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GUIDE on ECONOMICS of TRANSFORMER MANAGEMENT

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Guide on Economics of Transformer Management

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Foreword

WG 12-20 was started in Budapest in 1999 and redirected at the 2000 main session in Paris. The scope given to WG 12-20 was to produce a guide that will help the transformer managers in quantifying the economics (costs and benefits) related to the management of transformers. Due to a re-organisation in CIGRE in 2002 the WG was renamed A2-20 in keeping with the new designations of the technical committees. The guide was prepared during meetings in Paris (2000 and 2001), Geneva (2001), Dublin (2001 and 2002), Chicago (2002) and Oslo (2003).

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Part 1 – Introduction

Transformers are crucial not only to power system performance and reliability of supply but also to the financial performance and economic viability of electric utilities. Their technical complexities, high capital costs and long life expectancy pose unique decision making challenges to asset managers.

This guide is designed to help transformer asset managers perform economic evaluations of proposed solutions. A list of key parameters has been established, given in Part 1 and Appendix 8, covering technical, operational, economical, environmental and other strategic aspects that arose during the early development of this guide. Some approaches, models and flowcharts have been included to illustrate the criteria and steps used by various world class utilities in their decision making processes. While this guide may be of use to transformer experts, it is intended mainly for transformer managers or asset managers managing high-voltage electric systems.

As economic of transformer management is rather complex and because different issues arise throughout the life cycle of transformers, the guide is divided into four parts.

Risk Management : Demands for higher rates of return and cost of service reductions are resulting in increased equipment utilization, deferred capital expenditures and reduced maintenance allocations in many jurisdictions. The immediate cost savings of postponing investments and reducing budgets are readily quantifiable. However, the costs associated with the consequences of these actions such as increasing maintenance, repairs and failure rates can only be approximated using risk analysis techniques. Methods and approaches for managing the risk for a single transformer and a transformer population are discussed. The provision of spares to mitigate the risk of transformer failures is explored.

Specifications & Purchase : Consolidation and globalization have had significant impact on transformer manufacturing in the past 20 years. While many ‘local’ plants have closed, new plants have appeared submitting lower priced bids. Vendor qualification is required to ensure that design margins and equipment quality are not compromised. Furthermore, recent reviews of transformer specifications suggest that costs for new transformers can be reduced and reliability improved in many cases by eliminating unnecessary requirements based solely on past practices. The incremental costs of tertiary windings, On-Load Tap Changers with numerous tap positions, overload capability, on-line monitoring, etc. could be weighed against the need for these features and the benefits they provide. Comprehensive evaluations including not only price and loss capitalization but also transportation risks, installation costs, interchangeability, environmental considerations and issues affecting transformer life cycle costs are required.

Operation & Maintenance: The pressure to maintain low prices while delivering high reliability is forcing utilities to find ways to leverage the most out of their existing transformer asset base. Long standing loading practices are being reviewed with the intent of achieving higher loading during both normal and contingent operation. Besides insulation loss of life, transformer condition and evaluation of associated risk of failure are important considerations when raising loading limits. In mature utilities, aging transformer populations and reduced overall contingency margins point to an increased risk of affecting customer supply in the event of a transformer failure. Transformers are characterized by their low maintenance to capital cost ratio. However, over a large population of transformers the total maintenance budget can be substantial. Limited resources and the need to focus on prioritized needs is undermining the traditional time based approach to maintenance. Utilities are exploring condition based maintenance and implementation of a preventative/predictive approach using various diagnostic, on-line monitoring and data logging techniques and devices. Decision process flowcharts and cost/benefit analysis examples are provided in this chapter.

Repair vs. Replacement : Transformer managers are regularly expected to make this decision with respect to failed or troubled units. Besides the substantial technical and financial data specific to the transformer in question; demographics, condition, utilization and performance of the transformer population should be taken into consideration. These decisions require also intimate understanding of corporate risk tolerance, current investment strategy, prevailing business and regulatory environment. A ‘Normative’ model approach has been chosen to illustrate the decision making process. Suggested performance and financial measures as well as examples are provided.

KEY PARAMETERS INDEX

Key Parameters	See clause
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Part 2 - Risk Management

2.1 Introduction to Risk Management.

2.1.1 A brief history on risk.

Risk management is based on calculation of probabilities. Early in history summing up and multiplying the results of throwing dices did this. The fact the ancient Greeks and Romans had to depend on a very clumsy numbering system based on their alphabet, making it impossible to do moderately complex calculations, must be one of the reasons for the fact that neither the Greeks nor the Romans discovered the most powerful tool of risk management: the laws of probability (their numbering systems also prevented them from discovering calculus and algebra).

The numbering system we now use as a condition for calculations was invented by the Hindus circa500 AD, and was brought by the Arabs to Spain by the ninth and tenth centuries. It was not in common use until early in the fifteenth century. The early laws of probability were discovered in 1494 by Pacciola in his book *Summa*, where he discussed how to divide stakes in an uncompleted game of, *balla*. This was the beginning of the analysis of probability and brought risk analysis to the next step: the quantification of risk.

There are many famous names in the early history of probability and risk: Cardano, Galileo, Huygens, Pascal, Fermat, Graunt, Petty and Halley are some of the most famous. This guide is not the place to give an account of all their work, but two remarkable papers are worth mentioning:

In 1622 the members of a Paris monastery named *Port-Royal* made an exceptional and pioneering work in probability (and philosophy) with the title *Logic*. The authors blended measurement and subjective beliefs for the first time in the mathematical achievements of probability by stating: "Fear of harm ought to be proportional not merely to the gravity of the harm, but also to the probability of the event." This is a very early form of risk management that is still valid, but often overlooked.

The Swiss mathematician Daniel Bernoulli wrote the other remarkable work, in two papers published in 1731 and 1738. Both were presented in the *Papers of the Imperial Academy of Sciences in St. Petersburg*. In his paper *Exposition of a New Theory on the Measurement of Risk,* Bernoulli states: "the *value* of an item must not be based on its *price*, but rather on the *utility* that it yields". We may see a direct line from his statement and the definition of risk of today as "expected loss of utility".

Both papers contain the same argument that any decision based on a risk evaluation must involve two elements: the objective facts and inseparably, the subjective view of the desirability of the gain, or loss, of the decision. Hence, both objective measurements, i.e. facts finding, and a discussion of the subjective degrees of belief, are essential to reach a decision, or as Bernoulli states it: " ...the utility...is dependent on the particular circumstances of the persons making the estimate...There is no reason to assume ... that the risks anticipated by each [individual] must be deemed equal in value".

As people ascribe different values to risks, Daniel Bernoulli introduces further a significant idea and a great intellectual leap: "*[The] utility resulting from a small increase in wealth will be inversely proportionate to the quantity of goods previously possessed*." Hence, he applied measurement to something that cannot be measured, blending intuition and measurement. Appendix 5 gives an overview of a mathematical treatment of risk perception or risk aversion, used. as the basis of the insurance business.

This focus on decision-making and utility was enhanced when he further claimed his aim to establish: "...rules [that] would be set up whereby anyone could estimate his prospects from any risky undertaking in light of one's specific financial circumstances". Henceforward, these words have given economists, managers and investors options as risk no longer had to be faced as a given fact, but risk had become a set of opportunities open to an individual choice.

The question of a linkage between probability and the quality of information was raised at the same time by Jacob Bernoulli's, the older uncle of Daniel. In 1713 Jacob stated: We must assume that "*under similar* *conditions, the occurrence (or non-occurrence) of an event in the future will follow the same pattern as was observed in the past*". This is one of the giant assumptions in science: It is often difficult to get such complete information on a system that simple probabilistic calculus will predict the outcome. But Bernoulli saw that estimating probability, in systems with insufficient information to model deterministically is impossible if it cannot be assumed the past is a reliable guide to the future.

Through de Moivre's curve, now known as the standard deviation, we touch on the question of inverse probability: If we know the outcome of a selection of the result of a process, what does it say about the probability that the true average ratio of the process is x %?

The paper "*Essay Towards Solving A Problem In The Doctrine Of Chances*" by the Reverend Thomas Bayes published after his death in 1761 and little regarded at the time, laid the foundation for the great issue of statistical inference, first asserted by Jacob Bernoulli. The Bayesian formula uses new information to revise probabilities based on the old information, or in other words to calculate future probability distributions based on previous occurrences and new information, e.g. expert opinions. Bayes contribution was remarkably modern: there is no single answer under condition of uncertainty. Appendices 2 and 3 outline the use of Bayesian statistics on the transformer problem of aging.

In 1900 Louis Bachelier in his Sorbonne dissertation *The Theory of Speculation* spoke about his central thesis: "The mathematical expectation of the speculator is zero". His idea is now seen in everything from trading and business strategies (diversification), derivative instruments to portfolio management.

John Maynard Keynes, in his 1921 book: *A Treatise on Probability*, asserted statistical methods and concepts often seemed useless: "There is a relation between the evidence and the event considered, but it is not necessarily measurable".

A history of risk is also a history of reliability. The first reliability analysis in a technological connection was a detailed comparison just after the First World War of single and double-engined airplanes based on accidents per flight hour. German engineers performed the first more formal analysis developing further the V-1 flying bomb. All of the first new ten rockets failed, exploded on the ramp or fell in the Channel. The reliability of the flying bomb design was based on the theory of "the weakest link in the chain". During the investigation the mathematician Robert Lusser discovered that a "chain of heavy duty links" might be less reliable than a single considerably weaker link. He formulated the product rule of reliability: The reliability of the chain link-system is the product of the reliabilities of each of the subcomponents. Modifications based on this approach gave the V-1 a "success" rate of 60%.

Later in the 50's and 60's the risk analysis gained further momentum due to space research and nuclear science. A significant milestone in this regard was the 1974 "Rasmussen report" [2.2] analysing safety of commercial nuclear power stations.

Further advancement of risk management in the last decades will be described later in this part of the guide.

2.1.2 What is risk and risk management?

Peter L. Bernstein defines risk management as [2.1]:

> "When we take a risk, we are betting on an outcome that will result from a decision we have made, though we do not know for certain what the outcome will be. *The essence of risk management lies in maximizing the areas where we have some control over the outcome while minimizing the areas where we have absolutely no control of the outcome and the linkage between effect and cause is hidden from us*."

If we define risk as: the dangers an unwanted event represents on humans, environment and economical values, or *the expected loss of utility*, we see that risk management must involve risk analysis. To be able to make decisions, we must determine our risk perception and acceptability, our risk profile or the degree of risk aversion, and we must find the factors to be evaluated in the analysis.

Hence, a risk analysis contains two major parts:

1. The determination of the likelihood of the unwanted event. This includes the occurrence frequency of the event, or its probability. This includes analysis of known history, i.e. analysis of statistical data, or estimates based on judgements by experts.
2. Evaluation of the consequences of the unwanted events including evaluation of risk acceptability threshold and tolerance level (risk aversion).

This means the risk analysis in general consists of three steps, called the "Risk Triplets":

1. The hazard identification where the events or scenarios (or chain of events) are selected for analysis.
2. Determination of the likelihood of the selected hazardous events by estimating their frequency or probabilities.
3. Estimating the consequences of the selected hazardous events.

Quantitative risk may be expressed in several ways, often as a frequency of (or probability for) a consequence of an unwanted event. A general risk model may be illustrated as in Figure 2.1.

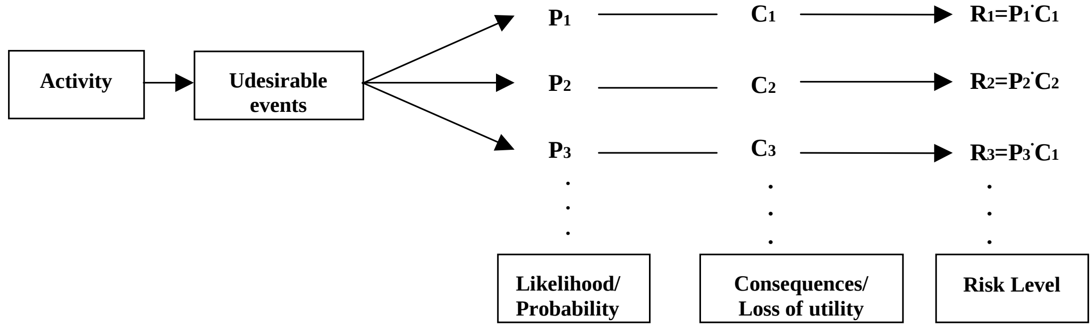


Figure 2.1: A general risk model.

If we know the losses C_1, C_2, ... the statistical *expected loss of utility* is often used as a measure of risk:

$$\textit{Expected loss of utility} = C_1 \cdot F_1 + C_2 \cdot F_2 + \ldots$$

(where F_i is the frequency of the unwanted event giving the consequence C_i , or the probability P_i that an event may happen which gives the consequence C_i.)

To perform an evaluation of the result it is necessary to know our perception of the risks, how we determine the ranking of risks and how we perceive the uncertainties in the method used.

2.1.3 Risk perception and acceptability

Perception of risk differs from objective measures and introduces an element of distorting, or politicizing, risk-management decisions. This is not the same as saying there is a true risk perception that management does not perceive, based on a "true" calculated risk without uncertainties. Our subjective judgements, our beliefs and our societal bias against unwanted events with a severe consequence, but a very low probability, may influence, or distort, our understanding of the risk analysis.

Our risk profile, i.e. how risk averse we are, may also substantially influence our decision. Appendix 6 supports the view that we tend to avoid (insure) the low probable, high risk, events that may easily get us into bankruptcy or severe financial problems. In our context here, the identification of these low probability events with severe consequences is paramount in a risk-management approach.

When evaluating the impact of such a risk on the public, and its perception of this risk, a company may use risk compensating factors to find risk tolerance thresholds of the public. This may include accounting for public bias against risks that are unfamiliar (it may, according to one report, be compensated by a factor of 10), catastrophic

(30), involuntary (100), uncontrollable (5-10) or have immediate consequences (30). These figures are not exact but show a general direction of public bias.

The same applies in principle to management, owners or investors, but the compensating factor is more difficult to find, but there are methods used, e.g. comparing with other projects or investments with known risks and historical decisions.

Risk acceptance vs. risk aversion, is a subject of controversy and heated debates, but using the results of risk assessment in a relative way it is possible to rank the projects and comparing with other business risks. Cost-benefit analysis will give added value to the ranking. Regulators often try to define or assess absolute levels of risk, as relative ranking gives a better risk management strategy when allocating resources and discussing regulatory control.

A more objective method may be to calculate a normalised risk exposure for comparison purposes and use the level as an acceptance criterion. Such risk acceptance criteria may be:

1. A statistical average for the business sector.
2. The same risk level as similar substations with similar layout.
3. A specific probability for a fatal accident.
4. An accident frequency per annum.
5. An accident frequency for a set of the most risky operations.
6. A frequency of fire or hazardous events per annum.
7. A frequency of accidents with great environmental impact.
8. "An optimal economical balance between material benefits and loss of production."

For serious undesirable events and accidents, a (log-log) frequency-number chart (F-N curve) may be used to define acceptance criteria. The probability P (i.e., the frequency) of the event is the ordinate (log P), and here the cost consequence C (actually for example in the oil business C is the number of fatalities) is put on the abscissa (log C). By constructing this risk profile, three levels (bands) or categories may be defined:

1. Not acceptable/tolerable, risk-reducing activities must be applied.
2. Acceptable/tolerable. No need for risk reducing activities.
3. A band in between where it its necessary to prove the risk is As Low As Reasonably Practical - ALARP.

An illustration of a F-N curve is given below. The ALARP area is between the boundaries of the two straight lines. The two diagonal lines are lines of equal risk level.

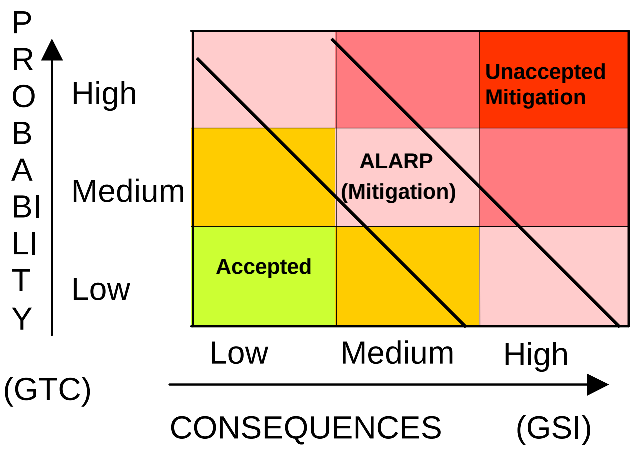


Figure 2.2 Probability vs. consequence

It is important to stress the fact that calculating probabilities of fatalities or serious accidents, and analysing the associated economic costs, does not entail an acceptance of these accidents. All accidents are unwanted and intolerable. The ideal and long-range policy is to avoid all accidents and this policy stimulates the continuous focus on improving the health and safety of work in the utility. But we do accept the risks involved in the events analysed, if the probability of the events is sufficiently low, or if the consequences may be lessened by some means.

2.2 Managing risk for a transformer population

2.2.1 Introduction

In a deregulated energy marked, or in a system where the customers demand a high reliability, and with system owners demanding higher profits, the need for better asset management methods taking also into account the risk involved for postponing reinvestment is required. The fact that the grid-monopoly regulator in some countries (e.g. Norway) has introduced penalties for Energy Not Served (ENS) supports this view.

Hence, there are many incentives to keep the reinvestments up at a level that secures the long-term reliability of the system, where the risks involved are managed. The need for a risk-based attitude to justify, and prioritise, reinvestments has been identified, and this part of the guide describes two macro-economic methods, on how to manage a family of power transformers. Such a method makes it also possible to address the desired risk profile in the utility, i.e. the risk aversion profile of the utility regarding reinvestments.

This part of the guide proposes two methods:

1. Increasing the technical lifetime of a component group, here transformers, where the associated average anticipated risk is acceptable. This method is here called: “The increased lifetime method”.

2. Identifying the components that need increased condition monitoring or other actions to be within an acceptable risk level according to a ranking system. This method is called: “The ranking method”.

2.2.2 The increased lifetime method

If a utility decides to increase the service period of one or several components in the grid, the utility must also expect that future failure rates for these components will increase. This means increased future costs for maintenance and repair, and ENS. Hence the decision criteria for a utility whether or not to postpone reinvestments in the grid will be the minimisation of overall costs related to reinvestment, maintenance, repair and ENS[2.9].

The basis of the method is first to perform a risk management analysis that introduces a linkage between cost savings from postponed reinvestments and the losses (i.e. consequences) for maintenance, repair and (for some utilities also compensating) ENS. This is based on actual, i.e. experienced, failure rates, which are then compared with a theoretical and calculated increased failure rate that balances the cost savings in postponing reinvestments.

The following steps describe the principle of the calculations performed in this risk management analysis:

1. By increasing the estimated technical lifetime of a component, an asset management analysis calculates the reinvestment cost savings, Δ Cost $_{\text{reinvestment}}$.

