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Guide for Transformer Fire Safety Practices

Working Group

A2.33

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cigré

GUIDE
FOR
TRANSFORMER FIRE SAFETY PRACTICES

Working Group A2.33

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I memory of Yoshihito Ebisawa san,

“ Ebi” as he was known to his friends made significant contribution to the completion of this brochure. Ebi passed away on the 27.12.2012 after the brochure was completed, but before it could be published. The members of the WG who worked with Ebi will remember him for exceptional competences, his intellectual rigor, and by his remarkable elegance and charm.

SUMMARY

The issue of transformer fire safety has been of concern to Cigre SCA2 for some time and it was evident from discussion of the topic within the Study Committee that the probability and risk of a transformer fires and the effectiveness of the various risk mitigation measures was not always well understood by many transformer users and other stakeholders.

SCA2 therefore decided to establish a working group [WG A2.33] to prepare recommendations for good Transformer Fire Safety Practices that would help transformer designers and users to define and apply best practices in the domain of transformer fire.

The working group WG A2.33 has endeavoured to do this by preparing this Technical Brochure which covers the following aspects of transformer fire safety:

Chapter 1 : An introduction to Transformer fire Safety issues with listing of useful Standards and Guide Documents with information on Transformer Fire Safety.

Chapter 2 : Physics of fires and typical transformer fire scenarios to give a broad perspective of the concepts and issues related to transformer fires.

Chapter 3: Providing guidance on the probability of a transformer fire event occurring based on information available in the public domain and also on how a transformer user might be able to assess the probability of a transformer fire event occurring in its transformer population.

Chapter 4 : Discusses the physics of arcing within transformer tank and gives formulas and examples on how a user might be able to predict the likely range of arcing energy, volume of gas generated and likely pressures which might be developed during an internal arcing event. The chapter also provides examples on pressure calculation models which are available for approximate calculation of the pressures which may be developed during and arcing fault with some examples on pressure venting and pressure containment. Although it must be stressed it is not possible to ensure with absolute certainty that the arcing energy can be contained within the transformer tank at high energy arcing faults.

Chapter 5 : Provides guidance on issues to consider when determining what fire protection may be required and what should be installed at a specific site. It gives examples on points to consider when determining the likely performance of fire protection systems and provides examples on the methodologies available when planning and designing a fire protection system for a transformer installation.

Chapter 6: Discusses the risk mitigation options available for the transformer, and provides some guidance on the ranking of the options based the risk reduction effectiveness and the degree of risk reduction required for the specific installation.-

Chapter 7 : Discusses the risk mitigation options available for the substations and other transformer installations to protect human life, maintain supply or if not possible minimise loss of supply and to protect adjacent plant and equipment.

Chapter 8 : Provides advice on planning and the importance of being prepared for a fire event, so as to minimise the effects and losses from a fire and be able to recover from the fire as early as possible.

Chapter 9 : Contain conclusions and some recommendation for improvement on Standards for improved fire safety on tanks and cable boxes.

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Chapter 1: Introduction

1.1 Scope

The risk of a transformer causing a fire is low, but not negligible and the consequences can be very severe if it does occur. The aim of this brochure is to promote "Good Fire Safety Practices". It endeavours to do this by:

- Presenting typical transformer fire scenarios,
- Quantifying the probability of transformer fires and tank ruptures,
- Discussing internal arcing, and possible measures which reduce the risk and consequences of a transformer fire.

Presenting practical and cost effective strategies for fire prevention and for control and risk mitigation measures which can be applied to both transformers and transformer installations. The brochure is intended for use by transformer users and engineers who specify and design transformers and transformer installation. Its aim is to help-them define and apply best practices in the domain of transformer fire safety.

However, this guide does not replace the relevant national, provincial or local regulations which must be considered, and where mandatory, complied with.

The brochure assumes that the reader has a basis understanding of transformer technology and substation installations.

Avoidance of tank rupture and containment of oil is critical for limiting the consequences of a transformer failure and reducing the risk that a minor transformer fire escalates into a major or catastrophic oil fire. The objective of this brochure therefore includes defining key parameters influencing tank ruptures. Results obtained by model simulation, laboratory testing and experiences during service life are presented to give an overview of the state-of-the-art in that domain.

We separate two different situations 1) where a transformer may catch fire, i. e. causing the fire and 2) being victim to a fire originating elsewhere. In this brochure we concentrate on the case where the transformer is the origin of the fire and the transformer installation and adjacent assets may become victims to a fire caused by the transformer.

The case when the transformer is the victim of the failure is also of concern. If an external fire is given sufficient time to heat up the transformer liquid so much that the liquid is spilled over via the conservator, then the external fire will be strengthened if the transformer is oil filled or contains other combustible liquid.

However, the case where the transformer is a victim to a fire originating elsewhere will not be covered here in any details.

1.2 Risk Context

Risk is defined as: **Probability x Consequence**

The risk of a transformer fire is therefore the probability of the event happening and the consequential destruction of the transformer and potentially other assets, environmental pollution and damage, loss of supply and in extremely rare cases loss of human life. The term "risk" is often used loosely and synonymously with the probability of or chance of an event such as a transformer fire, rather than strictly as defined above. This is also the case in the remainder of this document; however the meaning will be evident from the context of where the term is used.

The probability of transformer fires are in the order of 0.1 % per transformer service year i.e. 1 fire per 1000 in service transformers per year. This is not a high probability, but the consequence is nearly always total loss of the transformer and often with collateral damage to other adjacent assets and often with some environmental pollution and loss of supply for various durations. Also whilst 0.1 % may appears low, the accumulated probability of the event happening is on average in the order of 4 % per transformer over a typical service life of 40 years.

The risk is therefore not negligible and it is certainly too high to ignore and do nothing.

The probability of transformer fires varies considerably among utilities and even among types of transformers within the same utility. Some utilities have significantly higher and some significantly lower numbers of transformer fires than the average probability. Similarly some utilities may have types or voltage classes of transformers which have much higher probability of causing fires than others types.

When a transformer failure results in a fire the transformer will often be damaged to a degree where repair is not economic. The aim is therefore not to save the transformer if a transformer fire occurs, but rather:

- To prevent and minimise consequential damage to the substation installation and other plant items located in the vicinity of the transformer on fire.
- To avoid loss of supply from the substation and if not possible then to minimise the time of loss of supply.
- To minimise and if possible avoid pollution and contamination to the surrounding environment. Especially the environment outside the substation boundary. The potential pollution includes both airborne pollution in form of smoke, soot and noxious fumes and runoff causing ground water contamination by oil or other chemicals including foams and other fire-suppressant chemicals which may be used in fire fighting.

The probability and the consequential risk of transformer fires will be discussed more comprehensively in Chapter 3: of this brochure.

1.3 Types of Transformers Considered

The scope of this document is for transformers $\geq$ 10MVA and rated $\geq$ 66 kV. However, much of the discussion and many of the recommendations will also be applicable for transformer of lower ratings.

The main focus is on mineral oil immersed transformers, comprising an electrical grade laminated steel core, with Kraft paper and/or enamel covered copper or aluminium winding conductors where the active parts is contained within an oil filled steel tank. The design and construction of transformers is not discussed in this brochure and it is assumed that the reader is familiar with types of transformers which are within the scope of this brochure.

Much of the content of this brochure is equally applicable to industrial and other special purpose oil immersed transformers. However, some of these transformers have special features and installation requirements, which require specific attention and special requirements which may not be covered in this brochure.

Oil immersed reactors are not discussed as a separate item, however it can be considered all the discussions and recommendations made for oil immersed transformers are equally applicable to oil immersed shunt and series reactors.

Other form of insulating liquids is used in transformers for fire risk mitigation and/or environmental reasons. Most of these fluids are high flame point fluids which have lower but not zero fire risk. These fluids will be discussed in Chapter 5: of this brochure in the context of fire risk mitigation.

Gas Insulated Transformers using SF_6 gas as the cooling and insulation medium is the only type of transformer with virtually a zero fire risk.

1.4 Types of Transformer Installations Considered

The fire safety precautions to be taken at transformer installations are in the context of this document that the installation is being a "Victim" of a fire originating in or at the transformer. The precautions taken at transformers installation may not have much impact on reducing the likelihood of the transformer failing and causing a fire, but it can be a very important factor in limiting the consequential damage to the installation or other plant items located in the substation and to the duration of loss of supply to customers. Transformer fire safety is therefore an important consideration when specifying and designing both transformers and transformer installations.

The degree of fire safety measures required and the practical and cost effective solutions applicable at such installations varies enormously depending on the type and location of the specific transformer installation; from a remotely located open air low land cost transmission substation, to compact higher land cost open air an urban bulk supply substation or an indoor city substation located at the lower levels of a high rise office building or a power station generator step transformer or industrial transformer in close proximity to high cost industrial installation. It is therefore useful to categorise common types of transformer installations and discuss the considerations and the recommended fire safety measures to be taken at each type of installation separately.

Good fire safety practices applicable for each of the types of installations listed above will be discussed in details in Chapter 7:

1.5 Standards and Guides

A list of standard and guides which provide relevant guidance on transformers and fire safety issues related to transformers include, but is not limited, to the following publications:

- IEC 60076-1 Power transformers – Part 1 General [1]
- IEC 60137 Bushings for alternating voltages above 1000 V [2]
- IEC 61936-1 Power installation exceeding 1 kV AC Part 1: Common rules [3]
- ENA DOC 18-2008 Interim Guide for the Fire protection of Substations [4]
- NFPA Fire Protection Handbook 2008 [5]
- NFPA 70 National Electrical Code Article 450 [6]
- Australian/New Zealand Standard AS/NZS 3000:2000 Wiring Rules Section 7.8.8. [7]
- NFPA 850 Recommended Practice for Fire Protection for Electric Generating Plants and High Voltage Direct Current Converter Stations, 2010 Edition [8]
- NFPA 851 Recommended Practice for Fire Protection for Hydroelectric Generating Plants, 2010 Edition [9]
- IEEE 979 Guide of Substation fire protection [10]
- IEEE 980 INT 1-3 Guide for Containment and Control of Oil Spills in Substations [11]
- FM Global Property Loss prevention Data sheet 5-4 Transformers May 2010 [12]
- US Department of Interior Department of Reclamation Facilities Instructions, Standards and Techniques, Vol. 3-32 Transformer Fire Protection [13]
- NGTS 2.20 Oil Containment in Substations [14]

- NGTS 3.1.3 Limitation of Fire Risk in Substations [15]
- CEATI Report No.T023700-3022 - Transmission Stations and Transformers - Fire Protection and Prevention [16]
- Electrical Cooperative Research, Japan No 40-5 Design Guide for Tanks [17] (in Japanese) see CIGRÉ Summary Paper 12.02 1988
- EPRI Report TR-104994 Power Transformer Tank Rupture: Risk Assessment and mitigation [18]
- RTE Dispositions Type Postes (Design specifications for substations) [19]
- IEC/TC10 Classification of Insulation Liquids According to Fire Behaviour [20]

Chapter 2: Fire Physics and Typical Transformer Fire Scenarios

2.1 Fire Risk

Fires are depending of the control of heat energy, oxygen and fuel.

The fire triangle provides very good graphic representation of what is required to initiate and maintain a fire and therefore also how a fire can be prevented or extinguished.

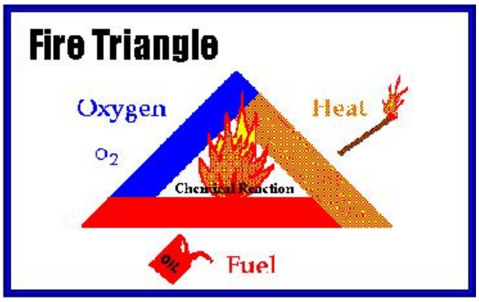


Figure 1: Fire Triangle

For a fire to exist and propagate, it requires the three key elements of Heat, Fuel and Oxygen in well defined ratios.

- **Without oxygen there will be no fire.**
- **Without heat there will be no fire.**
- **Without fuel there will be no fire.**

If anyone of these three elements is absent then the fire will not start, or if removed after a fire has started then the fire will extinguish.

It is therefore useful to consider the common ways heat can be produced in the context of transformer fire safety i.e. in addition to the heating produced from load and no load losses.

Two such sources of heat energy are of particular interest (1) Electrical (2) Chemical.

2.1.1 Heat Energy - Electrical

Electrical Heat Energy sources include:

Resistance Heating – this is always present in electrical equipment and can become excessive and cause fires in transformers if high resistance joints develop, if overloading occurs, or if cooling is diminished due to failure in cooling equipment or obstruction of flow of cooling medium.

Induction Heating – this occurs in transformer tanks and structures due to magnetic fields from leakage flux and also high currents in conductors in proximity to magnetic metals. It can become excessive, if overloading occurs or cooling is diminished.

Dielectric Heating – this occurs in dielectric materials when exposed to dielectric stress. It can become excessive and reach thermal run away, if the dielectric stresses become excessive or dielectric properties deteriorates or cooling is inadequate. The dielectric heating of concern in transformers is mainly with HV bushings and HV cable terminations, where it can cause thermal runaways, especially as dielectric properties deteriorates with age and increased moisture level. Bushing and cable termination failures cause the greatest number of transformer fires, although many of these failures are not necessarily due to dielectric heating.

Heating from Arcing – this is the main cause of transformer fires. Arcing occurs when the dielectric materials cannot withstand the dielectric stress imposed on it and a breakdown resulting in an arc developing between two electrodes occurs. The arc provides a low resistance path and causes a very high current to flow between the two electrodes. The energy in the arc can be very high, typically in the kilo - Mega Joule range and develop temperatures in thousands of degrees.

Heating from static electricity - is unlikely to cause fires as it is of low energy. However, static electric charge is known to have cause dielectric breakdown resulting in internal arcing and failure of transformers.

Heating from Lighting Strikes - is unlikely to cause fires in transformers, but transient overvoltage from lightning can cause dielectric breakdown, leading to failure and potentially a fire in some transformers.

2.1.2 Heat Energy - Chemical

Chemical heat energy is a product of all fires. It can be present in several forms including both explosion and combustion.

Explosion produces heat due to chemical changes. An explosion is a rapid release of energy in an extreme manner usually with the generation of high temperatures, release of gases and rapid increase in volume/ pressure in the generated gases.

A high current electrical fault can create an electrical explosion by forming a high energy electrical arc which rapidly vaporizes metal and insulation material. It is the rapid liberation of heat that causes the gaseous products of most explosive reactions. It causes the gases to expand and also generates high pressures. It is this rapid generation of gases under high pressures and the expansion of the gases, which constitutes the explosion and creates a shock wave.

If the shock wave is a supersonic detonation, then the source of the blast is called a "high explosive". Subsonic shock waves are created by low explosives, through the slower burning process known as deflagration.

Heat of Combustion - this occurs in fires and can be a complete or partial oxidation of a fluid or solid material.

Spontaneous combustion and spontaneous ignition is a process where combustion and ignition occurs without drawing of heat from its surroundings. This process can occur when hydrogen and hydrocarbon gases generated by an arc come in contact with oxygen. This is a typical mode of initiating transformer fire following a bushing failure where the upper porcelain fails explosively.

2.1.3 What is a Fire?

Fire is the common term for combustion which is the chemical reaction of oxidation, which happens when for example the organic compounds (paper, oil, wood) are combined with oxygen in air at a high temperature. The combustion is made up from a large number of chemical reactions in many steps. The first step is when the organic molecules are decomposed and many different gases are formed; including hydrogen, carbon oxide, methane and different alcohols.

This first step is called pyrolysis and the gases have not yet reacted with the oxygen in air. The pyrolysis consumes energy, so heat has to be added from outside during this part of the process.

The second step is when oxygen (from air) reacts with the gases from the pyrolysis and the process becomes exothermic (gives of heat), - this is combustion.

2.1.4 Combustion

The combustion can be:

Flameless type - where the surface is glowing without a flame, as is the case with deep seated glowing embers.

Flaming type - (which include the explosive type). The flaming type is associated with a relative high rate of combustion, where approximately 2/3 of the heat released is conducted away in the burning and approximately 1/3 is radiated away. If more heat is generated than lost to the surroundings then the fire will increase in intensity; conversely if more heat is lost to surroundings then is generated from the combustion then the fire will diminish.

2.1.5 Explosion

Explosion or explosive failure is a term often used in connection with a transformer failure, resulting from a pressure build up from arcing causing rupture of bushing porcelain, a cable box, a tap changer or the transformer tank. However, the term “explosion” does not have a precise meaning and therefore cannot be used as an accurate description of failure event.

Explosion occurs due to - Chemical changes

Detonation – which can occur in solid or liquid explosives, or in a mixture of gas and air (oxygen). This type of explosion is not applicable to transformers as the quantity of oxygen in oil is low and not available to react with combustible gases present in the oil or generated by an arc.

Deflagration – is a technical term describing subsonic combustion in which the output of heat is enough to enable the reaction to proceed and be accelerated without input of heat from another source. This type of explosion cannot occur in a sealed oil filled transformer tank, but it can occur in transformer enclosures and indoor substations, if arcing gases and vaporised oil have been vented to outside the transformer tank.

Explosion due to – Physical Changes

This type of explosion can and do occur in transformer bushings, cable boxes, tap changers and main tanks due to arcing within the component, if the force exerted by the pressure exceeds the withstand strength of the component for long enough time to cause movement beyond the elastic deformation limits. This type of failure mode is the most common cause of transformer fires, for example:

An explosive failure will cause a fire where a bushing, cable box, disconnection chamber, OLTC diverter or a transformer tank of an oil immersed transformer is ruptured from excessive pressure generated by arcing and the arcing gases ,or if the oil have reached the “auto ignition temperature” when exposed to oxygen. Or if the combination of oil, arcing gases and the arc is exposed to oxygen by the rupture, where the arc will cause the fuel/oxygen interface to exceed its flash point temperature.

An explosive failure without fire can occur if a bushing, tank, cable box or tap changer tank is ruptured from excessive pressure generated by arcing, and the arcing under oil has been interrupted by tripping of the controlling circuit breaker, without the arcing gases or the oil having reached its “auto ignition temperature” when exposed to oxygen by the rupture of the containment vessel. This type of explosive failure is not uncommon with ruptures in transformer tanks, but is very rare if the rupture is in the upper porcelain of an Oil Impregnated Paper bushing [OIP].

2.2 Fire Scenarios

How do fires start in transformers?

Normally there are two ways of getting high temperatures inside the transformer: Internal arcing (flashover) or external arcing (flashover).

Internal Arcing

An internal arcing in an oil immersed transformer will cause a high temperature in the arcing gases and the surrounding oil, but it will not cause a fire inside the tank without access to oxygen. The oxygen dissolved in the oil is not accessible to start a fire. If the current feeding a high energy arc is not disconnected rapidly, then the tank may rupture and high temperature gases and oil then gets access to oxygen and will combust if the temperature is high enough for auto ignition, or if it is exposed to an arc or makes contact with metal with sufficiently high temperature to cause ignition.

External Flash Over (Short Circuit)

A too high current through the transformer leads, terminals and windings can cause localised or even wide spread overheating within the transformer. Normally there is not sufficient oxygen to cause a fire inside the transformer tank and not sufficient fuel at the external terminals to cause a fire there because the electrical protections would normally interrupt the current independently of the temperature before any fire will start. If excessive over-current is not interrupted and sufficient heating occurs, then it can cause overflowing and possibly boiling of oil, which may cause spilling from the conservator, pressure relief valves or damaged gaskets. However, to start the fire there still must be a source to ignite the oil.

2.2.1 Internal Arcing Fault

Electrical arcs have temperatures of several thousand degrees. An internal arc (or flashover) as such cannot ignite a fire in the tank without free oxygen becoming present. An electrical arc can generate sufficient amount of gases to cause rupture a tank, if the arcing current is not disconnected rapidly. If the arcing occurs within a bushing or a cable box, then there is a very high probability that the bushing or the cable box will rupture, as it is unlikely that the protection and the circuit breaker can interrupt the arcing current fast enough to ensure rupture does not occur. If rupture of the oil containment (tank) occurs then the oil and gases generated by the arc will be released and get access to the air (oxygen). If the arc has heated some metal parts sufficiently to maintain a temperature above the fire point, when the liquid or gases is released, then it could start a fire.

If the arc has occurred within a bushing or oil filled cable box and the arcing gases not been cooled sufficiently by passage through liquid oil, then it is possible that the gases could still be above the auto ignition temperature and ignite upon contact with air. There is also a possibility that the arc is maintained even after that the tank, bushing or cable box has ruptured and that it will ignite the oil and/or gases as the rupture occurs and the arc and the oil get exposed to air.

The probability of that occurring with arcing inside a transformer tank will depend on: -

- Fault clearing time of protection and circuit breaker.
- The arcing energy available in the arc,
- The tanks expansion flexibility.
- Pressure withstand capability of the tank.
- The pressure reduction mitigation measures implemented on the tank.

The sequence of events that may lead to a fire from an internal fault can be summarized in 5 phases as below:

Phase 1: When electrical stress in insulation material (oil or solid) exceeds its dielectric strength it will break down and high energy electrical arcing can occur.

Phase 2: The very quick energy transfer between the arc and the liquid oil induces a very fast increase of temperature in the vicinity of the arc. The arc energy is then used: **(1)** to heat and vaporise the surrounding oil, **(2)** to crack this vapour into smaller molecules and flammables gases (hydrogen, methane, ethane, ethylene, acetylene, carbon, etc.) and **(3)** to decompose the gases into plasma.

Phase 3: The pressure within the gas bubble surrounding the arc increases very rapidly due to the very localized phase change (saturated vapour pressure at high temperature) and the oils inertia also prevents the gas bubble from expanding as fast as would be needed to keep the pressure equilibrium between gas and liquid.

Phase 4: The pressure difference between the gas and the surrounding liquid generates pressure waves that propagate at finite speed (close to speed of sound in oil) from the arc location throughout the transformer tank. The local pressure rises because of the front of the pressure wave passing. This pressurisation is characterised by very high pressure gradients ranging from 100Bar/sec to 5000Bar/sec. Some areas within the transformer tank can be pressurised, whilst other areas within the tank are not even affected by the overpressure yet. The pressurisation of the transformer is thus progressive and correlated to the progression of the pressure waves that are the first to reach the tank walls. The tank walls and assemblies (bolted and welded) are thus subjected to spatially progressive mechanical stresses. These local pressure levels have been measured up to 14 Bars absolute for energies up to 2.5MJ. Such pressures are far above the tank's static pressure withstand limits which are typically within the 1.0 – 2.0 Bar (at base of tank) unless special higher strength tank design has been specified. [1 bar = 100 kPa].

It is important to note that the tank walls can withstand these high local overpressures for only a very short time period (a few milliseconds) and that the tank will rupture if subjected to an overpressure exceeding its static pressure withstand limits for more than some millisecond or at best tenths of second. (The static pressure rupture limits is typically 1.5-2 times the elastic deformation limits).

The reason that the tank can withstand much higher pressures for a very short time is that it is not the pressure which ruptures the tank, but movement in tank walls and fittings causing the ruptures, when welds and bolted joints are stressed beyond their elastic stress/strain range. To cause movement and breakage in welds or bolted joints in tank walls, bushing turrets, cable boxes, inspection covers, or ancillary items requires sufficient pressure to be applied for a sufficient length of time to accelerate and move the material beyond it stress/strain limits.

Simulation studies show that specific features in transformer tank design might have a significant influence on the maximum local pressure peaks experienced after arcing. Indeed those features (angles, welds, protrusions, etc.) tend to act as "mechanical lenses" and focus the waves at certain locations, which may result in significant local overpressures, whereas tank flexibility will help to reduce the pressure gradient and final static pressure as it allows volume expansion of the tank.

Phase 5: Up to the stage when the pressure wave interacts with the tank structure the physical process is the same for whatever the arc energy, the transformer power rating and the arc location are. But from the moment the pressure wave interacts with the tank, scenarios can diverge and lead to permanent deformation in the tank or tank rupture and possible fire.

If a transformer tank, a cable box or and OIP bushing ruptures in the presence of an electrical power arc, then there is a high probability that an oil fire will follow. This is because the large quantity of oil present in a transformer tanks and the conservator my also become exposed to heat and oxygen when spilling through ruptures or flange openings or when oxygen enters the tank through such openings.

When an internal fault takes place in the oil filled transformer, a large volume of decomposition gas is generated by the arc, resulting in the rapid pressure increase in tank. In case of a high energy fault > 2- 8 MJ, tank flexibility/volume expansion may not be able to accommodate the large gas volume generated by the arc causing a rapid pressure increase and tank rupture may occur. A tank rupture may cause an outflow of a large amount of oil and gases, which in most cases will cause a mixture of hot combustible gas and oil to come in contact with the oxygen in the air which can lead to auto ignition.

Additional measures may therefore be required to reduce the risk transformer fires and consequential damage for high energy arcing faults:

Japanese National Standard for design of transformer tanks provides guidance of rupture resistant tank design.

NFPA Codes 850 and 851 also provide some guidance for protection of transformers.

2.2.2 Tank Rupture Process

After the pressure waves interact with the tank, core and coils, reflections impact upon and repartition the localised pressures and the mechanical stresses. There seems to be no pre-determined location for the rupture to occur as it seems to depend on the arc parameters and location, the local and global transformer tank features and associated structural weaknesses such as:

- Presence of bolted and welded joints;
- Presence of reinforcement beams and influence of their shapes, inertia and locations;
- Presence of other tank specific features such as bushing turrets, cable boxes and their location etc.

However the tank can withstand quite high dynamic pressure peaks of very short duration, [possibly up to a few tens of milliseconds]. The interaction of the pressure waves with one another causes pressure in the whole transformer to rise towards an average static pressure conditions, typically within a few tens of millisecond. The static pressure increase due to the bubble expansion over some tens, occasionally some hundreds of milliseconds], may cause the mechanical stresses to exceed the tanks withstand capability and cause tank rupture. Tank rupture due to static pressures will happen at the structure’s weakest point.

Subsequent Events

After tank rupture, the flammable gases generated are then released from the tank into the surrounding atmosphere.

As soon as the flammable gases get in contact with the oxygen contained in the surrounding air, several scenarios may occur:

- Hydrocarbons gases can auto ignite if their temperature is above the auto ignition point and the gas/oxygen mixture is within the critical ratio.
- Gases can be ignited by an external energy source located in the environment the gases are released into (hot metal parts of the transformer, sparks, external arcing, etc.)
- Or energy transfer to metal (hot spots) in contact with the mixture of flammable gases, oil and oxygen has been high enough to ignite it.

A fire can spread to the oil released or being spilled after the tank rupture. Nevertheless, even for high energy arcing faults, the rupture of the tank does not always cause a transformer oil fire. The reason for this is that the arc may have been extinguished by the protection before it is exposed to oxygen and the oil and gases have not reached the criteria for auto-ignition when exposed to contact with oxygen [21].

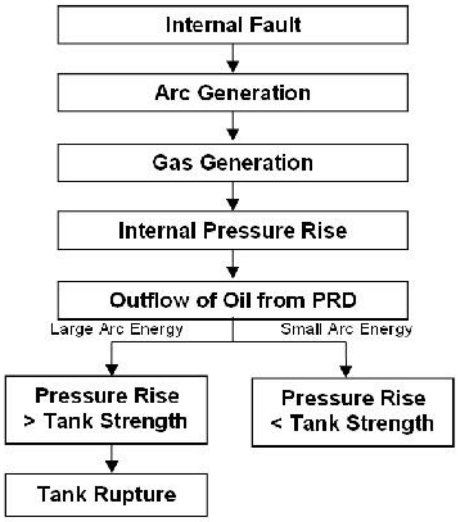


Figure 2: Tank Rupture Process

A flow chart for the analysis of an internal arc event is shown in **Figure 2** above. In this flow chart, the pressure rise at internal fault is simulated by dynamic analysis considering oil motion. Utilities and transformer manufactures can examine the tank rupture scenario for internal arcing according to this flow chart during the design planning stage for substation.

2.2.3 Transformer Bushing Fire Scenarios

OIP bushings are the single largest cause of transformer fires. The insulation in bushings is highly stressed and there are inherent fire risks in their design. Many OIP bushings use a design where the lower and upper porcelains are clamped against O-ring seals at metal flange interfaces and the clamping force is provided by pre-stressing of the central tube or a spring assembly acting on the central tube. If an arcing failure occurs within an OIP bushing, it frequently results in an explosive failure and shattering of the upper or the lower porcelain, which with this type of design will results in total loss of clamping force on both porcelains and in most cases cause dislocation of the condenser body relative to the bushing flange, resulting in oil spill, arcing in air and fire.

If the arcing failure occurs above the flange and the upper porcelain suffers explosive failure due to the pressure build up from of arcing gases, then the power arc will ignite the hydrogen and hydro-carbon arcing gases, the vaporised oil from the bushing and some of the oil saturated insulating paper. The condenser body will in most cases become dislodged from the flange and move downwards into the transformer tank, due to sudden loss of clamping pressure on the upper porcelain. This allows warm or hot oil to flow through the bushing flange and spill over the transformer, where it fuels the fire already ignited from the bushing failure and a serious and major oil fire will in most cases follow.

If the arcing occurs below the flange and the lower porcelain shatters, then arcing will initially occur under oil, which will not ignite the oil due the absence of oxygen. However, the loss of clamping pressure and the pressure from the explosion will in most cases cause the condenser body to move upwards. Arcing will in most cases occur to from the central tube to the flange or other earthed metal where oil spilling through the bushing flange which would then be exposed to air (oxygen) becomes ignited. The risk of a major oil fire following a failure in the lower part of the bushing is also very high, but slightly less than for arcing failures originating above the bushing flange.

The risk of fires being initiated by a failure of a Resin Impregnated Paper [RIP] bushing or a Synthetic Resin Bonded Paper [SRBP] bushing is significantly lower than for OIP bushings. The reason for this is that these types of bushings do not have porcelain insulators on the oil side (the lower end) of the bushing. A failure at the lower end of the bushing will therefore not cause breakage of porcelain and in most cases not cause loss of clamping pressure or damage to the Porcelain on the air side (upper part) of the bushing and not result in oil spill unless the arcing energy is very high.

A failure in the upper side of an SRBP or RIP bushing will in most likely cause fragmentation of the porcelain, if the bushing uses a porcelain insulator. But in most cases no fire will occur as a high proportion of RIP bushings do not contain any oil, or if it does contain oil between the porcelain shell and the condenser body then it only a very small amount. Similarly for the now obsolete SRBP bushings which also contains only a relative small quantity of oil.

Oil free RIP bushings are now common and available from most suppliers of RIP bushing. The use of polymer insulators on the air side is also common. This eliminates the risk of porcelain fragment being expelled in event of a bushing failure and also reduces the fire risk further as Silicone rubber will not sustain a fire without significant continuing heat input.

One common way to assess the risk of a bushing failures developing into a fire is to look at the risk of failure in the different components of a bushing, e.g. condenser core, insulating oil, conductors and external defects.

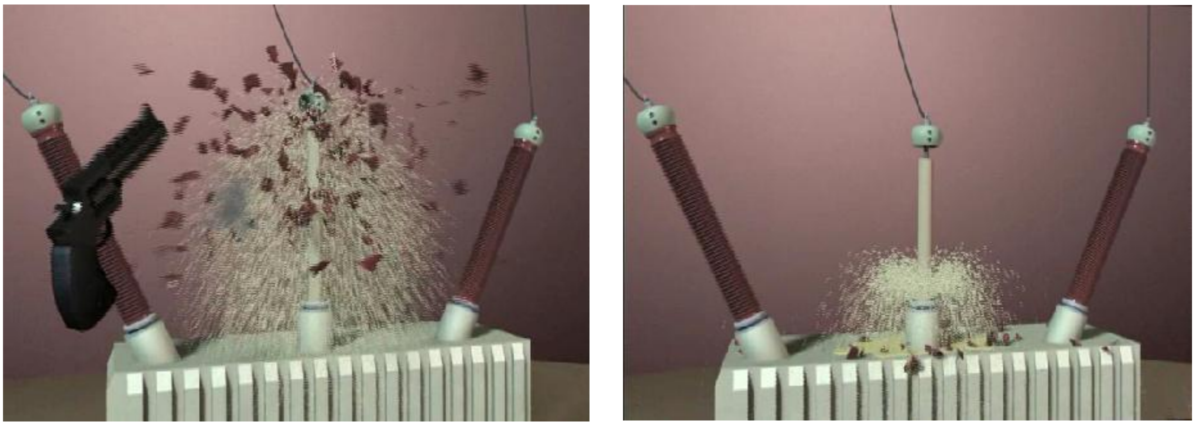
This perspective tends to focus only on the component that failed (the bushing) and disregard potential causes from external factors such as over-voltages of various types, overloads, vandalism, excessive line pull, seismic events, handling errors or improperly selected ratings.

Failures modes seen from a more overall view are both electrical and mechanical and the end result is commonly a violent explosion of the bushing, propelling shards of porcelain up to hundred meters away or even more for very high energy fault, and the high risk of fire, in the case of OIP bushings failures.

In the following we examine the scenario of a typical bushing failure, here illustrated graphically by someone firing a rifle at a bushing, but it could equally well have been caused an internal fault in the bushing from a number of different causes.

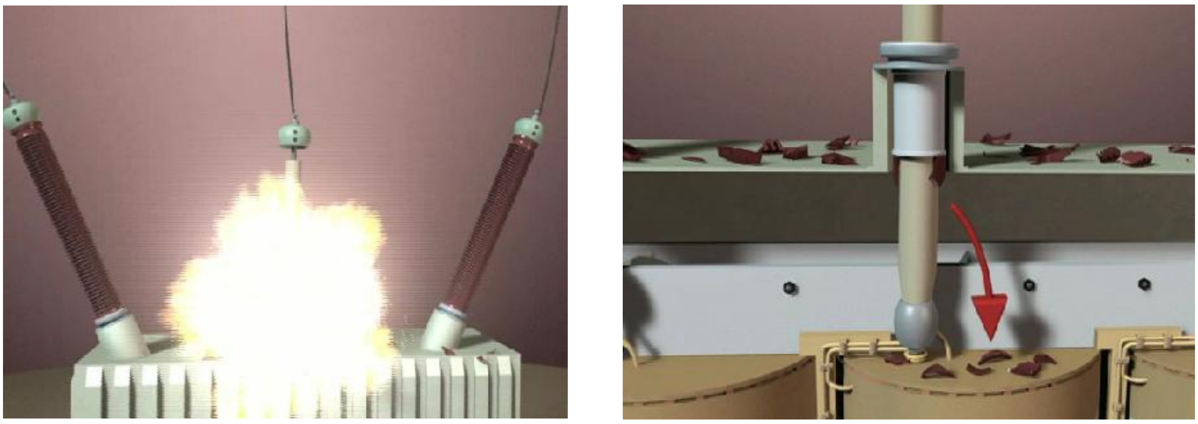
1. The external violence (or pressure pulse from an internal flashover) causes the insulator to fracture or explode. This carries a high risk of causing damage and possibly failure of the neighbouring bushings, as well as to other equipment or personnel, should anyone be in the substation. (Figure 3a)
2. As the insulator fractures or explodes the structure of the bushing collapses and the condenser body falls into the transformer and ejects oil through the bushing flange and the oil spilling through the bushing flange will be sustained by flow from the conservator. (Figure 3b).
3. Depending on several factors such as level of fault current, voltage level, location of the puncture, there is a high probability that the outcome will be an electric arc creating arcing gases and the arcing igniting the gases and the oil. (Figure 3c)
4. If the event had been a failure causing damage to the oil-side porcelain below the flange, then there is a high risk the result would have been loss of clamping force on the upper porcelain, upwards movement of the condenser body and spilling of oil through the bushing flange; probably resulting in flash over in the upper part of the bushing to and ignition of the oil spilling

through the flange (Figure 3d). (This scenario applies for OIP bushings of the common type which use pre-stressing of the centre tube to provide the clamping force on the upper and lower bushing porcelains).



a) Porcelain can explode under internal arcing

b) Bushing collapses into the transformer



c) Oil ignites

d) Oil side porcelain breakage

Figure 3: Typical Bushing Fire Scenario [22]

Regardless of the root cause and the sequence of events in a bushing failure, there are significant risk reduction benefits, if the consequences of a failure such as the type described above can be reduced by using a technology which eliminates or significantly reduces the risk of a consequential oil fire if a bushing fails.

This is now an option, and probably why a growing part of utility industry users today specifies dry insulation technology with outer insulation made on non-brittle materials, as is the case for Resin impregnated bushing using an outer insulator made from a polymer material (typically a silicon polymer).

2.2.4 Transformer Cable Box and Cable Termination Failures Fire Scenarios

Cable termination failures in air or oil filled cable boxes also cause a high percentage of transformer fires. The typical scenario with oil filled cable boxes is that an arcing fault is initiated within or at the cable termination. The pressure build up from the arc ruptures the cable box explosively and ignites the oil spilling or being expelled with force from the cable box. The fire continues and often escalates as it gets fuelled by oil spilling from either a pipe connected to the cable box from the conservator or the main tank. This allows the fire to develop into major oil fire which may cause burning of gaskets and the fire then gets fuelled from the larger quantity of oil spilling from the main tank. Refer to Figure 4a below where the fire was caused by a failure in a 132kV cable termination on the LV side of transformer. The fire in this failure spread into the cable basement where it burnt 132, 33 and 11kV cables to other transformers, in addition to causing other major damage to switchgear, control equipment and the building.

The rupture of a cable box will often occur before the protection and the circuit breaker can clear the fault, as the pressure rise in the much smaller volume of a cable box will cause a very rapid and higher pressure rise, than would be the case in the much larger transformer tank.

The common fault scenario for cable termination failures in 11-33 kV air insulated cable boxes is different to the scenario in an oil filled cable box, but the risk of the fault resulting in a major oil fire is also very high. An arcing fault in an air insulated cable box without arc venting will often result in complete destruction of the cable box, due to the rapid temperature increase and consequently explosive pressure increase within the cable box. The mechanical forces on the cables from the fault current and the gland plate been being blasted away by the pressure increase from the arc heating the air, will often cause breakage the bushings, which is often solid stem, oil filled porcelain type bushings. The oil spilling from the broken bushings will then be ignited by the arc. The oil in the conservator and possibly the main tank will then fuel the fire and cause it to develop into a major oil fire, Refer to Figure 4b and 4c.

If precautions have not been taken to seal cable ducts and cable trenches, then the oil may spill into and the fire travel along the cables trenches or conduits or cause serious damage in cable basements and or adjacent plant if their cables share the same cable trench/basement, refer to Figure 4a below.

a) Burnt out transformer after a 132kV cable termination failure.

b) Transformer fire caused by 11kV cable termination failure

c) Cable box after fire. Cables & gland plate blasted off by arcing fault

Figure 4: Cable Box and Cable Termination Fire Scenarios

It is the Working Group's experience that very few air insulated cable boxes on transformers have arc venting. Such venting could prevent damage to cable box, dislocation of the cables and breakage of bushings. Such deficiency is not tolerated in metal clad, air insulated switchgear which is always designed with arc venting. The arcing energy in an air insulated cable box can be very high even at 11-33 kV voltage levels, as the arcing path is often longer than under oil. Working Group 2.33 considers that "safe" arc pressure venting should be a standard feature on all air insulated cable boxes.

2.2.5 The Effect of a Transformer Fire in a Substation

If a fire occurs as a result of a failure in a transformer, then the transformer is nearly always a total write off. However, the total cost of a transformer fire is typically in the order of 2-3 times the cost of the replacement transformer [23] and can in unfavourable events be many times the cost of the transformer, even without including the cost of loss of supply for customer.

The strategy therefore is:

- Minimise the risk of the fire occurring.
- Protect the potential fire victims, humans and the remainder of the substation installation from also being fire damaged.
- Maintain supply during the fire, or if not possible then restore the supply as early as possible after the fire.
- Avoid pollution and contamination of the environment.

