_m = \sqrt{\{(I_0'')^2 - (I_c'')^2\}}$
(6) Primary no-load power factor	$\cos\phi_0 = I_c/I_0$	$\cos\phi_0 = I_c''/I_0'' = I_c/I_0$
On-load (Figure A2.1)		
(7) Secondary load current	$I_2' = I_2/n$	I_2
(8) Secondary load power factor	$\cos\phi_2$	$\cos\phi_2$
(9) Load component of total primary current	I_2'	$I_2 = nI_2'$
(10) Total primary current	$I_1 = \sqrt{\{(I_2'\cos\phi + I_c)^2 + (I_2'\sin\phi + I_m)^2\}}$	$I_1'' = nI_1 = \sqrt{\{(I_2\cos\phi + I_c'')^2 + (I_2\sin\phi + I_m'')^2\}}$
(11) Primary total load power factor	$\cos\phi_1 = \cos\ \tan^{-1}\dfrac{I_2'\sin\left\{\sin^{-1}\left(\dfrac{I_2'Z_e'}{V_1}\cos\overline{\beta+\phi_2}\right.\ +\phi_2\right\}+I_m}{I_2'\cos\left\{\sin^{-1}\left(\dfrac{I_2'Z_e'}{V_1}\cos\overline{\beta+\phi_2}\right.\ +\phi_2\right\}+I_c}$	$\cos\phi_1 = \cos\ \tan^{-1}\dfrac{I_2\sin\left\{\sin^{-1}\left(\dfrac{I_2Z_e''}{V_1''}\cos\overline{\beta+\phi_2}\right.\ +\phi_2\right\}+I_m''}{I_2\cos\left\{\sin^{-1}\left(\dfrac{I_2Z_e''}{V_1''}\cos\overline{\beta+\phi_2}\right.\ +\phi_2\right\}+i_c''}$

(*continued overleaf*)

Table A2.1 *(continued)*

Characteristics referred to	*Primary side*	*Secondary side*
(12) Primary resistance	R_1	$R_1'' = R_1/n^2$
(13) Secondary resistance	$R_2' = n^2 R_2$	R_2
(14) Total equivalent resistance	$R_e' = R_1 + R_2' = n^2 R_c''$	$r_e'' = R_1'' + R_2 = R_e'/n^2$
(15) Total equivalent resistance voltage drop	$I_2' R_e' = nI_2 R_e''$	$I_2 R_e'' = I_2' R_e'/n$
(16) Total equivalent reactance voltage drop	$I_2' X_e' = nI_2 X_e''$	$I_2 X_e'' = I_2' X_e'/n$
(17) Total equivalent impedance voltage drop	$I_2' Z_e' = nI_2 Z_e''$	$I_2 Z_e'' = I_2' X_e'/n$
(18) Voltage regulation	$\lvert V_1 - V_2' \rvert = I_2' R_e' \cos\phi_2 + I_2' X_e' \sin\phi_2 + + \dfrac{(I_2' X_e' \cos\phi_2 - I_2' R_e' \sin\phi_2)^2}{200}$	$\lvert V_1'' - V_2 \rvert = (\lvert V_1 - V_2 \rvert)/n = I_2 R_e'' \cos\phi_2 + I_2 X_e'' \sin\phi_2 + + \dfrac{(I_2 X_e'' \cos\phi_2 - I_2 R_e'' \sin\phi_2)^2}{200}$
(19) α	$\cos^{-1}(I_2' R_e'/I_2' Z_e')$ or $\sin^{-1}(I_2' X_e'/I_2' Z_e')$	$\cos^{-1}(I_2 R_e''/I_2 Z_e'')$ or $\sin^{-1}(I_2 X_e''/I_2 Z_e'')$
(20) β	$\cos^{-1}(I_2' X_e'/I_2' Z_e')$ or $\sin^{-1}(I_2' R_e'/I_2' Z_e')$	$\cos^{-1}(I_2 X_c''/I_2 Z_e'')$ or $\sin^{-1}(I_2 R_2''/I_2 Z_e'')$
(21) γ	$2\left(\cos^{-1} \quad \dfrac{S'(S' - I_0)}{I_1 I_2'}\right.$ where, $S' = \dfrac{1}{2}(I_1 + I_2' + I_0)$	$2\left(\cos^{-1} \quad \dfrac{S''(S'' - I_0'')}{I_1'' I_2}\right.$ where, $S' = \dfrac{1}{2}(I_1'' + I_2 + I_0'')$

(22)	δ	$2\left(\cos^{-1} \dfrac{U'(U'-V_2')}{V_1 I_2' Z_e'}\right.$ where, $U' = \frac{1}{2}(V_1 + V_2' + I_2' Z_e')$	$2\left(\cos^{-1} \dfrac{U''(U''-V_2)}{V_1'' I_2 Z_e''}\right.$ where, $U'' = \frac{1}{2}(V_1'' + V_2 + I_2 Z_e'')$
(23)	ψ	$2\left(\cos^{-1} \dfrac{U'(U'-I_2' Z_e')}{V_1 V_2'}\right.$ where, $U' = \frac{1}{2}(V_1 + V_2' + I_2' Z_e')$	$2\left(\cos^{-1} \dfrac{U''(U''-I_2 Z_e'')}{V_1'' V_2}\right.$ where, $U'' = \frac{1}{2}(V_1'' + V_2 + I_2 Z_e'')$
(24)	ϕ	$\phi_2 + \psi$	$\phi_2 + \psi$
	On short circuit (Figure A2.2)		
(25)	Total equivalent resistance voltage drop	$I_2' R_e'(S.C.) = I_2' R_e' V_1 / I_2' Z_e'$	$I_2 R_e''(S.C.) = I_2 R_e'' V_1'' / I_2 Z_e''$
(26)	Total equivalent reactance voltage drop	$I_2' X_e'(S.C.) = I_2' X_e' V_1 / I_2' Z_e'$	$I_2 X_e''(S.C.) = I_2 X_e'' V_1'' / I_2 Z_e''$
(27)	Total equivalent impedance voltage drop	$I_2' Z_e'(S.C.) = V_1$	$I_2 Z_e''(S.C.) = V_1''$
(28)	Short circuit current	$I_2'(S.C.) = I_2' V_1 / I_2' Z_e'$ (no-load current ignored)	$I_2(S.C.) = I_2 V_1'' / I_2 Z_e''$
(29)	α	$\cos^{-1}(I_2' R_2'(S.C.)/I_2' Z_e'(S.C.))$ or $\sin^{-1}(I_2' X_e'(S.C.)/I_2' Z_e'(S.C.))$	$\cos^{-1}(I_2 R_e''(S.C.)/I_2 Z_e''(S.C.))$ or $\sin^{-1}(I_2 X_e''(S.C.)/I_2 Z_e''(S.C.))$
(30)	β	$\cos^{-1}(I_2' X_e'(S.C.)/I_2' Z_e'(S.C.))$ or $\sin^{-1}(I_2' R_e'(S.C.)/I_2' Z_e'(S.C.))$	$\cos^{-1}(I_2 X_e''(S.C.)/I_2 Z_e''(S.C.))$ or $\sin^{-1}(I_2 R_e''(S.C.)/I_2 Z_e''(S.C.))$

Appendix 3
The transformer circle diagram

By means of the circle diagram the loci of the ends of the phasors representing terminal voltages and currents in single and polyphase transformers may be located at all power factors and all loads.

The amounts of, and the phasor relations between, the primary and secondary voltages and currents under any conditions of load and power factor may be determined and the regulation may be obtained graphically.

Referring all quantities to the secondary side, and working on a 'per phase' basis:

Let N_1 and N_2 be the number of primary and secondary turns respectively.

V_1''	primary terminal voltage, reversed in time phase and multiplied by the ratio N_2/N_1
V_2	secondary terminal voltage
I_1''	total primary full-load current, reversed in time phase and multiplied by the ratio N_1/N_2
I_2	secondary full-load current
I_0''	primary no-load current, reversed in time phase and multiplied by the ratio N_1/N_2
I_c''	primary core loss current, reversed in time phase and multiplied by the ratio N_1/N_2
I_m''	primary magnetising current, reversed in time phase and multiplied by the ratio N_1/N_2
$\cos\phi_0$	primary no-load power factor
$\cos\phi_1$	primary total load power factor
$\cos\phi_2$	secondary load power factor
R_e''	total equivalent resistance

X''_e total equivalent reactance
Z''_e total equivalent impedance

Note: If it is desired to refer quantities to the primary side, the secondary current phasors must be reversed in time phase and multiplied by the ratio N_2/N_1, and the secondary voltage phasors must be reversed in time phase and multiplied by the ratio N_1/N_2. In addition, the values of resistance, reactance and impedance as referred to the secondary side must be multiplied by the ratio $(N_1/N_2)^2$ in order to transfer them to the primary side. In calculating the resistance, reactance and impedance voltage drops, the effect of the no-load current has been ignored.

The following quantities can be obtained from design calculations as well as from the test results:

Total iron loss, total copper loss, percentage reactance, and percentage magnetising current.

Then,
$$I''_m = \frac{\text{percentage magnetising current}}{100} I_2 \text{ amperes}$$
$$I''_c = \frac{\text{total watts iron loss}}{\text{number of phases } V''_1} \text{ amperes}$$
$$I''_0 = \sqrt{\{(I''_m)^2 + (I''_c)^2\}}$$
$$X''_c = \frac{\text{percentage reactance}}{100} \frac{V''_1}{I''_1} \text{ ohms}$$
$$R''_e = \frac{\text{total watts copper loss}}{\text{number of phases } {I_2}^2} \text{ ohms}$$
$$Z = \sqrt{(X^2 + R^2)} \text{ ohms}$$
$$Z''_e = \sqrt{\{(X''_e)^2 + (R''_e)^2\}} \text{ ohms}$$

CONSTRUCTION OF CIRCLE DIAGRAMS
(see *Figures A3.1, A3.2)*

First draw the phasor OA $= V''_1$. With centre A and radius $= I''_2 Z''_e$ describe the circle BCD. This circle is the locus of the end of the secondary load terminal voltage phasor V_2 for various values of $\cos\phi_2$.

Draw the radius CA of the circle BCD such that O$\hat{\text{A}}$C $= \beta$ where $\cos\beta = X''_2/Z''_e$. Draw YY′, the right bisector of OA. Now draw AQ so that C$\hat{\text{A}}$Q $= \phi_2$, the phase angle of the secondary load current, and let AQ cut YY′ in Q.

(*Note*: If ϕ_2 is lagging, draw C$\hat{\text{A}}$Q clockwise; if ϕ_2 is leading, draw C$\hat{\text{A}}$Q counter-clockwise.) With centre Q and radius QA describe an arc cutting the first circle BCD in B. Join OB, AB. Then OB $= V_2$.

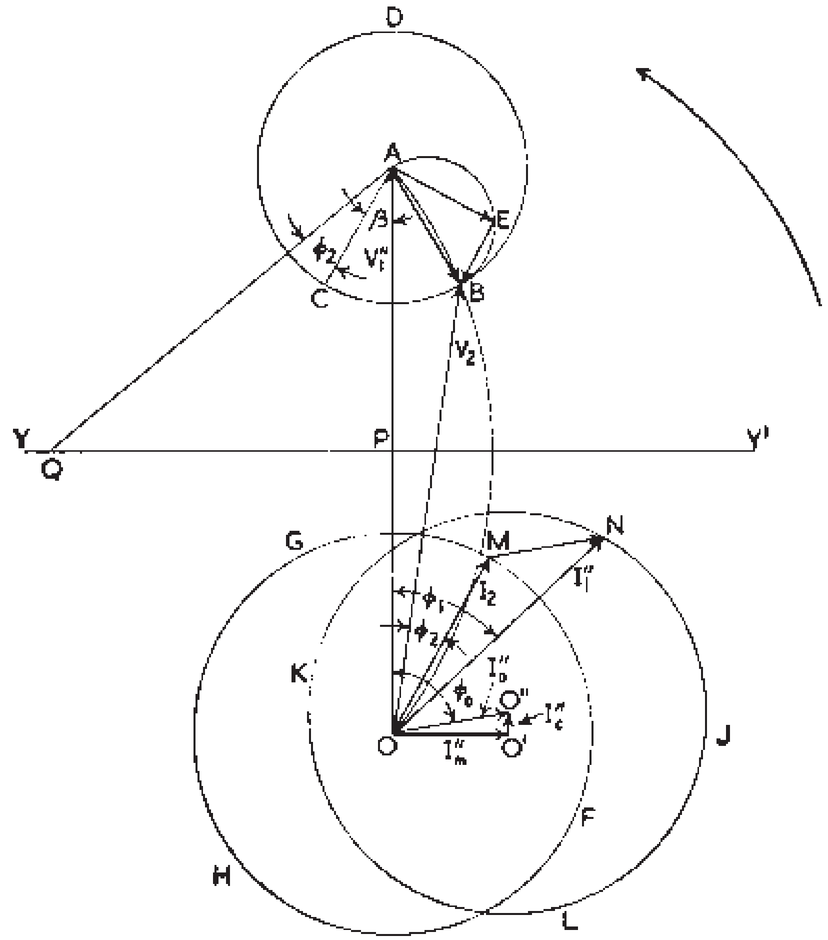

Figure A3.1 Circle diagram – lagging power factor load

Draw OO$'$ $= I_m''$ at right angles to OA, and O$'$O$''$ $= I_c''$ parallel to OA. Then OO$''$ $= I_0''$. With centres O and O$''$ and radii $= I_2$, draw two circles FGH and JKL as shown in *Figures A3.1, A3.2*.

Draw the radius OM of the circle FGH such that B$\hat{\text{O}}$M $= \phi_2$; then OM $= I_2$. Draw MN parallel to OO$''$, cutting the circle JKL in N. Join ON. Then ON $= I_1''$ and A$\hat{\text{O}}$N $= \phi_1$ = primary input current phase angle, i.e. primary input power factor $= \cos\phi_1$.

Also the phase angle of the primary no-load current = A$\hat{\text{O}}$O$''$ $= \phi_0$, i.e. the primary no-load power factor $= \cos\phi_0$.

It is evident that,

$$\cos\phi_0 = I_c''/I_0''$$

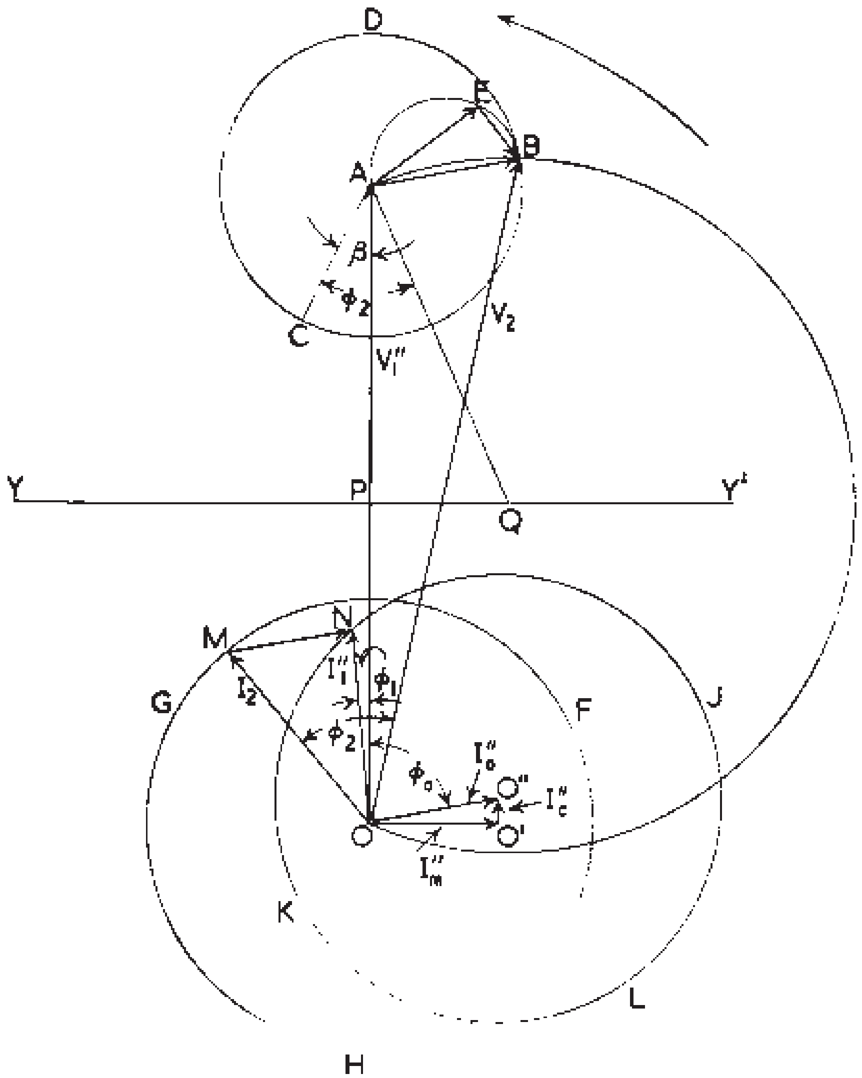

Figure A3.2 Circle diagram – leading power factor load

and it may be shown that,

$$\cos\phi_1 = \cos\quad \tan^{-1}\frac{I_2\sin\quad \sin^{-1}\left(\frac{I_2 Z_e''}{V_1''}\overline{\cos\beta+\phi_2}\quad+\phi_2\quad+I_m''\right.}{I_2\cos\quad \sin^{-1}\left(\frac{I_2 Z_e''}{V_1''}\overline{\cos\beta+\phi_2}\quad+\phi_2\quad+I_c''\right.}$$

On AB as diameter, describe a semicircle ABE. Draw BE parallel to OM, cutting the semicircle ABE in E. Join AE.

Then,

$$\text{BE} = I_2 R_e'' = \text{total resistance voltage drop per phase referred to the secondary side,}$$

and

$$\text{AE} = I_2 X_e'' = \text{reactance voltage drop per phase referred to the secondary side.}$$

The percentage regulation is given by the expression,

$$\text{percentage regulation} = \frac{\text{OA} - \text{OB}}{\text{OA}} \times 100$$

Appendix 4
Transformer regulation

The standard formula for determining the percentage regulation of a transformer at full load and at a power factor $\cos\phi$ is,*

$$V_X \sin\phi_2 + V_R \cos\phi_2 + \frac{(V_x \cos\phi_2 - V_R \sin\phi_2)^2}{200} \tag{A4.1}$$

where V_X = percentage reactance voltage at full load
V_R = percentage resistance voltage at full load
ϕ = angle of lag of the full-load current

This formula is correct for the determination of the regulation at any load differing from full load, and it is only necessary to divide V_x and V_R wherever they appear in the formula by the factor given by dividing the full-load current by the current corresponding to the particular load at which the regulation is desired. In most practical cases the load current flowing through a transformer has lagging power factor so that no doubts can arise with regard to the correct signs to be used, for these are exactly as given in the above general equation. From time to time, however, it is necessary to calculate the regulation for currents at leading power factors and it is, therefore, interesting to consider whether the standard formula given above applies in such cases.

Like many other problems of this kind, the solution can be obtained from the geometry of the figure, and the following investigation has been conducted upon this basis, referring all quantities to the secondary side, and working on a per phase basis.

* For impedances above 20% refer to Chapter 1.

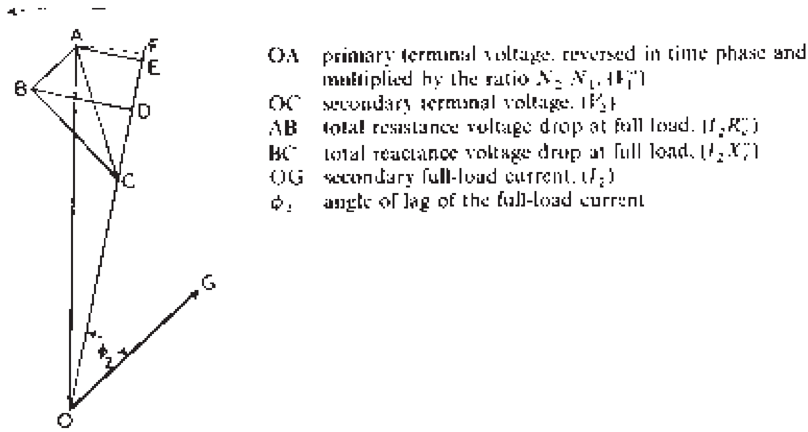

Figure A4.1 Regulation diagram – lagging power factor load

Drop perpendiculars from A and B to OC produced, meeting OC produced at E and D respectively. With radius OA and centre O draw an arc AF to meet OC produced at F.

$$\text{Power factor} = \cos\phi_2 = \cos \mathrm{C\hat{O}G}$$

Since AB is parallel to OG, AB must make an angle ϕ_2 with OC produced and BC must make an angle $90^\circ - \phi_2$ with OC.

$$\begin{aligned}
\text{Percentage regulation} &= 100\frac{\mathrm{OA} - \mathrm{OC}}{\mathrm{OA}} \\
&= 100\frac{\mathrm{OF} - \mathrm{OC}}{\mathrm{OA}} \\
&= 100\frac{\mathrm{CF}}{\mathrm{OA}} \\
&= 100\left(\frac{\mathrm{CD} + \mathrm{DE} + \mathrm{EF}}{\mathrm{OA}}\right. \\
&= 100\left(\frac{\mathrm{BC}\sin\phi_2 + \mathrm{AB}\cos\phi_2}{\mathrm{OA}} + \frac{\mathrm{EF}}{\mathrm{OA}}\right. \\
&= V_X \sin\phi_2 + V_R\cos\phi_2 + 100\frac{\mathrm{EF}}{\mathrm{OA}}
\end{aligned}$$

where V_X and V_R are the percentage reactance and resistance voltage drops at full load respectively.

In order to evaluate EF it must be remembered that OF is the radius of a circle and that AE is a perpendicular to it from a point on the circumference, and that, therefore,

$$\frac{\mathrm{EF}}{\mathrm{AE}} = \frac{\mathrm{AE}}{\mathrm{OE} + \mathrm{OF}}$$

$$\mathrm{EF} = \frac{\mathrm{AE}^2}{\mathrm{OE} + \mathrm{OF}}$$

Now although EF may be appreciable compared with CF, it is negligible compared with so large a quantity as OE + OF, and therefore it is permissible to write 20F for the latter.

Thus $$\mathrm{EF} = \frac{\mathrm{AE}^2}{2\mathrm{OF}} = \frac{\mathrm{AE}^2}{2\mathrm{OA}}$$

therefore $$100\frac{\mathrm{EF}}{\mathrm{OA}} = 100\frac{\mathrm{AE}^2}{2\mathrm{OA}^2}$$

$$= 100\frac{(\mathrm{BC}\cos\phi_2 - \mathrm{AB}\sin\phi_2)^2}{2\mathrm{OA}^2}$$

$$= \frac{(V_X\cos\phi_2 - V_R\sin\phi_2)^2}{200}$$

$$\text{percentage regulation} = V_X\sin\phi_2 + V_R\cos\phi_2 + \frac{(V_X\cos\phi_2 - V_R\sin\phi_2)^2}{200}$$

In *Figure A4.2* the power factor of the load

$= \cos\theta_2$ leading

$= \cos(360^\circ - \theta_2)$ lagging

$= \cos\phi_2$ lagging

AB and BC make angles θ_2 and $90^\circ - \theta_2$ respectively with OC.

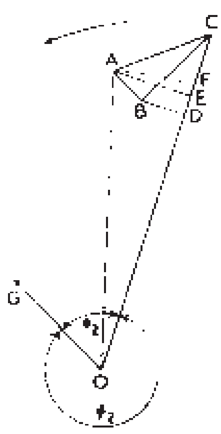

Figure A4.2 Regulation diagram – leading power factor load

Therefore,

$$\begin{aligned}\text{percentage regulation} &= 100\frac{(\mathrm{OA}-\mathrm{OC})}{\mathrm{OA}}\\ &= 100\frac{(\mathrm{OF}-\mathrm{OC})}{\mathrm{OA}}\\ &= 100\frac{(-\mathrm{CF})}{\mathrm{OA}}\\ &= 100\frac{(-\mathrm{CD}+\mathrm{DE}+\mathrm{EF})}{\mathrm{OA}}\\ &= -V_X\sin\theta_2+V_R\cos\theta_2+100\frac{\mathrm{AE}^2}{2\mathrm{OA}^2}\\ &= -V_X\sin\theta_2+V_R\cos\theta_2+\frac{(V_X\cos\theta_2+V_R\sin\theta_2)^2}{200}\end{aligned}$$

Now,

$$\theta_2 = 360^\circ - \phi_2$$

and therefore,

$$\sin\theta_2 = -\sin\phi_2$$

$$\cos\theta_2 = \cos\phi_2$$

and percentage regulation

$$= V_X\sin\phi_2 + V_R\cos\phi_2 + \frac{(V_X\cos\phi_2 - V_R\sin\phi_2)^2}{200} \tag{A4.2}$$

It will be seen from equations (A4.1) and (A4.2) that the final regulation formula is the same for lagging and leading power factors provided the angle ϕ_2 is the true angle of lag measured clockwise from the position of the secondary terminal voltage phasor. Thus, in the case of a lagging power factor $\cos\phi_2$ the angle ϕ_2 is substituted directly into the regulation formula, but in the case of a leading power factor $\cos\theta_2$ the angle to be substituted is not θ_2 but $\phi_2 = (360^\circ - \theta_2)$, and the following relationship must be observed:

$$\cos\phi_2 = \cos(360^\circ - \theta_2) = \cos\theta_2$$

and

$$\sin\phi_2 = \sin(360^\circ - \theta_2) = -\sin\theta_2$$

If the percentage regulation comes out negative, it indicates that the load has produced a rise in voltage.

Appendix 5
Symmetrical components in unbalanced three-phase systems

Modern technique in the calculation of system fault conditions demands a knowledge of the theory of symmetrical components and the phase sequence characteristics of the individual parts of the system. It would be out of place here to deal with symmetrical components as extensively as the subject demands. As transformers are involved in system fault calculations, a very brief study of the application of the theory to the phasor analysis of unbalanced three-phase systems may quite properly be given, and such is therefore presented in what follows. A consideration of phase sequence characteristics of transformers subsequently appears.

When a short-circuit fault occurs in a three-phase network, currents and voltages in the three phases become unequal in magnitude and unbalanced in their phase displacements, so that the phasors representing them are no longer equal and spaced 120° apart.

It is possible to analyse any given system of three-phase unbalanced phasors into three other balanced phasor systems which are called positive, negative and zero phase sequence phasors respectively.

The positive phase sequence system is that in which the phase (or line) voltages and/or currents reach their maxima in the same order as do those of the normal supply.

It is conventionally assumed that *all* phasors rotate in a counter-clockwise direction, and the positive phase sequence system is that in which the phase maxima occur in the order ABC.

Conversely, the negative phase sequence system is that in which the phasors, while rotating in the same direction as the positive phase sequence phasors, namely, counter-clockwise, reach their maxima in the order ACB.

The zero phase sequence system is a single-phase phasor, and it represents the residual voltage or current which is present in a three-phase circuit under fault conditions when a fourth wire is present either as a direct metallic connection or as a double earth on the system.

The positive phase sequence systems of voltages and currents are those which correspond to the normal load conditions.

The negative phase sequence systems of voltages and currents are those which are set up in the circuit by the fault, and their magnitudes are a direct measure of the superposed fault conditions between phases. The individual voltages and currents of this system are confined to the three lines.

The zero phase sequence systems of voltages and currents are also set up in the circuit by the fault, and their magnitudes are a direct measure of the superposed fault conditions *to earth*. The voltages and currents of this system embrace the fourth wire (or ground) in addition to the three line wires.

A balanced three-phase system, which corresponds to normal balanced load conditions, contains a positive phase sequence system only.

An unbalanced three-phase system, in which the phasor sum is zero, contains both positive and negative phase sequence systems, but no zero phase sequence phasors. In practice this corresponds to the case of a short circuit between two line wires. The positive phase sequence system is that part of the total unbalanced phasor system which corresponds to the normal loading condition. The negative phase sequence system is that which is introduced by the particular fault conditions.

An unbalanced three-phase system, in which the phasor sum has some definite magnitude, contains positive, negative and zero phase sequence systems. In practice this corresponds to the case of a line earth fault on a three-phase circuit having an earthed neutral. The positive phase sequence system is that part of the total unbalanced phasor system which corresponds to the normal loading conditions. The negative phase sequence system is that which is introduced by the particular fault conditions and which is confined to the three line wires. The zero phase sequence system is that which is introduced as a residual component by the particular fault condition, the voltages appearing between the lines and earth, while equal and co-phasal currents flow in the line wires, giving a resultant through the ground of three times their individual magnitudes.

Figure A5.1 shows a typical three-phase unbalanced phasor system which may be of current or voltage. The treatment is unaffected by the character of the quantities and it is assumed, in what follows, that we are dealing with current phasors. Counter-clockwise phasor rotation is taken to be positive, and the usual convention of positive and negative rectangular co-ordinates is adopted.

Let it be assumed the rectangular components of the unbalanced phasor system of *Figure A5.1* are:

phase A : $a + jb$

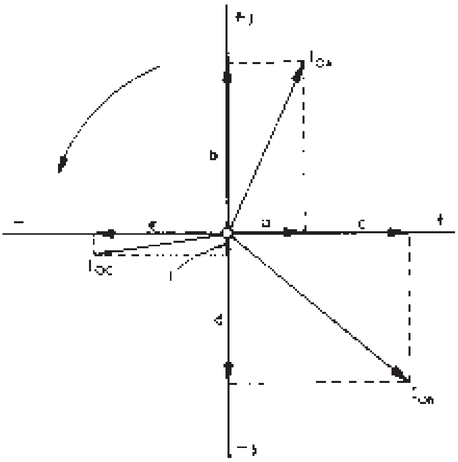

Figure A5.1 Typical three-phase unbalanced phasor system

phase B : $c + jd$

phase C : $e + jf$

These, of course, are the general expressions and do not indicate the relative positions of the phasors to each other. This would be given by inserting before each symbol letter the actual components sign shown by the diagram, thus:

phase A : $a + jb$

phase B : $c - jd$

phase C : $-e - jf$

Let it be assumed, further, that the rectangular components of the, as yet undetermined, positive phase sequence phasor system are:

$$\text{phase A}: \quad m + jn \tag{A5.1}$$

$$\text{phase B}: \quad o + jp = (m + jn)\left(-\tfrac{1}{2} - j\frac{\sqrt{3}}{2}\right) \tag{A5.2}$$

$$\text{phase C}: \quad q + jr = (m + jn)\left(-\tfrac{1}{2} + j\frac{\sqrt{3}}{2}\right) \tag{A5.3}$$

and of the negative phase sequence system:

$$\text{phase A}: \quad s + jt \tag{A5.4}$$

$$\text{phase B}: \quad u + jv = (s + jt)\left(-\tfrac{1}{2} + j\frac{\sqrt{3}}{2}\right) \tag{A5.5}$$

$$\text{phase C}: \quad w + jx = (s + jt)\left(-\tfrac{1}{2} - j\frac{\sqrt{3}}{2}\right) \tag{A5.6}$$

while the zero phase sequence system is:

$$\begin{array}{ll} \text{phase A} & \\ \text{phase B} & y + jz \\ \text{phase C} & \end{array} \tag{A5.7}$$

The terms $\left(-\frac{1}{2} - j\frac{\sqrt{3}}{2}\right)$ and $\left(-\frac{1}{2} + j\frac{\sqrt{3}}{2}\right)$ are operators and correspond with the clockwise or counter-clockwise rotation of the phasor representing phase A to the positions occupied by the phasors representing phases B and C, thus allowing the latter to be expressed in terms of the former.

The general operator is the expression $\cos\alpha + j\sin\alpha$, where α is the angle through which the original phasor is turned; the precise sign to be inserted before $\cos\alpha$ and $j\sin\alpha$ depends upon the quadrant into which the phasor is turned, as shown by *Figure A5.2*. The operator for rotating through any angle, counter-clockwise or clockwise, can be obtained from this expression in the manner shown by *Table A5.1*. Thus a combination of the $90°\, j$ operator with ordinary trigonometrical functions gives an operator for any angle of rotation.