2. The risk management analysis then finds a calculated failure rate λ_{Balance}. This calculated failure rate is the specific increase of the components existing failure rate that results in an increased average cost per failure ($\Delta\text{Cost}_{\text{Average}}$ for maintenance and repair and ENS) that exactly balances the reinvestment cost savings for the same family of components. The higher the calculated increase in the failure rate of a component is, the lower is the risk for increasing costs for maintenance and repair and ENS.

$$\Delta Cost_{Reinvestements} = \Delta Cost_{Maintenance} = \#_{Components} \cdot \lambda_{Balance} \cdot \Delta Cost_{Average}$$

3. The risk analysis will identify components groups which satisfy the following two criteria:

   - An increase in the estimated technical lifetime of the component results in major reinvestment cost savings.
   - The component requires a significant increase in the existing failure rate before the reinvestment cost savings are balanced by the increased costs for maintenance and repair, and compensating ENS.

By following the steps described above and in the figure 2.3 below, the utility planners can identify the reinvestment cost savings and associated risks. Hence, the utility may increase the quality of its reinvestment plans, maintenance and operation policies.

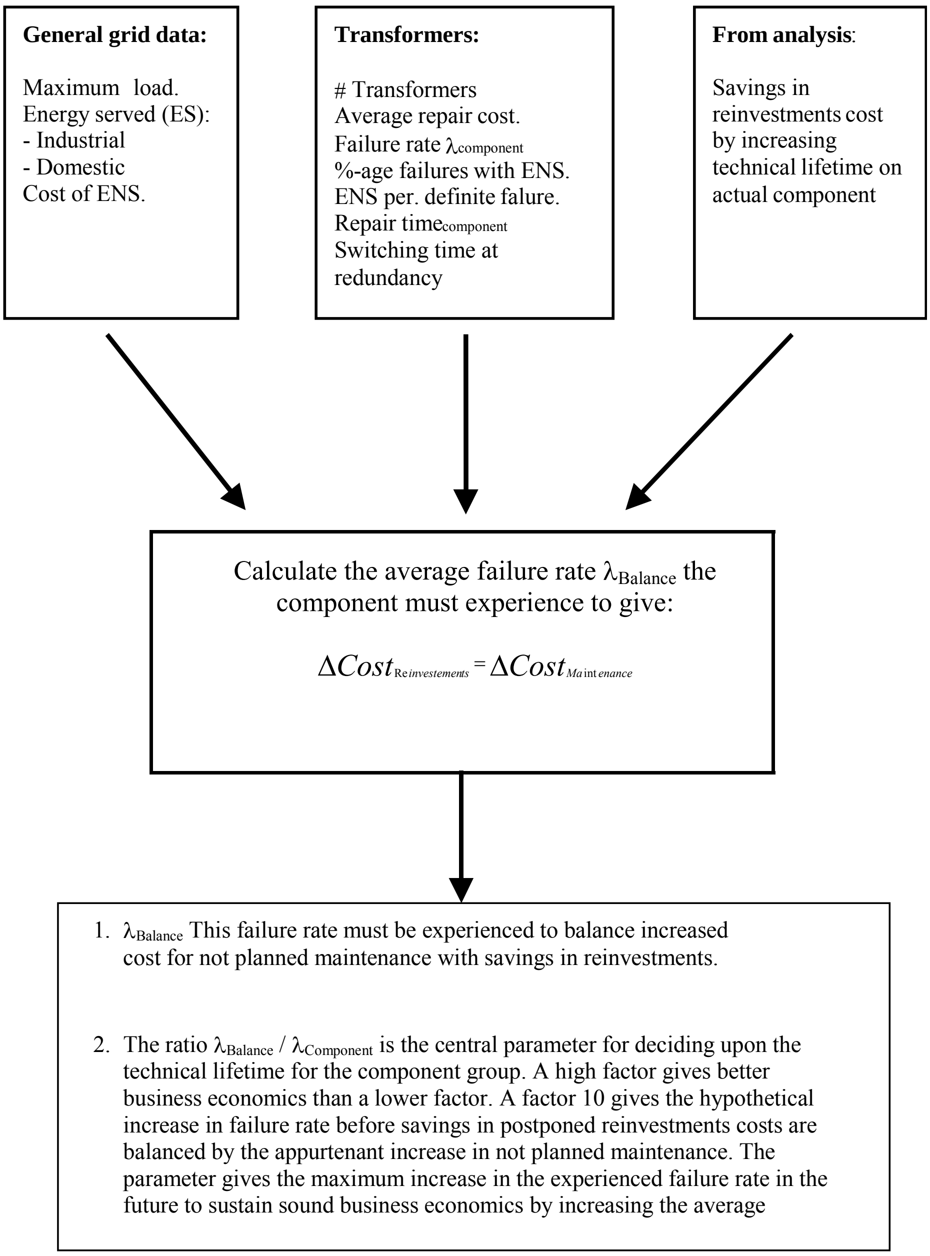


Figure 2.3 The general "increased lifetime method".

In general, the longer the delay before replacement, the greater the savings are. However it is important to note that the savings do not increase linearly. The savings increase most rapidly in the early years of replacement delay and then the rate decreases as time passes and failure rate increases. [2.13]. This fact must be taken into consideration when deciding on postponing reinvestments.

If the fault rate increases in the analysis period, the annual reinvestment cost savings will be reduced and may be negative. By monitoring the development of the annual failure rate in the analysis period, referred to the failure rate of today, the utility may evaluate the cost-benefit of the postponement of reinvestments.

However, it its again important to remember this method does not give a basis for the evaluation of what to do with a particular power transformer reaching the end of its life.

The actual reinvestment decision must be based on condition monitoring and condition evaluation and the risk involved for a major fault on this particular transformer.

The experienced historical fault rate may not be relevant for a component reaching the end of its life. Based on the utility experience, the design knowledge from the manufacturer, national and international failure statistics and the future utilization of the power transformer, it is possible for an expert group to find a better estimate for the future failure rate for the component group. The new failure rate may be calculated using Bayesian statistical methods.

2.2.3 The ranking method.

The relevance of a preventive or corrective action on a functional sub-set of a power plant or of a substation, in this case transformers, is based on considering two factors [2.11]:

- **GSI** (Global Strategic Impact) is a number expressing the impact of a possible failure of a given transformer; the more important the possible failure consequences are, the greater the GSI number.
- **GTC** (General Technical Condition) is a number expressing the probability of failure of a given transformer; the more the intrinsic condition of the piece of equipment is subject to a potential failure and damage, the greater the GTC number.

Finally, by combining these two notions, a grade is defined which represents the level of criticality of the transformer:

Global Criticality of transformer ***(C) = GSI x GTC***

The **GSI** is calculated by taking into account five main impacts, which can be differently weighted:

SI1-Safety of property and persons:
Transformers and especially substation transformer may have a direct impact on public safety in the sense of “damage/tort” in case of failure. At a minimum, they can represent a serious hazard to persons (employees, third parties) and property located in their immediate vicinity in case of significant damage (fire, explosion).

SI2-Safety of the electrical system:
Power transformers may be particularly important for the system reliability according to the network configuration, location of services to the system in terms of continuity and ability to react (energy supply, voltage control, connection) which are all of great value.

SI3-Environment:
A transformer failure can sometimes have serious consequences on the environment e.g. discharge of dielectric fluid into the environment. The consequences are a function of its location (near a waterway, indoor, etc…) and of the peripheral equipment such as a recovery container and/or a covered oil ditch.

SI4-Competitiveness
The potential economic consequences of the failure of the transformer are quantified by the following:

- **RC** - Rebuilding Cost (cost of the maintenance operation needed to overhaul the equipment: investigations, repair, replacement).
- **LPC** - Loss of Production Cost as cost of the transformer's statistical unavailability multiplied with the power of generators linked to it.
- **ENS** - Energy Non Served cost (direct loss of sales and possible penalties)

SI5-Company image

The direct impact of the failure of a transformer (leakage, fire, explosion, ENS) can jeopardize the utility image.

The **GTC** (General Technical Condition) is calculated by taking into account the criteria that characterize the risk of failure for a power transformer at any given time. The number and content of these criteria may be changed as explained elsewhere in this part of the guide. An outline of these is given below:

TC1-The transformer's State of Health

This criterion quantifies the observations relating to the transformer's "state of health". This state of health should consider two aspects: an external state of health and an internal state of health. The evaluation of the results from oil analysis and the interpretation of the DGA, is often the major indicator representing the state of health of the transformer.

TC2-Technological risk

This criterion estimates the influence of the transformer's specific technology: fragility, durability and ability to be repaired and maintained, against a risk of failure. The known feedback on the behaviour of similar transformers may help to quantify this risk.

TC3-The weight of the past

The age is specifically the subject of this paragraph even though it is also indirectly linked to the two paragraphs above.

TC4-Operating Conditions

The transformer's operating conditions (operating mode) is integrated into this paragraph through the parameters of the number of switching on/off cycles, the electrical environment, and the load factor.

A first collation of data according to decreasing global criticality **C = GSI x GTC** can be established for a whole population of transformer. This first rating gives a general perspective of the transformers and of their close environment and this is illustrated in figure 2.4 for an actual 900-transformer population.

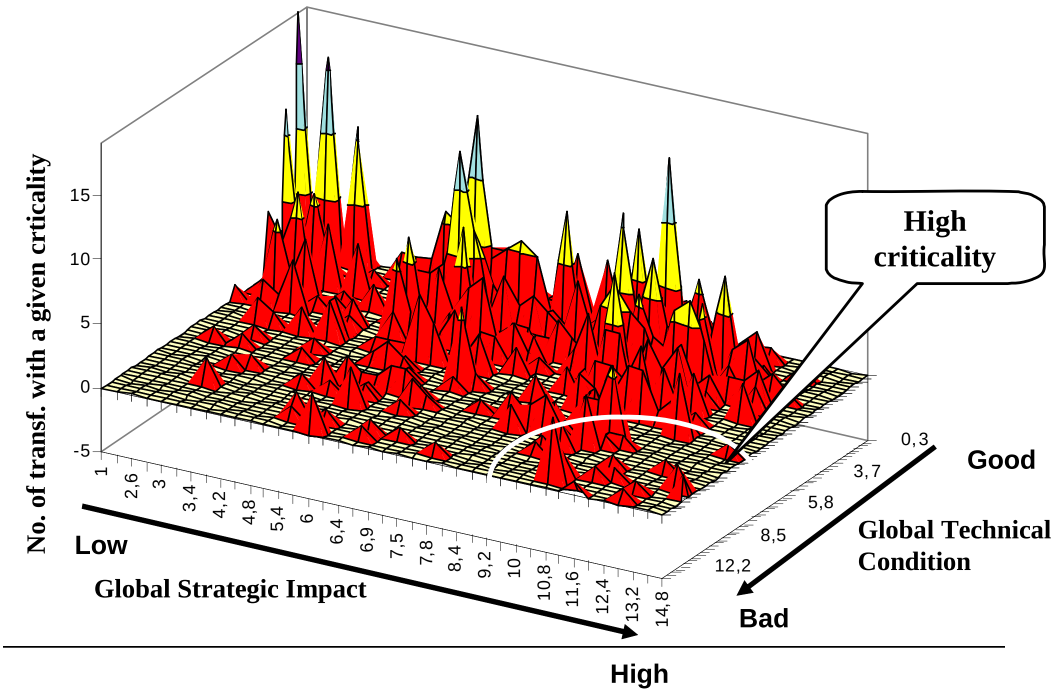


Figure 2.4 Example of GSI and GTC mapping for a population of 900 transformers.

2.3 Managing risk for one single transformer

2.3.1 Introduction

Increased equipment utilization, deferred capital expenditure and reduced maintenance expense are now all a part of the guidelines for Transmission and Distribution (T&D) Asset Strategists. Although budget constraints and reduced spending are not new to most utility engineers and planners, the need to leverage more out of existing equipment is, however, a new challenge today.

To add to this, declining capital spending in many countries has resulted in a significant increase in asset utilization, or normal transformer loading, over this period. This may have reduced overall system contingency margins and increased the risk of loss of supply in the event of a substation transformer failure.

Managing risks for a single transformer is the same as evaluating the condition of the transformer vs. failure rate and failure consequences and perform risk mitigating activities after performing the risk analysis.

2.3.2 Transformer condition evaluation

The condition and reliability of power transformers, especially larger ones, is a major concern, because each unit feeds many customers and its replacement would involve a considerable amount of time and expense. Contingency planning of power systems concerns, in this context, transformer loading limits and arrangements for contingency operation when a unit fails. Determining the condition of power transformers is a matter that involves many technical considerations:

a) All large transformers are individuals, and are therefore not ”created equal”. Historically, there has been little standardization in the design and manufacture of power transformers.

b) Most units are custom-designed to meet individual utility specifications that involves significant differences in design requirements, features, safety factors and use of materials. Economic and environmental requirements, such as no-load and load loss evaluation factors and noise levels, can have a significant impact on the design of any two "identical" units that have the same nameplate ratings.

c) Transformer insulation systems, particularly for EHV units, are complex structures that require thorough analysis to determine dielectric and thermal stress levels. Manufacturers may have different policies on adding margins to minimum requirements according to testing standards. In-house design rules are also based on long-term experience resulting in significant differences in design integrity for units in the same voltage class.

d) Differences between utility investment practices have over the years resulted in major differences in the loading policy and day to day operation, making condition or failure data difficult to apply between utility systems.

e) Due to deterioration of the insulation system resulting from temperature, moisture level and oxygen, two units of the same design and chronological age can have a totally different "service age", giving different margins for stress and residual life expectancy.

f) The position of the unit on the system (and protection system), the load and power factor, physical location, air temperature and cooling, short circuit capacity, probability of over-voltage from switching and lightning strikes and corrosive elements must also be considered.

g) Maintenance is not standardised and may be good and well-documented or it may be haphazard or undocumented especially for older units. Historically, individual transformer manufacturers and utility management dictated maintenance practices and frequency. Maintenance expenditure may now be low compared to the asset cost, and some utilities have or may enter a reduced maintenance and monitoring regime at a time when transformer loading is rising.

Condition appraisal or evaluation can be applied to a population of units by using statistical methods, which are based on historical failure modes, as proposed in section 2.2, but this method cannot identify the condition or vulnerability of individual units. For individual transformers the evaluation method will be modified or limited by the availability of information from the manufacturer or from the utilities operations and maintenance records. Added to this, the skill level and experience of the engineers involved in the process is a key parameter in deciding the quality of the available information and subsequently the probable condition of the unit. A complete appraisal method must also involve inspections and testing.

The process for benchmarking the probable condition of an individual unit compared to other units on the system, may contain three levels of investigations:

Level 1: Data and design analysis
Level 2: Energized and de-energized testing
Level 3: Internal inspection

The Level 1 condition evaluation method is analytical and subjective; based on the quality and quantity of the information, requiring the results to be weighted depending on each of the factors that have been selected. Typical factors used for evaluation are related to the equipment design, environment, usage and historical maintenance or testing data and are listed in Tab 2.1 [2.7]:

Design		**Operating Environment**	**Usage**	**Historical Tests & Diagnostic**
Main Unit • Manufacture • Vintage • Design period • Winding Config. • Materials • Short Circuit • BIL • Margins	Ancillary Equipment • Oil Preservation • OLTC • Cooling Equipment • Bushings	• Source Impedance • Protection Scheme • Lighting Level • Ambient Temperatures, Rainfall, Pollution • Load Power Factor • LTC Regulation Range	• Historical Loading Pattern • Prior Overload Conditions • Prior Through Faults • Fault Levels • Maintenance Practices	• DGA • Oil Quality (Physical) • Power Factor (Bushings/transf.) • Insulation Resistance • Maintenance Records • Ratio test • Winding resistance • FRA

Table 2.1: Some factors used for evaluation.

The factors must be considered and weighed against each other in order to achieve a realistic condition evaluation. A weighting factor may be applied e.g. the top 10 selected factors.

However, the probable condition of the internal insulation is usually the key consideration due to the fact that the condition is, for the most part, irreversible. With the possible exception of tightening loose windings or drying-out wet insulation, most insulation problems require a complete and expensive re-wind to actually correct the damage. However, defective ancillary equipment, bushings, cooling systems, tap changer mechanisms etc, can be repaired or replaced to restore their condition to “as new” with a regularly scheduled maintenance program. The decision to re-invest in refurbishing the unit must be based on a thorough economic evaluation. It is also a fact that failures from internal insulation damage or deficiency, often result in major damage or even catastrophic failure with long-term loss of service and severe financial implications. The possible risks of performing refurbishment work (e.g. at site) needs to be assessed.

Level 1 evaluation can be used as a preliminary process for evaluating groups of units and when considered in the light of the transformer priority (discussed in section 2.2) it can provide an overall ranking and provide the basis for deciding the subsequent, level 2 and 3, inspection and testing applicable to individual units. The analysis described here gives a background for deciding on the parameter General Technical Condition (GTC) used in section 3.3. The detailed evaluation is performed on the high risk part of the transformer family.

Guidelines for performing Level 2 and 3 activities are outside the scope of this document. The reader is referred to the CIGRE’s working group 12.18 report on Life management of transformers.

2.4 Risk mitigation

2.4.1 Introduction

In the last few decades efficient methods for performing system reliability and risk analysis have been developed. Some of these methods are:

a) Fault Tree Analysis (FTA)
b) Success Tree Method
c) Event Tree Method
d) Master Logic Diagram Method
e) Failure Mode and Effect Analysis (FMEA) with its extension
f) Failure Mode and Effect Criticality Analysis (FMECA)
g) Cause Consequence Analysis
h) Hazard and Operability Studies (HAZOP)
i) Job Safety Analysis
j) Sequentially Timed Events Plotting (STEP)

k) Stress-Strength Analysis
l) Markov models
m) Bayesian Reliability Analysis,
n) Management oversight and risk tree (MORT).
o) Safety management and organisation review technique (SMORT).

There exist many excellent textbooks for further study and implementation of these methods. Some such textbooks are listed in the references to this part of the guide.

The basis for managing risk is to perform a risk analysis by one or more of the above mentioned methods. A good approach to such an analysis is the international standard from IEC TC 56: Risk Analysis of Technological Systems- An Application Guide.

2.4.2 How to perform a risk analysis

The different stages in planning, performing and use of risk analysis is showed below:

A Planning:

1. Objective
2. Definition of activity (object of analysis)
3. Time planning
4. Organizing of the task

B Lead-through:

1. Describing of activity (object of analysis)
2. Assumptions and presumptions
3. Cause analysis
4. Consequence analysis
5. Data collection and data analysis
6. Presentation of results

C Use:

1. Risk evaluation/safety evaluation
2. Decisions

Hence, the first action is to identify the unwanted events that are to be part of the risk analysis. Then it is necessary to map where these unwanted events may occur within the object of analysis. On the basis of this information, the selection of the unwanted events that are to be included in the continuation of the analysis is done. In this way it is possible to ensure that all relevant events are included in the analysis.

Experience from previous analysis is important, but the methods below are also used on this level:

1. Failure and accident statistics
2. Coarse/early analysis
3. Job Safety Analysis
4. Failure Mode and Effect Analysis (FMEA) with its extension
5. Failure Mode and Effect Criticality Analysis (FMECA)
6. Hazard and Operability Studies (HAZOP)
7. Sequentially Timed Events Plotting (STEP)

After identifying the unwanted events, the analysis of event causes and the analysis of the consequences are performed.