Products of Combustion and their Effect on life and Safety [24]

The product of combustion can be divided into four categories: 1) fire gases; 2) flame; 3) Heat and 4) Smoke. In addition to the product from combustion, there is also the risk of pollution from oil spill and contamination by products use in fire fighting such as foam and possibly contaminated water. Each of these can have damaging effect on humans, other equipment and the environment.

Each item will be discussed briefly below:

Fire Gases – Transformer oil and cellulose insulation burn to mostly carbon dioxide, or carbon monoxide if air supply is restricted. Other more toxic or corrosive gases can be released from burning of cable insulation. This is of particular concern with indoor installations of transformers. Heat and fire gases are major cause of fatalities in fires.

Smoke - consist of very fine solid particles and condensed water vapour. In many cases smoke reaches untenable levels before the temperature does. This is especially so when fire occurs indoors or in confined areas. Smoke particles can cause damage to the respiratory system and it may impair vision if lodges in eyes and thus impair the ability to escape the fire.

Heat from fire - can cause dehydration and exhaustion and if intense and conducted into the lungs, cause serious decline in blood pressure and failure of blood circulation. Burns can be caused from contact with flames, heated objects or from radiation. Heat exposure can cause physical shock and possible death. High level of heat radiation can cause instant death.

Loss of Oxygen - fire consumes oxygen. The oxygen level in normal air is 21% and if it drops below 15% then muscular skills diminish, at a further reduction to 14 - 10%, fatigue sets in and judgement becomes impaired. If oxygen reduced to the range from10 to 6%, complete collapse and unconscious occurs, but revival may still be effected if fresh air or oxygen becomes available.

2.2.6 Classification of Fires and Extinguishing Agents

Classification of fires as determined by National Fire Protection Association [NFPA]:

Class A

Fires in ordinary combustible materials (glowing after burning). The extinguishing agent is water.

Class B

Fires in flammable liquids. The extinguishing agent is fine spray of water (water mist of fogging). The blanketing or smothering effect keeps the oxygen away from the fuel.

Class C

Fires in electrical equipment. The extinguishing agent must be non-conducting (powder, carbon dioxide, vaporizing liquid (foams or water sprays at safe distance).

2.2.7 Fire Resistance Classification

The resistance of a substation structure and its construction material including buildings is normally indicated by a combination of code letter and number. Significant variations exist between countries in the test methods used and the classification code applied. But it is common to use a combination of letters and numbers as is done using the REI classification. This classification method assign a fire rating grading period in minutes based on three distinct criteria using the letters as follows:

R Structural adequacy - The ability to maintain stability and load bearing capacity.

E Integrity – The ability to resist flame and passage of hot gases.

I Insulation – The ability to maintain a temperature on the non exposed surface below the specified limit.

REI 120/60/60 means the structure could be expected to maintain structural adequacy for 120 minutes; Integrity for 60 Minutes and Thermal insulation for 60 minutes for the defined conditions.

However to compare different classification it is necessary to understand both the test method and the classification coding applicable for the specific classification.

2.2.8 Extinguishment of Fires

The fire triangle listed in Chapter 2.1 provides a very good graphic presentation of how a fire can be extinguished.

Remove the Heat

The fire can be extinguished if the heat is removed and the fuel is cooled below its fire point temperature. Water can be very efficient as a cooling medium to extinguish external fires and to protect adjacent asset from being heated to their flash point. Water is less efficient in extinguishing a fire burning inside a transformer, as it is often difficult to get the water into the transformer tank and the oil will float on the top of the water and continue burning even if water is sprayed in to a transformer tank. Also for the same reason water alone is not efficient in extinguishing oil pool fires. Whereas water with foam can be very efficient for this purpose as it excluded oxygen from the oil surface.

Oxygen displacement or dilution

Removal of oxygen can be a very effective method of extinguishing fires where this method is possible. Only a slight decrease of the oxygen concentration in air decreases the fire intensity and below 16 % oxygen in the air there is no risk for a fire. Many alternative gases have been used successfully to displace or dilute oxygen and thus extinguish the fire. Gases commonly used for this purpose include carbon dioxide, halon and nitrogen. (halon is now disappearing from use, as it is considered a non-environmentally friendly gas).

The disadvantage for all of these gases has been that human beings could be suffocated, if the gas is injected before all humans have been evacuated. CO_2 is heavier than air and is often used in buildings and other areas where the gas can be contained and the displaced air can raise above the fire. Nitrogen is lighter than air and is uses for injection where the fire is at an upper surface and the nitrogen can be contained, as it can in a transformer tank. Some manufactures of transformer fire extinguishing systems, have used nitrogen for injection into the base of oil filled transformers to extinguishing a fire burning from the oil surface. In this application nitrogen will stir and cool the oil in the transformer tank and displace the air above the oil and suppress the fire.

Foam and high pressure water fogging can also be used to displace oxygen. Foam can be very effective for use on oil pool fires, but is less effective on oil fires where oil is spilling over a vertical surface and it is often difficult to get foam into a fire burning inside a transformer tank. Water deluge and high pressure water fog or water mist have the benefit of oxygen dilution as well as providing cooling.

<u>Removal of fuel</u>

Removal of fuel can be effective, but is often not possible. Some strategies for fuel removal exist for transformer oil, as it is possible to equip transformer tank with oil dump valves which can be opened by remote control. Dumped and/or spilled oil can be directed into oil/water separation tanks or into gravel or crushed rock beds or other safe holding areas. Discussed further in Chapter 7:. Alternative methods will be also discussed in some details under fire risk mitigation strategies in Chapter 7.

2.2.9 Transformer as a Fire Victim

The transformer can become a victim to a fire started elsewhere. As large power transformers contain large quantities of mineral oil, the potential for the transformer to add considerable quantities of high energy fuel to an existing fire exist and strategies to minimize the risk of releasing and igniting this fuel source should be considered as part of the substation design process. The most effective protection is probably fire barriers and water spray for cooling and keeping the oil within the transformer tank, away from oxygen and below the flashpoint temperature. However, a detailed discussion of this topic is considered outside the scope of this publication.

Chapter 3: Probability of a Transformer Fire

When considering transformer fire safety at the design phase of a transformer installation and weighing up what fire prevention and fire mitigation strategies should be implemented and how much should be spent fire prevention and fire mitigation, it is very useful to begin with:

- Assessing what is the risk of a transformer fire?
- What causes transformer fires? and
- What failure modes and consequential damage have the higher probability for the type of transformer installation being considered?

Quantifying the probability of a transformer fire and the contribution of the various failure modes is a useful first step for determining what risk reduction and risk mitigation measures should be implemented for each type of transformer installation.

Unfortunately there seem to be very few published papers which report on the probability of transformer fires in quantitative terms. There is more information published on the probability of transformer failures. Only a couple of authors have published finding on how large a percentage of transformer failures causes transformer fires and also provided some information on correlation between transformer failure modes and transformer fires. In this chapter we therefore present statistical data on probability of transformer failures and the correlation between failure mode and probability of transformer fires to present guidance on how to quantify the risk of transformer fires and also how the risk is related to the modes of failure.

3.1 Transformer Failure Rates from Survey Data

3.1.1 CIGRÉ Failure Survey

One of the earliest comprehensive failure rate surveys was carried out by CIGRÉ WG 12.05. The result of its survey was reported in Electra No 88 -1983. The survey result was divided into all failures and those causing forced outage. In the discussion of the results from this survey we consider only the failures causing forced outages as we will use the result to make prediction on the probability of transformer fires.

The survey was comprehensive as it covered a total of 47 000 transformer aged from 0 to 20 years old in the service years from 1968 -78 and included more than 1000 failures over the 10 year period. The analysis of the survey results present failure rates as function of transformer application, power station transformers, substation transformer and auto transformers, with and without OLTCs and as function of voltage level and age. Whilst there is some variation in failure rates with application, voltage class and whether the transformer has OLTC or not, for the purpose of this publication it is sufficient to conclude that transformers with an on load tap changer have slightly higher failure rates than transformers without tap changers and that transformers of higher voltage classes, above 300kV have higher failure rates than the voltage classes 300 kV and below.

A summary of the CIGRÉ International 1983 transformer failure survey results is presented in Table 1 below:

Table 1 : Summary of CIGRE 1983 Power Transformers Failure Survey

Age of transformers [Years]	Winding Highest Voltage [kV]						All Transformers	
	60 - < 100		> 100 - 300 <		> 300 - 700 <		> 60 -700 kV	
	Transfor-mer-years	Failure % p.a.	Transfor-mer-years	Failure % p.a.	Transfor-mer-years	Failure % p.a..	Transfor-mer-years	Failure % p.a.
0 - 5	3444	2.8	7795	1.7	2912	1.9	114151	2.01
>5 - 10	3891	2.1	7471	1.9	2055	2.5	13417	2.05
>10- 20	8533	1.7	9698	2.2	1267	3.2	19498	2.06
Total	15868	2.03	24964	1.96	6234	2.41	47066	2.04

3.1.2 CIGRÉ Australia – New Zealand Reliability Survey

A major failure survey was also performed by the CIGRÉ Australia – New Zealand transformer panel AP12. Its 1996 survey reported in [25] contains the total amount of failure data collected over a 10 year (1985-1995) period comprising:

- 51344 Transformer service years, 2906 Transformers
- 498 Failures, 92 Failures with expulsion of oil.
- 20 Explosive failures with rupture of tank or explosion vent operation
- 5 Oil fires

Table 2 : CIGRÉ Australia – New Zealand Reliability Survey

Transformer Type	Units	60< kV <100	100< kV	300 <kV <700	Total
Power station Dbl wound	482	1.33%	0.88%	2.36%	1.14%
Substation Dbl Wound	2040	0.73%	0.90%	1.80%	0.79%
Auto Transformers	363	2.42%	1.00%	1.40%	1.28%
Voltage regulators	21	1.04%			1.04%
Total	2906	0.85%	0.90%	1.73%	0.97%
			Costly failures Rate		0.4 %
			Fire Rate		0.01%

The failure rates reported in this survey was approximately 1% per year [p.a.] and costly failures only 0.4% p.a. Costly failures are those requiring prolonged outage for inspection/ remedy or removal from site for off- site repairs. The above survey also list the rates of fires 0.01 % this only 1% of all failures and 2.5% of the costly failures.

The Australian New Zealand survey also provides information on the percentage of failures caused by key components and as function of age.

It is evident that the major causes of failures are bushings, OLTC's and windings and winding accessories (tapping leads and cleat bars). The failure rates for these items are generally of same order of magnitude although there are some variations across the voltage classes exist.

The scope of the 1985-95 survey did not include shunt reactors. The consequences of the failure of oil immersed shunt reactors are very similar to transformer failures and the risk of reactor failures should therefore also had been included. The WG members are aware of four (4) major shunt reactor failures having occurred in Australia within the 1985-95 survey period. Three of these failures were due to failure of 300 kV bushings and the fourth due to dielectric failure of a barrier board. Two of the failed bushings were caused by bushings of the oil impregnated paper (OIP) type. Both of these bushings failed explosively with wide scattering of porcelain, major oil fires, loss of reactor and collateral fire damage to adjacent plant. The third bushing failure was in a Synthetic Resin Bonded Paper (SRBP) type bushing. This failure was not explosive and did not cause scattering of porcelain or fire; and neither did the winding barrier board failure, although it did cause expulsion of oil and distortion of the tank.

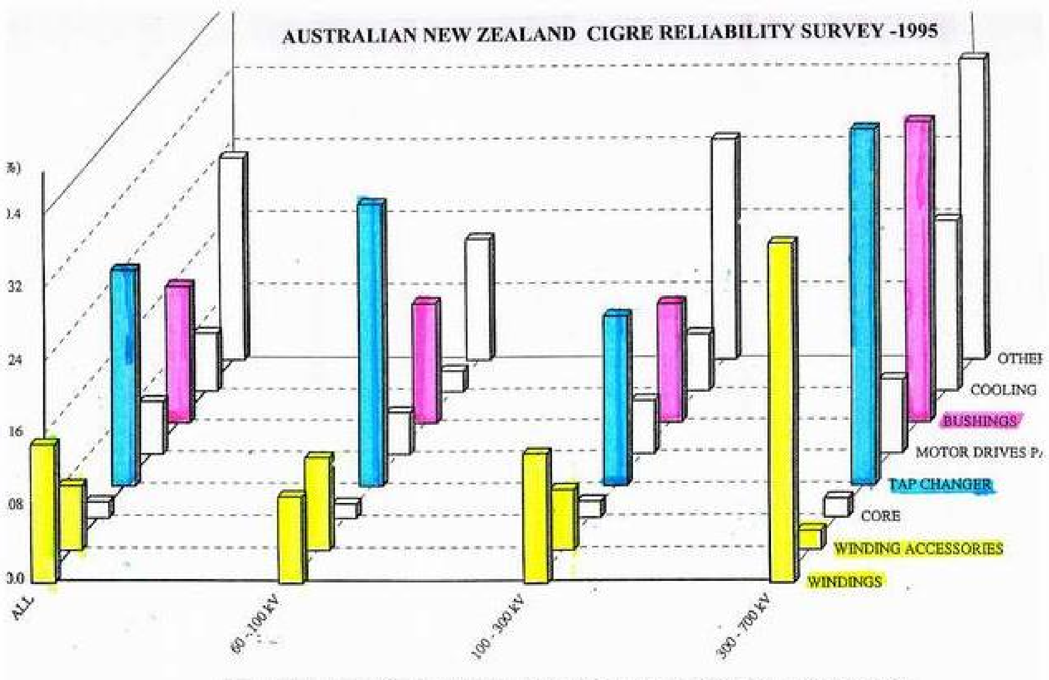


Figure 5: Transformer Failure Rate according to Component and Voltage level
Australian New Zealand Reliability Survey - 1995

The failure rate as a function of age in Figure **6** below shows that there is a high rate of the non costly failures in the first few years, but not in the costly failures. It is considered that many of these failures are fairly insignificant items related to leaks and minor control problems.

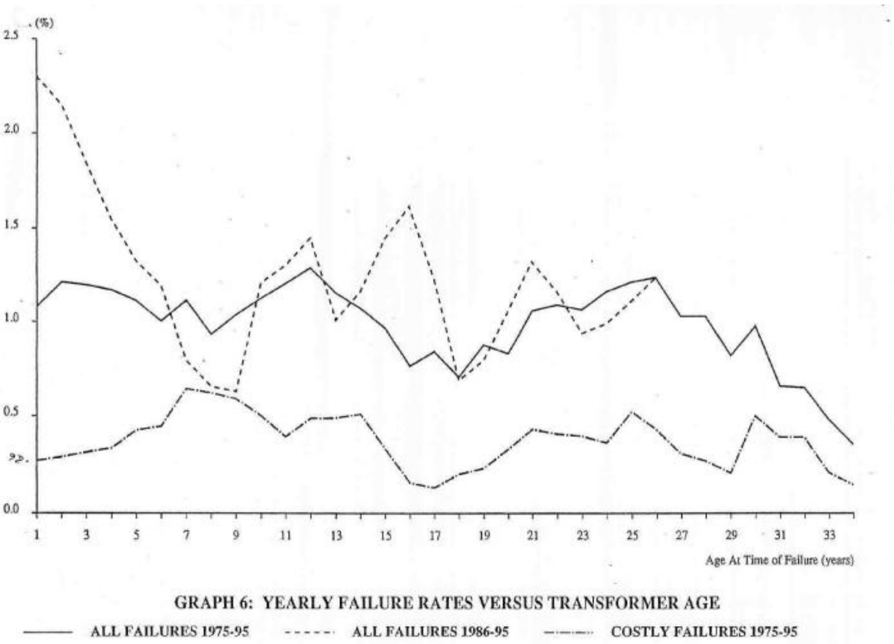


Figure 6: Yearly Failure rate according to age
Australian New Zealand Reliability Survey - 1995

It is often assumed that the failure rate follows a "bath tub curve" where failure rates are higher in the first few year of service, followed by a lower failure rate for many years thereafter and then rising to a higher failure rate towards the end of the transformer's service life.

The data on failure rates from the Australian / New Zealand transformer survey indicates that there is an increased risk of failure in the first few years of service, but it does not support the intuitive assumption that failure rate will increase towards the end of a transformer's in service life. The same trend is also evident in data from other transformer failure surveys.

It is not clear why this is so, but it could be due the fact that many utilities retire a high proportion of their older transformers before they fail and the remaining population of older transformer may be in as good or perhaps better condition than the average transformers of lesser age.

3.1.3 Surveys on Major Transformer Failures by Manufacturer

One of the major manufacturers reported the following failures of transformers rated above 100MVA at an Australian New Zealand transformer panel meeting in 2004 based on repairs and investigations they have carried out over the preceding five years on transformers owned by Australian utilities [25]

- Twenty two (22) major failures (excluding fires) caused total loss or necessitating major repairs.
- Eighteen (18) transformers suffered damage with repair costing in excess of 50 % of new replacement cost. The manufacturer considers that these failures represents approx 70 % of all Australian transformer failures for transformers rated $\geq$100 MVA. Based on estimated population over the time of these failures, the rate of serious failures would be approx. 1.0 % per transformer year.

The failure rate for major failures found in this survey is therefore 2.5 times higher than reported for costly failures in the 1985-95 survey. The causes for this increase are not evident from the survey.

However, based on observations of practising utility engineers the following changes have occurred between the two surveys:

- OIP bushings are now more common than they were in the 1975-1995 transformer population.
- Plant utilisation - (average loading) has increased.
- Utilities are more prepared to overload transformers now than in the past.
- The amount of maintenance has reduced and the number of maintenance technicians and their skill level in primary plant maintenance has reduced due to lesser degree of specialization.
- The average consumer has experienced an increased in loss of supply events and an increase in duration taken to restore supply.

3.1.4 CIGRE Australia 2002 Survey on Major Transformer Failures and Fires

A survey on transformer fires also was CIGRÉ Australia – New Zealand transformer panel APA2. This survey was carried by out in late 2002 covering the five-year period 1997-2002. Replies were received from six (6) utilities. This survey did not include any generator utilities, but included all Australian and New Zealand transmission utilities and approximately 2/3 of the sub-transmission/distribution utilities, which participated in the 1985-95 survey. This survey was therefore based on a smaller transformer population than the 1985-95 survey (approx. 1800 vs. 3000).

The number of transformer fires recorded from 1997 to 2004 was 11 fires over seven years. The average transformer population covered by this survey is estimated to be approx 1800 transformers for seven years = 12600 transformer service years, resulting in a major oil fire risk of 0.09 % per transformer service year. This figure, whilst still low, is 9 times higher than the figure from the 1985-95 survey. Anecdotal evidence supports the finding that transformer fires are now more common, even when allowing for possible under reporting in the 1985-95 survey.

In this survey 10 of the eleven fires was caused by explosive failures in HV bushings or in cable terminations within a cable box. The last fire was caused by a failure within an OLTC. No fires were caused by failures within windings or other in tank components.

3.1.5 Transformer Failure Rate Russia and Ukraine

A paper presented by the late V.Sokolov et.al [26] provides very comprehensive data on transformer failure rates and causes of transformer failures. The data presenting in that paper include more than 500 transformers and the time periods from 1955 up to 2005.

The failure rates reported in that paper varies for different voltage classes and types of transformers but most of the failure rates 0.5 at 1.5 % /year with an average failure rate in the order of approximately 1% /year. With the exception of the year 1-3 where failure rates tend to be higher (infant mortality) the failure rates are otherwise fairly constant with a slight increase at about midlife 19-21 years old and the reduced failure rates for older transformers of the 220/110 kV and the 500/220 kV voltage classes, which is similar to the failure rates reported in the Australian/ New Zealand survey. This survey does not provide any information of the incidence of transformer fires.

3.1.6 Power Transformer Fire Risk Assessment by a Major Canadian Utility

A significant contribution in for development of quantitative data for transformer failures, tank rupture and fire incidence was made by [27] in 2008. The following information and tables are from [27].

Table 3 : Statistics by a major Canadian Utility 1965 -1985: Fire rate

Voltage Class [kV]	Failure rate/year (%)	Fire incidence in % of failures	Fire incident rate /year (%)
735 (Transformers)	2.32	9.5	0.22
735 (Reactors)	3.15	11.4	0.36
315	0.84	21,9	0.18
230	0.49	15.8	0.08
161	0.50	0	0.00
120	0.6	2.6	0.02
Average	**1.21**	**8.38**	**0.14**

From the data presented in Table 3we can conclude that the average failure rate is 1.2%, but the failure and fire incidence rates for the 735 kV class is much higher than for all other voltage classes. The average fire incidence is 8.4% of all failures and the average fire incidence rate per year is 0.14%.

Table 4 : Statistics by a major Canadian Utility 1965 -1985: Explosion vs. Fire

Voltage Class [kV]	Explosions	Major oil spill	Fires
735	15	9	8
315	3	2	1
230	2	1	1
161	0	0	0
120	5	3	3
Total	**25**	**15**	**13**

From the data presented in Table 4 we can conclude that a high percentage [75%] of explosive failures (tank rupture) causes major oil spills and if there is an oil spill then there is also a high risk of a transformer fire.

Table 5 : Statistics by a major Canadian Utility 1965 -1985: Fault Location vs. Fire Rate

Fault location	Explosion	Fire	Fire rate %
Bushings	25	11	44
HV lead to tank	15	9	60
HV Lead to bushing turret	8	4	50
Within windings	21	0	00
OLTC, Core and others	9	0	00

From the data presented in Table 5 we can conclude that when a bushing, a HV lead to tank or a bushing and bushing turrets failure occurs [bushing line leads], then there is a very high risk of explosive failure and fire. These types of failures caused all of the above listed fires. It is interesting to note that winding, core, OLTC's and "other failures did not cause any of the fires. This is consistent with the findings from the Australian surveys except it had a single fire caused by and OLTC failure. The WG A2.33 is aware of other OLTC failures which have caused fires, but most of these have been minor fires involving ruptures of the OLTC diverter switch and OLTC conservator oil only.

Table 6 : Arc Energy versus Consequences (735 kV Transformers and Reactors)

Arc Energy (MJ)	Tank Ruptured	Resulted in a Fire
1.0	No	No
2.5	No	No
4.0	No	No
6.0	No	No
8.0	Yes	No
Between 8.5 and 13	Yes	Yes
14	Yes	Yes
Between 19 and 23	Yes	No
20	Yes	No
Between 26 and 67	Yes	Yes
94	Yes	Yes
147	Yes	No

From the data presented in Table **6**, it is evident that there is a strong correlation between the arc energy, tank rupture and transformer fire. This is of course what could be expected, however it is perhaps more surprising that it is possible to have a high arc energy rupture of a transformer tank and without a fire erupting. It appears that this scenario can occur where the arcing occurs in the lower part of the tank and the arc has been interrupted by the protection before the arc is exposed to air.

3.1.7 Transformer Failure and Fire Risk Rate in Japan

The transformer major failure and fire risk rate in Japan is relatively low compared to the other countries.

- The major failure rate (transformers which require replacement or repair) in Japan during 1998 to 2001 = 0.054% per annum (p.a.).
- The probability of transformer fire in Japan during 1991 to 2001 was only = 0.00012% p.a.

Since Japanese utilities have had a 500kV-1000/3MVA auto-transformer failure and fire in 1972, the quality of power transformer and manufacturing process has been improved, based on the information obtained during study in Japan conducted by the Electric Technology Research Association (ETRA). This joint study among the Academy, utilities and manufacturing in Japan were also let to the introduction of counter measures to improve explosion withstand capability for transformer enclosure. The counter measures included, reinforcement of transformer enclosures and pressure dispersion by enlarging the area between the main enclosure and the conservator. In addition to these activities, ETRA has still been conducting other countermeasures, such as diagnosis and LTC maintenance, to improve transformer's reliability.

The key factor in achieving the high reliability in Japan is the collaboration with utilities and manufactures. Whenever transformer failures occur in Japan, Japanese utilities carry out failure investigations jointly with the manufactures, and repair others transformers of same design in the field where needed this deemed to be required, the remedial action are also reflected into the design of new transformers.

As regard to diagnosis, Japanese utilities have done DGA since early 1970's, and if DGA test has found deterioration in a transformer, then this transformer will be replaced so not to cause a failure. The criteria or interpretation of DGA results in Japan is stricter than that of IEC.

Coordination with high-reliability & high-speed protection relays has also been improved to increase reliability. In order to ensure that the transformer protection system functions correctly and clears the fault in the minimum duration, older types of protection relays were replaced with the latest ones using the most modern digital technology. And the trip coils on circuit breaker are duplicated and a proportional differential relay and a high-speed over current relay are connected to the trip coils respectively to protect the transformer. In addition, the impedance of the transformer is specified slightly higher in transformers for indoor installation than for outdoor installations in order to reduce the fault current, taking the fault current and performance of the protection relays into consideration.

As regard to the transformer design, the tank of Japanese transformer is sealed with nitrogen gas to prevent oil degradation.

These are the main issues related to the reliability and design technology in Japan.

3.1.8 Insurance Company Experience

A large insurer, who insures a fleet of over 100,000 transformers in six continents, in the period from 2000 –2010, experienced a total of 594 transformer failures representing a loss of $650 million. Of these incidents, only 156 transformer failures, or about 25% of the total incidents resulted in fire. The incident of fires to failure reported here is higher than reported by most utilities a possible explanation could be that only the most serious failures are reported to insurers.

3.1.9 Transformer Failure and Fire Risk Rate - Data Other Sources

The rates of transformer failures and the probability of transformer fires were also assessed from information provided in discussions at WG 2.33 meetings which has member's representatives from several major utilities.

Table 7 : Transformer Failure and Fire Risk Rate - Data Other Sources

Utility	Transformer population (approx)	Rate of Serious Failures (%p.a.)	Rate of Transformer Fires (%p.a.).
Germany National Statistics		0.6	0.06 (Anecdotal - 10 % of Serious Failures)
RTE, France	1300	0.6	0.05
Eskom, SA	600	-	0.16
National Grid, UK	780	0.3	0.015
Swedish State Power Board Transmission	1300	-	0.02 (3 fires in 10 Years)
Swedish State Power Board Hydro stations	100	-	< 0.05 (no fire in 20-30 years)
Japan (1991-2001)		0.054	0.00012

3.2 Major Causes of Transformer Fire

3.2.1 Transformer Fire Initiated by Bushings and Cable Termination Failures

There is clear evidence that transformers using Oil Impregnated Paper [OIP] bushings or cables terminated in an air- or oil insulated cable boxes have an increased risk of fire following a bushing or cable termination failure. In the Australian New Zealand transformer fire survey it was found that 91 % of transformer fires originated from an OIP bushing or a cable termination failure, with bushing and cable termination each accounting for 5 fires out of a total of 11 transformer fires (91%) and the remaining 9 % from one OLTC failure.

The failure from a major Canadian Utility data listed in Table 5 above included 24 transformer fires, 46 % of these fires was caused by failure in OIP bushings and 54 % of fires from failure within bushing turrets or from HV line leads to tank wall arcing failures, causing rupture of bushing turret/tank or breakage of bolted flanges. The latter mode of failure is prevalent in very high Voltage (735 kV), high fault energy failures. It is evident that HV bushing and HV bushing lead failures are the two highest fire risk items on a transformer.

3.2.2 OIP Bushing Initiated Fires

When an arcing failure occurs within the porcelain shell of an OIP bushing, it frequently results in an explosive failure of the upper or the lower porcelain shell. (Refer to Chapter 2.2.3 for bushing failure initiated fire scenario).

Working Group A2.33 members are not aware of any oil fires having been initiated by a failure in a RIP or SRBP bushing. However, this is not a categorical statement that a fire could not initiated by such bushing, but merely that the risk is much less than for OIP bushings. (Refer to Section 2.2.4 for cable termination failure initiated fire scenario).

3.2.3 Fires Initiated by Cable Termination Failures

Cable terminations failures of often causes a transformer fire which can develop into a major fire where an oil filled cable box is connected to the main tank or the conservator and the oil from the main tan tank or the conservator feeds the fire, which then can burn gasket on inspection and access covers and cause a major spill of oil from the main tank. (Refer to Chapter 2.2.3 for bushing fire methodology).

3.2.4 Fires Initiated by OLTC Failures

OLTCs failures is the cause of 10 -15% of fires, however these fires are often minor fires as the volume of oil exposed to air is only a few hundred litres at the most, unless there has been a rupture of the barrier between the main tank and the OLTC diverter/arcing contact oil compartment. Arcing failure within the diverter switch or a combined selector switch will in most cases cause rupture of the recessed disc in the OLTC cover or activate the resealable pressure relief device, if the arc energy is relatively low, as it may be if the tapping winding is at the neutral end. A low arc energy fault may only initiate a small oil fire, as the oil surface exposed in the OLTC and the amount of oil in the OLTC conservator relative small. If the fault cleared quickly by the protection before the fire escalates, then it may or may not developed into a major oil fire. However, if the arc energy is high it is more likely that the OLTC cover or its tank may rupture and the barrier board to the main tank may be broken. If this occurs then the oil will spill from the main tank, the conservator and the fire will quickly cover a much bigger surface and be fed by much larger oil volume.

3.2.5 Fires Initiated by a Tank Rupture

Oil fires originating from rupture of transformer tanks is rare for voltages below 300 kV, but is less rare for voltages above 300 kV where the combination of longer flash over arc and higher system fault levels often have enough arc energy to cause rapid and very high pressure increase and rupture of the tank or bushing turrets, before the electrical protection have time to operate and interrupt the fault current.

If a rupture of the tank occurs whilst the arc is present, then there is a very high probability that it will ignite the hydrogen and other hydrocarbon gases generated by the arc and also the oil spilling from the tank, resulting in a major oil fire.

It is reported in [27] that 13 of 24 fires (54 %) caused by rupture of tank and bushing turrets (chimneys), 4 of these where HV lead to bushing turret faults and 9 where HV lead to tank faults, all faults causing a fire had very high fault energies (calculated to be > 13 MJ**)**.

It is interesting and important to note that the author of [27] also reported that there were 21 explosive failure caused by failures within windings and 9 explosive failures caused by faults in cores, OLTC and other parts in the same period , but none of these explosive failures caused fires.

These findings are supported by [25] which also reported that none of the 11 fires reported in the Australian New Zealand survey were caused by faults within windings.

Tank flexibility together with pressure withstand capability is an important factor when considering withstand against tank rupture and may be more important than pressure relief devices in reducing the risk of tank rupture. This becomes evident when considering the significant increase in volume which can be accommodated in standard tank for only small pressure increases.

One of the WG A2.33 members has performed oil volume expansion/pressure test on a 350 MVA transformer with an oil volume of 60 000 litres. The volume expansion was 600 litres for a pressure increase from 0.45 to 1.45 bar measures at base of tank. The rupture withstand of this tank was not determined, but it is unlikely that it would have been less than 2 Bars measured at base of tank. By extrapolation it can be concluded that this tank could accommodate at least a volume expansion of 1000 litres at 2 bars at base of tank. This volume expansion capacity is very significant when compared the amount of oil which could be discharged from a conventional PRV with 127mm dia. opening in say 50- 60 ms (typical breaker clearing). Much larger volume expansion could have been achieved, if maximising volume expansion had been considered in the design criteria for the tank design criteria. Tank flexibility (volume expansion) as function of pressure increase is an important factor when evaluating tank rupture withstands capability. The indications from the test determining gas volumes vs. arcing energy is that the tank used in this test could withstand an arc energy in the order of 10+ MJ before rupturing, unless the rupture were caused by fast acting localised pressure build-up.

3.3 The Probability of Transformer Fires - Summary

From the data presented in this chapter it can be concluded that the probability of major transformer failure, which requires major repairs or scrapping of the transformer varies from about 0.5 to 2.5 % per transformer service year, with the average being approximately 1%.

A few utilities have significantly higher or lower failure rates, but they are exceptions. The majority of utilities have close to the average rate, with some variations depending on the type and service condition of the transformer, the maker, the user’s procurement and maintenance practices. The failure rates tend to be higher for auto transformers, generator step up transformers and transformers with On Load Tap Changers [OLTC], whereas two winding transformers in the 11- 300 kV tend to have failure rates lower than the average failure rate.

The percentage of transformer failures resulting in a transformer fire is typically in the order of 5 to 15 % of serious transformer failures, with an average probability of approximately 10 % of all serious failures.

This is a useful figure for utilities to have for calculating the approximate probability of transformer fires for their particular situation, as they can determine what risk they have of serious transformer failure and the use the figure of 10 % of the failures resulting in a transformer fire.

From the above it can be concluded that the probability of a transformer fire is in the range of 0.04 - 0.25 %/year, with the average probability of a transformer fire being approximately 0.1% /year (=1/1000 p.a.).

This represents an accumulated probability range 1.6-10 % per transformer and an average probability of 4% over a 40 years' service life for the average utility owned transformer.

Transformer fires are therefore a low, but not a negligible risk. A four step approach for estimating the probability (risk) of a transformer fire is proposed below:

Step 1

Utilities can improve the accuracy of their risk estimate for their transformer population and even specific transformers firstly by determining the failure rates they have in their transformer population and then look at the specific transformer.

Step 2

Is it a type of transformer, or a voltage class which have a higher or lower than average probability? If it is, then make the appropriate adjust to determine the risk of failure of this type or class of transformer.

Step 3

Use the revised "average" probability of a failure resulting in a fire from Step 2 and then determine what risk mitigating factors have been implemented on this specific transformer to reduce the probability of fire further (RIP bushings; no cable box; condition of transformer etc.) and then determine what fire risk factor should be used to determine the risk applicable for the specific transformer. Sufficient to say at this point that they include, the protection and circuit breaker operating time, tank flexibility and tanks strength, pressure mitigation / depressurisation factor, type of bushing, cable termination. The effect of risk minimisation measures will discussed further in the remainder of this document

Step 4

The probability of a transformer fire can then be determined as follows:

[The probability of serious failure] x [The probability of a failure causing fire] x [Risk reduction measures K1, x K_2, x K_3.x..... K_n]

Example

Probability of a transformer fire = 0.01x 0.1x [K_1 x K_2 x K_3 x K_n] /year

3.4 The Risk to Potential Fire Victims – Other Substation Assets

When considering the probability and potential consequences of a transformer fire it is often useful to categorise substations into types of substations as the specific strategies which can and should be applied for fire risk management varies between types of Installation:

- Open air substation where land cost is low: - space separation will often be most economic risk management strategy.
- Compact air insulation substations where land cost is high: In such installations fire barriers in form of reinforced concrete panels/wall, sound/fire enclosures, or water spray "curtain" is common forms of fire protection in such installation.
- Under ground or city building substation: Such installation will normally have a very site specific and fire prevention and fire contingency management strategies. Japan has well developed designs for risk management in such installation, using a combination fast acting protection, large duct opening between the banks and to the conservator and high strength tanks design, to allow oil to move reduce rate of pressure rise and contain the oil and arcing gases without rupture of the tank. If the installation is in the basement of an occupied office building or people traffic area then SF6 cooled transformers will probably be the safest option [Such transformer can be made virtually free of fire risk].
- Power station unit and generator step-up transformers: Deluge or fogging water spray system can be effective in protection the other power station assets, as reliable and high capacity water supply is usually readily available at most power stations. It is important to consider that water spray may also be required to cool nearby building structure or other critical assets, not just the fire origin – the transformer.
- Other types of installation – Installation which does not lend itself to be categorised must be considered on a one by one basis.

Other common precautions which apply to all installations and should be considered include:

- Oil containment - spilling of oil outside the substation during a fire is not considered an accident, but negligence and a failure to foresee and manage the risk. However, the Oil containment system should be fit for the specific site conditions.
- Oil spilled from the fire source (one transformer) should not be able to travel along cable trenches or conduit or other means where it can potentially spread the fire to building or other plant items.
- Most utilities have well developed oil containment systems to suit their specific requirements. Key requirements are that oil should be directed rapidly away from the fire zone so it is not available to fuel the fire and not contaminate the environment. The oil containment system must be fit for the climatic and other site specific conditions. Underground oil/water separation tank is becoming widely used in Australia and some other. This system will separate transformer oil mixed with water to less than 10ppm oil in the water at the outlet from the from oil separation at max flow rate through the separation tank. A Canadian utility [28] uses a mat/membrane system suitable for cold climate, which allows water to flow through, but will contain oil and prevent it from contaminating the ground water.
- Emergency plans which include clearly defined responsibilities, delegated authorities and a range of pre-considered contingencies and "what if" scenarios and drill practice plans.

- Access to key areas of the substation with anyone transformer on fire. Multiple access point may be necessary.
- Radiated or wind borne heat should not be able to initiate fire in other substation assets.
- Fire brigade access, availability of water/foam/other fire suppressants for fire fighting. Whilst water is generally not effective in extinguishing transformer oil fires and foam not effective in fighting oil fires with oil spilling over vertical surfaces, water can be very effective in cooling the fire to reduce heat output and also in prevent fire spreading to adjacent assets and foam and water can be very effective in extinguish pool fires.

The above points will be discussed further in the remainder of this document.

Chapter 4: Internal Arcing and Tank Ruptures

4.1 Arc Energy

The oil vaporisation process is linked to the arc energy but not directly to the transformer power. Moreover, the arc energy depends on the transformer location in the grid, which drives the maximum available arc current.

Arc energy E (Joule, J) is then a function of arc current I_{arc} (Amperes, A) voltage V_{arc} (Volt, V) and duration t_{arc} (seconds, sec) as shown by the following formula:

$$E = \int_0^{t_{arc}} V_{arc}(t)\, I_{arc}(t)\, dt \qquad \text{Equation 1}$$

- **Arc current:** In the survey undertaken by the authors seems to show that the most probable range for an arc current will be between 10 kA and 30 kA with a probabilistic peak between 10 kA and 20 kA.
- **Arc duration:** It seems that the most probable range is 3 to 4 cycles for a 50-60Hz current. Arc current can in most cases easily be evaluated by the short-circuit levels, as well as the duration by the type of protection (relay and breaker);
- **Arc voltage:** Difficulties arise in the evaluation of arc voltage. Most of the time online direct measurements are not available to assess this parameter.

A simple correlation between the arc length and the arc voltage [29] is shown in Figure 7. Nevertheless it remains difficult to estimate a priori the arc length as the pressure and temperature at the arc is unknown.