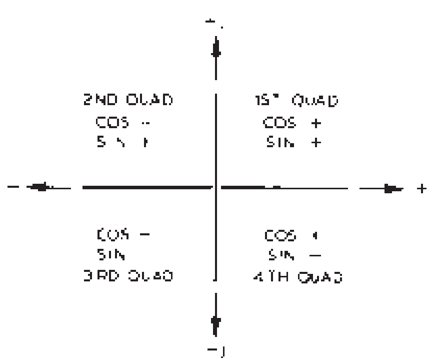

Figure A5.2 Signs of trigonometrical functions in the different quadrants

The study will be facilitated by introducing at this stage the graphical methods of separating out the positive, negative and zero phase sequence phasor systems. These are shown in *Figures A5.3*, *A5.4* and *A5.5* respectively. In *Figure A5.3* the positive phase sequence phasor for each phase is derived as follows. For phase A, add to the phasor I_{OA} the phasor I_{OB} rotated, in the positive counter-clockwise direction, through 120°, as shown by I'_{OB} and to I'_{OB} add the phasor I_{OC} rotated in the same direction through 240° as

Table A5.1 Operations for 30° increments for counter-clockwise and clockwise turning of phasors

	Direction of turning					
Angle,	*Counter-clockwise*			*Clockwise*		
degrees	*Cos*	*Sin*	*Operator*	*Cos*	*Sin*	*Operator*
0	1	0	$1+j0$	1	0	$1+j0$
30	$\sqrt{3}/2$	$\frac{1}{2}$	$\sqrt{3}/2+j\frac{1}{2}$	$\sqrt{3}/2$	$-\frac{1}{2}$	$\sqrt{3}/2-j\frac{1}{2}$
60	$\frac{1}{2}$	$\sqrt{3}/2$	$\frac{1}{2}+j\sqrt{3}/2$	$\frac{1}{2}$	$-\sqrt{3}/2$	$\frac{1}{2}-j\sqrt{3}/2$
90	0	1.0	$0+j1$	0	-1	$0-j1$
120	$-\frac{1}{2}$	$\sqrt{3}/2$	$-\frac{1}{2}+j\sqrt{3}/2$	$-\frac{1}{2}$	$-\sqrt{3}/2$	$-\frac{1}{2}-j\sqrt{3}/2$
150	$-\sqrt{3}/2$	$\frac{1}{2}$	$-\sqrt{3}/2+j\frac{1}{2}$	$-\sqrt{3}/2$	$-\frac{1}{2}$	$-\sqrt{3}/2-j\frac{1}{2}$
180	-1	0	$-1+j0$	-1	0	$-1+j0$
210	$-\sqrt{3}/2$	$-\frac{1}{2}$	$-\sqrt{3}/2-j\frac{1}{2}$	$-\sqrt{3}/2$	$\frac{1}{2}$	$-\sqrt{3}/2+j\frac{1}{2}$
240	$-\frac{1}{2}$	$-\sqrt{3}/2$	$-\frac{1}{2}-j\sqrt{3}/2$	$-\frac{1}{2}$	$\sqrt{3}/2$	$-\frac{1}{2}+j\sqrt{3}/2$
270	0	-1	$0-j1$	0	1	$0+j1$
300	$\frac{1}{2}$	$-\sqrt{3}/2$	$\frac{1}{2}-j\sqrt{3}/2$	$\frac{1}{2}$	$\sqrt{3}/2$	$\frac{1}{2}+j\sqrt{3}/2$
330	$\sqrt{3}/2$	$-\frac{1}{2}$	$\sqrt{3}/2-j\frac{1}{2}$	$\sqrt{3}/2$	$\frac{1}{2}$	$\sqrt{3}/2+j\frac{1}{2}$
360	1	0	$1+j0$	1	0	$1+j0$

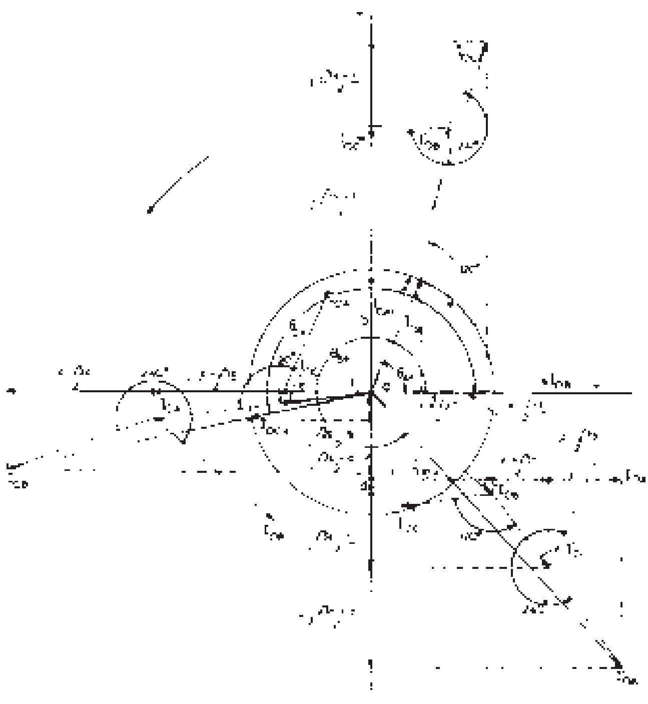

Figure A5.3 Derivation of positive phase sequence phasor system shown by I'_{OC}. Join the extremity of I'_{OC} to the star point O and trisect the line so obtained. This gives the phasor I_{OA+} which is the positive phase sequence phasor for phase A. For phase B, add to I_{OB} the phasor I_{OC} rotated positively through 120° as shown by I'_{OC}, and to I'_{OC} add the phasor I_{OA} rotated positively through 240° as shown by I'_{OA}. Join the extremity of I'_{OA} to the star point O and trisect as before to obtain I_{OB+}, the positive phase sequence phasor for phase B. For phase C, add to I_{OC} the phasor I_{OA} rotated positively through 120° as shown by I'_{OA}, and to I'_{OA} add the phasor I_{OB} rotated positively through 240° as shown by I'_{OB}. Join the extremity of I'_{OB} to the star point O and trisect as before to obtain I_{OC+}, the positive phase sequence phasor for phase C.

In *Figure A5.4* the negative phase sequence phasor for each phase is obtained in exactly the same way as the positive phase sequence phasors of *Figure A5.3*, except that the rotations through 120° and 240° are effected in the negative clockwise direction.

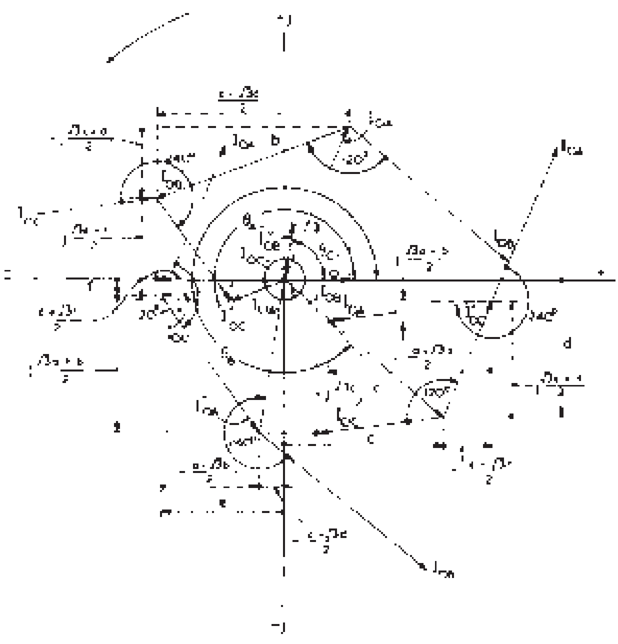

Figure A5.4 Derivation of negative phase sequence phasor system

Having obtained the positive or negative phase sequence component for phase A, the corresponding components for phases B and C can be obtained without repeating the graphical performance for those phases but simply by drawing the phasors $I_{OB\pm}$ and $I_{OC\pm}$ equal in length to $I_{OA\pm}$ and spaced 120° and 240° therefrom in the sequences shown in *Figures A5.3* and *A5.4*. The graphical construction is shown for all phases, however, in order to clarify the derivation of the final equations for the phase sequence components.

In *Figure A5.5* the single-phase zero phase sequence phasor, which is the same for all three phases, is obtained by adding I_{OA}, I_{OB} and I_{OC} together without any rotation, joining the extremity of I_{OC} to the star point O and trisecting the line so obtained.

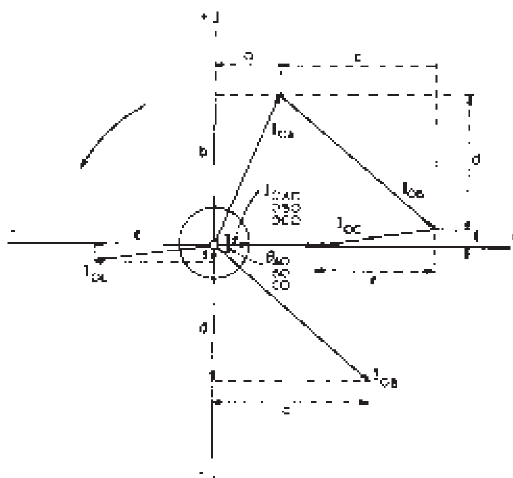

Figure A5.5 Derivation of zero phase sequence phasor system

It has already been stated that the equation of a phasor turned through 120° in a clockwise direction is the equation to the phasor in the original position multiplied by,

$$-\tfrac{1}{2} - j\frac{\sqrt{3}}{2} \quad \text{(equation A5.2);}$$

for clockwise turning through 240° the multiplier is

$$-\tfrac{1}{2} + j\frac{\sqrt{3}}{2} \quad \text{(equation A5.3);}$$

for counter-clockwise turning through 120° the multiplier is

$$-\tfrac{1}{2} + j\frac{\sqrt{3}}{2} \quad \text{(equation A5.5);}$$

for counter-clockwise turning through 240° the multiplier is

$$-\tfrac{1}{2} - j\frac{\sqrt{3}}{2} \quad \text{(equation A5.6).}$$

We are thus equipped for expressing mathematically the phasor rotations through 120° and 240° in both directions shown in *Figures A5.3* and *A5.4*. The relevant equations are as follows:

POSITIVE PHASE SEQUENCE

Phase A

$$I_{OA} = a + jb \tag{A5.8}$$

$$I'_{OB} = (c + jd)\left(-\tfrac{1}{2} + j\frac{\sqrt{3}}{2}\right. = -\left(\frac{c+\sqrt{3}d}{2}\right. + j\left(\frac{\sqrt{3}c - d}{2}\right. \tag{A5.9}$$

$$I'_{OC} = (e + jf)\left(-\tfrac{1}{2} - j\frac{\sqrt{3}}{2}\right. = -\left(\frac{e-\sqrt{3}f}{2}\right. - j\left(\frac{\sqrt{3}e + f}{2}\right. \tag{A5.10}$$

$$\begin{aligned}
I_{OA} + I'_{OB} + I'_{OC} &= (a + jb) + \left\{-\left(\frac{c+\sqrt{3}d}{2}\right. + j\left(\frac{\sqrt{3}c+d}{2}\right.\right\} \\
&\quad + \left\{-\left(\frac{e-\sqrt{3}f}{2}\right. - j\left(\frac{\sqrt{3}e+f}{2}\right.\right\} \\
&= \left\{a - \frac{c+\sqrt{3}d}{2} - \frac{e-\sqrt{3}f}{2}\right\} \\
&\quad + j\left\{b + \frac{\sqrt{3}c-d}{2} - \frac{\sqrt{3}e+f}{2}\right\}
\end{aligned} \tag{A5.11}$$

Simplifying equation (A5.11) and dividing by 3 gives the positive phase sequence component for phase A thus:

$$I_{OA+} = \left(\frac{a}{3} - \frac{c+e}{6} + \frac{f-d}{2\sqrt{3}}\right. + j\left(\frac{b}{3} - \frac{d+f}{6} + \frac{c-e}{2\sqrt{3}}\right. \tag{A5.12}$$

Putting equation (A5.12) as in (A5.1),

$$I_{OA+} = m + jn$$

then

$$\theta_{A+} = \tan^{-1} n/m$$

Phase B

$$I_{OB} = c + jd$$

$$I'_{OC} = (e + jf)\left(-\tfrac{1}{2} + j\frac{\sqrt{3}}{2}\right. = -\left(\frac{e+\sqrt{3}f}{2}\right. + j\left(\frac{\sqrt{3}e - f}{2}\right.$$

$$I'_{OA} = (a + jb)\left(-\tfrac{1}{2} - j\frac{\sqrt{3}}{2}\right. = -\left(\frac{a - \sqrt{3}b}{2}\right. - j\left(\frac{\sqrt{3}a + b}{2}\right.$$

$$I_{OB} + I'_{OC} + I'_{OA} = (c + jd) + \left\{-\left(\frac{e + \sqrt{3}f}{2}\right. + j\left(\frac{\sqrt{3}e - f}{2}\right.\right\}$$

$$+\left\{-\left(\frac{a - \sqrt{3}b}{2}\right. - j\left(\frac{\sqrt{3}a + b}{2}\right.\right\}$$

$$= \left\{c - \frac{e + \sqrt{3}f}{2} - \frac{a - \sqrt{3}b}{2}\right\}$$

$$+ j\left\{d + \frac{\sqrt{3}e - f}{2} - \frac{\sqrt{3}a + b}{2}\right\} \qquad \text{(A5.13)}$$

Simplifying equation (A5.13) and dividing by 3 gives the positive phase sequence component for phase B, thus,

$$I_{OB+} = \left(\frac{c}{3} - \frac{e + a}{6} + \frac{b - f}{2\sqrt{3}}\right. + j\left(\frac{d}{3} - \frac{f + b}{6} + \frac{e - a}{2\sqrt{3}}\right. \qquad \text{(A5.14)}$$

Putting equation (A5.14) as in equation (A5.2),

$$I_{OB+} = o + jp$$

then

$$\theta_{B+} = \tan^{-1} p/o$$

Phase C

$$I_{OC} = e + jf$$

$$I'_{OA} = (a + jb)\left(-\tfrac{1}{2} + j\frac{\sqrt{3}}{2}\right. = -\left(\frac{a + \sqrt{3}b}{2}\right. + j\left(\frac{\sqrt{3}a - b}{2}\right.$$

$$I'_{OB} = (c + jd)\left(-\tfrac{1}{2} - j\frac{\sqrt{3}}{2}\right. = -\left(\frac{c - \sqrt{3}d}{2}\right. - j\left(\frac{\sqrt{3}c + d}{2}\right.$$

$$I_{OC} + I'_{OA} + I'_{OB} = (e + jf) + \left\{-\left(\frac{a + \sqrt{3}b}{2}\right. - j\left(\frac{\sqrt{3}a + b}{2}\right.\right\}$$

$$+\left\{-\left(\frac{c - \sqrt{3}d}{2}\right. - j\left(\frac{\sqrt{3}c + d}{2}\right.\right\}$$

$$= \left\{e - \frac{a + \sqrt{3}b}{2} - \frac{c - \sqrt{3}d}{2}\right\}$$

$$+\,j\left\{f+\frac{\sqrt{3}a-b}{2}-\frac{\sqrt{3}c+d}{2}\right\} \tag{A5.15}$$

Simplifying equation (A5.15) and dividing by 3 gives the positive phase sequence component for phase C, thus,

$$I_{OC}=\left(\frac{e}{3}-\frac{a+c}{6}+\frac{d-b}{2\sqrt{3}}\right.\quad+\,j\left(\frac{f}{3}-\frac{b+d}{6}+\frac{a-c}{2\sqrt{3}}\right. \tag{A5.16}$$

Putting equation (A5.16) as in (A5.3),

$$I_{OC+}=q+jr$$

then

$$\theta_{C+}=\tan^{-1} r/q$$

NEGATIVE PHASE SEQUENCE

Phase A

$$I_{OA}=a+jb$$

$$I''_{OB}=(c+jd)\left(-\tfrac{1}{2}-j\frac{\sqrt{3}}{2}\right.\quad=-\left(\frac{c-\sqrt{3}d}{2}\right.\quad-\,j\left(\frac{\sqrt{3}c+d}{2}\right.$$

$$I''_{OC}=(e+jf)\left(-\tfrac{1}{2}+j\frac{\sqrt{3}}{2}\right.\quad=-\left(\frac{e+\sqrt{3}f}{2}\right.\quad+\,j\left(\frac{\sqrt{3}e-f}{2}\right.$$

$$\begin{aligned}I_{OA}+I''_{OB}+I''_{OC}=(a+jb)&+\left\{-\left(\frac{c-\sqrt{3}d}{2}\right.\quad-\,j\left(\frac{\sqrt{3}c+d}{2}\right.\quad\right\}\\&+\left\{-\left(\frac{e+\sqrt{3}f}{2}\right.\quad+\,j\left(\frac{\sqrt{3}e-f}{2}\right.\quad\right\}\\&=\left\{a-\frac{c-\sqrt{3}d}{2}-\frac{e+\sqrt{3}f}{2}\right\}\\&+\,j\left\{b-\frac{\sqrt{3}c+d}{2}+\frac{\sqrt{3}e-f}{2}\right\}\end{aligned} \tag{A5.17}$$

Simplifying equation (A5.17) and dividing by 3 gives the negative phase sequence component for phase A, thus,

$$I_{OA-}=\left(\frac{a}{3}-\frac{c+e}{6}+\frac{d-f}{2\sqrt{3}}\right.\quad+\,j\left(\frac{b}{3}-\frac{d+f}{6}+\frac{e-c}{2\sqrt{3}}\right. \tag{A5.18}$$

Putting equation (A5.18) as in (A5.4),

$$I_{OA-} = s + jt$$

then

$$\theta_{A-} = \tan^{-1} t/s$$

Phase B

$$I_{OB} = c + jd$$

$$I''_{OC} = (e + jf)\left(-\tfrac{1}{2} - j\frac{\sqrt{3}}{2}\right. = -\left(\frac{e - \sqrt{3}f}{2}\right. - j\left(\frac{\sqrt{3}e + f}{2}\right.$$

$$I''_{OA} = (a + jb)\left(-\tfrac{1}{2} + j\frac{\sqrt{3}}{2}\right. = -\left(\frac{a + \sqrt{3}b}{2}\right. + j\left(\frac{\sqrt{3}a - b}{2}\right.$$

$$\begin{aligned} I_{OB} + I''_{OC} + I''_{OA} &= (c + jd) + \left\{-\left(\frac{e - \sqrt{3}f}{2}\right. - j\left(\frac{\sqrt{3}e + f}{2}\right.\right\} \\ &\quad + \left\{-\left(\frac{a + \sqrt{3}b}{2}\right. + j\left(\frac{\sqrt{3}a - b}{2}\right.\right\} \\ &= \left\{c - \frac{e - \sqrt{3}f}{2} - \frac{a + \sqrt{3}b}{2}\right\} \\ &\quad + j\left\{d - \frac{\sqrt{3}e + f}{2} + \frac{\sqrt{3}a - b}{2}\right\} \end{aligned} \tag{A5.19}$$

Simplifying equation (A5.19) and dividing by 3 gives the negative phase sequence component for phase B, thus,

$$I_{OB-} = \left(\frac{c}{3} - \frac{e + a}{6} + \frac{f - b}{2\sqrt{3}}\right. + j\left(\frac{d}{3} - \frac{f + b}{6} + \frac{a - e}{2\sqrt{3}}\right. \tag{A5.20}$$

Putting equation (A5.20) as in (A5.5),

$$I_{OB-} = u + jv$$

then

$$\theta_{B-} = \tan^{-1} v/u$$

Phase C

$$I_{OC} = e + jf$$

$$I''_{OA} = (a + jb)\left(-\tfrac{1}{2} - j\frac{\sqrt{3}}{2}\right. = -\left(\frac{a - \sqrt{3}b}{2}\right. - j\left(\frac{\sqrt{3}a + b}{2}\right.$$

$$I''_{OB} = (c + jd)\left(-\tfrac{1}{2} + j\frac{\sqrt{3}}{2}\right. = -\left(\frac{c + \sqrt{3}d}{2}\right. + j\left(\frac{\sqrt{3}c - d}{2}\right.$$

$$\begin{aligned} I_{OC} + I''_{OA} + I''_{OB} &= (e + jf) + \left\{-\left(\frac{a - \sqrt{3}b}{2}\right. - j\left(\frac{\sqrt{3}a + b}{2}\right.\right\} \\ &\quad + \left\{-\left(\frac{c + \sqrt{3}d}{2}\right. + j\left(\frac{\sqrt{3}c - d}{2}\right.\right\} \\ &= \left\{e - \frac{a - \sqrt{3}b}{2} - \frac{c + \sqrt{3}d}{2}\right\} \\ &\quad + j\left\{f - \frac{\sqrt{3}a + b}{2} + \frac{\sqrt{3}c - d}{2}\right\} \end{aligned} \tag{A5.21}$$

Simplifying equation (A5.21) and dividing by 3 gives the negative phase sequence component for phase C, thus,

$$I_{OC-} = \left(\frac{e}{3} - \frac{a + c}{6} + \frac{b - d}{2\sqrt{3}}\right. + j\left(\frac{f}{3} - \frac{b + d}{6} + \frac{c - a}{2\sqrt{3}}\right. \tag{A5.22}$$

Putting equation (A5.22) as in (A5.6),

$$I_{OC-} = w + jx$$

then

$$O_{C-} = \tan^{-1} x/w$$

In practice it is not necessary to calculate out the positive and negative phase sequence components for all three phases as all positives are equal and all negatives are equal.

ZERO PHASE SEQUENCE

Phases A, B and C

As this is a single-phase phasor, common to all three phases, one calculation only is involved.

$$I_{OA} = a + jb$$

$$I_{OB} = c + jd$$

$$I_{OC} = e + jf$$

$$\begin{aligned} I_{OA} + I_{OB} + I_{OC} &= (a + jb) + (c + jd) + (e + jf) \\ &= (a + c + e) + j(b + d + f) \end{aligned} \tag{A5.23}$$

Dividing equation (A5.23) by 3 gives the zero phase sequence component for each phase, thus,

$$I_{\substack{OAO\\OBO\\OCO}} = \left(\frac{a + c + e}{3}\right) + j\left(\frac{b + d + f}{3}\right) \tag{A5.24}$$

Putting equation (A5.24) as in (A5.7),

$$I_{\substack{OAO\\OBO\\OCO}} = y + jz$$

then

$$\theta_{\substack{AO\\BO\\CO}} = \tan^{-1} z/y$$

When zero phase sequence currents exist in an unbalanced three-phase system the current in each line wire is that given by equation (A5.24). The current in the return circuit, that is the ground or a fourth wire, is the sum of the currents in the three lines. Zero phase sequence voltages are simply three voltages in parallel between each line and the return.

The magnitudes of the phase sequence components obtained by means of equations (A5.12), (A5.14), (A5.16), (A5.18), (A5.20), (A5.22) and (A5.24) are not affected in any way if the non-standard convention of *clockwise* direction of phasor rotation is adopted.

The whole of the foregoing treatment gives the *general* formulae for calculating the different quantities, and in evaluating them care must be taken to insert the actual co-ordinate sign before each component value according to the quadrant in which each unbalanced phasor lies. Similarly, in evaluating the angular displacements of the phase sequence components from the assumed reference phasor position, i.e. the $+x$ axis of *Figures A5.3*, *A5.4* and *A5.5*, due account must be taken of the quadrant in which the component is found. In the first quadrant the total angle is that given directly by the $\tan^{-1}$ value; in the second quadrant the total angle is $180°$ minus the $\tan^{-1}$ value; in the third quadrant the angle is $180°$ plus the $\tan^{-1}$ value, and in the fourth quadrant the angle is $360°$ minus the $\tan^{-1}$ value.

An interesting example of the application of symmetrical components is afforded by the phasor analysis of the conditions which arise when a three-phase star/star core-type transformer, having a three-wire primary and a four-wire secondary, supplies an unbalanced load. Taking the extreme case of a single load on one phase from line to neutral, the phasor quantities are illustrated typically by *Figure A5.6*, in which diagram I shows all primary currents and applied voltages, diagram II primary magnetising currents and induced voltages, and diagram III secondary current and induced voltages. Loss currents are neglected, and it is assumed that primary and secondary

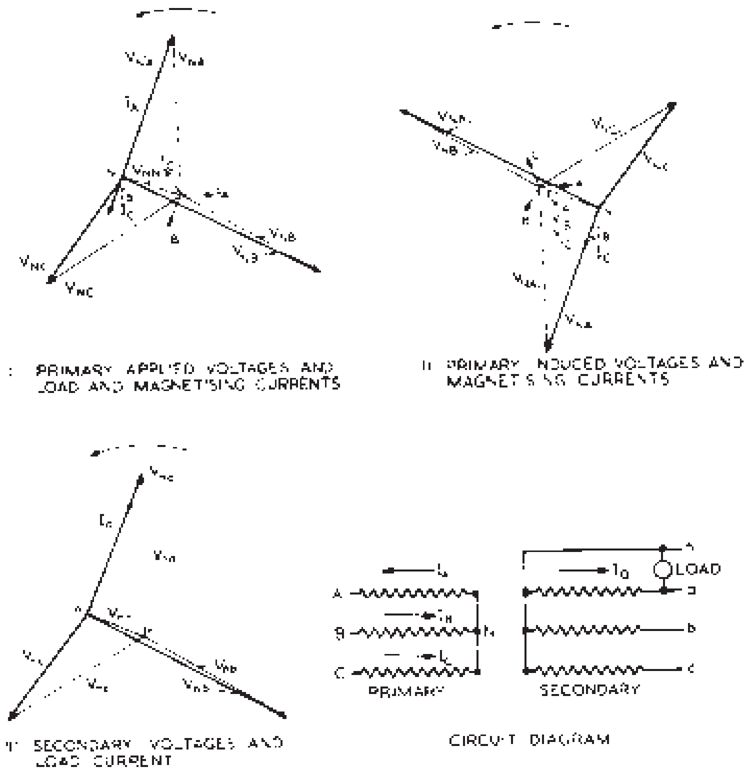

Figure A5.6 Phasor diagrams showing the voltage and current conditions in a three-phase, core-type, star/star-connected transformer with three-wire primary and four-wire secondary when supplying a single-phase load from one line to neutral

coils are wound in opposite directions. The secondary load has a unity power factor. The primary current I_A is 67% of the secondary current I_a, while I_B and I_C are each 50% of I_A.

The current I_a in the loaded secondary phase winding is a true zero phase sequence current, having its return path through the neutral conductor. There is, however, no zero phase sequence current on the primary side of the transformer, as is shown by the phasor analysis of *Figure A5.7*, in which diagram I shows the summation of the load and magnetising currents in the primary phase windings, diagram II the resulting positive phase sequence currents, and diagram III the negative phase sequence currents; diagram IV gives the construction for the zero phase sequence current, which, it will be noted, is *nil*. The reason for this is that zero phase sequence current in the secondary winding becomes converted to zero phase sequence voltage in the primary windings by the choking effect of the two unloaded primary windings, resulting from the absence of a fourth wire from the primary neutral.

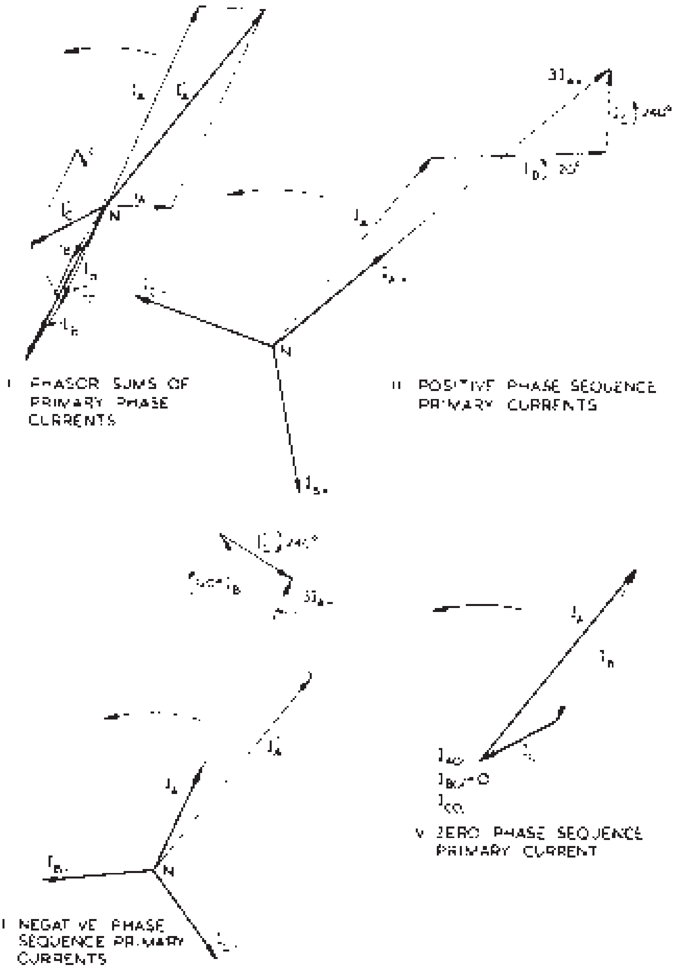

Figure A5.7 Phasor diagrams showing total primary currents and their phase sequence analysis corresponding to *Figure A5.6*

Zero phase sequence current cannot flow in a circuit if there is no neutral connection.

It is clear from inspection of *Figure A5.6* that, under the loading conditions illustrated, the voltage components in both primary and secondary windings are of positive and zero phase sequences only; the negative phase sequence component is absent. The positive sequence components are simply the no-load line to neutral voltages, while the zero sequence components are represented by the voltages induced in the phase windings by the currents I_B and I_C in the unloaded phases; the latter is also the voltage difference between the star point of the windings and the true neutral of the system.

With the more common delta/star connection of three-phase core-type transformers having a four-wire secondary, an unbalanced load produces positive, negative and zero phase sequence secondary line currents, but only positive and negative phase sequence primary line currents. Zero phase sequence currents flow round the primary delta winding, however.

These conditions are shown in phasor form by the diagrams of *Figure A5.8* on the assumption of a one-to-one ratio of phase windings.

From diagram I it is seen there are zero phase sequence currents in the secondary star windings and in the lines connected thereto; there are also zero phase sequence currents in the primary delta windings but not in the primary lines. Diagrams II and III show that there are positive and negative phase sequence currents in the primary and secondary windings and lines; in the respective windings the corresponding primary and secondary currents are in phase, but corresponding line currents are displaced by 30°; corresponding winding currents are equal, but line currents are in the ratio of $\sqrt{3}$ to 1. Thus zero phase sequence currents flow in the secondary lines but not in the primary lines; positive and negative phase sequence currents flow in both primary and secondary lines.

In transformers, positive and negative phase sequence impedances* are the normal load leakage impedances of the transformer; they are series impedances in the equivalent network diagrams. In those cases where zero phase sequence currents can flow in *both* primary and secondary *lines* the zero phase sequence impedance* per phase also is the normal load leakage impedance of the phase windings, assuming symmetry of the phases; it is also a series impedance. Where zero phase sequence currents cannot flow in the *lines on both sides* the series zero phase sequence impedance is open circuited and is thus equivalent to infinity in its relation to the series network.

Thus the series zero phase sequence impedance per phase is the same as the positive or negative phase sequence impedance per phase, or, alternatively, it is equivalent to infinity, due to an insulated star neutral or a delta connection, or to an interconnected star winding on the other side.

As, under certain conditions, a star or interconnected star winding may present an impedance to earth to the flow of zero phase sequence current if the neutral is earthed, a zero phase sequence impedance shunted to earth from the star end of the series impedance branch of the equivalent circuit diagram may quite properly be included. This must not be confused with shunted exciting admittance, which is neglected. If zero phase sequence current flows *only* to earth on the star side the shunted impedance is shown as connected directly to earth; if the current flows from one winding to the other over the normal load leakage series impedance of the transformer the shunt impedance to earth is shown open circuited. With star-connected windings thus shunt zero phase sequence impedance is, in general, considerably higher than the normal load leakage impedance, being of the average order of 50%; for interconnected star

* Strictly speaking, the impedances to positive, negative and zero phase sequence currents respectively.

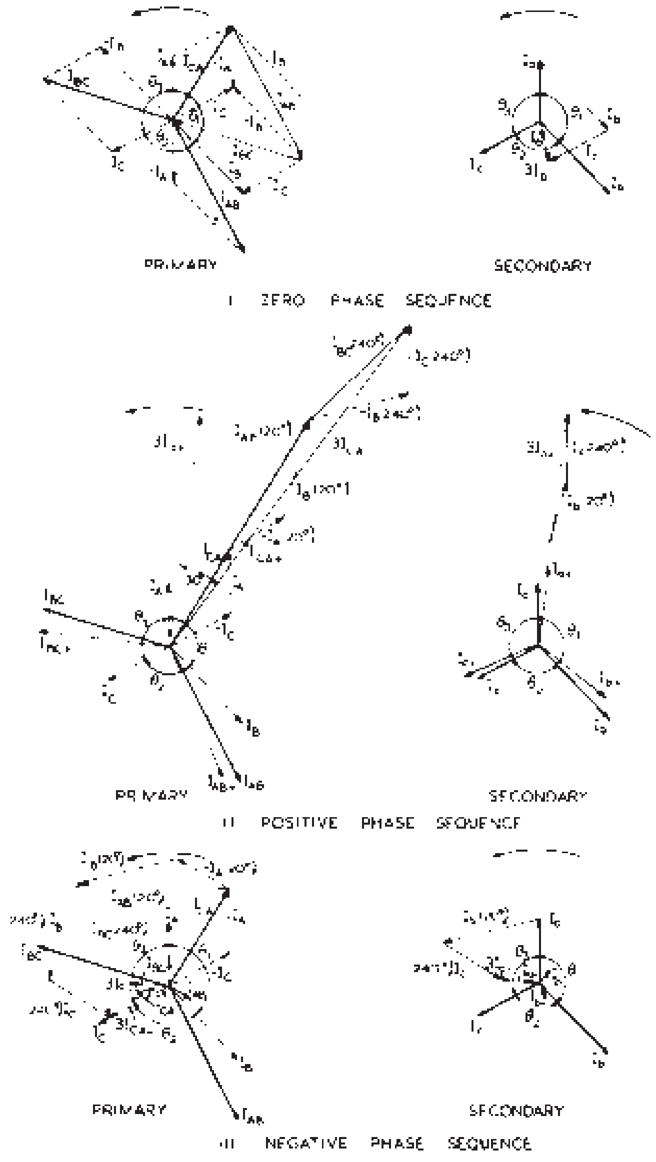

Figure A5.8 Phasor diagrams showing phase sequence currents in a three-phase delta/star-connected transformer with three-wire primary and four-wire secondary supplying unbalanced loads to neutral windings it is much lower than the normal load leakage impedance being of the same order as that of an interconnected star neutral earthing transformer.

In the case of an insulated neutral star winding, zero phase sequence currents cannot flow either from the lines or in the transformer winding, so that in the zero phase sequence network a star-connected winding with an insulated neutral is denoted by open links at the star end of the series impedance and at the earth end of the star side shunt impedance. When a star-connected winding is earthed or a fourth wire is used, zero phase sequence currents can flow *through* the particular winding and the external circuit connected thereto, but they cannot *circulate* in the transformer winding itself, so that in the equivalent network diagram an earthed neutral, or four-wire, star-connected winding is denoted by closed links at the star end of the series impedance and at the earth end of the star side shunt impedance branches of the network.

When a delta-connected winding is used, zero phase sequence currents cannot flow from the delta to the connected lines, or vice versa, but they can circulate in the delta winding without flowing through the external circuit. A delta winding thus represents a closed path with respect to the transformer but an open circuit with respect to that side of the equivalent network to which the delta winding is connected. The zero phase sequence connections for the equivalent circuit of a delta winding thus are represented by an open link between the delta end of the series impedance branch of the network and the lines, and a direct shunt connection to earth of the delta end of the equivalent series impedance.

The interconnected star neutral earthing transformer has an open circuit for applied positive or negative phase sequence voltage. For zero phase sequence, however, the currents in all the lines have the same value, so that the zero phase sequence impedance per phase is the normal load leakage impedance between the two winding halves on the same limb. The zero phase sequence connection is, therefore, a simple shunt impedance to earth.

In single-phase transformers, positive, negative and zero phase sequence impedances are the same when the circuit conditions are such as to permit the flow of zero phase sequence currents in the lines on both sides.