In this analysis the possible event chains which follow from the unwanted events are identified. This wanted particularity of the analysis decides when it is finished.

The suitable particularity level is decided on the basis of :

1. Objective of the risk analysis and the decision to be made.
2. Delimitations made earlier in the analysis.
3. Availability of relevant/detailed data.
4. The consequences of the unwanted events, with its associated frequencies or probabilities. Some events may be omitted in the analysis on the basis of their insignificant consequences or negligible probabilities.

It is important to include the effects the unwanted events may have on other systems, human beings and the environment, e.g.:

1. Increased strain on other components in the system.
2. Pressure waves, flames, heat, splinter, ejected material from explosions.
3. Flows of liquids and gases.

The chains of events are affected by events that are caused by the initiating unwanted event, e.g. actions taken by automatic or manual systems. They may be systems like emergency shut down (trip), fire alarms, fire fighting systems (deluge etc.) which are installed to take care of the causes and the consequences of the unwanted event.

Methods are developed to analyse such chains of events, e.g.:

1. Fault Tree Analysis (FTA)
2. Cause Consequence Analysis.

If a quantitative risk analysis is desirable it is necessary to establish a probability model of the activity.
There are many different methods for risk mitigation but only one well known method is covered in detail in the following section: the use of spare transformer(s).

2.4.3 Risk mitigation by use of spare transformers

In the power transmission business, system spare components are usually stored in convenient locations to facilitate the restoration of service caused by component failures. While the stocking of spares is required to maintain reliability, it is necessary to optimize the quantity to minimize costs associated with purchasing, storing, handling and maintaining the spares. Historically, the focus has been on meeting reliability requirements rather than cost-risk trade off. A consistent and documented cost/risk analysis process should be adopted.

To effectively deal with the strategic spares problem the size of the population, their failure rate, their lead time to replace or repair, the costs of purchasing, storing and maintaining spares and the consequences of not having a spare in the event of a failure must be evaluated and appraised. A sensitivity analysis to quantify trade off between costs, performance and risk is advisable. The analysis should help an investment planner to determine the optimum number of strategic spares required to meet the desired level of reliability at the lowest feasible cost.

It is also recommended that an emergency plan be developed for each station in preparation for unexpected situations such as losing one or more transformers at a station. With the long repair times of power transformers, it may be necessary to take into account the probability for N-2 situations. The emergency plan should list all viable solutions and with preference priority identified. It may include like for like replacement of failed transformer, the feasibility of transferring load to adjacent stations, possible replacement with a higher rating unit or strategic relocation of a specific transformer from a lightly loaded station. It could include preparation for the reconnection of a transmission line between two stations to a lower voltage (transformer LV voltage) where the loss of the next transformer would result in loss of all distribution supplies.

Plans should be made to reduce the average transportation/replacement time to within a specified number of days to align with the emergency or planned (over)loading capability of the reserve transformer(s). Such a plan may utilise the transformers limited time rating and improve on service availability. In addition, the technical feasibility of the installation of the spare transformers on each site considered needs to be verified:

1. Technical compatibility of the relief transformer's dimensions, impedance, voltage, ratio etc.
2. Ability to connect the relief transformer to the existing installations (checking the possible fitting parts, cooling system, etc.),
3. Transportation by rail, ship and/or by road (validity and maintenance in operational condition of the relief equipment routes) and
4. In case a different spare transformer (e.g. single vs. double secondary coils transformer and/or different vector group) the possibility of operating with this new configuration should be checked such as modifications to the connections and the protection and relay settings etc.).

The ranking method from section 3.3 may be used when deciding on the question of spare transformers, and on the replacement and major maintenance of transformers in operation. This risk of not having spare transformers may be very high,[2.12].

As this aspect deals with the transformer alone without its environment, criticality data can be established $\mathbf{C_T = GSI_T \times GTC}$ where GSI_T is the GSI value obtained without taking into account the value of SI3 Environment.

The whole population of transformers is divided into two categories (high or low C_T). The threshold is established through successive iterations. For the category High C_T transformers one should consider the existence of a spare transformer, the relevance of a replacement or of a major preventive maintenance.

The "theoretical" number of spare transformers needed to cover the high criticality equipment is compared to the existing spare transformers. When an incomplete or insufficient coverage of these high C_T devices is observed, a specific technical and economic study taking into account the possibilities of refurbishment and replacement has to be done. A probabilistic Markov model may be used in this respect.

For low $\mathbf{C_T}$ devices, in principle, preventive maintenance operations may be reduced, nor may it be necessary to provide for spare transformers. For this category the maintenance will not be preventive, it will be corrective. One can consider that only a small fraction of these will need a corrective action such as replacement or major maintenance in the future.

Experience gained with such evaluations show:

1. While for example in a specific analysis three spares are required to maintain the historical service availability level, keeping two spares may be more cost effective, but depending on the utility's own costs and cost for ENS.
2. Reducing the actual number of spares a little from the theoretical number of spares, the decrease in service availability level may be minimal.
3. Financial saving of reducing spares from the theoretical number may be substantial and include the cost of capitalizing an additional spare plus other acquisition, storage and maintenance costs.
4. The risk of a no spare situation is further hedged by identifying transformers at lightly loaded stations for possible relocation in event of an emergency.
5. Review the inter-changeability of transformers of different ratings an voltages:
   - A higher rating transformer with similar voltages may also be used as a temporary spare.
   - A higher voltage transformer may be also used as a spare in a lower voltage grid (within limits), e.g. a 66/22kV transformer may be used in a 50/17.5kV grid.
6. The impact of using spares on customer satisfaction and brand surveys would be small.
7. There is also no adverse impact to employee/public safety and the environment.
8. The transformer repair time and transportation time can be reduced through better station emergency planning and thus improving on service availability.
9. Information database issues must be identified and remedied to ascertain the information needed in an emergency situation really is available (transformer data, location of tools, transportations means, cooler flange caps, caps for bushing lid holes....).
10. Investigate the feasibility of a spare with multiple-voltage rating and taps to cover a broader population of transformers.
11. Explore the opportunity to share strategic spares with other utilities.
12. The decision of having a spare transformer is reversible, e.g. use it when a transformer is needed due to load increase or not replace the spare when it is used.

Let us consider one example from Australia. [2.12]. One utility had no spares for 27 transformer banks (total of 47 transformers). In most cases there were only two transformers per station and little or no option of load transfers to other stations. Loss of both transformers would lead to loss of supply to a relatively large town and a number of smaller country towns. The time to provide a replacement transformer is in the order of 9 months and for a repair a similar time or less depending on the nature of the fault. It is during this time that the community is exposed to possible loss of supply. A (N-2) situation may be initiated not only from a transformer failure, but also includes the circuit breakers, instrument transformers, isolators, secondary equipment, animals, weather and human incidents. Failure statistics are essential in studying this situation.

Australian experience is a failure rate for costly failures of 0.4% per transformer year.
Average station load 100 MW repair time 9 months
Value to the community of lost load = $10.000/MWhr

For the 47 transformers the probability of a transformer failure in one year (p.a.):

P(1) major failure = 0.004 x 47= 0.188
P(2) av. minor failure rate for primary plant = 0.03

Probability of loss of station (N-2) during transformer repair time of 9 months:

1.	Transformer fault:	0.03 x 0.75	= 0.023
2.	Circuit breaker faults:	0.03 x 0.75 x 2	= 0.046
3.	Isolator fault:	0.03 x 0.75 x 2	= 0.046
4.	CT, bus, SA fault:	0.046	= 0.046
5.	Weather, animals:	0.03 x 0.75	= 0.023

The probability of loss of the remaining transformer from any cause during the repair time is therefore the sum: P(3) = 0.18

Probability of both events: P(4) = P(1) x P(3)= 0.188 x 0.18 = 0.03384

Cost of second transformer failure (N-2):

Average power not supplied:		= 100 MW/day
Energy not supplied per day:	100 x 24 hrs	= 2,400 MWh

Based on outages statistics duration of minor outage is 2 days:

Total energy lost for two days: 2,400 MWh x 48h	= 4,800 MWh
The community cost of an outage: 10,000$ x 4,800	= 48 M$

The cost of risk in each year: 0.03384 x $48m = $1.62 m

An economic analysis shows:

Present value cost of a spare	= $2.6m
Present value cost of failure risk	= $16.7m

This is a strong case to purchase one spare transformer.

Part 3 - Specification and Purchase

3.1 Introduction

Because of the relatively large capital expenditure involved when purchasing a transformer, most utilities are generally very well aware of the economic factors and savings that can be achieved at this stage of the transformer's life cycle. The system planning department will normally determine the number and size of the transformers required and will request the transformer specialists to prepare the purchase/technical specification, which in this case will be based only on the user's knowledge/experience. For this reason, the specification might not be fully optimized for the specific service requirements. Therefore, it is strongly recommended to involve the supplier at this early stage, in order to take full advantage of their manufacturing knowledge/experience resulting in a specification, which will cover the needs for a fully optimized transformer from the manufacturer's and the user's points of view.

Planning and operation of the system might be quite different from one utility to an other and the specifications for transformers need to capture these differences. Specific needs will have a significant impact on the complexity, reliability and cost [3.7]. The factors, which can affect those aspects might be as follows:

- Winding configurations, like Yy against Yyd or Yd or Dy, etc
- On-load tap changer, on HV or LV?, what range?, how many number of tap positions?
- De-energized tap changer, if required
- Life Expectancy requirements
- MVA size, overloading capability
- Capitalization of No-load and Load-losses
- Environmental conditions (sound level, oil type, etc)
- Transportation and Installation limitations – decision on single phase or 2 x half rated three phase
- Test requirements, special tests (FRA, Short Circuit, etc)
- Insulation coordination and insulation level of power transformer
- On-Line Monitoring, if needed on new units
- External accessories and arrangement
- Factory and Design reviews
- Recommended maintenance plan

3.2 Winding configurations

The transformer winding configuration has a fairly high effect on economic aspects from a manufacturing/operating point of view. Depending on the configuration, the material and labour costs may be reduced for the same or better operating conditions and even for higher reliability.

In general the use of a fully insulated delta winding (D) for the HV costs more than a star (Y) winding with reduced insulation at the neutral end, especially when a tap-changer is used. The cost difference depends on the voltage level and it could be in the range of up to 10% for the higher insulation levels.

For more reliable operation the on-load tap changer should be, if possible, located at the grounded neutral end of a star connected HV winding.

For the same throughout MVA, autotransformers cost less then fully double wound transformers, but, electrically ties the two systems together, i.e. cannot have independent earthing.

3.3 Tertiary stabilizing winding for star/star transformers

A tertiary delta stabilizing winding (connection Yyd) increases the transformer cost by about 7% - 8%.

Star/star transformers without stabilizing winding have a much higher zero-sequence impedance (50% - 80%) than the transformers with stabilizing winding (10 – 20%). Except for its cost, a tertiary stabilizing winding is seldom a disadvantage for a transformer, especially if provision is made to open the delta circuit (2 bushings are brought out) in case it is not needed.

It should be noted that a delta connected stabilizing winding for star/star transformers is not always necessary; this depends mainly on the location of the transformer in the system (single-phase short circuit currents).

Transformers with a properly designed and manufactured buried tertiary stabilizing winding normally do not have a higher failure rate than transformers without tertiary. This is not the case for brought out and loaded tertiary windings, where a three-phase short-circuit at the tertiary side can occur.

The disadvantage of not having tertiary windings can be solved by other internal technical solutions, in certain conditions.

3.4 On-load tap changers (OLTC) / De-energized tap changer (DETC)

In general, a delta winding on the -HV side is more expensive than star winding and especially when a tap-changer is required. When an OLTC/DETC is required, depending on the service conditions, the cost of the transformer is reduced when it is located on the HV side. For the operational point of view this generally does not affect the operation capability of the transformer. The OLTC/DETC is able to cover the full range of regulation (for voltage variation on both LV and HV sides). An OLTC/DETC that switches lower current is more reliable and needs less maintenance.

The cost of transformers will increase by about 15 – 20% with OLTC's and about 8 – 12% with DETC's.

The cost of the OLTC depends also on the regulating range; if for instance the cost of a transformer with an OLTC regulating range of +/- 10% is 100%, the costs of a regulating range of +/-15% will be about 2-3% higher and for +/- 20% about 5% higher.

OLTC's are always necessary for substation transformers, but the increasing tendency with step-up transformers (unit generator transformers) in generating stations is to specify DETC's.(OLTC's are still specified in only a few countries)

DETC's are rarely or never operated and could become a source of problems after some years of operation at the same tap position.

3.5 Life Expectancy, Capacity, Capitalization of Losses and Overloading

Normally, the planning department in a utility will determine the capacity of the transformers required and it is not an area over which transformer managers have much say. The maintenance planning group will usually have taken into account the current and future loads, over-loading and emergency loading. However, one area that the transformer manager could have some say would be in inter-changeability of the transformer in the event of a transformer failure elsewhere. Obviously, the capacity of the transformer is only one factor, which will affect how it could be re-used in the system if required at some point in the future. It may make good economic and risk management sense for a transformer manager to request a larger capacity transformer then otherwise required.

No existing standards define the life duration of a transformer (which is different then the life duration of the insulation system). The accountant's view has prevailed on the life expectancy of transformer about 25-35 years when it is operated at normal load and service condition. Modern calculation techniques are available to calculate the effect of an overloading [3.5].

However, experience has shown that transformers often last up to 40-50 or more years and this is due to reduced loading. This can give a life expectancy, which can be some 60% longer. It is equally (if not more) valid to use the longer life expectancy in evaluations and the longer life can have a significant change on the valuations of competing transformer bids. This fact can be linked with the cost of losses and also with the expected working condition of the transformers. It should be pointed out that the higher cost of loss causes a higher purchasing cost. Hence, one should take this into account, particularly in cases where the loading of the transformer shows substantial deviation with the seasons and the time of day. Lower cost is justified in these circumstances. On the other hand the transformer manager responsible not only for current maintenance but for cost of losses in a system (including the transformer) may insist on introducing to the bid a higher value on the cost of losses.

There is a good description of the capitalization of losses and their attendant assumptions in [3.3]. Utilities often, in tender evaluations, re-use the same capitalization figures year after year without reviewing them and the assumptions that are used in deriving them. Tariffing structures may have greatly changed, test discount rates may apply and the life expectancy may be lengthened based on more experience.

Overloadings are possible and acceptable and are laid out according to different standard requirements. When the operation condition requires different overloading capability, it should be defined and specified clearly. An increased overloading capability has an impact on the costs, as it shall be designed as a special unit. These costs shall be balanced against a unit with a higher standard rating or to specify higher overloading capacity of the transformer than necessary at the time of purchasing.

Rough estimation of an increase of a mass of active materials (magnetic steel, copper, oil, etc) with rated power of the transformer can be done by a formula:

$$\frac{m_2}{m_1} = \left(\frac{S_2}{S_1}\right)^{3/4}$$

in which:

- "m" stands for a mass,
- "S" stands for a rated power,
- subscripts "1" and "2" stand for transformer 1 and 2.

For example, if the rated power of the transformer increases by 60% (for example from 100 to 160MVA) then the mass of active material increases by 42%. This rate of increasing is also valid for the load and no-load losses.

However, a cost of the transformer does not depend linearly upon the mass, particularly in case of network transformers. This is because of the cost of an on-load tap changer, bushing and some auxiliaries. In this example the cost should increase of order of 23-30%.

In general, the cost of a transformer (PR) increases with an exponent of about 0.5 – 0.6 on the relation (S1/ S2) of transformer power:

$$PR_2 = PR_1\left(\frac{S_2}{S_1}\right)^{0,5-0.6}$$

3.6 Test specification and factory test

During standardization, it might be possible that the design and routine tests required by existing standards are not enough to prove that the specified requirements are fulfilled. In this case, the specification should include some "special tests". Guide [3.1] defines and proposes in chapter 17 additional tests, which should be taken in consideration. Special requirements on the loading ability shall be proved by other special tests in an agreement between the purchaser and the manufacturer. The use of DGA as a tool to detect weak characteristics in design and manufacture should especially be taken into consideration.

3.7 Environmental conditions (noise, oil type)

Due to economic reasons, the use of 're-used' or "equivalent to new" oil is in discussion in some countries. The use of such oil should be strongly considered when specifying new transformers. The performance of this type of oil should be at least equivalent to new oils. Special attention should be paid to accelerated aging tests. However, increased frequency oil maintenance in order to check oil quality will generate additional costs however, these are generally small compared to the capital cost of the equipment.

Risk of pollution may require the use of fluids other than mineral oil. The use of vegetable or agricultural oils has been developed and its use is under discussions to establish its ability to fulfil the required performance. The use of such oil has a strong economic influence as it increases the price of the equipment.

Regulations in many countries are specifying more and more the noise levels of power transformers. The sources of noise are both in the core and in the windings. Some standards don't relate the noise level required in the specification for both sources. In the latest designs, sometimes the noise level produced by the current passing through the windings is higher then the noise produced by the flux passing through the core. The specification should define in more detail the noise limits required.

External barriers to reduce the noise level should be considered only in extreme cases when the required noise limit is very low.

3.8 Insulation coordination and insulation level of power transformer

In building the insulation system of a power transformer, all stresses on the equipment should be taken into consideration. Those stresses are: : LI, SI, applied voltage, induced voltage with PD measurements, transients and service voltage. The worst case in each point of the insulation is considered in order to coordinate the insulation system to withstand the highest stresses. Changes of the LI withstand will not automatically reduce the insulation system and consequentially it may not reduce the price of the transformer [3.6].

3.9 Maintenance and On-Line Monitoring

On-line monitoring on new units shall be considered only on strategic units. In any case, provisions for future installation of sensors should be taken in consideration.

The maintenance of a transformer has a high contribution to the lifetime of the equipment, as well as to its reliability and availability. Manufacturers in their instruction manuals specify the minimum maintenance required. However, transformer users should have maintenance policies that depend on many factors such as importance of the unit, costs of outages, costs of maintenance, etc.

3.10 Factory and Design review, Short-circuit performances

Factory and Design review are a key issue to establish a mutual understanding on the requirements and abilities to fulfil the spec. The use of typical guidance for such review can be found in [3.2]. With respect to the short circuit withstand capability, the guide [3.4] gives recommendations. It is important to stress that the short circuit withstand capability depends not only on the adequate design, but very much on how well the manufacturing processes are controlled.

3.11 Auxiliary Equipment

Auxiliary equipment, such as bushings, CT's, tap-changers, etc shall meet the overloading capability required by the specification. Generally, the lifetime of the auxiliary equipment is much shorter than the active part of the transformer. Moreover, it requires much more attention (i.e. cost) then the active part. From that point of view the transformer manager should insist that bidders carefully specify which equipment shall be implemented (quality, durability). On the other hand he shall reserve extra money for a maintenance. That extra cost can be easily accommodated as a fraction of K_{ma} in the equation in section 5.3 of this guide.

3.12 Miscellaneous

In order to achieve an economical apparatus, it is recommended to unify the specification as much as possible. This standardise the transformers sizes, ratings, impedances, etc.

Part 4 - Operation and Maintenance

This part of the guide covers most economic aspects of managing transformers that are in service and that are deemed, by the transformer manager, to be in an acceptable condition for service.