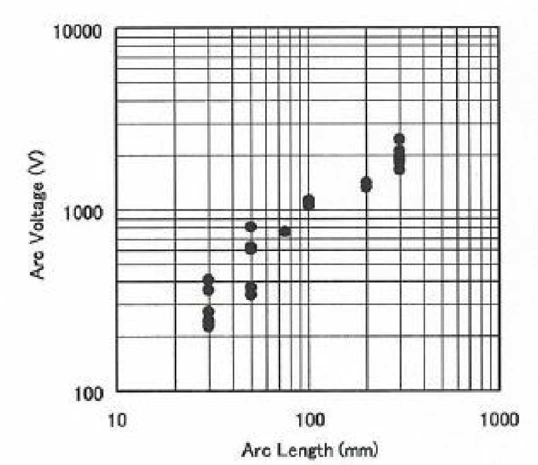
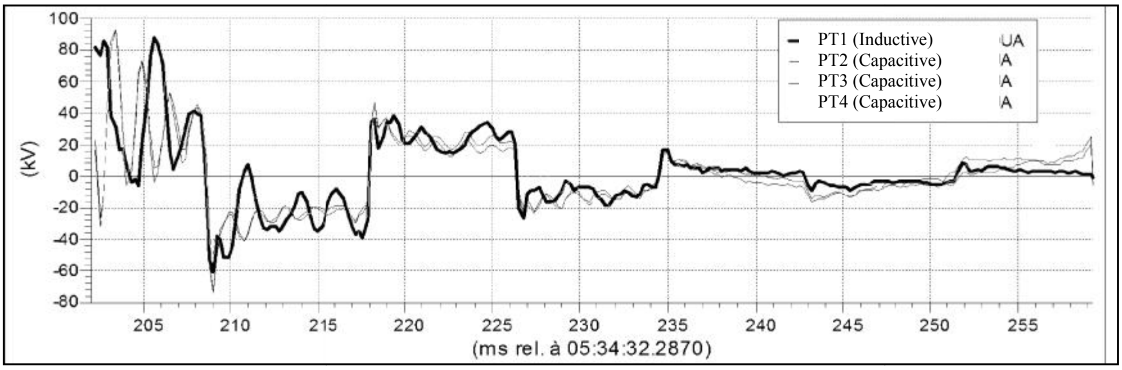
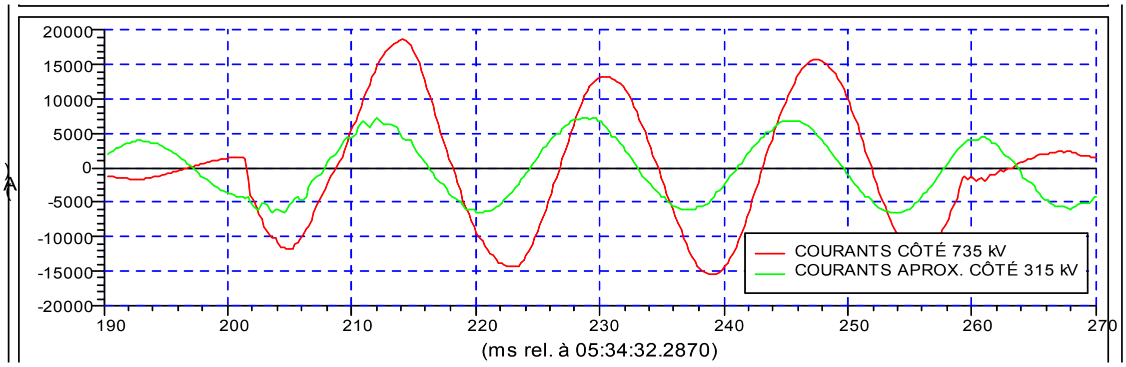


Figure 7: Arc voltage as a function of arc length [29]

One utility have been able to carry out this type of measurements using high precision inductive PT´s installed on their 735-kV systems. In a typical recording Figure 8, voltage is shown to reach significant values (more than 40 kV) during the first instants after ignition. The fault current is in most cases known from the known fault level of the substation or from fault event recorders, so where volt current and fault duration is known.



a) Arc voltage (kV) from different PT



b) Arc currents for HV (red) and LV (green) sides

Figure 8: Example of arc energy calculation (8 MJ) based on actual fault voltage and current measurements.

The peak arc voltage values observed cannot be explained by only an effective arc length longer than the insulation distance. Some other phenomena need to be involved, one of them being the possible effect of pressure on the voltage. In [30] and [31] for example the authors propose another correlation between the arc voltage and the arc length that tries to model the gas bubble pressure influence:

$$V_{arc} = 55L\sqrt{P} \qquad \text{Equation 2}$$

with:

- 55 : empirical constant (V/cm)
- V_{arc} : arc voltage (Volt, V)
- L : arc length (cm)
- P: absolute pressure in the gas bubble surrounding the arc (Atm)

At arc ignition and the few following ms, vaporization process results in high local overpressures, the influence of this pressure peak might explain the unexpected arc voltage measurements displayed in Figure 8. The fault current is in most cases known from failure event recordings or known fault level, so if the arc voltage and arc duration can be established then it becomes possible to calculate the arc energy through Equation 1.

4.2 Gas Generation

The volume of gas generated by an arc in oil has been mainly investigated for the application of oil circuit breakers. One of the first reported studies on that matter was published in 1953 [31]. This investigation established an approximate arc energy dissipation breakdown as follows:

13.8%	Energy loss at contacts
11.8%	Energy radiated from arc column
4.0%	Energy to heat oil to its boiling point
14.5%	Energy to breakdown the oil into gas
34.6%	Energy to heat gas at constant volume
10.2%	Energy to cause expansion of gas formed
10.2%	Energy used to dissociate the hydrogen formed

Average gas volume generation was found to 70 cc (Standard Temperature and Pressure) per kJ of arc energy with a composition of about 70 % H_2, 25 % C_2H_2 and 5 % other hydrocarbons (CH_4 and C_2H_4). The report also includes a discussion on arc and surrounding gas temperature. Values mentioned for the reaction zone ranged from 1700°K to 3500°K with a suggested average of 2000°K. Values of gas generation rate reported by a number of other investigators are quite similar, see Table 8 below:

Table 8 : Measured Gas Generation Rate

Reference	Year published	Gas volume (STP) generated (cc/kJ)
Trencham [31]	1953	70
Castonguay [32]	1975	61
Goto et Miura [33]	1987	50-70
Cuk [34]	1990	85
Darian et al. [35]	2009	110

All the authors mentioned above concluded that the gas generation rate can be represented by linear function with arc energy, and found evidence that an average gas formation temperature of about 2000 °K is a reasonable assumption. There was also good agreement on the gas composition between the different investigations.

The linear relationships proposed yielded an energy transfer factor from the arc to the gas bubble in the range of 15 % to 40 %. Gas generation rate has been observed to show a stochastic behaviour [34], [36] for that reason a value of 100 cc/kJ (STP) has been used by several investigators as a conservative assumption in the 20 to 2640 kJ arc energy range.

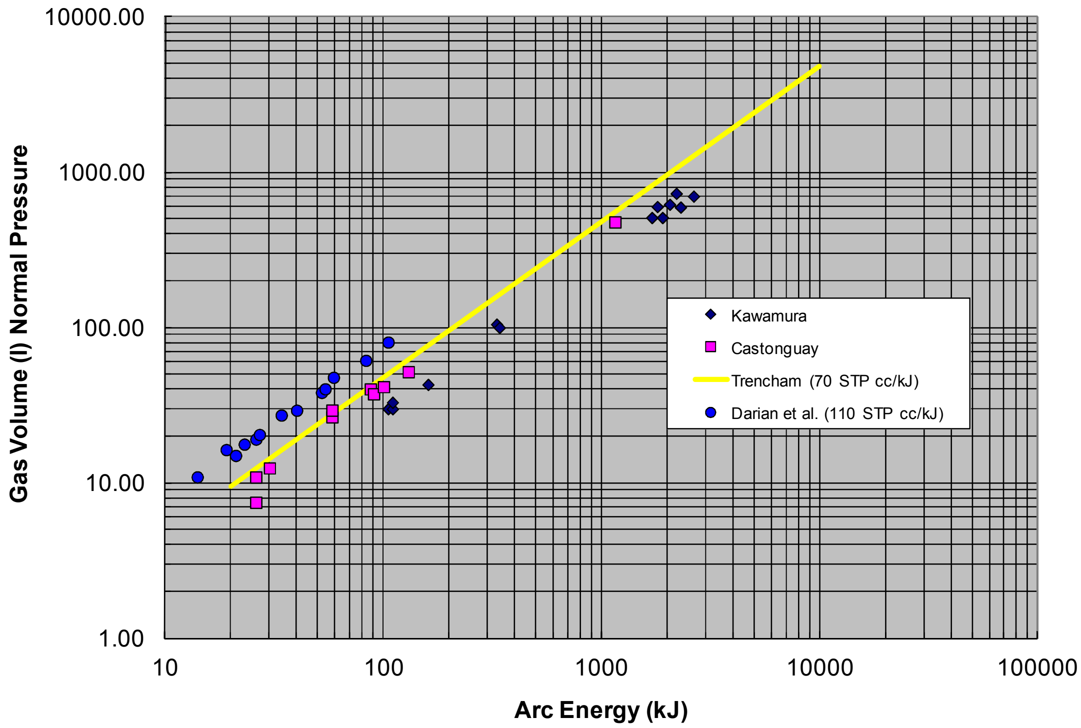


Figure 9: Comparison of gas generation models and experiments from different authors (Gas volume at Normal Pressure and 2000 °K)

4.3 Pressure Calculation Models

4.3.1 Simplified Containment Model

Pressure build-up following an arc inside a transformer depends on the volume of gas generated by the arc and the tank expansion characteristics. A simplified expression was first proposed by [37]; it is based on the conservative assumption of an isothermal expansion of the gas bubble. Equation 3and Figure 10 from [38] present a modified version which includes different arc parameters and a more elaborate dynamic amplification factor than the single value suggested in [37].\

$$P_s = F\left[100\sqrt{\frac{1}{4}+\frac{kE}{100C}} - 50\right] \qquad \text{Equation 3}$$

Where:

- Ps: calculated tank pressure [kPa above atmospheric]
- E: fault energy level (kJ)
- k: arc energy conversion factor (= 5.8 x 10^{-4} m^3/kJ) [@2000 °K]
- C: tank expansion coefficient (m^3/kPa)
- F: dynamic amplification factor given in Figure 10.
- V: volume of oil in main tank (m^3).

Factor k is based on internal experiments which suggest a gas generation rate of 85 cc/kJ and an average temperature of 2000 °K. This represents about 24 % of arc energy transferred into enthalpy (available expansion energy) of the gas bubble.

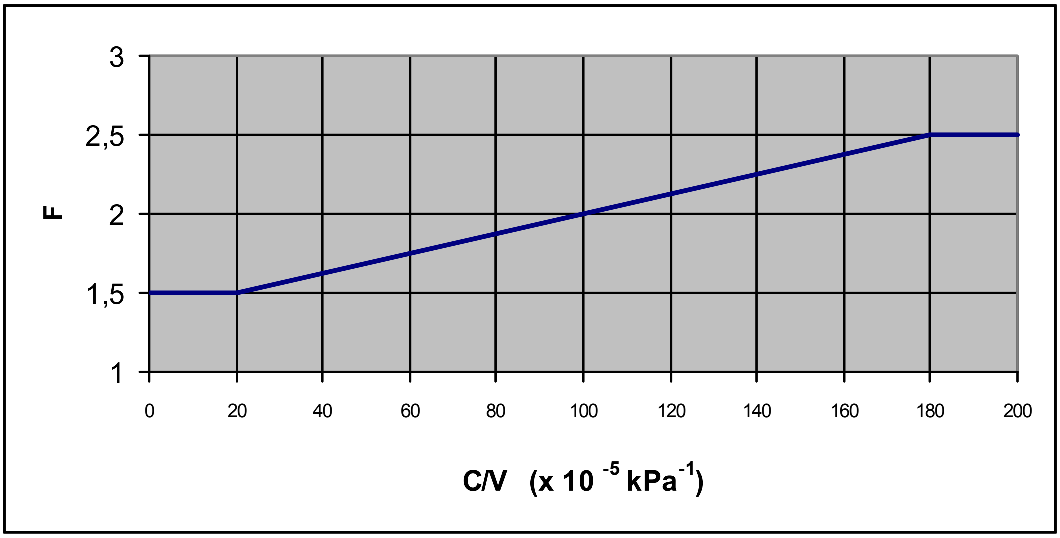


Figure 10: Variation of the dynamic amplification factor F for Equation 3

F is a factor which indicates the ratio of the localised dynamic pressure and the static pressure from developed from an internal arcing fault. Extensive numerical and experimental (high-speed gas injection) simulations have shown that local pressure and, more specifically, deformation exhibit a dynamic amplification factor that is best expressed as a function of the ratio of tank flexibility over oil volume (C/V).

4.3.2 Simplified Venting Model

In a model proposed by [39], the tank is divided into the several tank elements in the calculation as shown in Figure 11. The pressure rise in each element at the internal fault is calculated by the dynamic analysis considering oil motion (inertia and pressure losses).

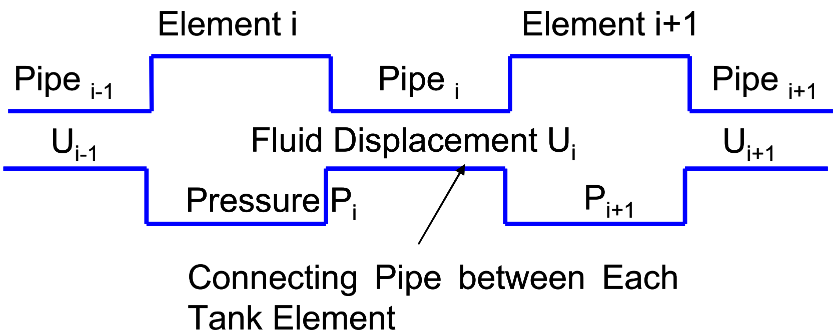


Figure 11: Simplified numerical model for venting to adjacent tanks

Pressures can then obtained by solving numerically a set of equations relating the pressure of the different elements with velocities in the pipes. This model proved to be useful in the evaluation of venting pipes and pressure reduction spaces.

4.3.3 Hydrodynamic Numerical Models

Other investigators have used hydrodynamic models where oil motion is described 3-dimensionnaly inside infinitely rigid boundaries representing the tank. These models will produce pressure and velocity field as illustrated in Figure 12 below.

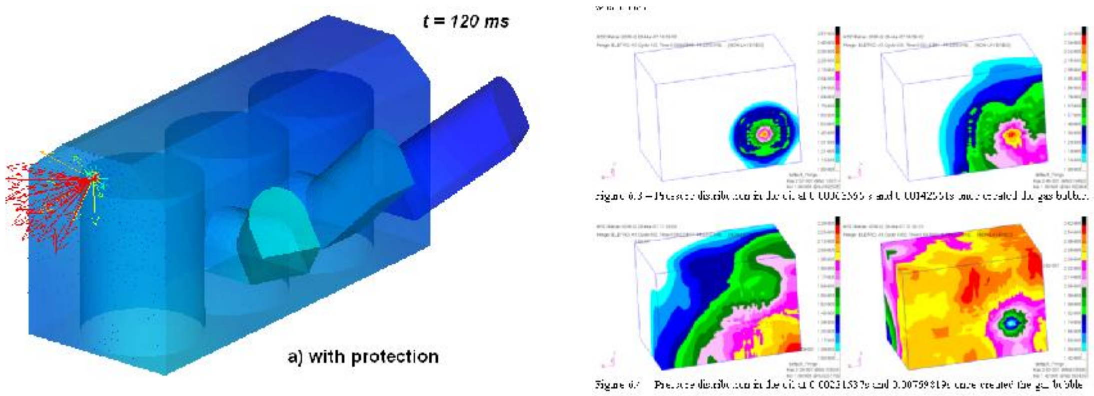


Figure 12: Example of pressure field calculation outputs from hydrodynamic models

While the models illustrated [40] [41] above can be instructive of some oil flow and pressure propagation phenomena; their practical use is limited by the fact that they do not take into account the tank flexibility.

4.3.4 Structural-Hydrodynamic Numerical Models

A number of commercial software programs with full structural and hydrodynamic capabilities are nowadays available. These computer programs are designed to analyze high-speed impact or explosive phenomena in different media including gas, oil and steel and their interactions. They therefore lend themselves very well to the simulation of arcing in a transformer.

In the application of such commercial software, a study [42] made use of an equivalent explosive quantity to simulate a pre-defined amount of arcing energy. This investigation aimed at demonstrating the importance of the position of the fault with respect to the location of damages and the eventual rupture point as illustrated in Figure 13. The main drawback from this approach is that burn rate of explosive (typically less than a millisecond) is much faster than the typical duration of an arc (typically 40-60 milliseconds). Some dynamic effects may therefore be significantly overestimated.

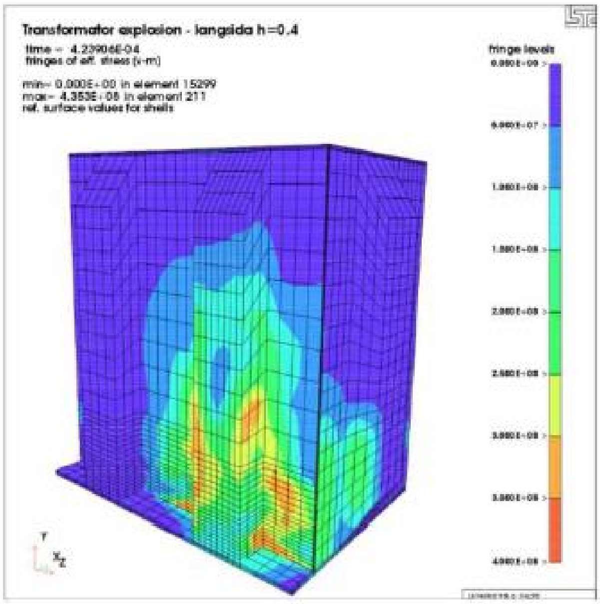


Fig. 17 Distribution of effective stress at 0.24 ms after ignition

Figure 13: Example of stress field outputs from an explosive simulation of the arc

In reference [43] a methodology to simulate the effects of an arc by the injection of a given quantity of gas with properties such as detailed in is described. The resulting model has been used to investigate real failure cases such as shown in Figure 14. This model, also based on commercial software, includes the complete set of equations and therefore simulates all relevant phenomena such as: oil compressibility, pressure wave propagation, elastic-plastic deformation of the tank, gas-oil-tank interactions, etc. These features however require important modelling and computational resources.

Figure 14: Example of a real chimney rupture case with an arc simulation methodology

4.4 Pressure Containment

In general transformer tanks are designed to withstand an internal operating pressure of approximately 50-100 kPa (relative to Atmospheric and above head of oil), and to withstand full vacuum without plastic deformation. Therefore the ultimate rupture pressure can be evaluated somewhat above 150-200 kPa. It is the working groups experience that tanks for large HV transformers >100 MVA, typically have flexibility in the range of 0.5 -1.5 % volume expansion per 100 kPa pressure increase.

Tanks with withstand pressure and typical volume expansion as listed above; can be expected to have arc energy containment within the range listed below.

Table 9 : Approximate range of arc energy containment capability of three phase transformer with conventional tank designs

Voltage (kV)	Lower (MJ)	Upper (MJ)
500 – 800	4.0	10.0
275 – 400	3.5	8.0
132 – 170	3.0	6.0
100 – 120	2.0	4.0

4.5 Pressure Venting

Up to 1960-70, it was common practice to equip transformers with over pressure venting in form of a "gooseneck" shaped venting pipe (sometimes also called an explosion vent). The interface to the air on the pipe was usually sealed with a membrane designed to rupture at a pre-determined over pressure on the oil side of the membrane. In the last few decades it has become common practice for many transformer users to specify one or more spring loaded self re-sealing Pressure Relief Valve [PRV] instead of the "gooseneck type vent pipe". Such PRV's are available in a range of sizes. A 5 inch (127 mm) opening diameter is a very common size and it is common practice fit one PRV for transformer small and medium size transformer < 40000 litres of oil, and to use two or more PRV's valves for large power transformers. Many users are fitting these types of PRVs to transformers in the belief that they would prevent tank rupture in the event of internal arcing fault.

Upon field cases investigations it is often wrongfully assumed that a PRV which operated without a tank rupture is a proof of performance. However, the venting capacity of such PRVs is completely inadequate to provide sufficiently fast pressure relief to prevent tank rupture for a high energy arcing fault. At best they might have a material effect on pressure reduction for arcing fault close to the venting port, where the vented product is mainly arcing gases. For faults further away from the venting port where the vented product is mainly oil, the pressure reduction provided by one or two 5" PRVs are far less, than the contribution made by the elasticity/ volume expansion of the tank within the plastic deformation range. (Refer to Figure 15 and Figure 16).

PRVs do nevertheless have benefits insofar they act as a safety valve for over pressure when filling tanks with oil and will provide pressure relief for residual pressures from and arcing fault where the fault have been cleared by protection prior to the tank ruptures. It is also considered they can make material impact on pressure reduction on hermetically sealed gas cushion transformers, where the vented product would be gases and the pressure build would be slower due to the compressibility of the gas cushion.

The question of determining the efficiency of venting devices in preventing tank rupture during a major fault is quite complex and therefore cannot be based on anecdotal field evidence, but requires extensive failure statistics of well documented forensic reports. Such data is, if any, is not easily accessible and the only alternative is to rely on theoretical and numerical investigations.

4.5.1 Theoretical Upper Bound Analysis

While a detailed calculation of the efficiency of pressure venting would require much effort, a simple analysis with only conservative assumptions can give an upper bound for the venting efficiency of typical venting apertures. Hence, if we consider the following simplifying assumptions:

- Venting discharge area is fully open immediately at arc ignition (no time delay for the valve to open or the disc to rupture)
- Oil discharge velocity is the maximum theoretically possible immediately at arc ignition and it stays constant throughout the fault. An internal static pressure of 200 kPa is used to calculate this discharge velocity (18.0 m/s).
- Gas discharge velocity is the theoretical maximum for compressible gases (at choking). Based on a temperature of 2000K, this velocity is estimated to be less than 850 m/s.
- There is no flow friction through the aperture
- Dynamic effects (oil inertia and arc location) are neglected. Peak pressures are therefore assumed to coincide with arc extinction.

Then a simple formulation can be derived using equation presented previously (see also reference [44] for a detailed derivation) and the venting efficiency can be evaluated by comparing the vented and non-vented calculated situations. Since this is an upper bound analysis, it is not easy to estimate the difference with realistic venting efficiency values, it can only be stated that actual performance from any venting device should be considerably less than the values presented below.

In the following paragraphs, an example case is considered for illustration purposes, actual parameters were selected from a modern tank design, in order to represent a typical size power transformer:

- Rating: 100 MVA
- Height: :3m
- Width: 4m
- Depth: 2.5m
- Tank flexibility: K = 0,0066 m^3/kPa

Firstly, if we consider the most favourable case for venting efficiency, i.e. when the arc is located in the immediate vicinity of the venting aperture, or in a gas cushion transformers then the formulation is based on the maximum gas discharge velocity. Making the upper bound assumption that this gas will discharge at a velocity of about 1000 m/s (corresponding to a gas bubble temperature of about 2000 °K) then the maximum theoretical pressure reduction can be plotted as in Figure 15 below.

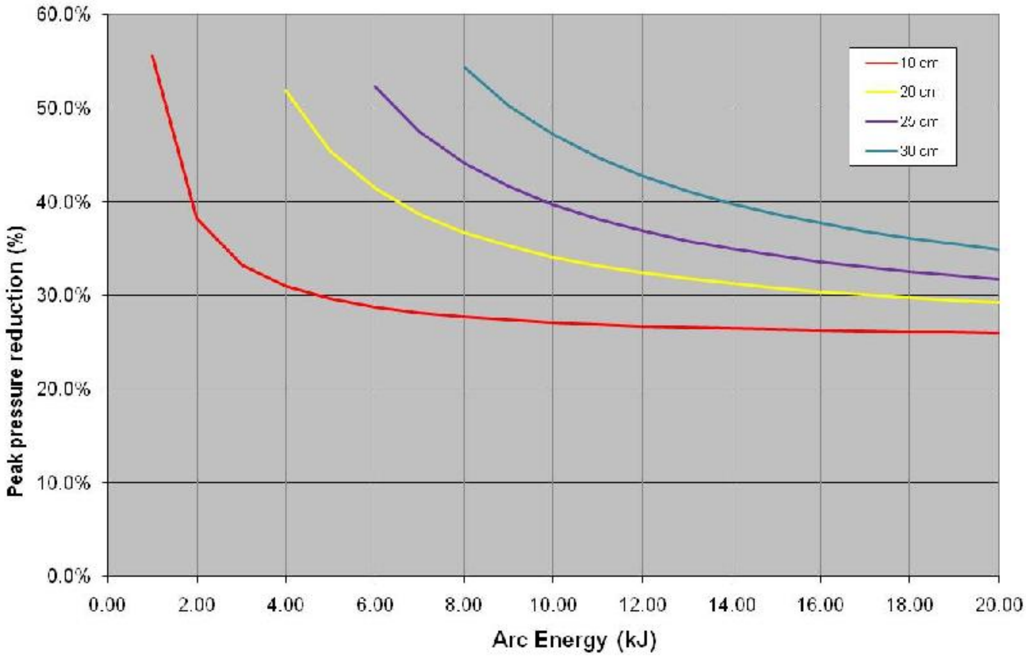


Figure 15: Upper bound for venting efficiency (% peak pressure reduction)
Arc (3 cycles duration) located in the immediate vicinity of the aperture

It can be seen that pressure venting by PRV's, rupture discs of or other form vent opening can have a material effect on the pressure reduction for faults close to the venting port where the main product vented is decomposition gases. A common size PRV with 127 mm dia. opening could achieve a 30 % venting efficiency for arcing energies up 6 MJ and a 200 mm dia. PRV could achieve up to 40 % venting efficiency for up to 6 MJ.

For arcing fault located even a short distance away from the venting port (say 1m or more) efficiency will be reduced as the venting product will become essentially oil. The venting efficiency is far less when the vented product is oil, as the discharge velocity is severely reduced by the material. This is illustrated in the next example in Figure 16 below.

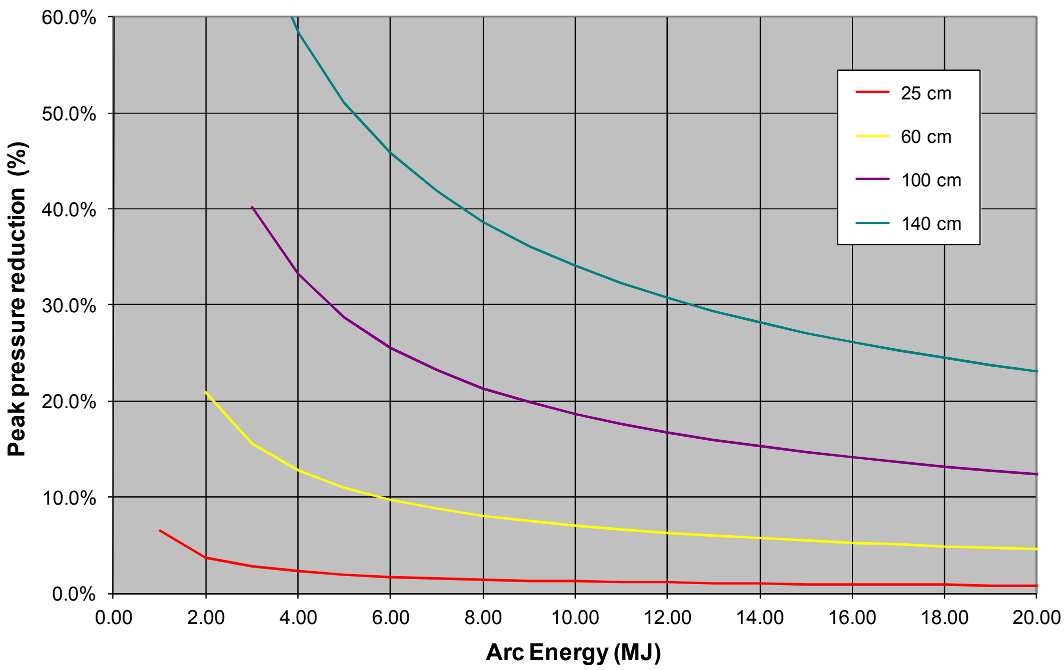


Figure 16: Upper bound for venting efficiency (% pressure reduction)
Arc (3 cycles duration) located more than 1 m from the aperture

While the analysis considers arc energies up to 20 MJ, the range of interest lies between 3 and 10 MJ which are lower and upper bounds for rupture in a tank of this size. It can be seen that for the typical power transformer considered:

- The required aperture diameter for a significant pressure reduction (30 %) should be at least 100 cm for arc energies up to 3.5 MJ and 140 cm for arc energies up to 6 MJ.
- The pressure reduction that can be expected from a 25 cm aperture is less than 3 % for arc energies where tank rupture becomes a serious risk.

Tank rupture have been observed to rupture after fault of typically 3-4 cycles, but if we consider, for the sake of this upper bound analysis, a 30 cycles arc duration, then the relative venting efficiency can be shown to significantly increase as illustrated in Figure 17 below: However it should be clearly understood that the reason the venting efficiency is increased is that an arc which produced the same amount of acing energy over 30 cycles as another arc over 3 cycles has only 1/10th of the formers intensity.

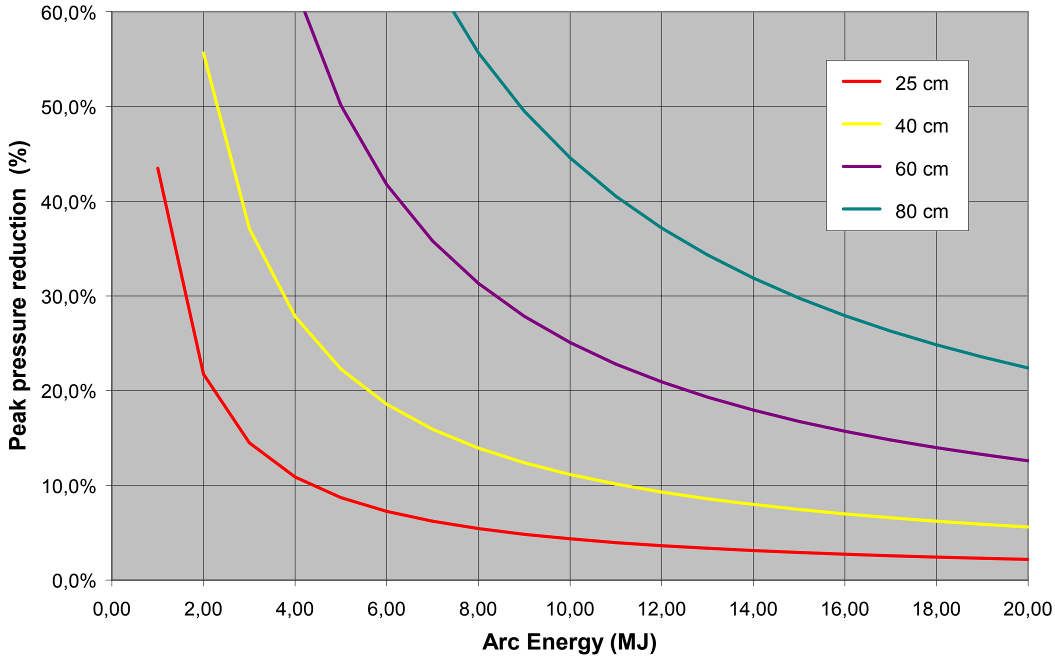


Figure 17: Upper bound for venting efficiency (% pressure reduction)
Arc (30 cycles duration) not located within the immediate vicinity of the aperture

4.5.2 Venting Simulation

The theoretical evaluation above has been verified with simulation studies that have been carried out with the advanced numerical tool described in [43]. The tank conditions were the same as the case above, arc energy was set to 10 MJ with a 50 ms duration. The model and more detailed simulation results are also presented in reference [43]. In particular, the peak pressure reduction from a 25cm diameter disc was confirmed to be well within the maximum of 3% calculated with the upper bound analysis.

Other investigators have also presented simulations (experimental and theoretical) that led to very similar conclusions:

- The first investigation by a Japanese consortium and summarized in [37] considered a concept where the pressure is vented to adjacent tanks and the conservator. Calculation models and experiments on actual tanks (in which the arc was simulated by explosives) were used to establish the pressure reduction achieved by different duct diameter. It was concluded that a venting duct area of about 0.7 m^2 would only yield a pressure reducing effect of 20 %.
- The EPRI research team [44] analysed the same issue through numerical simulations. The pressure reduction effect of a 1 m^2 venting area was estimated to be less than 10% for a 20 MJ arc with duration of 75 msec. This pressure reduction estimate was increased to about 15 % if the same energy level was liberated during a 150 ms arcing fault.
- At least one power transformer manufacturer has put forward some solutions making use of venting through bursting discs. The modelling methods they used to design the venting system are described in [45]. Based on their analysis, they came to the conclusion that a high

number of bursting disc were required to cover local overpressure effects and provide sufficient venting area. One such design made use of a total of more than 40 discs connected to oil containment tanks such as illustrated in Figure 18 below.

Figure 18: Transformer equipped with a 40 rupture discs depressurization system

Chapter 5: Fire Risk and Performance Analysis

5.1 Introduction

The aim of this chapter is to provide an overview of fire safety performance evaluation for a transformer as well as its installation.

- Performance evaluations do not answer the question: Was a transformer designed and installed in accordance with applicable codes and standards?
- Rather, it examines the questions: Will its protection layers perform the function for which it was intended? When required?
- The focus in performance evaluation is on understanding behaviour, not on regulatory compliance.

5.2 Performance Analysis

The prevailing assumption is that fire safety can be achieved through a combination of common sense and the enforcement of regulatory practices, i.e. a prescriptive approach to fire safety. However, today's transformer installations are rarely simple and unchanging. Their complexities require a more effective approach to fire safety, given the uncertainties surrounding its design, construction, operation and maintenance.

There is a tendency, particularly in the reports of public inquiries following a disaster, for a detailed range of prescriptive measures to ensure this never happens again. Such prescriptive requirements have met with success in reducing losses. There is no doubt that the use of standards of care, i.e. good practices, helps to reduce risks. But, they provide no means of measuring the level of safety of a complex system such as a substation. Therefore, an effective approach to fire safety is needed to deal with the complexities and changes that exist in substations. This chapter proposes that performance analysis recognize the multifaceted approach to safety so as to help engineers to provide effective safety.

Figure 19 provides an overview of performance analysis steps.

5.3 Understanding the Problem and Identifying System Features

These two essential stages of the performance analysis identify how the transformer installation operates and functions as well as the potential fire scenarios:

- what is at risk (people, special property, function, neighbours and the environment);
- what is important regarding potential fire losses;
- and efficiently documents the important risk management information.

In other words, they describe the installation and its site features that influence fire safety performance and the associated risks.

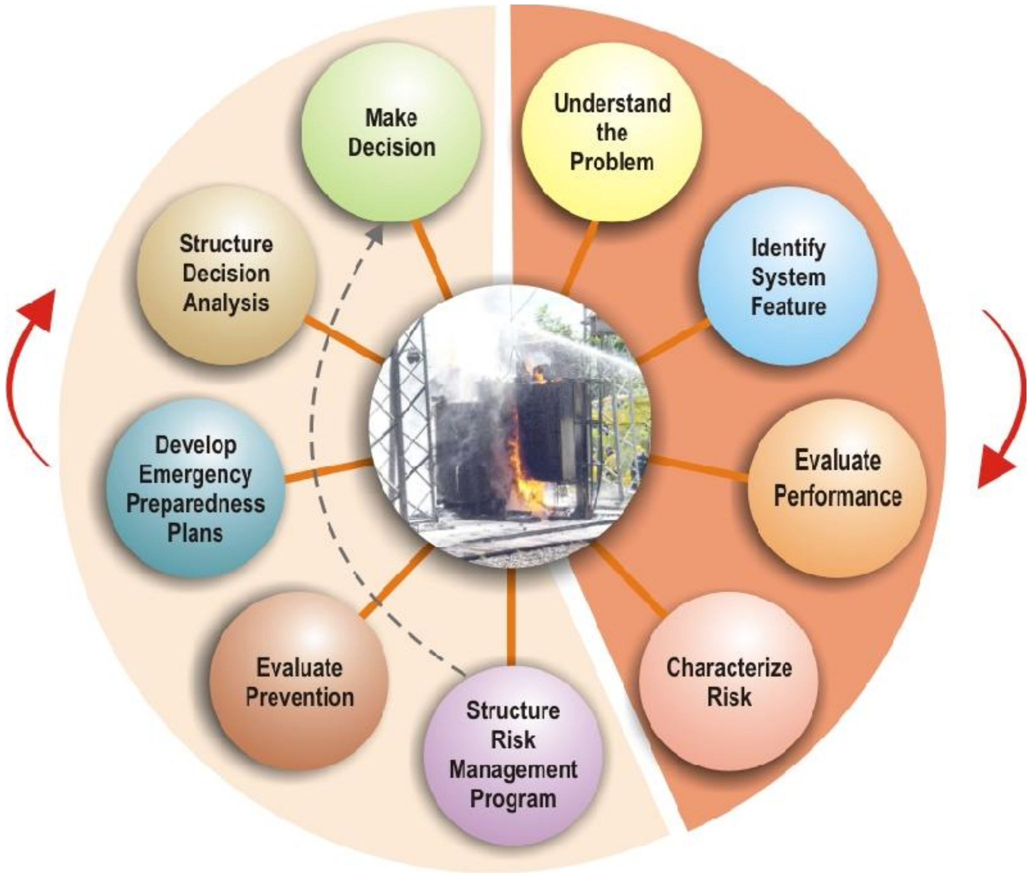


Figure 19: Performance Fire Risk Management

The following questions aim to show how understanding the problem, Figure 20, can help organizations to make appropriate decisions. Ignoring these issues during the life cycle of the transformer and its installation can lead to inefficient safety process activities.

1. *What are the organization's goals?* Should be non-controversial statements that are measured qualitatively, i.e. provide physical safety for workers and the general public.
2. *What are the organization's loss objectives?* To support the above goals, i.e. no loss of life and no fire spreading beyond its source.
3. *How will the organization achieve its loss objectives?* By ensuring the integrity of the transformer tank and its protection layers with proper design, inspection and maintenance.
4. *What indicators will meet the organization's goals and loss objectives?* After stakeholders' goals and objectives have been established, the next step is the selection of performance criteria. This criterion can take the form of damage indicators (i.e. a threshold values) or follow applicable codes such as NFPA 101 or NFPA 810.The damage indicator utilized should come from technical documents and their selection should be thoroughly explained to and documented for stakeholders.

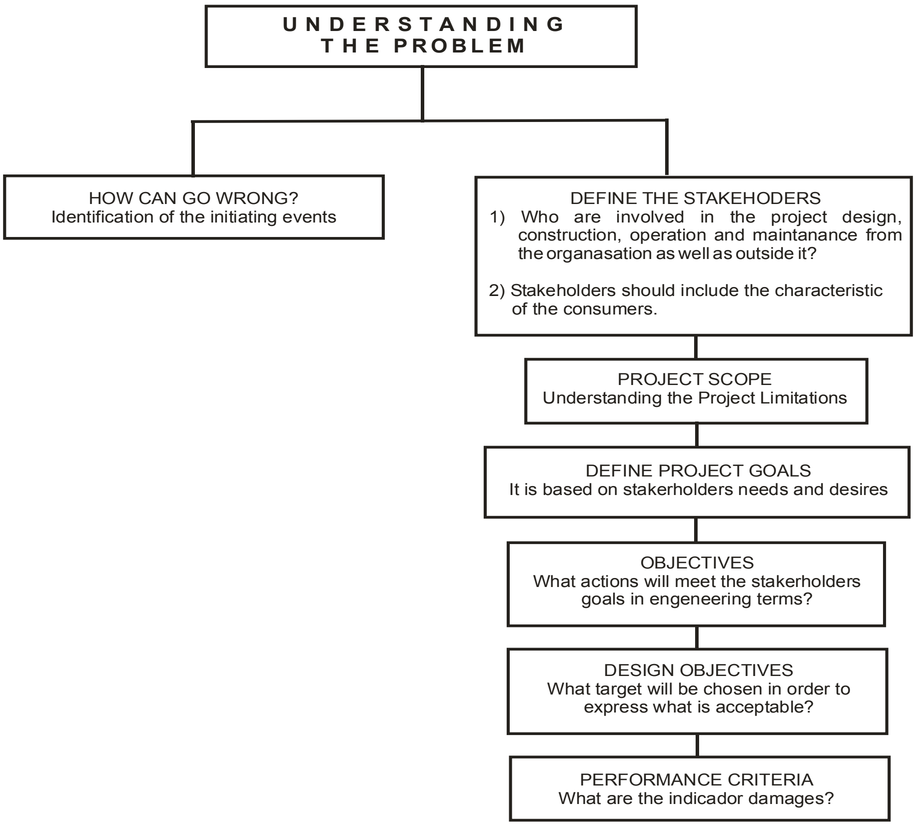


Figure 20: Understanding the problem

Understanding the problem means understanding how protective layers of transformer installation will react during an emergency situation, such as transformer explosion. This process begins by establishing the level of risk acceptable to the stakeholders. The responsibilities, degrees of authority, objectives and possible conflicts among stakeholders should be identified during the understanding the problem stage.