It is important to distinguish the difference between zero phase sequence series and shunt impedances, and these are summarised in *Figure A5.9* for the different three-phase transformer connections and conditions of earthing.

The true shunt impedances Z_{AN} and Z_{BN}, shown in *Figure A5.9*, are effective only for the star/star, star/interconnected star, and interconnected star/star connections, and then only when the neutral point is earthed on *one* side with the star/star connection, but on one or both sides with the other two connections. For transformers connected star/star with one neutral earthed, the shunt impedance on the earthed side is, on the average, of the order of 50% for three-phase core-type transformers, while for three-phase shell-type and three-phase groups of single-phase transformers it is of the average order of 400%. For star/interconnected star and interconnected star/star transformers with the star neutral earthed, the shunt impedance on the star side is of the

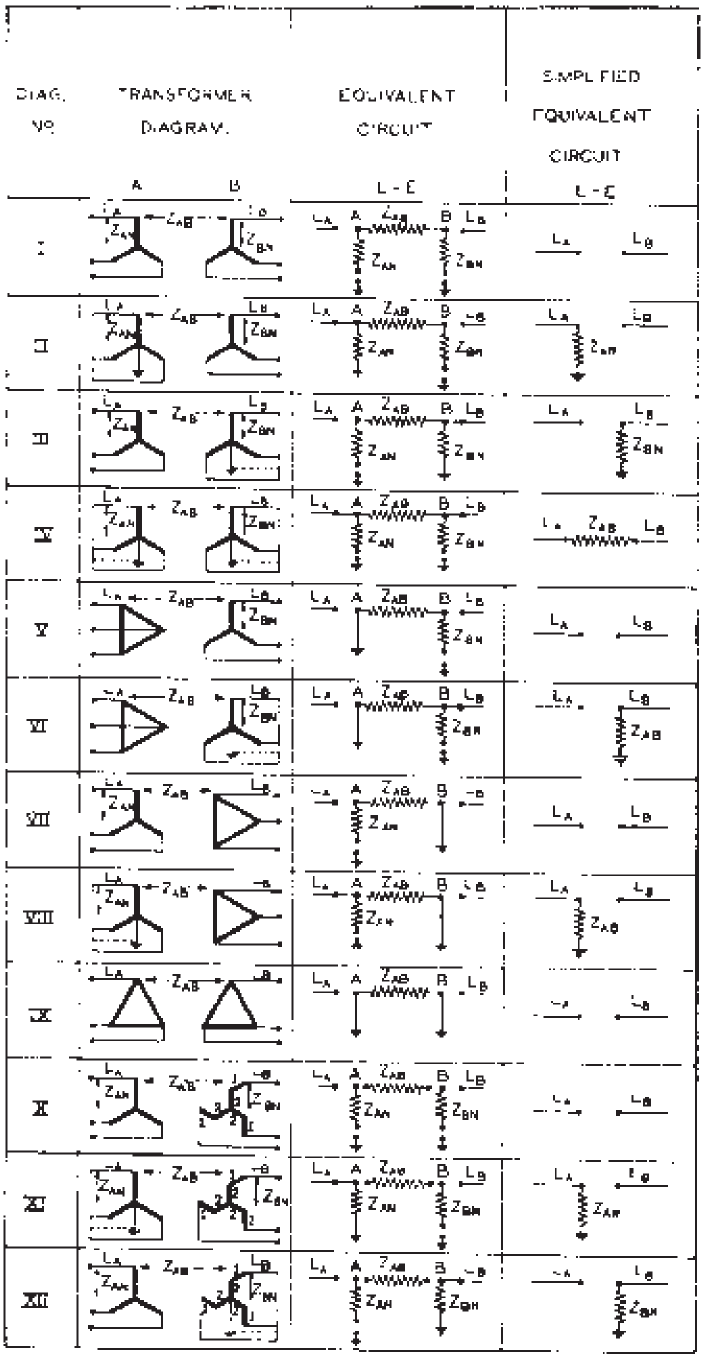

Figure A5.9 Zero phase sequence equivalent circuits and impedances for two-winding and three-winding transformers

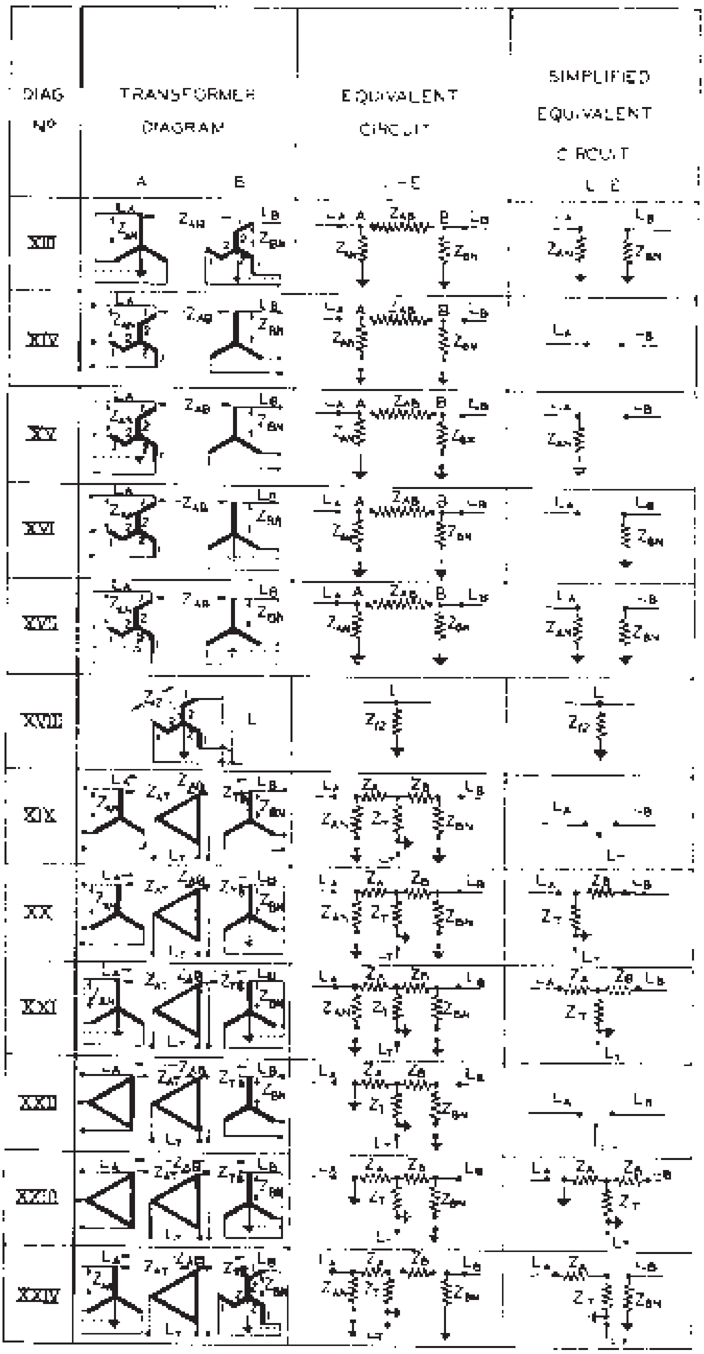

Figure A5.9 (*continued*)

average order of 50% for three-phase core-type transformers and 400% for three-phase shell-type and three-phase groups of single-phase transformers; where the interconnected star winding is earthed the shunt impedance on the interconnected star side is much lower than the normal series impedance of the transformer for all types of transformers, being the impedance between winding halves on the same limb of the core. In those cases where *both* primary and secondary neutrals of star/interconnected star and interconnected star/star windings are earthed the respective shunt impedances are of the same orders of magnitudes as given above.

Where both neutrals of star/star connected windings are earthed, as in diagram IV of *Figure A5.9*, the shunt impedance in the equivalent circuit is a small exciting impedance which, being neglected, is shown open circuited. A delta winding in conjunction with an earthed neutral star winding also results in the true shunt impedance of the latter being open circuited in the equivalent circuit diagram.

Where an interconnected star connection is used on one side, either winding is non-inductive to the other to zero phase sequence currents, so that Z_{AN} and Z_{BN}, as the case may be, is the leakage impedance between the winding halves on the same core limb for zero phase sequence currents in the interconnected star winding or the self-inductive impedance to earth in the star-connected winding. The series impedance Z_{AB} is thus infinity even when both neutrals are earthed, as in diagrams XIII and XVII of *Figure A5.9*.

For an interconnected star neutral earthing transformer the shunt impedance to earth, Z_{12}, is the leakage impedance between the winding halves on the same core limb, as is diagram XVIII.

For three-winding transformers the following expressions show the relationship of the impedances between the different windings, assuming, in each case, that the third winding is open circuited:

$$Z_A = \tfrac{1}{2}(Z_{AT} + Z_{AB} - Z_{TB}) \quad Z_{AT} = Z_A + Z_T$$

$$Z_T = \tfrac{1}{2}(Z_{AT} + Z_{TB} - Z_{AB}) \quad Z_{TB} = Z_T + Z_B$$

$$Z_B = \tfrac{1}{2}(Z_{BA} + Z_{TB} - Z_{AT}) \quad Z_{BA} = Z_B + Z_A$$

Where an impedance having an assigned value is open circuited, its circuit value thereby becomes converted to infinity.

The shunt impedances to which an approximate average value of 400% has been assigned are based upon average normal load leakage impedances of 5% and average normal magnetising currents of 5%. The actual value of shunt impedance varies with the size and design of transformer, and as a percentage it is

$$(\text{short circuit kVA} \div \text{magnetising kVA}) \times 100$$

The shunt impedances to which an approximate average value of 50% has been given are based upon tests carried out on three-phase core-type transformers.

Where, in the foregoing remarks, reference is made to the equality of the zero phase sequence impedance and the normal impedance, the qualifying statement that this is not exact for three-phase core-type transformers should be borne in mind. The normal load impedance is due to three-phase currents in the phase windings, while the series zero phase sequence impedance is due to single-phase winding currents; the impedance due to the latter is thus affected by the interlinking of the magnetic circuits of the three phases, but it does not differ very considerably from the normal load leakage impedance. If exact figures are required they should be obtained from the manufacturer.

All the references to three-phase core-type transformers apply to the three-limb core construction. For the five-limb core-type the equality of zero phase sequence impedances and normal load leakage impedances, where applicable, is exact.

It should be remembered that zero phase sequence currents in transformer windings depend not only upon the connections of the windings and the earthing of the winding neutral points but also upon the external circuit conditions, particularly as regards earthing. Thus in any complete zero phase sequence network involving transformers the effective zero phase sequence transformer impedances given in *Figure A5.9* may be modified by the external circuit conditions. The impedances shown, therefore, in *Figure A5.9*, and also the orders of magnitudes given in the foregoing remarks, assume that the external circuit conditions are such as regards arrangement and earthing as to permit zero phase sequence currents to flow in the earthed transformer windings.

In brief summary the position is that series positive and negative phase sequence impedances of a transformer are the normal load leakage impedance; the shunt positive phase sequence impedance due to normal no-load magnetising impedance is ignored, as usually it does not enter into short-circuit calculations. The zero phase sequence impedance of a transformer with an earthed neutral and no electrical connection between windings (either direct or via earth) constitutes a shunt impedance. Shunt zero phase sequence impedances are those over which zero phase sequence currents flow from the lines to neutral, while zero phase sequence impedances are those over which zero phase sequence currents flow from one transformer winding to the other.

The zero phase sequence impedances depend upon the connections of the transformer windings and also upon the earthing conditions of the windings and of the rest of the circuit.

Appendix 6
A symmetrical component study of earth faults in transformers in parallel

The behaviour of transformers in parallel under earth fault conditions is governed largely by the neutral point earthing of the circuit in which the fault occurs. The current and voltage distributions may be determined in a direct and simple manner by the application of symmetrical components, and the present study demonstrates the procedure and shows the influence of the neutral point earth circuits.

For the examples a typical three-phase, 50 Hz, duplicate transformer grid substation of the smaller type is chosen; from the secondary busbars of this are fed two duplicate step-down transformers supplying a factory load, as shown in *Figure A6.1*. The specifications of these transformers are as follows:

Grid transformers, each:
5000 kVA
33 000 delta to 11 000 star volts
87.5 to 262.5 line amperes
6.7% reactance
Primary resistance per phase winding, 2.3 Ω
Secondary resistance per phase winding 0.07 Ω

Consumer's transformers, each:
1500 kVA
11 000 delta to 440 star volts
78.8 to 1970 line amperes
4.5% reactance
Primary resistance per phase winding, 1.05 Ω
Secondary resistance per phase winding 0.0005 Ω

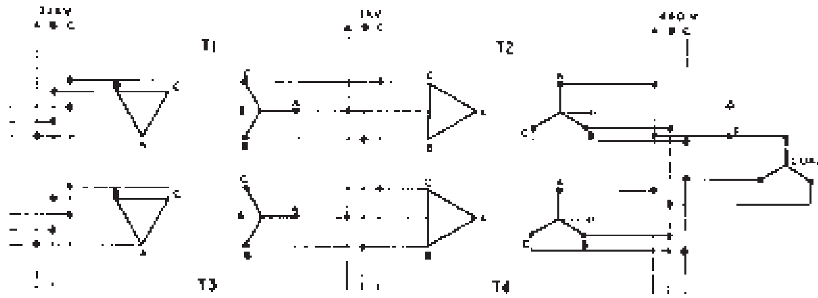

Figure A6.1 Layout of system

The following constants will be used in the investigation:

Grid transformers:
Primary line to neutral voltage = 19 050
Secondary line to neutral voltage = 6350
Secondary line to neutral reactance voltage = 6.7% of 6350 = 425.5

Consumer's transformers:
Primary line to neutral voltage = 6350
Secondary line to neutral voltage = 254
Secondary line to neutral reactance voltage = 4.5% of 254 = 11.42

Three cases are investigated, namely:

1. Both consumer's transformers in commission and both secondary neutrals earthed solidly.
2. As (1), but the neutral of one transformer only earthed.
3. One consumer's transformer only in commission, its neutral being earthed solidly.

In all cases the neutrals of both the grid transformers are earthed solidly.

A dead earth fault (i.e. zero resistance) is assumed to occur on one of the secondary busbars of the consumer's transformers or on the l.v. distributor to the consumer's premises sufficiently near to the transformers for the distributor impedance to the fault to be neglected.

It is first assumed that the neutral earths of the consumer's transformers have zero resistance, and subsequently it is shown how the fault currents and voltages are modified by earth resistance.

It is further assumed that the applied voltages at the primary terminals of the grid transformers remain balanced under fault conditions.

As the fault is assumed to occur on the l.v. secondary side of the consumer's transformers, the constants of all transformers are referred to the 440 V circuit. This gives fault currents and voltages in terms of that circuit, and subsequently they are converted to equivalent 11 and 33 kV values in order to show the true magnitudes in all the other windings.

Resistances and reactances are expressed in ohms, and this avoids the use of an arbitrary kVA base. All constants and values are per phase, that is, line to neutral, and where delta windings are involved, their equivalent line to neutral resistances are determined first, before conversion to a different voltage base, for the sake of uniformity of treatment.

The transformer constants, referred to the 440 V side, are then as follows:

Each grid transformer:

(*a*) Equivalent primary resistance, line to neutral, by the usual delta star conversion formulae is:

$$\frac{2.3^2}{2.3 \times 3} = 0.767\ \Omega$$

Equivalent primary resistance in terms of secondary line to neutral voltage is:

$$0.767 \left(\frac{6350}{19\,050}\right)^2 = 0.0853\ \Omega$$

Total resistance to neutral referred to 11 kV side $= 0.0853 + 0.07 = 0.1553\ \Omega$.

The total equivalent resistance to neutral referred to the 440 V side is then:

$$0.1553 \left(\frac{254}{6350}\right)^2 = 0.0002485\ \Omega$$

which will be rounded up to $0.00025\ \Omega$.

(*b*) The ohmic reactance, line to neutral, referred to the 11 kV secondary side is $425.5/262.5 = 1.62\ \Omega$, and referred to the 440 V side it is:

$$1.62 \left(\frac{254}{6350}\right)^2 = 0.00259\ \Omega$$

which will be rounded up to $0.0026\ \Omega$.

The impedance of each grid transformer, line to neutral, referred to the 440 V circuit is thus:

$$Z = R + jX = 0.00025 + j0.0026 = 0.00261\ \Omega$$

Each consumer's transformers:

(*c*) Equivalent primary resistance, line to neutral, by delta star conversion is:

$$\frac{1.05^2}{1.05 \times 3} = 0.35\ \Omega$$

Equivalent primary resistance in terms of secondary line to neutral voltage is:

$$0.35 \left(\frac{254}{6350}\right)^2 = 0.00056\ \Omega$$

Total equivalent resistance to neutral referred to 440 V side is:

$$0.00056 + 0.0005 = 0.00106\ \Omega$$

(*d*) The ohmic reactance, line to neutral, referred to the 440 V secondary side is $11.42/1970 = 0.0058\ \Omega$.

The impedance of each consumer's transformer, line to neutral, referred to the 440 V circuit is thus:

$$Z = R + jX = 0.00106 + j0.0058 = 0.0059\ \Omega$$

Since with the grid transformers, the equivalent reactance at 254 V is only 0.04% less than the total impedance, while with the consumer's transformers the equivalent reactance at 254 V is only 1.7% less than the total impedance, the error involved in assuming impedances to be in phase, and treating them as reactances, is negligible. This course will be adopted, therefore, as it saves a good deal of labour in the subsequent calculations.

In this study the phases and lines on the 440 V side are lettered A, B and C, rotation being in the order named. The earth fault is assumed to occur on line A, and the normal voltage to neutral of this line is taken as the reference phasor. In accordance with established procedure the voltage phasor V_A is regarded as lying on the $+Y$ axis of the usual X, Y system of co-ordinates, in order to clarify the presentation of the current terms. The ultimate results are not affected thereby.

In the study of short-circuit currents by symmetrical components the phase sequence networks are derived to embrace the entire circuit from the source of supply *up to the point of the system fault* but not beyond it. If the network is fed from more than one source, the circuits between the fault and all the sources are included. Similarly, if an earth fault occurs at some point along one of a pair of paralleled transmission lines fed from one end, the whole of the lines (and transformers, if any) up to the point at the receiving end where they are paralleled are included in the phase sequence diagrams, but nothing beyond that point affects the problem. That is, so far as all three phase sequence networks are concerned, it is assumed all three lines or busbars of the faulty circuit are connected together and to earth for the study of earth fault short-circuit currents and voltages, and thus only those parts of the actual network which can supply such a three-phase short circuit to earth can be included in the phase sequence networks.

PART I: CURRENTS

The general theorems controlling the currents and voltages in this study are:

The total earth fault current is:

$$I_F = 3V/Z \tag{A6.1}$$

where V is the normal line to neutral voltage of the system on the voltage base adopted and Z is the sum of the impedances of the zero, positive and negative phase sequence networks, so that:

$$Z = Z_0 + Z_1 + Z_2 \tag{A6.2}$$

As we are dealing only with static plant, the positive and negative sequence impedances are equal and the same as the normal circuit impedances. The zero sequence impedances depend upon the normal and fault earthing conditions, but for delta/star transformers they have the same values as the normal load impedances, or alternatively infinity, according to whether or not the earthing conditions permit the flow of zero phase sequence currents. This will become clear from the subsequent diagrams.

The zero, positive and negative sequence currents *in the fault* are equal and each one-third of I_F, so that:

$$I_{F0} = I_{F1} = I_{F2} = I_F/3 \tag{A6.3}$$

These are also the total currents in the respective phase sequence networks, and they each divide into the branches of the networks in inverse proportion to the branch sequence impedances. The total sequence network currents are then,

$$I_0 = I_{F0},\ \ I_1 = I_{F1} \text{ and } I_2 = I_{F2} \tag{A6.4}$$

respectively.

In the faulty phase A the total fault current is the sum of the three sequence total currents, I_0, I_1 and I_2, so that:

$$I_A = I_0 + I_1 + I_2 = I_F \tag{A6.5}$$

and it divides up into the branches of the faulty phase in inverse proportion to the branch sequence impedances. Alternatively, the total fault current in each branch of the faulty phase is the sum of the sequence currents in the corresponding branches of the three sequence networks.

The total fault currents in the other two phases B and C are given by the expressions:

$$\left.\begin{aligned} I_B &= I_0 + h^2 I_1 + h I_2 \\ I_C &= I_0 + h I_1 + h^2 I_2 \end{aligned}\right\} \tag{A6.6}$$

in which the phasor operators h and h^2 are:

$$h = -\tfrac{1}{2} + j\frac{\sqrt{3}}{2} = -0.5 + j0.866$$

$$h^2 = -\tfrac{1}{2} - j\frac{\sqrt{3}}{2} = -0.5 - j0.866$$

so that

$$\begin{aligned} I_B &= I_0 + I_1(-0.5 - j0.866) + I_2(-0.5 + j0.866) \\ &= I_0 - 0.5(I_1 + I_2) - j0.866(I_1 - I_2) \end{aligned}$$

$$\begin{aligned} I_C &= I_0 + I_1(-0.5 + j0.866) + I_2(0.5 - j0.866) \\ &= I_0 - 0.5(I_1 + I_2) + j0.866(I_1 - I_2) \end{aligned} \tag{A6.7}$$

These fault currents divide up into the branches of their respective phases in inverse proportion to the branch impedances. Alternatively, the total fault current in each branch of the two sound phases is the sum of the sequence currents in the corresponding branches of the three sequence networks.

The final short-circuit fault currents derived in this way are all in terms of the 440 V star circuit, and they must be converted to delta and star currents at 11 kV, and at 33 kV where applicable. The conversion factors to be used are as follows:

$$\text{Star current at 440 V to delta current at 11 kV} = \frac{254}{11\,000} = 0.0231$$

$$\text{Star current at 440 V to star current at 33 kV} = \frac{440}{33\,000} = 0.01333$$

The proper application of these conversion factors to the final short-circuit currents in the complete system, derived on a $440/\sqrt{3}$ V base, gives the true fault currents in the respective paths.

Case 1

The complete circuit is as shown in *Figure A6.1*, and all transformer neutrals are earthed. The complete sequence networks are shown in *Figure A6.2*, those parts which do not enter into the final sequence diagrams as carrying any of the sequence current concerned being left open circuited. The simplified sequence networks are given in *Figure A6.3*, and the component impedance values are inserted.

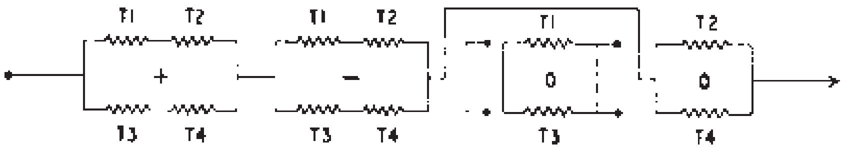

Figure A6.2 Complete phase sequence networks. Case 1.
E.R.* = 0

From *Figure A6.3* the sequence impedances are:

$$Z_0 = 0.0059/2 = 0.00295\ \Omega$$

$$Z_1 = (0.00261 + 0.0059)/2 = 0.004255\ \Omega$$

$$Z_2 = 0.004255\ \Omega$$

* In this appendix E.R. denotes ‘earth resistance’.

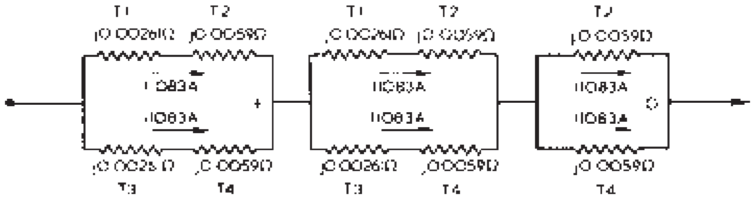

Figure A6.3 Simplified phase sequence networks with sequence impedances and currents. Case 1. E.R. = 0

From equation (A6.2) the total impedance of the entire circuit of *Figure A6.3* is:

$$Z = Z_0 + Z_1 + Z_2 = 0.00295 + 0.004255 + 0.004255 = 0.01146\ \Omega$$

From equation (A6.1) the total current in the fault is:

$$I_F = 3V/Z = (3 \times 254)/0.01146 = 66\,498\ \text{A}$$

From equations (A6.3) and (A6.4) the total current in each of the sequence networks is:

$$I_0 = I_1 = I_2 = 66\,498/3 = 22\,166\ \text{A}$$

and these currents divide equally into the two branches of each sequence diagram, as shown in *Figure A6.3*, since the impedances of the parallel connected branches are equal.

The total current in the faulty phase throughout the circuit is, as given by equation (A6.5), the sum of the various sequence currents, so that, remembering the 440 V base and equivalent star network throughout, we have:

I_A in primary line of T1 and T3 $= 11\,038 + 11\,083 = 22\,166$ A

I_A in secondary line of T2 and T4 $= 22\,166 + 11\,083 = 33\,249$ A

In phases B and C the total currents are, from equations (A6.7),

I_B in primary line of T1 and T3

$$= 0 - 0.5(11\,083 + 11\,083) - j0.866(11\,083 - 11\,083) = -11\,083\ \text{A}$$

I_B in secondary line of T2 and T4 $= 11\,083 - 11\,083 = 0$

I_C in primary line of T1 and T3

$$= 0 - 0.5(11\,083 + 11\,083) + j0.866(11\,083 - 11\,083) = -11\,083\ \text{A}$$

I_C in secondary line of T2 and T4 $= 11\,083 - 11\,083 = 0$

These currents are shown in *Figure A6.4*.

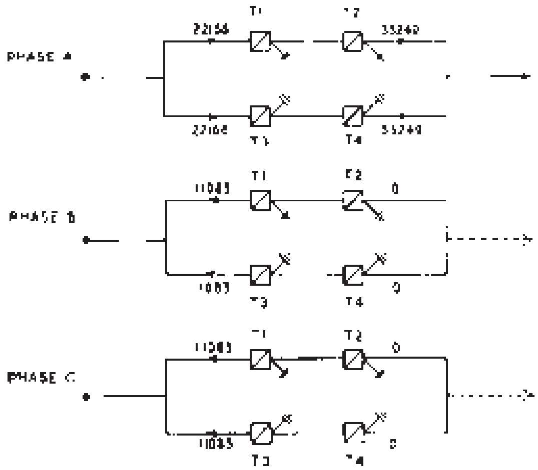

Figure A6.4 Phase currents on 440 V star base. Case 1. E.R. = 0

Applying the delta star current conversion factors, we have:

I_A in primary line of T1 and T3 $= 22\,166 \times (-0.0133)^* = -295$ A

I_A in secondary line of T2 and T4 $= 33\,249$ A

I_B in primary line of T1 and T3 $= -11\,083 \times (-0.0133)^* = 147.5$ A

I_B in secondary line of T2 and T4 $= 0$

I_C in primary line of T1 and T3 $= -11\,083 \times (-0.0133)^* = 147.5$ A

I_C in secondary line of T2 and T4 $= 0$

In the case of the secondary circuits of transformers T1 and T3 and of the primary circuits of T2 and T4, phase displacements with respect to the 440 V star base are involved, and account must be taken of these. From *Figure A6.5* the following equations apply for conversion of delta to star currents and vice versa.

$$\begin{aligned} I'_a &= n(I''_b - I''_c) = I'_B - I'_C \\ I'_b &= n(I''_c - I''_a) = I'_C - I'_A \\ I'_c &= n(I''_a - I''_b) = I'_A - I'_B \end{aligned} \tag{A6.8}$$

where n is the turns per phase ratio of transformation in whichever transformation direction is being considered.

* The minus sign is introduced here to take account of the reversal of line currents brought about by the cascade delta star transformations in each of the parallel circuits between the 33 kV and 440 V busbars (see *Figure A6.5*).

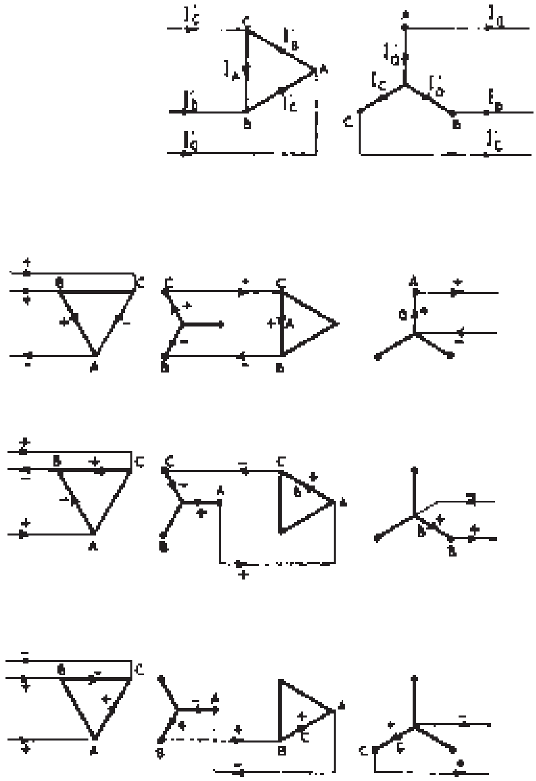

Figure A6.5 Star delta and delta star current conversions

From equation (A6.8), the actual currents in the secondary circuits of T1 and T3 and in the primary circuits of T2 and T4 are:

I_A in primary line of T2 $= 0.0231(0 - 0) = 0$

I_A in primary line of T4 $= 0$

I_B in primary line of T2 $= 0.0231(0 - 33\,249) = -768$ A

I_B in primary line of T4 $= -768$ A

I_C in primary line of T2 $= 0.0231(33\,249 - 0) = 768$ A

I_C in primary line of T4 $= 768$ A

I_A in secondary line of T1 $= 0$

I_A in secondary line of T3 $= 0$

I_B in secondary line of T1 $= -768$ A

I_B in secondary line of T3 $= -768$ A

I_C in secondary line of T1 $= 768$ A

I_C in secondary line of T3 $= 768$ A

The final true current distribution throughout the circuit is then as shown in *Figure A6.6*.

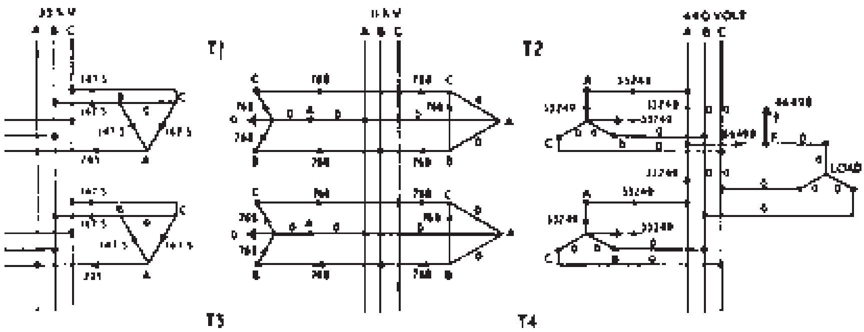

Figure A6.6 Fault current distribution. Case 1. E.R. $= 0$

In practice, currents of the magnitudes derived in the foregoing would not be attained due to earth resistance values. Suppose the total resistance R in the earth circuit between the neutral point of *each* transformer T2 and T4 and the fault to be 0.25 Ω. The only diagrams affected by these additions are the zero sequence networks in *Figures A6.2* and *A6.3*, in which a resistance equal to $3R = 0.75\ \Omega$ is inserted in each branch of the network in series with the zero sequence impedances of T2 and T4 respectively.

Then the total zero sequence impedance of T2 and T4 in parallel including the earth resistances is:

$$Z_0 = R + jX = (0.75106 + j0.0058)/2 = 0.37553 + j0.0029$$

$$= 0.376\ \Omega$$

and $\quad Z_1 = 0.004255\ \Omega \quad$ as before

$Z_2 = 0.004255\ \Omega \quad$ as before

From equation (A6.2),

$$Z = Z_0 + Z_1 + Z_2 = 0.37553 + j(0.0029 + 0.004255 + 0.004255)$$

$$= 0.37553 + j0.01141 = 0.376\ \Omega$$

It will be seen that the total fault current is now controlled by the earth resistances, and, moreover, it is reduced to a value which, compared with the previous one, makes it almost unrecognisable as a short-circuit current.

From equation (A6.1) the total current in the fault is, then:

$$I_F = 3V/Z = (3 \times 254)/0.376 = 2028\ \text{A}$$

From equations (A6.3) and (A6.4) the total current in each of the sequence networks is:

$$I_0 = I_1 = I_2 = 2028/3 = 676 \text{ A}$$

The current in each branch of each sequence network is one half the foregoing, that is, 338 A.

By the same procedure as already indicated and combining the different steps, the final fault currents throughout the entire circuit prior to star delta conversions are:

I_A in primary line of T1 and T3 $= (338 + 338)(-0.0133) = -9$ A

I_A in secondary line of T2 and T4 $= 676 + 338 = 1014$ A

I_B in primary line of T1 and T3

$= [0 - 0.5(338 + 338) - j0.866(338 - 338)](-0.0133) = 4.5$ A

I_B in secondary line of T2 and T4 $= 338 - 338 = 0$

I_C in primary line of T1 and T3

$= [0 - 0.5(338 + 338) + j0.866(338 - 338)](-0.0133) = 4.5$ A

I_C in secondary line of T2 and T4 $= 338 - 338 = 0$

Applying the star delta conversions of equations (A6.8), the actual currents in the secondary circuits of T1 and T3 and in the primary circuits of T2 and T4 are:

I_A in primary line of T2 $= 0.0231(0 - 0) = 0$

I_A in primary line of T4 $= 0$

I_B in primary line of T2 $= 0.0231(0 - 1014) = -23.4$ A

I_B in primary line of T4 $= -23.4$ A

I_C in primary line of T2 $= 0.0231(1014 - 0) = 23.4$ A

I_C in primary line of T4 $= 23.4$ A

I_A in secondary line of T1 $= 0$

I_A in secondary line of T3 $= 0$

I_B in secondary line of T1 $= -23.4$ A

I_B in secondary line of T3 $= -23.4$ A

I_C in secondary line of T1 $= 23.4$ A

I_C in secondary line of T3 $= 23.4$ A

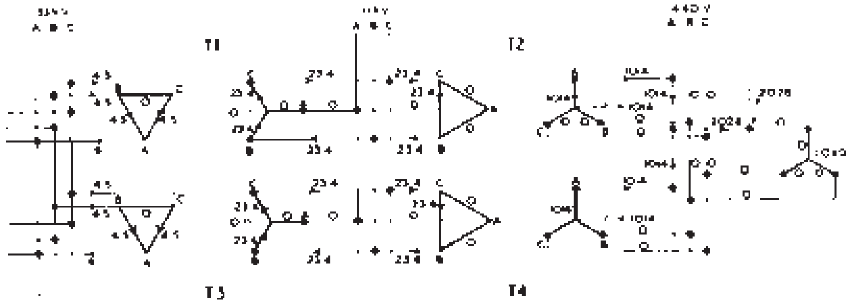

Figure A6.7 Fault current distribution. Case 1. E.R. = 0.25 Ω

The final true current distribution throughout the circuit is shown in *Figure A6.7*, and it will be seen that, compared with *Figure A6.6*, the proportionality between *all* currents is the ratio of the total currents in the fault.