4.1 Retain transformer in service?

Power system transformers differ from other network assets from the economic management perspective for a number of reasons:

1. Capital cost to O&M cost ratio is very large
2. Uncertainties with current data surrounding the issue of failure rate vs. age of unit
3. Failures tend to be of a random nature
4. No generally established criterion for technical end-of-life
5. Transformer normal load is generally significantly lower than the peak load designed for
6. Unit failure is often ‘acceptable’ ((n-1) criterion)

For these reasons, when traditional economic tools are applied to transformer management invariably capital investment deferment (i.e. retain existing transformers in service) is the preferred option [4.6]. Often factors other than economic will influence the decisions relating to managing transformer populations such as environmental, public relations, traditional practices and perceived risk reduction. However, [4.6] shows in a sensitivity analysis that the savings do not change linearly year-on-year but do reduce significantly after a number of years (in his study 9 years) and that could be used to determine the ideal retirement age of certain transformers combined with individual condition assessment. [4.7] uses another model when deciding to retain transformers in service taking into account also any regulatory consequences of unit failures.

When it has been decided to remove a unit from service either because the risk of failure is deemed unacceptable or because it has already failed in service then the economic factors in this scenario are covered in this guide in Part 5.

4.2 Operation

4.2.1 Loading

Apart from the decision to continue a transformer in service one of the biggest economic decisions a manager will have to make is to determine the allowable loading on the unit.

A transformer is specified for certain assumed conditions. At certain points in the future these conditions may change and the loading on the transformer may have to change as a result. System loads may increase to the point that, for certain time periods, loading the transformer beyond nameplate is required. This may or may not result in accelerated insulation aging or increased risk of transformer failure. In summary when deciding policy on transformer loading the following needs to be taken into account:

- Transformer specifications
- Transformer condition including age
- Environmental conditions
- Electrical operating conditions
- Type of loading
- Acceptable loss-of-life
- Risk of major/minor failure including financial loss & insurance impact
- Financial benefits of loading policy

Figure 4.1 attached shows a typical decision-making model that may be employed when deciding policy on transformer loading.

Elaboration of Figure 4.1:

1. The type of load (cyclical, emergency 1hr etc.) is as important as the level of load.
2. Assessing the condition of the transformer can be simply from oil screen/DGA test to full suite of condition assessment tests covering insulation tan-delta, winding mechanical integrity and OLTC condition.
3. Was the transformer originally specified to be loaded beyond nameplate?
4. Loading beyond nameplate may or may not cause accelerated ageing (because of lower ambient temperatures or brevity of extra load etc.). Consequently, lifetime of the transformer may be shortened below the expected\required value.
5. Transformer generally regarded as fully fit for service?
6. Need to estimate the risk of the transformer failing under new load. [4.3], [4.4] and [4.5] estimate that 10% of transformer failures are due to loading beyond nameplate.
7. Is the new risk of failure acceptable?
8. Calculate in today's money the loss of transformer-years in the future.
9. Calculate the value to the company of deferring the investment.
10. Does the benefit of deferring the investment outweigh the cost of loss-of-life?

Transformer Loading and Loss-of-Life

When loading a transformer beyond nameplate, apart from the increased risk of failure, there is a consequential loss-of-life, or in other words, accelerated insulation ageing. This is a complex topic which has been studied in considerable detail over the years. Two useful guides which can be used by the transformer manager to calculate the consequential loss-of-life due to a particular loading pattern are the IEEE's Guide C57.91 [4.8] and IEC's Standard 60354 [4.9] both of which cover this in detail and present models for the use in the calculation.

Assessing Transformer Condition

CIGRE's Working Group WG12.18 (Life Management of Transformers) has written a guide on diagnostic tools which can be used in transformer condition assessment. The guide covers the type of diagnostic tests available, the theory behind each of the tests and interpretation of test results [2.7].

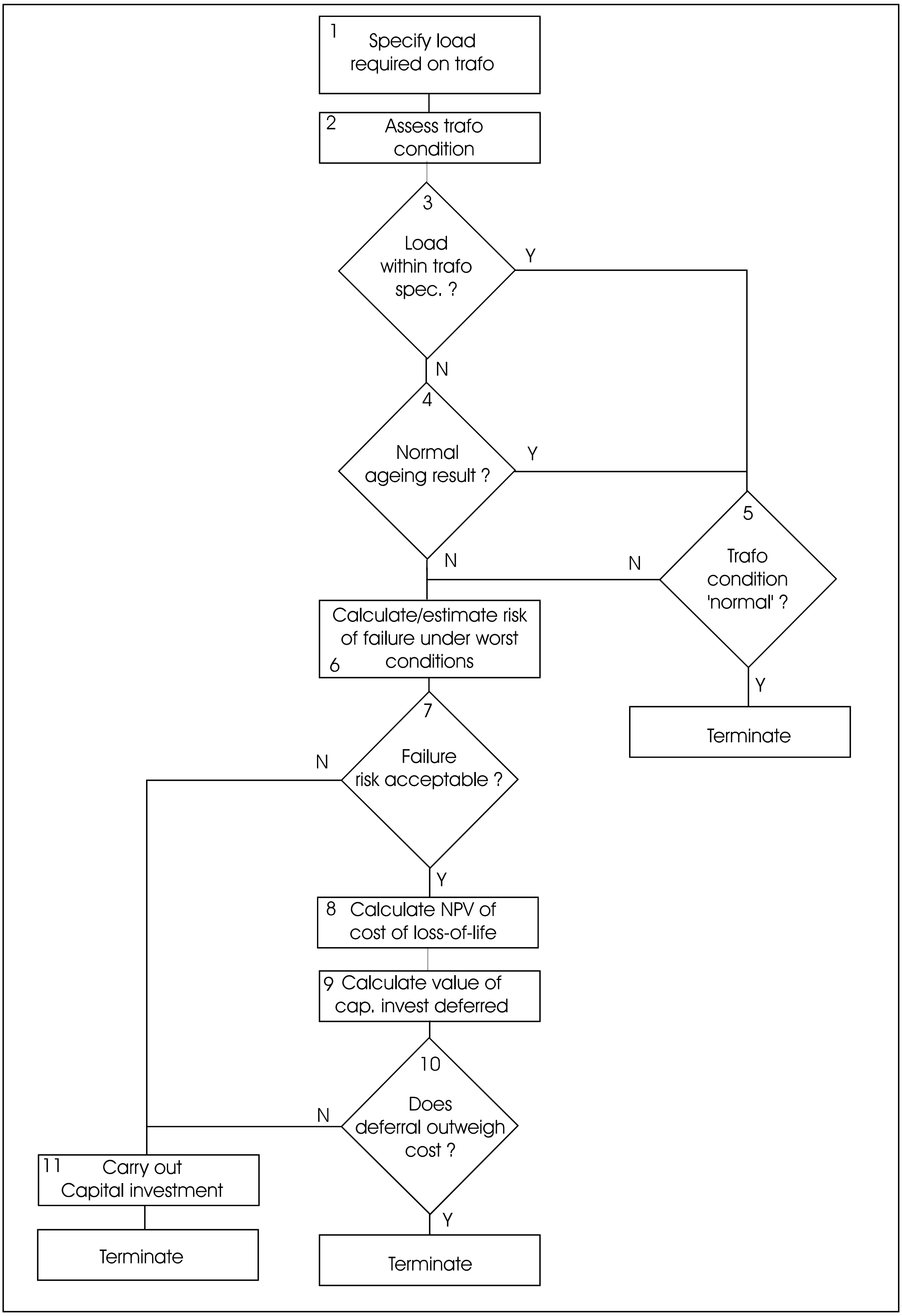


Fig. 4.1 : Decision-making model

4.2.2 Availability & Outage Management

A transformer is only earning its owner money when it is in service. A transformer out of service and unavailable to the system operators (due to maintenance or repairs) can not be earning its owner money and may be costing money indirectly through increased loading on other system elements, inefficient generation dispatch or directly through repairs and maintenance costs. Issues which need to be considered when dealing with transformer outages and availability would include:

- Efficient generation dispatch
- Efficient network loading
- Length of outage period
- Weather conditions (seasonal)
- Transformer condition
- Emergency return-to-service time allowed
- Maintenance work optimization
- Repairability and spare part availability

Rarely will a transformer manager be able to have a large influence over the first 2 items above but in the light of the other factors s/he may be able to justify a less-than-optimally-efficient outage of a transformer.

4.2.3 Voltage Regulation & Power Quality

Increased system loading and changes to network configurations can result in a transformer having a very different voltage regulation regime than was initially envisaged. Transformers are far more vulnerable in the case of overvoltages than overcurrents. Consequently, much greater care needs to be taken to ensure that a transformer is operating in a voltage environment that is within its specification. [4.4] and [4.5] estimate that over 60% of transformer failures are due to insulation breakdown from electrical disturbances or lightning. For example, introduction of capacitor banks close to transformers can result greatly increased switching transients and new transmission lines in high isokeraunic areas can lead to significantly greater number of lightning surges each year etc. In essence, these system changes can lead to very different operating conditions for a transformer than those for which it was first specified. All of these changes can lead to an increased risk (possibly calculable) of transformer failure. The transformer manager has mitigation measures that s/he can consider using to reduce the risk of failure up to and including replacing the transformer. Amongst the issues that would be considered in this area are the following:

- Required voltage regulation under new network conditions
- Number of OLTC operations per year
- Lightning impulse withstand level (including bushings)
- Lightening protection
- Harmonic content of load

The decision process model for this area would be similar to that for the transformer loading.

4.3 Maintenance

This section covers all aspects of transformer management that are not operation related such as maintenance itself, on\off-line monitoring, spares policy etc.

4.3.1 Maintenance Costs

The cost of maintenance, both actual and proposed, is readily calculated by the transformer manager. Rarely, will maintenance costs result in a manager deciding to replace a transformer but it will often result in the decision to replace transformer accessories such as fans, OLTC drive mechanisms etc. Generally high maintenance costs would be accompanied with low reliability and low availability and this rather than the actual cost of the maintenance itself would be the deciding factor. Transformers generally are high reliability elements on a network with a low maintenance cost to capital cost ratio and so rarely will this issue be prominent in the economics of transformer management. Regular maintenance activities include replacing breather consumables, checking oil levels, DGA tests, cleaning bushings, checking for leaks, corrosion repairs, functional tests on OLTC and fans\pumps, protection systems tests etc.

4.3.2 Spare Units & Spare Parts

Transformers have few parts to them so the stocking of spare parts likely to be required is generally economically feasible.

Spare transformers are an entirely different matter and require much greater scrutiny to justify their economic advantage. The transformer manager would need to take into account at least the following:

- Transformer populations that require a spare unit
- Opportunity cost of transformer
- Cost of storing transformer (incl. iron losses if energized)
- Cost of additional infrastructure and protection equipment
- Aging of unit
- Transportation of unit (incl. decommissioning from storage)
- Reliability of transported transformers

However, there is a case is made for system spares to meet a Transformer Required Availability Level. Based on average failure rates and average repair times the optimum number of spares to meet the regulatory requirement can be calculated. Essentially, this method involves calculating the risk (i.e. the cost) of system failure in a system of n transformers. If the risk-cost is greater than the annual cost of the spares then it makes economic sense to purchase the spare(s). From this calculation given the expected performance level and the cost of system failure the optimum number of spares for a given population of transformers can be calculated.

4.3.3 On-Line Monitoring

In recent years there has appeared an increasing array of devices for on-line monitoring and data logging of various transformer parameters. Many such parameters can be cost effectively monitored today in comparison to the cost and availability of such data acquisition equipment as little as 10 or so years ago. Factors which the transformer manager needs to consider when determining what if any on-line monitoring to place on some or all of the transformers under his/her control:

- Equipment reliability and maintenance costs
- Benefit of increased reliability or earlier detection of impending failure
- Cost of equipment, installation and training
- Reduction of insurance costs
- Future benefit of additional information for transformer condition determination
- Value of information
- Cost of data archiving and retrieval (IT burden)

Some economic models have been proposed to evaluated the cost/benefit of such on-line monitoring systems as well as the ability of such systems to reduce transformer failure rates. [4.2] presents one such model to justify on-line monitoring. [4.1] looks retrospectively at its transformer failures over the previous 50 years and sees what the net cost/benefit would have been if on-line monitoring had been used. The most recognised benefit of early detection of incipient faults is the major savings that can be achieved sometimes in repair costs. The purpose of monitoring is to try to prevent major catastrophic failures and turn them instead into failures that can be repaired at a reduced cost during a planned outage.

On-Line Monitoring Evaluation Example

In order to evaluate the economic aspects of on-line monitoring it is first necessary to consider the probability of failure both with and without on-line monitoring. In order to estimate the probability of failures adequately it is easiest to construct a failure probability tree. The figure below shows 2 failure probability trees, one for transformer failures with no on-line monitoring and the second with on-line monitoring. The figures included are for the purposes of illustration only and are not necessarily the preferred figures to use in an economic evaluation. The user's own experience and literature reviews should be used to supply the percentage (and hence probability) figures throughout.

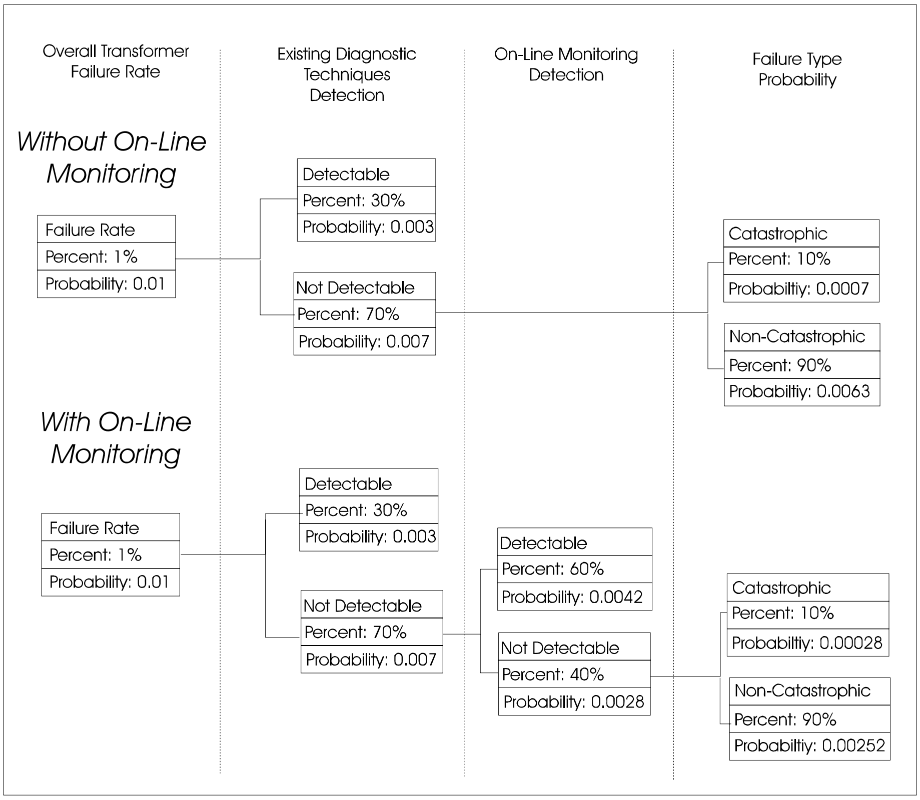


Figure 4.2: Failure Probability Trees

One possible method of doing an economic evaluation of the cost\benefit of on-line monitoring is to reduce all failure probabilities and actual outlays to an annualized cost. The following example illustrates this method:

Example:

- Repair cost of major failure* €1,500,000
- Catastrophic failure multiple (300%)* €4,500,000
- Early detection repair to major repair ratio (20%) € 300,000
- On-line Monitoring System (assume 20 year life span):
  - System Cost € 40,000
  - Installation € 5,000
  - Maintenance Cost (annual) € 1,000

(* A major failure requires the removal of the transformer from site but the damage is contained within the unit itself whilst a catastrophic failure includes very significant collateral damage.)

Using these costs and the estimated failure probabilities the costs can be compared as follows (the costs of repair of an incipient fault detected with existing techniques are not included as they are the same for both scenarios):

Without On-Line Monitoring

Major Failure	(€1,500,000 * 0.0063)	€ 9,450	
Catastrophic Failure	(€4,500,000 * 0.0007)	€ 3,150	
Annualized Cost			*€12,600*

With On-Line Monitoring

Major Failure	(€1,500,000 * 0.00252)	€ 3,780	
Catastrophic Failure	(€4,500,000 * 0.00028)	€ 1,260	
Early Detection Repair	(€300,000 * 0.0042)	€ 1,260	
Monitor System Cost	(€45,000 / 20)	€ 2,250	
Monitor System Maint.		€ 1,000	
Annualized Cost			*€ 9,550*

Annual Benefit of On-Line Monitoring € 3,050

Sensitivity Analysis: The user should always conduct a sensitivity analysis on any assumptions or estimates used in the calculation. For example, in the above example if the early detection repair cost was 50% of the major repair cost and the annual monitoring system maintenance increased to €2,000 then there is no economic benefit in on-line monitoring. Likewise, if the monitoring system detection rate was reduced to 40% from 60% then the economic benefit reduces to €950.

Costs associated with Energy Not Sold\Delivered or Degraded System Operation

The above example, for the sake of simplicity, only included the cost of repair and not any other additional costs in the event of a major failure. The following are some additional costs that may need to be considered and added to the cost of repair:

1. Energy Not Sold (ENS): If the outage involves the loss of some energy sales then this loss of revenue would need to be added to the repair cost. This would normally only be a significant cost factor for GSU transformers. The annualised risk-cost is calculated as follows:

$$\begin{pmatrix} Lost \\ Power \\ (MW) \end{pmatrix} \times \begin{pmatrix} Outage \\ Duration \\ (Hours) \end{pmatrix} \times \begin{pmatrix} Gross \\ Contribution \\ (\$/MWh) \end{pmatrix} \times \begin{pmatrix} Major \\ Failure \\ Rate \end{pmatrix} \qquad \text{Eqn. 1}$$

2. Energy Not Delivered: Increasingly utilities are being penalised by regulators for unanticipated customer outages. Usually it is by means of a penalty charged to the utility for the 'Value of Lost Load' (VOLL) per MWh of power not delivered. The risk-cost of the penalty is calculated as in equation 1 with the VOLL penalty figure replacing the Gross Contribution. In some instances both loss of revenue and penalties may apply in the event of a major failure.

3. Degraded System Operation: In networks often a major failure does not result in loss of supply or revenue but it may still be necessary to consider the risk-cost of operating the network in the degraded condition. Such a network is then very vulnerable to minor failures on other transformers as this often will result in customer power loss with the associated costs outlined just above. Transformer minor failure rates are generally considered to be an order of magnitude higher than major failure rates. The 2nd contingency probability is calculated as follows:

$$\begin{pmatrix} Major \\ Failure \\ Rate \end{pmatrix} \times \begin{pmatrix} Outage \\ Duration \\ (Years) \end{pmatrix} \times \begin{pmatrix} Minor \\ Failure \\ Rate \end{pmatrix} \qquad \text{Eqn. 2}$$

Example:
A single major failure is assumed not to result in customer power loss. However, a minor failure during the major failure outage is assumed to result in power loss in the following scenario:

Major Outage Duration	0.2 Years
Minor Outage Duration	16 Hours
Minor Failure Rate	5%
Lost Power	200MW
VOLL Penalty	€10,000 MWh

With no on-line monitoring the 2nd contingency probability is (0.007) * (0.2) * (0.05) = 0.00007 and therefore the annualised risk-cost is:

VOLL ((200 * 16 * 10000) * 0.00007) €2,240

With on-line monitoring this cost reduces to approximately €900.