Understanding the limitations of the installation (i.e. project scope) in a fire situation is achieved by establishing the limits of the performance analysis. These limits include: installation project constraints, regulations and budgetary parameters. Identifying the limitations of the installation in a fire situation include:

1. Understanding how the installation will function and operate. This establishes the installation's layers of protection and identifies other undesirable interactions that may influence its performance.
2. Understanding how the installation's layers of protection will react in the case of a transformer fire. By gaining an understanding of how the layers of protection work, it is possible to identify what is at risk and the sensitivity of the target.
3. After understanding how the installation's layers of protection will behave during a transformer fire and how unacceptable interactions could pose a threat to people, property, function, neighbours and the environment, then it is possible to characterize the risks.

In this way, a complex system such as a transformer installation can be divided into small subsystems. Understanding the problem begins with the simplest subsystem and moves up to more complex ones. It is crucial to understand the details of each subsystem and their interactions and to produce likelihood estimates. The consequences of transformer fire can thus be quantified.

5.4 Evaluating Performance and Risk Characterization

This section analyzes the expected extent of the transformer fire, smoke, and structural collapse. A functional performance analysis uses the previous information with other on-site observations and fire knowledge to analyze fire suppression. This analysis provides an understanding of expected system or transformer fire conditions and the ease and likelihood of fire control and extinguishment. Expectations about the elapsed time to target spaces damage and structural collapse performance may be estimated with greater confidence. Collectively, fire behaviour from ignition to extinguishment, the associated smoke conditions, and structural responses for the fire duration describe system fire performance.

Performance evaluation goal is to understand the range of performance scenarios in order to paint a likely picture of the installation's behaviour in the event of a transformer fire or explosion, Figure 21**:** Transformer Fire Performance. This understanding, combined with the information gathered in order to understand the problem, provides the basis for characterizing the risks.

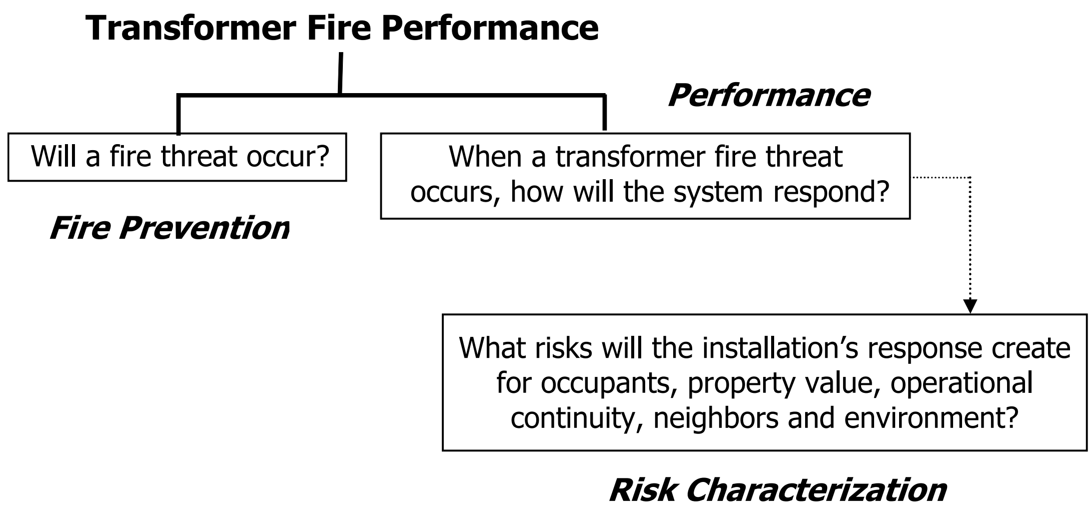


Figure 21: Transformer Fire Performance

The purpose of Risk Characterization is to understand the target's response to adverse physical phenomena. Performance criteria provide a consequence measurement tool by establishing ranges and limits for the target and potential damage to the system.

5.5 Structuring a Fire Risk Management Program

Structuring a fire risk management program starts after characterizing the risks. However, much knowledge will have been gained during the evaluations and some ideas will have been formulated during that process. This step involves making a conscious effort to put together a fire risk management program. The process may continue in parallel with other activities because alternatives will depend on or be influenced by fire prevention, emergency planning, and decisions relating to actions.

5.6 Evaluate Prevention

The **evaluation of the fire prevention** involves two stages. One is the traditional prevent transformer failure that could lead to a transformer fire or explosion. The second considers the fire from other equipment or building near the transformer. The ease and speed with which the fire grows as well as the impact on the transformer depends on the fuel and heat flux.

The concept of design fire is an essential part of every fire component evaluation, because it affects fire protection performance. The design fire identifies the fire rate-of-heat release, the speed of fire growth of a series of scenarios, the energy incident on a target. The design fire can be estimated using the fire and explosion models available on the literature. The vulnerability models provide an estimation of the effects of the physical phenomena to the receptors (i.e. people, structures/building and environment).

The type of fire protection for oil insulated transformers depends on the size and criticality of the transformer. A single transformer under 10,000 kVA could be protected by portable extinguishers. A single transformer over 10,000 kVA could have hydrant protection. Single transformer over 100,000 kVA could have a fixed automatic water spray system. Multiple transformers over 10,000 kVA could also be separated by sufficient clear space and/or non-combustible barriers between the units or could be protected by a fixed water spray system.

The application of a water spray to a transformer oil spill or fire can control or extinguish the fire by emulsification of the oil. When water and oil (immiscible liquids) are agitated together and one of the liquids dispersed throughout the other it causes a cooling effect on the oil surface and prevents the release of flammable vapour.

If water is unavailable, a dry chemical system should be considered as a suitable alternate, especially if the transformer is in an enclosure. Dry chemicals are effective for extinguishing oil fires, but due to limited capacity, are generally second choices to water. For outdoor installations, the system should be designed to operate successfully against adverse winds. A carbon dioxide fixed system is usually of questionable value outdoors due to winds effects. Although foam is effective, it may act as a conductor of electricity. Foam should not be used on or near energized equipment. A combination of foam to starve the fire of oxygen and water to lower the temperature of the fire is used in some jurisdictions. Dry pipe fire suppression systems, must be used where sub –zero temperatures is a possibility.

Passive fire suppression consist of barriers, such as space separation, fire resistance walls and enclosure that confine the oil in the event of oil leakage or tank rupture. If an automatic fire suppression system is present, it reliability to operate successfully depends on the project, installation and maintenance (Figure 22). The project describes manufacturing quality control of all water spray components (i.e. water spray nozzles, pipe and tube, joining of pipe and fittings, hangers, control valves, etc.). NFPA 15 describes water spray protection design for transformers. Installation is related to the quality control during construction. The success of the system operation depends on long term maintenance of the system. This is a major concern as fires can occur many decades after installation when the performance of the fire suppression system could have degraded.

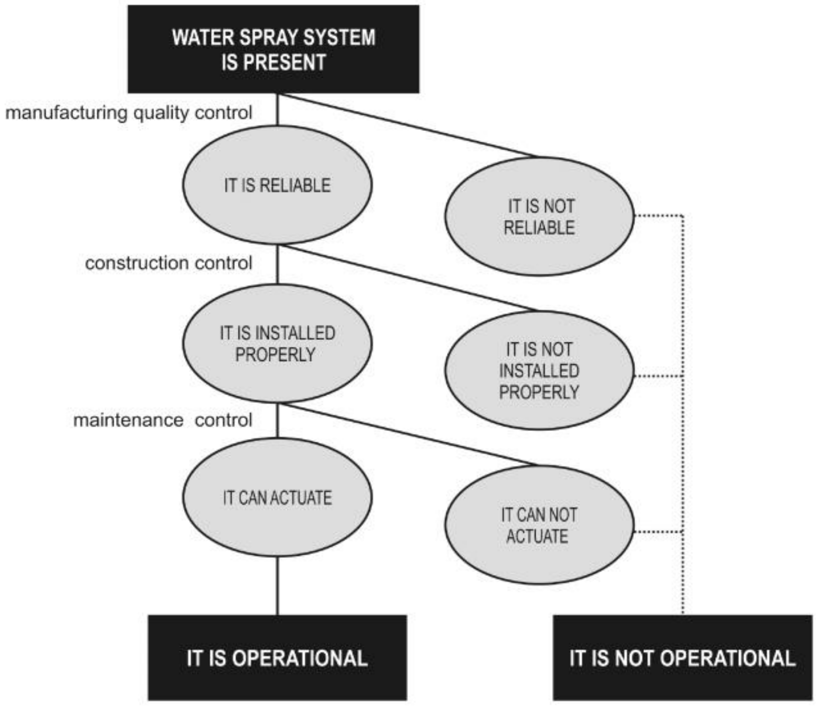


Figure 22: Reliability of the Water Spray Systems

A water spray system usually involves heat actuated detectors operating an automatic mechanical flooding valve to supply water to spray nozzles arranged over and around the unit being protected. When the detectors are activated a number of system components must function to deliver the water to the nozzles. It is essential to have adequate pressure and flow rate. The expected performance of the water spray system could be evaluated based on information about reliability and operational effectiveness, as shown in Figure 23 and Figure 24.

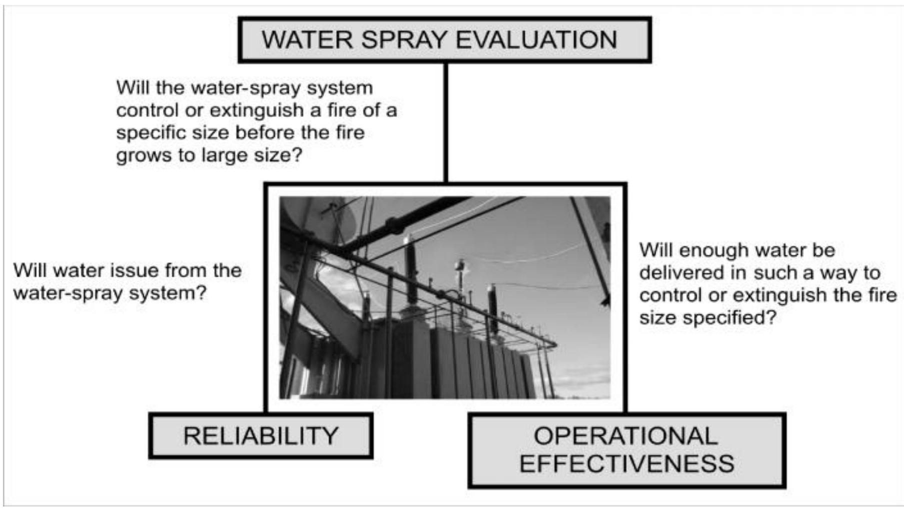


Figure 23: Evaluation of Water Spray Systems

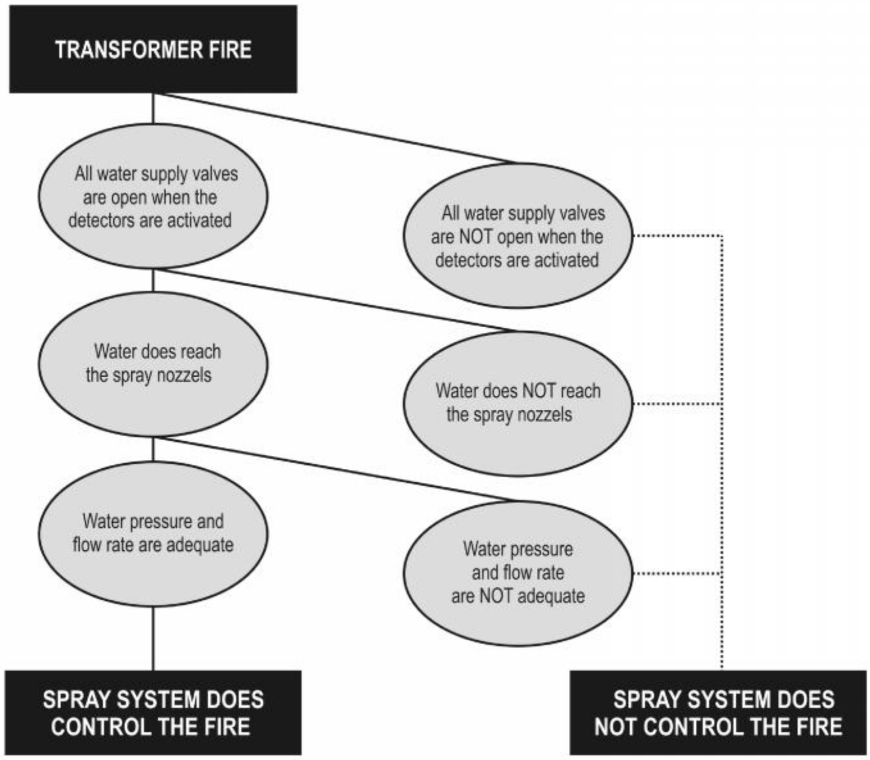


Figure 24: Success or Failure of the Agent Application

5.7 Emergency Planning

The emergency plan provides a strategy for saving lives, property, and the operational continuity or function of the system. The knowledge gained from the performance analyses provides a basis for identifying concrete actions to be taken in the event of a transformer fire.

5.8 Decision Analysis and Management Decisions

The primary goal of **DECISION ANALYSIS** is to organize feasible alternatives to concisely inform a decision-maker of courses of action. Each alternative has different advantages, disadvantages, costs, effectiveness, and potential consequences. Clear communication of outcomes and costs is fundamental for a decision analysis structure. When managers base risk outcomes on the understanding that emerges from performance evaluations, the effect of proposed changes can be described relatively quickly and easily. Therefore, the knowledge derived from a performance analysis enables one to recognize rational potential changes in the system and their effect on performance. These potential changes may be incorporated into candidate risk management programs to enable decisions to concentrate on the big picture and the associated costs. The choice may be to do nothing, select one of the alternatives, or investigate other changes. **MANAGEMENT DECISIONS** should be based on a clear understanding of the system's performance and associated risks.

5.9 Consequences of Transformer Fires

Liquid fuel may burn in an open storage container or on the ground in the form of a spill. Figure 25 shows a transformer involved in a pool fire. When spilled the flammable liquid may form a pool of any shape and thickness and may be controlled by the confinement of the area geometry such as a curb or dyke. Once ignited, a pool fire spread rapidly over the surface of the liquid spill area. Pool fire in a transformer may result from either rupture at the oil end of the bushing housing or the tank rupture when oil is expelled.

Figure 25: A transformer involved in a pool fire

The thermal radiation from a pool fire depend on a number of parameters such as composition of the hydrocarbon, size and shape of the fire, duration of the fire, its proximity of the target (i.e. the object at risk) and the thermal characteristics of the object exposed to the fire. The objective of this section is to identify the best and simple techniques which could be used in the daily routine of an electrical engineer to estimate the heat release rate from a transformer fire.

$$q = q_{conductive} + q_{convection} + q_{radiative} \qquad \text{Equation 4}$$

A pool fire with a diameter greater than about 1 meter, the radiative term in Equation 4 dominates the heat flux to the pool, because the flame becomes a large, optically thick, radiating blackbody. This is the region of interest since diameter of bushing base of a power transformer is assumed to be greater than 1 meter.

The general equation for a pool fire heat release rates with unlimited air access is given by Equation 5. Where:

- Q is the chemical heat release rate (kW),
- m'' is the mass burning rate per unit surface area (g/m^{2}s),

- ΔH_c is the net heat of combustion (kJ/g),
- x_{chem} is the combustion efficiency and
- D is the pool diameter (m).

$$Q = \frac{m^{"}.\Delta H_c.x_{chem}.\pi.D^2}{4}$$ Equation 5

An equation for the mass burning rate of burning liquid surface under windless conditions has been given by [46] as follows:

$$m^{"} = m_{\infty}\left(1 - e^{-k.D}\right)$$ Equation 6

Where:

- $m^{"}_{\infty}$ is the asymptotic burning rate for large pools and
- k is an effective absorption coefficient including the mean beam length correction factor.

The mass burning rate - $m^{"}$ and the asymptotic burning rate - $m^{"}_{\infty}$ could be expressed in m/s. In other worlds, the mass burning rate in g/m^2s is determine by multiplying the burning rate (m/s) by the liquid fuel density. According to [47] the burning rate can either decrease or increase in a tank or dyke with a large freeboard or lip height, with decreased burning rates being more common at a freeboard height greater than about 20% of the tank, for a typical transformer oil:

- $m^{"}_{\infty} = 39\,(g/m^2 - s)$
- $k = 0{,}7\,(m^{-1})$
- $\Delta H_c = 46{,}4\,(kJ/g)$
- $x_{chem} = 0{,}84$.
-

Thomas [48] has developed a correlation for the visible length of flame taking into account the wind velocity, which is expressed in Equation 7, where:

- H is the pool flame height (m),
- ρ_a ambient air density (kg/m^3),
- g gravity acceleration (m/s^2) and
- u^* non-dimensional wind velocity given by Equation 8.
- u_w is the wind velocity (m/s).
-

$$\frac{H}{D} = 55\left(\frac{m^{"}}{\rho_a \cdot \sqrt{gD}}\right)^{0,67} .u^{*-0,21}$$ Equation 7

$$u^{*} = \frac{u_w}{\left(\frac{g.m^{"}.D}{\rho_v}\right)^{1/3}} \qquad \text{Equation 8}$$

Reference [48] also gave the following correlation for flame tilt based on data from two dimensional wood cribs.

$$\cos\Theta = 0{,}7\left[\frac{u_w}{\left(\frac{g.m".D}{\rho_a}\right)}\right]^{-0{,}49} \qquad \text{Equation 9}$$

Wind can significantly increase the effective pool diameter and corresponding mass burning rates. The wind tends to both tilt and increase the flame diameter in the downwind direction. Mudan and Croce [49] suggest the following correlation to estimate the increase in flame diameter. However, Equation 10 should be used with caution at very large wind velocities or small pool diameter due to a possible flame blow off.

$$\frac{D_w}{D} = 1.25 \cdot \left(\frac{u_w^2}{g \cdot D}\right)^{0.069}\left(\frac{\rho_v}{\rho_a}\right)^{0.48} \qquad \text{Equation 10}$$

Where:

- D_w is the effective flame diameter in the presence of wind,
- u_w is the wind velocity (m/s) measured at an elevation of 10m,
- ρ_v and ρ_a are the densities of vapour and air, respectively.

The thermal radiation flux from a pool fire can be estimate by a point source model or a solid flame model. The point source model removes most of the geometrical parameters from the calculation. It assumes that all of the radiative energy from the fire is emitted at a single point rather than distributed over an idealized shape meant to represent the fire. It requires an estimate of the total heat release rate-HRR of the fire, and the fraction of that energy that is emitted as thermal radiation. If atmospheric absorption effect are negligible, and the target distance is large compared to the flame height the radiant point source approximation provides an attractive simplification to obtain the incident heat flux on the target, Equation 11.

$$q_r^{"} = \frac{Q}{4.\pi.x^2} \qquad \text{Equation 11}$$

In a solid flame radiation model the thermal radiation flux q_r'', from a fire to a nearby object is given by Equation 12, where:

- F is a geometric view factor that intercepted by the receiving object, i.e. target.
- ζ is the atmospheric transmissivity for thermal radiation, it is a function of humidity and the distance between the radiation source and receiver.
- ε_f is the effective emissivity of the flame, expressed by $\varepsilon_f = \left(1 - e^{-\kappa \cdot D}\right)$ where: κ and D are the attenuation coefficient and pool diameter respectively.
- E_f is the total emissive power of the flame at the flame surface.

$$q_r'' = F \cdot \zeta \cdot \varepsilon_f \cdot E_f \qquad \text{Equation 12}$$

For pool fires greater than a few meter in diameter the effective emissivity-ε_f is approximately equal to one. If the atmospheric transmissivity-ζ was taken as one Equation 12 become:

$$q_r'' = F \cdot E_f \qquad \text{Equation 13}$$

which is the equation proposed by IEEE 979.

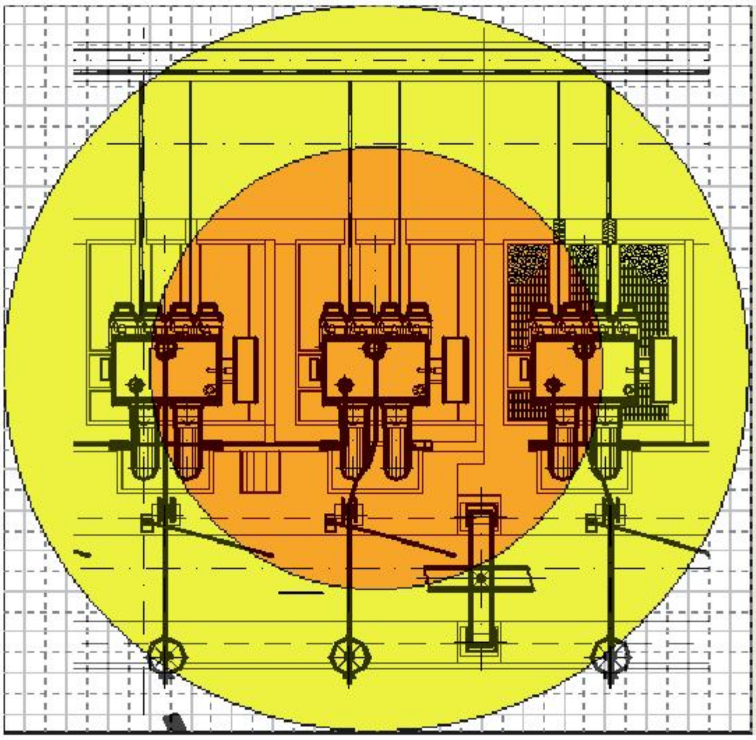
5.10 Case Study of a Pool Fire on a Transformer with 40,000 l of Mineral Oil

The thermal impacts as a consequence of a transformer pool fire are estimated in this section. The radiation energy from the pool fire of various pool diameters is presented in Table 10. It was assumed that the point source model will provide reasonable results for a target that is double the flame height (i.e. 2H meter) away from the fire.

Table 10 : Radiated energy (kW/m²) on a target from a transformer pool fire

Distance to the Target (m)	Pool Diameter and Radiate Energy-kW/m^2				
	1 m	2 m	3 m	4 m	5 m
1	--	--	--	--	--
2	3,6	--	--	--	--
3	1,6	--	--	--	--
4	0,9	5,4	--	--	--
5	0,6	3,4	--	--	--
6	0,4	2,4	6,3	--	--
7	0,3	1,7	4,6	--	--
8	0,2	1,7	3,5	6,7	--
9	0,2	1,1	2,8	5,3	--
10	0,1	0,9	2,3	4,3	7,0
11	0,1	0,7	1,9	3,5	5,7
12	0,1	0,6	1,6	3,0	4,8
13	0,1	0,5	1,3	2,5	4,0
14	0,1	0,4	1,1	2,2	3,5
15	0,1	0,4	1,0	1,9	3,0

In Figure 26 below, a pool fire of 5 meter in diameter is superimposed over a transformer bay layout.



Zone	Energy	Target Distance
(orange)	> 5 kW/m²	11 meters
(yellow)	> 2kW/m²	18 meters

Figure 26: A Pool Fire Transformer Superimposed on Transformer Bay

Personnel Safety:

The exposure time, as a general criterion, will be the time the individual react plus the time taken to reach shelter or to reach a distance where I < 1kWm^2. The effective exposure duration can be express by Equation 14, where:

- t_r is the reaction time in seconds,
- d_o is the distance between the flame surface and the initial position of the individual, in meters;
- u is the escape velocity in m/s (4m/s has been suggested as a general value) and;

- $t_{\exp}$ is the total exposure time in seconds (if the duration of the fire t is shorter than $t_{\exp}$, then $t_{\exp} = t$).

$$t_{eff} = t_r + \frac{3}{5} \cdot \frac{d_o}{u} \left\{ 1 - \left[1 + \frac{u}{d_o} \cdot \left(t_{\exp}\, t_r \right) \right]^{-5/3} \right\} \qquad \text{Equation 14}$$

The transformer could generate a thermal flux of 7 kW/m^2, Table 10. It could cause 99% first degree burn to individuals 10 meters from the flame and exposed to the fire in 60 seconds. Table 11 shows the impact of this transformer fire. The impact was estimated based on the relationship between the *probit* (from probability unit) variable and the percentage. The probability of 7 kW/m^2 cause fatalities, first or second degree burn is 1% with a time exposure of 9 seconds, but according to [50] it is the threshold of pain. The data on time for pain threshold is summarized in Table 12.

Table 11 : Thermal flux impact from transformer fire of 7 kW/m^2

Impact	**Exposure time t_{eff}**			
	6 sec	**60 sec**	**90 sec**	**180 sec**
Lethality - Unprotected	0%	25%	64%	99%
Lethality - Protection clothing	0%	6%	31%	90%
First Degree Burns	0%	99%	99%	99%
Second Degree Burns	0%	45%	85%	99%

Table 12 : Exposure time necessary to reach pain threshold [50]

Radiation Intensity	**Time to Pain Threshold**
1,74 kW/m²	60 seconds
2,33 kW/m²	40 seconds
2.90 kW/m²	30 seconds
4.73 kW/m²	16 seconds
6.94 kW/m²	9 seconds
9.46 kW/m²	6 seconds
11.67 kW/m²	4 seconds
19.87 kW/m²	2 seconds

Property damage:

Of most concern is fire damage to the relay building containing the protection, monitoring and control systems for the whole substation. The loss of the relay building is the worst case scenario as it impacts the whole substation and replacement can take 6 months or longer. In the substation shown in Figure 27 there are two relay buildings. Their structure is masonry with glass windows. The structural thermal performance simulation of one of the buildings during a transformer pool fire was carried out by use of the finite elements method. The distance between the transformer and the relay house is 3.50 meters. 90 minutes after the fire was initiated, the wall temperature distribution showed some wall temperatures to be above 300°C. Such high temperatures can cause wall failure. The structural integrity of the walls, pillars and beams is compromised 117 minutes after the fire started. On the other hand, 45 minutes after the fire is initiated, the glass windows will break. Therefore there will be a rapid growth of the gas temperature inside the relay building. The gas temperature distribution analysis showed that temperatures higher than 70°C could be reached in approximately 30 minutes. At about 70°C, thermal damage to electronic components is irreversible.

Figure 27: Layout of the substation

As the high radiation energy from a transformer pool fire increase the temperature of the structures nearby their strength and stiffness are reduced. This may lead to unacceptable deformations or structure failure of the high voltage bus bar Figure 28.

Figure 28: Deformation of the High Voltage Landing Span Structure after a Transformer Fire

When the applied load becomes equal to the load-bearing capacity, structure failure will result. During the present study, two structural analysis of an unprotected steel member (i.e. tension and compression member) were carried out as presented below. The analysis was based on the EUROCODE 3 part 1-2. It suggests a simplified method to estimate the temperature and the load-bearing capacity. In other words, the temperature is assumed uniform over the cross-section, and the effects real structures' restrictions are not taken into account.

- *Case 1- Tension member:*
    - Unprotected steel section – MR250 steel;
    - ½ I cross section 152 mm x 18.6 mm;
    - Length of member: 4,5 m
    - Tension effort in member: 224 kN;
- *Case 2- Compression member:*
    - Unprotected steel section – MR250 steel;
    - 2 C cross section 305 mm x 30.8 mm;
    - Length of member: 4,0 m
    - Tension effort in member: 200 kN;

Time to failure is a function of radiation intensity, material properties and type of loading. An example for case 1 and 2 is set out in Table 13 below and shown in

Figure 29 and Figure 31 for 20 kW/m^2 and 7 kW/m^2, respectively.

Table 13 : Time to failure of the structure members in case 1 and 2

Energy (kW/m²)	**Case 1: Tension Member Section Factor: 271 m^{-1}**		**Case 2: Compression Member Section Factor:175 m^{-1}**	
	Temperature (°C)	**Failure Time (min)**	**Temperature (°C)**	**Failure Time (min)**
20		10		11
18		12		13
16		16		15
14	507	No Failure	415	18
12		No Failure		23
10		No Failure		35
08		No Failure		No Failure

(NF =

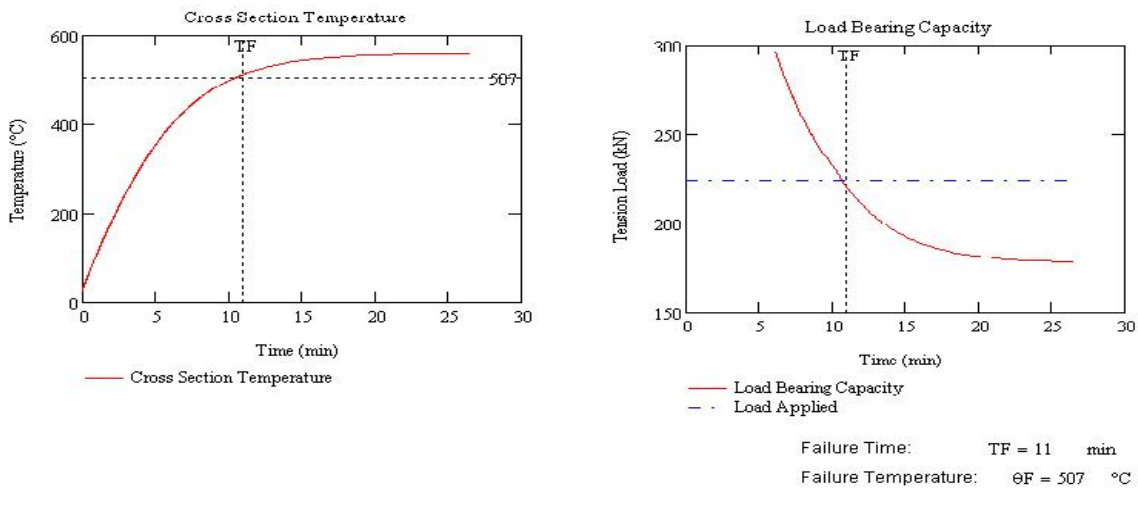


Figure 29: Case 1: Temperature versus time and load-bearing capacity versus time graphs to an exposed energy of 19 kW/m²

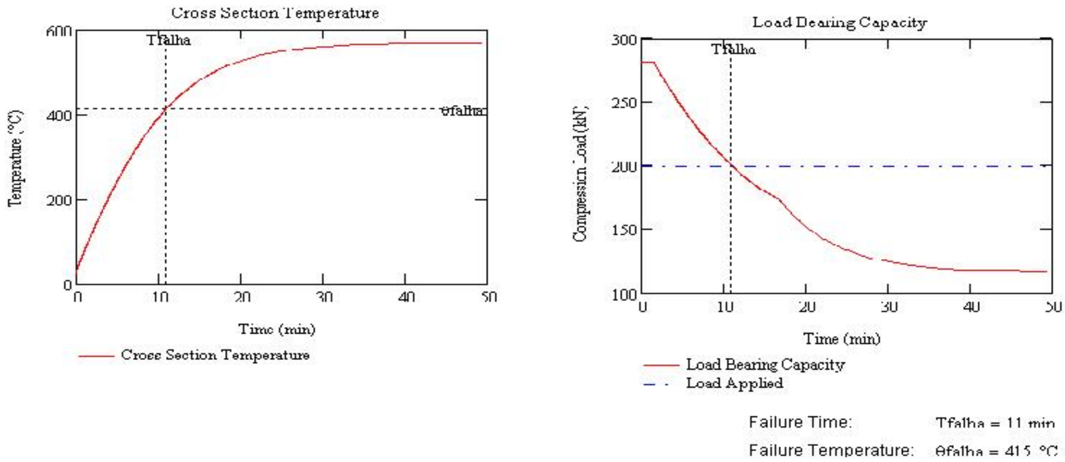


Figure 30: Case 2: Temperature versus time and load-bearing capacity versus time graphs to an exposed energy of 20 kW/m²

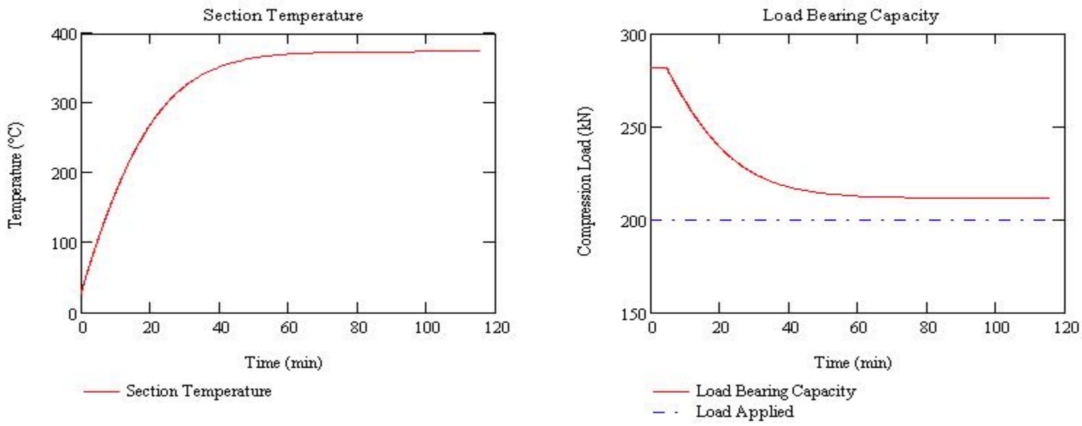


Figure 31: Case 2: Temperature versus time and load-bearing capacity versus time graphs to an exposed energy of 7 kW/m²

The structure failure depends on fire severity, steel area exposed to the flames, the applied load and support conditions. Tension member failures (case 1) are associated with energies higher than 16kW/m^2. Compression member failure is probable with energies around 10kW/m^2. For the fire simulation, neither tension or compression members failures are foreseen, but scenarios are subject to uncertainty.

5.11 Conclusions

The life cycle of a transformer installation involves complex operations which deal with a variety of day-to-day decisions to keep the business operating. Fire safety is normally low on the list of immediate needs. Fire safety moves up the agenda when a fire occurs and the organization's financial health and image are affected.

Fire risk management can mean many different things to the organization. For some companies it involves understanding specifically what is at risk, for others it is having a sense of its relative severity, and a third course of action is to make a decision about what to do about the risk.

Sometimes these issues are addressed in a rigorous, at others in a casual manner, sometimes with a mixture of both. Some view fire risk management exclusively in terms of a decision as to what type of insurance to purchase.

Fire safety performance is dynamic. At one point in time, one may be certain that a failure will not occur. At others, one may be confident that one will occur. Between these positions there is a window of uncertainty. Fire safety process performance evaluation requires a different way of thinking from the traditional practices, because a narrow emphasis on what organizations should do offers little help.

Chapter 6: Fire Risk Mitigation Options for Transformers

6.1 Introduction

This chapter will discuss some of the options transformer users have in mitigating the risk of transformer fires. Most of the risk reduction measure carries additional upfront capital cost and the owner of the transformer should make careful consideration (possibly in consultation with other stakeholders) of what level of fire risk is acceptable for the specific transformer or class of transformers, given its application and location, both in the network and also to its surroundings.

It is evident that the fire risk which may be acceptable for a 30 MVA sub-transmission bulk supply transformer located in a two transformer open air widely spaced substation is quite different to that of a 600 MVA generator step up transformer located close to the turbine hall in a power station, or a 100 MVA bulk supply transformer located in a compact urban substation where land cost is high and the risk to both human life and adjacent valuable properties, or the extreme case where the transformer is located in the basement of a high rise office tower.

In this chapter we will discuss the risk mitigation measures available for transformers.

However, it should be understood the whilst risk of transformer fires can be reduced significantly by using one or more of the available risk mitigating options, none of these mitigating options can completely eliminate the risk of a fire in a mineral oil immersed transformer. It should also be understood that it is not possible to cover all possible risk mitigation measures in a short guide document like this brochure.

It is therefore strongly recommended that transformer user makes their own assessment or seeks further guidance on what type of risk will be reduced and even more importantly assess what risk will not be reduced from each mitigation measure before deciding what risk mitigation measures should be applied for their specific installation.

Protection strategies available for potential victims of a transformer fire - other substation assets will be considered and discussed in Chapter 7:

6.2 Minimizing the Risk of Transformer Fires

The first step in minimizing the risks of a transformer fire, is to minimize the risk of a transformer failure causing the fire occurring. This begins with the transformer specification (and may include increased insulation levels and reduced temperature rise) and extends to maintenance and operating practices, but also includes the electrical protection installed to clear electrical faults rapidly and protect the transformer if an external or internal fault occurs.

The second step is directed towards minimizing the risk of a transformer failure developing into an oil fire, if a transformer failure does occurs.

The possibilities for reducing this include: Use transformers which do not use mineral oil as insulation and cooling medium, and for mineral oil and non mineral oil filled transformers, the choice of low explosion risk types of bushings, avoiding cable terminations on the transformer terminals and prevention measures applied to the tank to minimize the risk of tank rupture and uncontrolled release of oil and arcing gases, and for indoor installation avoiding oil and arcing gases coming in contact with oxygen (air) if released.

The steps listed above relating to the transformer will be discussed in further detail in the reminder of this chapter, and for steps related to the substation installation in Chapter 7.

6.2.1 Standard Tanks with Pressure Safety Margin above PRV Opening Pressure

When considering failure rates, there appears to be a correlation between failure rates and specified requirements in so far that utilities who have more demanding specifications and choose to buy transformers from well reputed manufacturers with proven ability to supply high quality transformers, also have lower failure rates than transformer users who have less demanding specifications and is less discerning in their choice of suppliers.

Specifications from these transformer users will in general have additional requirements to those listed in IEC 60076, IEEE C 57 or equivalent national standards in terms of permissible flux density, temperature rise insulation levels and requirements with regards to tank strength expressed either in terms arc energy containment capability or pressure withstand capability. They typically also specify rating of bushings and tap changers with margin above the minimum requirements for the transformer and require that major and critical components such as bushings, tap changers be sources from suppliers prequalified by the end user. They also pays critical attention to the sourcing of other key components such as copper conductors, insulating materials and important ancillaries such gas and oil surge relays, temperature indicators, pressure relief devices, conservator bags.

Their specifications typically have more stringent test requirements and include additional tests to those required for compliance with the above mentioned standards. They often include tests for verification of overload capabilities to the full extent of intended emergency overloads in terms of over-voltage and over-current, both in magnitude and duration. They will have stringent requirements in terms of: permissible levels of partial discharge during overvoltage tests, temperature rise limits during over-current tests and specify limits for permissible increases in gasses dissolved in the oil from before to after completion of these tests.

They also conduct detailed tender evaluation on offers from prequalified tenders or make careful assessment and/or Quality Assurance Audits of potential new suppliers. They conduct pre- and/or post order design reviews to ensure specified requirements are fully understood by the supplier. They inspect work in progress and witness critical tests to ensure that the transformers meet or exceed specified quality and performance requirements. (Cigre Technical Brochure 528 provides Guidance on Preparing Specifications for Power Transformers, Cigré Technical Brochure 529 provides Guidance for Conducting Design Reviews for Power Transformers Cigre Technical brochure 530 provides Guidance for Transformer Factory Capability assessment for Power Transformers).

6.2.2 Enhanced Maintenance Practices

Enhanced maintenance practices can reduce the probability of in-service failures and consequently the probability of a transformer failure causing a fire.

The most critical areas to monitor are: The level of the critical gasses dissolved in the oil, the oil quality, the moisture level and condition of solid insulation and especially the condition of tap-changers and bushings. The latter in terms of freedom from leaks, absence excessive increases in tan delta, and capacitance not increasing more than 3-5% beyond the “when new” level. Transformers should not be allowed to remain in service if the capacitance of the condenser bushings has increased by more than 5 %, as a bushing failure have a high probability of causing a transformer fire. Tap-changers should be serviced in accordance with the suppliers’ recommendation unless the transformer owners own experience justifies it to be done otherwise. Off Circuit tap-changers should be operated across the whole tapping range several times periodically to wipe the contacts and maintain low contact resistance.

Enhanced maintenance can ensure incipient defects are detected and remedied or the transformer is removed from service before a defect progresses to the point where it develops in a catastrophic failure.

The CIGRÉ Technical Brochure 445 provides guidance on the appropriate levels of maintenance for the required reliability.