It will be noticed that in this example the fault current in the earthed secondary line A of each consumer's transformers T2 and T4 is only about 50% of the normal full-load current of the transformer, and this serves to emphasise the importance of securing particularly low resistance neutral earth connections for 1.v. circuits. At light load periods a short-circuit current of this magnitude may be inadequate (apart from 'doubling' effects) to operate line overload trips, and unless sufficiently sensitive earth leakage tripping is provided, the fault would be maintained with disastrous consequences. In h.v. circuits the absolute *ohmic* value of the earth resistance connection may be higher, although the same limitation is imposed upon its value in relation to the impedance of the circuit to which it is connected, as is necessary in 1.v. circuits.

Case 2

The complete circuit is the same as *Figure A6.1*, except that the secondary neutral of the consumer's transformer T4 is insulated from earth. The phase sequence networks are shown in *Figures A6.8* and *A6.9*, and it will be seen that these differ from *Figures A6.2* and *A6.3* only by reason of the elimination of the impedance of transformer T4 from the zero sequence network.

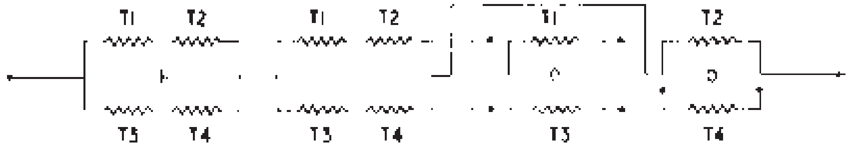

Figure A6.8 Complete phase sequence networks. Case 2. E.R. = 0

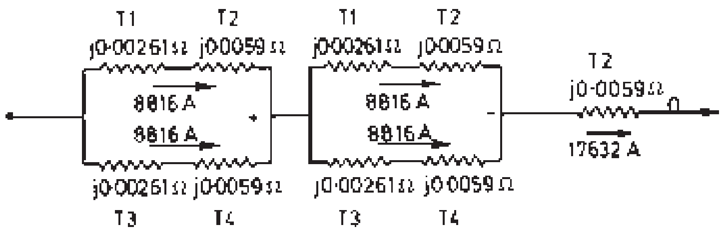

Figure A6.9 Simplified phase sequence networks with sequence impedances and currents. Case 2. E.R. = 0

For this case the sequence impedances are, then:

$Z_0 = 0.0059\ \Omega$

$Z_1 = 0.004255\ \Omega$

$Z_2 = 0.004255\ \Omega$

From equation (A6.2) the total impedance of the entire circuit of *Figure A6.9* is:

$$Z = Z_0 + Z_1 + Z_2 = 0.0059 + 0.004255 + 0.004255 = 0.01441\ \Omega$$

From equation (A6.1) the total current in the fault is:

$$I_F = 3V/Z = (3 \times 254)/0.01441 = 52\,896\ \text{A}$$

From equations (A6.3) and (A6.4) the total current in each of the sequence networks is:

$$I_0 = I_1 = I_2 = 52\,896/3 = 17\,632\ \text{A}$$

The current in each branch of the positive and negative sequence networks is one half of this, or 8816 A, as shown in *Figure A6.9*.

By the same procedure as adopted in case 1 the line currents on the 440 V base and equivalent star network throughout are:

By equation (A6.5),

I_A in primary line of T1 and T3 $= 8816 + 8816 = 17\,632$ A

I_A in secondary line of T2 $= 17\,632 + 17\,632 = 35\,264$ A

I_A in secondary line of T4 $= 8816 + 8816 = 17\,632$ A

By equation (A6.7),

I_B in primary line of T1 and T3

$$= 0 - 0.5(8816 + 8816) + j0.866(8816 - 8816) = -8816\ \text{A}$$

I_B in secondary line of T2 $= 17\,632 - 8816 = 8816$ A

I_B in secondary line of T4 $= -8816$ A and similarly

I_C in primary line of T1 and T3

$= 0 - 0.5(8816 + 8816) + j0.866(8816 - 8816) = -8816$ A

I_C in secondary line of T2 $= 17\,632 - 8816 = 8816$ A

I_C in secondary line of T4 $= -8816$ A

These currents are shown in *Figure A6.10.*

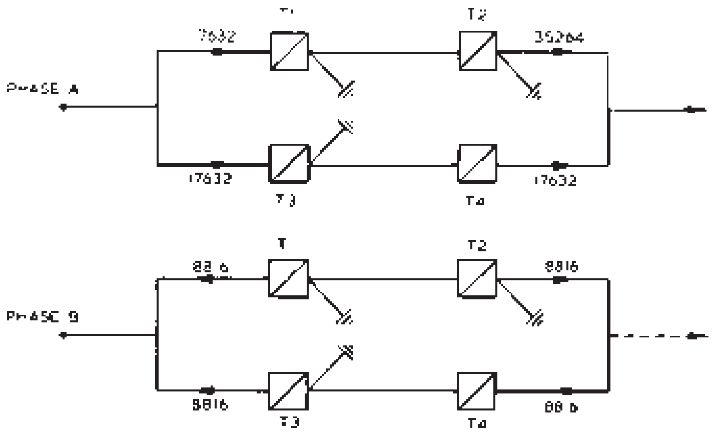

Figure A6.10 Phase currents on 440 V star base. Case 2. E.R. = 0

Applying the delta star conversion factors previously given together with the provisions of equations (A6.8), the actual currents throughout the entire circuit are:

I_A in primary line of T1 and T3 $= 17\,632 \times (-0.0133) = -235$ A

I_A in secondary line of T2 $= 35\,264$ A

I_A in secondary line of T4 $= 17\,632$ A

I_B in primary line of T1 and T3 $= -8816 \times (-0.0133) = 117.5$ A

I_B in secondary line of T2 $= 8816$ A

I_B in secondary line of T4 $= -8816$ A

I_C in primary line of T1 and T3 $= -8816 \times (-0.0133) = 117.5$ A

I_C in secondary line of T2 $= 8816$ A

I_C in secondary line of T4 $= -8816$ A

I_A in primary line of T2 $= 0.0231(8816 - 8816) = 0$

I_A in primary line of T4 $= 0.0231(-8816 + 8816) = 0$

I_B in primary line of T2 $= 0.0231(8816 - 35\,264) = -612$ A

I_B in primary line of T4 $= 0.0231(-8816 - 17\,632) = -612$ A

I_C in primary line of T2 $= 0.0231(35\,364 - 8816) = 612$ A

I_C in primary line of T4 $= 0.0231(17\,632 + 8816) = 612$ A

I_A in secondary line of T1 $= 0$

I_A in secondary line of T3 $= 0$

I_B in secondary line of T1 $= -612$ A

I_B in secondary line of T3 $= -612$ A

I_C in secondary line of T1 $= 612$ A

I_C in secondary line of T3 $= 612$ A

These currents are shown in *Figure A6.11*.

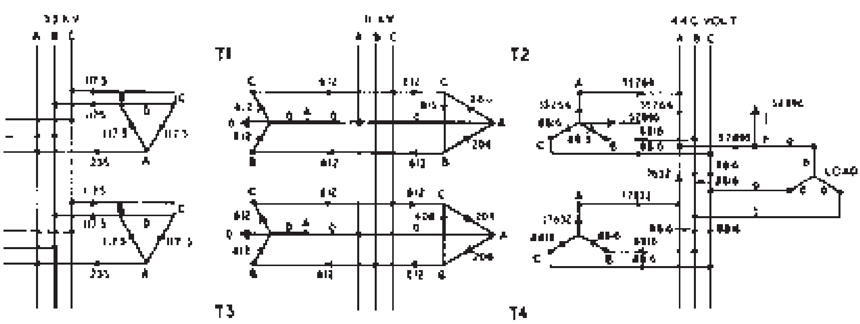

Figure A6.11 Fault current distribution. Case 2. E.R. = 0

If, now, it is assumed the resistance R of the earth circuit between the neutral point of T2 and the fault is 0.25 Ω, the sequence impedances are as given in *Figures A6.8* and *A6.9*, except that a resistance of $3R = 0.75$ Ω is inserted in series in the zero sequence network.

Then:

$$Z_0 = R + jX = 0.75106 + j0.0058 = 0.752\ \Omega$$

$$Z_1 = 0.004255\ \Omega \text{ as before}$$

$$Z_2 = 0.004255\ \Omega \text{ as before}$$

From equation (A6.2),

$$Z = Z_0 + Z_1 + Z_2 = 0.75106 + j(0.0058 + 0.004255 + 0.004255)$$

$$= 0.75106 + j0.01431 = 0.752\ \Omega$$

From equation (A6.1) the total fault current is:

$$I_F = 3V/Z = (3 \times 254)/0.752 = 1014\ \text{A}$$

This current, it will be seen, is one half that obtaining in case 1, where the same resistance was assumed to be present in the neutral earth circuit.

The values of the true currents throughout the entire circuit are then those given in *Figure A6.11* reduced in direct proportion to the respective total currents in the earth fault, that is, multiplied by the ratio $1014/52\,896 = 0.0192$.

It will be noticed how much less likely is the transformer with insulated neutral to be tripped out of circuit should an earth fault occur when there is appreciable resistance in the earth fault circuit.

Case 3

In this case the system is the same as in *Figure A6.1*, except that transformer T4 is disconnected from the busbars on both sides. The simplified phase sequence networks are shown in *Figure A6.12*, together with their impedance values. The total sequence impedances are then:

$$Z_0 = 0.0059\ \Omega$$

$$Z_1 = (0.00261/2) + 0.0059 = 0.0072\ \Omega$$

$$Z_2 = 0.0072\ \Omega$$

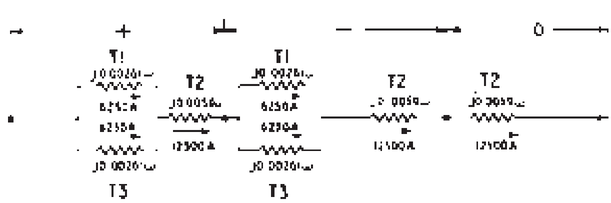

Figure A6.12 Simplified phase sequence networks with sequence impedances and currents. Case 3. E.R. = 0.

The total impedance of the entire circuit of *Figure A6.12* is:

$$Z = Z_0 + Z_1 + Z_2 = 0.0059 + 0.0072 + 0.0072 = 0.0203\ \Omega$$

The total fault current is:

$$I_F = 3V/Z = (3 \times 54)/0.0203 = 37\,500\ \text{A}$$

The total current in each sequence network is:

$$I_0 = I_1 = I_2 = 37\,500/3 = 12\,500 \text{ A}$$

and the distribution is as in *Figure A6.12*.

The total current in the faulty phase, on the 440 V base and equivalent star network throughout, is:

$$I_A \text{ in primary line of T1 and T3} = 6250 + 6250 = 12\,500 \text{ A}$$

$$I_A \text{ in secondary line of T2} = 12\,500 + 12\,500 + 12\,500 = 37\,500 \text{ A}$$

$$I_B \text{ in primary line of T1 and T3}$$
$$= 0 - 0.5(6250 + 6250) - j0.866(6250 - 6250) = -6250 \text{ A}$$

$$I_B \text{ in secondary line of T2}$$
$$= 12\,500 - 0.5(12\,500 + 12\,500) + j0.866(12\,500 - 12\,500) = 0$$

$$I_C \text{ in primary line of T1 and T3}$$
$$= 0 - 0.5(6250 + 6250) + j0.866(6250 - 6250) = -6250 \text{ A}$$

$$I_C \text{ in secondary line of T2} = 12\,500 - 12\,500 = 0$$

Applying the star delta current conversion factors:

$$I_A \text{ in primary line of T1 and T3} = 12\,500 \times (-0.0133) = -166 \text{ A}$$

$$I_A \text{ in secondary line of T2} = 37\,500 \text{ A}$$

$$I_B \text{ in primary line of T1 and T3} = -6250 \times (-0.0133) = 83 \text{ A}$$

$$I_B \text{ in secondary line of T2} = 0$$

$$I_C \text{ in primary line of T1 and T3} = -6250 \times (-0.0133) = 83 \text{ A}$$

$$I_C \text{ in secondary line of T2} = 0$$

Applying equations (A6.8), the final currents in the primary lines of T2 and the secondary lines of T1 and T3 are:

$$I_A \text{ in primary line of T2} = 0.0231(0 - 0) = 0$$

$$I_B \text{ in primary line of T2} = 0.0231(0 - 37\,500) = -866 \text{ A}$$

$$I_C \text{ in primary line of T2} = 0.0231(37\,500 - 0) = 866 \text{ A}$$

$$I_A \text{ in secondary line of T1} = 0$$

$$I_A \text{ in secondary line of T3} = 0$$

$$I_B \text{ in secondary line of T1} = -866/2 = -433 \text{ A}$$

$$I_B \text{ in secondary line of T3} = -866/2 = -433 \text{ A}$$

$$I_C \text{ in secondary line of T1} = 866/2 = 433 \text{ A}$$

I_C in secondary line of T3 $= 866/2 = 433$ A

The final current distribution is shown in *Figure A6.13*.

If a resistance of 0.25 Ω be assumed in the neutral earth circuit of consumer's transformer T2:

$$Z_0 = R + jX = 0.75106 + j0.0058 = 0.752\ \Omega$$

$$Z_1 = 0.0072\ \Omega \text{ as before}$$

$$Z_2 = 0.0072\ \Omega \text{ as before}$$

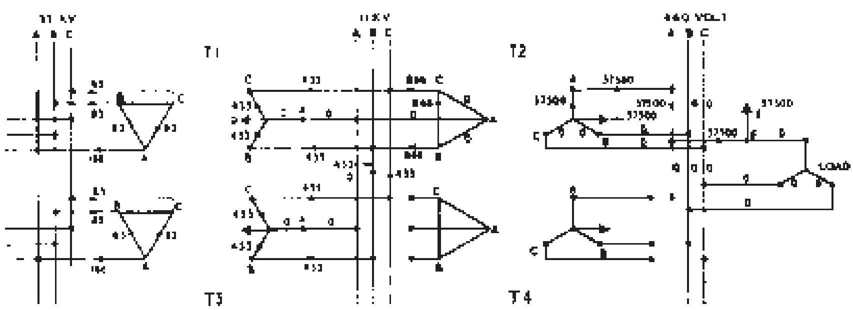

Figure A6.13 Fault current distribution. Case 3. E.R. $= 0$

and

$$Z = Z_0 + Z_1 + Z_2 = 0.75106 + j(0.0058 + 0.0072 + 0.0072)$$
$$= 0.75106 + j0.0202 = 0.752\ \Omega$$

The total current in the fault is,

$$I_F = 3V/Z = (3 \times 254)/0.752 = 1014\ \text{A}$$

being one half the current flowing in the fault when T1 and T2 are both in commission and with assumed earth circuit resistances of 0.25 Ω each. This, of course, is because of the predominating effect of the earth resistances upon the fault current magnitudes.

The qualitative current distributions is the same as in *Figure A6.13* and quantitatively the currents are those of *Figure A6.13* multiplied by the ratio of the total earth fault currents in the two cases, namely, $1014/37\,500 = 0.02705$.

In the foregoing treatments the fault currents throughout the circuits are $\pm j$ with respect to the voltage to neutral reference phasor of phase A on the secondary side of T2 and T4, when the earth resistances are zero. This is due to the transformer resistances being negligible compared with the reactances. When resistances are included in the earth circuits, however, the fault currents practically are in phase or in opposition with the voltage reference phasor V_A

(or V_a), due to the overwhelming effect of the earth resistances, the transformer reactances being negligible by comparison.

PART 2: VOLTAGES

The voltages under fault conditions, at any point in the system, may be obtained in the following way. The phase sequence voltages are first calculated at the 440 V and at the 11 kV busbars on the 440 V base. The voltages from all three lines to neutral are then determined at the same points, still on the 440 V base. The values so derived at the 440 V busbars, i.e. on the secondary sides of transformers T2 and T4, are the actual ones. The true 11 kV delta primary voltages of T2 and T4 and star secondary voltages of T1 and T3 are obtained by applying star delta conversion factors and phase transformation terms. The 33 kV delta primary voltages of T1 and T3 have been postulated as remaining balanced under fault conditions.

The general equations used to determine the circuit voltages are then as follows:

For each phase sequence, the sequence component of line to neutral voltage at any point in the system is equal to the generated line to neutral voltage V_G (which in this case is the voltage at the 33 kV busbars) minus the sequence voltage drop v at that point. Thus, in general, we have, for the sequence line to neutral voltages at any point in a given system,

$$\begin{aligned} &\text{positive sequence component,} && V_1 = V_G - v_1 \\ &\text{negative sequence component,} && V_2 = 0 - v_2 \\ &\text{zero sequence component,} && V_0 = 0 - v_0 \end{aligned} \tag{A6.9}$$

The generated voltage V_G is of positive sequence only, so that for negative and zero sequences $V_G = 0$.

The sequence voltage drops are, of course,

$$\begin{aligned} v_1 &= I_1 Z_1 \\ v_2 &= I_2 Z_2 \\ v_0 &= I_0 Z_0 \end{aligned} \tag{A6.10}$$

The total voltage to neutral at any point in the system is given by the general expression,

$$\begin{aligned} V &= V_0 + V_1 + V_2 \\ &= V_G - (v_0 + v_1 + v_2) \end{aligned}$$

In a three-phase system the line to neutral voltages at any point are then,

$$\begin{aligned} V_A &= V_0 + V_1 + V_2 \\ V_B &= V_0 + h^2 V_1 + h V_2 \\ V_C &= V_0 + h V_1 + h^2 V_2 \end{aligned}$$

when applying the usual phasor operators h and h^2, given on page 855.

For use in the calculations, the equations above are rewritten,

$$
\begin{aligned}
V_A &= V_0 + V_1 + V_2 \\
V_B &= V_0 + V_1(-0.5 - j0.866) + V_2(-0.5 + j0.866) \\
&= V_0 - 0.5(V_1 + V_2) - j0.866(V_1 - V_2) \\
V_C &= V_0 + V_2(-0.5 + j0.866) + V_2(-0.5 - j0.866) \\
&= V_0 - 0.5(V_1 + V_2) + j0.866(V_1 - V_2)
\end{aligned}
\tag{A6.11}
$$

being comparable with the current equations (A6.5), (A6.6) and (A6.7).

Voltage conversion factors are as follows:

Star voltage of 254 V to delta voltage of 11 kV = 0.0231

Star voltage of 254 V to star voltage of 6.35 kV = 0.01333

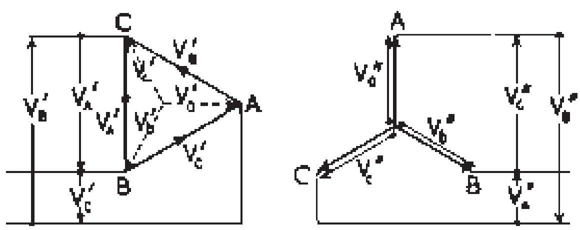

Figure A6.14 Star delta and delta star voltage conversions

Figure A6.14 shows the conversions adopted for star delta and delta star voltage conversions. The corresponding equations are:

$$
\begin{aligned}
V'_A &= -V''_a/n = V'_b - V'^{*}_c \\
V'_B &= -V''_b/n = V'_c - V'_a \\
V'_C &= -V''_c/n = V'_a - V'_b
\end{aligned}
\tag{A6.12}
$$

$$
\begin{aligned}
V'_a &= \tfrac{1}{3}V'_A + \tfrac{2}{3}V'_C \\
V'_b &= \tfrac{1}{3}V'_B + \tfrac{2}{3}V'_A \\
V'_c &= \tfrac{1}{3}V'_C + \tfrac{2}{3}V'_B
\end{aligned}
\tag{A6.13}
$$

$$
\begin{aligned}
V''_A &= V''_b - V''_c \\
V''_B &= V''_c - V''_a \\
V''_C &= V''_a - V''_b
\end{aligned}
\tag{A6.14}
$$

* The minus signs are introduced into the central terms of these equations to denote opposition of primary and secondary phase winding voltage phasors.

Additions and subtractions are, of course, carried out vectorially. The factor n is the turns per phase ratio of transformation in whichever transformation direction is being considered.

The detailed calculations can now be proceeded with by application of the foregoing equations.

Case 1. Circuit diagrams (*Figures A6.1 to A6.6***)**

Voltages at 440 V busbars

Phase sequence voltages, from equations (A6.9) and (A6.10) and *Figure A6.3*:

Positive sequence voltage is:

$$\begin{aligned} V_1 &= V_G - I_1 Z_1 \\ &= j254 - 11\,083(j0.00261 + j0.0059) \\ &= j254 - j94.3 = j159.7 \text{ V} \end{aligned}$$

Negative sequence voltage is:

$$\begin{aligned} V_2 &= V_G - I_2 Z_2 \\ &= 0 - 11\,083(j0.00261 + j0.0059) \\ &= 0 - j94.3 = -j94.3 \text{ V} \end{aligned}$$

Zero sequence voltage is:

$$\begin{aligned} V_0 &= V_G - I_0 Z_0 \\ &= 0 - (11\,083 \times j0.0059) = -j65.4 \text{ V} \end{aligned}$$

Line to neutral voltages, from equations (A6.11):

Line A to neutral,

$$\begin{aligned} V_A = V_a'' &= V_0 + V_1 + V_2 \\ &= -j65.4 + j159.7 - j94.3 = 0 \end{aligned}$$

Line B to neutral,

$$\begin{aligned} V_B = V_b'' &= V_0 - 0.5(V_1 + V_2) - j0.866(V_1 - V_2) \\ &= -j65.4 - 0.5(j159.7 - j94.3) - j0.866(j159.7 + j94.3) \\ &= -j65.4 - j32.7 + 220 \\ &= -j98.1 + 220 = 241 \text{ V} \end{aligned}$$

Line C to neutral,

$$V_C = V_c'' = V_0 - 0.5(V_1 + V_2) + j0.866(V_1 - V_2)$$

$$= -j65.4 - 0.5(j159.7 - j94.3) + j0.866(j159.7 + j94.3)$$
$$= -j65.4 - j32.7 - 220$$
$$= -j98.1 - 220 = 241\ \text{V}$$

Line to line voltages, from equations (A6.14):

$$V''_A = V''_b - V''_c$$
$$= -j98.1 + 220 + j98.1 + 220 = 440\ \text{V}$$
$$V''_B = V''_c - V''_a$$
$$= -j98.1 - 220 - 0$$
$$= -j98.1 - 220 = 241\ \text{V}$$
$$V''_C = V''_a - V''_b$$
$$= 0 + j98.1 - 220$$
$$= j98.1 - 220 = 241\ \text{V}$$

Voltages at 11 kV busbars

Phase sequence voltages, from equations (A6.9) and (A6.10) and *Figure A6.3*:

Positive sequence voltage is,

$$V_1 = V_G - I_1 Z_1$$
$$= j254 - (11\,083 \times j0.00261)$$
$$= j254 - j28.9 = j225.1\ \text{V}$$

Negative sequence voltage is,

$$V_2 = V_G - I_2 Z_2$$
$$= 0 - (11\,083 \times j0.00261)$$
$$= -j28.9\ \text{V}$$

Zero sequence voltage is $V_0 = 0$

Line to neutral voltages, from equations (A6.11):

Line A to neutral,

$$V_A = V''_a = V_0 + V_1 + V_2$$
$$= 0 + j225.1 - j28.9 = j196.2\ \text{V}$$

Line B to neutral,

$$V_B = V''_b = V_0 - 0.5(V_1 + V_2) - j0.866(V_1 - V_2)$$
$$= 0 - 0.5(j225.1 - j28.9) - j0.866(j225.1 + j28.9)$$
$$= -j98.1 + 220 = 241\ \text{V}$$

Line C to neutral,

$$\begin{aligned} V_C = V_c'' &= V_0 - 0.5(V_1 + V_2) + j0.866(V_1 - V_2) \\ &= 0 - 0.5(j225.1 - j28.9) + j0.866(j225.1 + j28.9) \\ &= -j98.1 - 220 = 241 \text{ V} \end{aligned}$$

Converting these line to neutral voltages on a 440 V star base to true 11 kV delta values, from *Figure A6.14* and equations (A6.12):

$$\begin{aligned} V_A' &= -V_a''/n \\ &= -j196.2/0.0231 = -j8500 \text{ V} \\ V_B' &= -V_b''/n \\ &= (j98.1 - 220)/0.0231 \\ &= j4250 - 9530 = 10\,420 \text{ V} \\ V_C' &= -V_c''/n \\ &= (j98.1 + 220)/0.0231 \\ &= j4250 + 9530 = 10\,420 \text{ V} \end{aligned}$$

The corresponding true line to neutral voltages on the 11 kV side of T1 and T3 are obtained from equations (A6.13), thus,

$$\begin{aligned} V_a' &= \tfrac{1}{3}V_A' + \tfrac{2}{3}V_C' \\ &= \tfrac{1}{3}(-j8500) + \tfrac{2}{3}(j4250 + 9530) \\ &= -j2833 + j2833 + 6353 = 6353 \text{ V} \\ V_b' &= \tfrac{1}{3}V_B' + \tfrac{2}{3}V_A' \\ &= \tfrac{1}{3}(j4250 - 9530) + \tfrac{2}{3}(-j8500) \\ &= j1417 - 3177 - j5667 \\ &= -j4250 - 3177 = 5300 \text{ V} \\ V_c' &= \tfrac{1}{3}V_C' + \tfrac{2}{3}V_B' \\ &= \tfrac{1}{3}(j4250 + 9530) + \tfrac{2}{3}(j4250 - 9530) \\ &= j1417 + 3177 + j2833 - 6354 \\ &= j4250 - 3177 = 5300 \text{ V} \end{aligned}$$

The voltages of T1 and T3 are the same and those of T2 and T4 are identical. All the voltages throughout the circuits are summarised as follows.

Transformers T1 and T3:

All primary line voltages, 33 kV
Secondary line to neutral voltage,

$$V_a' = 6353 \text{ V}$$
$$V_b' = j4250 - 3177 = 5300 \text{ V}$$
$$V_c' = j4250 - 3177 = 5300 \text{ V}$$

Transformers T2 and T4:

Primary line voltages,

$$V_A' = -j8500 \text{ V}$$
$$V_B' = j4250 - 9530 = 10\,420 \text{ V}$$
$$V_C'' = j4250 + 9530 = 10\,420 \text{ V}$$

Secondary line to neutral voltages,

$$V_a'' = 0$$
$$V_b'' = -j98.1 + 220 = 241 \text{ V}$$
$$V_c'' = -j98.1 - 220 = 241 \text{ V}$$

Secondary line voltages,

$$V_A'' = +440 \text{ V}$$
$$V_B'' = -j98.1 - 220 = 241 \text{ V}$$
$$V_C'' = j98.1 - 220 = 241 \text{ V}$$

These are shown in phasor form in *Figure A6.15*.

The voltages throughout the circuit are very different from the foregoing if neutral earth resistances be included. Taking 0.25 Ω in the neutral earth circuits of transformers T2 and T4 as before, and by the same procedure as just given, the circuit voltages are as follows.

Voltages at 440 V busbars

Phase sequence voltages, from equations (A6.9) and (A6.10) and *Figure A6.3*, bearing in mind the inclusion of a series resistance $R_0 = 3R = 0.75$ Ω in each branch of the zero sequence network:

Positive sequence voltage is,

$$\begin{aligned} V_1 &= V_G - I_1 Z_1 \\ &= j254 - j338^{*}(j0.00261 + j0.0059) \\ &= j254 + 2.9 = j254 \text{ V} \end{aligned}$$

* The j operator is attached to the current throughout as it is virtually in phase with V_G.

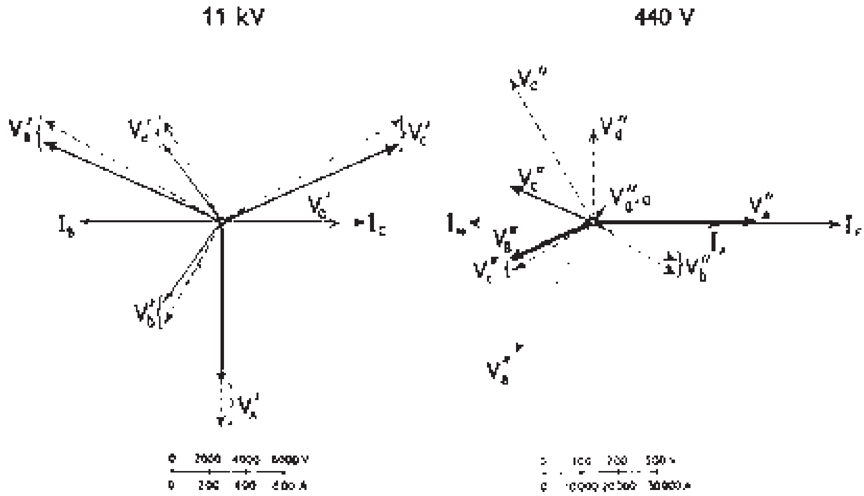

Figure A6.15 Currents and voltages. Case 1. E.R. = 0. Broken lines show no-load voltages

Negative sequence voltage is,

$$\begin{aligned} V_2 &= V_G - I_2 Z_2 \\ &= 0 - j338(j0.00261 + j0.0059) \\ &= 0 + 2.9 = 2.9 \text{ V} \end{aligned}$$

Zero sequence voltage is,

$$\begin{aligned} V_0 &= V_G - I_0 Z_0 \\ &= 0 - j338(0.75106 + j0.0059) \\ &= 0 - j254 + 2 = -j254 \text{ V} \end{aligned}$$

Line to neutral voltages, from equations (A6.11):

Line A to neutral,

$$\begin{aligned} V_A = V_a'' &= V_0 + V_1 + V_2 \\ &= -j254 + 2 + j254 + 2.9 + 2.9 = 7.8 \text{ V} \end{aligned}$$

Line B to neutral,

$$\begin{aligned} V_B = V_b'' &= V_0 - 0.5(V_1 + V_2) - j0.866(V_1 - V_2) \\ &= -j254 + 2 - 0.5(j254 + 2.9 + 2.9) \\ &\quad - j0.866(j254 + 2.9 - 2.9) \end{aligned}$$

$$= -j254 + 2 - j127 - 1.45 - 1.45 + 220 - j2.5 + j2.5$$
$$= -j381 + 219.1 = 440 \text{ V}$$

Line C to neutral,

$$V_C = V_c'' = V_0 - 0.5(V_1 + V_2) + j0.866(V_1 - V_2)$$
$$= -j254 + 2 - 0.5(j254 + 2.9 + 2.9)$$
$$+ j0.866(j254 + 2.9 - 2.9)$$
$$= -j254 + 2 - j127 - 1.45 - 1.45 - 220 + j2.5 - j2.5$$
$$= -j381 - 220.9 = 440 \text{ V}$$

Line to line voltages, from equations (A6.14):

$$V_A'' = V_b'' - V_c''$$
$$= -j381 + 219.1 + j381 + 220.9 = 440 \text{ V}$$
$$V_B'' = V_c'' - V_a''$$
$$= -j381 - 220.9 - 7.8$$
$$= -j381 - 228.7 = 443 \text{ V}$$
$$V_C'' = V_a'' - V_b''$$
$$= 7.8 + j381 - 219.1$$
$$= j381 - 211.3 = 435 \text{ V}$$

The voltage drop across the neutral earth resistance is, of course,

$$V_R = I_0 R_0 = I_0 3R = j338 \times 0.75 = j254 \text{ V}$$

Voltages at 11 kV busbars

Phase sequence voltages, from equations (A6.9) and (A6.10) and *Figure A6.3*:

Positive sequence voltage is,

$$V_1 = V_G - I_1 Z_1$$
$$= j254 - (j338 \times j0.00261)$$
$$= j254 + 0.9 = 254 \text{ V}$$

Negative sequence voltage is,

$$V_2 = V_G - I_2 Z_2$$
$$= 0 - (j338 \times j0.00261) = +0.9 \text{ V}$$

Zero sequence voltage is $V_0 = 0$

Line to neutral voltages, from equations (A6.11):

Line A to neutral,

$$V_A = V_a'' = V_0 + V_1 + V_2$$
$$= 0 + j254 + 0.9 + 0.9 = j254 + 1.8 = 254 \text{ V}$$
$$V_B = V_b'' = V_0 - 0.5(V_1 + V_2) - j0.866(V_1 - V_2)$$
$$= 0 - 0.5(j254 + 0.9 + 0.9) - j0.866(j254 + 0.9 - 0.9)$$
$$= -j127 - 0.45 - 0.45 + 220 - j0.8 + j0.8$$
$$= -j127 + 219.1 = 253 \text{ V}$$
$$V_C = V_c'' = V_0 - 0.5(V_1 + V_2) + j0.866(V_1 - V_2)$$
$$= 0 - 0.5(j254 + 0.9 + 0.9) + j0.866(j254 + 0.9 - 0.9)$$
$$= -j127 - 0.45 - 0.45 - 220 + j0.8 - j0.8$$
$$= -j127 - 220.9 = 254 \text{ V}$$

True 11 kV delta voltages are, from equations (A6.13):

$$V_A' = -V_a''/n$$
$$= (-j254 - 1.8)/0.0231$$
$$= -j11\,000 - 77 = 11\,000 \text{ V}$$
$$V_B' = -V_b''/n$$
$$= (j127 - 219.1)/0.0231$$
$$= j5500 - 9500 = 10\,750 \text{ V}$$
$$V_C' = -V_c''/n$$
$$= (j127 + 220.9)/0.0231$$
$$= j5500 + 9560 = 11\,020 \text{ V}$$

The corresponding true line to neutral voltages on the 11 kV side of T1 and T3 are, from equations (A6.13):

$$V_a' = \tfrac{1}{3}V_A' + \tfrac{2}{3}V_C'$$
$$= \tfrac{1}{3}(-j11\,000 - 77) + \tfrac{2}{3}(j5500 + 9560)$$
$$= -j3667 - 26 + j3667 + 6373 = 6347 \text{ V}$$
$$V_b' = \tfrac{1}{3}V_B' + \tfrac{2}{3}V_A'$$
$$= \tfrac{1}{3}(j5500 - 9500) + \tfrac{2}{3}(-j11\,000 - 77)$$
$$= j1833 - 3167 - j7333 - 51$$
$$= -j5500 - 3218 = 6380 \text{ V}$$

$$
\begin{aligned}
V'_c &= \tfrac{1}{3}V'_C + \tfrac{2}{3}V'_B \\
&= \tfrac{1}{3}(j5500 + 9560) + \tfrac{2}{3}(j5500 - 9550) \\
&= j1833 + 3187 + j3667 - 6367 \\
&= j5500 - 3180 = 6350 \text{ V}
\end{aligned}
$$

The voltages of T1 and T3 are the same, and those of T2 and T4 are identical. All voltages throughout the circuits are summarised as follows:

Transformers T1 and T3:

All primary line voltages, 33 kV
Secondary line to neutral voltages:

$$
\begin{aligned}
V'_a &= 6347 \text{ V} \\
V'_b &= -j5500 - 3218 = 6380 \text{ V} \\
V'_c &= j5500 - 3180 = 6350 \text{ V}
\end{aligned}
$$

Transformers T2 and T4:

Primary line voltages:

$$
\begin{aligned}
V'_A &= -j11\,000 - 77 = 11\,000 \text{ V} \\
V'_B &= j5500 - 9500 = 10\,750 \text{ V} \\
V'_C &= j5500 + 9560 = 11\,020 \text{ V}
\end{aligned}
$$

Secondary line to neutral voltages:

$$
\begin{aligned}
V''_a &= 7.8 \text{ V} \\
V''_b &= j381 + 219.1 = 440 \text{ V} \\
V''_c &= j381 - 220.9 = 440 \text{ V}
\end{aligned}
$$

Secondary line voltages:

$$
\begin{aligned}
V''_A &= 440 \text{ V} \\
V''_B &= -j381 - 228.7 = 443 \text{ V} \\
V''_C &= j381 - 211.3 = 435 \text{ V}
\end{aligned}
$$

Voltage drop across earth resistance, $V_R = j254$ V

Figure A6.16 shows in phasor form the voltages at the 440 V and the 11 kV busbars. The current phasors qualitatively are the same as those of *Figure A6.15*, but rotated through 90°, and quantitatively are of the magnitudes shown in *Figure A6.7*. Small apparent discrepancies in the co-ordinate values of the different voltages are due to slide rule working and to minor adjustments made in rounding off certain figures.