All of the above additional costs are based on the assumption that the outage duration would be reduced in the event of incipient major failure detection and\or that the utility would have some control over when the unit was removed\replaced after the incipient fault was detected. If neither of these are apply then the above 3 additional costs would not be applicable in the economic evaluation.

4.3.4 Periodic On-Line Condition Assessments

DGA and oil-screen tests fall into this category of assessment. DGA is one of the most widely used and trusted means to determine the condition of a transformer during service or after a failure during the fault investigation. Increasingly, utilities are also using Partial Discharge (PD) measurements on live transformers to determine their condition.

4.3.5 Off-Line Condition Assessment

Many of the off-line condition assessment tools have been available to utilities for many years. Traditionally, these were primarily used to commission new transformers and to fault find on failed units. Increasingly today utilities are using these tools to conduct regular and widespread benchmarking and condition assessment of transformers under their control as the average age of their units is rising. New diagnostic tools are appearing which claim to diagnose aspects of the transformer not hitherto examined or to diagnose some aspect in a more accurate or consistent manner. Like on-line monitoring tools, there is a wide selection for the transformer manager to choose from in the marketplace. The economic factors which s/he would be very similar as in section 4.2.3 but the following would have to be considered as well:

- Cost of outage (energy not served, increased network burden etc.)

Often this additional element can be minimized by a optimal selection of outage time.

4.3.6 Databases for Transformer Management and Condition Assessment

In order to support maintenance activities, computer-based tools and databases are usually used by utilities. From these data repositories, it is possible to extract information that may be used for transformer management and risk management. For example, questions such as ‘What is the average age of a transformer when a major failure occurs?’ or ‘Is there usually an increase in the gas dissolved in oil before a failure occurs?’ may be answered by information extraction from a good quality database.

The database with the asset inventory is the core of the computer-based tools for transformer management. Key data for each transformer has to be recorded in the database such as manufacturer, year of manufacture, serial number, high and low nominal voltages, nominal power for different cooling stages, bushing and On-Load Tap Changer (OLTC) types, transformer localization, etc. One of the most important elements of the database should be the regular updating of key assessment data for the transformer (not just active part but bushings, cooling system etc.). This will simplify and make more accurate the ranking of the transformer population as outlined in section 2.2.3 of this guide.

Utilities usually have a maintenance program based on time or condition. A list of transformers due maintenance is created and used by maintenance crews. For Time-Based Maintenance (TMB), task list and task intervals has to be specified for different transformers, taking into account differences such as transformer position, age, tap changer type and any other relevant criteria. Any transformers that have not been maintained within the required interval will be added to the list. For Condition-Based Maintenance (CBM), limit values may be defined for key condition assessment parameters. An out of range transformer may be included in the list of transformers due maintenance that year.

So, condition assessment data generated by a on-site measurements (visual inspection or measurement with an instrument) or by an On-Line Monitoring Systems (OLMS) should be archived in a condition assessment database. Condition Assessment data includes gas-in-oil analysis, oil tests, transformer insulation and resistance tests or even visual inspection (oil leak, failed fan, etc.).

Finally, all relevant data concerning a transformer outage should also be archived. Key data such as reason for outage (forced, time-based maintenance, condition-based maintenance), outage start time and duration, failure mode (failure due to insulation, failure due to load, failure due to OLTC fault, etc.), failure causes (bushing insulation, hot spot on connection, etc.) and remedial action (number of man-hours, components replaced, costs, transformer disposal, etc.) should be archived.

4.3.7 Miscellaneous

With the break-up of traditional vertically integrated utilities in Europe and North America and the deregulation of these markets the generation and supply of electricity is becoming a more ‘normal’ business model with financial performance starting to have as much bearing on decision making as engineering requirements used to have. This is changing very many aspects of the electricity business but in relation to the transformer manager 3 in particular are worth mentioning.

Firstly, utilities have entered into more stringent contractual arrangements with their customers and failure to deliver power can impose severe financial penalties. This may apply on a network-wide basis or just in specific isolated parts of the network supplying key industrial customers. Outage costs and/or collateral costs of failure may necessitate a re-think on acceptable failure rates on some or all transformers on a system as well as the necessity for both energised and non-energised spare transformers.

Secondly, shareholder pressure for financial performance (usually a short and medium term performance viewpoint) often will reduce the resources available to the transformer manager and it will force him/her to find a more cost effective way to carry out the same function or abandoning such a function and accepting the consequences of same.

Thirdly, with less state support and backing for utilities they are increasingly having to take out insurance as a means of risk management. Insurance companies which will operate in many countries and continents may seek changes in practices in a utility in order to bring them closer to other utilities which they insure. There may be significantly increased insurance costs for utilities that adopt a different approach as insurance companies underwrite risk based on historical information which may not be applicable under different practices.

Part 5 - The Repair versus Replacement Decision Process

5.1 Introduction to the "Normative" Model Approach

Work practices in the electric utility industry are most often guided by standards and specifications that provide the reader with explicit and detailed rules. Other informational tools such as Standard Operating Procedures (SOPs), are extensively used by Utility Operations and Maintenance personnel to provide direction when following a series of specific tasks. Such informational tools tend to be inflexible and are required to achieve proper and consistent results demanded by the utility company's quality assurance program.

In managing the life cycle of the electric utility's aged population of transformers, the list of variables governing both technical and financial decision-making is such that it precludes the use of "standards" that describe in detail the course to be followed by any more than one utility organization. In fact, due to the widespread geographic nature of some utility companies, as well as some of their customs and practices that have been historically developed, it is often not possible to set firm rules and standards for any one "global" organization. In these less definitive work situations and when the subject area is quite broad, more general and flexible informational tools can and should be used.

The "Normative" model approach, we have chosen to use here, provides the reader with good direction while enabling flexibility to chose a variety of project-specific details that match their company's own unique decision making criteria.

Normative models are knowledge-based tools that prescribe a course of action, or decisions leading to actions, recommended by others with expertise in similar decision-making situations. The normative model approach also provides a pragmatic means of passing-on vital knowledge that in the past resided in individuals who are less likely to be found in the "modern" utility companies' lean organizational structure.

The normative or prescriptive model can be an invaluable tool in decision-making when the task-at-hand is affected strongly by factors outside the domain of the decision-maker. Engineers and Asset Managers in the electric power and distribution business often find themselves in such a situation and are required to make technical decisions about equipment and systems in an environment closely controlled by financial factors and non-technical people. Engineers and asset managers have responsibility for valuable and technically complex assets, such as power transformers, which are crucial to the financial performance of the electric utility company that is today faced with the risks and realities of competing in the deregulated and privatized economy.

5.2 Normative Models and Flow Charts

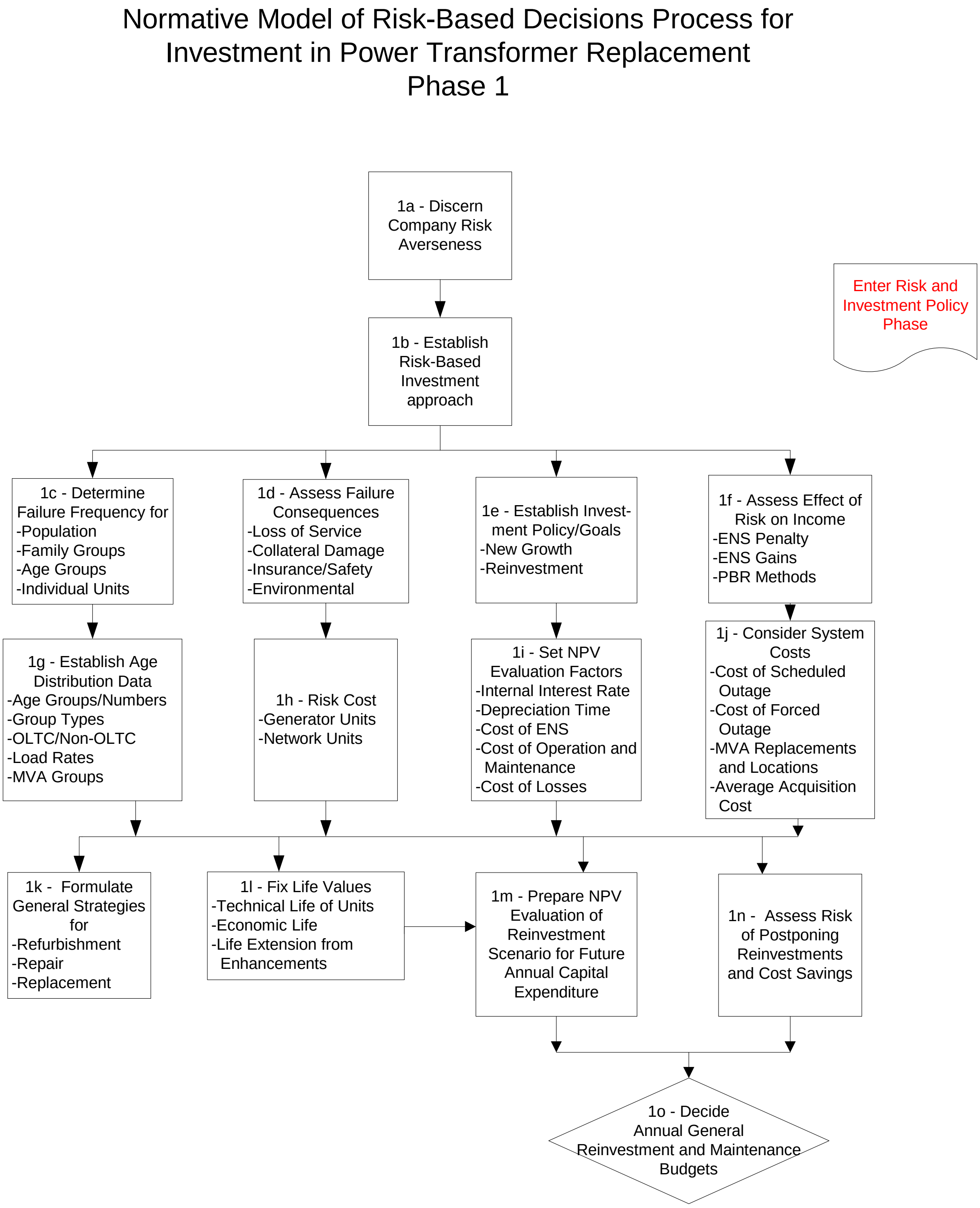
The normative model given in this chapter does not reflect or attempt to define the "Best Practices" used in the industry. Due to the previously discussed industry factors, this objective is not practically possible. This normative model was developed from a broad base of information and technical papers pertaining to the subject area. These papers ranged from detailed technical thesis to the "this is how we did it" theme. No attempt was made to select the best, most modern or prevalent concepts and to translate them into a "standard". We have reviewed the body of available information and extracted the concepts or ideas proposed by each referenced contributor and moulded them into a uniform or "normative" process as described by the flow charts in the following section. The flow charts are designed to guide the reader through a series of activities leading to decisions necessary in taking a specific action or to arrive at a specific result.

The flow charts follow a logical path of activities and decisions given by the available literature and do not attempt to consider all the probable "peripheral" involvement or interdependences needed by other management areas. The start and end of each flow chart was also set by the subject literature and does not recognize that this process (or project) probably overlaps with other operations and maintenance activities carried out in the overall on-going process of generating and distributing electricity.

The flow charts given in this chapter are supported by a section elaborating on the content of each point in the process. This is followed by a bibliography of all the available literature on the subject and to which specific reference has been made in the prior elaborations.

The flow charts given in this chapter consider the strategic reinvestment option available to the Asset Manager in deciding an overall repair versus replacement for single units or for groups of units. However, the intent of this section is to focus on decisions for failed or troubled units. The inclusion of the flow charts and elaborations for "normal" units in this chapter was made due to the overlapping activities and considerations that can exist for both "normal" and "abnormal" situations.

5.2.1 Flow Chart – Phase 1



5.2.1.1 Elaboration on the Flowchart - Phase 1

1a. Many industrial countries invested heavily in the development of electrical energy throughout the mid-1960s to mid-1980s period. The purchase of power transformers followed this trend. The peak development period was followed by a sharp decline in capital spending for the past 20 years. At the same time, load growth, or demand for electrical energy, has steadily increased resulting in the average power transformer being highly loaded and at an age of 30 to 35 years, which is generally considered to be approaching the end of its useful life. Electric utility companies, driven by their customers' needs, have a low tolerance for failures and hence risk-cost is a very real cost of doing business. Power transformers are, therefore, a major concern because each unit feeds large numbers of customers and their failure will result in loss of service with a considerable amount of expense associated with lost revenue, replacement and other collateral costs.

1b. Utility regulators in many areas of the world are applying Performance-Based Rates (PBRs) or Energy Not Served (ENS) penalties on income. There exists an obvious need for future reinvestment but capital in the amounts required is almost universally not available. There is, therefore, a need to deal with the peak of capital reinvestment and distribute it across the transformer population over time. This requires a clear understanding of the age distribution of units on a particular system, the probable condition of individual units along with a strategy for refurbishment and replacement. This will also require sound financial methods of evaluation and means of establishing the risk costs for groups and individual units[5.3]. The risk-cost would then be estimated based on the frequency of failure times the consequential cost.

1c. The utility company management must set boundaries on its risk averseness which would include a financial mechanism for factoring this into their reinvestment strategy. This topic is fully covered in Chapter 2 of this guide. The Net Present Value (NPV) method of evaluated capital investments over time is well recognized. This evaluation method must include the change in risk-cost over time or age of equipment to be truly meaningful. The use of a simple average risk-cost, not considering age and failure probability relationship, will result in favouring the postponement of investment and ultimately result in an unacceptable high risk-cost[5.2].

1d. It is most important to understand failure frequency, or the failure rate, applied to the number of transformers in service. Other methods of determining failure frequency are the mean time between failures (MTBF) and the mean time to failure (MTTF)[5.4].

Proposals for estimating the change in failure rate with are given as ranging from 0.5% as being excellent and 2% being acceptable and >2% being unacceptable[5.5]. Establishing a course method for applying failure rate changes based on age, for a large number of units, or for evaluated condition of individual units could follow the typical examples given in the below charts.

Good statistics on failure probability are almost universally not available and do vary from system-to-system. Much conflict in published data and in expert opinion can be found throughout the industry. Significant variables, such as the type of application (GSU versus transmission auto or distribution substation for example), normal and contingent loading practices, system impedance and protection, age distribution and oil quality maintenance can have a major impact on failure probability and should be compared when using data from other systems. Some surveys have indicated values listed below. The reader should use these values with caution as other surveys have indicated significantly different failure rates. The reader should apply failure rates that are consistent with their failure rate definition, experience and expert evaluation of their own transformer population.

Failure Rate Change by Age of Unit

Transformer Age	Substation Units	Generator Units
≤ 15 years	0.5%	0.8%
16 - 24 years	1.0%	1.5%
25 – 34 years	1.5%	2.0%
35 – 50 years	2.0%	2.5%
> 50 years	3.0%	3.5%

Failure Rate Change by Evaluated Condition for Individual Units

Condition Rating	Failure Rate
Good	0.6%
Satisfactory	1.0%
Fair	1.5%
Poor	2.0%
Bad	3.0%

Failure consequences can include a broad range of tangible and intangible costs that are difficult to access. These are not limited to loss of service, collateral damage and environmental costs associated with clean up after a failure. These costs can be many times the cost of the transformer replacement and can vary dramatically with the duration of a forced outage. There is good correlation between the increase in failure frequency followed by an increase in failure duration as indicated by System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI) increases. It can also be said the service age of the transformer insulation system will have a strong effect on the severity of the failure. Close-in short circuit faults on units with old deteriorated and loose windings are more likely to result in catastrophic failure than in newer units that may have seen the same number of faults. This may also relate to the age deterioration of the protection system which may take longer for a fault to clear, resulting in a higher energy-level failure. There is, therefore, a strong reason to assess an increase in consequential costs with increasing unit age.

1e. Utility system studies on age distribution versus reinvestment strategy point to the conclusion that investment in refurbishment and life extension of comparatively modern and median age units (less than 35 years) is favourable to investment in new units in the short term[5.3].

1f. The loss of income or cost of ENS penalties on income revenue can have a serious impact on the ability of the utility to reinvest. Therefore, pro-active reinvestment is encouraged to reach a higher level of reliability. This, again, is a function of the Risk vs. Reward evaluation and the utility company's level of risk aversion.

1g. Establish the age distribution and other "demographic" information about the prominent features that make up the utilities' transformer population cannot be overemphasized as being fundamental to the formulation of general strategies and priorities related to refurbishment and replacement. The use of modern databases for collecting, sorting, and querying information can help considerably in accomplishing this task[5.15]. A proposed "Transformer Population Information" listing is given in ANSI/IEEE 057.117 which considers virtually all aspects of the required data to be collected.

1h. Risk-costs will differ for small and large units in addition to the transformer application and the loading. This is due to the failure frequency and consequential cost being different for the aforementioned groupings[5.3].

1i,1j. Net Present Value (NPV) calculations require the prior determination of appropriate interest rate (Discount Rate) or the internal rate of return as well as period of time / expected lifetime. Most literature related to this subject excludes the cash flow and tax implications for evaluation purposes. NPV calculation method should model all the associated costs, including the capitalized cost of losses.

1k. Given the age distribution data and information about transformer groupings in elaboration 1g above, general strategies can be formulated and priorities can be set for NPV evaluation of specific units or family groups. These general strategies would consider available resources and logistics or unusual cost factors which may have a bearing on selecting possible candidates for refurbishment, repair or replacement with new units.

1l. It is essential to set the expected limits for technical and economic life of new units and rewound / rebuild units, in addition to the extension of the technical life for refurbished units, that will result from the estimated life extending costs[5.1], [5.3] & [5.4]. Due to the difference in life expectancy the NPV calculation would consider the equivalent annual costs for each alternative[5.1], [5.7].

1m. The risk-based NPV evaluation for the population, or groups of units, is based on age distribution and can be performed once all of the above factors have been considered. With values set for time and cost, a number of potential scenarios can be calculated to consider the distribution of future capital investment options[5.3].