6.2.3 Operating Practices

Operating at high loads beyond the nominal rating carries additional risk. (With loading values beyond the nameplate rating, all the individual limits stated in IEC 60076-7 should not be exceeded.) Transformer users, who intent to load their transformers beyond the rating(s) stated on the rating plate, should ensure that the transformer and all its elements such as bushings, OLTC's and CT's are capable of such loading and is in fit condition for the intended loading. Ideally the transformer should have been specified and tested at manufacturers work for the intended loading. If this has not happened then the user should as a minimum precaution, check and ensure that all the series elements such as the tap-changer, bushings and bushing line/draw leads and the CT's all have sufficiently high current rating for the intended overload and that the conservator can accommodate the increased volume expansion of the oil without overflowing. If the transformer is located indoor, or in a partial or fully enclosed sound enclosure, then it should also be ensured that the airflow is sufficient for the cooling the transformer when it is operating at higher losses. Dissolved gas analysis should also be performed on oil samples, ideally before overload commences and again within 24 hour after commencing the overloading and again after one week, if the over loading exceeds 1.2 p.u. or if the hot spot temperature of winding, lead or flux shields > 115 ^{o}C. Infrared scan can also be used to check that terminals and tanks do not suffer from excessive localised hotspot temperatures.

6.3 Protection

6.3.1 Electrical Protection

Fast reliable, duplicate protection together with a fast acting circuit breaker is the most important defence in limiting the risk of potential transformer failures from through-faults. Fast protection minimizes the risk of a through fault casing the failure of the transformer, and in the event of a transformer failure limits energy injected into an arcing fault within the transformer tank and thus reduces the risk of tank rupture. Good protection together with a fast acting circuit breaker can achieve interruption within 2.5-3.5 cycles, 50-70 ms for 50 and 60 Hz systems. The arcing energy for a given arcing fault is directly proportional to the duration of the arc, so minimizing the arcing time of an in tank arcing, fault reduces the risk of tank rupture and therefore the risk of oil spill and fire.

Guidance on protection schemes for protection of transformers is outside the scope of work by SCA2. Readers are referred to CIGRÉ Technical Brochure 463 - Modern Techniques for Protecting, Controlling and Monitoring Power Transformers [51].

The most common elements of typical transformer protection schemes for the type of transformers covered by this document are listed below:

Over current protection consists of a relay usually connected to a current transformer monitoring the current on the primary side of the transformer

Earth fault protection is usually provided by monitoring of neutral current or by using restricted earth fault protection which can provide an improved and more sensitive protection against earth faults.

Differential protection is connected to current transformers monitoring the ampere turn current in the primary secondary and if applicable also tertiary and other additional windings. The relay is activated if the ampere-turn difference between input and output exceeds a predetermined bias level. Whilst this protection can be very effective in detecting electrical faults within the transformer, its sensitivity is limited by the bias required to allow for inrush current and ratio changes due to tap changer operations.

Over current, Earth fault and Differential protection are used to provide trip signals to the transformer circuit breaker(s).

Other commonly used Protective Devices include:

Buchholz Relay which provides a signal for gas accumulation in the relay caused by discharge or overheating in the transformer this signal is normally used as alarm signal. The relay also provides a signals initiated by oil surge from the transformer tank to the conservator and for oil level falling below the mounting height of the relay, these two signals are usually used as trip signals.

Sudden Pressure Relay is sometimes provided on transformer tanks and on bolt on type OLTC's. The relay is activated by sudden increase in tank pressure (rate of pressure rise) and is it fitted with a contact which can be used to provide trip signal to a protective relay.

OLTC Oil Surge relay is mounted in oil pipe connecting the OLTC conservator to the diverter or combined diverter/selector tank and like the Buchholz relay provide trip signal on oil or gas surge from arcing faults within the diverter switch or combined selector diverter tank.

Pressure Relief Valve [PRV] typically consists of a spring loaded diaphragm which opens a pre-determined pressure to provide pressure relief by venting of oil and/or gases. It is usually fitted with a contact which can be used to provide trip.

Rupture Discs of various types/design are in use as an alternative to PRV's. They can open faster than spring loaded PRV's and has less oil flow restriction. Rupture disc systems from some suppliers include signalling devices which can be used to generate trip signals and/or activate nitrogen injection when activated.

Protection by over-fluxing relay: Over-fluxing can be a serious risk if the frequency falls by more than 5%, especially if it coincides with a voltage rise following load shedding or other system disturbances. Over-fluxing of more than 10-20 % can only be sustained for very short period unless the transformer is designed with special low flux density. This type of protection is commonly used for generator step up transformers.

Over temperature protection: It is common to monitor the top oil and the winding hot spot temperatures and include contacts for alarm and trip on the temperature monitoring devices. Some utilities choose not to have such devices connected to a trip relay, but prefer to monitor transformer for excessive temperatures manually to reduce risk of an unscheduled load shedding.

Duplicate Protection: It is common to provide duplicate protection [x and y] for larger and important transformers. The elements duplicated are usually, the protection trip relays, circuit breaker trip coils and the most important electrical relays (differential and earth fault) and the current transformers supplying them, whereas other trip functions are normally distributed between the two trips relays. Other alarm, control of monitoring devices are also commonly used on transformers, however as their role is outside the scope of this document, they will not be discussed here.

Current and Voltage Limiting Devices:

Reducing or limiting the current through the windings during external faults can reduce the risk of internal winding faults and also reduce the arcing current for internal fault and thus provide a significant reduction in arcing energy, the risk of tank rupture and consequently the risk of a transformer oil fire. Common methods of reducing the fault current include:

- Increasing the impedance of the transformer or using an external series reactor. The disadvantages of both of these are higher losses and higher voltage drop through the transformer and the reactor with increased loading losses.
- Use of neutral earthing: resistor, reactor or an earthing transformer. These devices only reduce fault current for line to ground faults, the most common fault mode, but not for phase to phase or three phase faults.
- Use of current limiters, devices such a fuse which interrupts the supply to the load, if a short circuit fault develops on the load side of the device. It can be effective in limiting fault current; however its application is at present limited to medium voltage levels below 50 kV.

6.3.2 Overvoltage Protection

Lightning strikes and other transient over voltages can cause dielectric breakdown and when they occur it is often at or near line terminals, cable terminations, bushing line leads or at the line end of the winding i.e. locations of high arcing energy.

Metal oxide surge arresters are therefore an important part of transformer protection in reducing the risk of a transformer failure. All line terminals of transformer should be protected by surge arresters. This is particularly important, if the transformer is connected directly to overhead lines, open bus bars and also where the last tens or some hundreds of meters are supplied through cables. For such installations it is important that surge arresters are provided both at the overhead line/cable interface and also at the transformer terminals as voltage reflection from the higher surge impedance of the transformer windings and the overhead line can cause voltage build up in the cable and at the transformer terminals and consequently initiate insulation failure.

6.4 Less-Flammable Insulating Media

It is possible to virtually eliminate the fire hazard associated with transformer oil fires by selecting dry type transformers or gas insulated transformers and reducing the fire risk significantly by use of less flammable insulating/cooling fluids.

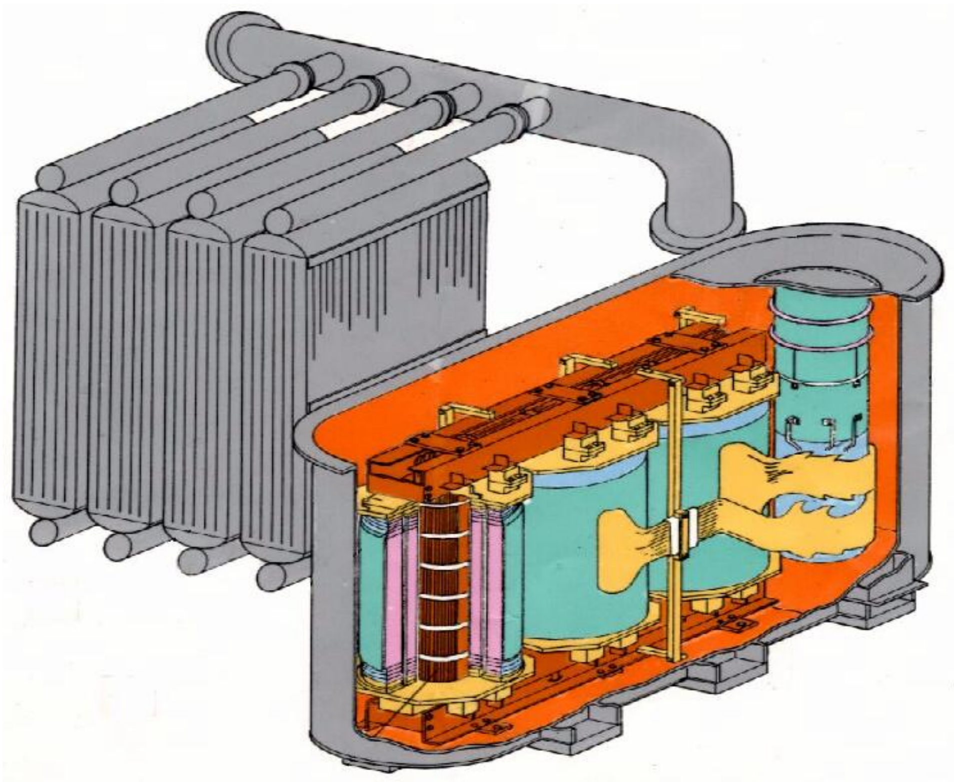
6.4.1 Dry Type Transformers

As the scope of this document is for transformer with their highest voltage $\geq$ 66 kV, dry transformers will not be discussed in this document as they are only in common use at voltage levels below 66 kV, although it is recognised that they have very low, virtual negligible fire risk.

6.4.2 Gas Insulated Transformers (GIT)

Gas insulated transformers (GIT) using the inert gas sulphur hexafluoride (SF_6) as a cooling and insulating medium have excellent non-flammable and non-explosive characteristics. GITs are the only nil fire risk and virtual explosion proof transformers for voltages $\geq$ 66. GIT's are widely used in major indoor city substation in Japan and other Asian cities and also in some countries outside Asia including Australia. Because of their virtual nil fire risk they have been installed in office buildings, underground substations in urban business districts. They are often located adjacent to, or in same room as gas insulated switchgear [GIS] which reduce the cost of inter connections. GIT's have virtually absolute fire safety. However, the (SF_6) is a very potent green house gas and the potential leakage to the atmosphere is of concern. Some users have taken significant precaution to minimise the release of SF_6 gas in the event of leakage or unintended spill or accidental release of such gases. The initial cost of SF_6 transformers is significantly higher than oil filled transformers. GITs are not commonly used in Europe or the Americas.

The construction of a gas-insulated transformer is basically the same as an oil-immersed transformer (OIT), with the exception of insulating material and cooling medium. Therefore, broad experience of OIT technology can be applied to GIT design, manufacturing and maintenance. Figure 32 shows an example of GIT structure, and summarizes the basic features comparison between OIT and GIT.



		Oil Immersed Transformer (OIT)	Gas Insulated Transformer (GIT)
Insulation / Cooling		**Insulation Oil**	**SF_6 Pressure 0.14 or 0.43 Mpa (20℃)**
Solid Insulation Material		Oil Impregnated Paper, Pressboard	PET film, PPS film, Aramide paper, Pressboard
Thermal Class		Class - A (Max 105℃)	Class - E (Max 120℃)
Conservator		Necessary	Unnecessary
On-Load Tap Changer	Diverter Switch	Arcing Switching in Oil	Vacuum Interrupter
	Tap Selector	Slide Contact	Roller Contact

Figure 32: GIT Structure and Features

There are two types of GITs, determined by the internal pressure of the SF_6 gas:

- low-pressure types (0.12 ~ 0.14 MPa at 20° C);
- and high-pressure types (0.4 ~ 0.43 MPa at 20° C).

The latter type operates at higher gas pressure in order to boost the insulating and cooling performance of the SF_6 gas. In accordance with Japanese domestic regulations regarding the pressure vessels, if the maximum pressure in a gas insulated transformer is to exceed 0.2 MPa during operation, the transformer tank should be designed specifically as a pressure vessel.

a) Low Pressure GIT 110kV-50MVA

b) High Pressure GIT 275kV-300MV

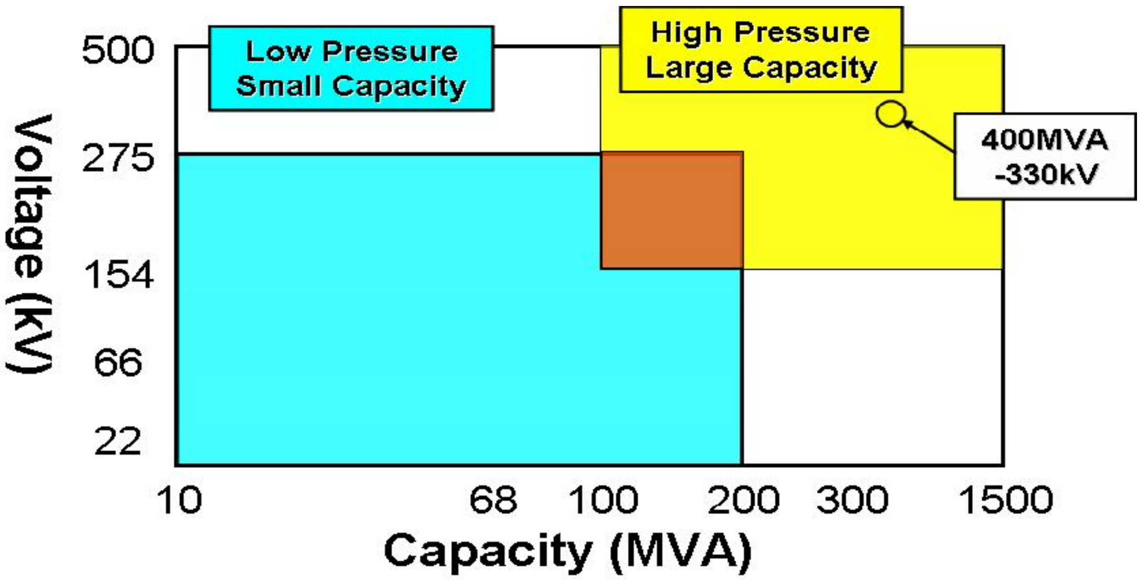


Figure 33: GIT Application Range

6.5 Less Flammable Insulating Fluids

A less flammable fluid is defined as a fluid with a fire point greater than 300°C. Commonly used less flammable fluids include synthetic or natural ester based oils and silicone based fluids.

Whilst the use of such fluids cannot totally eliminate the fire risk they can significantly reduce the fire hazard associated with transformers. But unlike non flammable fluids, less flammable fluids can still generate a short lived fire ball, if the fluid is released as a mist and then ignited. Although the use of less flammable fluids may carry similar risk of tank rupture, their key benefit is that they will not support a long burning pool fire and will in most case not sustain a fire unless energy input is contributed from other sources.

Whilst these fluids can and will burn at sufficiently high temperatures, it is worth noting that in the 30+ years history of less flammable fluids there have, to the best of the knowledge of the WG A2.33 members not been any reported transformer fire incidents involving these fluids.

Historically less flammable fluids have been used in distribution and smaller industrial types of transformers since the polychlorinated biphenyl was banned from use as a transformer fluid in new transformers. In recent years their use have been extended to larger transformers and a few transformers at the 132 and 220 kV system voltage levels are now in use. The interest in their use is not only for their less flammable properties, but for the esters also for their non-toxic and bio-degradable properties.

A major insurer of industrial plant and assets has developed a standard for less flammable transformers. This standard takes advantage of the use of less flammable fluid and adds certain protective and design requirements to prevent the release of the fluid as a mist which can generate a fire ball. Transformer manufacturers who build transformers to this standard can earn the insurers stamp of approval. These transformers are treated by the insurer as having the same low fire risk as dry type, gas insulated or silicone fluid filled transformers. This allows reduced separation and bunding.

It is also possible to apply the Insurers guidance for existing transformers retro-filled with less flammable fluids. Transformers that fall in this category are identified as “equivalent” transformers and would also be considered by the insurer to have the same low fire risk as dry type, gas insulated or silicone oil filled transformers.

Whilst it is possible to retro-fill existing mineral oil transformers with a non flammable or less flammable fluid to eliminate or reduce the fire hazard, it is rarely an economic solution for existing larger mineral oil filled transformers unless it is part of an asset replacement plan or special requirements justifies the cost.

Retro filling of power transformers requires qualified engineering assessment for design considerations to accommodate the differences between mineral oil and other fluids.

Special attention should be paid to:

- the parameters which describe the thermal and dielectric properties of the fluid in regard to a given design
- the compatibility of materials and equipment to the fluid (especially gaskets in order to prevent leakages, operation of the tap changer etc.)
- the applied liquid preservation system

6.5.1 Properties of Less-Flammable Fluids

In the past PCB’s were used in transformers as it did not have a measureable fire point and hence were thought to be an ideal solution. However in the late 1970’s PCB’s were banned from use due to the fact that they are toxic and harmful to the environment. The phasing out of PCB has led to other fluids with high fire point being developed as an alternative to mineral oil. The use of these alternative fluids means that the risk of pool fires can be significantly reduced, since the fluid must be raised to a much higher temperature before it will sustain a fire.

Standard O class transformer oil is commonly referred to as “mineral oil” and has a typical fire point in the range of 120°C to 160°C.

The common, less flammable K-class fluids currently available fall into four categories:

1 High Molecular Weight Hydrocarbon (HMWH)
2 Synthetic Ester
3 Natural Ester
4 Silicone Oil

Table 14 below lists some typical characteristics of mineral oil and less flammable liquids which are relevant for evaluating their use in transformers. A comparison of performance characteristics of low flammability fluids can also be found in Table 3 of IEC 60076-14.

Table 14 : Typical Characteristics of Insulating Liquids

Liquids Properties	Silicone 20cSt	Silicone 50cSt	Ester oil Natural	Ester oil Synthetic	Mineral oil
Density (at 15 °C)	0.95	0.96	0.92	0.97	0.87
Pour point (°C)	< -60	< -50	< - 21	< -55	< - 32.5
Flash point (°C)	> 260	> 310	> 330	> 260	145
Kinematic viscosity (mm^2/s at 40 °C)	16.0	38.0	33	29	8

Typical fire risk scenario is similar to the scenario for mineral oil filled transformers; however the low flammability transformers are superior in combustion performance and have good ignition time characteristics. Testing result of combustion performance has been reported in several papers [52] [53]. The fire of the silicone liquid in open cup tests is smaller than other oils because a silica layer (residue from combustion) is covering the surface of the silicone liquid as combustion progresses and it shut off oxygen the supply to silicone liquid under the flame. However, these properties may be less relevant where the silica layer is mechanically disturbed or the oil is spilling down over a vertical surface which would break up the silica layer.

In the fluids with higher flash point and/or higher fire point, silicone liquids and ester oils have similar good ignition time characteristics. However, silicone liquids have better (lower) heat release rate than all types of ester oils. Silicone liquids and all ester oils have similar good flame propagation velocity characteristics. Silicone has higher cooling capability than esters. Low-viscosity silicone liquids have overall superior characteristics in comparison to esters except for bio degradable characteristics where ester based oils are superior.

6.5.2 High Molecular Weight Hydrocarbon (HMWH)

Introduced in the late 1970’s, these fluids are based on petroleum oils. In order to raise the fire point of the fluid, the lighter fractions are refined out of the oil. This leaves a product that has a high fire point (>300°C), but also higher viscosity, which must be taken into account when considering thermal design. These fluids also tend to have a relatively high pour point, making them less suitable for use in colder climates. Being pure hydrocarbons, these fluids are fully miscible with mineral oil and can be used to retro fill existing transformers. However these fluids are not widely used in transformers.

6.5.3 Synthetic Esters

Introduced in the late 1970's synthetic esters as the name suggests are synthesised by reacting acids with an alcohol to produce the final fluid. These fluids have a high fire point, combined with low pour point (typically <-55°C). They are oxygen stable and suitable for use in free breathing equipment. Synthetic esters are also typically readily biodegradable, bringing extra benefits for the environment. To date these fluids have mainly found applications in distribution transformers and specialist applications such as traction transformers where their excellent high temperature stability is utilised. In recent years there has been a move towards using synthetic esters in larger power transformers to increase fire safety. Although Synthetic Esters typically have a higher viscosity than standard transformer mineral oil, the higher thermal conductivity of these fluids somewhat offsets this, such that their cooling performance is close to mineral oils. Synthetic esters are fully miscible with mineral oil and can be used to retro-fill mineral oil transformers to increase fire safety. However, the fire point and flame point will be with lowered proportionally to the amount of mineral oil mixed into the less flammable fluids [52].

6.5.4 Natural Esters

Since the 1990's, there has been a move towards introducing the use of vegetable based fluids in transformers. Initially, it was limited to small distribution transformers, but more recently also in larger high voltage transformers up to 90 MVA 220 kV [54]. However the number of large transformer using this type of insulating fluid is still small and the in-service history is still very limited for large transformers. So potential users should ensure they have the up to date information on all the aspects of this type of fluid before making the decision to use it in large high voltage transformers. The natural esters are made from a variety of oil seeds, such as soya bean or rape seed. They are usually non toxic and readily biodegradable. Natural esters have a higher viscosity than mineral oil, which must be considered in thermal design, however the higher thermal conductivity of these fluids somewhat offsets this [54]. Natural esters are miscible with mineral oil and can be used to retro-fill mineral oil transformers, however caution must be taken as the flash point may be infringed by small residual amount of mineral oil. (Maximum 4% mineral oil to get a 300^{o}C classification - Refer to "Transformer Fire Protection - Bureau of reclamation"). Natural esters are very hygroscopic and oxidise very readily and therefore require a hermetically sealed design.

6.5.5 Silicone Oil

Silicone oil is also a synthetic product introduced in the late 1970's. It is manufactured via a series of chemical intermediates generated primarily from sand and methanol. This fluid has a high fire point (>350°C) and excellent thermal and oxidation stability. Silicone liquid has the lower kinematic viscosity for below 20 ^{o}C among high flash and fire point liquids (20 cSt), however viscosity changes with temperature and for temperatures above 40 ^{o}C which is the normal working temperature of transformer silicone oil has higher viscosity than both synthetic and natural esters. Refer to [55] for further details of comparative properties of mineral oil, silicone fluids and synthetic and natural esters.

Historically silicone fluid became the fluid of choice for fire safety in distribution transformers and compact design traction transformers, where the high temperature stability is utilised after askarels were phased out. Silicone fluid has found limited applications in larger transformers due to its weaker dielectric electrical strength when compared to other alternative fluids and its tendency to form gels under arcing conditions. Environmental safety is also an issue with silicone oils, as these are extremely slow to bio-degrade. Concern has also been raised with fumes from burning silicone fluid in enclosed spaces. It has been reported [53] the fumes clog breathing apparatus filters and the visibility in silicone oil smoke is very limited. However, WG A2.33 does not have specific information to verify or disprove these points. Although Silicone oil is miscible with mineral oil it can lead to foaming problems in oil processing equipment. For this reason the retro-filling of mineral oil transformers with silicone oil is generally not recommended, and oil treatment equipment used for silicone oil should not be used for other types of insulating oils.

6.5.6 Combustion Characteristics and Test Results

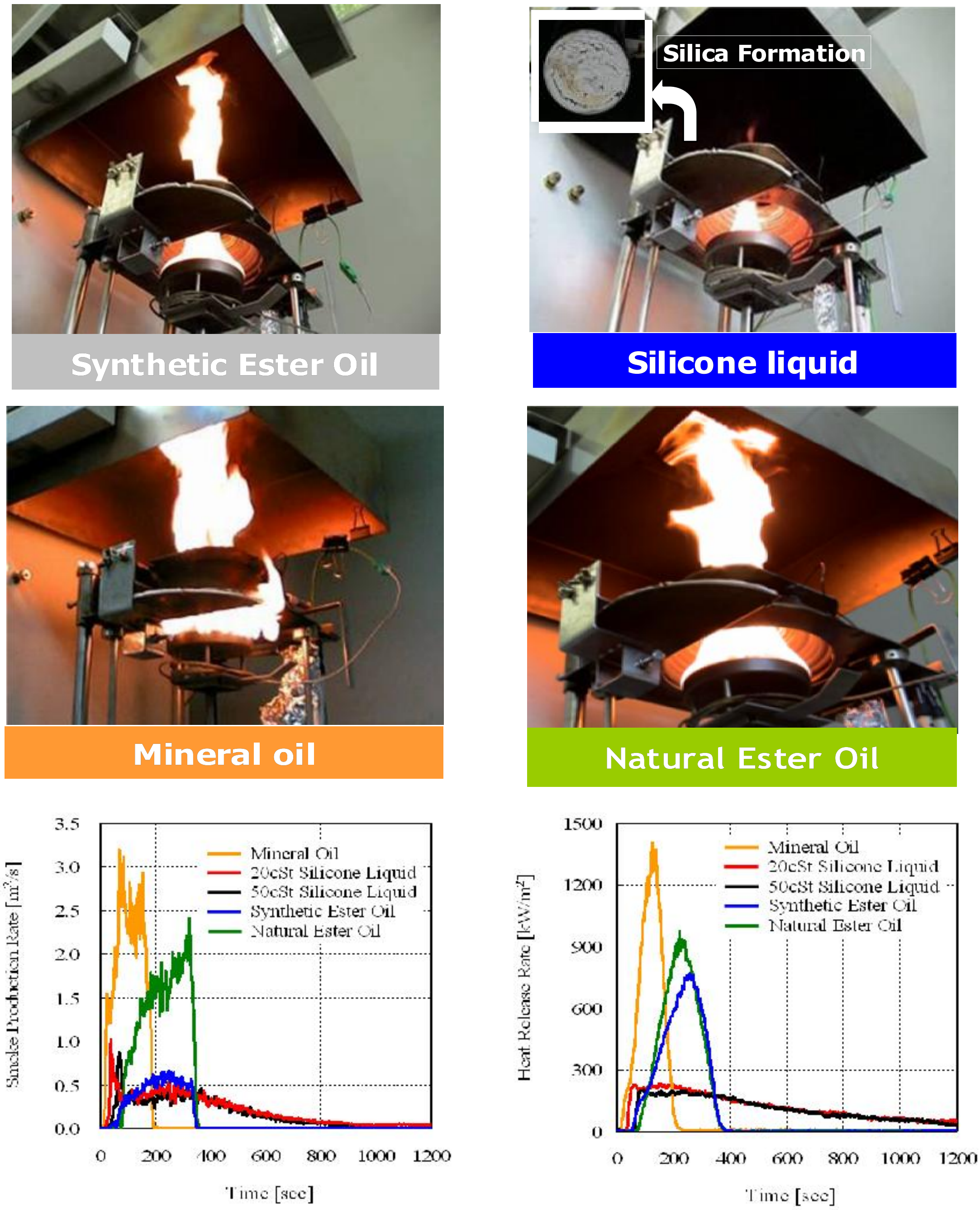
Cone calorimeter method in IEC60695-8-3 (Draft) was used to conduct evaluation of combustion characteristics and thereby to evaluate the fire risk of 20cSt silicone liquid immersed transformers by a Japanese laboratory.

The samples were heated by a conical heat-transfer heater in the experimental apparatus, and flashing/ignition was induced by applying a spark to the produced gas. The changes in the samples' heat release amount, gas production amount, weight, and combustion product gases over time were measured, and each sample's combustion weight loss rate when loaded with a particular radiant heat flux was determined. The insulation fluid samples were kinetic viscosity 20cSt and 50cSt silicone liquids corresponding to the high flash point insulation fluids of IEC-60076-14. They were compared with two other fire-resistant insulation fluids – synthetic ester oil and natural ester oil – and with the conventionally used mineral oil.

The pictures and the graphs in Figure 34 below show the experimental results when each insulation fluid was loaded with a particular radiant heat flux. Results for four fluids were experimentally derived in terms of: heat release and smoke production.

In terms of maximum smoke production rate, the ranking from this test was: mineral oil > natural ester oil > 20 cSt silicone liquid > 50 cSt silicone liquid > synthetic ester oil. The silicone liquids have a low maximum smoke production rate compared with the other insulation fluids. The fire of the silicone liquid is smaller than other oils because a residue silica layer formed by the combustion covers the surface of the silicone liquid and it is shut off oxygen supply to silicone liquid under the flame. However, these properties may be less relevant where oil is spilling down over a vertical surface which would break up the silica layer.

In terms of maximum heat release rate, the ranking was mineral oil > natural ester oil > synthetic ester oil > 20 cSt silicone liquid > 50 cSt silicone liquid.



a) Time histories of the smoke production rate of burning insulation fluids.

b) Time histories of the heat release rate of burning insulation fluids.

Figure 34: Comparative Combustion Test Results

6.6 Tank Design as Protective Strategy

If the oil and arcing gases can be contained in the transformer tank during and immediately following an arcing fault then there will not be any fire. Unfortunately there are at present no international standards for the design and testing of transformer tanks.

To the best of the knowledge of WG A2.33, Japan is the only country which has a national standard (design guide) with requirement for the design of transformer tanks. The development of the Japanese Standard [17] (design guide) followed extensive research and verification testing of water filled tank with internal arcing simulated by ignition of powder charges.

For other countries, design and verification testing of transformer tanks is therefore often non-existing, unless the individual transformer purchaser has included such requirement in their purchasing specification.

The following subsections will give a brief description of the issues related to containment of internal arcing with the majority of this information extracted from the Japanese standard for design of high strength transformer tanks.

6.6.1 General

The transformer tank structure varies depending on the purchaser's specification, the required transportation method and the individual manufacturer's design standard, etc.

In general, the transformer tank is commonly designed to withstand full vacuum (zero internal pressure), stresses related to the mode of transportation and over pressure related to the static head of oil pressure with a safety margin, or if included - the requirement detailed in the purchaser's specification.

However, only few purchaser specifications include specific requirements for the rupture withstand strength of transformer tanks. I.E. , the estimated internal pressure (P_0) developed from internal arcing under credible internal fault conditions.

Ideally the transformer tank design should be coordinated with pressure control measures and the specified fault level/time characteristics, to ensure that the internal pressure build up during internal arcing faults does not exceed the verified design withstand strength of the tank. However, ensuring this poses many difficulties for high arcing energy faults, and only a very small percentage of transformers presently in service would be able to meet such a requirement.

Firstly, because the potential arcing energy is difficult to calculate with a reasonably degree of accuracy and secondly, the commonly used Pressure Relief Protective Devices are in general not able to respond sufficiently fast and with sufficient relief capacity to prevent the tank from rupturing, if exposed high energy arcing fault (refer Chapter 4:).

The diagram below depicts the requirement for ideal protective performance of a Pressure Relief Device.

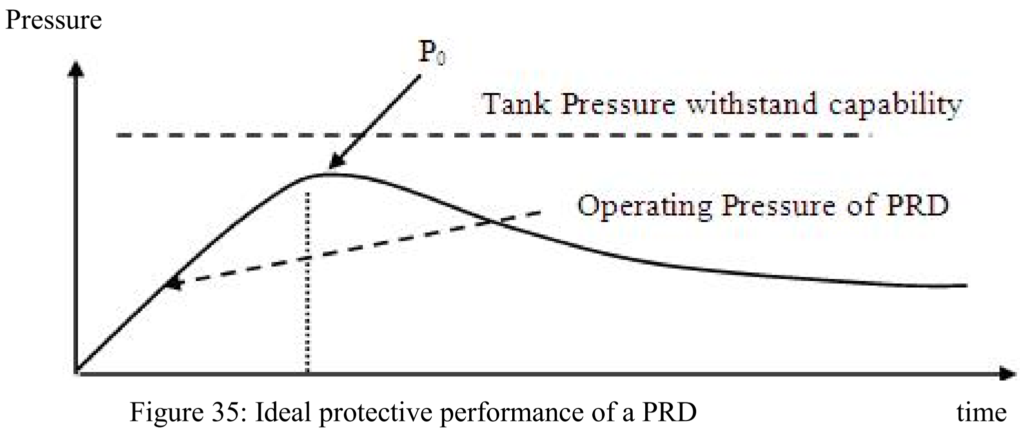


Figure 35: Ideal protective performance of a PRD

6.6.2 Tank Strength Requirements

A prerequisite requirement for good tank design is knowledge of the required tank strength. In the absence of a standard for required strength for tanks to withstand internal arcing fault, it is recommended that the reader refers to Chapter 4: of this document for guidance, unless he has better methods at his disposal.

However, it should be noted that guidance provided in this document cannot and does not guarantee that this will ensure that the transformer tank has the required strength to protect the transformer tanks from rupture under all internal arcing faults conditions and certainly not from a fire, as only a minor part **of transformer fires originates from tank rupture**.

6.6.3 Tank Design

The transformer tank is a welded structure consisting in general of plates with stiffeners and is equipped with some bolted connections at flanges for bushings, tap changers and access /inspection covers. The structural design of a transformer tank includes the analysis for various types of loads the tank is exposed to. The determination of the stresses and deflection under various load conditions requires a certain number of simplifying assumptions, due to the high number of accessories, fittings, welding-joints and different tank-shapes present on a transformer tank. The stress analysis of a transformer tank can be done either by analytical or by numerical methods (FEM). In both cases the analysis is based on static considerations and focused on the objective to limit the stresses and the deflection during to remain within the elastic deformation range of the tank material.

For the majority of transformers installed so far, considerations regarding the mechanical stresses on the transformer tank structure resulting from an internal arcing fault, were not necessarily included in the normal design process. The dynamic ability of a transformer tank to resist internal arcing can only be demonstrated by testing. However it is commonly acknowledged practice that a rupture strength test for larger transformer tanks is normally not applicable; therefore the resistance of a transformer tank to internal arcing can only be proved with limited accuracy by a simulation calculation.

Different calculation methods are available to evaluate the pressure rise developed by internal arcing and the resulting mechanical stresses on the transformer tank. Any model, particularly of such a complex system, is necessarily approximate. From the point of view of practical application the use of the formula in Chapter 4: of this document may be an appropriate approach for handling the complexities of the pressure rise which is associated with an arcing fault in a transformer tank. Equation 3 for the estimated internal overpressure, developed from internal arcing under credible internal fault conditions, reduces the transient nature of the pressure rise into a quasi-static consideration. The numerical analysis of the tank design considers the homogenous internal overpressure as a function of the volumetric stiffness behaviour of the tank structure. The calculation has to prove that the transformer tank may become largely plastic deformed, but has to remain fluid-tight because its rupture withstand strength meets the estimated internal overpressure at least.

The rupture withstand strength of a transformer tank can be determined based on the elastic-plastic material behaviour, as the tank rupture occurs when the materials are stressed beyond their elastic deformation range.

If arcing fault withstand strength is required then the Purchaser should specify the simulation calculation required for proving the rupture withstand strength of the transformer tank to internal arcing as well as the required fault energy, or the fault current and the clearing time (for details see Chapter 4:). The analysis of the rupture withstands strength of a transformer tank should be accompanied by considering following items:

- Welding skill
- Method for estimated pressure at internal fault
- Verification experience for tank rupture strength

6.6.4 Improvement of the Tank Strength

The weak points for the tank rupturing by internal pressure identified in the Japanese guide for tank designs are joined flanges and the corner seams of the tank. Reinforcement of these parts, can improve the rupture withstand strength of the tank.

Figure 36 shows an example of a method for reinforcement of a weak point: joining flanges. This simple modification proved to be very effective in increasing the pressure withstand without increasing the overall tank stiffness [37] [39].

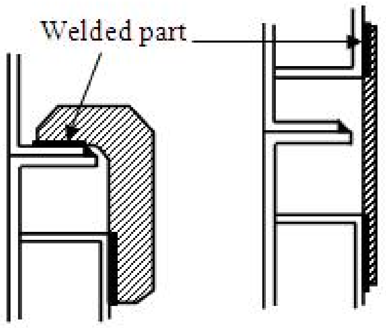


Figure 36: Example of reinforcement at joining flanges

6.6.5 Pressure Reducing Techniques

To reduce the internal pressure during an internal arcing fault, following measures are effective:

<u>Increase tank flexibility:</u>

Increasing the tank flexibility allows volume expansion and thus reduces the pressure rise and especially the pressure rise gradient. Conversely, increasing the reinforcement to improve the tank rupture strength decreases the flexibility of the tank and thus increases the pressure rise when an internal fault occurs. However, reinforcing for improving the strength locally at stress concentration points is effective. The reinforcement should be appropriately arranged for the stress relaxation of these parts of the tank whilst at the same time maintaining tank flexibility. A number of recommended techniques are described in [44].

Increase expansion volume:

It is possible increase expansion volume by using a conservator with large diameter connecting pipe as shown in Figure 37 [39]. This technique is sometimes used by Japanese manufacturers for reducing the internal pressure of the tank. If the tank flexibility is low and there is a risk that the pressure rise might exceed the tank withstands strength, then it is useful to utilize a diaphragm or bag type conservator as a pressure reducing space. The values of the pressure reducing space and the connecting duct size shown in Figure 37 were obtained from tests on a full-scale model. The data are referenced to the maximum pressure generated with no pressure reducing space.

A volume increase of about 1,000 litres can decrease the maximum pressure to 70-80% during an arcing fault compared to the no volume increase. A larger volume can reduce the pressure further, but with decreasing pressure reducing effect. A pressure reducing effect of more than about 20 % can be obtained with connection pipe openings of 900 mm or more. A larger duct size makes no further change in pressure reducing effect. Optimum volume and duct size are considered to depend significantly on the tank's expansion coefficient (i.e., the flexibility of the tank); this should be taken into account in the actual tank design for reducing the internal pressure.

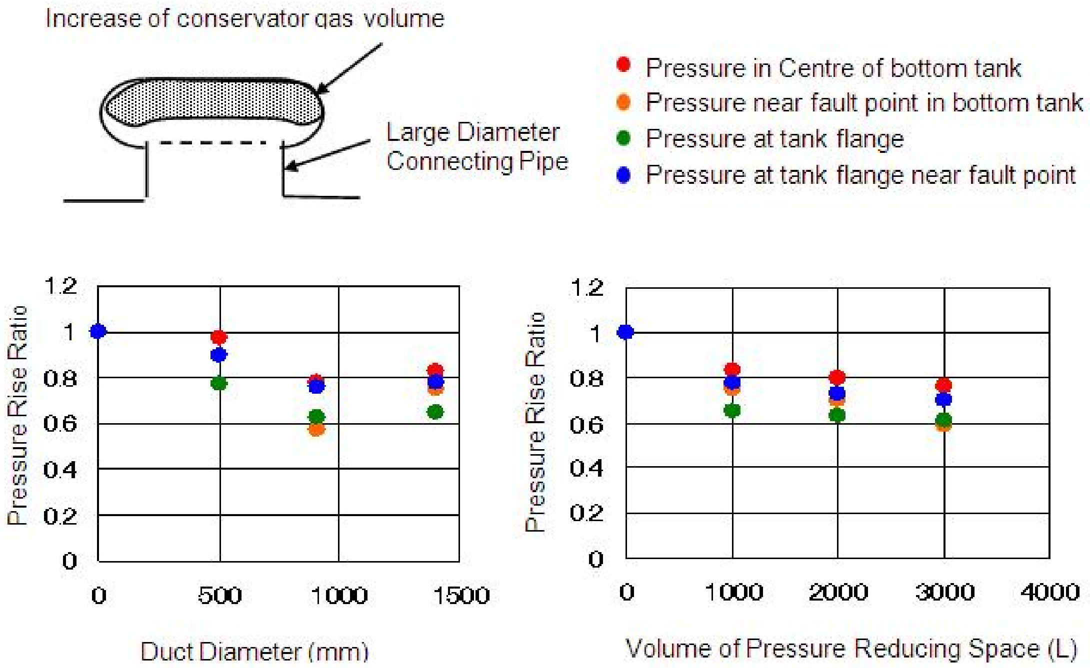


Figure 37: Pressure reduction effect of an expansion volume

6.6.6 Gas Cushion Transformers

Hermetically sealed transformers with air or nitrogen filled space in the upper level of the Transformer to compensate for volume expansion of the oil during load cycling, have inherently much lower rate of pressure rise during arcing fault due to the compressibility of the large gas space. Also a PRV fitted to the tank wall in the gas space area above the oil has much larger volume venting capacity for air than one fitted below level of oil (see Chapter 4:). Such design is particular useful for small and medium size power transformers.