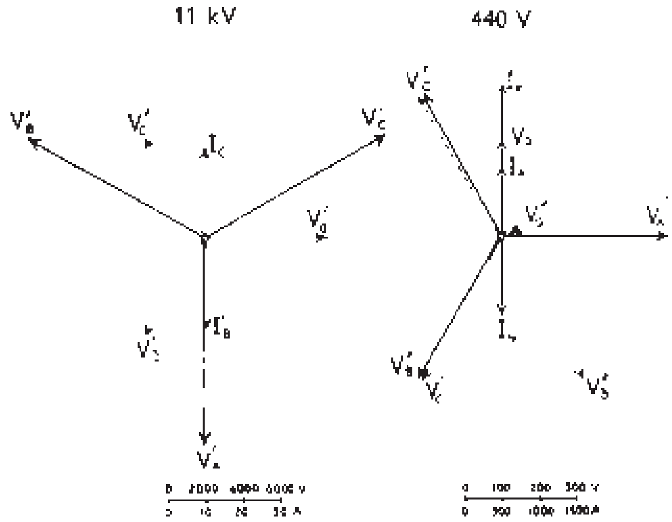

Figure A6.16 Currents and voltages. Case 1. E.R. = 0.25 Ω.
Broken lines show no-load voltages

Case 2. Circuit diagrams (*Figures A6.1* and *A6.7* to *A6.10***)**

Voltages at 440 V busbars

Phase sequence voltages, from equations (A6.9) and (A6.10) and *Figure A6.9*:

Positive sequence voltage is,

$$\begin{aligned} V_1 &= V_G - I_1 Z_1 \\ &= j254 - 8816(j0.00261 + j0.0059) \\ &= j254 - j75 = j179 \text{ V} \end{aligned}$$

Negative sequence voltage is,

$$\begin{aligned} V_2 &= V_G - I_2 Z_2 \\ &= 0 - 8816(j0.00261 + j0.0059) \\ &= 0 - j75 = -j75 \text{ V} \end{aligned}$$

Zero sequence voltage is,

$$\begin{aligned} V_0 &= V_G - I_0 Z_0 \\ &= 0 - (17\,632 \times j0.0059) \\ &= -j104 = -j104 \text{ V} \end{aligned}$$

Transformer T2, line to neutral voltages, from equations (A6.11):

Line A to neutral,

$$V_A = V_a'' = V_0 + V_1 + V_2$$
$$= -j104 + j179 - j75 = 0$$

Line B to neutral,

$$V_B = V_b'' = V_0 - 0.5(V_1 + V_2) - j0.866(V_1 - V_2)$$
$$= -j104 - 0.5(j179 - j75) - j0.866(j179 + j75)$$
$$= -j104 - j89.5 + j37.5 + 155 + 65$$
$$= -j156 + 220 = 270 \text{ V}$$

Line C to neutral,

$$V_C = V_c'' = V_0 - 0.5(V_1 + V_2) + j0.866(V_1 - V_2)$$
$$= -j104 - 0.5(j179 - j75) + j0.866(j179 + j75)$$
$$= -j104 - j89.5 + j37.5 - 155 - 65$$
$$= -j156 - 220 = 270 \text{ V}$$

Line to line voltages, from equations (A6.14):

$$V_A'' = V_b'' - V_c''$$
$$= -j156 + 220 + j156 + 220 = 440 \text{ V}$$
$$V_B'' = V_c'' - V_a''$$
$$= -j156 - 220 - 0 = 270 \text{ V}$$
$$V_C'' = V_a'' - V_b''$$
$$= 0 + j156 - 220 = 270 \text{ V}$$

Transformer T4, line to neutral voltages, from equations (A6.11):

Line A to neutral,

$$V_A = V_a'' = V_0 + V_1 + V_2 = 0 + j179 - j75 = j104 \text{ V}$$

Line B to neutral,

$$V_B = V_b'' = V_0 - 0.5(V_1 + V_2) - j0.866(V_1 - V_2)$$
$$= 0 - 0.5(j179 - j75) - j0.866(j179 + j75)$$
$$= -j89.5 + j37.5 + 155 + 65$$
$$= -j52 + 220 = 226 \text{ V}$$

Line C to neutral,

$$V_C = V_c'' = V_0 - 0.5(V_1 + V_2) + j0.866(V_1 - V_2)$$
$$= 0 - 0.5(j179 - j75) + j0.866(j179 + j75)$$

$$= -j89.5 + j37.5 - 155 - 65$$

$$= -j52 - 220 = 226 \text{ V}$$

Line to line voltages, from equations (A6.14):

$$V''_A = V''_b - V''_c$$

$$= -j52 + 220 + j52 + 220 = 440 \text{ V}$$

$$V''_B = V''_c - V''_a$$

$$= -j52 - 220 - j104$$

$$= -j156 - 220 = 270 \text{ V}$$

$$V''_C = V''_a - V''_b$$

$$= j104 + j52 - 220$$

$$= j156 - 220 = 270 \text{ V}$$

Voltages at 11 kV busbars

Phase sequence voltages, from equations (A6.9) and (A6.10) and *Figure A6.8*:

Positive sequence voltage is,

$$V_1 = V_G - I_1 Z_1$$

$$= j254 - (8816 \times j0.00261)$$

$$= j254 - j23 = j231 \text{ V}$$

Negative sequence voltage is,

$$V_2 = V_G - I_2 Z_2 = 0 - (8816 \times j0.00261) = -j23 \text{ V}$$

Zero sequence voltage is $V_0 = 0$

Line to neutral voltages, from equations (A6.11):

Line A to neutral,

$$V_A = V''_a = V_0 + V_1 + V_2$$

$$= 0 + j231 - j23 = j208 \text{ V}$$

Line B to neutral,

$$V_B = V''_b = V_0 - 0.5(V_1 + V_2) - j0.866(V_1 - V_2)$$

$$= 0 - 0.5(j231 - j23) - j0.866(j231 + j23)$$

$$= -j115.5 + j11.5 + 200 + 20$$

$$= -j104 + 220 = 243 \text{ V}$$

Line C to neutral,

$$V_C = V''_c = V_0 - 0.5(V_1 + V_2) + j0.866(V_1 - V_2)$$
$$= 0 - 0.5(j231 - j23) + j0.866(j231 + j23)$$
$$= -j115.5 + j11.5 - 200 - 20$$
$$= -j104 - 220 = 243 \text{ V}$$

Converting these voltages to true 11 kV delta values, from *Figure A6.14* and equations (A6.12):

$$V'_A = -V''_a/n$$
$$= -j208/0.0231 = -j9000 = 9000 \text{ V}$$
$$V'_B = -V''_b/n$$
$$= (j104 - 220)/0.0231$$
$$= j4500 - 9520 = 10\,500 \text{ V}$$
$$V'_C = -V''_c/n$$
$$= (j104 + 220)/0.0231$$
$$= j4500 + 9520 = 10\,500 \text{ V}$$

The corresponding line to neutral voltages on the 11 kV side of T1 and T3 are, from equations (A6.13):

$$V'_a = \tfrac{1}{3}V'_A + \tfrac{2}{3}V'_C$$
$$= \tfrac{1}{3}(-j9000) + \tfrac{2}{3}(j4500 + 9520)$$
$$= -j3000 + j3000 + 6347 = 6347 \text{ V}$$
$$V'_b = \tfrac{1}{3}V'_B + \tfrac{2}{3}V'_A$$
$$= \tfrac{1}{3}(j4500 - 9520) + \tfrac{2}{3}(-j9000)$$
$$= j1500 - 3173 - j6000$$
$$= -j4500 - 3173 = 5500 \text{ V}$$
$$V'_c = \tfrac{1}{3}V'_c + \tfrac{2}{3}V'_B$$
$$= \tfrac{1}{3}(j4500 + 9520) + \tfrac{2}{3}(j4500 - 9520)$$
$$= j1500 + 3173 + j3000 - 6347$$
$$= j4500 - 3173 = 5500 \text{ V}$$

All the voltages throughout the circuits are summarised as follows:

Transformers T1 and T3:

All primary line voltages, 33 kV

Secondary line to neutral voltages,

$V'_a = 6347$ V

$V'_b = -j4500 - 3173 = 5500$ V

$V'_c = j4500 - 3173 = 5500$ V

Secondary line voltages,

$V'_A = -j9000 = 9000$ V

$V'_B = j4500 - 9520 = 10\,500$ V

$V'_C = j4500 + 9520 = 10\,500$ V

Transformers T2 and T4:

Primary line voltages,

$V'_A = -j9000 = 9000$ V

$V'_B = j4500 - 9520 = 10\,500$ V

$V'_C = j4500 + 9520 = 10\,500$ V

Secondary line voltages,

$V''_A = +440$ V

$V''_B = -j156 - 220 = 270$ V

$V''_C = j156 - 220 = 270$ V

Transformer T2:

Secondary line to neutral voltages,

$V''_a = 0$

$V''_b = -j156 + 220 = 270$ V

$V''_c = -j156 - 220 = 270$ V

Transformer T4:

Secondary line to neutral voltages,

$V''_a = j104 = 104$ V

$V''_b = -j52 + 220 = 226$ V

$V''_c = -j52 - 220 = 226$ V

Neutral to earth voltage, $V_{NE} = j104 = 104$ V

These voltages are shown in phasor form in *Figure A6.17*.

If a resistance of 0.25 Ω is now included in the earth fault current circuit, the sequence impedances are as given in *Figure A6.8*, except that the resistance

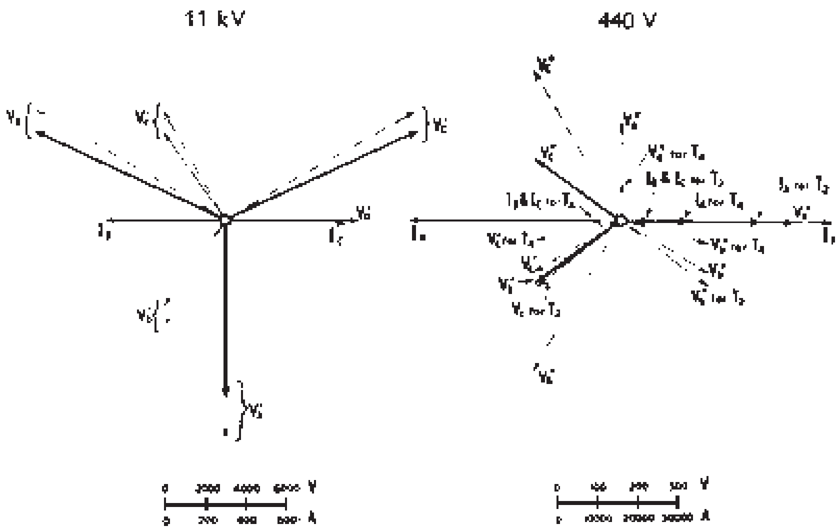

Figure A6.17 Currents and voltages. Case 2. E.R. = 0. Broken lines show no-load voltages

$R_0 = 3R = 0.75$ is inserted in series in the zero sequence network; the overall zero sequence impedance is then,

$$Z_0 = 0.75106 + j0.0058 = 0.752\ \Omega$$

as given before.

The total current in each sequence network is 338 A, and one half this in each of the parallel branches of the positive and negative sequence networks. The voltages through the circuit are then as follows.

Voltages at 440 V busbars

Phase sequence voltages, from equations (A6.9) and (A6.10) and *Figure A6.8*, bearing in mind the inclusion of the series resistance $R_0 = 0.75\ \Omega$ in the zero sequence network:

Positive sequence voltage is,

$$\begin{aligned} V_1 &= V_G - I_1 Z_1 \\ &= j254 - j169(j0.00261 + j0.0059) \\ &= j254 + 1.44 = 254\ \text{V} \end{aligned}$$

Negative sequence voltage is,

$$\begin{aligned} V_2 &= V_G - I_2 Z_2 \\ &= 0 - j169(j0.00261 + j0.0059) \\ &= +1.44 = 1.44\ \text{V} \end{aligned}$$

Zero sequence voltage is,

$$V_0 = V_G - I_0 Z_0$$
$$= 0 - j338(0.75106 + j0.0058)$$
$$= -j254 + 2 = 254 \text{ V}$$

Transformer T2, line to neutral voltages, from equations (A6.11):

Line A to neutral,

$$V_A = V_a'' = V_0 + V_1 + V_2$$
$$= -j254 + 2 + j254 + 1.44 + 1.44 = 4.88 \text{ V}$$

Line B to neutral,

$$V_B = V_b'' = V_0 - 0.5(V_1 + V_2) - j0.866(V_1 - V_2)$$
$$= -j254 + 2 - 0.5(j254 + 1.44 + 1.44)$$
$$- j0.866(j254 + 1.44 - 1.44)$$
$$= -j254 + 2 - j127 - 0.72 - 0.72 + 220 - j1.25 + j1.25$$
$$= -j381 + 220.55 = 440 \text{ V}$$

Line C to neutral,

$$V_C = V_c'' = V_0 - 0.5(V_1 + V_2) + j0.866(V_1 - V_2)$$
$$= -j254 + 2 - 0.5(j254 + 1.44 + 1.44)$$
$$+ j0.866(j254 + 1.44 - 1.44)$$
$$= -j254 + 2 - j127 - 0.72 - 0.72 - 220 + j1.25 - j1.25$$
$$= -j381 - 219.45 = 440 \text{ V}$$

Line to line voltages, from equations (A6.14):

$$V_A'' = V_b'' - V_c''$$
$$= -j381 + 220.55 + j381 + 219.45$$
$$= 440 \text{ V}$$
$$V_B'' = V_c'' - V_a''$$
$$= -j381 - 219.45 - 4.88$$
$$= -j381 - 224.35 = 443 \text{ V}$$
$$V_C'' = V_a'' - V_b''$$
$$= 4.88 + j381 - 220.55$$
$$= j381 - 215.65 = 438 \text{ V}$$

Transformer T4, line to neutral voltages, from equations (A6.11):

Line A to neutral,

$$\begin{aligned} V_A = V_a'' &= V_0 + V_1 + V_2 \\ &= 0 + j254 + 1.44 + 1.44 \\ &= j254 + 2.88 = 254 \text{ V} \end{aligned}$$

Line B to neutral,

$$\begin{aligned} V_B = V_b'' &= V_0 - 0.5(V_1 + V_2) - j0.866(V_1 - V_2) \\ &= 0 - 0.5(j254 + 1.44 + 1.44) - j0.866(j254 + 1.44 - 1.44) \\ &= -j127 - 0.72 - 0.72 + 220 - j1.25 + j1.25 \\ &= -j127 + 218.55 = 252 \text{ V} \end{aligned}$$

Line C to neutral,

$$\begin{aligned} V_C = V_c'' &= V_0 - 0.5(V_1 + V_2) + j0.866(V_1 - V_2) \\ &= 0 - 0.5(j254 + 1.44 + 1.44) + j0.866(j254 + 1.44 - 1.44) \\ &= -j127 - 0.72 - 0.72 - 220 + j1.25 - j1.25 \\ &= -j127 - 221.45 = 255 \text{ V} \end{aligned}$$

Line to line voltages, from equations (A6.14):

$$\begin{aligned} V_A'' &= V_b'' - V_c'' \\ &= -j127 + 218.55 + j127 + 221.45 = 440 \text{ V} \\ V_B'' &= V_c'' - V_a'' \\ &= -j127 - 221.45 - j254 - 2.88 \\ &= -j381 - 224.35 = 443 \text{ V} \\ V_C'' &= V_a'' - V_b'' \\ &= j254 + 2.88 + j127 - 218.55 \\ &= j381 - 215.65 = 438 \text{ V} \end{aligned}$$

The voltage drop across the neutral earth resistance is,

$$V_R = I_0 R_0 = I_0 \times 0.3R = j338 \times 0.75 = j254 \text{ V}$$

Voltages at 11 kV busbars

Phase sequence voltages from equations (A6.9) and (A6.10) and *Figure A6.8*:

Positive sequence voltage is,

$$V_1 = V_G - I_1 Z_1$$

$$= j254 - (j169 \times j0.00261)$$
$$= j254 + 0.44 = 254 \text{ V}$$

Negative sequence voltage is,

$$V_2 = V_G - I_2 Z_2$$
$$= 0 - (j169 \times j0.00261)$$
$$= +0.44 = 0.44 \text{ V}$$

Zero sequence voltage is $V_0 = 0$

Line to neutral voltages, from equations (A6.11):

Line A to neutral,

$$V_A = V_a'' = V_0 + V_1 + V_2$$
$$= 0 + j254 + 0.44 + 0.44$$
$$= j254 + 0.88 = 254 \text{ V}$$

Line B to neutral,

$$V_B = V_b'' = V_0 - 0.5(V_1 + V_2) - j0.866(V_1 - V_2)$$
$$= 0 - 0.5(j254 + 0.44 + 0.44) - j0.866(j254 + 0.44 - 0.44)$$
$$= -j127 - 0.22 - 0.22 + 220 - j0.38 + j0.38$$
$$= -j127 + 219.55 = 254 \text{ V}$$

Line C to neutral,

$$V_C = V_c'' = V_0 - 0.5(V_1 + V_2) + j0.866(V_1 - V_2)$$
$$= 0 - 0.5(j254 + 0.44 + 0.44) + j0.866(j254 + 0.44 - 0.44)$$
$$= -j127 - 0.22 - 0.22 - 220 + j0.38 - j0.38$$
$$= -j127 - 220.45 = 254 \text{ V}$$

Converting these voltages to true 11 kV delta values, from *Figure A6.14* and equations (A6.12):

$$V_A' = -V_a''/n$$
$$= (-j254 - 0.88)/0.0231$$
$$= -j11\,000 - 39 = 11\,000 \text{ V}$$
$$V_B' = -V_b''/n$$
$$= (j127 - 219.55)/0.0231$$
$$= j5500 - 9500 = 10\,750 \text{ V}$$

$$V'_C = -V''_c/n$$
$$= (j127 + 220.45)/0.0231$$
$$= j5500 + 9550 = 11\,020 \text{ V}$$

The corresponding line to neutral voltages on the 11 kV side of T1 and T3 are, from equations (A6.13):

$$V'_a = \tfrac{1}{3}V'_A + \tfrac{2}{3}V'_C$$
$$= \tfrac{1}{3}(-j11\,000 - 39) + \tfrac{2}{3}(j5500 + 9550)$$
$$= -j3667 - 13 + j3667 + 6367 = 6354 \text{ V}$$
$$V'_b = \tfrac{1}{3}V'_B + \tfrac{2}{3}V'_A$$
$$= \tfrac{1}{3}(j5500 - 9500) + \tfrac{2}{3}(-j11\,000 - 39)$$
$$= j1833 - 3167 - j7333 - 26$$
$$= -j5500 - 3193 = 6360 \text{ V}$$
$$V'_c = \tfrac{1}{3}V'_C + \tfrac{2}{3}V'_B$$
$$= \tfrac{1}{3}(j5500 + 9550) + \tfrac{2}{3}(j5500 - 9500)$$
$$= j1833 + 3183 + j3667 - 6333$$
$$= j5500 - 3150 = 6340 \text{ V}$$

All the voltages throughout the circuits are summarised as follows:

Transformer T1 and T3:

All primary line voltages, 33 kV

Secondary line to neutral voltages,

$$V'_a = +6354 = 6354 \text{ V}$$
$$V'_b = -j5500 - 3193 = 6360 \text{ V}$$
$$V'_c = j5500 - 3150 = 6340 \text{ V}$$

Secondary line voltages,

$$V'_A = -j11\,000 - 39 = 11\,000 \text{ V}$$
$$V'_B = j5500 - 9500 = 10\,750 \text{ V}$$
$$V'_C = j5500 + 9550 = 11\,020 \text{ V}$$

Transformers T2 and T4:

Primary line voltages,

$$V'_A = -j11\,000 - 39 = 11\,000 \text{ V}$$
$$V'_B = j5500 - 9500 = 10\,750 \text{ V}$$
$$V'_C = j5500 + 9550 = 11\,020 \text{ V}$$

Secondary line voltages,

$V_A'' = +440 = 440$ V

$V_B'' = -j381 - 224.35 = 443$ V

$V_C'' = j381 - 215.65 = 438$ V

Transformer T2:

Secondary line to neutral voltages,

$V_a'' = +4.9 = 4.9$ V

$V_b'' = -j381 + 220.55 = 440$ V

$V_c'' = -j381 - 219.45 = 440$ V

Transformer T4:

Secondary line to neutral voltages,

$V_a'' = j254 + 2.9 = 254$ V

$V_b'' = -j127 + 218.55 = 252$ V

$V_c'' = -j127 - 221.45 = 255$ V

Voltage drop across earth resistance, $V_R = j254 = 254$ V
These voltages are shown in phasor form in *Figure A6.18*.

Case 3. Circuit diagrams (*Figures A6.1*, *A6.12* and *A6.13***)**

Voltages at 440 V busbars

Phase sequence voltages, from equations (A6.9) and (A6.10) and *Figure A6.12*:

Positive sequence voltage is,

$$V_1 = V_G - I_1 Z_1 = j254 - [(6250 \times j0.00261) + (12\,500 \times j0.0059)]$$
$$= j254 - j16.3 - j73.8 = j163.9 \text{ V}$$

Negative sequence voltage is,

$$V_2 = V_G - I_2 Z_2 = 0 - [(6250 \times j0.00261) + (12\,500 \times j0.0059)]$$
$$= 0 - j16.3 - j73.8 = -j90.1 \text{ V}$$

Zero sequence voltage is,

$$V_0 = V_G - I_0 Z_0 = 0 - (12\,500 \times j0.0059)$$
$$= 0 - j73.8 = -j73.8 \text{ V}$$

Line to neutral voltages, from equations (A6.11):

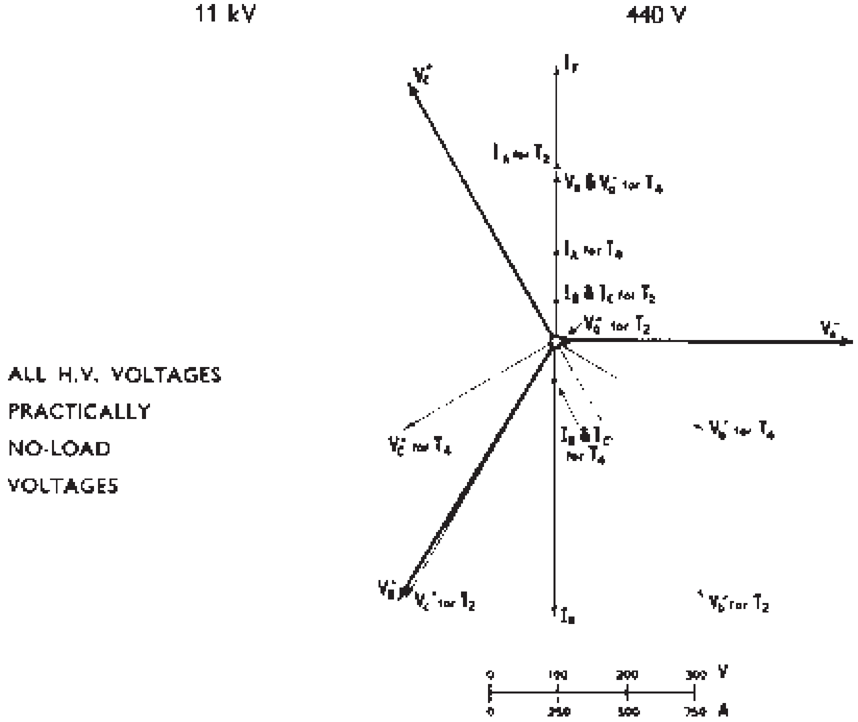

Figure A6.18 Currents and voltages. Case 2. E.R. = 0.25 Ω

Line A to neutral,

$$V_A = V_a'' = V_0 + V_1 + V_2$$
$$= -j73.8 + j163.9 - j90.1 = 0$$

Line B to neutral,

$$V_B = V_b'' = V_0 - 0.5(V_1 + V_2) - j0.866(V_1 - V_2)$$
$$= -j73.8 - 0.5(j163.9 - j90.1) - j0.866(j163.9 + j90.1)$$
$$= -j73.8 - j81.95 + j45.05 + 142 + 78$$
$$= -j110.7 + 220 = 246 \text{ V}$$

Line C to neutral,

$$V_C = V_c'' = V_0 - 0.5(V_1 + V_2) + j0.866(V_1 - V_2)$$
$$= -j73.8 - 0.5(j163.9 - j90.1) + j0.866(j163.9 + j90.1)$$
$$= -j73.8 - j81.95 + j45.05 - 142 - 78$$
$$= -j110.7 - 220 = 246 \text{ V}$$

Line to line voltages, from equations (A6.14):

$$
\begin{aligned}
V''_A &= V''_b - V''_c \\
&= -j110.7 + 220 + j110.7 + 220 \\
&= 440 \text{ V} \\
V''_B &= V''_c - V''_a \\
&= -j110.7 - 220 - 0 \\
&= -j110.7 - 220 = 246 \text{ V} \\
V''_C &= V''_a - V''_b \\
&= 0 + j110.7 - 220 \\
&= j110.7 - 220 = 246 \text{ V}
\end{aligned}
$$

Voltages at 11 kV busbars

Phase sequence voltages, from equations (A6.9) and (A6.10) and *Figure A6.12*:

Positive sequence voltage is,

$$
\begin{aligned}
V_1 &= V_G - I_1 Z_1 \\
&= j254 - (6250 \times j0.00261) \\
&= j254 - j16.3 = j237.7 \text{ V}
\end{aligned}
$$

Negative sequence voltage is,

$$
\begin{aligned}
V_2 &= V_G - I_2 Z_2 \\
&= 0 - (6250 \times j0.00261) \\
&= 0 - j16.3 = -j16.3 \text{ V}
\end{aligned}
$$

Zero sequence voltage is $V_0 = 0$

Line to neutral voltages, from equation (A6.11):

Line A to neutral,

$$
\begin{aligned}
V_A = V''_a &= V_0 + V_1 + V_2 \\
&= 0 + j237.7 - j16.3 = j221.4 \text{ V}
\end{aligned}
$$

Line B to neutral,

$$
\begin{aligned}
V_B = V''_b &= V_0 - 0.5(V_1 + V_2) - j0.866(V_1 - V_2) \\
&= 0 - 0.5(j237.7 - j16.3) - j0.866(j237.7 + j16.3) \\
&= -j118.85 + j8.15 + 205.9 + 14.1 \\
&= -j110.7 + 220 = 246 \text{ V}
\end{aligned}
$$

Line C to neutral,

$$V_C = V_c'' = V_0 - 0.5(V_1 + V_2) + j0.866(V_1 - V_2)$$
$$= 0 - 0.5(j237.7 - j16.3) + j0.866(j237.7 + j16.3)$$
$$= -j118.85 + j8.15 - 205.9 - 14.1$$
$$= -j110.7 - 220 = 246 \text{ V}$$

Converting these to true 11 kV delta values, from *Figure A6.14* and equations (A6.12):

$$V_A' = -V_a''/n$$
$$= -j221.4/0.0231 = -j9600 = 9600 \text{ V}$$
$$V_B' = -V_b''/n$$
$$= (j110.7 - 220)/0.0231$$
$$= j4800 - 9530 = 10\,650 \text{ V}$$
$$V_C' = -V_c''/n$$
$$= (j110.7 + 220)/0.0231$$
$$= j4800 + 9530 = 10\,650 \text{ V}$$

The corresponding true line to neutral voltages on the 11 kV side of T1 and T3 are, from equations (A6.13):

$$V_a' = \tfrac{1}{3}V_A' + \tfrac{2}{3}V_C'$$
$$= \tfrac{1}{3}(-j9600) + \tfrac{2}{3}(j4800 + 9530)$$
$$= -j3200 + j3200 + 6353 = 6353 \text{ V}$$
$$V_b' = \tfrac{1}{3}V_B' + \tfrac{2}{3}V_A'$$
$$= \tfrac{1}{3}(j4800 - 9530) + \tfrac{2}{3}(-j9600)$$
$$= j1600 - 3177 - j6400$$
$$= -j4800 - 3177 = 5820 \text{ V}$$
$$V_c' = \tfrac{1}{3}V_C' + V_B'$$
$$= \tfrac{1}{3}(j4800 + 9530) + \tfrac{2}{3}(j4800 - 9530)$$
$$= j1600 + 3177 + j3200 - 6353$$
$$= j4800 - 3177 = 5820 \text{ V}$$

The voltages of T1 and T3 are, of course, the same.
All voltages throughout the circuit are summarised as follows:

Transformers T1 and T3:

All primary line voltages, 33 kV

Secondary line to neutral voltages,

$$V'_a = 6353 \text{ V}$$

$$V'_b = -j4800 - 3177 = 5820 \text{ V}$$

$$V'_c = j4800 - 3177 = 5820 \text{ V}$$

Secondary line voltages,

$$V'_A = -j9600 = 9600 \text{ V}$$

$$V'_B = j4800 - 9530 = 10\,650 \text{ V}$$

$$V'_C = j4800 + 9530 = 10\,650 \text{ V}$$

Transformer T2:

Primary line voltages,

$$V'_A = -j9600 = 9600 \text{ V}$$

$$V'_B = j4800 - 9530 = 10\,650 \text{ V}$$

$$V'_C = j4800 + 9530 = 10\,650 \text{ V}$$

Secondary line voltages,

$$V''_A = 440 \text{ V}$$

$$V''_B = -j110.7 - 220 = 246 \text{ V}$$

$$V''_C = j110.7 - 220 = 246 \text{ V}$$

Secondary line to neutral voltages,

$$V''_a = 0$$

$$V''_b = -j110.7 + 220 = 246 \text{ V}$$

$$V''_c = -j110.7 - 220 = 246 \text{ V}$$

These voltages are shown in phasor form in *Figure A6.19*.

If a resistance of 0.25 Ω is now included in the earth fault current circuit, the sequence impedances are as given in *Figure A6.12*, except that the resistance $R_0 = 3R = 0.75$ is inserted in series in the zero sequence network; the overall zero sequence impedance is then,

$$Z_0 = 0.75106 + j0.0058 = 0.752 \ \Omega$$

as given before.

The total current in each sequence network is 338 A and one half this value is in each of the parallel branches of the positive and negative sequence networks. The voltages throughout the circuit are then as follows.