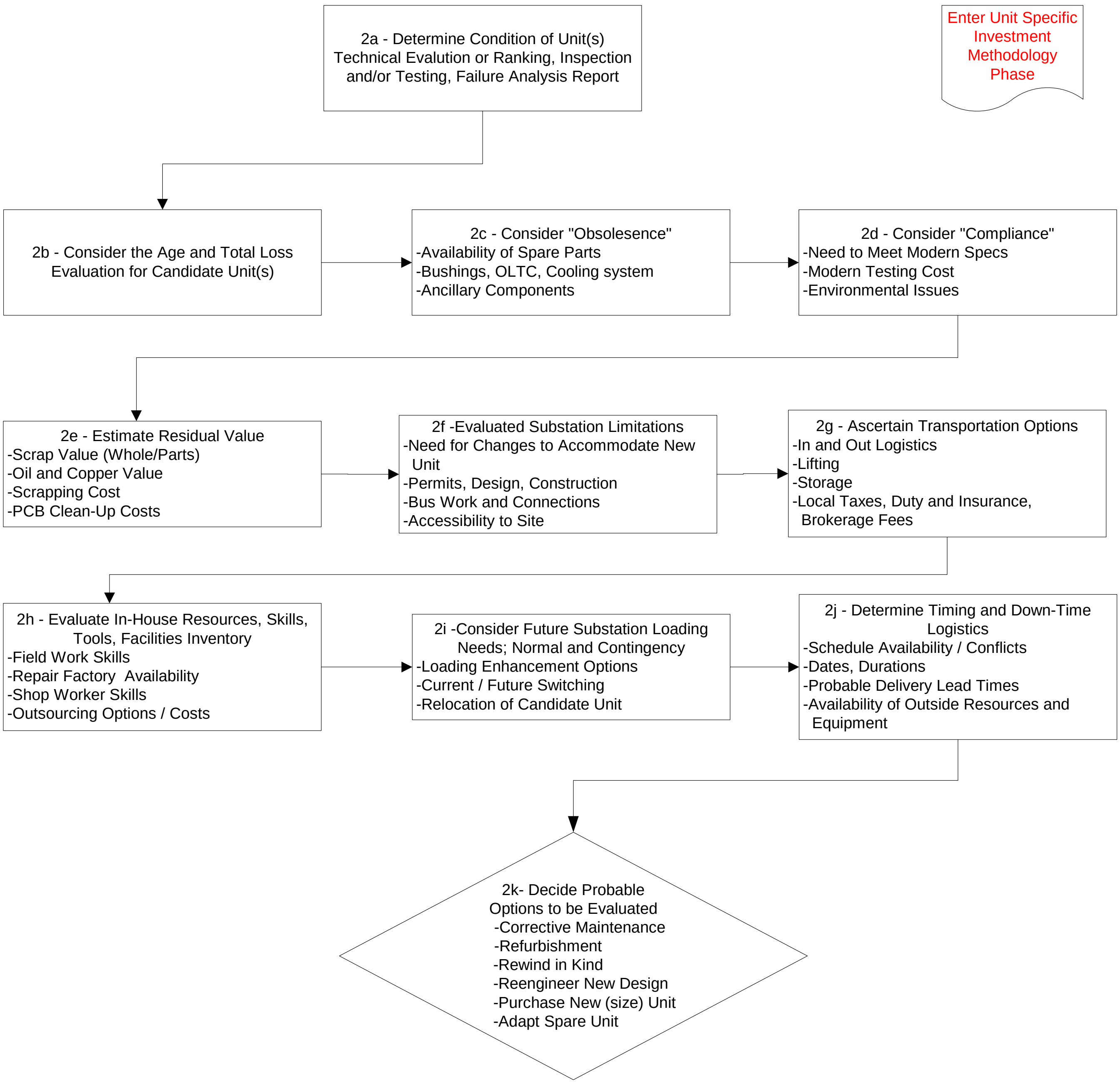
1n. With the predetermined risk-cost it is possible to evaluate the sensitivity of cost savings associated with reinvestment deferral[5.2], [5.3].

1o. Modelling future reinvestment distribution based on refurbishment and replacement strategies provides the ability to manage a situation that may otherwise be overwhelming. Economic Modelling expressed in financial terms will considerably strengthen the Asset Manager's internal decision to select a path forward for overall reinvestment[5.2], [5.3].

1. The above methods apply primarily to the population or groups of units on a system. It considers the age distribution of units (or comparable units) and failure rates based on deterioration of an active part of a transformer. It is, however, necessary to make decisions for individual units based on the probable service condition. A unit-specific economic evaluation must consider the life expectancy or extension on specific cost factors including loading profile and capitalized cost of losses for the specific unit. The probable condition of the individual unit must be made by a thorough review of available operation and maintenance data, involving inspection and testing of the operating or failed unit.

5.2.2 Flow Chart – Phase 2

Normative Model of Risk-Based Decisions Process for Investment in Power Transformer Replacement Phase 2



5.2.2.1 ELABORATION ON THE FLOWCHART - PHASE 2

2a. The normative literature, related to determination of condition, recognizes that the refurbishment, repair or replacement with a new unit must first depend on a clear understanding of the condition state. Four typical circumstances require the Asset Manager to understand the asset's condition state.

- Ranking of probable condition during normal operation usually as part of a life assessment or loading study project[5.13], [5.16], [5.17], [5.18], [5.19] & [5.23].

- Evaluation of condition because of warning or diagnostic results indicating concern over reduced life expectancy.

- Condition resulting from fault or known trouble indicating removal from service or incipient failure. Condition is normally evaluated versus impact of failure on system prior to deciding on action plan[5.20], [5.22].

- Failed unit condition needed to determine extent of refurbishment or repair. Failure analysis often required to determine failure mode as consideration in repair or monitoring of similar or other family units on system[5.20], [5.22].

2b. The cost of no-load and load losses are vital in making the repair / replace decision. Several of the referenced papers suggest that if the unit is more than 35 to 40 years old, the cost of no-load losses will be too high to consider keeping the unit compared to the significantly lower core losses of a modern unit[5.1], [5.6], [5.7], [5.17].

2c. A key factor in deciding the viability of refurbishing older transformers is the availability or obsolescence of spares. Replacement of obsolete parts with non-factory originals is sometimes possible providing that good documentation is available and the required engineering expertise exists to apply the parts in the field. “However, replacement of parts external to the tank (including bushings) by non-original requires extra money and time.”

2d. Many utilities take the opportunity presented by a failed unit to update it to modern standards during the repair process. This is not however always practical or economical due to the original design configuration and the subsequent need for major redesign to comply with modern standards such as a short-circuit withstand capability, overload limits and noise levels.

2e. The remnants of a failed unit can have both positive and negative implications on the repair / replace decision. The unit may have a scrap value, however, this may well be offset by the cost to dispose of the potentially contaminated parts and clean-up services required to change ownership of the parts.

2f. Physical limitations of existing older substations can have a major impact on the decision to repair the original unit or modify the station to accommodate a new unit. The location of the substation may make the removal of the unit an impracticality.

2g. Transportation costs can be very high in some locations around the world. These costs can outweigh the decision to remove the existing unit from site and return it, in favour of transporting a new unit to site and storing the old carcass on site.

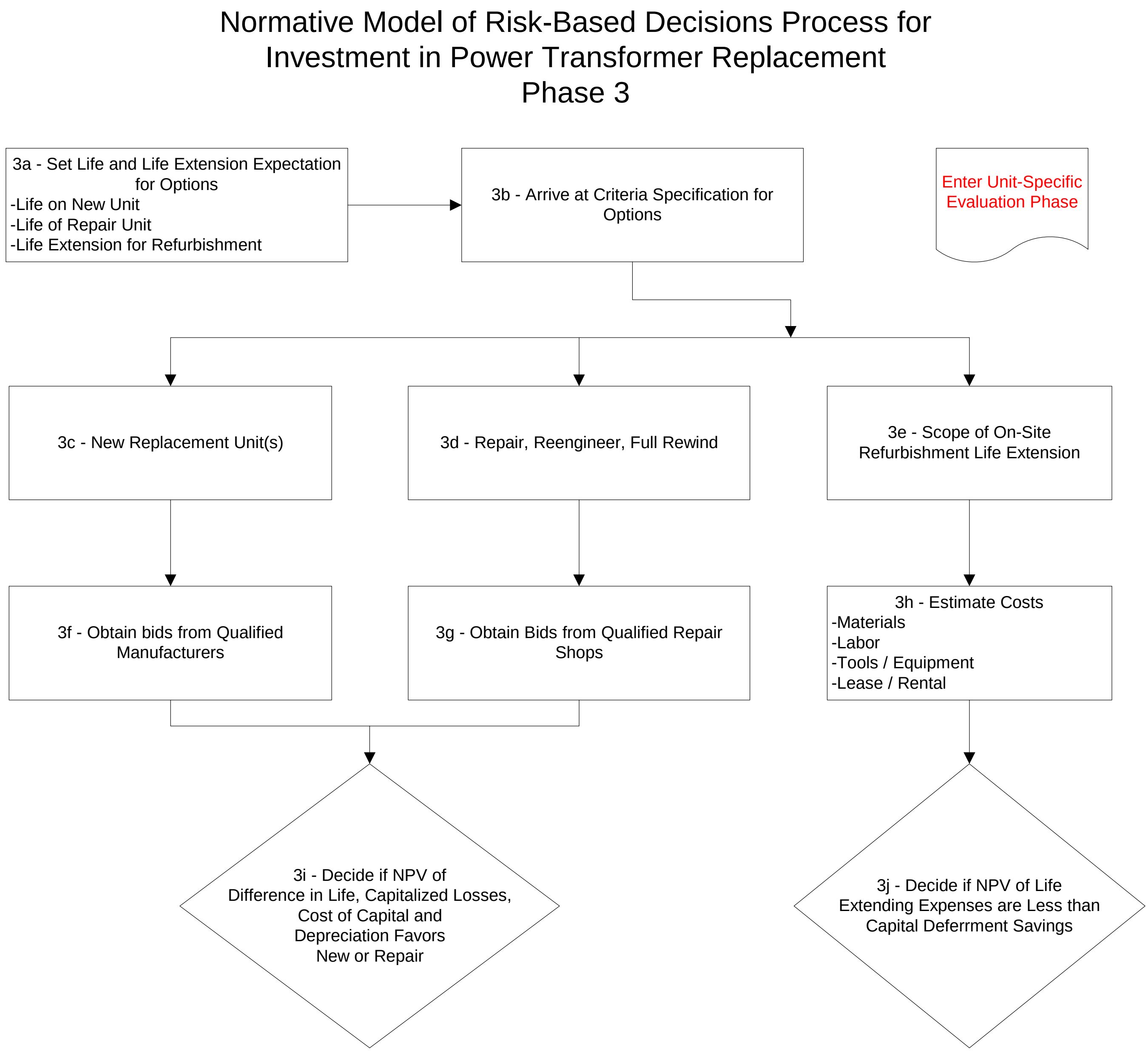
2h. The practicality and economic viability of on-site refurbishment often revolves around the availability of skilled people to do the work. Many utilities in today’s “lean” organizations do not have the trained personnel to take on tasks other than routine maintenance, and the cost of hiring field workers and equipment is prohibitive in some locations [5.1], [5.20], [5.22].

2i. Many failed transformers are replaced by new larger units depending on the utility’s forecasted load growth. However, not all failed units are repaired and returned to the same location; often some units are moved to locations to replace smaller units or to replace another failed unit or to be stored as a spare unit.

2j. The cost of downtime and the potential need to reduce electrical service for a prolonged period can have enormous financial implications. Sometimes the timing of a failure may not coincide with the economic availability of a work crew to do major refurbishment, making the purchase of a new unit a necessity.

2k. The refurbishment, repair, replacement comparison evaluation can only be performed if all the above cost considerations are available and make economic sense. The least-cost alternative is nearly always the major deciding factor. An evaluation that considers all factors included in prior elaborations 2b through 2j will assist in a high level of confidence that the correct asset management decision will be made.

5.2.3 Flow Chart – Phase 3



5.2.3.1 – ELABORATION ON THE FLOWCHART - PHASE 3

3a. It is crucial to assign a value to the anticipated life that can be expected in the repair or refurbishment process in order to make a meaningful NPV calculation. How much capital cost will be incurred by extending the life of an existing asset for a given period? Will the repaired unit have the same life expectancy as a new replacement unit? These questions must be answered realistically based on the utility expense.

3b. A written specification for on-site refurbishment and/or off-site repair must be prepared to assume that all costs are known up-front, and that outside bidders clearly understand and account for all anticipated costs at the outset of the project.

3c-3j. Examples of the relevant refurbish, repair, replacement evaluations are given here and in several of the referenced technical / economic papers. The examples given can be expanded to include or exclude any of the above considerations given in the flow chart or specific to the reader's case. For instance the below Example One (from a transmission company in Poland) includes the annualized cost of maintenance which is not applicable in methods used by other utility companies, such as in Example Two (from a utility company in Spain).

5.3 Example One[5.17]

An economical estimation can be done by means of a commonly known method, which may be resolved to the below formula for replacement/rebuilding cost (C_R). It gives an average annual discounted cost referred to the reference year and represents capital and maintenance expenses during an assumed period of 'N' years from the moment of calculation, i.e. from the moment of selection of an option: rebuilding – replacement.

$$C_R = C_R + \left(\Delta P_0 + f^2 \Delta P_{CU}\right) 8760 k_j \frac{(1+p)^N - 1}{p(1+p)^N}$$

$$+ K_{inw} \frac{1}{(1+p)^n} + P_{end} P_n f k_{nen} 8760 \frac{(1+p)^N - 1}{p(1+p)^N}$$

$$+ K_{ma} \frac{(1+p)^N - 1}{p(1+p)^N} - K_{scr} \frac{1}{(1+p)^n}$$

Where :

C_R – total cost of the rebuilding/replacement, including transportation and erection costs,

ΔP_0, ΔP_{CU} – no-load and load loss of the transformer,

f – average weighted load of the transformer referred to its rated power,

Pn – rated power of the transformer,

kj – cost of 1 kWh energy needed to cover no-load and load loss,

knen – cost of 1 kWh energy not delivered (or not taken over),

p – interest rate, i.e. an estimated average interest rate over the expected period of time,

N – expected lifetime of the rebuilt / replaced transformer,

n – number of years after which the rebuilt transformer should be replaced by another one,

Kinw – cost of purchasing of the new transformer or cost of rebuilding another one which should substitute the installed one after 'n' years,

Pend – average probability of energy either not delivered or not taken over,

Kma – average annual maintenance cost, *Kscr* – residual value of the broken transformer.

In case of a new transformer the segment with *Kinw* is omitted.

Numerical example:
One utility intends to rebuilt a transformer in which few phase windings were damaged.
It was decided to make all new, modern windings. All bushings with their current transformer will be exchanged. Moreover, few new internal current transformer will be installed. Oil will be exchanged. The whole wiring including all cabinets with their switching equipment will be replaced. Moreover, all measuring and protecting equipment will be replaced. Some new are going to be added.
Core lamination will not be changed, but the core will be re-stacked. Some bad lamination as well as core insulation will be exchanged. The bulk of valves will be exchanged.
A tank with a cover, cooling equipment and on-load tap changer will be repaired, comprehensively.

Since the core will not be exchanged no-load and on-load losses will be the same, i.e. $\Delta P_0 = 85\ kW$ and $\Delta P_{CU} = 360\ kW$.
The losses for a new transformer are expected to be: $\Delta P_0 = 35\ kW$ and $\Delta P_{CU} = 300\ kW$.
An average weighted load of the transformer referred to its rated power for both the rebuilt and new transformer was estimated to be: $f = 0.6$. The cost of energy needed to cover losses was assume $kj = 0.025\ EUR/kWh$.
An interest rate is of order of 11% ($p = 0.11$).

According to offers such comprehensive rebuilding would cost $C_R = 380{,}000\ EUR$. The purchasing cost should be $K_{inv} = C_R = 800{,}000\ EUR$. The transportation and erection costs are included into a price.
Because of an extended rebuilding it can be assumed that an expected lifetime of the rebuilt unit should be at least 30 years, i.e. $N = n = 30$. After that period the rebuilt unit will be replaced by either the new transformer or by another rebuilt one. The expected lifetime of the new transformer assumed to be as long as 55 years, i.e. $N = 55$.

To simplify calculation it was assumed that an average annual maintenance cost for both the new and rebuilt units are negligible small compared wit the purchasing / rebuilding cost, i.e. $K_{ma} \approx 0$.
Moreover, it could be assumed in a discussed case that a breakdown of both the new and rebuilt unit would not limit energy not delivered / not taken. This is because of arrangement of a system in places in which the discussed transformers are installed. Consequently: $k_{nen} \approx 0$.
Scrapping value can be neglected, as is small compared with the purchasing and rebuilding cost, i.e. Kscr ≈ 0.

Substituting values to the above equation following values of the average annual discounted cost referred to the reference year are obtained:
For the new transformer:

$$C_{Rnew} = 800{,}000 + (35 + 0.6^2\ 300)\ 8760\ 0.025 \quad \frac{(1+0.11)^{55} - 1}{0.11(1+0.11)^{55}}$$

$$= 1{,}081{,}841\ EUR$$

For the rebuilt transformer, in case after N = n = 30 years it would be replaced by the new one:

$$C_{Rreb\text{-}new} = 380{,}000 + (85 + 0.6^2\ 360)\ 8760\ 0.025 \quad \frac{(1+0.11)^{30} - 1}{0.11(1+0.11)^{30}}$$

$$+800{,}000 \quad \frac{1}{(1+0.11)^{30}} \quad = 820{,}733\ EUR$$

For the rebuilt transformer, in case after N = n = 30 years it would be replaced by the rebuilt one:

$$C_{Rreb\text{-}reb} = 380{,}000 + (85 + 0.6^2\ 360)\ 8760\ 0.025 \quad \frac{(1+0.11)^{30} - 1}{0.11(1+0.11)^{30}}$$

$$+380{,}000 \quad \frac{1}{(1 + 0.11)^{30}} \quad = 802{,}386 \text{ EUR}$$

The ratios of the average annual discounted costs are:

$$C_{Rreb\text{-}new} / C_{Rnew} = 820{,}733 / 1{,}081{,}841 \approx 0.759,$$

$$C_{Rreb\text{-}reb} / C_{Rnew} = 802{,}386 / 1{,}081{,}841 \approx 0.742.$$

It can be seen that rebuilding enables to save approximately 24…26% of the average annual discounted cost compared with that cost of the new transformer.
As far as investment cost is concern, rebuilding require only 48% of the money needed to purchase the new transformer.

5.4 Example Two[5.7]

Symbols:

P – Cost of a new transformers

R – Cost of repair / refurbishment

i – Equivalent rate of money

p – Cost of losses ($/kWh)

n – Remaining life

f – load factor

Pl – Load losses (kW)

Pf – No load losses (kW)

A. Partial repair in factory:

n = 50 – current year + fabrication year

$$\text{Re}\,pair\ Cost = R + P_1 \cdot \frac{(1+i)^n - 1}{i(1+i)^n} \cdot 8760 \cdot f^2 \cdot p + P_f \cdot \frac{(1+i)^n - 1}{i(1+i)^n} \cdot 8760 \cdot p + P\frac{1}{(1+i)^n}$$

B. Refurbishment:

n = 60 – current year + year fabrication year (never n > 45 years)

Refurbishment cost = same formula

C. New Transformer:

n is the same as for repair / refurbishment alternative selected

$$New\ T.\ Cost = P + P_1 \cdot \frac{(1+i)^n - 1}{i(1+i)^n} \cdot 8760 \cdot f^2 \cdot p + P_f \cdot \frac{(1+i)^n - 1}{i(1+i)^n} \cdot 8760 \cdot p$$

Note: ‘n’ is the remaining life of the repaired / refurbished transformer; after this life it is supposed that “new transformer” continues in service (substituting the old one or being the “new one” installed.