6.6.7 Verification of Pressure Withstand Capability

In the verification tests for the rupture strength of the tank, there are two methods which could be considered, one is the dynamic test and the other is the static test.

For a dynamic pressure rise, an electrical test is difficult because of the limitation of the shorting generator capacity and the difficulty to obtain an adequate test place, etc. Powder combustion [37] or air pressure methods [56] [57] have been used for simulating pressure rise occurring during internal arcing fault. Generally, it is too difficult to verify the tank strength by the dynamic method mentioned above due to limitation of test equipment, test space, cost, etc.

A hydraulic static pressure test is therefore a useful alternative for tank strength verification. Figure 38 shows the comparison between the dynamic stress by powder combustion test and the static stress by hydraulic pressure test. The dynamic stresses are good agreement with the static stress.

Therefore, the tank strength at internal fault can be verified by the hydraulic test.

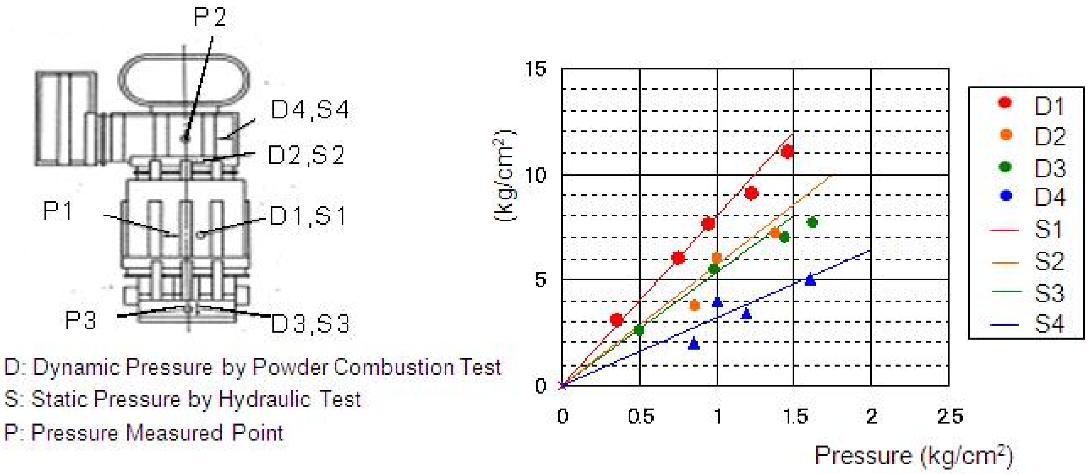


Figure 38: Comparison between Dynamic and Static Pressure Testing

6.7 Pressure Venting & Depressurization as Protective Strategies

A variety of pressure reduction techniques have been developed to provide pressure reduction against excessive pressure being developed by arcing fault within transformer tanks, tap changer tanks and oil filled cable boxes. Some of these solutions are very basic and their pressure relief effectiveness is very limited and in general insufficient to provide sufficient pressure relief for other than low arcing energy faults. Others are more sophisticated and provide faster and higher relief capacity. Some include additional feature such as contacts for trip signals, self resealing after pressure subsides, safe venting and separation of oil and arcing gases, and may activate nitrogen injection if fire has been initiated. The following sections provided a brief description of the most common devices.

Also refer to Chapter 4.5 for discussing of venting efficiency of pressure relief or depressurization systems.

6.7.1 Goose Neck Explosion Vent

This type of pressure venting is the simplest and oldest form of pressure relief. It consist of a pipe typically raising from the tank cover to the height of the maximum oil level in the conservator at where the pipe is typically formed with bend of approximately 150 degrees to ensure ejected oil and gases is directed away from the transformer. The exit opening is covered by a diaphragm designed to rupture at a pre-determined pressure. The diameter of the pipe is designed to provide suitable pressure relief. The benefit of this solution is low cost. The disadvantages is the head of oil in the pipe and possible remoteness from the fault location, which may provide a back pressure which reduces the effectiveness of the venting for high energy arcing faults, and the spilling of oil and venting gases from a high point above the transformer which add to the risk of ignition of vented oil and gases. To provide effective pressure relief during high energy arcing faults would require several large diameter pipes located at several venting points on the tank and re-enforcing of the tank to ensure that it can withstand the pressure required to rupture the diaphragm and accelerate oil/gases against the head of oil in the gooseneck pipe. Whilst a sufficient number of gooseneck pipes together with reinforcing the tank could provide pressure relief for relative high arcing energy faults, the reality seems to be that that most transformer users and designers do not realise how large vent openings / tank strength are necessary to relieve the pressure fast enough to avoid tank rupture during a high arcing energy fault. This is evident from the many examples of the transformer tanks having ruptured whilst the gooseneck diaphragm still remains intact. The reason for this is that most transformer using this type of pressure relief protection has insufficient tank strength combined with too few or too small vent openings to have effective protection against tank rupture in the event of a high energy internal arcing fault.

6.7.2 Pressure Relief Valves (PRV)

This type of devices consists of a spring loaded valve with a dual gasket sealing systems mounted directly on the transformer tank typically on the transformer tank side near the top of the tank. PRV's are also commonly referred to as PRD's. The valve opens at a pre-determined differential pressure across the valve. The benefit over the goose neck type pressure relief and rupture disc vents is that it will reseal when the pressure differential across the valve has reduced to typically 50-60 % of the opening pressure. The PRV's can be fitted with contacts to provide trip signals when activated and also with pipe work to direct the oil and gasses towards the base oil the bunded area. PRV's are available in a range of sizes. A 5 inch (127mm) opening diameter is a very common size. It is common to fit one PRV to small and medium size transformers and 2 PRV's to the tank of larger transformers. One manufacturer of a common brand of this type of PRV recommends one valve transformer up to 40000 L of oil and two valves for larger tanks. Some utilities would use up to 4 valves for large transformers. The PRV can be fitted with pipes to direct oil and gasses to a "safe" point at ground level within the bunded oil containment area.

The disadvantage over the rupture disc is that opening time is longer and its venting path has higher flow resistance. The advantage is the valve will reseal after the protection has cleared the fault, for faults with arcing energy within the withstand capacity of the tanks and the venting capacity of the valve.

Whilst there a many reported cases on PRV having operated with and without tank rupturing, it is the view of WG A2.33 members that one or two PRV's cannot be relied upon to prevent tank rupture for high energy arcing faults.

However, as discussed in Chapter 4 venting efficiency improves for faults located close to the venting port where the vented product is gasses and it is considered that PRV venting can be effective for gas cushion transformers where the arcing is below the oil and valve is mounted above the oil level, as the volume of gas which can be vented through PRV during a very short opening time is much higher than for oil (refer Figure 15).

6.7.3 Rupture Discs

Rupture disc has advantages above the gooseneck type pressure relief vent in so far they can be designed to rupture with far less tolerance on the differential pressure across the rupture disc than can be achieved with "Goose neck" type pressure relief. They can also be mounted directly on the transformer tank, and therefore respond faster to excessive pressures. However rupture discs also requires collection pipe work and holding tank for the collection /separation of vented oil and gases, as they would poses a serious fire risk if oil and gases were vented freely to the ambient atmosphere.

6.7.4 Tank Protection Systems Based on Rupture Discs and Nitrogen Injection

One supplier of transformer fire protection equipment which has carried out extensive research into transformer fire protection offers a combined transformer pressure relief/fire protection system. The pressure relief part of their system utilizes a single or multiple rupture discs for pressure relief on main tank (depending on customer willingness to invest) and separate rupture discs for pressure relief on the tap changer tank and each cable box. The system comprises, a conservator shut-off valve, pipe work and a holding/separation tank for collection and separation of the vented oil and explosive gases, and nitrogen injection equipment for injection of nitrogen into the base of the main tank for evacuation of the explosive gas after the tank explosion has been avoided. The purpose of the nitrogen injection is to also to stir the oil and extinguish a fire, in the event the tank has ruptured and a fire has been initiated. The size and the number of the rupture discs will vary depending of fault level and tank design parameters, but each rupture disc is generally less than 30 cm in diameter because it is difficult to adapt larger discs to standard transformer tank design.

The manufacturer of the transformer protection equipment has carried out modelling calculations and testing of the pressure relief capabilities of his equipment on full size transformer's rated up 20 MVA and with arcing energy level of up to 2.4 MJ. The manufacturer claims that modelling and calculations performed by the company has verified that the system is capable of preventing tank rupture for fault level much higher fault levels than the levels verified by tests.

The manufacturer has named the system describe above as "Fast Tank Depressurisation Technique [FTDT]" [58] [59] [60].

"Fast Tank Depressurization" is recognised as a method of fire protection for transformers in NFPA codes 850 and 851. NFPA describes Fast Depressurisation Systems "as a passive mechanical system designed to depressurise the transformer within a few milliseconds after the occurrence of an electrical fault". The is no specific quantitative measure given in the NFPA documents for what venting capacity is required to qualify for being a "Fast Depressurisation System".

Other suppliers also offer variants of this type of transformer fire protection system. One of these suppliers offers a system which pro-actively opens a large oil drain valve and initiates nitrogen injection in response to an internal fault detected by the transformer differential or the master trip relay, in addition to trip signal from a Rapid Pressure Rise Relay, a PRV or a Buchholz Relay. Whilst such a protection system may cause dumping of oil and injection of nitrogen for internal arcing fault, which could have been cleared by conventional protection and possibly contained within the tank without causing tank rupture and fire, the vendor of this system considers that dumping of the oil into a oil gas separation/collection tank and injection of nitrogen is a worthwhile safety precaution whenever internal arcing is present.

The WG A2.33 has insufficient experience with the above systems so intending users should do their own investigations into the merits of these systems.

6.7.5 Tank Protection Systems Using Multiple Rupture Discs

At least one transformer manufacturer has built transformer tank pressure relief protection based on the use of multiple rupture discs for pressure relief, in order to increase the effective total venting area and to increase the likelihood that a rupture disc will be located in the vicinity of the fault. One manufacturer has produced at least one large transformer with a large number of rupture discs and extensive pipe work for gas/oil collection. This manufacturer has also published a paper with calculations of pressure reduction they consider achievable for a 48 MJ. 83 ms arcing fault with 2, 4, 6 and 8 rupture discs. The published paper did not detail the size of the venting apertures. They concluded that to achieve a 30 % reduction of the peak pressure for an arcing fault located anywhere in the tank would require 8 rupture discs. The calculated results tabulated in their published paper [45] are listed in the table below. It can also be noted that, according to this analysis, a 48 MJ arc would produce an internal pressure (1500 kPa) far above the current tanks withstand capability (about 200 kPa) and that 2 rupture discs would only reduce that peak pressure by about 3-5%.

Table 15: Pressure reducing effect of multiple rupture discs

Arcing position	Tap changer		Upper winding part	
No. of rupture disk	**Exhausted pressure (kPa)**	**Peak pressure on the tank wall (kPa)**	**Exhausted pressure (kPa)**	**Peak pressure on the tank wall (kPa)**
0	0	1480	0	1590
2	70	1410	58	1532
4	250	1230	155	1435
6	286	1194	201	1389
8	446	1034	376	1214

The manufacturer has not made any claim in the published paper on how many rupture discs would be required for a given fault energy /tank design, but merely conclude that "that because the arc location is random, pressure relief points should be installed at multi positions on the tank wall to ensure that a t least one pressure relief point will always be located in vicinity of the arc", and that based on the procedure listed in the referenced paper, it is possible to determine the number and positions of rupture discs required to keep the tank wall pressure under the allowable pressure no matter where the arc takes place.

Whilst there a many reported cases on PRV having operated with and without tank rupturing it is the view of WG A2.33 members that one or two PRV’s cannot be relied upon to prevent tank rupture for high energy arcing faults. However, as discussed in Chapter 4: venting efficiency improves for faults located close to the venting port.

6.8 Choice of Components as Protective Strategies

6.8.1 Bushings

It is known that high voltage Oil Impregnated Paper [OIP] bushing failures are the single component which causes the highest number of transformer fires. Refer to Chapter 2.2.3 Transformer Bushing Fire Scenarios and Chapter 3: for statistics

It is considered that Resin Impregnated Polymer [RIP] Insulated bushing has the lowest fire risk of any condenser type HV bushing bushings. Using RIP High voltage bushings is most cost effective method of reducing the risk of transformer fires.

For low voltage bushings; oil filled solid stem porcelain bushings is the type of low voltage bushings with the highest fire risk. The reason is that when this type of bushing breaks there is a high risk that it will cause a serious oil spill as oil will be emptied from the conservator and higher part of the tank and if the breakage occurs during an arcing fault, as it often does in a cable termination fault within an air insulated cable box, then there is a high risk that the oil will be ignited and a serious oil fire will follow.

Plug in type low voltage connections, RIP or moulded resin type low voltage bushings have much lower risk of causing a serious oil spill than the oil filled solid stem porcelain type bushings.

6.8.2 Cable Terminations and Cable Boxes

Cable termination failures and cable box ruptures are the 2nd highest cause of Transformer fires. Refer 2.2.4. If an arcing fault occurs in a cable box then there is a high risk that the cable box will be seriously damaged and an oil spill will follow. This is not only the case with oil filled cable boxes. But even more so with air insulated cable boxes without explosion venting. If an arcing fault occurs in air insulated cable box which does not have arcing fault venting and oil filled solid stem porcelain type bushings are used then there is a high risk that the bushings will break and an oil spill will follow and the oil will be ignited by the arc.

The simplest and most effective risk mitigation measure against arcing fault in cable boxes is to avoid the use of cable boxes. This can be done by terminating cables at a cable termination pothead at a short distance from the transformer and make the connection to cover mounted bushings on the transformer by flexible links or short bus bars. If a cable termination fault occurs, then this will in general not affect the transformer.

As an alternative to terminating cables in a cable box, consider using moulded type bushings with plug-in type connectors.

If a cable box is used then the following risk mitigation measures should be considered:

6.8.3 Insulating Liquid Filled Cable Boxes

For high voltage cable terminated in cable boxes, consider using single phase cylindrical cable boxes, fitted with a large opening PRV's at the top cover of the cable box and the top flange also being the weakest point of the cable box. Arrange oil expansion containment so oil from main conservator and the transformer tank will not be drained a spilled from the cable box if top flange or other parts of the cable box rupture. For low and medium voltage cable terminations, consider using moulded resin type bushings or plug-in type connectors.

6.8.4 Air Insulated Cable Boxes

An air filled cable box should always be fitted with pressure relief venting. So if an electric arc occurs then the arcing gases (hot air) is vented away without causing excessive and damaging pressure rise within the cable box. This safety measure is common practice with air insulted metal clad switchgear. If this is not done, then there is a serious risk the cable box will be totally destroyed, and with bushings breakage, possibly oil spill and fire a high probability if a cable termination fault occurs...

6.8.5 SF6 Connection

The direct connection of a transformer to SF_6-metal enclosed switchgear is often achieved by oil-SF_6 condenser bushings with specific gas tight sealing system or an intermediate chamber, which can insure than SF_6 gas is not leaking into the transformer or oil into the SF_6 bus bar chamber. This type of bushing arrangement has significant lower risk of causing a fire than connection via OIP bushing or cables.

6.8.6 Conservator Shut-off Valve

This type of valve is fitted in the oil pipe connecting the conservator and the main tank, but can also be fitted between the conservator and oil filled cable boxes. The typical shut off valve is a flap valve, where the flap is held in a partial open position by a spring. This allows oil flow in both direction at a flow rate which occurs to compensate for thermal expansion and contraction within the normal operation of the transformer. However the valve will close “shut-off” the oil flow from the conservator and initiate an alarm, if abnormal oil flow occurs from the conservator to the main tank or associated cable boxes, as would occur if oil filled solid stem porcelain bushing breakage, or OIP bushing failure, or rupture to the main tank had occurred.

The benefit of the shut off valve is substantial, as it can prevent the oil from the conservator being spilling out through a bushing turret, damaged bushings, ruptured cable box or a minor rupture near the top of the main tank and thus reduce the amount of oil (fuel) spilling from the conservator and feeding the fire at the early and very critical stages of fire.

However, whilst the concept of the Shut-off valve is very good, it is the WG A2.33 members experience that it is difficult to ensure that the valve closes consistently at the required oil flow (not to low and not too high) as it seems that the flow rate at which the currently commercially available valves operate varies considerably, and are very dependent on the mounting angle and the head of oil above the valve.

6.8.7 Tap Changers

There is often a need to be able to provide voltage regulation by means of an On Load Tap changer (OLTC) or an Off Circuit Tap Changer (OCTC), (also known as De–Energised Tap Changer DETC). Modern day tap changers supplied by a well reputed manufacturer and maintained correctly are very reliable. Tap changers are only the root cause of approximately 10 % of transformer fires.

The most effective risk mitigation measures for tap changers are:

- Ensure the tap changer has ample capacity for its duty, including any intended short term emergency overloads both in terms of insulation class and current rating.
- Ensure the tap changer is only maintained by personnel that have the skills and competence to maintain the type and model they maintain.

- Ensure that the tap changer is maintained in accordance with the OEM's instructions, unless you as user have proven superior information on its maintenance.
- Always check with the OEM if there has been any maintenance requirement updates issued since the printing date of your service manual before commencing maintenance.
- Maintain and check the oil quality for the diverter / combined diverter/selector tank regularly and including DGA. DGA interpretation and other forms of online monitoring such as vibration analysis, runtime and motor current on OLTC's are still at the early stages of knowledge for its interpretation. However, the body of knowledge is growing and should be made use of.
- Operate tap changer across the whole range of tapping positions several times periodically (with transformer de-energised) to wipe and clean the contacts to maintain low contact resistance and avoid pyrolitic carbon growth. This type of operation is especially important for De–Energised (DETC) types of Tap Changers.
- Specify, whenever possible, the installation of the tap changer on the neutral end of the Wye winding, so that energy (voltage) is limited in case of a fault.
- Specify a vacuum interrupter technology with less-flammable fluids.

Chapter 7: Transformer Fire Damage Control Practices

7.1 Introduction

This chapter will discuss strategies available to control the impact of a transformer fire on potential victims. In this context potential victims include humans, economic assets and the environment.

Humans, include utility staff that may be exposed to the risk of injury due to proximity to a transformer fire in course of their normal duty, fire brigade staff in event of fighting a transformer fire, and members of the public which could be in the vicinity of a substation or other transformer installation when a transformer catches fire.

Economic asset at risk as victims to a transformer fire are primarily nearby substation or power station plant, equipment, buildings or structures within close proximity of the transformer. Transformer installation and substations located in a city buildings where the public have access to the building or adjacent buildings requires special considerations; both in terms of risk to human life and high value assets.

The major risks to the environment is primarily from spill of oil or other forms of insulating fluid, water contaminated by oil, foam and other fire fighting chemicals, but it also include risk of air pollution from accidental released gases and smoke from a fire.

It is not possible to provide a single set of simple uniform guidelines as each installation must comply with the national and local laws, regulations and codes of practice applicable for each type of installation, both in terms, buildings codes and regulations, and also Laws, regulations and codes for fire prevention and protection of the environment. Laws, regulation and codes vary from country to country and even between states within the same country. Climatic and local site conditions also vary considerably, this means that a solution which is suitable for one location may not be suitable for other locations.

In this chapter we will discuss the risk mitigation measures available to mitigate the risk of a transformer fire causing damage beyond the transformer already at fire, and provide examples for a range of typical transformer fire control and risk mitigation measures. However, it is not possible to all the variants of Substation installations.

Most of the risk reduction measures carries additional upfront capital cost and the owner of the transformers should make careful consideration (possibly in consultation with other stakeholders) of what level of fire risk is acceptable for the specific transformer or class of transformers, given its application and location, both in the network and also to its surroundings.

It is evident that the fire risk which may be acceptable for a 30 MVA sub-transmission bulk supply transformer located in a two transformer open air widely spaced substation, is quite different to that of a 600 MVA generator step up transformer located close to the turbine hall in a power station; or a 100 MVA bulk supply transformer located in a compact urban substation where land cost is high and a transformer fire imposes risk to both human life and valuable adjacent properties, or the extreme case where the transformer is located in the basement of a high rise office tower.

It should also be understood that it is not possible to cover all possible risk mitigation measures in a short guide document like this brochure. It is therefore strongly recommended that transformer users makes their own assessment or seeks further guidance on <u>what type of risk will be reduced, and even more importantly, assess what risk that will not be reduced from each mitigation</u> <u>measure</u> when assessing; Which risk mitigation measures is required by laws and statutes, which may have economic merit as well as to be “Good Fire Safety Practice, before finally deciding what risk mitigation measures should be implemented at the specific site.

The primary fire spread mechanism for transformer fires is the flow of burning oil beyond the origin of the fire and heat radiated from the transformer fire. Transformer fires are essentially large oil fires. Oil containment is therefore most the effective means of reducing the spread of a fire and should be provided for all oil filled transformers of the size covered by this guide ($\geq$ 10 MVA).

7.2 Standards and Guides

A number of useful standards and reference guides with information on how to minimise risk of fire damage to and from transformers have been developed and published by standard organisations, utility associations, insurance companies and utilities. Please refer to the listing such documents provided in section 1.4 of this brochure. These guides and standards can be accessed by readers of this document for reference and further guidance on a much wider range of fire safety topics and in further details than it is possible to cover in a short document like this technical brochure

7.3 Fire Control Measures

When a transformer failure has developed into a transformer fire, the transformer is in most cases destroyed beyond economic repair.

The aim of fire protection control measures is therefore directed to minimize the damage to the fire "victims" generally in the following in the order of priorities:

- Minimize risk of loss of life and injury to humans.
- Minimize the risk of the fire spreading or causing damage to adjacent transformers, control building, structures and other items of plant and equipment which is critical for maintaining supply during a transformer fire or restoring supply quickly after a transformer fire if supply cannot be maintained during the fire.
- Minimize contamination and damage to the environment.
- Minimize overall economic loss in the event of a transformer fire.

7.3.1 Minimising the Risk of Loss of Life to Humans

Whilst the probability of a transformer explosion and/or fire is a very low, it can be a catastrophic event if it happens, with the potential to cause injury or death to anyone in close proximity to the transformer when it happens.

Minimizing this risk therefore begins with restricting access to energized transformers.

Some access for performance operational and maintenance tasks is unavoidable, but it should be restricted to qualified and authorized staff and limited to the degree necessary for operating and maintaining the transformer and ensuring entrapment does not occur.

If a transformer is located within a sound enclosure, then the spacing around the transformer should be such that it does not impede escape and the enclosure should have at least two outwards opening access/escape doors, located at diagonal opposite corners.

Transformers installed in vaults or indoor substations require special consideration for personnel safety, both in terms of safe escape routes and the fire suppression systems.

If oxygen exclusion gases such as CO_2 or others oxygen displacement gases are used, then it is essential that all personnel inside the area to be flooded with the fire suppressant gas are evacuated before the gas is released. Normal safety procedures for such fire suppressant systems include dual fire signal interlocks, warning/evacuation siren operation for 30-60 seconds, closing of vent and stopping of fans and unless impossible, de-energizing of the transformer before the fire suppressant gas is released. Trip signals from electrical protection relays, Buchholz or PRVs should not be used alone to initiate automated fire suppression system.

Proximity and access to transformers for the public should be restricted to the very minimum, if not eliminated altogether.

Layout of access driveways, walkways and vehicle parking areas within the substation should also be such that the time spends in proximity of potentially high risk energised equipment is minimized.

Two entry gates should be available for fire fighting vehicles, and fire hydrants should be located in sufficient distance from transformers to ensure they can be accessed safely during a transformer fire [30-60m from the transformer]. Driveways for fire vehicle access should have sufficient width, height clearance and corner radii, so they all transformer can be access expeditiously and safely, irrespective of which transformer is on fire.

7.3.2 Passive Protection Systems

Separation by distance can be an effective and economic solution at transmission and substation sites where sufficient land is available at low cost.

In suburban or more densely populated areas where land value is higher or there is insufficient land available at the site to maintain the clearance required for fire safety to an adjacent transformers or buildings, it becomes necessary to provide additional protection in form of fire barriers between adjacent transformers and to construct the buildings of fire resistant materials.

There is no uniformly agreed method for determining the required space separation to other transformers or buildings.

This point is illustrated very well by the graphs in Figure 39 extracted from Reference [16] which provide a graphical listing of the variations in spacing required from transformers with < 500; between 500-5000; and > 5000 gallons of oil, for distances from the transformer used in guides from a major utility [61], National [8] and International [3] guides and an insurance company [12].

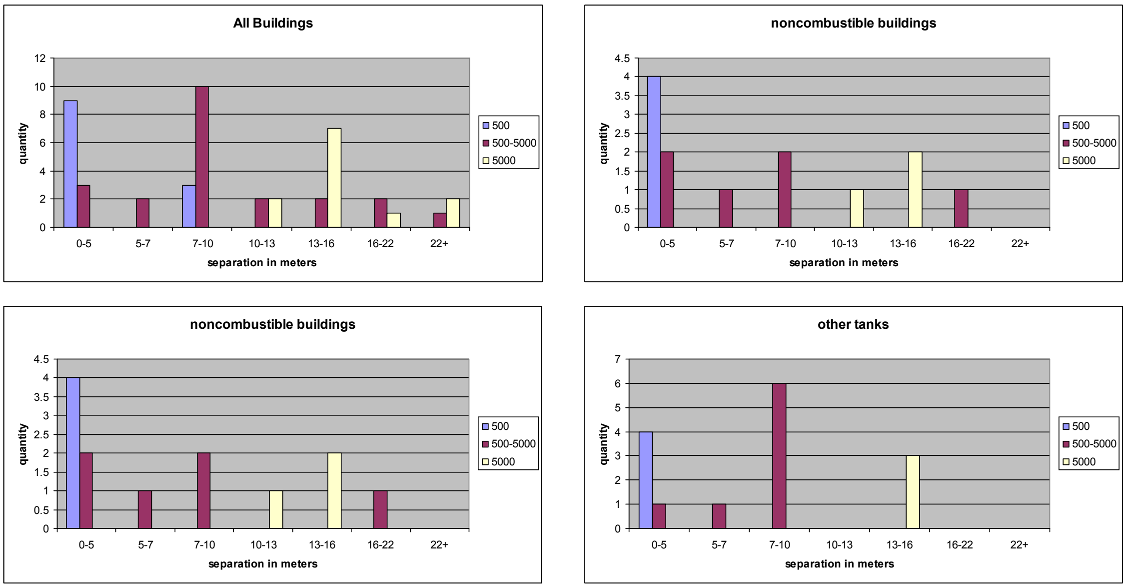


Figure 39: Variations in the recommended separation distance between transformer tank and other assets.

Some guides provide recommendation based on heat flux calculated from potential size of fire pool [16] [15]. Other reference document provides guidance on separation distance based on the oil volume [3] [12] or the MVA rating of the transformers.

Reference [16] provides comprehensive list of data on how to calculate heat flux at varying fire pool sizes and separation distances, and also provides a number of graphs where the heat flux can be determined as a function of fire pool size and distance from the fire pool.

Heat flux at a given distance from the fire pool can vary significantly dependent of the wind direction. This point is illustrated very well in Figure 40 which shows up-wind and down-wind from a transformer fire. The temperature contours has been prepared from test performed by Ontario Hydro, Canada.

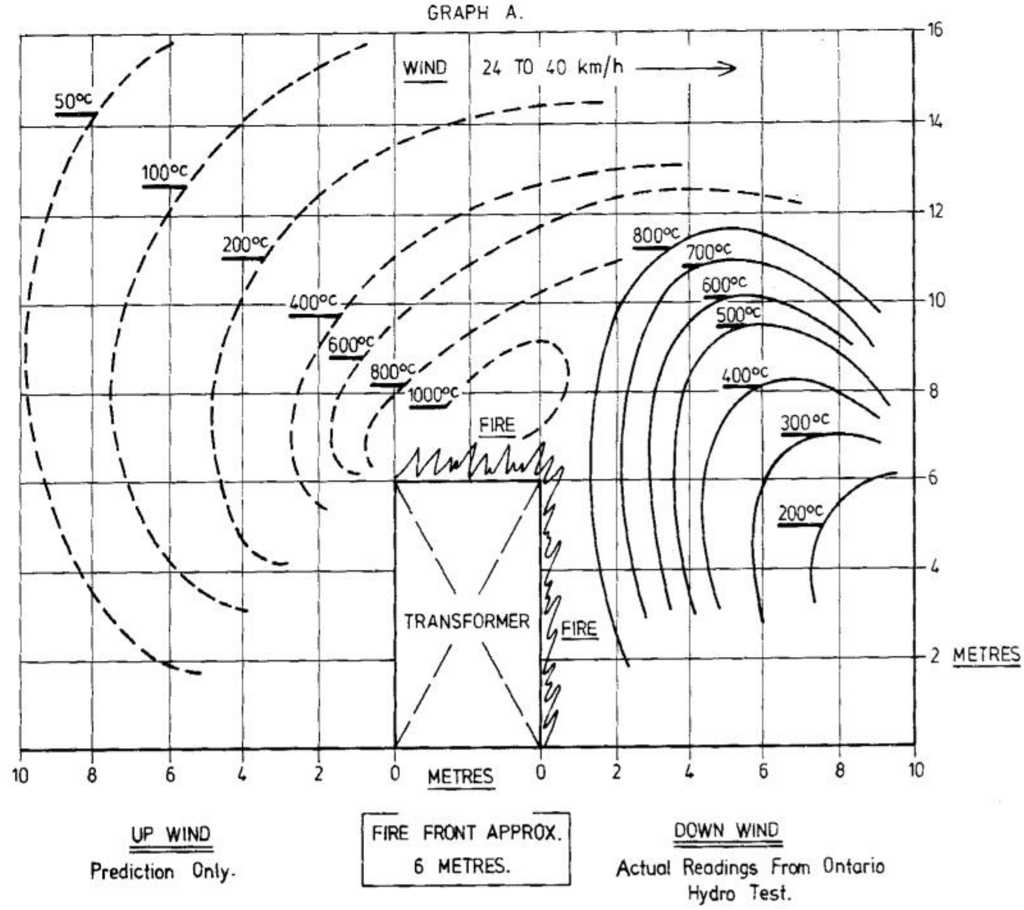


Figure 40: Wind direction effect on temperature - distance contours.

Most Fire safety standards and guide documents provided tables on recommended distances separation between various sizes and types of transformers. The present document contains tables from IEC 61936 and from FM Global. Two well known and reputable references. However, similar table can also be found in several of the other listed references.

The recommended separation distance can be reduced significantly where the transformer uses a less flammable class “K” insulated liquid rather than mineral oil. Further reduction in separation distance can be achieved if the transformer has enhanced protection features such increase strength of tank, pressure relief and additional fault current protection.

Table 16 : IEC 61936-1 2002 Recommendations for separation distances between outdoor transformer and buildings

Transformer Type	Liquid Volume (l)	Clearance to	
		Other Transformers or non Combustible Building Surfaces [m]	Combustible Building Surfaces [m]
Oil Insulated Transformers (O)	>1 000 < 2 000	3	7.6
	≥ 2 000 < 20 000	5	10
	≥20 000 < 45 000	10	20
	≥ 45 000	15.2	30.5
Less Flammable Liquid insulated Transformers (K) without Enhanced Protection	≥1 000 < 3 800	1.5	7.6
	≥ 3 800	4.6	15.2
Less Flammable Liquid insulated Transformers (K) with Enhanced Protection	**Clearance to Building Surfaces or Adjacent Transformers**		
	Horizontal [m]	**Vertical [m]**	
	0.9	1.5	

Note: Enhanced protection means: Increased Tank rupture strength, Tank pressure relief, Low current fault protection, High current fault protection. For examples of enhanced protection, see Factory Mutual Global's standard 3990 or equivalent.

Reference [12] provides guidance on separation between transformers and buildings and adjacent transformers as set out in tables below. This guidance is based on the type and volume of fluid in the transformers as well as the wall construction of the exposed building.

Table 17 : FM Global's recommendations for separation distances between outdoor transformer and buildings

Fluids	FM Approved or Equivalent Transformer	Liquid Volume [l]	Horizontal Separation [m]			Vertical Separation [m]
			2 Hour Fire Resistant	Combustible Walls		
				No	Yes	
Less flammable	Yes	n/a	0.9	0.9	0.9	1.5
	No	< 38,000	1.5	1.5	7.6	7.6
		>38,000	4.6	4.6	15.2	15.2
Mineral oil	N/A	< 1900	1.5	4.6	7.6	7.6
		1,900 to 19,000	4.6	7.6	15.2	15.2
		> 19,000	7.6	15.2	30.5	30.5

In addition to guidance on separation distances between transformers and buildings, FM Global also has guidance on separation distances between transformers and other equipment (namely transformers).

Table 18 : FM Global's recommendations for separation distance between outdoor transformers

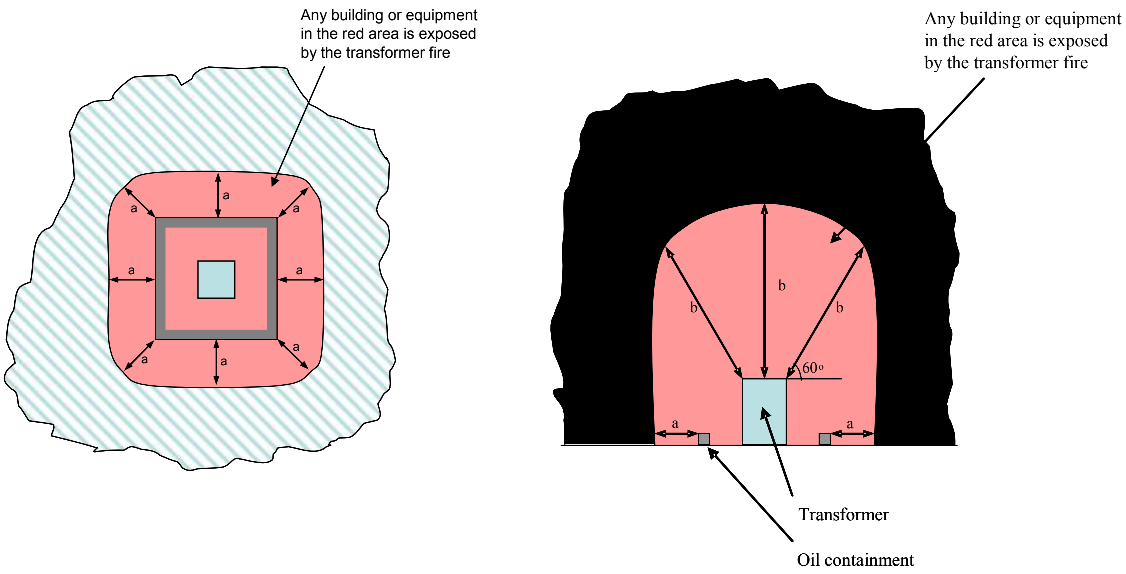
Fluid	FM Approved or Equivalent Transformer	Liquid Volume [l]	Horizontal Separation [m]
Less flammable	Yes	N/A	0.9
	No	< 38,000	1.5
		> 38,000	7.6
Mineral oil	N/A	< 1900	1.5
		1,900 to 19,000	7.6
		> 19,000	15.2

Reference [4] provides another set of recommendations for separation distance between outdoor transformer and other equipment.

Table 19 : ENA Document 18.-2008, Recommendation for separation distance between outdoor transformer and equipment

Transformer Liquid Volume [l]	Minimum Clearance to Other TXs or Non-combustible Building Surface [m]	Minimum Clearance to Combustible Building Surface [m]
1,000 < 2,000	3	7.5
2,001 < 20,000	5	10
20,001 < 45,000	10	20
45,001 < 60,000	15	30
> 60,000	23	30

The diagrams shown in Figure 41 are another way of visualizing the separation distances recommended to prevent a transformer fire spreading from exposing buildings and equipment. Any equipment or building that falls within the area defined by the red colour is exposed by a transformer fire. The distance "a" refers to the horizontal separation distances, and distance "b" refers to the vertical separation distance in the diagrams.



Side elevation view **Plan view**

Figure 41: Suggested separation distances.

7.3.3 Fire Barriers / Walls

Loss control measures utilizing separation as a means of reducing the risk of transformer fires is really only practical and cost effective for new projects. And even with most new projects, there is often not enough space to achieve the necessary separation distances to reduce the fire risk unless less flammable insulation fluid is used.

Where there is inadequate separation from buildings and adjacent transformers and equipment, fire barriers can be used to reduce the risk of a transformer fire causing damage to adjacent assets.

Recommendation from guides based on heat flux indicates that barriers/non combustible walls should be provided, if the heat flux in event of a fire is likely to exceed 5 kW/m^2 at adjacent buildings or transformers. The 5 kW/m^2 is considered a critical level and it is also considered a heat flux greater than 5 kW/m^2may cause shattering of porcelain bushings on the adjacent transformers.

Most guides prescribe that external walls, doors and fire barriers should have a fire rating of at least 2 hours [12] [4]. Reference [15] prescribes a 4 hours fire rating.

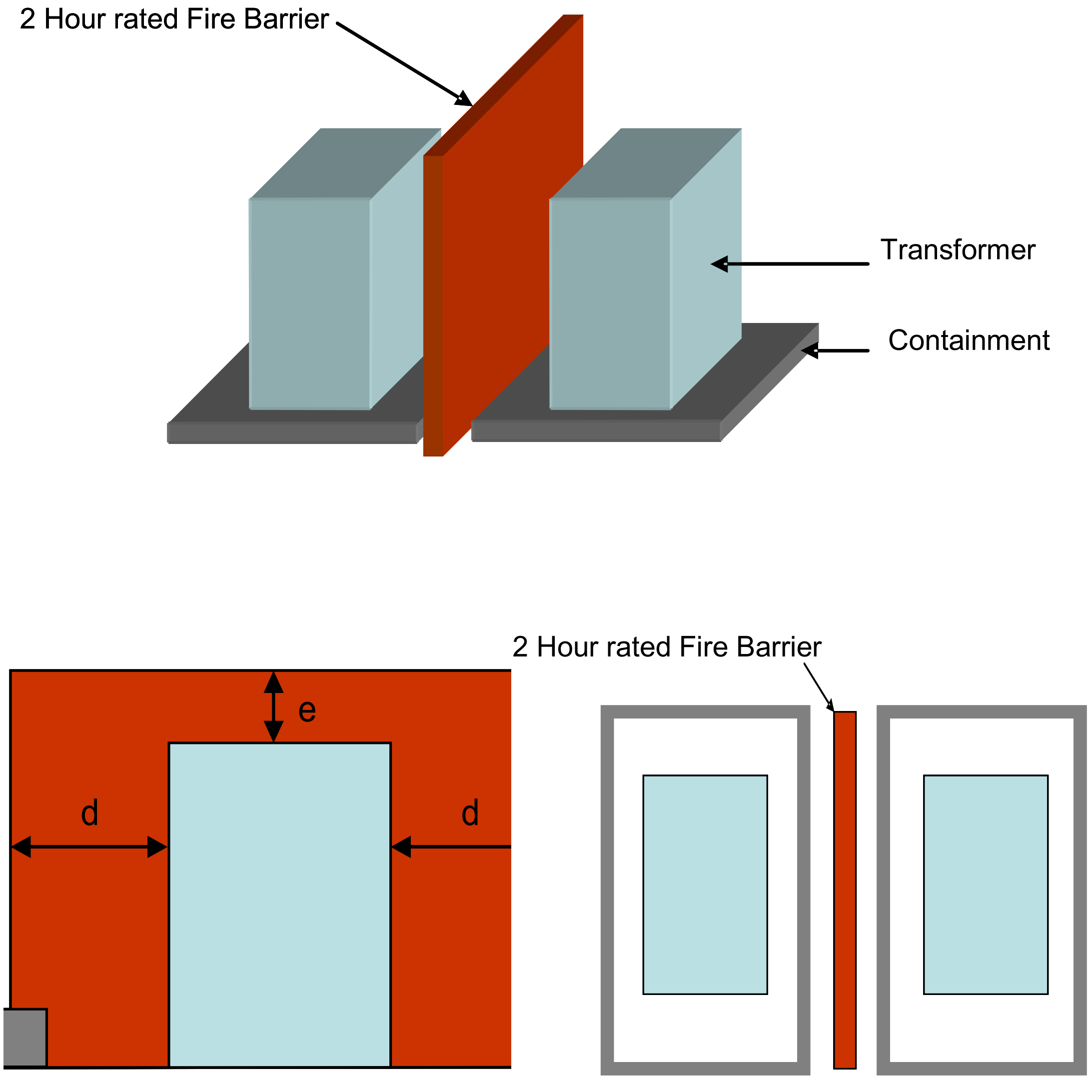
Fire rated barriers are typically constructed from reinforced concrete or masonry supported by reinforced concrete piers. But they can also be constructed by from metal protected by a fire and heat resistant material to give at least a 2 hours fire rating. There are many alternative products available from a range of suppliers.