Phase sequence voltages, from equations (A6.9) and (A6.10) and *Figure A6.12*, bearing in mind the inclusion of a series resistance $R_0 = 0.75 \ \Omega$ in the zero sequence network:

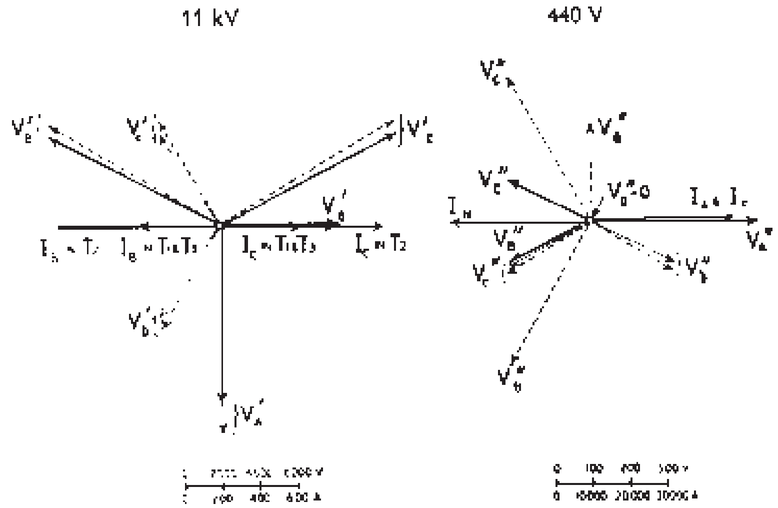

Figure A6.19 Currents and voltages. Case 3. E.R. = 0. Broken lines show no-load voltages

Positive sequence voltage is,

$$V_1 = V_G - I_1 Z_1$$
$$= j254 - [(j169 \times j0.00261) + (j338 \times j0.0059)]$$
$$= j254 + 0.44 + 2$$
$$= j254 + 2.44 = 254 \text{ V}$$

Negative sequence voltage is,

$$V_2 = V_G - I_2 Z_2$$
$$= 0 - [(j169 \times j0.00261) + (j338 \times j0.0059)]$$
$$= 0.44 + 2 = 2.44 \text{ V}$$

Zero sequence voltage is,

$$V_0 = V_G - I_0 Z_0$$
$$= 0 - j338(0.75106 + j0.0059)$$
$$= -j254 + 2 = 254 \text{ V}$$

Line to neutral voltages, from equations (A6.11):

Line A to neutral,

$$V_A = V_a'' = V_0 + V_1 + V_2$$
$$= -j254 + 2 + j254 + 2.44 + 2.44 = 6.88 \text{ V}$$

Line B to neutral,

$$\begin{aligned}V_B = V_b'' &= V_0 - 0.5(V_1 + V_2) - j0.866(V_1 - V_2)\\ &= -j254 + 2 - 0.5(j254 + 2.44 + 2.44)\\ &\quad - j0.866(j254 + 2.44 - 2.44)\\ &= -j254 + 2 - j127 - 1.22 - 1.22 + 220 - j2.11 + j2.11\\ &= -j381 + 219.6 = 440 \text{ V}\end{aligned}$$

Line C to neutral,

$$\begin{aligned}V_C = V_c'' &= V_0 - 0.5(V_1 + V_2) + j0.866(V_1 - V_2)\\ &= -j254 + 2 - 0.5(j254 + 2.44 + 2.44)\\ &\quad + j0.866(j254 + 2.44 - 2.44)\\ &= -j254 + 2 - j127 - 1.22 - 1.22 - 220 + j2.11 - j2.11\\ &= -j381 - 220.4 = 440 \text{ V}\end{aligned}$$

Line to line voltages, from equations (A6.14):

$$\begin{aligned}V_A'' &= V_b'' - V_c''\\ &= -j381 + 219.6 + j381 + 220.4 = 440 \text{ V}\\ V_B'' &= V_c'' - V_a''\\ &= -j381 - 220.4 - 6.88\\ &= -j381 - 227.3 = 444 \text{ V}\\ V_C'' &= V_a'' - V_b''\\ &= 6.88 + j381 - 219.6\\ &= j381 - 212.7 = 436 \text{ V}\end{aligned}$$

The voltage drop across the neutral earth resistance is,

$$\begin{aligned}V_R = I_0R_0 &= I_0 3R\\ &= j338 \times 0.75 = j254 \text{ V}\end{aligned}$$

Voltages at 11 kV busbars

Phase sequence voltages, from equations (A6.9) and (A6.10) and *Figure A6.12*:

Positive sequence voltage is,

$$V_1 = V_G - I_1Z_1$$

$$= j254 - (j169 \times j0.00261)$$
$$= j254 + 0.44 = 254 \text{ V}$$

Negative sequence voltage is,

$$V_2 = V_G - I_2 Z_2$$
$$= 0 - (j169 \times j0.00261) = 0.44 \text{ V}$$

Zero sequence voltage is $V_0 = 0$

Line to neutral voltages, from equations (A6.11):

Line A to neutral,

$$V_A = V_a'' = V_0 + V_1 + V_2$$
$$= 0 + j254 + 0.44 + 0.44$$
$$= j254 + 0.88 = 254 \text{ V}$$

Line B to neutral,

$$V_B = V_b'' = V_0 - 0.5(V_1 + V_2) - j0.866(V_1 - V_2)$$
$$= 0 - 0.5(j254 + 0.44 + 0.44) - j0.866(j254 + 0.44 - 0.44)$$
$$= -j127 - 0.22 - 0.22 + 220 - j0.38 + j0.38$$
$$= -j127 + 219.6 = 254 \text{ V}$$

Line C to neutral,

$$V_C = V_c'' = V_0 - 0.5(V_1 + V_2) + j0.866(V_1 - V_2)$$
$$= 0 - 0.5(j254 + 0.44 + 0.44) + j0.866(j254 + 0.44 - 0.44)$$
$$= -j127 - 0.22 - 0.22 - 220 + j0.38 - j0.38$$
$$= -j127 - 220.4 = 254 \text{ V}$$

Converting these to true 11 kV delta values, from *Figure A6.14* and equations (A6.12):

$$V_A' = -V_a''/n$$
$$= (-j254 - 0.88)/0.0231$$
$$= -j11\,000 - 39 = 11\,000 \text{ V}$$
$$V_B' = -V_b''/n$$
$$= (j127 - 219.6)/0.0231$$
$$= j5500 - 9500 = 10\,970 \text{ V}$$
$$V_C' = -V_c''/n$$

$$= (j127 + 220.4)/0.0231$$

$$= j5500 + 9545 = 11\,020 \text{ V}$$

The corresponding true line to neutral voltages on the 11 kV side of T1 and T3 are, from equation (A6.13):

$$V'_a = \tfrac{1}{3}V'_A + \tfrac{2}{3}V'_C$$

$$= \tfrac{1}{3}(-j11\,000 - 39) + \tfrac{2}{3}(j5500 + 9545)$$

$$= -j3667 - 13 + j3667 + 6363 = 6350 \text{ V}$$

$$V'_b = \tfrac{1}{3}V'_B + \tfrac{2}{3}V'_A$$

$$= \tfrac{1}{3}(j5500 - 9500) + \tfrac{2}{3}(-j11\,000 - 39)$$

$$= j1833 - 3167 - j7333 - 26$$

$$= -j5500 - 3193 = 6360 \text{ V}$$

$$V'_c = \tfrac{1}{3}V'_C + \tfrac{2}{3}V'_B$$

$$= \tfrac{1}{3}(j5500 + 9545) + \tfrac{2}{3}(j5500 - 9500)$$

$$= j1833 + 3182 + j3667 - 6333$$

$$= j5500 - 3151 = 6340 \text{ V}$$

The voltages of T1 and T3 are the same.
All voltages throughout the circuit are summarised as follows:

Transformers T1 and T3:

All primary line voltages, 33 kV

Secondary line to neutral voltages,

$$V'_a = 6350 \text{ V}$$

$$V'_b = -j5500 - 3193 = 6360 \text{ V}$$

$$V'_c = j5500 - 3151 = 6340 \text{ V}$$

Secondary line voltages,

$$V'_A = -j11\,000 - 39 = 11\,000 \text{ V}$$

$$V'_B = j5500 - 9500 = 10\,970 \text{ V}$$

$$V'_C = j5500 + 9545 = 11\,020 \text{ V}$$

Transformer T2:

Primary line voltages,

$$V'_A = -j11\,000 - 39 = 11\,000 \text{ V}$$

$$V'_B = j5500 - 9500 = 10\,970 \text{ V}$$

$$V'_C = j5500 + 9545 = 11\,020 \text{ V}$$

Secondary line voltages,

$$V''_A = +440 = 440 \text{ V}$$

$$V''_B = -j381 - 227.3 = 444 \text{ V}$$

$$V''_C = j381 - 212.7 = 436 \text{ V}$$

Secondary line to neutral voltages,

$$V''_a = +6.88 = 6.88 \text{ V}$$

$$V''_b = -j381 + 219.6 = 440 \text{ V}$$

$$V''_c = -j381 - 220.4 = 440 \text{ V}$$

Voltage drop across earth resistance, $V_R = j254 = j254$ V.

The phasor diagram corresponding to these voltages is shown in *Figure A6.20*.

Currents and voltages for all the three cases chosen for this investigation are scheduled in *Table A6.1* (pages 899–900) and *Table A6.2* (pages 901–903). Current *magnitudes* are controlled almost entirely by the value of the earth resistances, while the *distribution* of current depends upon the impedances of the various parallel paths of the circuit.

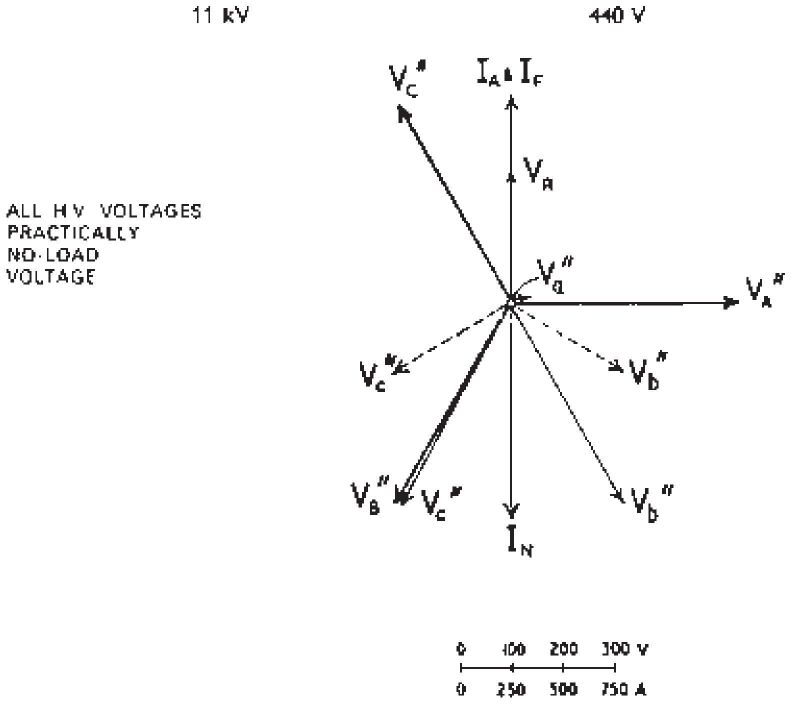

Figure A6.20 Currents and voltages. Case 3. E.R. = 0.25 Ω.
Broken lines show no-load voltages

Table A6.1 Line currents-amperes

	Case 1		*Case 2*		*Case 3*	
	$E.R. = 0$	$E.R. = 0.25\ \Omega$	$E.R. = 0$	$E.R. = 0.25\ \Omega$	$E.R. = 0$	$E.R. = 0.25\ \Omega$
On 440 V side:						
I_F	66 498	2028	52 896	1014	37 500	1014
T2, secondary:						
I_A	33 249	1014	35 264	676	37 500	1014
I_B	0	0	8816	169	0	0
I_C	0	0	8816	169	0	0
I_N	33 249	1014	52 896	1014	37 500	1014
T4, secondary:						
I_A	33 249	1014	17 632	338	–	–
I_B	0	0	−8816	−169	–	–
I_C	0	0	−8816	−169	–	–
I_N	33 249	1014	–	–	–	–
On 11 kV side:						
T1, secondary:						
I_A	0	0	0	0	0	0
I_B	−768	−23.4	−612	−11.75	−433	−11.75
I_C	768	23.4	612	11.75	433	11.75
T2, primary:						
I_A	0	0	0	0	0	0
I_B	−768	−23.4	−612	−11.75	−866	−23.5
I_C	768	23.4	612	11.75	866	23.5
T3, secondary:						
I_A	0	0	0	0	0	0
I_B	−768	−23.4	−612	−11.75	−433	−11.75
I_C	768	23.4	612	11.75	433	11.75

(*continued overleaf*)

Table A6.1 Line currents-amperes *(continued)*

	Case 1		*Case 2*		*Case 3*	
	$E.R. = 0$	$E.R. = 0.25\ \Omega$	$E.R. = 0$	$E.R. = 0.25\ \Omega$	$E.R. = 0$	$E.R. = 0.25\ \Omega$
T4, primary:						
I_A	0	0	0	0	–	–
I_B	−768	−23.4	−612	−11.75	–	–
I_C	768	23.4	612	11.75	–	–
On 33 kV side:						
T1, primary:						
I_A	−295	−9	−235	−4.5	−166	−4.4
I_B	147.5	4.5	117.5	2.25	83	2.25
I_C	147.5	4.5	117.5	2.25	83	2.25
T3, primary:						
I_A	−295	−9	−235	−4.5	−166	−4.5
I_B	147.5	4.5	117.5	2.25	83	2.25
I_C	147.5	4.5	117.5	2.25	83	2.25

Table A6.2 Voltages

			Case 1	
		At no-load	*E.R. = 0 (Figure A6.15)*	*E.R.=0.25 Ω (Figure A6.16)*
At 11 kV bars and windings:				
Line to neutral	V'_a	$+6351 = 6351$ V	$+6353 = 6353$ V	$+6347 = 6347$ V
	V'_b	$-j5500 - 3175 = 6351$ V	$-j4250 - 3177 = 5300$ V	$-j5500 - 3218 = 6380$ V
	V'_c	$+j5500 - 3175 = 6351$ V	$+j4250 - 3177 = 5300$ V	$+j5500 - 3180 = 6350$ V
Line to line	V'_A	$-j11\,000 = 11\,000$ V	$-j8500 = 8500$ V	$-j11\,000 - 77 = 11\,000$ V
	V'_B	$+j5500 - 9526 = 11\,000$ V	$+j4250 - 9530 = 10\,420$ V	$+j5500 - 9500 = 10\,750$ V
	V'_C	$+j5500 + 9526 = 11\,000$ V	$+j4250 + 9530 = 10\,420$ V	$+j5500 + 9560 = 11\,020$ V
At 440 V bars and windings:				
Line to neutral	V''_a	$+j254 = 254$ V	$0 = 0$ V	$+7.8 = 7.8$ V
	V''_b	$-j127 + 220 = 254$ V	$-j98.1 + 220 = 241$ V	$-j381 + 219.1 = 440$ V
	V''_c	$-j127 - 220 = 254$ V	$-j98.1 - 220 = 241$ V	$-j381 - 220.9 = 440$ V
Line to line	V''_A	$+440 = 440$ V	$+440 = 440$ V	$+440 = 440$ V
	V''_B	$-j381 - 220 = 440$ V	$-j98.1 - 220 = 241$ V	$-j381 - 228.7 = 443$ V
	V''_C	$+j381 - 220 = 440$ V	$+j98.1 - 220 = 241$ V	$+j381 + 211.3 = 435$ V
Neutral to earth*	V_{NE}	$0 = 0$ V	$0 = 0$ V	$+j254 = 254$ V
E.R. drop	V_R	$0 = 0$ V		$+j254 = 254$ V

* Voltage from neutral point to zero earth potential

Table A6.2 Voltages *(continued)*

			Case 2			
		At no-load	*E.R. = 0 (Figure A6.17)*		*E.R. = 0.25 Ω (Figure A6.18)*	
At 11 kV bars and windings:						
Line to neutral	V'_a	$+6351 = 6351$ V	$+6347 = 6347$ V		$+6354 = 6354$ V	
	V'_b	$-j5500 - 3175 = 6351$ V	$-j4500 - 3173 = 5500$ V		$-j5500 - 3193 = 6360$ V	
	V'_c	$+j5500 - 3175 = 6351$ V	$+j4500 - 3173 = 5500$ V		$+j5500 - 3150 = 6340$ V	
Line to line:	V'_A	$-j11\,000 = 11\,000$ V	$-j9000 = 9000$ V		$-j11\,000 - 39 = 11\,000$ V	
	V'_B	$+j5500 - 9526 = 11\,000$ V	$+j4500 - 9520 = 10\,500$ V		$+j5500 - 9500 = 10\,750$ V	
	V'_C	$+j5500 + 9526 = 11\,000$ V	$+j4500 + 9520 = 10\,500$ V		$+j5500 + 9550 = 11\,020$ V	
			T2	*T4*	*T2*	*T4*
At 440 V bars and windings:						
Line to neutral	V''_a	$+j254 = 254$ V	$0 = 0$ V	$+j104 = 104$ V	$+4.9 = 4.9$ V	$+j254 + 2.9 = 254$ V
	V''_b	$-j127 + 220 = 254$ V	$-j156 + 220 = 270$ V	$-j52 + 220 = 226$ V	$-j381 + 220.55 = 440$ V	$-j127 + 218.55 = 242$ V
	V''_c	$-j127 - 220 = 254$ V	$-j156 - 220 = 270$ V	$-j52 - 220 = 226$ V	$-j381 - 219.45 = 440$ V	$-j127 - 221.45 = 255$ V
Line to line	V''_A	$+440 = 440$ V	$+440 = 440$ V		$+440 = 440$ V	
	V''_B	$-j381 - 220 = 440$ V	$-j156 - 220 = 270$ V		$+j381 - 224.35 = 433$ V	
	V''_C	$+j381 - 220 = 440$ V	$+j156 - 220 = 270$ V		$-j381 - 215.65 = 438$ V	
Neutral to earth*	V_{NE}	$0 = 0$ V	$0 = 0$ V	$+j104 = 104$ V	$+j254 = 254$ V	$+j254 = 254$ V
E.R. drop	V_R	$0 = 0$ V			$+j254 = 254$ V	

*Voltage from neutral point to zero earth potential

Table A6.2 Voltages *(continued)*

			Case 3	
		At no-load	*E.R. = 0 (Figure A6.19)*	*E.R. = 0.25 Ω (Figure A6.20)*
At 11 kV bars and windings:				
Line to neutral	V'_a	$+6351 = 6351$ V	$+6353 = 6553$ V	$+6350 = 6350$ V
	V'_b	$-j5500 - 3175 = 6351$ V	$-j4800 - 3177 = 5820$ V	$-j5500 - 3193 = 6360$ V
	V'_c	$+j5500 - 3175 = 6351$ V	$-j4800 - 3177 = 5820$ V	$+j5500 + 3151 = 6340$ V
Line to line	V'_A	$-j11\,000 = 11\,000$ V	$-j9600 = 9600$ V	$-j11\,000 - 39 = 11\,000$ V
	V'_B	$+j5500 - 9526 = 11\,000$ V	$+j4800 - 9530 = 10\,650$ V	$+j5500 - 9500 = 10\,970$
	V'_C	$+j5500 + 9526 = 11\,000$ V	$+j4800 + 9530 = 10\,650$ V	$+j5500 - 9545 = 11\,020$ V
At 440 V bars and windings:				
Line to neutral	V''_a	$+j254 = 254$ V	$0 = 0$ V	$+6.9 = 6.9$ v
	V''_b	$+j127 + 220 = 254$ V	$-j110.7 + 220 = 246$ V	$-j381 + 219.6 = 440$ V
	V''_c	$-j127 - 220 = 254$ V	$-j110.7 - 220 = 246$ V	$-j381 - 220.4 = 440$ V
Line to line	V''_A	$+440 = 440$ V	$+440 = 440$ V	$+440 = 440$ V
	V''_B	$-j381 - 220 = 440$ V	$-j110.7 - 220 = 246$ V	$-j381 - 227.3 = 444$ V
	V''_C	$+j381 - 220 = 440$ V	$+j110.7 - 220 = 246$ V	$+j381 - 212.7 = 436$ V
Neutral to earth*	V_{NE}	$0 = 0$ V	$0 = 0$ V	$+j254 = 254$ V
E.R. drop	V_R	$0 = 0$ V		$+j254 = 254$ V

*Voltage from neutral point to zero earth potential

Appendix 7

The use of finite element analysis in the calculation of leakage flux and dielectric stress distributions

In the mid-1960s, when this work had already been published for over 40 years and revised at least nine times, the application of computers was just beginning to revolutionise the transformer design process. Prior to this time the designer's basic tool was the slide rule, and even this was capable of performing calculations which were considered to be more accurate than was required for the design of transformers. After all, the basic materials, paper and pressboard, were not very stable and the designer's requirements could not be translated into reality with accuracies better than plus or minus two or three millimetres. Impedance and stray loss formulae contained empirical factors derived from years of experience and practical testing, and tolerances of 10% were truly necessary on calculated values, and were occasionally exceeded.

Insulation structures for very high-voltage transformers were laboriously developed with the assistance of laboratory models and occasionally electrolytic tank tests were made on important items such as main EHV lead arrangements.

The availability of the computer greatly changed this, but it was not until the development of the appropriate calculation techniques that the full benefits of the computer could be realised. *Finite element modelling* is now one of the most powerful tools available to the designer. It enables accurate computer modelling to be carried out of complex structures, whether it is required that these should represent electrical or magnetic field distributions, or both.

While the benefits obtained from the ability to perform calculations of electrical stress distribution will be immediately obvious, the advantages from being able to accurately predict the pattern of magnetic flux distribution are possibly even greater. This enables leakage reactance to be determined far more simply and accurately than hitherto; stray losses, which are dependent on leakage flux, can be accurately and simply calculated, and forces both during normal loading and under short-circuit can be determined with an accuracy and to a rigour which was not possible using traditional methods.

Finite element modelling is now such an important tool to the advanced transformer designer that it is important that everyone with an interest in design should have an appreciation of the process. The following paper, ‘Application of the Finite Element Method in the Design of High Voltage Equipment’ by T.W. Preston and M.A. Timothy of the GEC Alsthom Engineering Research Centre, should enable this to be obtained, it gives an excellent overall view of the subject and, although the examples used as illustration are not transformers, they clearly demonstrate of the capabilities of the process and it is a simple matter to envisage its use in transformer-related topics.

APPLICATION OF THE FINITE ELEMENT METHOD IN THE DESIGN OF HIGH VOLTAGE EQUIPMENT

Today’s competitive market ensures that electrical equipment and systems are designed to be efficient, reliable, cost effective and able to operate under both normal and abnormal conditions. The weight given to each of these criteria will vary with the application. For the design of critical, high stress or high performance equipment the engineer must have the appropriate computational tools at his disposal as well as the computer facilities to support them.

Design procedures were originally based on analytically derived formulae. Over the years improvements to these procedures have been made based on experimentation, empirical factors derived from previous performance of the apparatus and, last but not least, the experience of the designer. Where the equipment is small and cheap to produce it is possible to assess its design by building and testing prototypes. However, this is expensive if many design changes are necessary for optimisation purposes. Clearly, high voltage electrical equipment such as turbine generators and transformers are not amenable to prototype testing due to the high capital costs involved, and so alternative techniques need to be used. This is also true in the design of high voltage electrical transmission systems.

One alternative is the use of computer modelling. This enables the engineer to optimise the design in relation to cost, weight, reliability, performance etc. before manufacture and so avoids the expense of modifying the design once manufacture has begun. In addition, the computer model may be used to examine a wide range of operating conditions inside and outside of the original specification without fear of damaging the equipment or incurring excessive development costs. However, these advantages are only available when the modelling offers an accurate representation of the equipment and its environment, the software package is flexible, easy to use and cost effective.

The following sections detail the progress made in the development of such a modelling tool for the electromagnetic design of high voltage electrical apparatus ranging from transformers to transmission lines.

Advance design techniques

Standard design techniques, although proving adequate to meet customer specifications, cannot be used with confidence to guarantee the safety and reliability of equipment when working materials near the limits of their properties. If such design techniques are used equipment failure can occur and is often traced to electric discharge or fatigue in localised regions. Thus, more advanced computational techniques are required to supplement the existing design procedures.

Such techniques should be capable of modelling accurately some or all of the following items:

(a) Complex Geometry
(b) Induced Currents
(c) Excitation Arrangements
(d) Non-Sinusoidal Quantities
(e) Non-Homogeneous Regions
(f) External Circuits
(g) Proximity Effects

These requirements virtually prohibit analytic approaches, but it is possible to model them using numerical techniques, such as the finite element method. This was first used for structural analysis in the aerospace and construction industry in the late 50's and early 60's but was not used for solving electromagnetic problems until the late 60's (Refs [1] and [2]). GEC ALSTHOM were foremost in recognising the potential of the finite-element method as a design tool for electrical apparatus and, from about 1967, the method has developed from a research tool to being used in day-to-day design work.

Basic principles of the finite-element method

The finite-element method is based on the concept that the distribution of the electromagnetic field is such as to ensure that the energy of the problem concerned is in a minimum or maximum state. If this is not possible then the technique cannot be used.

To make use of this concept the problem area is sub-divided into numerous regions, commonly called elements. The energy of the problem, known as the functional χ, is formulated in terms of the describing potential and then extremised with respect to the potential at the nodes which define the elements. Thus:

$$\frac{\partial \chi}{\partial A} = 0 \text{ to define a minimum or maximum} \qquad \text{Equation 1}$$

where χ is the energy functional
A is the describing potential

If the potential over each element is defined by an assumed polynomial variation then an equation at each node can be formed which is expressed in terms of the nodal co-ordinates, the nodal potentials and the material properties of the elements. This results in a large set of numerical equations which can be written as:

$$[S] \cdot [A] = [B] \qquad \text{Equation 2}$$

where $[S]$ = Stiffness matrix.
$[A]$ = Potentials.
$[B]$ = Defined from the boundary or excitation conditions of the problem.

The resulting matrix is sparse and inversion methods such as the Compact Storage Scheme (Ref [3]) or the ICCG (Ref [4]) are used to exploit this feature to give a quick and economical solution.

In order to illustrate the mechanism of the finite element method the equations relating to a 2D electrostatic formulation in rectangular co-ordinates is considered. The formulation follows well defined procedures being:

(a) derivation of the partial differential equation
(b) formulation of the functional
(c) numerical representation of the functional
(d) meshing/discretisation of the problem
(e) solution
(f) processing of results.

(a) Derivation of the partial differential electrostatic equations

The partial differential equation for describing the electrostatic field, V, in a zero charge density space can be obtained as follows:

$$\text{div } D = 0 \qquad \text{Equation 3}$$

$$D = \varepsilon_0 \varepsilon_r E \qquad \text{Equation 4}$$

thus

$$\varepsilon_0 \varepsilon_r \text{ div } E = 0 \qquad \text{Equation 5}$$

since

$$E = -\text{grad } V \qquad \text{Equation 6}$$

then

$$-\varepsilon_0 \varepsilon_r \text{ grad } \cdot \text{ div } V = 0 \qquad \text{Equation 7}$$

Expanding gives:

$$-\varepsilon_0 \varepsilon_r \nabla^2 V = 0 \qquad \text{Equation 8}$$

which in rectangular co-ordinates and in 2 dimensions is:

$$\varepsilon_0\varepsilon_r\left\{\frac{\partial^2 V}{\partial x^2}+\frac{\partial^2 V}{\partial y^2}\right\} \qquad \text{Equation 9}$$

Note: ε_r can only be eliminated if there is only one region under consideration. If two or more regions are modelled then ε_r *must* be present in equation 9.

(b)–(c) Formulation and numerical representation of the functional

The energy functional can be derived in several ways all having their advantages and disadvantages. The method being:

(i) Galerkin
(ii) Energy Approach
(iii) Euler's Equation

The following sections give a brief outline of these methods related to the 2D electrostatic partial differential equation, equation 9.

(i) Galerkin method

Consider the partial differential equation given in the previous section equation 9.

$$\varepsilon_0\varepsilon_r \nabla^2 V = 0 \qquad \text{Equation 10}$$

$$\varepsilon_0\varepsilon_r\frac{\partial^2 V}{\partial x^2}+\varepsilon_0\,\varepsilon_r\frac{\partial^2 V}{\partial y^2}=0 \qquad \text{Equation 11}$$

In the finite element formulation the Galerkin weighting factor is the shape function which is used to approximate the field distribution over the elements. For a linear approximation the field over a triangular element, Figure A7.1 is described as:

$$V = N_iV_i + N_jV_j + N_kV_k \qquad \text{Equation 12}$$

where $N_i = (a_i + b_ix + c_iy)/2\Delta$
$a_i = x_jy_k - x_ky_j$
$b_i = y_j - y_k$
$c_i = x_k - x_j$
Δ = area of the triangle.

Similarly for N_j and N_k.

Thus multiplying by the shape function N and integrating over area Ω gives:

$$\sum_i \int_\Omega \varepsilon_0\varepsilon_r N_i\frac{\partial^2 V}{\partial x^2}\,\mathrm{d}\Omega+\sum_i \int_\Omega \varepsilon_0\varepsilon_r N_i\frac{\partial^2 V}{\partial y^2}\,\mathrm{d}\Omega=0$$

Equation 13

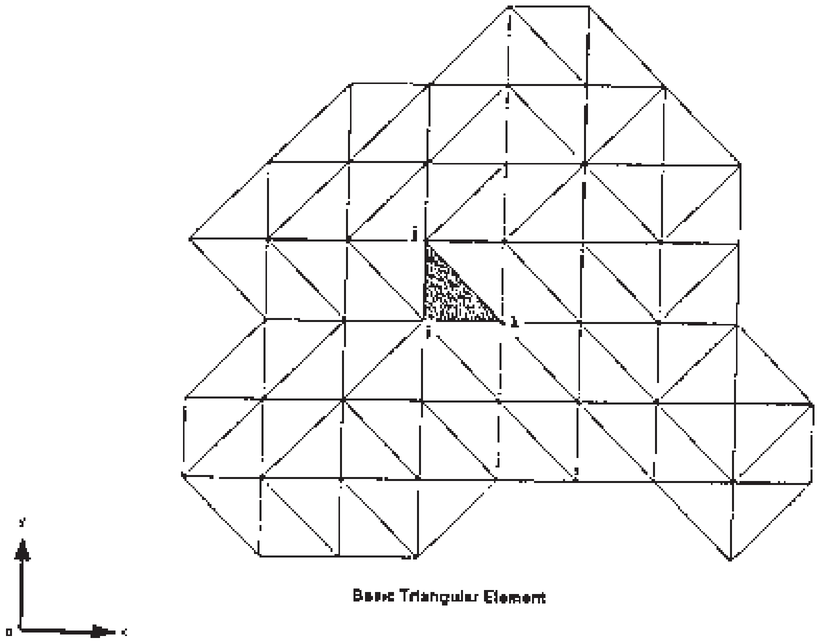

Figure A7.1

Apply Greens theorem to equation 13 which states:

$$\int_\Omega \phi \frac{\partial^2 \psi}{\partial x^2}\,\mathrm{d}\Omega = -\int_\Omega \frac{\partial \phi}{\partial x}\frac{\partial \psi}{\partial x}\,\mathrm{d}\Omega + \int_s \phi \frac{\partial \psi}{\partial x} n_x\,\mathrm{d}S \quad \text{Equation 14}$$

gives:

$$-\sum_i \int_\Omega \varepsilon_0 \varepsilon_r N_i \frac{\partial N_i}{\partial x}\frac{\partial V}{\partial x}\,\mathrm{d}\Omega - \sum_i \int_\Omega \varepsilon_0 \varepsilon_r N_i \frac{\partial N_i}{\partial y}\frac{\partial V}{\partial y}\,\mathrm{d}\Omega$$

$$+ \int_s \sum_i N_i \frac{\partial V}{\partial x} n_x\,\mathrm{d}s + \int_s \sum_i N_i \frac{\partial V}{\partial y} n_y\,\mathrm{d}s = 0 \quad \text{Equation 15}$$

or

$$-\sum_i \int_\Omega \varepsilon_0 \varepsilon_r N_i \frac{\partial N_i}{\partial x}\frac{\partial V}{\partial x}\,\mathrm{d}\Omega - \sum_i \int_\Omega \varepsilon_0 \varepsilon_r N_i \frac{\partial N_i}{\partial y}\frac{\partial V}{\partial y}\,\mathrm{d}\Omega$$

$$+ \int_s \sum_i N_i \frac{\partial V}{\partial n}\,\mathrm{d}s = 0 \quad \text{Equation 16}$$

since

$$\frac{\partial V}{\partial x} n_x + \frac{\partial V}{\partial y} n_y = (\underline{\Delta} V)\cdot \underline{n} = \frac{\partial V}{\partial n} \quad \text{Equation 17}$$

This approach is excellent at defining the boundary conditions but it is difficult to relate to the physics of the problem.

(ii) Euler's method

It is required to find the functional χ corresponding to the partial differential equation

$$\varepsilon_0\varepsilon_r\left\{\frac{\partial^2 V}{\partial x^2}+\frac{\partial^2 V}{\partial y^2}\right\}=0 \qquad \text{Equation 18}$$

The general form of the functional is:

$$\chi = \quad {}_{\Omega}\, f\,\mathrm{d}x\,\mathrm{d}y \qquad \text{Equation 19}$$

where

$$f = f \quad x, y, V, \frac{\partial V}{\partial x}, \frac{\partial V}{\partial y} \qquad \text{Equation 20}$$

To obtain the functional χ for equation 18 requires the use of Euler's equation which states

$$\frac{\partial}{\partial x}\quad\frac{\partial f}{\partial\left(\frac{\partial V}{\partial x}\right.}\quad+\frac{\partial}{\partial y}\quad\frac{\partial f}{\partial\left(\frac{\partial V}{\partial y}\right.}\quad-\frac{\partial f}{\partial V}=0 \qquad \text{Equation 21}$$

The correct functional is found when after operating on the functional with Euler's equation the resulting equation is the original partial differential equation, i.e. equation 18. In some cases the functional is obtained by trial and error but in simple cases like the electrostatic formulation it can be derived by comparing terms.

Comparing terms in Equations 21 and 18 gives

$$\frac{\partial}{\partial x}\quad\frac{\partial f}{\partial\left(\frac{\partial V}{\partial x}\right.}\quad=\varepsilon_0\varepsilon_r\frac{\partial^2 V}{\partial x^2}=\varepsilon_0\varepsilon_r\frac{\partial}{\partial x}\quad\frac{\partial V}{\partial x} \qquad \text{Equation 22}$$

$$\frac{\partial}{\partial y}\quad\frac{\partial f}{\partial\left(\frac{\partial V}{\partial y}\right.}\quad=\varepsilon_0\varepsilon_r\frac{\partial^2 V}{\partial y^2}=\varepsilon_0\varepsilon_r\frac{\partial}{\partial y}\quad\frac{\partial V}{\partial y} \qquad \text{Equation 23}$$

Thus the values of f (say f_1, and f_2) for the two parts equations 22–23 may be found as follows:

Considering equation 22, it is required that

$$\frac{\partial f_1}{\partial\left(\dfrac{\partial V}{\partial x}\right)} = \frac{\partial V}{\partial x} \qquad \text{Equation 24}$$

so that

$$f_1 = \frac{1}{2}\varepsilon_0\varepsilon_r\left(\frac{\partial V}{\partial x}\right)^2 \qquad \text{Equation 25}$$

Similarly from equation 23

$$f_2 = \frac{1}{2}\varepsilon_0\varepsilon_r\left(\frac{\partial V}{\partial y}\right)^2 \qquad \text{Equation 26}$$

then

$$f = f_1 + f_2 \qquad \text{Equation 27}$$

A check will indicate that this value of f satisfies the Euler condition. From equation 19 the required functional becomes

$$\chi = \int_\Omega \frac{\varepsilon_0\varepsilon_r}{2}\left\{\left(\frac{\partial V}{\partial x}\right)^2 + \left(\frac{\partial V}{\partial y}\right)^2\right\} \mathrm{d}x\,\mathrm{d}y \qquad \text{Equation 28}$$

$$\frac{\partial \chi}{\partial V} = 0 \qquad \text{Equation 29}$$

should give the same as equation 16 when V is substituted for the numerical equation 12.