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Appendix 5: What is risk aversion?

The idea with this appendix is to show that risk awareness, or risk aversion, has a clear mathematical basis that gives a sound background for understanding how to manage a risk profile in a company.

Let us assume we have a utility where the management want to reduce its risk profile. Operating high voltage equipment induces an appurtenant risk which may lead to a loss of utility by an unwanted event. This loss of utility may be property damage; third party liabilities, value of energy not served, or increased not planned maintenance such as repair/reinvestments after failures.

How the grid owner should spend some money to reduce its risk profile is not discussed here. Alternatives may be increased testing, monitoring, maintenance, reinvesting or insuring. The first four alternatives hopefully reduces the failure rate of the equipment amended, but insurance only reduces the monetary risk and not the inherent business risk in operating the utility.

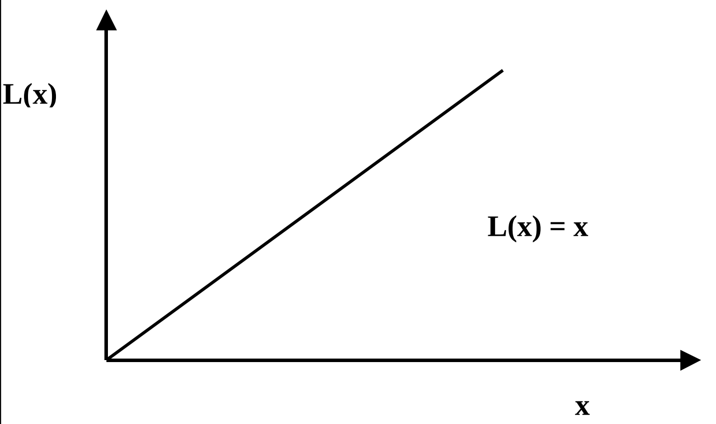

Figure 2.5: A linear loss-function

Here in Figure 2.5 we have assumed it is possible to give a simple and linear numerical expression for the loss of welfare, or loss of utility, we experience when losing the amount of x (in some currency). We name this loss of utility, or the Loss-function L(x).

At once it may seem reasonable that a loss of say 2.000 is considered twice as serious as a loss of 1.000. This is not necessarily the case. It may be as rational to evaluate the loss of the first 1.000 to be less severe than to be deprived of the last 1.000, which are additional. The better off we are, the easier it is to dispense with a small amount (confer Daniel Bernoulli's statement). Examining the other bearing, if we have lost most of our fortune, the loss of an additional 1.000 may have severe personal consequence like bankruptcy and have to sell under execution, loss of credit and credibility, and, hence, a severely reduced standard of living and loss of social position and prestige.

This may give background for asserting the loss function should raise steeper the higher amount lost, confer figure 2.6. A marginal loss of say 1.000 is now higher evaluated the higher the loss has been on beforehand. This loss function is in accordance with the factual conduct of the insured in the market, and not the linear function of Figure 2.5.

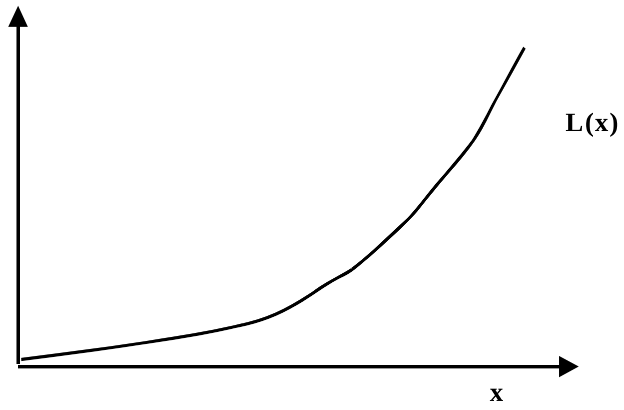

Figure 2.6: A curved loss-function L(x).

Assume we have a risk of the simplest kind: There is a probability p for an event to occur including a loss of utility, for instance property damage, during the year. The loss of utility is a fixed amount, z. The probability p may be interpreted as a (idealised) relative frequency: Assume e.g. p = 0.01. If a ("infinite") number of risks of the same kind are exposed in one year, 1% of these will cause loss of utility. The average annual loss of utility per risk is then:

$$pz \qquad (1)$$

The common interpretation of this average is expressed as "expected" annual loss of utility for the one risk we are regarding. Correspondingly we find our expected annual loss of utility is:

$$pL(z) \qquad (2)$$

Let us now assume we get an insurance company to offer a covering for full reimbursement of the risk for an annual premium of π, and further assume the insurance company covers a huge number of similar risks on the same conditions in the insurances. To not lose money on this way of doing insuring business (with our conditions and assumptions, see Note 1 at the end of this Appendix), the annual premiums must be equal or higher than the annual sustained claims:

$$pz \leq \pi \qquad (3)$$

By insuring we experience a loss of utility L(π). Insuring is beneficial for us if:

$$L(\pi) < pL(z) \qquad (4)$$

The L(oss)-function is obviously a growing function and $pz \leq \pi$, hence:

$$L(pz) \leq L(\pi) \qquad (5)$$

And combining (4) and (5) gives:

$$L(pz) < pL(z) \qquad (6)$$

for all z>0 and all p between 0 and 1. Dividing with pz on both sides, and putting y = pz gives:

$$\frac{L(y)}{y} < \frac{L(z)}{z}$$, for all y and z, 0 < y < z (7)

From (7) we see this just implies the form of the curve in Figure 2.7. Now we can infer if we want insurance covering the risk despite the fact the annual premium is higher than the annual expected loss of utility, our interpretation of this loss of fortune is really represented by a upwards curving loss function as Figure 2.6, in and not by the linear curve in Figure 2.5.

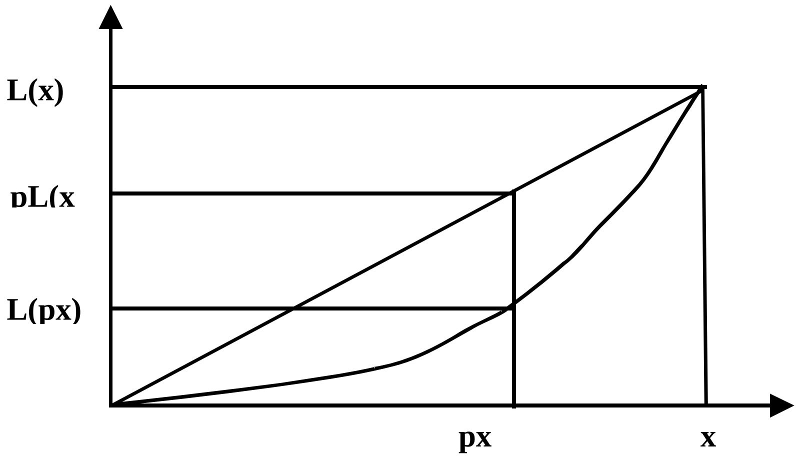

Figure 2.7: A risk aversion presentation.

If we have two alternatives: Risk R has the probability p for loss and amount lost z, and risk S has the probability q for loss and amount lost y (which are not the same y as above!).

Risk R has probability p for loss z.
Risk S has probability q for loss y.

If we put:

$$L(px) \leq pL(x) \tag{8}$$

and we assume the probability q is greater than p, but at the same time the loss y is much lower than z, in such a way that the expected loss per year is identical in both cases:

$$pz = qy \quad p < q,\ z > y$$

The expected loss of utility for S, when using $0 \leq \frac{p}{q} \leq 1$ and (8):

$$S = qL(y) = qL(\frac{p}{q}z) \leq q\frac{p}{q}L(z) = pL(z) \tag{9}$$

This is the expected loss of utility for R.

We could also have multiplied (7) with qy on the lhs and with pz on the rhs directly as (7) applies when y < z.

We may conclude we prefer risk S in preference to risk R, in spite of the fact both cases has the same annual expected loss of utility.

In practical insurance business the annual premiums is always fixed far higher than the insurance compensation paid because the insurance company must cover administration costs and a rate of return to its shareholders. The equality sign as stated in (3) ($pz \leq \pi$) is in fact never there.

But, this is no critic of sound practise based on long experience in the insurance business. It is here important to remember we have considered a theoretical approach with an infinite number of equal insurance cases. In the real world the premium will be decided upon by the insurance company based on the specific risk profile of the policy-holder. Hence, the theoretical considerations above do for say anything about a specific insurance case.

Based on the theory above, why do we then consider insuring? If we are risk averse we prefer a certain annual premium to an outcome with very low probability, but with a heavy cost consequence, in spite of the fact the premium "in average" is higher than the loss by carrying the risk.

The prudent power engineer may advise the management to look upon all maintenance, repair and reinvestments as a methodical system to manage risk. This highlights of course methods for condition monitoring, test methods and R&D activities trying to establish a better knowledge of how all our transformer maintenance activities affects the failure rates.

Note 1

We do not state the risks associated with a premium cost are *always* higher than the risk of a failure cost. This is true if the risk only involved one piece of equipment, but the cumulative effect of failure probabilities will normally make p*L(z) larger, i.e. here the probability for a bushing failure + short circuit + fire + collateral damage or the maximum possible loss that involves a piece of equipment.

Insurance premiums are normally based on a location value percentage using expected equipment costs and probability of an insurance related occurrence. The insured risk assumption levels defined by the purchased insurance is normally related to a deductible or exclusions, which may be equipment specific like transformers with capacities over 100 MVA or Unit #1 GSU. The deductible and/or exclusion is a tool used to control premium levels and risk assumption by insured and the insurer, higher deductible may mean a lower premium but also a higher insured risk assumption level.

The deductible may be set to the normal expected loss level for a piece of equipment, which may be a bushing replacement or a larger deductible may also be set for a large event like a transformer rewind or replacement. A cash reserve or self-insured level may be used to justify the higher level of risk to keep a premium at a lower level. This cash reserve impacts the business model but failure to have sufficient funds to handle a probable loss situation can jeopardize the business financial condition. Another example may be a transformer failure that catastrophically fails which also involves the electrical generator, steam turbine and a large portion of the generating station.

Appendix 6: An application of Bayes formula re. updating probabilities based on new information.

The idea of this appendix is to give a relevant example of how to use simple Bayesian methods and to underline it its possible to manage uncertainties without getting lost in the process.

The power transformer engineer is in more or less the same situation as an veterinarian: It is not possible to ask the patient relevant questions and a consultation of a patient assumed ill will always include uncertainties. The latter is also a fact for physicians dealing with humans. Most of us know illness may exist even with normal consultations and test results (i.e. the test results are "normal", but later the patient returned ill).

Less known is probably the fact that consultation and test results may be positive, without the patient being ill (i.e. the tests "proved illness", but the patient was healthy!) In this latter case we talk about "false positive". Uncertainties and the possibility of making a fault is a relevant normal situation in many areas and shows the scientific methods cannot prove anything, only state an argument with a certain probability of making a fault (Lat. *probare*, to prove).

So, when a veterinarian, physician or power engineer gives her opinion on a case by trying to identify a disease/condition from its signs and symptoms, i.e. by stating a diagnosis, this is not an absolute truth; it is only a specific probability for the condition, disease or illness to exist.

The other way around, the diagnosis "healthy" is only made probable with a various degree of certainty. For the physicians the probability of being right is fortunately rather high, especially with important and serious diseases where many different tests are taken. But it is important to remember that with some conditions the physicians are able to give a correct diagnosis in less than 50% of the cases.

The situation for the power transformer engineer is unfortunately not much better; many of us have performed a post mortem on scrapped transformers only to find some of the transformers in a disappointingly "healthy" condition.

The probability-theoretical hand tools being a glove to the hand regarding these questions are the Bayes formula. There exists a general agreement on whatever people think of the interpretation of, or basis for, Bayesian statistics.

The conditional probability for an event B, given A, is $P(B \mid A)$. If A is "component 1 is not functioning", and B is "component 2 is not functioning", the conditional probability $P(B \mid A)$ then states the probability component 2 is not functioning, *given* we know component 1 is not functioning:

$$P(B \mid A) = \frac{P(B \cap A)}{P(A)}$$

$$P(B \cap A) = P(B \mid A) \cdot P(A) = P(A \mid B) \cdot P(B)$$

Solved for $P(B \mid A)$:

$$P(B \mid A) = \frac{P(A \mid B) \cdot P(B)}{P(A)} \qquad \text{(Bayes formula)}$$

Let us illustrate the use of Bayesian methods reckoning a made, but relevant, example for a power transformer engineer or manager of a transformer fleet:

Let us suppose we are testing the "patient", a specific power transformer, assuming the winding insulation paper are in a very bad condition having low DP values.

We are defining the following events:

S = { The transformer is in a **S**erious bad condition }
L = { The transformer is in a **L**ittle/slightly bad condition }
N = { The transformer is in a **N**ormal/good condition }

+ = {The test gives a positive result }
- = { The test gives a negative result }

Out of international, national and/or our own transformer statistics (e.g. from inspecting scrapped or failed transformers being repaired) we know/believe that 2% of the transformer population are in a serious bad paper condition, 10% are in somewhat better condition, but still slightly bad, and 88% of the transformer population are in a good paper condition.

From this statistics we may assume, if we do not utilise more subjective supplementary information, that these frequencies may represent the probabilities of the conditions:

$P(S) = 0{,}02$
$P(L) = 0{,}10$
$P(N) = 0{,}88$

Assume also we have, on the basis of a rather extensive database of experience, the following knowledge of the qualities of the testing method:

a) Taking one sample, the test in 90% of the cases gives a positive result when taken from a transformer in a seriously bad condition (i.e. 10% false negative).
b) Correspondingly gives the test a positive result in 60% of the cases when applied on a transformer in a slightly bad condition, and
c) finally the test gives a completely wrong answer in 10% of the cases when administered on a healthy transformer (i.e. 10% false positive).

In our transformer case we may for instance take paper samples near the lid through manholes and testing for DP values. We take a paper sample near the lid where there are the highest average temperatures. Some transformer owners place a wire mesh basket with paper samples and presspan under a manhole for easy access through the lid for taking samples through the transformer lifetime.

From this information we can further assume:

$P(+|S) = 0{,}90$ (i.e. the probability for a positive test result given the transformer is in a serious bad shape)
$P(+|L) = 0{,}60$
$P(+|N) = 0{,}10$

Now we of course want to calculate the probability for the transformer, really being in a seriously bad shape, given the test result is positive, i.e. we want to find $P(S|+)$.

It is here the Bayes formula (still) is a useful tool and gives us:

$$P(S\,|\,+) = \frac{P(+\,|\,S)\cdot P(S)}{P(+\,|\,S)\cdot P(S) + P(+\,|\,L)\cdot P(L) + P(+\,|\,N)\cdot P(N)}$$

If we now insert the numerical values for the probabilities on the rhs of the sign of equation we get:

$$P(S\,|\,+) = \frac{0{,}90\cdot 0{,}02}{0{,}90\cdot 0{,}02 + 0{,}60\cdot 0{,}10 + 0{,}10\cdot 0{,}88} = 0{,}11$$

Hence, the probability for the transformer to be in a seriously bad condition, given the result of the test was positive, is as low as 0.11. This is problematical low if this result is to be the foundation for a multimillion Euro reinvestment. Some (all?) will assert the test really is unfit for use.

The situation may be alleviated by taking another, independent, test, to gain more information. In our case, we take another paper sample from the transformer. This correspond to the A and B samples in doping tests. Both of these tests must be positive to give a negative judgement.

Now we of course want to calculate the probability for our "patient", the transformer, really being in a seriously bad shape, given both of the test result are positive.

Let us introduce the following notation:

+1 = { First test is positive. }
+2 = { Second test is positive. }

Hence, we hunt: $P(S\,|\,+1 \cap +2)$, i.e. the probability for the transformer, really being in a seriously bad shape, given both test results are positive.

Now we look at the situation after the first test is performed and has given a positive result. In stead of using the starting point $P(S)$, $P(L)$ and $P(N)$, based on our general transformer statistics, we now take the starting point with the *updated* probabilities $P(S|+1)$, $P(L|+1)$ and $P(N|+1)$ based on the information, the known fact, the result of the first test was positive.

By utilising Bayes formula we above calculated $P(S|+1) = P(S|+) = 0{,}11$.

Correspondingly we get:

$$P(L\,|\,+1) = \frac{0{,}60\cdot 0{,}10}{0{,}90\cdot 0{,}02 + 0{,}60\cdot 0{,}10 + 0{,}10\cdot 0{,}88} = 0{,}36$$

$$P(N\mid +1) = \frac{0{,}10 \cdot 0{,}88}{0{,}90 \cdot 0{,}02 + 0{,}60 \cdot 0{,}10 + 0{,}10 \cdot 0{,}88} = 0{,}53$$

The independence of the tests may be interpreted like this: If we want to calculate the probability for the second test result being positive, given the transformer is in a serious bad shape, this second test is not dependent on the result of the first test.

Hence, we have:

$$P(+2\mid S \cap +1) = P(+2\mid S) = P(+\mid S) = 0{,}90$$

$$P(+2\mid L \cap +1) = P(+2\mid L) = P(+\mid L) = 0{,}60$$

$$P(+2\mid N \cap +1) = P(+2\mid N) = P(+\mid N) = 0{,}10$$

which are exactly the same probabilities as we used in the calculation of $P(S|+)$ above.

With this we replace $P(S)$, $P(L)$ and $P(N)$ with $P(S|+1)$, $P(L|+1)$ and $P(N|+1)$ and by again using Bayes formula we get:

$$P(S\mid +1 \cap +2) = \frac{0{,}90 \cdot 0{,}11}{0{,}90 \cdot 0{,}11 + 0{,}60 \cdot 0{,}36 + 0{,}10 \cdot 0{,}53} = 0{,}27$$

This is much better than 0,11, but still rather (too?) low.

This method has been quite uncontroversial for many years because all information is based on "hard facts". The backwards style at some statisticians emerges when the starting point is subjective supplementary information about the specific transformer instead of the general transformer statistics. It is difficult to understand this.

Appendix 7: An application of Bayesian Decision Theory

Let us pursue our dubious power transformer also after both tests of the paper samples have given positive results, i.e. a low DP value.

Let us also assume the power engineer is told by management they need an advice for a decision based on the updated probabilities.

We have $P(S \mid +1 \cap +2) = 0{,}27$. Correspondingly we find:

$$P(L \mid +1 \cap +2) = \frac{0{,}60 \cdot 0{,}36}{0{,}90 \cdot 0{,}11 + 0{,}60 \cdot 0{,}36 + 0{,}10 \cdot 0{,}53} = 0{,}59$$

$$P(N \mid +1 \cap +2) = \frac{0{,}10 \cdot 0{,}53}{0{,}90 \cdot 0{,}11 + 0{,}60 \cdot 0{,}36 + 0{,}10 \cdot 0{,}53} = 0{,}14$$

Based on these two tests the transformer most probably is only in a slightly (not too) bad condition, which should not initiate costly investigations, for instance by moving the transformer to factory and open it for a thorough inspection at this instance.

On the other hand there is a not insignificant probability for the transformer to really be in a seriously bad condition and should maybe be tended to immediately. Hence, the power engineer/management is faced upon a decision with great uncertainties. Move the transformer to the factory or not?