Most guides recommend that such barriers extend 1 m beyond the potential fire pool perimeter/oil containment area and 1 m above the height of the bushings and the conservator.

The application of fire barriers to control the transformer fire risk can be complicated.

The following examples provided by FM Global show how fire walls are used in various scenarios to protect equipment and buildings from a transformer fire.

Figure 42 illustrates how a fire barrier is used to protect two adjacent transformers. FM Global advises that the fire wall should extend at least 600mm horizontally and 300 mm vertically beyond any transformer component that could be pressurized as a result of an electrical fault, including oil filled bushings. This is represented by the distance “d” and “e” respectively.



Elevation view

Plan view

Figure 42: Fire Barrier protecting two adjacent transformers.

FM Global has also defined a region downwind of a transformer where any building or equipment in this zone will be exposed by a transformer fire. Figure 43 shows the extent of this zone. The distance “c” is dependent on the oil volume. A distance of 4.6 m applies for oil volumes less than 19,000 l and a distance of 7.6 m applies for oil volumes above 19,000 l.

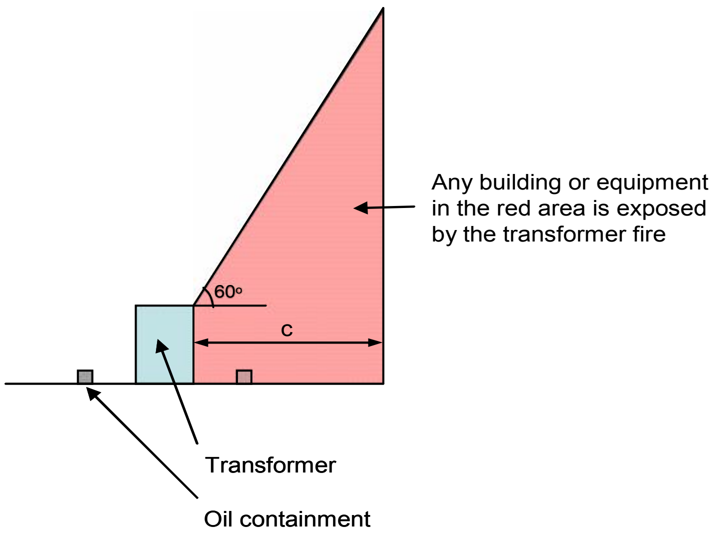


Figure 43: Zone of exposure downwind of burning transformer

Figure 44 illustrates how a fire barrier can be used to protect the roof of a building located downwind of a transformer from being exposed by a transformer fire. The exposed wall of this building has 2 hours fire resistance, which allows the building to be situated inside the exposed zone. However the roof of the building is now exposed. For the roof of this building to be protected from the transformer fire exposure, the exposed portion of the roof needs to be Class A (i.e. non-combustible) construction.

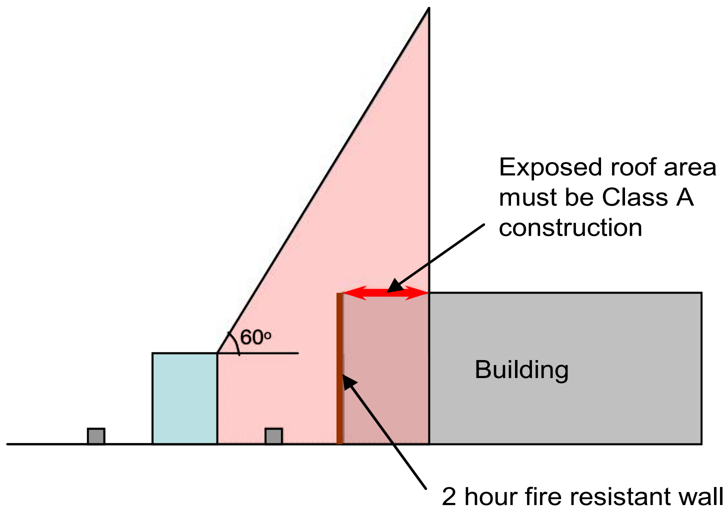


Figure 44: Exposed building roof downwind of burning transformer

The alternative solution is to extend the 2 hour fire resistant wall of the building as shown in Figure 45 and to use the wall as a fire barrier to protect the roof. Depending on the height of the building and how high we have to extend the wall, it is often too onerous to extend the wall beyond what would be considered a typical parapet height (less than 2 m).

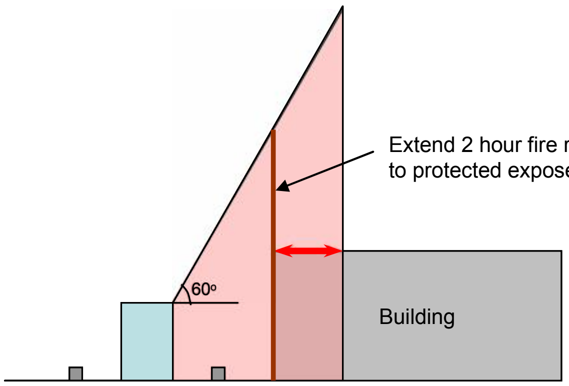


Figure 45: Extending building wall to protect exposed roof section

It is also possible that the exposed building is much higher than the transformer. In this case, only the exposed area of the wall of the building needs to be 2 hour fire resistant. The exposed wall area can be determined as shown in Figure 46. The horizontal and vertical distances “a” and “b” are taken from Table 18.

It should be noted that the vertical distance “b” is read from Table 18. It is not calculated from Figure 46 (by determining the height at which the 60^{o} line from the top edge of the exposing transformer intersects the exposed building). This is to simplify the process of determining the size of the exposed wall. The end result is more conservative.

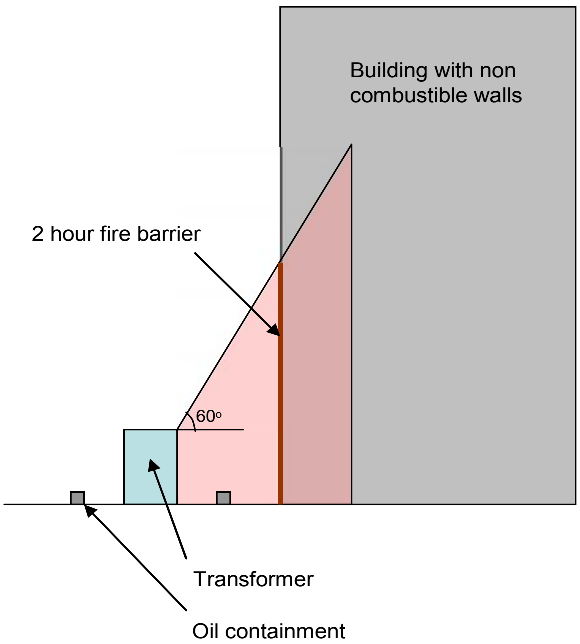


Figure 46: Side elevation of exposed area of a tall building

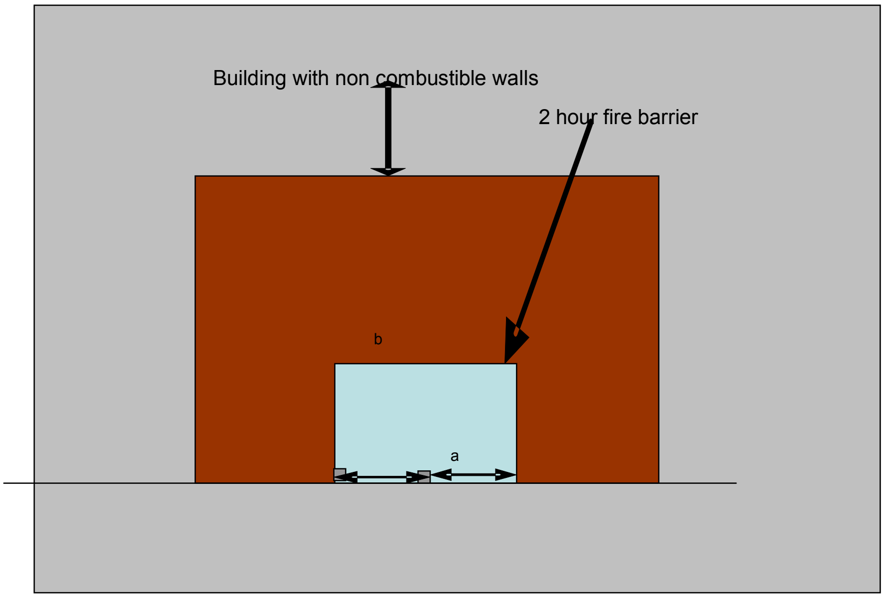


Figure 47: Front elevation of exposed area of a tall building

An open top masonry sound enclosure can be a very effective fire barrier as it can contain the fire within the enclosure. Most of the heat from the combustion will rise vertically into the air above the sound enclosure. The pictures in Figure 48 below illustrate the effectiveness of such an enclosure for fire containment. It is also interesting to note the silicone polymer insulators on the surge arresters were only burnt on the side facing the fire. They do not sustain a fire. The only component burning outside the enclosure is the upper half of the OIP bushing condenser which was blasted away from the Transformer to the outside of the sound enclosure wall, where it remained hanging, connected to a surge arrester by the flexible busbar lead.

The substation was de-energized for approximately three hours whilst the fire brigade extinguished the fire, but the supply could be restore quickly from the remaining two transformers as the fire was totally contained to the transformer within the sound enclosure.

The 110 kV HV switchgear and the 33kV secondary power cables and cable terminations located just outside the sound enclosure remained undamaged and serviceable. This allowed the burn out transformer to be replaced and supply restored from the replacement transformer within 10 days.

Fire contained to 1 of 3 transformers

Fire contained to within sound enclosure. Polymer SA insulators on top of enclosure wall only melted on side towards fire only. HV Switchgear remained intact.

Aluminium busbar partly melted, but secondary cables and cable terminations intact.

Top of transformer the day after

Figure 48: Fire on 80 MVA Transformer in sound enclosure

7.3.4 Oil Containments

Oil containment is important both from a fire risk reduction strategy and also from an environmental protection point of view. In this section oil containment is only discussed from the fire risk reduction and containment point of view.

The aim is to contain spilled oil to avoid a pool fire spreading to adjacent plant, structures and buildings and also to avoid it adding to the fuel load otherwise available to the fire as well as for environmental protection purpose. Older installation may have used earth barriers or dams, but modern day practice in most countries now uses an oil bunding which contains the oil either within the bunding or pipes it away to an oil / water separation tank or an oil tight storage pond away from the transformer. If the oil is kept within the bund surrounding the transformer, then it is common practice to it store it within or below the surface of rock ballast or other form of oil containment medium where the oil is out of reach of the fire.

7.3.4.1 Oil Bunding

Several forms of oil bunding exist, but the most common ones consist of an oil tight concrete base with a low 400-800 mm concrete, or oil tight masonry wall with the height determined so it can contain all oil from sudden loss of oil following a tank rupture, plus a percentage allowance for fire fighting water, if this is to be contained within the bunded area. The area of the bund should be sufficient to be able to capture all oil ejected from pressure relief devices, ruptured bushing turrets, main tank, oil coolers and the conservator. It is common practice to allow for an ejection trajectory of 30^{o} from vertical from the highest point on these structures.

All cable conduits or trenches should be raised and sealed so spilled oil and fire cannot enter cable paths to other plant items or buildings.

Several effective methods has been developed and the most effective and economic solution depends of several local factor, land available, terrain - flat or sloping ground, proximity to water courses. Climatic conditions, (rainfall, temperature snow fall, frost, dust or sand storm) each of these and at times other factors must be considered to determine the optimum solution for the specific sites.

7.3.4.2 Oil-Water Separation Tanks

A concrete bund connected to an underground oil/water separation tank, can be very effective in draining oil spilled from a ruptured tank, oil draining from the conservator due to a failed bushing, cable box due to failed cable terminations at sites with favourable terrain and climatic conditions. A relative simple oil water separation tank with a multi baffle system can separate oil from water with droplet size down to a 1mm diameter and still allow sufficient water to flow through the separation tank from fire fighting or sudden heavy downpour of rain and still retain the oil within the separation tank for recovery and safe disposal later. A common tank can be shared by multiple transformers. This means that the separation tank only need to be designed to hold the oil from the largest transformers plus an additional margin of 15-20 % as a buffer for water flow.

One of the great advantages of the use of the separate oil water separation tank is that the bunded area has a reduced size and the base can be left with an unobstructed concrete base which provided a low maintenance solution and a good safe surface area for maintenance work. An example of oil water separation tank is provided in Figure 49 below [62].

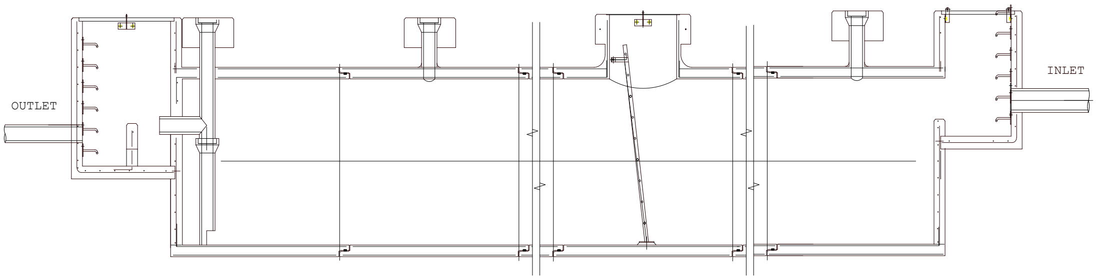


Figure 49: Example of an Oil-Water separation tank

The tank is constructed from modular large diameter concrete pipes with oil – water separation barriers provided at approx every 2 meters This tank can separate oil from water down to 1 mm diameter droplet size. For full details can be found in reference [62].

An alternative oil water separation tank design is shown in Figure 50. The tank is shown with both oil and water. As the specific gravity of oil is less than water this allow the oil on the top of the water to be separated from the water by overflow of oil into the oil tank area.

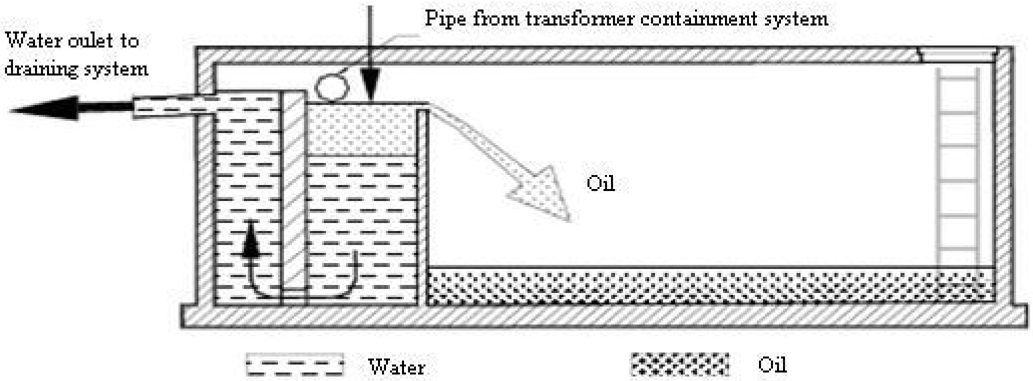


Figure 50: Alternative Oil-Water separation system

Depending on the size of the bund or the volume oil in the transformers one or two flow lines may be required to handle the flow of oil from a tank rupture. Each flow lines should be fitted with flame-trap at the oil bund end to ensure the fire cannot follow the oil to the oil separation tank Figure 51.

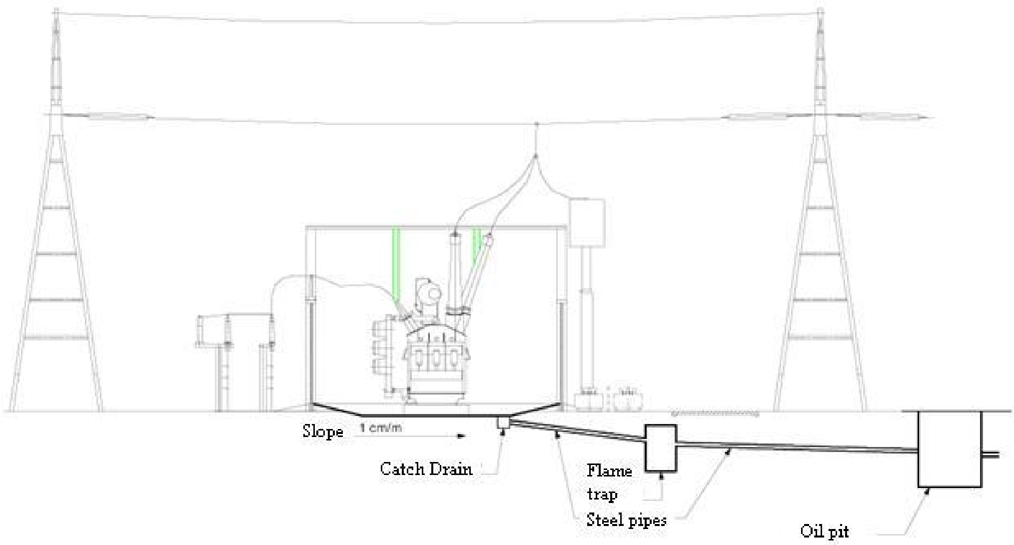


Figure 51: Oil separator installation

A variant from the underground oil separation tank is to direct the oil to a lined pond of sufficient capacity where oil and water can be contained at a fire safe distance from the transformers. The disadvantage of this arrangement is that the oil water separation must still be dealt with before possibly contaminated runoff rainwater and any fire fighting water can be disposed into nearby water courses.

7.3.4.3 Oil Containment within Bunds

Several types of bunds have been developed for this purpose. One of the common methods is to have the bunded are filled with a rock ballast, consisting of 30-50 mm diameter rocks. The rocks need to be clean and a reasonable size to allow oil to flow rapidly through the rocks. The volume of the bunding and the rock ballast must be sufficient to hold the total volume of oil from the transformer at 100mm below the surface of the rocks to ensure that a pool fire is not sustained.

The advantages of a rock-ballast are: That it can cool the oil and thus quench the fire by reducing the temperature to below the oils flame point and ensure vapours from hot oil is not ignited.

The disadvantages of rock ballasts are: The larger volume required for the bunded area, partly because the volume occupied by the rocks and also because it must be able to hold the large amount of water which may be required for fire fighting without the oil /water becoming exposed or overflowing the bund. Other disadvantages are the high maintenance requirements as collected rainwater must be drained from the bunded area regularly to ensure the bund retain its required capacity, usually via an oil water cleaning filter or other methods, as the bund may contain oil from minor leaks or spills from maintenance work, which is difficult to clean from the rock ballast.

Also rock ballast tends to collect dust and other wind born debris over times and may silt up and require cleaning at infrequent intervals. This is an important consideration, because it means that rock filled pits are not a practical solution in areas where there is a lot of dust in the environment, such as at coal fired power stations where fly ash and coal dust will quickly collect in the rock filled pit, or substations near mines, cement plants and ore processing facilities where dust is present in large quantities. Even substations located in areas where windblown dust from the surrounding land is common, are not suitable for rock filled pits.

A variant of the oil bund with rock ballast resting on bottom of the bund is to have the transformer raised on a plinth and the surrounding area partly or fully suspended at a grate which allows the oil and water to drain to a sump below the rock ballast or to a holding pond away from the bund. This reduces the volume required for the rock ballast and the bund.

Figure 52 shows a typical arrangement of such a rock filled pit. The rock layer must be sufficient to cool the oil and ensure the fire does not follow the oil entering the containment space below the rocks where it could then continue to burn as a pool fire.

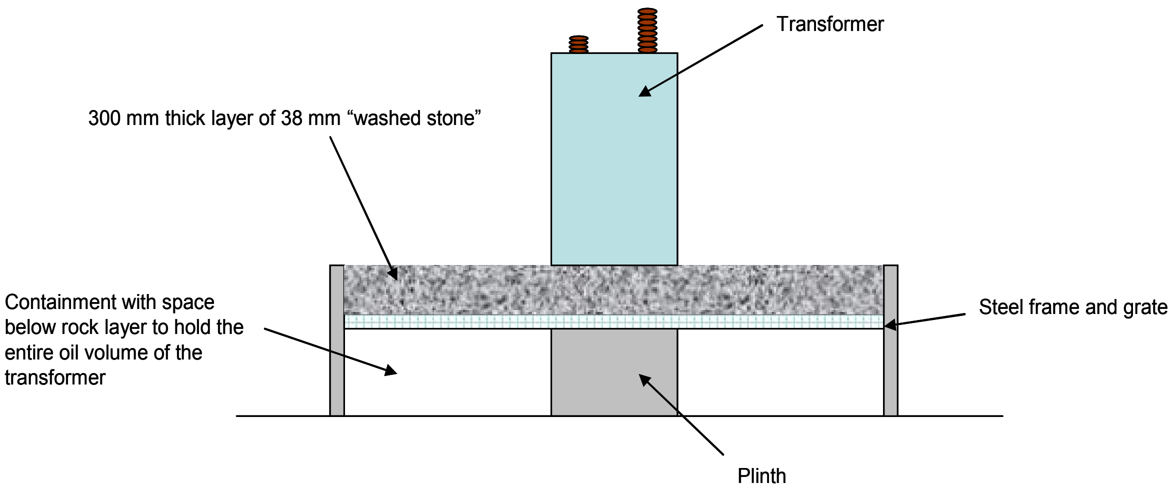


Figure 52: Rock filled pit arrangement

7.3.5 Active Fire Suppression Systems

Many forms of active fire suppression systems have been developed over time and there are too many for a short brochure like this to describe all these systems. The readers are therefore referred to References [5] [8] [9] [12] and vendor proprietary information for a fuller description of each system. The key point to remember is that when a transformer fault has developed in to an oil fire, then the transformer is in most cases destroyed. The aim is therefore o protect adjacent asset and minimize cost of collateral damage and not to “save” the transformer. A short description of some of the available systems is given in the following sections.

7.3.5.1 Deluge Systems

A deluge system is a fixed fire protection system in which the pipe system is empty of water and kept pressurized with dry air, until the a fire condition is detected and the deluge valve is operated to distribute pressurized water to the nozzles or sprinklers directing the water onto the protected object(s). Various types of sensors can be used in the detection systems. The common ones include sensors for detection of: heat, smoke, infrared and/or ultraviolet radiation. Some common types of detection sensors use a low melting point material at the spray nozzles, where the melting of the sensor causes a loss of pressure in pipe downstream from the deluge valve. The loss of downstream pressure causes opening of the deluge valve and activation of the deluge system. Other types of activation can also be used. The dry pipe system also allows this system to be used in areas where sub-zero temperatures occurs.

Deluge systems are typically used where quick application of large quantities of water is required to control a fire and protect high value adjacent assets, such as on generator and unit transformers in power stations, bulks supply transformers at industrial plant and major transmission or substation transformer in city locations. The deluge system can quench a fire externally to a transformer by cooling the fire and the fuel and also by reducing the oxygen available for the combustion. It can also cool the transformers tank, oil pipes and the cooler bank to prevent rupture form being caused by the fire and possible against explosion caused by heat from the fire. It does not prevent tank rupture caused by internal arcing from the initiating fault. Figure 53 shows a typical water spray arrangement for a transformer and its oil containment area in a diagrammatic presentation.

Nozzles and sprinklers must be aimed to project water across all horizontal and vertical areas to be protected, but not aimed directly at bushings. As this could possible cause flashover, or crack and rupture of bushings by thermal shock, not only during a fire, but also if the system is tested whilst the transformer remains energised.

A deluge system can also be effective for cooling adjacent structures and building surfaces to prevent deformation, structural collapse and the spread of the fire.

Foam can be added to a water deluge system. In such systems an air- or water-foam concentrate is introduced into the deluge water at a controlled rate. Foam water systems are used to control and/or extinguish fires, which require both smothering and a cooling agent. It can be effective on transformer fires as it can cover horizontal surfaces such as the top of the transformer and the bund floor area where it reduces the risk of a pool fire. It also adheres better to vertical surfaces than pure water. The disadvantage of foam is that the fire fighting water is contaminated with the foaming agent and may require decontamination before it can be released to the drains or nearby streams.

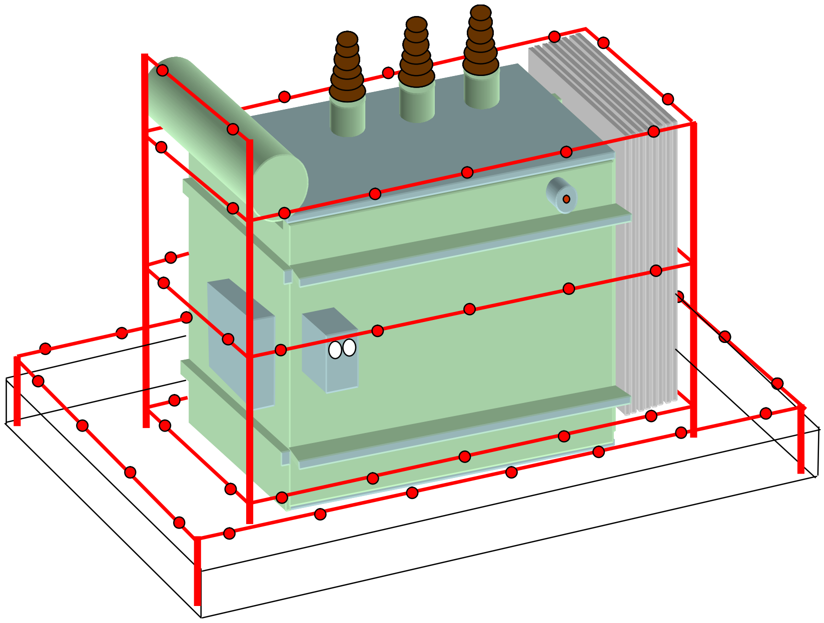


Figure 53: Typical water spray arrangement for transformer and oil containment area

Deluge system requires a large volume of water NFPA guidelines states 10.2 l/minute/m^2 for a deluge system for transformer fire protection. This means that the water must be available and the delivery system must be designed to deliver this quantity at the required pressure. The drainage/oil separation system must also be able to handle the large flow of water from such a system. However, it may be possible to reclaim and re-use of the water for ongoing fire fighting, if an effective oil-water separation system has been implemented as part of the design.

Figure 54: Water spray system with rock filled pit

Figure 54 shows a water spray system being tested on a transformer. Note that that there is no water spray protected directly onto the rock filled pit. This is not necessary as long as the pit has enough volume to contain any spilled oil and the fire fighting water well below the rock surface. The reduced flow volume of water will assist in this objective.

Cable insulation is considered to be the source of fuel and propagates the fire. Cable trays and cable run to and from the transformer must therefore also be included for protection by the deluge system.

To be effective a deluge system must be designed by design engineers, who have specific expertise in such systems.

7.3.5.2 Water Mist Systems

Water Mist is also an efficient fire-fighting medium. The difference between Water Mist and a traditional water based fire fighting systems is that the Water Mist systems require much less water as they uses have smaller water droplet (typically only 0.025 to 0.25mm dia. for high pressure water mist systems).

As heat absorption is a function of surface area and not volume, smaller droplets mean more surface area are available and therefore faster heat absorption for same quantity of water or equal heat absorption with much less water. When a droplet of water vaporises to steam, it expands by approx 1,600 times. Water mist is quickly converted to steam that smothers the fire and prevents further oxygen from reaching it. At the same time, the evaporation creates a significant cooling effect of combustion gases and blocks the transfer of radiant heat.

Water Mist combines the fire suppression properties of both conventional water-based deluge or sprinkler systems and gaseous fire suppression systems.

Water mist is available in both as low and high pressure systems. However for fire protection on transformers the high pressure system should be used as this is considered suitable for protection of machine containing Class B flammable liquid.

7.3.5.3 Water Curtain

Water spray protection with water curtain fire protection for adjacent transformer, is a high water volume water spray system where water is also sprayed in a narrow line between closely spaced objects as well as onto the object on fire. It is therefore especially suitable for fire protection of adjacent units of single phase transformer used to form a three phase banks. Fig.55 shows two banks of three single phase transformers protected by water curtain spray system between adjacent transformers.

Figure 55: Water curtain protection in Japan

A critical part of the design of Water Curtain protection is that there must be sufficient water available to maintain the required flow rate for the duration the protection is required. Where there are multiple transformers installed adjacent to each another, the water spray system needs to be designed for the simultaneous operation of the exposing transformer as well as all exposed transformers. For example, in a bank of six single phase transformers that are arranged in a row, it needs to be designed for the simultaneous operation of the water spray systems on at least three transformers, the one on fire and the two adjacent transformers.

7.3.5.4 Hypoxic Enclosure

Background. As previously stated oxygen is (among other factors) needed to start and sustain a fire. The oxygen dissolved in the insulation liquid is not accessible for a fire. Even if the gas analysis says 30,000 ppm oxygen in the oil, this is not a fire risk.

The solution to keep oxygen away from the origin of a fire has in the past successfully used carbon dioxide, halon, nitrogen and other gases. The disadvantage for all of these has been that human beings could be suffocated and for halon its environmental impact when release to the atmosphere.

It has been shown that there is oxygen concentrations in air, which prevents fire and still allows allow human to breathe.

Only a slight decrease of the oxygen concentration in air decreases the fire intensity and at 16 % oxygen in the air there is no risk of a fire. One mean to avoid a fire in an oil filled transformer would be to ensure the air surrounding the transformer has an oxygen content of less than 16 %. It would then be 100 % fire proof. Humans can continue to work in oxygen concentrations as low as 14-13% although with reduced work output. And can survive in air with concentration in the oxygen even below 10 %. However, when the air has an oxygen content of less than 17 % it is called hypoxic and there should be some time restraints on working in hypoxic air because the haemoglobin cannot not carry its full amount of oxygen. Fig. 56 shows graphs for fire intensity and haemoglobin as a function of oxygen content in air.

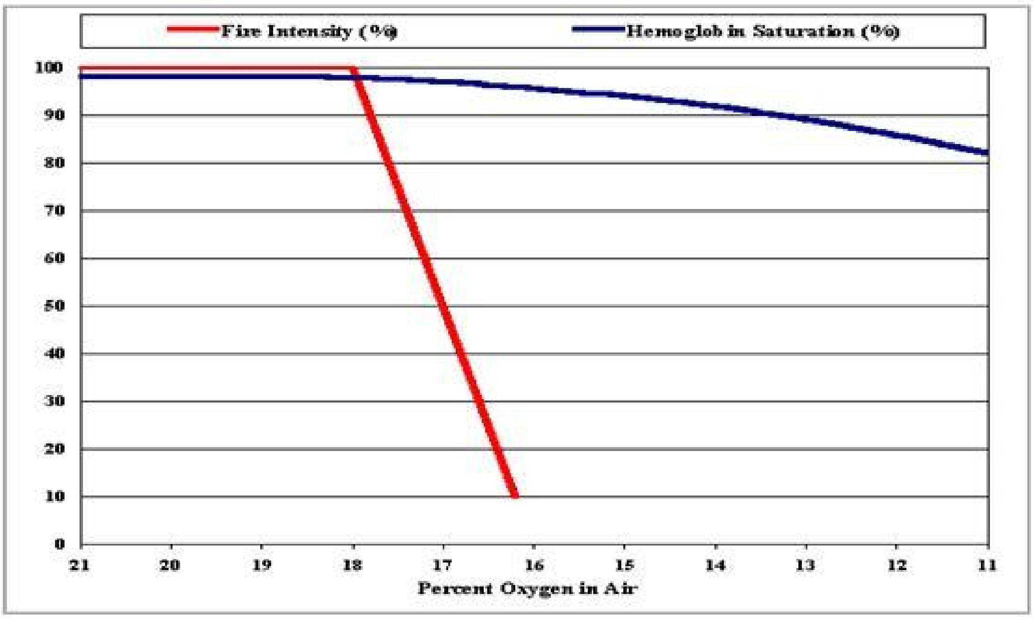


Figure 56: Oxygen percentage effect on fire intensity and haemoglobin saturation

7.3.5.5 Fire Suppression using Inert Gas for Oxygen Displacement

Compared with water spray system, gas injection system has advantages such as reducing civil work at installation, no necessity of securing water, reducing piping installation, and so on. It should be noted that for an Inert Gas for Oxygen Displacement or a Hypoxic enclosure to provide effective fire protection, the enclosure must remain intact. So pressure venting may be required to ensure that the enclosure is not breached by the transformer failure event.

Gas injection systems have in the past been using CO_2 or halon, but these gases have potential of attack to ozone layer and also have physiological influences. So today, from the view point of the global environmental protection and safety for human beings, the inert gas applied for fire protection of power transformers is now mainly nitrogen and also sometimes a mixture gas of Nitrogen, Argon, and CO_2, Nitrogen is a cost effective and readily available gas.

As an example, when nitrogen gas is discharged to extinguish a fire, the concentration of nitrogen gas and oxygen gas in the room will charge to about 87% (normally 78%) and 12.5% (normally 21%) by volume respectively, according a supplies data. This means that oxygen concentration can be reduced from 21% to 12.5% within 1 minute after start of discharge. Continuous combustion requires more than 15% of oxygen concentration by volume, so the above data shows that the gas mixture as stated above is effective for fire suppression.

For application on power transformers where sound insulation panels are installed the panel enclosure can be used as outer enclosure for the gas containment for the fire suppression.

It is required than any ventilation provided on the sound enclosure if fitted with dampers which closes during the gas injection and remains closed until the fire extinguishing is completed.

If there is no sound insulation enclosure, then an additional enclosure will be necessary.

Figure 57 shows a diagrammatic presentation of a gas protection system.

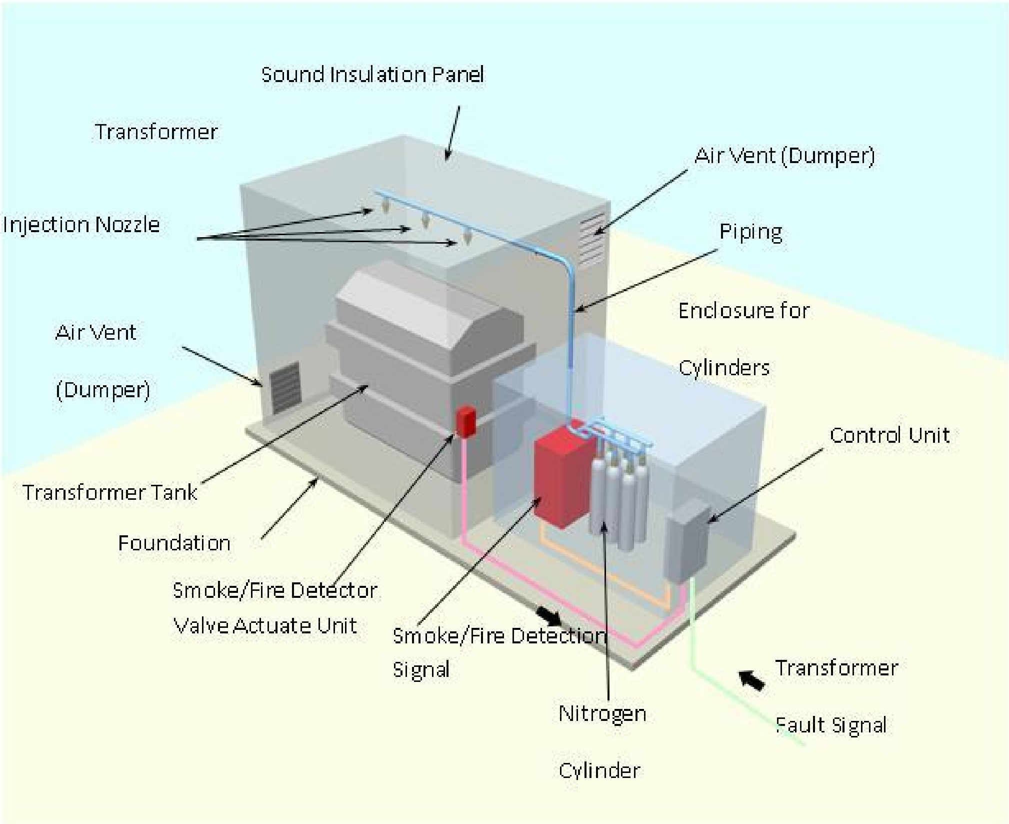


Figure 57: Transformer sound enclosure with Nitrogen gas fire protection

Figure 58 shows a photo of a two transformer installation in with sound enclosure panels and Nitrogen fire suppression system. The Inert gas cylinders are installed outside the sound insulation panel and can be located near transformer, then length of piping can be minimized.

Inert gas is injected into the enclosure by smoke detection signal and transformer fault detection signal. Selection and combination of trigger signal depends upon each user's practice and they are formed AND gate circuit for alarm evacuation. Transformer fault detection signal can be pressure relief device or Buchholz Relay.

Figure 58: Fire Suppression system using inert gas on transformers installed within sound enclosure panels

7.3.6 Indoor City Substations

Indoor city substations have many more aspects which need to consider from a safety point of view than is applicable for conventional outdoor substations located in areas with low population density. For indoor city substations human safety is paramount and if the probability of a transformer fire cannot be totally eliminated, then it must be reduced to an extremely low probability. This is especially so where a major city substation are located in the basement of a high rise office tower or with residential or business properties located wall to wall with the substation on a busy street with pedestrian traffic in front of the building.

The design of city substations are complex and each site must be studied and assessed on a case by case basis. It is beyond this document to address all the issues which must be considered for such installations.

Chapter 6: of this document discussed steps available to mitigate the risk of the transformer causing a fire, these steps are still applicable to indoor substations.

In this section we will discuss the consideration and key preventative measures which must be taken into account to prevent a fire spreading and endangering human life and adjacent assets from a fire spreading in the event a transformer failure occurs.

For this purpose we will discuss the key considerations and then present two alternative examples for city substation installations:

- one installation using mineral oil insulated/cooled transformers

- the other using SF_6 insulated/cooled transformers

The concepts and issues to be addressed for the two type of installation are quite different.

7.3.6.1 Key Considerations for City Substations

The keys issues of concern discuss are mainly, - but not solely from a Fire Safety Point of view.