(iii) Directly from energy

The integral χ can be equated directly to the energy of the region in which a solution is required, and so offers an alternative way of deriving the functional. A generalised energy equation can be developed by consideration of Maxwell's equations as follows:

$$\mathrm{curl}\ H = J + \frac{\partial D}{\partial t} \qquad \text{Equation 30}$$

$$\mathrm{curl}\ E = -\frac{\partial B}{\partial t} \qquad \text{Equation 31}$$

also

$$J = \frac{E}{\rho} \qquad \text{Equation 32}$$

$$B = \mu_o\mu_r H \qquad \text{Equation 33}$$

$$D = \varepsilon_0\varepsilon_r E \qquad \text{Equation 34}$$

If a scalar multiplication of equation 30 by $(-E)$ is added to a multiplication of equation 31 by (H), the resulting equation is:

$$H \text{ curl } E - E \text{ curl } H = -H\frac{\partial B}{\partial t} - E \cdot J - E\frac{\partial D}{\partial t} \quad \text{Equation 35}$$

Now:

$$\text{div}(E \times H) = H \text{ curl } E - E \text{ curl } H \quad \text{Equation 36}$$

Therefore, integrating over a volume, V, gives from equations 35 and 36:

$$\int_V \text{div}(E \times H)\,\text{d}V = -\int_V \left(H\frac{\partial B}{\partial t} + E\frac{\partial D}{\partial t}\right)\text{d}V - \int_V E \cdot J\,\text{d}V \quad \text{Equation 37}$$

But

$$\int_V \text{div}(E \times H)\,\text{d}V \quad \text{Equation 38}$$

can be expressed as a surface integral by applying Gauss's equation to give:

$$\int_A (E \times H)\,\text{d}A \quad \text{Equation 39}$$

Therefore, equation 37 can be written as:

$$\int_A (E \times H)\,\text{d}A = -\int_V \left(H\frac{\partial B}{\partial t} + E\frac{\partial D}{\partial t}\right)\text{d}V - \int_V E \cdot J\,\text{d}V \quad \text{Equation 40}$$

which can be re-arranged to give the loss equation as:

$$\underbrace{-\frac{\partial}{\partial t}\int_V \left\{\frac{\mu_0\mu_r H^2}{2} + \frac{\varepsilon_0\varepsilon_r E^2}{2}\right\}\text{d}V}_{\text{Rate-of-change of stored magnetic/electric energy}} = \underbrace{\int_V E \cdot J\,\text{d}V}_{I^2R \text{ loss}} + \underbrace{\int_A (E \times H)\,\text{d}A}_{\text{Power flow across boundaries}} \quad \text{Equation 41}$$

If it is assumed that E, J and H vary sinusoidally in time, i.e. $\text{e}^{j\omega t}$, then the left-hand side of equation 41 can be integrated with respect to time to yield:

$$\underbrace{\int_V \frac{\mu_0\mu_r H^2}{2}\,\mathrm{d}V}_{\text{Magnetic stored energy}} + \underbrace{\int_V \frac{\varepsilon_0\varepsilon_r E^2}{2}\,\mathrm{d}V}_{\text{Electric stored energy}} = \underbrace{\frac{1}{2j\omega}\int_V E\cdot J\,\mathrm{d}V}_{I^2R\text{ energy}}$$

$$+ \underbrace{\frac{1}{2j\omega}\int_A (E\times H)\,\mathrm{d}A}_{\text{Poynting vector*}} \qquad \text{Equation 42}$$

To determine the functional, the variable H, E and J are redefined in terms of the controlling variables, such as the magnetic vector potential or the magnetic scalar potential.

Thus for an electrostatic formulation the functional simply becomes:

$$\chi = \int_V \frac{\varepsilon E^2}{2}\,\mathrm{d}V = 0 \qquad \text{Equation 43}$$

In 2D this becomes

$$\chi = \int_A \frac{\varepsilon}{2}\left(E_x^2 + E_y^2\right)\mathrm{d}A \qquad \text{Equation 44}$$

Since $E = -\mathrm{grad}\ V$

$$\chi = \frac{\varepsilon}{2}\int_A \left\{\left(\frac{\partial V}{\partial x}\right)^2 + \left(\frac{\partial V}{\partial y}\right)^2\right\}\mathrm{d}A \qquad \text{Equation 45}$$

To extremise this equation χ is differentiated with respect to V, i.e

$$\frac{\partial\chi}{\partial V} = \frac{\partial}{\partial V}\left\{\frac{\varepsilon}{2}\int_A \left\{\left(\frac{\partial V}{\partial x}\right)^2 + \left(\frac{\partial V}{\partial y}\right)^2\right\}\mathrm{d}A\right\} \qquad \text{Equation 46}$$

Again the numerical form of this equation is formed from the substitution of the numerical approximation of V, equation 12. For engineers this is, by far, the best approach although it does not readily define how to treat the boundaries.

(d) Mesh generation

Typically, to solve a problem in which the active space may be discretised by 3000 nodes, requires about 25 000 items of data, all of which have to be correct. When these were defined manually the potential for error was great. However, continuing improvements in

* This term relates to the energy transfer into or out of a region across a boundary: this is particularly useful when dealing with boundaries represented by surface impedance.

computer technology have made it possible to develop interactive mesh generating systems, pre-processors. Within these systems nodes and elements can be created and distributed in the required regions from initial geometric data defining the basic outline of the problem. Instructions such as ‘group bisect’, ‘mesh grid’, etc. can be used to refine the discretisation but if repetitive sections such as stator slots require modelling, then a ‘macro’ can be used to transform and join models many times. Material definition is specified by an element label and either ‘unary’ or ‘binary’ constraints can be imposed on the boundary nodes. Even so, it is becoming evident that designers do not have the time nor inclination to generate finite element meshes, so automatic mesh generating procedures have been written in which the mesh is generated from basic design parameters. These methods enable designers to obtain the required results without an in depth knowledge of the finite element method.

(e) Solvers

In the CAD package SLIM a range of finite element solvers are available to the user. These can be selected depending on the type of problem to be solved, the special modelling facilities required and the number of dimensions for which a solution is intended.

At present the solvers cover 2-dimensional, axi-symmetric, quasi-3-dimensional and full 3-dimensional problems with special treatment for:

(i) Non-linearity of magnetic materials
(ii) Permanent magnets with both linear and non-linear characteristics
(iii) Induced currents
(iv) Foils which are surfaces of constant voltage but unknown at the time of solution
(v) Materials in which the induced currents flow in a thin region beneath the surface

In all the solvers the resulting matrix is inverted by a pre-conditioned Incomplete Choleski Conjugate Gradient Method (ICCG) to make maximum use of available store and speed of solution.

(f) Post processing

Finite element solutions produce a large amount of information which has to be efficiently processed to meet the designer’s needs. Normally flux or potential plots are required to assess the validity of the solution obtained since errors can be made in the data input or the model used is not adequate to represent the problem being solved. However, the designer is mainly interested in local values of flux density, electrical stresses, currents, losses or global values such as inductance, torque, capacitance etc.

The post processing modules of SLIM have been designed with these attributes in mind making it interactive and fast to use. It can display the flux, flux density, stresses, or current density either as contours, vectors or by colour shading. In addition individual quantities can be pinpointed to determine local values. Results can also be manipulated by differentiation, integration along lines or around regions to obtain values such as induced voltages, forces, torques, etc. Besides manipulation of results, post processing has been developed to provide the designer with a range of presentation facilities. Such facilities include multi-windowing, zoom, graphs (2-dimensional and 3-dimensional), and annotation. The facility to record session results is also available and is particularly useful when many solutions require the same post-processing procedure.

Worked example using the finite element method

To demonstrate the working of the finite element method, and to indicate its accuracy compared with an analytical approach an example for which analytical solutions are obtainable is considered. The example is to derive the scalar potential distribution in a rectangular sheet with a specified potential on one edge and zero potential on the other three.

Rectangular plate

Finite element solution The problem is illustrated in Figure A7.2 and is symmetric about the line AB.

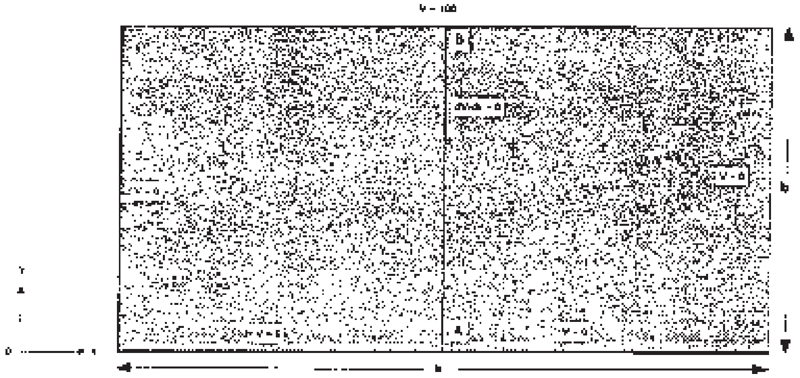

Figure A7.2

The potential within the plate is described by Laplace's equation, which in cartesian co-ordinates is:

$$\frac{\partial^2 V}{\partial x^2} + \frac{\partial^2 V}{\partial y^2} = 0 \qquad \text{Equation 47}$$

The functional corresponding to equation 47 can be obtained from any of the techniques mentioned earlier as:

$$\chi = \int_A \frac{1}{2}\left[\left(\frac{\partial V}{\partial x}\right)^2 + \left(\frac{\partial V}{\partial y}\right)^2\right] \mathrm{d}x\,\mathrm{d}y \qquad \text{Equation 48}$$

The functional is extremised by differentiating equation (48) with respect to V and equating to zero. This gives:

$$\frac{\partial \chi}{\partial V} = \int_A \left[\frac{\partial V}{\partial x}\frac{\partial}{\partial V}\left(\frac{\partial V}{\partial x}\right) + \frac{\partial V}{\partial y}\frac{\partial}{\partial V}\left(\frac{\partial V}{\partial y}\right)\right] \mathrm{d}x\,\mathrm{d}y \qquad \text{Equation 49}$$

To solve equation 49 numerically, the rectangular plate is divided into triangular elements as shown in Figure A7.3, and the potential is assumed to vary linearly over each triangle.

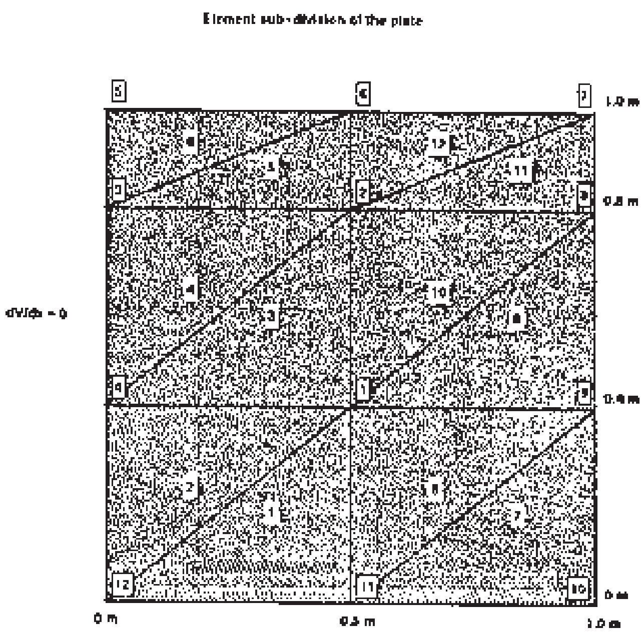

Figure A7.3

This can be written as:

$$V = \alpha_1 + \alpha_2 x + \alpha_3 y \qquad \text{Equation 50}$$

which, expressing the coefficients α in terms of the nodal potentials and coordinates of the general triangle i, j, k, gives:

$$V = \frac{1}{2\Delta}\left\{(a_i + b_i x + c_i y)V_i + \left(a_j + b_j x + c_j y\right)V_j + (a_k + b_k x + c_k y)V_k\right\} \qquad \text{Equation 51}$$

where

$$a_i = x_j y_k - x_k y_j \quad b_i = y_j - y_k \quad c_i = x_k - x_j$$

$$a_j = x_k y_i - x_i y_k \quad b_j = y_k - y_i \quad c_j = x_i - x_k$$

$$a_k = x_i y_j - x_j y_i \quad b_k = y_i - y_j \quad c_k = x_j - x_i \qquad \text{Equation 52}$$

In the numerical treatment, the functional is extremised with respect to potentials at all nodes. Thus, for one node 'i' of the general triangle (Figure A7.1) extremisation is carried out by differentiating equation 49 with respect to V_i, summing similar equations formed from all triangles connected with node 'i' and equating to zero; i.e.

$$\sum \frac{\partial \chi^e}{\partial V_i} = \sum \quad {}_A \quad \frac{\partial V}{\partial x} \frac{\partial}{\partial V_i} \frac{\partial V}{\partial x} + \frac{\partial V}{\partial y} \frac{\partial}{\partial V_i} \frac{\partial V}{\partial y} \quad \mathrm{d}x\,\mathrm{d}y$$
$$= 0 \qquad \text{Equation 53}$$

where Σ represents the summation of all connected triangles.

Substituting for V from equation 51 gives the final numerical equation as:

$$\sum \frac{\partial \chi^e}{\partial V_i} = \sum \frac{1}{4\Delta} \left\{ \left(b_i^2 + c_i^2\right) V_i + \left(b_i b_j + c_i c_j\right) V_j + \left(b_i b_k + c_i c_k\right) V_k \right\}$$
$$= 0 \qquad \text{Equation 54}$$

For the example from Figure A7.3, the extremisation of the functional leads to the following equations:

$$\text{Node 1: } \frac{\partial \chi_1}{\partial V_1} + \frac{\partial \chi_2}{\partial V_1} + \frac{\partial \chi_3}{\partial V_1} + \frac{\partial \chi_8}{\partial V_1} + \frac{\partial \chi_9}{\partial V_1} + \frac{\partial \chi_{10}}{\partial V_1} = 0 \qquad \text{Equation 55}$$

$$\text{Node 2: } \frac{\partial \chi_3}{\partial V_2} + \frac{\partial \chi_4}{\partial V_2} + \frac{\partial \chi_5}{\partial V_2} + \frac{\partial \chi_{10}}{\partial V_2} + \frac{\partial \chi_{11}}{\partial V_2} + \frac{\partial \chi_{12}}{\partial V_2} = 0 \qquad \text{Equation 56}$$

$$\text{Node 3: } \frac{\partial \chi_4}{\partial V_3} + \frac{\partial \chi_5}{\partial V_3} + \frac{\partial \chi_6}{\partial V_3} = 0 \qquad \text{Equation 57}$$

$$\text{Node 4: } \frac{\partial \chi_2}{\partial V_4} + \frac{\partial \chi_3}{\partial V_4} + \frac{\partial \chi_4}{\partial V_4} = 0 \qquad \text{Equation 58}$$

(Nodes 3 and 4 actually lie on the line of symmetry, where the boundary condition is:

$$\frac{\partial V}{\partial x} = 0 \qquad \text{Equation 59}$$

but, these can be treated as unknown values.)

Each component of equations 55–58 is derived from the general equation 54, and from the dimensions for Figure A7.2 they reduce to:

$$4.1V_1 - 1.25V_2 + 0.0V_3 - 0.8V_4 = 0$$

$$-1.25V_1 + 4.95V_2 - 0.6V_3 + 0.0V_4 = 25$$

$$0.0V_1 - 0.6V_2 + 2.475V_3 - 0.625V_4 = 125$$

$$-0.8V_1 + 0.0V_2 - 0.625V_3 + 2.05V_4 = 0$$

The right-hand side values 25 and 125 originate from the potential on the boundaries.

In matrix form these become:

$$\begin{matrix} 4.1 & -1.25 & 0 & -0.8 \\ -1.25 & 4.95 & -0.6 & 0 \\ 0 & -0.6 & 2.475 & -0.625 \\ -0.8 & 0 & -0.625 & 2.05 \end{matrix} \cdot \begin{matrix} V_1 \\ V_2 \\ V_3 \\ V_4 \end{matrix} = \begin{matrix} 0 \\ 25 \\ 125 \\ 0 \end{matrix} \qquad \text{Equation 60}$$

(The coefficient matrix is symmetrical about the leading diagonal.)

Solving equation 60 gives:

$$V_1 = 27$$

$$V_2 = 69.5$$

$$V_3 = 75.6$$

$$V_4 = 31.4$$

A computer program has been written to enable calculations to be made with finer mesh systems. Figure A7.4 shows two degrees of sub-division, one having 121 nodes, and the other 286. The latter has small elements concentrated in the area of rapidly changing potential.

The resulting scalar potential plots are given in Figure A7.5.

Analytical solution The problem to be solved is illustrated in Figure A7.2. The potential has a constant value of V_0 on the upper surface, but goes to

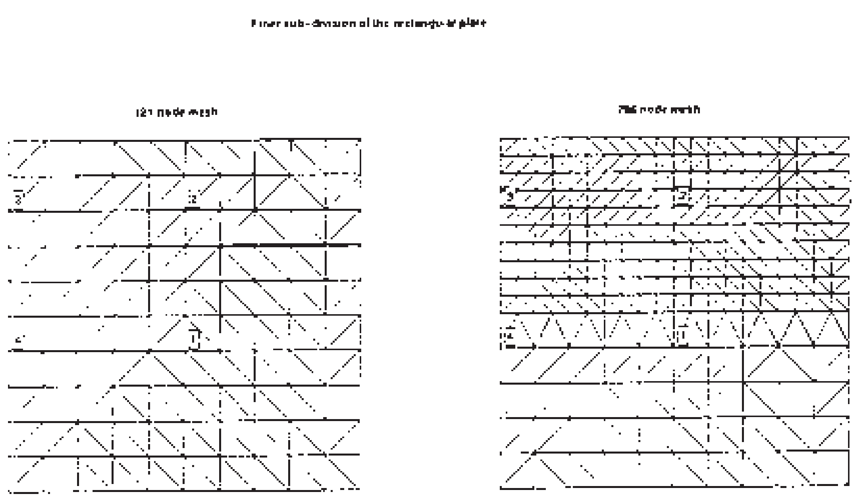

Figure A7.4

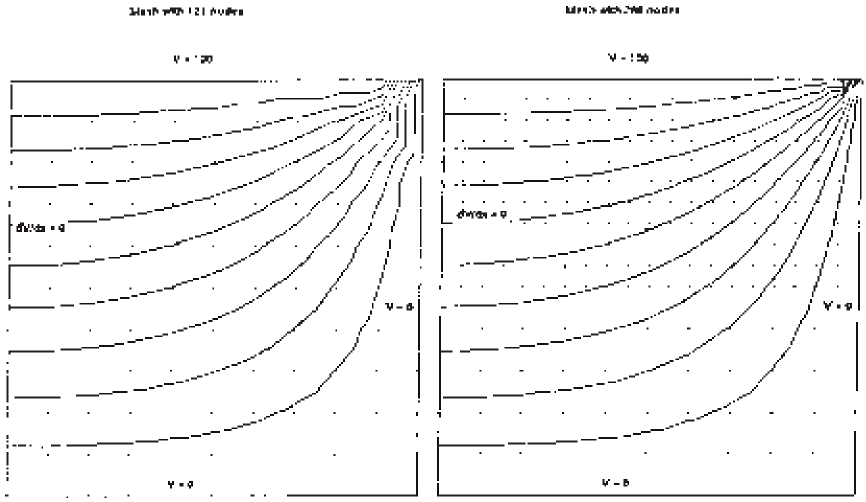

Figure A7.5

zero at the vertical edges. This can be represented by a Fourier series of half-wavelength 'a' and odd harmonics only, since V is symmetrical about $a/2$.

$$\therefore V = \sum_{n=1,3,5,\ldots}^{\infty} \frac{4}{\pi}\frac{V_0}{n}\sin\frac{n\pi x}{a} \qquad \text{Equation 61}$$

The potential within the plate is obtained by substituting

$$V = V(y)\sin\frac{n\pi x}{a} \qquad \text{Equation 62}$$

into equation 18 giving

$$\frac{\partial^2 V}{\partial y^2} - \frac{n^2\pi^2 V}{a^2} = 0 \qquad \text{Equation 63}$$

for which the solution is:

$$V = \sum_{n=1,3,5,\ldots} Ae^{\frac{n\pi}{a}y} + Be^{-\frac{n\pi}{a}y} \quad \sin\frac{n\pi x}{a} \qquad \text{Equation 64}$$

constants A and B are determined from the following boundary conditions:

At $y = 0, \quad V = 0$
$\quad y = b, \quad V = V_0$

These give:

$$A = \frac{V_0}{2\sinh\dfrac{n\pi b}{a}} \quad \text{and} \quad B = -\frac{V_0}{2\sinh\dfrac{n\pi b}{a}} \qquad \text{Equation 65}$$

Equation 64 was used to calculate the potential at nodes corresponding to those used in the finite element studies. Results are compared in Table A7.1.

Comparison

The potentials at the four nodes indicated in Figure A7.3 are used to assess the accuracy of the numerical study.

Table A7.1

Node No	Analytic	Finite Element Study – Total Number of Nodes		
		12	121	287
1	27.7	27.0	27.78	27.74
2	70.4	69.5	70.2	70.3
3	76.6	75.6	76.57	76.6
4	34.8	31.4	34.77	34.78

The results of the numerical and analytical methods agree well, even for the coarse mesh with only four internal nodes.

The finite-element method, although an extremely powerful computational technique, is only an approximation to the real problem. Thus, care should be taken to assess the solution in respect of the accuracy of the model used. This accuracy will depend upon the position and type of boundaries, discretisation and the representation of the real problem being solved.

Application to high voltage problems

To illustrate the use of the finite element method in the design of high voltage problems occurring in transmission system equipment, two examples are considered:

(a) the reduction of the stresses at the flange/ceramic interface of a high voltage bushing.

(b) the determination of a low voltage region in which an optical fibre can be placed without risk of electric breakdown.

High voltage bushing

The outline of the bushing is shown in Figure A7.6. It consists principally of a ceramic bushing with metal flanges at each end across which the voltage appears. The regions of concern are at the flange/ceramic interface mainly due to the sharp corners on the flange. To remedy this situation several radii on the metal flange were modelled in an attempt to reduce the stresses in this region. The problem with reducing the flange stresses in the region is that voids can be created which could initiate local electric discharge. Thus it is important to remember that a modification in one region could give adverse effects in other regions. The advantage of the finite element method is that it enables the designer to assess such effects.

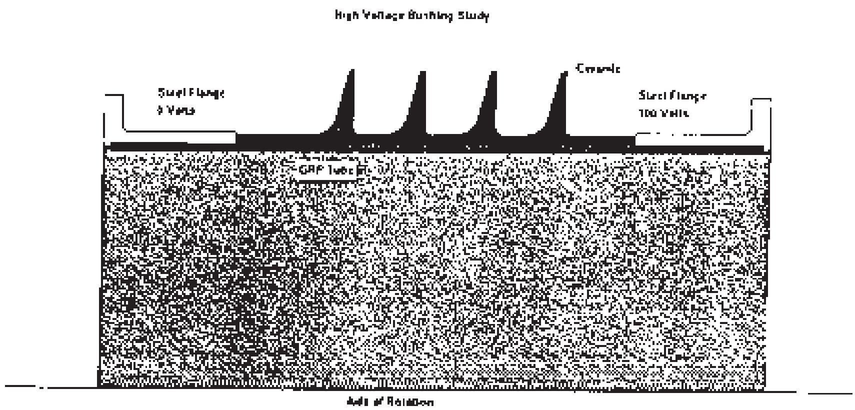

Figure A7.6

In this study radii of 0, 1, 2 and 3 mm where used on the inner edge of the flange.

Due to its rotational symmetry an axi-symmetric electrostatic solver was used to evaluate the voltage distribution and hence the electric stresses. Figure A7.7 illustrates the sub-division of the problem using triangular elements.

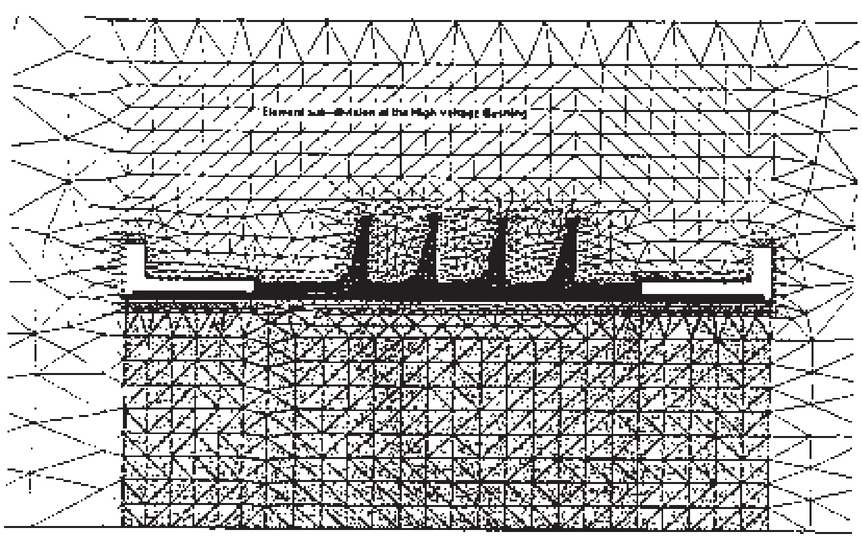

Figure A7.7

Figure A7.8 shows contours of constant voltage and Figure A7.9 the electric stress distribution, in the flange region. The tangential stress along an axial line from the flange end and along the inner surface of the ceramic bushing is shown in Figure A7.10 for various radii. It can be seen that the stress reduces as the radius increases.

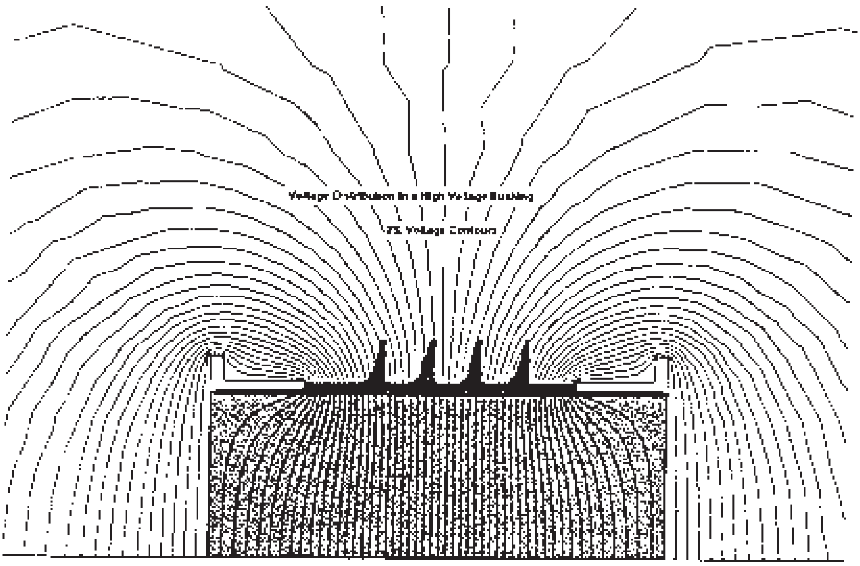

Figure A7.8

Placement of an optical fibre cable in a low intensity field

A method of transmitting information along the transmission system is to use an optical fibre cable. The obvious position for such a cable would be on the earthing wire situated on top of the transmission pylons. However, to place the cable in this position would require complete sections to be closed down which is not convenient to the end user.

One way to overcome this problem is to place the cables between the ground and the phase wires but in a region of low field intensity in order to reduce the risk of electrical breakdown. To determine this region the finite element formulation developed in the previous sections is used.

Figure A7.11 outlines the problem concerned and indicates the 2D section to be modelled which was situated mid-way between towers. The sub division of this section is shown in Figure A7.12 and used 7423 nodes with 14 502 elements. The voltage on the individual cables is time varying so either the formulation derived in the previous sections is re-formatted in terms of complex numbers or the voltage distribution is found at discrete times throughout the time cycle. Excitation for developing the voltage distribution is by voltages imposed on the phase wires.

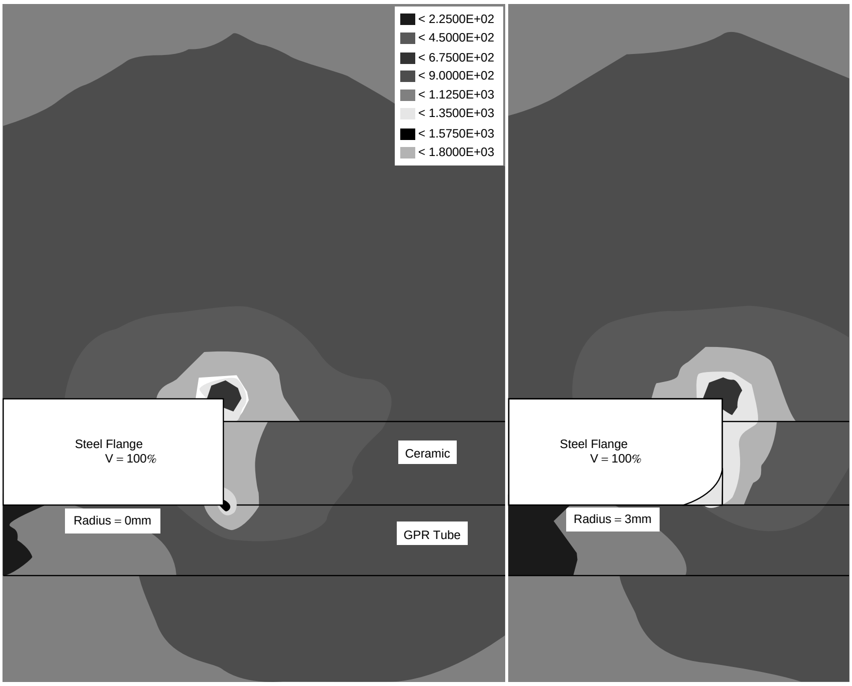

Figure A7.9

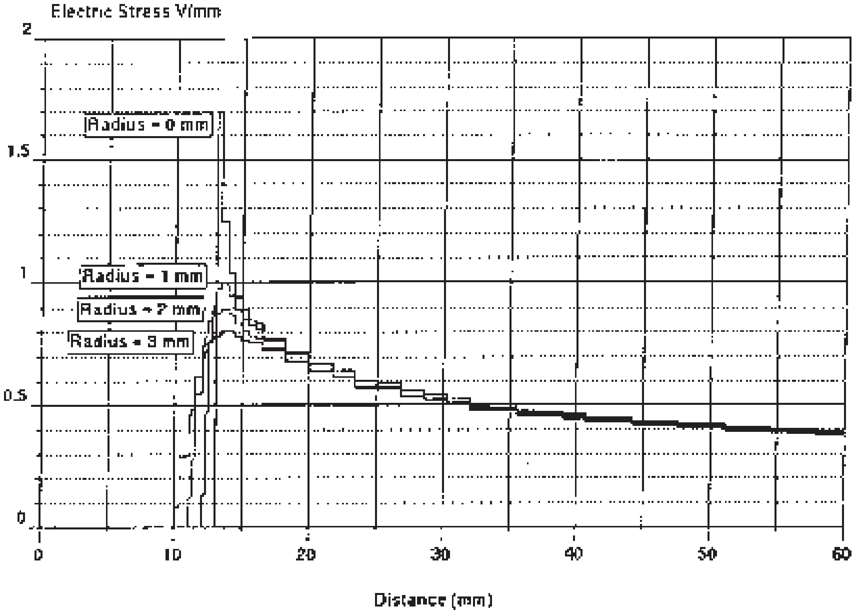

Figure A7.10

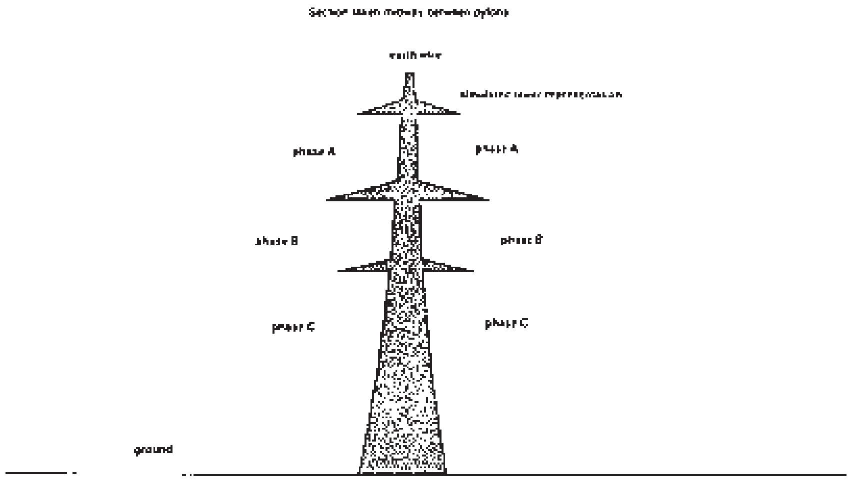

Figure A7.11

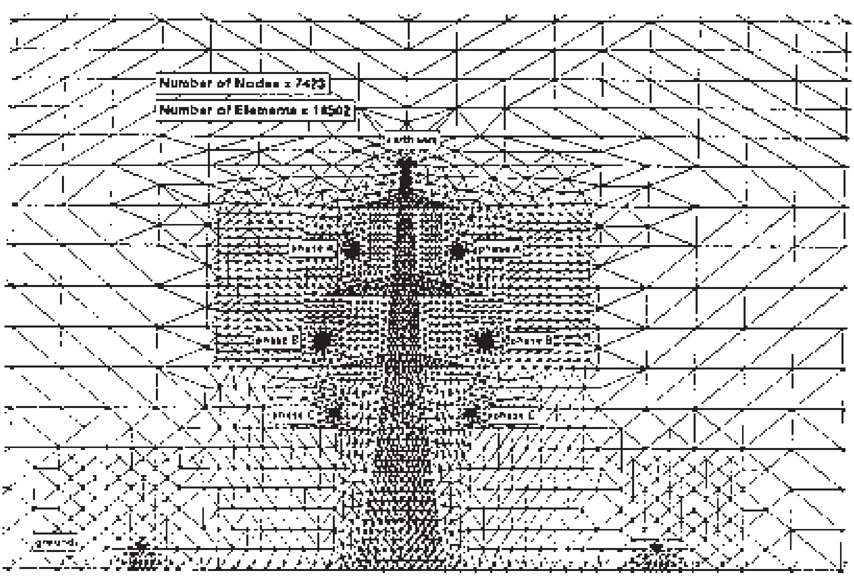

Figure A7.12

For the case where complex numbers are used the voltage on the individual phases is given as

$$Va = V(1 + j0) \qquad \text{Equation 66}$$

$$Vb = V\left(-0.5 + j\frac{\sqrt{3}}{2}\right. \qquad \text{Equation 67}$$

$$Vc = V\left(-0.5 - j\frac{\sqrt{3}}{2}\right) \qquad \text{Equation 68}$$

If real arithmetic is used then the phase voltages at $\omega t = 0$ are

$$Va = 1$$
$$Vb = -0.5$$
$$Vc = -0.5 \qquad \text{Equation 69}$$

and at $\omega t = 30^\circ$

$$Va = \frac{\sqrt{3}}{2}$$
$$Vb = -0$$
$$Vc = -\frac{\sqrt{3}}{2} \qquad \text{Equation 70}$$

similarly for other times.