Let us again introduce the following notation for the two alternatives (decisions D):

D1 = { The transformer is moved immediately to the factory for inspection and possibly repair. }
D2 = { Wait some time and see. }

To come to a decision in this question it is not possible to avoid a *partly subjective* estimation of the loss of utility by choosing D1 or D2 related to the factual condition of the transformer, *S*, *L* or *N*. If the engineer advises management to move the transformer to the factory and it really is in a healthy (enough) condition, this action represents wasted money entirely, for the factory which could have repaired or manufactured another, needier, transformer and for the utility which should have used the money on another transformer. The transformer itself is certainly not better off transported to and from the factory without any need, with increased probability for being damaged (faulted) in the process.

Let us assume the power engineer assessing the transformer tabulated the loss of utility to be (in some currency):

		Transformer condition:		
		S	**L**	**N**
Decision:	**D1**	**0**	**50.000**	**50.000**
	D2	**200.000**	**25.000**	**0**

Table 1 Estimated loss of utility for the two alternative decisions.

We see from the table the loss of utility is 0 if the transformer is in a seriously bad condition and the engineer rightly advises management to "hospitalise" the transformer at once. If the engineer advises wrongly to wait and see in this situation, the most serious fault is done when the transformer fails with a loss of utility beeing a 200.000, due to cost of Energy Not Served and the extra cost for unplanned moving and repair.

If the transformer is in a slightly bad condition, the loss of utility is the cost for transportation and inspection, 50.000, which is the same in both cases (D1-L) and (D1-N). If it is necessary to dry and reclamp the windings in case (D1-L), the cost for doing this is of course not a loss of utility, and may even lead to a reduction in the loss of utility due to the increased life time expectancy, and the reduced failure rate, of the refurbished transformer.

If the transformer is in a good condition and the engineer advises to wait and see, again the loss of utility is 0. If, in this good condition, the transformer is moved to the factory, the second worst decision is taken with a loss of utility of 50.000. The loss of utility may even be higher as the moved, inspected and not repaired transformer may be faulted during transportation and handling, and thus may have a higher probability for a future failure than before moving.

We use here the common definition of risk as the *expected loss of utility*. This means it is necessary to weigh together the loss of utility for the different thinkable conditions that may arise, where the weights are the best estimated probabilities for these conditions.

Hence, the appurtenant risk with the decision to "hospitalise" the transformer at once, RD1, is:

$$RD1 = 0 \cdot P(S \mid +1 \cap +2) + 50.000 \cdot P(L \mid +1 \cap +2) + 50.000 \cdot P(N \mid +1 \cap +2) =$$
$$= 0 \cdot 0{,}27 + 50.000 \cdot 0{,}59 + 50.000 \cdot 0{,}14 = 36.500$$

Corresponding, the appurtenant risk for "wait and see", RD2, is:

$$RD2 = 200.000 \cdot 0{,}27 + 25.000 \cdot 0{,}59 + 0 \cdot 0{,}14 = 68.750$$

Consequently we see the expected loss or risk for a "wait and see" decision is, in this example, much higher than the risk for "hospitalising" the transformer at once.

It is quite obvious if this was the only available information on the condition of the transformer, the engineer should advise the management to decide upon the first decision (RD1), regardless the best estimated probability for the transformer being in a seriously bad condition is as low as 0,27. A brief sensitivity analysis shows this decision to be robust for relatively gross changes in the costs chosen.

Appendix 8 - Key Parameters

Utility Perspective

As power systems all over the world experienced rapid expansion in the post World War II era, utilities purchased and installed a significant number of transformers from the mid 50's to the end of the 70's. Nowadays, many transformers have already reached or are approaching their financial end of life. Although a significant increase in failure rates is not yet apparent for this older population, transformers cannot have an infinite technical life. Grid utilities that used to replace transformers only for capacity increases or failures are now rethinking their approach. Considerable efforts are being spent in tools, techniques and criteria to determine the condition of the transformer population. As the risk of failure increases with deteriorating condition, proactive transformer replacement programs have to be established.

Failure risk analysis

Transformer failure risk, or failure criticality (probability * consequence) evaluation requires good condition assessment techniques. Moreover, utilities usually track transformer outage data as outage frequency, duration, causes and consequences. This has resulted in establishing baselines, determining target levels of performance, highlighting trends and identifying those components/units/families that require focused corrective action. Moreover, as transformer failures are relatively rare, benchmarking can provide the critical mass required for analysis.

Maintenance

Utilities need to continuously ensure that their maintenance program provides optimal risk mitigation. Nevertheless, the maintenance capability is limited by financial aspects (historical maintenance costs, pressure to reduce operation costs, etc.) and by technical aspects (impossibility to prevent certain types of failure, outage constraints, etc.).

Maintenance programs can be improved and optimized by using techniques as Reliability Centered Maintenance that allows identifying the most critical failures, identifying their causes, and selecting the most efficient tasks to prevent such failures. Maintenance includes tasks as Time Based Maintenance (TBM), Condition Based Maintenance (CBM) and Condition Assessment (CA). CA tasks may be as simple as visual inspections to more sophisticated on or off line diagnostic tests. On-Line-Condition-Monitoring (OLCM) may be implemented to allow frequent measurements of critical parameters in real time with no human intervention. Nevertheless, OLCM are usually expensive to buy, install and operate. They create huge volumes of data that have to be analyzed by competent personal or by sophisticated software to be transformed into useful information. It is also generally accepted that it is very difficult to design an OLCM that is as reliable and durable as the monitored apparatus itself.

On-Load Tap-Changer (OLTC) is usually the only transformer component that requires relatively intensive and regular TBM or CBM, and is also a component that has an important contribution on the failure rate of transformers. For these reasons, utilities need to continuously improve maintenance program of OLTC.

Loading

Historically, utilities tended to be conservative in their loading strategies and manufacturers tended to supply transformers with considerable margins. These factors, combined with the presence, for many utilities, of transformer redundancy (n-1 criteria), provided a significant margin between "real installed MVA" and "real MVA needed". When utilities takes advantage of this situation to postpone transformer investments due to load growth, it may result in higher load per transformer, more outage constraints and more severe impacts when failures do occur. Moreover, it can be cost effective to supply a high load for a certain period and by doing so, significantly reduce the remaining live of the transformers involved. All these factors put a strong pressure on the transformer manager to improve remaining life evaluation based on load and loading above nameplate.

Refurbish versus Replacement

When a major failure occurs, the refurbish versus replacement discussions always takes place before a decision. Cost comparison of the two solutions is one of the most important parameter. Usually, utilities expect to pay less for a refurbishment than for a new transformer, and a typical rule of thumb limit is 60% of the new transformer cost. The lead time for a new transformer is also a factor. If the transformer is required in a short time, refurbishment may require less time compared with manufacturing a new one. Loss reduction for modern transformers may also affect decision.

Refurbishment even when economically viable raises concerns about the reliability of a refurbished transformer as compared to a new one. The extent of the refurbishment (essential, desirable, non-essential), appropriate testing, reliability and remaining life of the refurbished unit must also be taken into account.

Spares

Spare transformers may be considered as the ultimate risk mitigation solution. In some instances, due to long purchase or refurbishment lead times, spare transformers may be the only solution to significantly reduce some unacceptable risks. In large utilities, the significant population of sister units make it possible to evaluate the number of spares needed to reduce the risks to an acceptable level. For smaller utilities, it may be difficult to acquire spare units, sharing spares transformers with other utilities may be an option. When spare units are acquired, it is very important to provide an appropriate storage location where units can be kept in good working condition to allow fast and effective transformer replacement.

The Third Party Perspective

Utility Reputation

Utility reputation with the general public does not seem to be the overriding factor for companies with the main concern being the possibility of regulator intervention or penalties for low reliability or low availability. The population density also plays an important factor with public awareness in transmission and distribution situations. This is mainly due to the amount of political clout or economic disruption that occurs during a forced outage. All electrical customers are concerned about rates but a subset of customers are equally concerned with reliability.

The balancing act between reliable power generation and transmission with maintenance requires experience dependent on system or even on regional levels. Past operating histories and forecast operating requirements insert many variables into the level of equipment reliability. Poor or no historical records removes any bases for determining the amount of life expended from a transformer. Changes in operating criterion can quickly change a unit from apparent satisfactory operation to a distressed state. The lack of creditable equipment life assessment in light of these questions is highlighted by some of the stated variables with equipment evaluation.

Typically electrical generating stations and large transmission transformers have higher costs so have higher risk levels. Electrical generating stations can have restrains based on type of generation, hydroelectric, thermal, fossil, or renewable energy. A hydroelectric station may have a higher dispatch priority than a peaking combustion turbine station based on governmental regulations creating a problem with regulatory availability requirements. Therefore the transformers at higher priority stations have a higher level of risk. The loss of a generating station transformer is considered a small portion of a potential loss when combined with the energy not served component.

Even scheduled outages can also incur problems when outage times are limited by regulatory action. Issues or problems that could be repaired can be postponed until a less expensive time frame is available but could increase the amount of equipment damage during the extended period of operation. These examples show a need for advance warning of problems to allow time to plan outages. Frequency and severity issues should be evaluated based on past experience levels and expected system changes. The combination of frequency and severity presents a more complete risk image.

Collateral damage

The amount of collateral damage that is possible with a single failure and no viable alternative should be considered as a possible source of risk. Location of equipment, possible failure modes, and available means of protection must be considered to achieve satisfactory results. A newer vintage transformer with fire protection that is segregated from other major equipment poses a lower risk of collateral damage than a unit transformer nearing its end of life, located adjacent to the power plant without an automatic initiation deluge system. Preventive measures can reduce the amount of collateral damage like an automatic initiation fire deluge system that protects surrounding equipment and buildings. The fire deluge system is designed to reduce damage to surrounding equipment but not meant to protect the faulted equipment. Properly designed electrical relays can protect both surrounding equipment and transformer with electronic multifunction relays being the industry standard. Mechanical methods for restricting insulating fluid contamination of surrounding areas are also a standard. The amount of protection can significantly decreases the level of risk for all parties and any subsequent costs associated with a failure but mainly address post-fault action.

Loss Of Energy Not Served

Single point loss analysis at a power generating station will routinely identify the unit transformer as a limiting item. Unit transformers with unique design characteristics can results in long replacement lead-times that should be a major factor with engineering decisions. Reduction in distribution transformer spare units and reduction in transformer manufacturers requires engineering work to prevent additional delays.

The advantage of four single-phase generator step-up transformers (GSU) versus 1 three-phase transformer is limiting the amount of damage from a single failure. The economic justification for purchasing equipment costing up to 240% of 1 three- phase transformer can be seen in a nine-month replacement lead time. The question is not single- phase versus three- phase, but whether a spare transformer is justified. There are insurance benefits with maintaining a spare when issues like extra expense and business interruption type insurance coverages are considered but it benefits all parties by reducing restoration delays.

Storage of the spare unit is critical for ensuring the equipment is available for reliable operation. Periodic testing for insulating oil moisture content or gas blanket relative humidity is key to monitoring the equipment condition. Storage location, compatibility issues with other locations, and the loss of use are major issues to be addressed by engineering and risk management groups alike.

Changes in equipment supply or the loss of a spare because of usage can prevent a successful outcome by altering emergency plans and varying the risk levels without prior evaluation. Periodic monitoring of transformer manufacturer lead times, manufacturer facility availability, and material specification can reduce replacement lead times. A spare winding can be cost effective depending on the expected transformer problem, available storage, and manufacturing cost. A change in the spare transformer supply traditionally seen in investor owned utilities could affect other related industries that can involve high electric usage customers. Larger customers normally have greater impact on regulatory bodies because of access to governmental lobbying associations.

Testing and monitoring have the largest impact on energy not served issues because of the asset value compared to the revenue produced by a large transmission or unit transformer. When business interruption is included in insurance coverage, on-line monitoring can significantly impact reliability and lower associated risk levels for all parties.

Indirect benefits

The direct financial benefit may be difficult to determine on some consequence of catastrophic failure. Depending on the accepted practices of each organisation, financial value may be applied to some or all of these indirect benefits:

- Personnel and public safety
- Customer confidence and customer retention
- Reduction in insurance costs

Insurance Issues

Insurance is used to expand the financial capacity of a company by assuming excess layers of risk and sometimes to secure financial backing for large capital projects. An insurance company will normally rate a location by its Total Insured Value (TIV). TIV will determine the amount of premium based on type of coverage but may also include factors pertaining to the type equipment, replacement cost, age of equipment, and equipment reparability.

Business interruption type of coverage that addresses energy not served will normally be used at electrical generating stations to reduce a company or investor group exposure to risk. A typical method of determining the amount of risk is used to evaluate the business cost and sales revenue or Average daily value (ADV). Insurance policy limits state the maximum monetary amount that the insurance company is liable for various types of coverage. There may be limits for insurance coverage like extra expense and electrical injury, but also limits can be based on the combination items like contingency expense and property damage. The policy definitions are key to identifying the equipment included in a policy limit and the amount of risk your company is assuming with an insurance policy.
The type of coverage will also include if the equipment will be replaced at the current cost level or at a depreciated value, normally based on equipment age. Type of insurance coverage, deductible levels, and insurance limits can be tied to insurance premium levels. An important point to remember is that insurance costs are based on the past loss history and not directly tied to the actions to reduce potential losses.

The insurance company will normally identify equipment with high failure rates, generic maintenance issues, and the potential for catastrophic loss. Risk modifiers are used to address various levels of maintenance, equipment condition, and other relevant factors. Insurance deductibles will normally address the likelihood of the most common type of failures. Deductibles dictate the amount of risk assumption the transformer owner is willing to accept.

Testing and monitoring modify the associated risk level but on a limited basis. On-line monitoring can reduce the potential for a problem going unnoticed and increase the system reliability but will normally have a small impact on the overall location TIV. On the other-hand if a form of business interruption or extra expense that involves the cost of energy not served with the insurance coverage, the impact may be significant.

Insurance will normally classify the cause of a failure and the collateral damage for allocating the expense to the proper insurance coverage or insuring company. An example would be the electrical failure of a transformer bushing that starts a fire with the insulating oil. The failed transformer bushing coverage may be included in the electrical injury provision of a boiler/machinery type of insurance, but the subsequent fire would be considered a property loss. Sometimes different insurance companies will handle the property and boiler/machinery portions of the claim with different deductibles and policy limits. Agreements between insurance companies will normally limit company exposure to problems associated with this type of arrangement.

Risk management will normally adjust equipment deductible and coverage limits based on the companies risk assumption appetite. Purchasing lower deductible levels increases the initial cost of the insurance but can greatly affect the amount of risk exposure and amount of required on-hand capital to survive a loss. A combined effort between the financial and engineering management to identify high-risk assets is essential for a successful outcome.

Changing Faces in Maintenance

A maintenance program requires company resources and program outcomes will change as the resource levels change. Allocating the proper amount of resources for the desired outcome depends on the acceptable level of risk assumption by the transformer owner.
Factors that effect viable program operation can escape notice by financial management looking at the immediate and mainly tangible effects of cost reduction. Reduction in workforce or dispersing program duties to other divisions can incapacitate the program by underestimating required man-hours needed to support the maintenance program. The maintenance personnel experience level will also effect the program outcomes.

Recent changes in generating plants to profit-loss centers can remove centralized maintenance groups from direct control of maintenance processes like oil samples. Several issues arise that effect equipment reliability with the unfamiliarity with reviewing sample results and drawing samples including the responsibility of scheduling the samples with contractors. Divestiture of assets and reorganization of company departments can also disrupt program operation. Former program responsibilities can change without redistribution of resources and the lack of communication can leave the program ineffective. Prompt resolution of discovered problems is critical to reducing transformer failure rates.

The communication problem can be addressed with a computer maintenance management system (CMMS) designed to track maintenance procedure completion. Archived test and maintenance data is a key issue with present and future maintenance activity and directly effects equipment reliability.

Personnel changes reduces a basic knowledge level that requires an inherit learning curve and a deterioration in the ability to interpret or resolve problems. The loss of past problems base of knowledge or the mental checklist of issues to be resolved is a weak-link in maintenance programs without CMMS. Ensuring that needed testing and monitoring are performed at the correct intervals is secondary only to follow-up actions to rectify the condition or problem.

Company resources plays the over riding roles for both processes with reschedule maintenance activities and emergency maintenance actions taking priority over routine maintenance.

Prompt identification of changing plant conditions is also critical for using the proper monitoring technique or maintenance interval. Examples for changes in plant condition that effect transformers could include the installation of a variable speed drive fan motor and controller that is known to create harmonics that could overload the auxiliary/start-up transformer or a plant upgrade that increases net unit power generation higher than previously generated. Both cases should prompt maintenance to increase monitoring of the effected systems including the transformers.

Experience shows that prompt evaluation of abnormal test results reduces failures. Maintenance recommendations and results not evaluated by engineering that should prompt a decision can be filed away without timely resolution until rediscovered at the time of a failure. Placing the test results and recommendations into a central data bank is one step to limiting the challenges that personnel changes present to equipment reliability. Providing a link between recommendations and scheduled maintenance is needed to ensure discovered problems are not omitted from the planning process.

The Manufacturer Perspective

Thermal aspects

The normal aging, directly related with the normal use of a transformer, shall be strictly differentiate of operation under loading beyond name plate with the corresponding accelerated aging. This accelerated aging has to be accepted as the transformer is working harder. The loss of life should be compared with the increased powerflow on an economic basis.

In case of overloading, i.e. emergency overloading, the risk of bubbling and gassing has to be considered. These two conditions may represent a severe risk of failure due to the reduction of the electrical withstand of the insulation generated by the presence of gas bubbles in the oil. Critical informations on the status condition of the insulation system are needed at time of a decision on loading above nameplate.

For modern transformers, the hot spot factor, the location of this spot and his effects on the insulation can be calculated to determine the possible overloading. For old units the situation is quite different, at least when the design parameters are not available.

Electrical aspects

The insulation level have a big impact on the cost . To reduce cost one may select a lower BIL level, which decreases the insulation distances but increases the electrical field during nominal operation and therefore increased risk.

The frequency of occurrences and the type of overvoltage are important parameters to determine the insulation level needed. In a system with increased level of overvoltages and so more risk, a more appropriate BIL level should be selected, although it results in a more expensive transformer. The use of protection by utilisation of surge arresters may be used to limit overvoltages in the system.
The withstand behaviour of the insulation system against electrical stresses can only be guarantied if no abnormal degradation dues to moisture or other pollution does exist. Improving the quality of the insulation system by preventive maintenance and advanced diagnostic reduces the risks of failure and the transformers will last longer.

Mechanical aspects

The clamping pressure is an important factor in the short circuit withstandability. Reduced clamping pressure due to shrinkage of the insulation material increases the risk of failure during a short circuit. Other parameters like : clamping structure, drying process, process for coil sizing have also a major impact on the short circuit withstand capability.

Reclamping or dynamic clamping options reduce the risk of a failure and improve the short-circuit withstandibility and reliability over time.

The withstand behaviour of tertiary winding against short circuit shall be taken in consideration, particularly if this winding has to be brought out. This will increase the size of such windings considerably and may be economically not justified.