- Proximity to other buildings and consequences of transformer explosion and fire, but also emission of hot air, noise and the need for access for delivery and installation of the transformers, other major equipment and its ongoing maintenance
- Pedestrian walkway beside substation, explosion and fire risk, (but also noise, hot air, installation and maintenance access)
- Community perceptions concerning probability and risk of transformer fires
- The indoor substation itself – explosion and fire risk to the building
- Containment oil and/or gases from major failure
- Containment oil and/or gases from minor leaks, including possible fumes from such leaks
- Provide oil and water retention systems to contain oil and foam contaminated fire fighting water.
- Prominence and special “value” of adjacent buildings and environment, uniqueness, heritage, river, etc
- Future building above substation – fire, noise, vibration, hot air, maintenance
- Aesthetics presentation and fit in with neighbourhood and street scape

The design of the building will need to take into consideration:

- The use of non-flammable or low flammability materials in the design of the transformers and in the substation building generally.
- Segregation and layout of transformers
- Fire and explosion protection for building
- Pressure release of oil and combustible gases following explosive failure
- Retention oil and water following a failure and fire
- Possible leakage or sudden release of gas from a gas insulated transformer
- Segregation and layout of the transformers and (reactors and capacitor banks where applicable) to mitigate the consequences of an explosion and fire.
- Choice of cable types and cable terminations and non combustible sheating materials or coatings
- Fire detection and fire fighting equipment
- Oil delivery, storage and processing during installation and future maintenance
- Incorporate fire and blast protection for the building itself and adjacent public areas and commercial developments, if an explosive failure is possible

- Access for delivery of plant during construction and the subsequent maintenance

Some of these the issues are very dependent on the choice of the transformer design and the insulation/cooling medium used in the transformer.

To illustrate the concept and design consideration for city substations it has been decided to provide a series of diagrams, sketches and photos which illustrate the concepts and then discuss the key the key points with reference these depictions.

7.3.6.2 City Substations Using Oil Insulated/Cooled Transformers

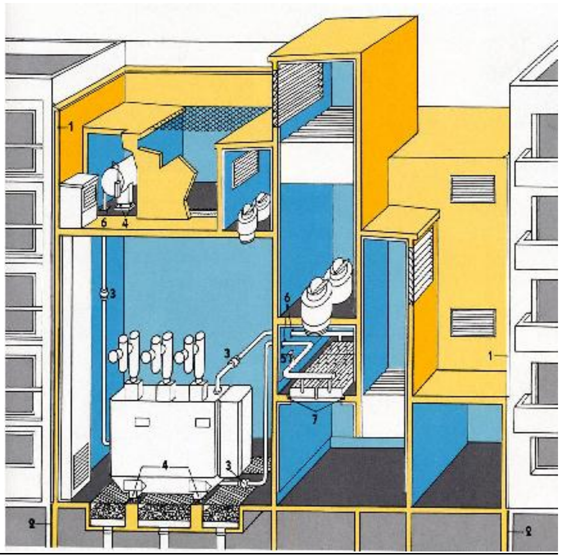
The illustrations in Figure 59 below have been provided by the member of the working group from RTE France. The illustrations are from substations located in Paris.

The most critical aspect for an indoor city substation with oil insulated transformers from a fire safety point of view is to avoid a transformer oil fire. In the substation designs depicted above this has been done by use of:

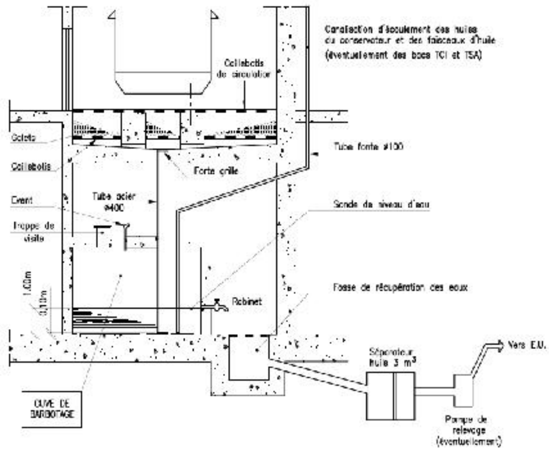
- Cables with dry insulation only
- SF6 insulated cable terminations and SF6 to oil bushings to minimize risk of a cable termination bushing failure initiating a fire.

The oil capture and bunding has been arranged to capture a large quantity of oil and cool it by passing it through a rock ballast grate and directing it safely away from the building.

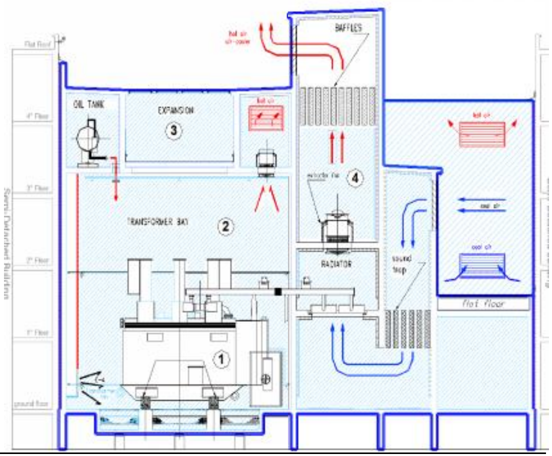
Exterior View. As can be seen from the picture the substation blends in well with the street-scape, with the only noticeable difference being the fairly wide access door



Internal arrangement of transformer and transformer ancillaries. Note Gas insulated bushings and cable terminations and stone grate over oil capture sump.



Schematic elevation view of oil sump with oil water separator.



Elevation view of arrangement for the transformer section of the substation.

Figure 59: Internal design of a city substation with fire protection consideration

7.3.6.3 City Substations Using SF_6 Insulated/Cooled Transformers

The illustrations used for the SF6 Gas insulated substation 330/132 kV has been copied from a paper and presentation material listed as Reference [63] which provides much more details of the background and choice of design than is listed in this Technical Brochure.

The key differences between a City indoor substation using oil filled transformer and a substation using SF6 insulated transformer and, switchgear and cable terminations are :

- There is no oil and SF6 is non combustible.
- The SF6 transformers and switchgear are virtually explosion proof and even if any of these should rupture or develop a leak, then they would only release a non-combustible gas.
- Combustible material used in the building can be kept to a minimum which leaves very little to cause or sustain a fire.
- Control cables and power cables up to and including 132 kV cables can be chosen with dry cable insulation.
- Cable sheeting can be non-flame propagating or painted with a non-flame propagating coating.
- This means that the fire risk can be virtually nonexistent and the fire protection can be kept to a minimum and no more than required for a standard commercial or residential building.
- The capital cost of large SF6 insulated transformers is substantial higher than the cost of oil filled transformer. But the substantial savings on building cost and fire risk reduction measures will to a large extent, if not fully offset the higher capital cost of the SF6 insulated transformers and is probably the only solution with a virtual nil fire risk transformer.

This then raises the question why with all the virtues of virtual nil fire risks, why is not all indoor city substations using SF6 insulated transformers. The most like cause is probably, that SF6 is not an environment friendly gas. Many potential users have severe concern with its potential impact on the environment if spilled or otherwise released into the environment.

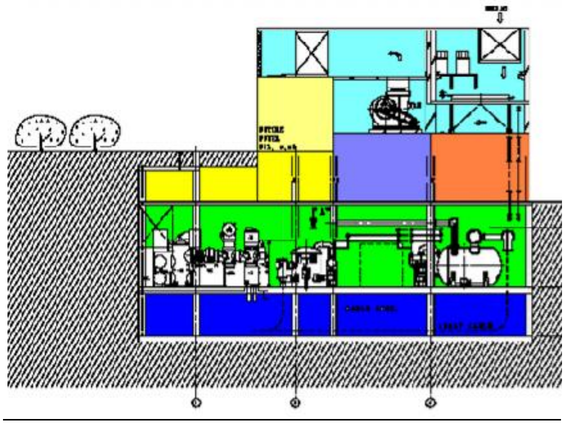
Some of the key consideration from a fire safety point of view listed in [63] are:

- Close to other buildings – noise, hot air, explosion and fire risk, maintenance
- Close to Darling Harbour – oil containment
- Indoor substation – explosion and fire risk to building
- Pedestrian walkway beside substation – noise, hot air, fire
- Future building above substation – noise, vibration, hot air, fire, maintenance
- Community perceptions concerning transformer fires

Depending on transformer design, there is a need to consider:

- Segregation and layout of transformers
- Fire detection and fire fighting equipment
- Fire and explosion protection for building
- Pressure release and combustible gases following explosive failure
- Oil and water retention following failure and fire
- Access for maintenance

External view



Cut through elevation view

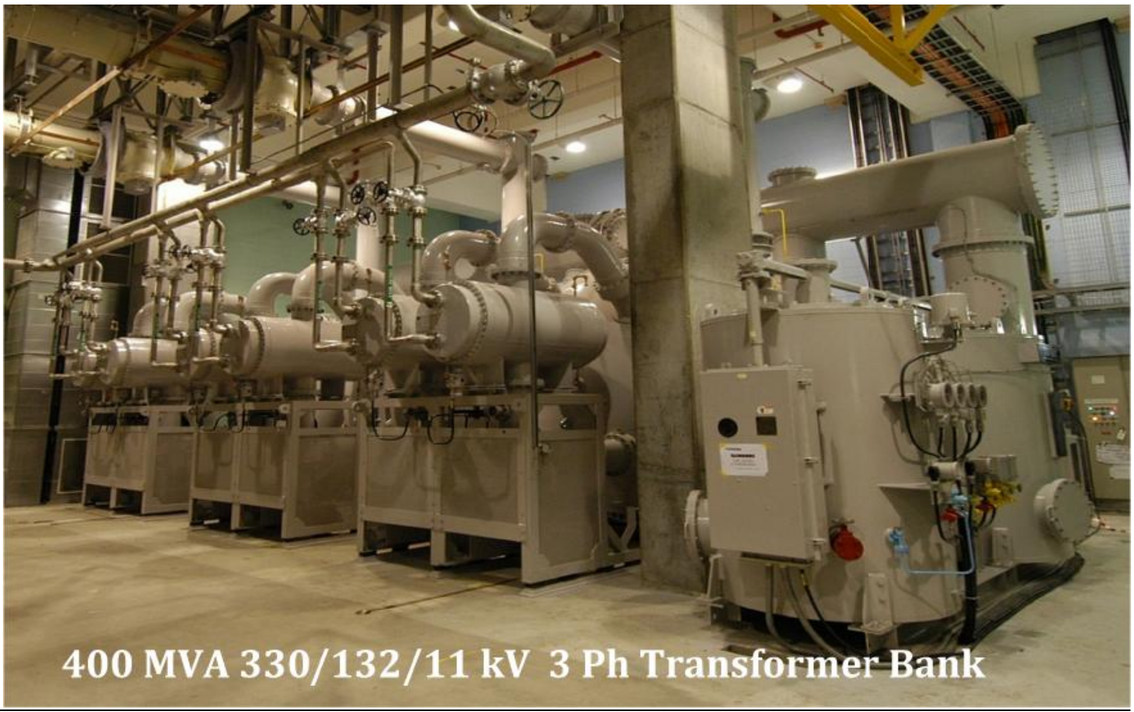


Figure 60: SF6 underground substation in Sydney [63]

The choice of SF6 insulated transformers solved or reduced the complexity of these design issues substantially:

- Because of the SF_6 transformers, only smoke detectors and water sprinklers are used - standard building design practice.
- All 132kV connections with solid insulation cables to GIS.
- 330kV cables have paper oil insulation, but are within substation buried in a sand/cement ix.
- 330kV cables are connected to GIS in building basement.

- Fire proof coating on major control cable runs.
- The SF_6 designs for main transformers and reactor have removed the risks of fire and explosion
- There is no risk of oil leakage into Darling Harbour.
- The containment and collection of SF_6 gas can be achieved with a reasonably simple building design.
- The SF_6 designs have allowed a significantly simpler and cheaper building design than oil insulated designs.
- Minimal fire protection systems apart from standard building requirements.

7.4 Underground Substations

Fire Protection for Underground substation are complex and varies significantly between the types of underground substation and therefore must be assessed on a case by case basis and this document can only address some of the basis considerations.

However, the common requirement for all underground substations is to reduce the fire risk to a very low risk value. This is true whether it is a mining shaft, a power generation station, or a distribution substation.

The following measures are considered by various industries as best practices in terms of implementing fire risk management for underground substations using oil filled power transformers.

- The transformers are located on their specific transformer hall which is isolated from the other important assets, like generators and turbines hall and also from buildings/chambers often occupied by people.
- Each of the power transformers is located in its specific bay, which has fire and blast walls on either side.
- Where is there a number of power transformer, say exceeding three, it is recommended to further subdivide the transformer hall e.g. two units on the left and two units on the right of the access tunnel if there were four transformers. The main access tunnel will then run between these transformer groups.
- Transformers are normally fitted with the emulsifier system or other oxygen exclusion system which enables automatic fire fighting. In addition to these protection deluge or water mist or water based foam system may also be installed to contain and extinguish any fire in the wider area around the transformer.
- The oil catchment and containment areas must be such that it is not possible for a burning oil to flow pass the other areas.
- The fire/flame detectors are usually positioned at several locations near the transformers and within the transformer hall.
- Like in ground level installations, the transformer bays are equipped by a bund wall which contains oil spills. The spilled oil will then be channelled into an oil catchment area where it is contained.
- The air conditioning system must be linked to the fire protection system and must switch off when fire is detected in the area.

- The main access doors at the tunnel opening and the transformer hall must be closed shut to provide some containment from the transformer hall.
- Personnel have to have an escape route located alongside the lifts which is far away from the transformer hall side.

7.5 Highest Impact Strategies

(The following is from an industrial insurer's point of view)

7.5.1 Outdoor Substations

The following **passive** loss control alternatives are recommended for reducing the risk associated with transformer fires:

Physical Separation

The main hazard associated with mineral oil filled transformers is the severe fire exposure presented by a high heat release, long burning oil pool fire. The most effective means of controlling this exposure is by separating important buildings and equipment from burning transformers.

Fire barriers

It should be noted that fire barriers used to control transformer fire risk do not need to be blast walls. The pressure exerted on the fire barriers during a transformer explosion is no higher than the normal wind load the fire barrier has to withstand. This is always true as long as the transformer is not enclosed on all sides.

Since fire barriers for transformer exposure protection only need to be 2 hour fire resistant construction, no special foundations or reinforcement are needed to install these fire barriers. This has given rise to a growing market for lightweight, modular fire barrier products. These products make it cheap and quick to install fire barriers and also allow the fire barriers to be removed for maintenance access.

Rock filled pits

Another passive loss control measure against transformer fires is the use of rock filled pits to contain as well as extinguish the oil pool fire from a transformer failure.

Water spray system

Where passive fire protection solutions are not practical or cost effective, a water spray system designed to provide 12 mm/min over the transformer surfaces and 8 mm/min over the oil containment area can be used to control the transformer oil fire and prevent it from exposing other equipment and buildings.

7.5.2 Indoor Substations

The insurer also recommends the following **passive** methods for reducing the fire risk associated with mineral oil filled indoor transformers:

Elimination or reduction of the hazard

It is possible to eliminate or reduce the fire risk associated with an indoor transformer fire by utilizing dry type, gas insulated, FM Approved or equivalent, and silicone filled transformers. These low fire risk transformers were discussed in the previous section for outdoor transformers.

Three hour fire resistant construction

Where it is not practical or cost effective to utilize low fire risk transformers, the exposure presented by indoor mineral oil filled transformers to the rest of the building can be controlled by housing the transformer in a three hour fire rated area. This area has to be liquid tight to prevent burning oil from flowing outside the cut-off area.

Where multiple transformers are located in the fire cut-off area, each transformer should be located within its own three hour fire rated room.

It is also good practice to locate the fire rated area along an outside wall of the building and on the ground floor where practical. This will facilitate manual fire fighting efforts, minimize the fire exposure to the rest of the building and make it less onerous to achieve the required three hour fire rating.

Reference [12] recommends the following **combination of active and passive** methods for reducing the fire risk associated with mineral oil filled indoor transformers:

One hour fire resistant construction with automatic fire protection

It is not always practical or cost effective to construct a three hour fire rated room to contain the exposure presented by indoor mineral oil filled transformers. In these cases, automatic fire protection can be used to reduce the fire rating of the room. The automatic fire protection options are:

- Carbon dioxide extinguishing systems
- Water mist systems designed for machinery spaces
- Sprinkler systems (designed for a density of 12 mm/min over the entire fire area)

Where multiple transformers are located in the fire cut-off area, automatic fire protection designed to protect the entire cut-off area can be used in lieu of locating each transformer it is own separate cut off area.

A unique hazard associated with indoor oil filled transformer is the **non-thermal damage** exposure to equipment in the building where the transformer is housed. For example electronic relay and DCS equipment in substation and power station equipment rooms, or power electronics in the valve hall of HVDC substations. Where this exposure exists, steps should be taken to mitigate this exposure. These steps normally include the provision of a mechanical ventilation system, venting to an area that does not expose the occupancy and should be supplied from a power source that will not be affected by the transformer fire.

Chapter 8: Plans for a Fire Event

8.1 The Importance of Planning for a Fire Event

The earlier chapters of this report provide advice for preventing or reducing the risk of transformer fires. Solutions for controlling the damage caused by transformer fires were also presented.

However, even with the best loss prevention and control measures in place, without a proper contingency plan the damage and business impact caused by a transformer fire can still be significant.

A study [68] conducted by a large property insurer analyzed 100 random losses. Of these losses, 54 had some amount of contingency planning in place prior to the loss. The average cost of these 54 losses was US$7.1 million. Where contingency plans were poorly developed the average cost was US$7.9 million. However, where proper contingency plans were available, the average cost dropped to US$4 million – a 51% reduction in the loss cost.

Figure 61: Loss analyzed for contingency planning (Average loss totals in US$ Millions)

This study shows not just the importance of contingency planning in reducing the impact of a loss, but also the importance of having a properly developed contingency plan in place. Very often, companies view contingency planning as a paper exercise and falsely believe that they have proper contingency plans in place after developing an emergency response procedure and posting the procedure for its staff to read.

8.2 Contingency Planning

Good contingency planning should consist of three separate plans:

- An Emergency Response Plan (immediate to short term mitigation)
- A Disaster Recovery Plan (short to medium term mitigation)
- A Business Continuity Plan (short to long term mitigation)

Because contingency planning is very much influenced by local conditions, it is not possible to provide a definitive guide to proper contingency planning. This chapter provides general guidelines for developing an effective contingency plan with a special focus on managing transformer fire events.

Additional reading on contingency planning can be found in References [23] [24] [64] [65] [66] and [67].

8.3 Emergency Response Plan

The Emergency Response Plan is the initial "reaction" to an incident. This plan focuses on how local personnel respond to an event in the minutes to hours following an incident.

The objectives of the Emergency Response Plan are:

- Personnel safety
- Damage containment
- Damage assessment

Emergency Response Plans are very critical. How well local personnel react to a fire event often determines the size of the loss.

A study [68] by a large property insurer where 1,341 losses were analyzed over a recent 10 year period showed that where emergency response was effective, the average loss cost was US$1.3 million, compared to an average loss cost of US$5.3 million where emergency response was ineffective.

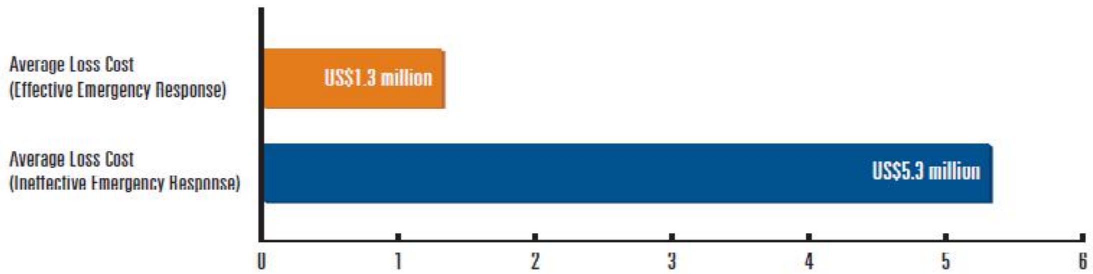


Figure 62: The impact of effective emergency response

8.3.1 Emergency Response Policy

The Emergency Response Plan should be formalised by developing a policy that is supported by senior levels of management. The policy should include the following sections:

A Purpose section to declare the company's intent and objectives. It should also specify limitations to the response to certain site-specific incidents. For example, the policy may state that it is the company's decision not to fight certain types of fires. Instead, only defensive action would be provided until the public fire service arrives.

A Policy section to outline the emergency response plan and to state executive management's commitment to the emergency response plan. The policy should be reviewed at least annually to ensure that changing conditions are included and kept up to date.

A Responsibility section to designate the persons responsible for generating and maintaining the emergency response plan.

Having an Emergency Response Policy in place communicates the importance of the Emergency Response Plan to employees and lets the Emergency Response Team know that their role is considered to be critical to the company's ability to handle and recover from emergencies and disasters.

8.3.2 Members of the Emergency Response Team

Staffing the Emergency Response Team (ERT) will depend on local conditions. Large generating stations typically maintain fully staffed ERTs. These dedicated teams may not be feasible when dealing with remote unmanned facilities. This limitation has to be recognised and taken into account by the company when developing the Emergency Response Policy. For example the recognition that it is not practical to maintain a fully staffed ERT may result in a risk management decision to apply only passive means of fire control to manage transformer fires and to rely entirely on the local authority Fire Department to manage the fire. This is likely to result in higher business impacts and is a risk that the company must accept.

Table 20 gives a generic list of the members of a typical ERT. The responsibilities of each member of the team have also been described as it relates to a transformer fire event.

The ERT Leader is a key member of the Emergency Response Team.

In addition to their responsibilities during an emergency, the ERT Leader is also responsible for the following:

- Develops a Pre-Incident Plan with the Fire Department (please see Chapter 8.3.3 below).
- Organises regular familiarisation visits to the substation for members of the Fire Department.
- Develops step by step response procedures for handling transformer fire events as well as other emergencies.
- Co-ordinates regular training for the ERT members and involves the Fire Department in emergency response exercises.
- Audits and updates the emergency response procedures and the emergency response policy regularly, especially when there have been any changes in either the substation or the company's operating practices.

Table 20: Responsibilities of the Emergency Response Team

Position	**Responsibilities**
ERT Leader	• Directs the ERT actions during an emergency. • Co-ordinates with Emergency Services personnel. • Communicates with the Disaster Recovery Team and senior management. • Ensures that material required by the ERT such as hoses, foam concentrate, spill containment kits, breathing apparatus, radios and torches are available.
Notifier.	• Ensures that the emergency services are properly notified of the event. • Notifies ERT members of the emergency. • Ensures that the ERT is properly staffed and arranges for alternates when necessary.
Fire protection system operator	• Has a full understanding of the fire protection system and makes sure that the fire protection system is operating correctly during the fire event. • Ensures that the control valves supplying the fire protection systems at the fire area remain open until instructed otherwise by the ERT Leader or the Emergency Services Leader.
Fire pump operator	• Has a full understanding of how to operate the fire pump. • Checks that the fire pump has started in a fire event and is able to start the pump manually if needed. • Ensures the fire pump stays running until instructed otherwise by the ERT Leader or the Emergency Services Leader.
Fire fighting team	• Depending on the level of training and expertise, the ERT's fire fighting team may carry out significant manual fire fighting efforts in support of the Fire Department. • In most cases the fire fighting team is only equipped and trained to carry out basic fire fighting using fire extinguishers and small hose lines.
Switching personnel	• These are key members of the ERT because they carry out switching operations to make the substation safe for the ERT fire fighting team and the Fire Department.
Support personnel	• Depending on the local conditions, support personnel may include fitters whose role is check that oil containment, oil separation and oil drainage systems are functioning properly. • They may also be responsible for setting up temporary lights and barricades to assist the ERT fire fighting team and the Fire Department with their fire fighting efforts.
Salvage team	• A salvage team may be *needed* if the fire event is expected to expose nearby equipment and buildings. • The salvage team may take steps such as salvaging important documents from exposed buildings, moving exposed equipment away or protecting equipment from fire-fighting water or foam.
Evacuation co-ordinator	• The evacuation co-ordinator makes sure that all personnel have been safely evacuated and accounted for.

8.3.3 Pre-Incident Planning with Emergency Services

A key component of an effective Emergency Response Plan is pre-incident planning with Emergency Services, in particular the Fire Department. It is a widely held misconception that because fire-fighters are trained to fight fires, the Fire Department will be able to handle a transformer fire. However, fighting a transformer fire is a something that most fire departments are not trained to handle, especially volunteer Fire Departments that are most likely to respond to a transformer fire at a rural substation.

Even professional metropolitan Fire Departments consider transformer fires in electrical substations to be a special challenge for the following reasons:

- Risk of electrocution: Fire Departments will generally not attempt any fire fighting efforts until they are assured that the electrical hazards have been removed and it is safe to enter the substation. If there is no emergency response plan in place, there may not be any person that can give this assurance to the Fire Department.
- Unfamiliarity with fire fighting capabilities: Electrical Substations are usually not supplied by the public water supply and will often have their own fire fighting systems. Unless the Fire Department is familiar with these fire fighting systems, they are unlikely to utilise any of the substation's fire fighting systems to fight a fire. The Fire Department may also choose to isolate the substation's fire protection system if they are unsure about its operation.
- Hazardous Materials: The Fire Department usually need to be aware of all hazardous materials present on site before they will commence fire fighting efforts. Without this knowledge the Fire Department may not even be willing to apply water to the fire in case there are materials in the substation that may react dangerously with water.

Security: Electrical substations are often high security areas that are deliberately poorly signposted. If the Fire Department does not know the location of the electrical substation, they may not be able to respond in a timely manner. The Fire Department will also be reluctant to enter the fenced perimeter of a substation if there is no-one available to grant them access and to assure them of safe working clearances to live electrical equipment.

Because of these special challenges, it is important to involve the Fire Department in the development of the Emergency Response Plan. In particular, the ERT leader should develop an Incident Command System with the Incident Commander of the Fire Department where the roles of the Fire Department and the ERT are clearly defined. The Fire Department and the ERT should work as a team to handle any emergency at the substation.

The Fire Department should also be taken on a regular familiarisation tours of the substation so that they are aware of all the special conditions that would affect their fire fighting efforts. The substation's fire protection systems should be explained to the Fire Department so that the Fire Department is aware that of the fire control philosophy adopted by the substation. For example, the substation may use fire walls or water spray systems to contain a transformer fire to the affected unit. This approach means that the Fire Department no longer has to apply water on adjacent equipment or buildings to prevent fire spread. This would significantly reduce any damage caused by fire fighting efforts and would also reduce the urgency with which the Fire Department needs to respond to a fire at the substation. This may allow for a controlled shutdown of the substation with minimal customer impact.

Familiarisation tours of the substation will also allow the Fire Department to develop a Hazardous Materials Response plan so that their Hazardous Material team is aware of the actions that need to be taken during a substation fire. The Fire Department should also be involved in the development of the Emergency Response Procedures. And wherever possible, joint exercises should be conducted with the ERT team and the Fire Department in-order to understand and test the inter-relationship of each group's reaction to various emergency scenarios.

Figure 63: Situation where no Emergency Response Plan was in place.

Figure 63 above shows the consequence of a transformer fire where no Emergency Response Plan was in place. The fire was reported to the Fire Department by the public. And when the Fire Department arrived, there was no utility personnel present to co-ordinate fire fighting efforts or to give the Fire Department access to the substation. The Fire Department ended up fighting the fire from outside the substation fence. Fire fighting efforts had minimal impact on this loss.

8.4 Disaster Recovery Plan

The Disaster Recovery Plan is the ongoing process of disaster mitigation. The objectives of the Disaster Recovery Plan are to expedite the following actions:

- Damage assessment
- Damage control
- Recovering business operations

Whereas ERT members are selected from local personnel, the Disaster Recovery Team (DRT) should be comprised of members with senior management roles and having a high level of decision making authority.

This is necessary because the DRT may need to make decisions that place the company at an increased risk in order to expedite the recovery from a transformer fire. These actions may include operating the electrical system at a reduced state of reliability, altering protection relay settings such that the system is at a reduced level of protection, or operating equipment at above their nameplate ratings. The DRT may also need to engage contractors and authorise large sums of expenditure to expedite damage control and business recovery activities such as authorising the use of mobile substations, rental transformers, and emergency generation to restore power to customers affected by the transformer fire.

In the same way that local conditions play a large part in the make-up of the ERT, it is also not possible to exactly define how the DRT should be staffed. However, an effective DRT should include the following roles as a minimum:

Table 21 : Responsibilities of the Disaster Recovery Team

Role	Responsibility
A crisis or incident management team	• Strategic decision making and communication with executive management and other high level stakeholders. • Expediting the recovery of operations to pre-incident conditions.
A site disaster recovery team	• Early damage assessment. • To provide advice to the crisis management team on different damage control actions as well as options for expediting recovery to pre-incident conditions. • Communication and liaison with Emergency Services as well as other authorities such as the Environment Protection Agency.
A media spokesperson	• To provide a positive commentary to the public, company staff, customers and other stakeholders about the disaster.
An insurance company liaison	• Works with the insurance company to report the loss and to track the costs associated with expediting recovery to pre-incident conditions. • Utilise the insurance company's resources to help the company recover quickly from the transformer fire.

Although the importance of the Crisis Management Team and the Site Disaster Recovery Team is self evident, the role of a Media Spokesperson should not be overlooked. A transformer fire is a highly public event and if the news of this event is not properly managed, the public image and reputation of the company may be adversely affected. This could in turn translate to a loss of market value and market share. Negative public sentiment could also impede the company's efforts to recover quickly from this event.

The role of the Insurance Company Liaison should also not be overlooked. Involvement of the insurance company as early as possible will ensure a quick recovery to normal operations. It is often in the insurance company's interest for their clients to recover as quickly as possible from a disaster and the insurance company may be able to help expedite recovery by offering to pay for contractors that can help with clean up, decontamination, forensic investigation and repairs. Because of their past experience with similar losses, the insurance company often has good access to contractors who specialise in business recovery activities. This makes the insurance company a good resource to help with business recovery strategies.

One other key responsibility of the DRT that has not been discussed is the decision to invoke the company's Business Continuity Plan.

8.5 Business Continuity Plan

It is beyond the scope of this document to provide detailed guidance on Business Continuity Plans. These are business continuity strategies developed at executive management level to recover from a disaster as quickly as possible while addressing the impact of the disaster to its customers and preserving the company's market value.

For a transformer fire event, the business continuity strategies include the contingency plans for dealing with severe transformer failures such as:

- Entering into an agreement with transformer manufacturers to maintain a manufacturing slot that can be used in an emergency to expedite the delivery of a replacement transformer.
- Entering into a transformer leasing program with transformer manufacturers where the manufacturer commits to providing spare transformers in an emergency.
- Purchasing replacement transformers from competitors or from the used equipment market.
- Re-directing transformers currently being built for another substation or project to replace the failed transformer.
- Expediting the manufacture of a replacement transformer by paying additional costs to the manufacturer.
- Expediting the delivery of a replacement transformer by arranging for air transportation.
- Maintaining an inventory of spare transformers.
- Drafting transportation plans to move transformers.

To be effective, these business continuity strategies need to be developed, implemented and documented before an emergency occurs. These strategies should also be regularly reviewed and updated to ensure that all assumptions made are still correct.

8.6 Summary

It is the responsibility of the management to ensure that good loss prevention and control measures are in place to manage the risk of a transformer fire.

Chapter 9: Conclusions and Recommendations

9.1 General

The conclusions for this brochure are divided into two parts: Actions to avoid a transformer fire and actions to mitigate the damage of a transformer fire that has already started.

The probability of a transformer causing a fire is low (reported typically 0.01-0.4 %), but not negligible and the consequences can be very severe if it does occur. The aim of this brochure is to promote "Good Fire Safety Practices". However it is recognized that whilst it is possible to reduce the probability of a transformer failure causes a transformer fire significantly, it is not possible to eliminate the risk of transformer fires totally.

9.2 Actions to Avoid a Fire

To avoid a fire the fire triangle shown in Section 2.1, provides a very good graphic representation of what is required to initiate and maintain a fire and therefore also how a fire can be prevented or extinguished.

- Without oxygen there will be no fire.
- Without heat there will be no fire.
- Without fuel there will be no fire.

A general recommendation is to reduce the probability of in-service failures and consequently the probability of a transformer failure causing a fire.

9.2.1 Electrical Protection

Ensure the transformers have fast, good quality, duplicate protection and preferably 2 cycle circuit breakers. This will reduce the impact of through faults and minimise the arcing energy within transformer if an internal failure does occur.

9.2.2 Bushings

Oil Impregnated Paper [OIP] bushings are the single largest cause of transformer fires. The risk of fires being initiated by a failure of a Resin Impregnated Paper [RIP] bushing or a Synthetic Resin Bonded Paper [SRBP] bushing is significantly lower than for OIP bushings.

9.2.3 Cable Boxes and Terminations

Cable termination failures in air or oil filled cable boxes are the second largest cause for transformer fires. It is recommended that cable termination inside a cable box is avoided wherever practical to do so, and the cable termination be made at a cable termination pot head and the connection to the transformer be made via rigid or flexible busbar connections. Alternatively, use of plug-in type cable connections is recommended.

Where termination of the cables in a cable box is the only practical solution, then special precautions should be taken to minimise the risk of an explosive failure of the cable box from arcing within the cable box.

<u>Air insulated cable boxes:</u>

It is strongly recommended that all air insulated cable boxes be fitted with pressure relief venting with a venting capacity similar to that used on medium and high voltage metal clad switchgear. The pressure vent should be designed to open well below the rupture withstand capability of the cable box.

Oil insulated cable boxes:

The safest design for oil filled cable boxes is a single phase cylindrical design raising vertical, with bottom cable entry and a large rupture disc discs or PRV mounted at the top cover of the cable box. Cable box should be designed so the top cover is the weakest point of the cable box so if a rupture occurs then it is at the top cover of the cable box and the arcing products are vented safely.

The cable box oil supply should not be connected to the main tank or the main conservator as this can cause release of a large volume oil feeding a fire. It would be better to design the cable box with an air or nitrogen cushion at the top part of the cable box or provide a separate small common conservator for the three cable boxes.

The air / nitrogen cushion design has the benefit of reducing the pressure gradient during an arcing fault and also ensuring that the vented product is a mixture of air / nitrogen and arcing gases and not oil.

9.2.4 Tanks

An electric arc is almost the only normal way to rupture the tank and start a fire. The transformer is normally lost if there has been a major arc inside the tank which develop into a fire. The probability of a fire starting from an arc occurring inside a transformer tank will depend on:

- Probability of an arc.
- Fault clearing time of protection and circuit breaker.
- The arcing energy available in the arc.
- Pressures withstand capability: determined by flexibility, pressure venting provisions and strength of the tank.

Flexibility – rigidity:

The tank shall be very flexible so it can provide the volume expansion, but also withstand the pressure and deformation from the pressure generated by the arc for the time require by the protection and the circuit breaker to clear the fault and the arc. A power transformer tank of conventional design can typically contain arc energy of at least 2 MJ. Tanks can be designed and built to withstand substantially higher arcing energy, provided special attention to arc withstand capability has been incorporated into it design. .

For higher fault energy sites, transformer user could consider more rigid and higher strength tanks with large opening to the conservator for rapid movement of large quantity oil into the conservator. The strength needs to be sufficient for it to withstand the high pressures generated from the arc for at least the time required for the electrical protection to clear the fault and interrupt the arc. However it should be noted there can be no guarantee that even strong tanks will withstand internal arcing under all fault conditions.

Venting:

The effectiveness of venting devices is very dependent on the time to open, the size of the venting port and most importantly, the distance from arc location. If the distance is such that the vented product is oil rather than arcing gases then such devices cannot be relied upon to provide adequate and sufficiently fast pressure relief to prevent tank rupture for high energy arcing faults.

However, it is considered that pressure venting can make material impact on pressure reduction on hermetically sealed gas cushion transformers of reasonably strong design, where the vented product would be gases and the pressure build up would be much slower due to the compressibility of the gas cushion.

9.2.5 Alternative Insulating Media

Alternative insulating liquids are used in transformers for fire risk mitigation and/or environmental reasons. All of these fluids have a high fire point and carry a lower fire risk. They can still burn, but they need a much higher temperature than mineral oil to ignite and will not propagate fire in the absence of external energy input.

Gas Insulated Transformer using SF_6 gas as the cooling and insulation medium is the only type of transformer with virtually a zero fire risk.

Dry type transformers also have a low probability of fire, but are not produced in any substantial number in the power and voltage range described in this brochure.

9.3 Actions to Mitigate the Damage of a Fire

When a transformer failure results in a fire the aim is not to save the transformer, but rather:

- Prevent injury to humans and minimise consequential damage to the substation installation and other plant items located in the vicinity of the transformer on fire.
- Avoid loss of supply from the substation and if not possible then to minimise the time of loss of supply.
- Minimise, and if possible avoid pollution and contamination to the surrounding environment.

Do not rely on that the existing fire safety codes and today's standards will be sufficient for all installations. Treat them as minimum requirements.

It is strongly recommended that owner of the transformer makes his own assessment or seeks further guidance on what type of risk will be reduced and even more importantly assesses what risk will not be reduced from each mitigation measure and decide what further risk mitigation measures may be required for their specific installation.

In understanding your system and your risks, you should understand your problem, identify your system features, evaluate performance and characterize the risks.

Ask the "what if" question? What can go wrong? Consider different fire scenarios. Assess the consequences and decide what response would be required to get the desired outcome.

The assessment should include different kinds of possible passive protections (fire walls, safe distances, oil containment)

<u>Remove the heat</u>:

The fire can be extinguished if the heat is removed and the fuel is cooled below its fire point temperature. Water can be very efficient as a cooling medium to extinguish external fires and to protect adjacent asset from being heated to their flash point. Water is less efficient in extinguishing a fire burning inside a transformer as it is often difficult to get the water into the transformer tank and the oil will float on the top of the water and continue burning, even if water is sprayed in to a transformer tank. It is therefore necessary to also get foam or an oxygen excluding gas into the transformer tank to extinguish an oil fire within a transformer tank. This is why transformer fire protection systems using nitrogen injection into the tank can be effective for fire extinguishing oil fires in transformer tanks.

For the same reason water alone is not efficient in extinguishing oil pool fires. Whereas water with foam can be very efficient for this purpose, as it excludes oxygen from the oil surface.

Oxygen displacement or dilution:

Removal of oxygen can be a very effective method of extinguishing fires where this method is possible. Only a slight decrease of the oxygen concentration in air decreases the fire intensity and below 16 % oxygen in the air there is no risk for a fire. Many alternative gases have been used successfully: carbon dioxide, halon and nitrogen. These methods are only suitable for indoor installations or where the transformer is located in other forms of sealed enclosures. Foam and high pressure water fogging can also be used to displace oxygen in both indoor and outdoor installations.

Removal of the fuel:

Removal of the oil can be effective, but is most often not possible and would add new risks.

9.4 Recommendations for Future Work

It is the view of the WG A2.33 that the current IEC Standard and most national standards for transformers are deficient in that they do not provide any guidance on the requirements and methods of verification of designs of transformer tanks and cable boxes.

It is the WG A2.33's view that these Standards should have minimum requirements and provide guidance on pressure withstands capability or internal arcing withstand capability with or without venting.

To the best of the WG A2.33's knowledge, only Japan has a guide document for design of transformer tanks [17].

It is therefore recommended that the IEC extends the existing 60076 series on Transformer Standards to include prescriptions or guidance for the internal arcing withstand capability of transformer tanks. This document should address:

- Guidance for the purchaser on what information should be provided in the specification or other form of documentation.
- Guidance for the supplier on how to document performance of tanks.
- The requirement for different "classes" of transformers: (distribution transformers, power transformer, gas cushion transformers, and possibly with different requirements for various voltage classes, system fault levels and installed location).
- Possibly venting type / requirements
- Arc energy withstand capability rating of tanks
- Verification method(s) for fault energy withstand capability rating of tanks.

It is further recommended that the IEC produces a new standard on cable boxes to address:

- Guidance for the purchaser on what information should be provided in the specification or other form of documentation for cable boxes.
- Guidance for the supplier on how to document performance of cable boxes.
- Classification of different types of cable boxes: Oil insulated, Air or gas insulated, possible voltage rating, current rating, Degree of protection (IP class), Venting method,
- Arc energy withstand capability rating of cable boxes.
- Verification method(s) for fault energy withstand capability rating

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