Figure A7.13 shows the voltage distribution at $\omega t = 0$ and $\omega t = 90$. The voltage along a line from the ground position vertically up to the middle of the cables is shown in Figure A7.14 every 30° through the time cycle. It can be seen from this study that there is a region of lower field intensity at a distance 28 metres above the ground. It is at this position the optical cable can be placed to minimise the risk of electrical breakdown.

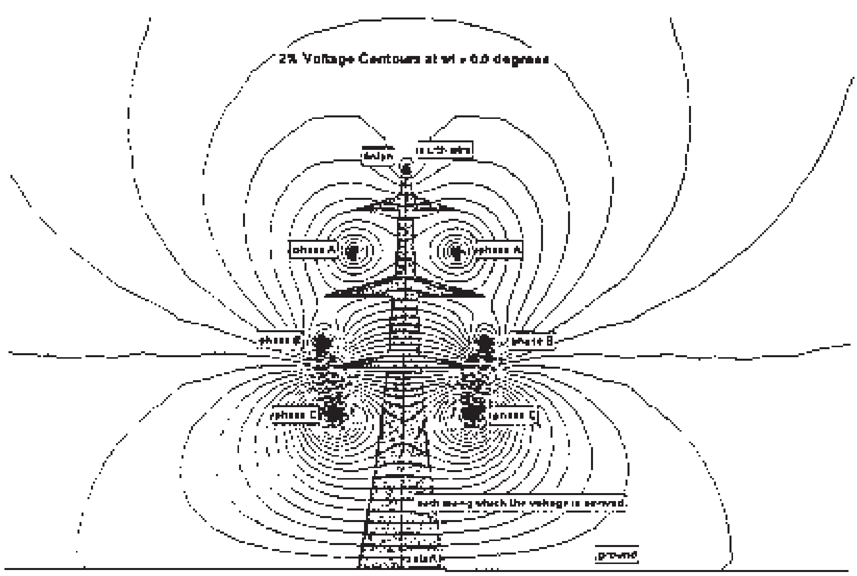

Figure A7.13

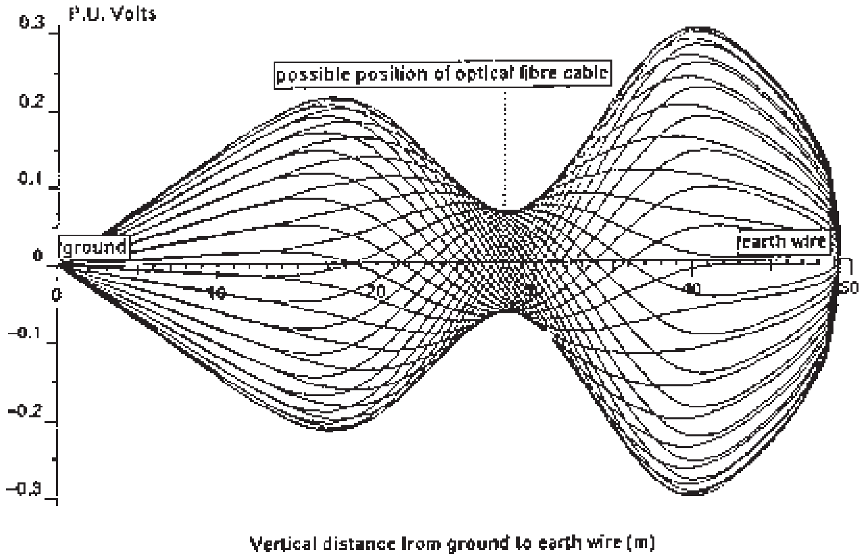

Figure A7.14

Contamination on bushing

Insulators/bushings can, in their working life, be exposed to the environment and consequently can be contaminated by the pollution in the atmosphere. Because this contamination is a semi-conductor the electrical field distribution can be modified as shown in the following example.

Figure A7.15 shows the outline of a finite element model of a HV instrument bushing. The model consists of a longitudinal section through the bushing geometry, and the field solution assumes rotational symmetry about the axis (which is arbitrarily horizontal).

Figure A7.16 shows the voltage pattern on and around the bushing in its pristine, just-delivered, state. Figure A7.17 shows a similar voltage pattern when a uniform thin layer of greasy dirt is assumed to have formed on the bushing surface. The contamination is represented in the model as a semi-conducting layer. Figure A7.18 shows the distortion in the voltage distribution if dry-banding has occurred or if the contamination has been cleaned off two of the sheds at the right-hand end. The differences in voltage distribution along the bushing surface are clearly shown in Figure A7.19, with the corresponding electric stresses in Figure A7.20.

Clearly, a uniform layer of contamination smoothes out the voltage distribution, reducing localised electric stress (although it will have the undesirable effect of allowing leakage currents to flow along the column). It is cautionary to find, however, that dry-banding or even incomplete cleaning of the insulator can lead to hugely increased electrical stresses and a higher risk of breakdown.

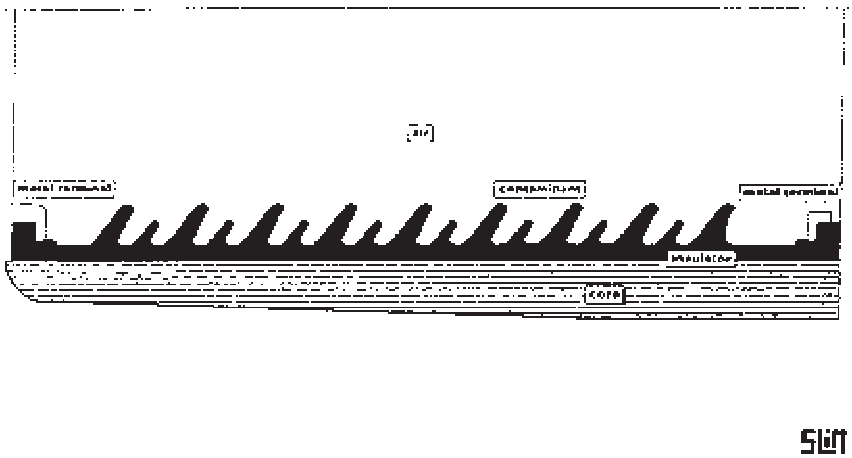

Figure A7.15

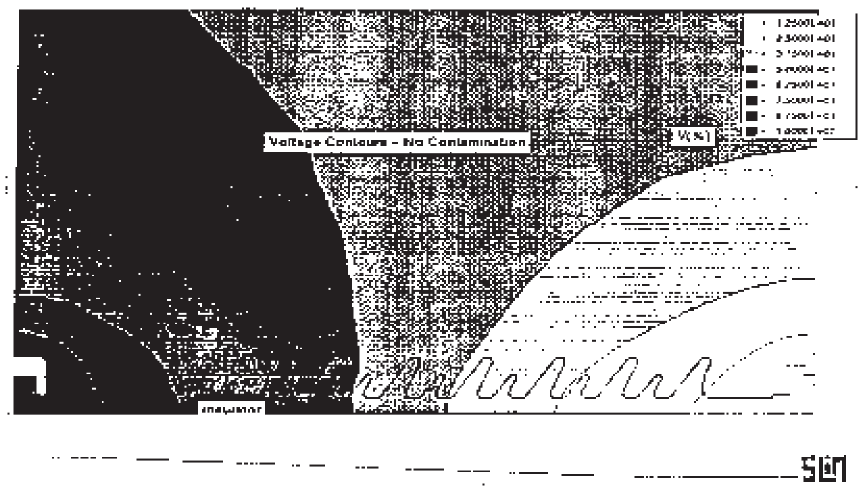

Figure A7.16

Future development

It is clearly evident from assessing the needs of designers that fully automated procedures, in which the finite element approach appears as a 'black box', are required. The current software has been written with this in mind and it is becoming relatively simple to link mesh routines, solvers and post processors together through the use of shell scripts. The modular form of the programs also makes it easier to merge with other engineering design procedures such as Thermal, Mechanical etc. Even though the design process becomes automated it is still possible to inspect or locally modify the mesh. As far as improvement

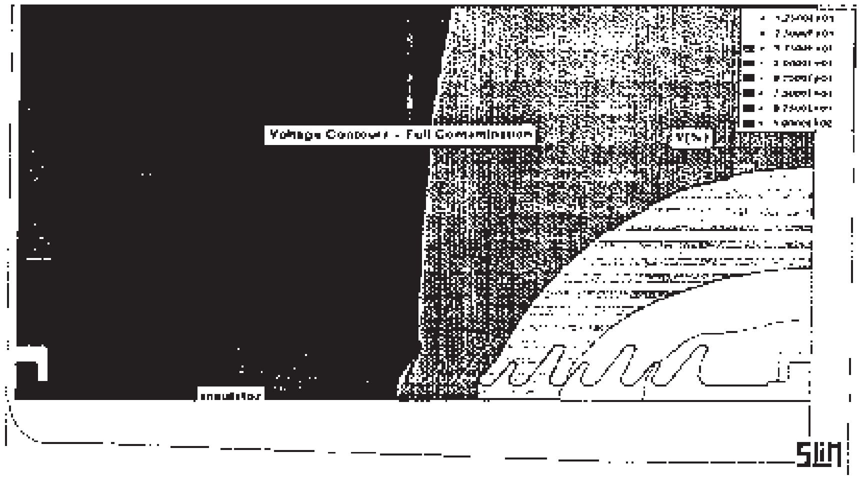

Figure A7.17

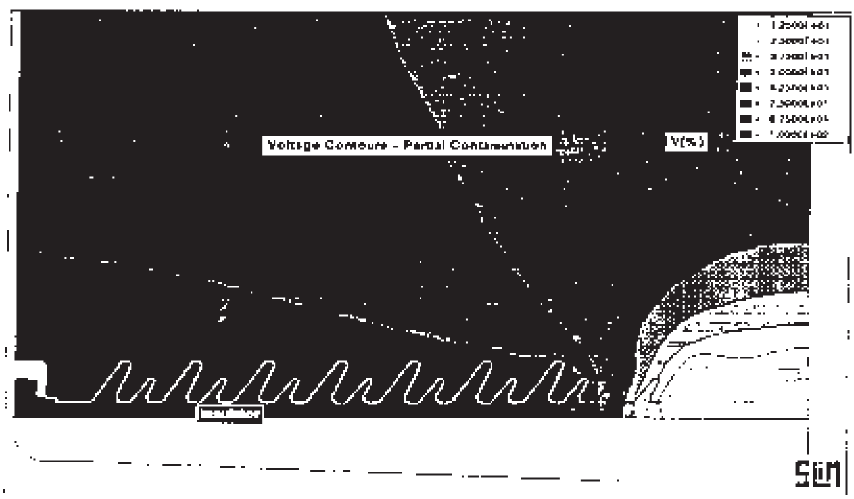

Figure A7.18

to the solvers is concerned more work is required to improve time stepping techniques to reduce solution times and make them more flexible in their use. Further development of 3-dimensional solvers is required to simplify their use on difficult ‘real’ engineering problems, but it will not be long before they are used as a regular design tool.

Finally, other techniques are being researched and one which may improve modelling capabilities, especially in 3-dimensions, is the hybrid method. This is a combination of the boundary element and finite element method: the

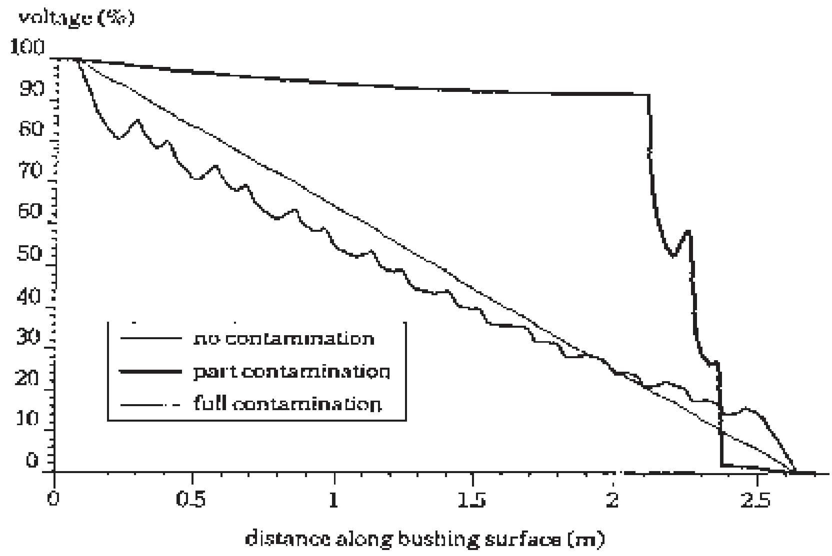

Figure A7.19

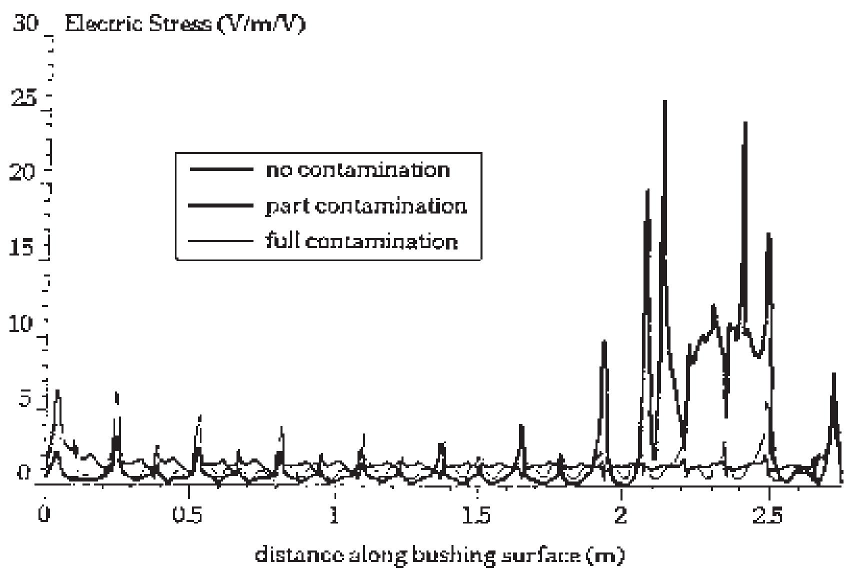

Figure A7.20

finite element method models non-linear regions while the boundary element method models linear regions and external boundaries. The main advantage is that individual components can be discretised without the need to mesh the air region which links them together, so reducing the time taken to build 3-dimensional models.

Conclusions

The preceding sections have shown that the finite element method has become a well established design tool enabling the solution of engineering problems not previously possible.

In order to facilitate its regular use in the design environment automatic procedures, which incorporate the finite element method, have been developed. These have proved extremely useful in optimising designs but most of all in providing a clear understanding of the complete electromagnetic effect within the equipment.

Finally, it is only the engineer who can be innovative but it is believed that these electromagnetic CAD tools will enable him to achieve his aims more quickly and with a high degree of reliability.

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Appendix 8
List of National and International Standards relating to power transformers

UK National Standards	*European Standards*	*International Standards*
BS EN 60076-1 (1997): Power transformers: Part 1 – General	EN 60076-1 (1997): Power transformers: Part 1 – General	IEC 76-1 (1993): Power transformers: Part 1 – General
BS EN 60076-2 (1997): Power transformers: Part 2 – Temperature rise	EN 60076-2 (1997): Power transformers: Part 2 – Temperature rise	IEC 76-2 (1993): Power transformers: Part 2 – Temperature rise
BS 171: Part 3: 1987 Power transformers: Part 3 – Insulation levels and dielectric tests	HD 398.3 (1986): Power transformers: Insulation levels and dielectric tests	IEC 76-3 (1980): Power transformers: Part 3 – Insulation levels
		IEC 76-3-1 (1987): External clearances in air
BS 171: Part 5: 1978 Ability to withstand short-circuit	HD 398.5 (1983): Ability to withstand short-circuit	IEC 76-5 (1976): Power transformers: Part 5 – Ability to withstand short-circuit
BS 4571: On-load tapchangers	HD 367 (1992): On-load tapchangers	IEC 214 (1989): On-load tapchangers
BS EN 60289: 1995 Reactors	EN 60289 (1984): Reactors	IEC 289 (1988): Reactors
BS 7735: 1994 Guide to loading of oil-immersed power transformers	Not harmonised	IEC 354 (1991): Loading guide for oil-immersed transformers

UK National Standards	*European Standards*	*International Standards*
BS 5611: 1978 Application guide for on-load tapchangers	Not harmonised	IEC 542 (1976): Application guide for on-load tapchangers
BS EN 60551 (1993): Determination of transformer and reactor sound levels	EN 60551 (1987): Determination of transformer and reactor sound levels	IEC 551 (1987): Determination of transformer and reactor sound levels
BS 5953: Part 1: 1980 – Application guide for power transformers		IEC 606 (1977): Application guide for power transformers
		IEC 616 (1978): Terminal and tapping markings for power transformers
		IEC 722 (1982): Guide for lightning impulse and switching impulse testing of power transformers
BS 7806: 1995 – Dry-type power transformers	HD 464 (1991): Dry-type power transformers	IEC 726 (1982): Dry-type power transformers
		IEC 905 (1987): Loading guide for dry-type power transformers

UK National Standards	*European Standards*
BS 7821: Part 1: 1995 Three-phase oil-immersed distribution transformers: Part 1 – General requirements and requirements for transformers with highest voltage for equipment not exceeding 24 kV	HD 428.1 (1991): Three-phase oil-immersed distribution transformers: Part 1 – General requirements and requirements for transformers with highest voltage for equipment not exceeding 24 kV
BS 7821: Part 2: Section 2.1: 1995 Three-phase oil-immersed distribution transformers: Part 2.1 – Distribution transformers with cable boxes on the high voltage and/or the low voltage side	HD 428.2.1 (1994): Three-phase oil-immersed distribution transformers: Part 2.1 – Distribution transformers with cable boxes on the high voltage and/or the low voltage side

UK National Standards	*European Standards*
BS 7821: Part 3: 1995 Supplementary requirements for transformers with highest voltage for equipment equal to 36 kV	HD 428.3 (1994): Supplementary requirements for transformers with highest voltage for equipment equal to 36 kV
BS 7821: Part 4: 1995 Determination of the power rating of a transformer loaded with non-sinusoidal currents	HD 428.4 (1994): Determination of the power rating of a transformer loaded with non-sinusoidal currents
BS 7844: Part 1: 1996 Three phase dry-type distribution transformers: Part 1 General requirements and requirements for transformers with highest voltage for equipment not exceeding 24 kV	HD 538.1 (1992): Three phase dry-type distribution transformers: Part 1 – General requirements and requirements for transformers with highest voltage for equipment not exceeding 24 kV
BS 7844: Part 2: 1996 Supplementary requirements for transformers with highest voltage for equipment equal to 36 kV	HD 538.2 (1995): Supplementary requirements for transformers with highest voltage for equipment equal to 36 kV
BS EN 50195: 1997 Code of practice for the safe use of askerel filled electrical equipment	EN 50195 (1996): Code of practice for the safe use of askerel filled electrical equipment
BS EN 50225: 1997 Code of practice for the safe use of fully enclosed oil-filled electrical equipment which may contain PCBs	EN 50225 (1996): Code of practice for the safe use of fully enclosed oil-filled electrical equipment which may contain PCBs
BS 2562: 1979 Cable boxes for transformers and reactors	
BS 6435: 1984 Unfilled enclosures for the dry termination of HV cables for transformers and reactors	
BS 6436: 1984 Ground mounted distribution transformers for cable box or unit substation connection	

Appendix 9
List of principal CIGRE reports and papers relating to transformers

REPORTS FROM STUDY COMMITTEE 12 (TRANSFORMERS) WORKING GROUPS

1. WG 12.02 HVDC transformers
   'Voltage tests on transformers and smoothing reactors for HVDC transmission'.
   Electra No. 46, May 1976, pp. 19–38.

2. WG 12.03 Partial discharge testing
   'Volt–time relationships for PD inception in oil paper insulation'.
   Electra No. 67, December, 1979, pp. 17–28.

3. WG 12.05 Reliability survey
   'An international survey on failure in large power transformers in service'.
   Electra No. 88, January 1983, pp. 21–48.

4. WG 12.06 Large transformers
   'Final report of WG 06 of Study Committee 12 (Transformers)'.
   Electra No. 82, May 1982, pp. 31–46.

5. WG 12.07 Part-winding resonance
   'Resonance behaviour of high-voltage transformers'.
   CIGRE Report 12–14, 1984.

6. WG 12.09 Thermal problems in transformers
   6.1 'Recent developments by CEGB to improve the prediction and monitoring of transformer performance', Burton, P. J., Graham, J., Hall, A. C., Laver, J. A. and Oliver, A. J., September 1984.

6.2 'Heat run test procedure for power transformers'.

6.3 'Direct measurement of hot spot temperature on transformers'.

6.4 'A survey of facts and opinions on the maximum safe operating temperature of power transformers under emergency conditions'.
Electra No. 129, March 1990, pp. 37–64 (see also items 13 and 16).

6.5 'Estimation of the remaining service life of power transformers and their insulation'.
Electra No. 133, December 1990, pp. 652–72.

6.6 'Lifetime evaluation of transformers'.
Electra No. 150, October 1993, pp. 38–51.

6.7 'Dissolved gas analysis during heat-run tests on power transformers'.

6.8 'Analytical determination of transformer windings hot-spot factor'.

6.9 'Experimental determination of power transformers hot-spot factor'.

6.10 'Survey of power transformer overload practices'.
Electra No. 168, August 1995, pp. 21–52.

7. JWG 12/14.10 HVDC converter transformers

7.1 'HVDC converter transformers – a review of specification content'.
Electra No. 141, April 1992, pp. 34–50.

7.2 'In-service performance of HVDC converter transformers and oil cooled smoothing reactors'.
Electra No. 155, August 1994, pp. 7–32.

7.3 'The relationship between test and service stresses as a function of resistivity ratio for HVDC converter transformers and smoothing reactors'.
Electra No. 157, December 1994, pp. 33–60.

7.4 'HVDC converter transformer noise considerations'.
Electra No. 167, August 1996, pp. 39–48.

7.5 'Considerations of impedances and tolerances for HVDC converter transformers'.
Electra No. 167, August 1996, pp. 49–58.

8. WG 12.11 Fast transients in transformers
'Distribution of very fast transient overvoltages in transformer windings'.
CIGRE Report 12-204, 1992.

9. WG 12.12 Noise measurements for transformers

9.1 IEC TC 14 (Secretariat) 190
Appendix B to IEC 551: Measurement of sound power level using sound intensity.

9.2 IEC TC 14 (Secretariat) 194
Appendix C to IEC 551: Determination of current sound level.

9.3 ‘Transformer noise: determination of sound power level using the sound intensity measurement method’.
Electra No. 144, October 1992, pp. 78–95.

10. JWG 12/15.13 Static electrification
‘Static electrification in power transformers’.
CIGRE Report 15/12.03, 1992 (see also item 13.4).

OTHER ELECTRA PUBLICATIONS

11. ‘Problems related to cores of transformers and reactors’, H. Kan.
Electra No. 94, May 1984, pp. 15–33.

12. ‘Experience of the new dielectric tests (IEC publication 76-3) for power transformers with highest voltage for equipment greater than or equal to 245 kV’, W. D. Lampe.
Electra No. 108, October 1986, pp. 104–117.

13. Joint Colloquium of Study Committees 12 and 15 on ‘Current problems in insulating systems including assessment of ageing and degradation’, 1989 Rio de Janeiro, Brazil.
13.1 ‘Dissolved gas analysis – current problems of a mature technique’, C. Sobrel Vieira.
13.2 ‘Dissolved gas analysis – new challenges and applications’, M. Duval.
13.3 ‘HLPC contribution to transformer during service and heat run tests’, M. Carballiera.
13.4 ‘Progress in the control of static electrification in transformers’, S. R. Lindgren.
13.5 ‘Factors which affect the electric strength and endurance of polymeric materials’, J. H. Mason.
13.6 ‘Estimation of the remaining service life of power transformers and their insulation’, L. Pettersson.
Electra No. 133, December 1990, pp. 32–72.

14. ‘Effects of geomagnetically induced currents in power transformers’, J. Aubin.
Electra No. 141, April 1992, pp. 24–33.

15. ‘Use of ZnO varistors in transformers’, R. Baehr.
Electra No. 143, August 1992, pp. 32–37.

OTHER PUBLICATIONS CIRCULATED WITHIN STUDY COMMITTEE

16. ‘Summary of contributions from colloquium on thermal aspects of transformers at Rio de Janeiro, October 1989’, J. Aubin.

Appendix 10

List of reports available from ERA Technology Ltd, formerly British Electrical and Allied Industries Research Association (ERA), relating to transformers and surge phenomena therein

TRANSFORMERS

Ref. Q/T101a ‘Mechanical stresses in transformer windings’, by M. Waters.

Ref. Q/T103 ‘Electrical and mechanical effects of internal faults in transformers’, by E. Billig.

Ref. Q/T113 ‘The measurement of axial magnetic forces in transformer windings’, by M. Waters.

Ref. Q/T115 ‘The calculation of transformer thermal data from readings taken in service’, by M. R. Dickson.

Ref. Q/T116 ‘Generation of gases in transformers. Résumé of available information’, by M. R. Dickson.

Ref. Q/T117 ‘Temperature gradients in transformer windings and rates of oil flow in transformer tanks. A critical review of published information’, by B. L. Coleman.

Ref. Q/T118 ‘The operation of naturally cooled outdoor transformers as affected by weather and surroundings. Preliminary review’, by M. R. Dickson.

Ref. Q/T121 ‘The calculation of currents due to faults between turns in transformer windings’, by B. L. Coleman.

Ref. Q/T126 ‘The causes and effects of water in oil-immersed transformers. A critical résumé’, by M. R. Dickson.

Ref. Q/T130 ‘Corrosion of internal tank surfaces in non-conservator transformers’, by M. Waters.

Ref. Q/T134 ‘The measurement and calculation of axial electromagnetic forces in concentric transformer windings’, by M. Waters.

Ref. Q/T139 'The effects of dissolved gases in the design and operation of oil immersed transformers', by M.R. Dickson.
Ref. Q/T141 'An adjustable ambient-temperature thermometer for use when testing transformers', by M. R. Dickson.
Ref. Q/T144 'The effect of core properties on axial electromagnetic forces in transformers with concentric windings', by M. Waters.
Ref. Q/T151 'A method based on Maxwell's equations for calculating the axial short-circuit forces in the concentric windings of an idealized transformer', by P. R. Vein.
Ref. Q/T153 'The measurement of axial displacement of transformer windings', by M. Waters.
Ref. Q/T158 'Measurement of axial forces in a transformer with multi-layer windings', by E. D. Taylor, J. Page and M. Waters.
Ref. Q/T161 'Copper for transformer windings', by J. E. Bowers and E. C. Mantle.
Ref. Q/T163 'E.R.A. researches on transformer noise 1951–59', by A. I. King, A. S. Ensus and M. Waters.
Ref. G/T130 'The effect of zero phase sequence exciting impedance of three-phase core transformers on earth fault currents', by L. Gosland.
Ref. G/T140 'Some measurements of zero phase sequence impedance of three-phase, three-limb, core-type transformers with a delta winding', by L. Gosland.
Ref. G/T313 'Measurement of overvoltages caused by switching out a 75 MVA, 132/33 kV transformer from the high voltage side', by M. P. Reece and E. L. White.
Ref. V/T123 'Application of the dispersion test to the drying of high voltage transformers', by D. C. G. Smith.
Ref. 5028 'The mechanical properties of high conductivity copper conductors for power transformers', by M. Waters.
Ref. 5081 'The mechanical properties of high conductivity aluminium conductors for power transformers', by M. Waters.
Ref. 5096 'The ventilation of transformer substations or cubicles', by M. R. Dickson.
Ref. 5149 'An exploration of some mechanical factors affecting vibration and noise of transformer cores', by L. Gosland and M. Waters.
Ref. 5152 'Transformer magnetising inrush currents. A résumé of published information', by A. A. Hudson.
Ref. 5146 'The effect of the level of magnetostriction upon noise and vibration of model single-phase transformers', by N. Mullineux, D. E. Jones and J. R. Reed.
Ref. 5213 'Effect of slots or ducts on breakdown voltage with particular reference to transformer windings', by N. Mullineux, D. E. Jones and J. R. Reed.
Ref. 5252 'Detection of winding damage in power transformers using the low-voltage impulse method', by M. Waters and R. R. Smith.

Ref. 5285 'A study of ferrous based soft magnetic materials for transformer and similar applications', by T. F. Foley, D. A. Leak, R. A. Newbury, A. R. Pomeroy and A. R. Matthews.

SURGE PHENOMENA

Ref. S/T35 'Surge phenomena. Seven years' research for the Central Electricity Board (1933–1940)', edited by H. M. Lacey with a foreword by E. B. Wedmore.
Ref. S/T43 'Surge tests on a transformer with and without protection', by H. M. Lacey and E. W. W. Double.
Ref. S/T48 'Surge voltage distribution in a continuous-disc transformer winding', by K. L. Selig.
Ref. S/T54 'An investigation of flashovers on a low voltage busbar system', by L. Gosland and E. L. White.
Ref. S/T69 'The effects of cylindrical end rings on the distribution of surge voltages in transformer windings', by E. L. White.
Ref. S/T73 'Surge voltage distribution in transformer windings due to current chopping', by E. L. White.
Ref. S/T85 'Impulse-excited terminal oscillations due to no-load switching of a three-phase transformer installation', by E. L. White.
Ref. S/T95 'Transients in transformer windings', by B. L. Coleman.
Ref. S/T97 'Line and neutral currents in multi-limb transformers under impulse-test conditions', by E. L. White.
Ref. S/T98 'An experimental study of transient oscillations in windings of core-type transformers', by E. L. White.
Ref. S/T103 'A simple technique for producing test voltages across a transformer winding by current chopping', by M. P. Reece and E. L. White.
Ref. S/T109 'Transference of surges through a generator transformer with special reference to neutral earthing. Field tests on a 15.8 MVA generator', by E. L. White.
Ref. S/T111 'Switching surges on a 275/132 kV auto-transformer', by E. L. White.
Ref. S/T112 'A summary of the E.R.A. theory of oscillations and surges in transformer windings', by R. J. Clowes and E. L. White.
Ref. S/T115 'A capacitive probe method of exploring voltage distributions in windings', by E. L. White.
Ref. S/T116 'Maximum voltages on concentric transformer windings subjected to one-, two- or three-pole impulses', by R. J. Clowes.
Ref. 5015 'Excessive voltages induced in an inner winding of a transformer during impulse tests on an outer winding', by R. J. Clowes.
Ref. 5063 'Calculation of voltages induced in an inner winding of a transformer when an impulse is applied to the outer winding', by R. J. Clowes.

Ref. 5133 'Surge transference in generator transformers. A study based on published information', by E. L. White.
Ref. 5134 'Controlled current chopping as a possible overvoltage test method for transformers on site', by E. L. White.
Ref. 5144 'Excessive surge voltages in a 33 kV earthing transformer', by E. L. White.
Ref. 5153 'Surge voltage transference in a 100 MW unit-connected generator set at Aberthaw Station', by E. L. White.
Ref. 5210 'Surge transference measurements on generator transformers connected to systems above 100 kV', by E. L. White.

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81–0062R 'Monitoring transformers in service for winding displacement using the low voltage impulse method', E. L. White, 1981, ISBN 0 7008 0283 5, 44 pp.
87–0021 'The low flammability transformer', M. R. Dickson, April 1987, ISBN 0 7008 0365 3, 83 pp.
87–0259R 'Measurement of the frequency response characteristics of typical distribution transformers and their influence on mains signalling', G. W. A. McDowell, W. W. C. Hung, December 1987, ISBN 0 7008 0457 9, 43 pp.
88–0406 Coil Winding International – Wembley, London, 6–8 September 1988 – Conference Proceedings, ISBN 0 7008 0385 8, 184 pp.
88–0478R 'A report and commentary on insulating materials, transformers, and HV cables in CIGRE 1988', N. A. Parkman, December, 1988, 83 pp.
88–0566R 'Condition monitoring of power transformers to assess residual life and fault damage', G. W. A. McDowell, June 1989, ISBN 0 7008 0447 1, 44 pp.
90–0715 'Winding design for high-frequency transformers', G. Dubois, January 1991, 42 pp.

Index