APPLICATION NOTE

TRANSFORMER REPLACEMENT DECISIONS

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SUMMARY

Transformer replacement before failure can be motivated by several legitimate reasons. These include environmental and fire safety regulations, changes in the load or the voltage level, an increased risk of failure due to transformer ageing, or the aim to improve the energy efficiency. This last motivation is less common. This is unfortunate, because replacing a transformer with a new one with higher energy efficiency will in many cases lead to a lower Life Cycle Cost of the device. This Application Note will demonstrate how to assess whether it is worthwhile to leave a transformer in place for another year, or whether it is sound practice to replace it with a more efficient and reliable one immediately. The primary factor is that of life-cycle costing. The methodology proposed is to calculate the Equivalent Annual Cost (EAC) for the upcoming year of both the existing and the new transformer. The cost of the load losses, which depend upon the loading pattern of the transformer, and the reliability penalty (risk of failure), which depends on the ageing state of the transformer, are the most difficult terms of the EAC to estimate accurately. In the majority of cases, the EAC is dominated by the energy losses, as we will demonstrate in a calculation example.

INTRODUCTION: TRANSFORMER FAILURE AND REPLACEMENT

Distribution transformers rarely catch the attention of the Operation and Maintenance department. They do not have any moving parts; they cannot jerk or misfire. They do what they have to do, day after day, year after year, with a remarkably high level of energy efficiency and reliability. Transformers provide an almost constant quality of service. Their decrease in energy efficiency and reliability is at a very slow rate and generally remains unnoticed. Until, that is, they fail and have to be replaced.

A transformer failure occurs when the quality of the internal insulation system fails and a short-circuit results. The electrical insulation of transformer windings consists of a particular type of paper, immersed in oil. The physical properties of this paper are largely dependent on the degree of polymerization of its molecules, which degrades over time, albeit very slowly and not always at the same pace. An insulation failure typically happens when this degree of polymerization of the insulating paper drops below a threshold value. In such cases, the paper becomes brittle and the breakdown voltage is reduced. A surge in the voltage level, caused by a lightning strike or a fault on the line, can be enough to cause an internal arc. In the worst case, an internal arc can occur without an external trigger.

In theory, distribution transformers don't have an age limit. If they are constructed, operated, and maintained well, the insulation paper can preserve its quality for a very long time. Some distribution transformers are known to have been in operation for more than 60 years. However, even newly purchased transformers can fail when circumstances are bad. Consequently, if you want to replace a transformer before it fails, age is a poor criterion to use in selecting the most opportune moment.

If reliability is the only criterion, a rewinding or other type of thorough repair action can be a good alternative to an entire replacement of the transformer. This is especially the case for relatively young transformers (<30 years) for which maintenance measurements have shown that risk of failure has risen substantially above the average. However, in the sense of economic and environmental best practice, other criteria should be considered as well. Energy efficiency is the most important of these considerations.

POSSIBLE REASONS FOR EARLY REPLACEMENT

1) To improve energy efficiency

In 1999, the Swiss journal Bulletin SEV/VSE[1] carried a cover story entitled *Replacing old transformers pays off* [2]. The article showed that as a result of the significant improvements in the efficiency of modern transformers, there are now sound economic reasons why older transformers should be decommissioned even when they are still functioning properly. However, despite being generally recognized as the best practice under many circumstances, transformers are still rarely replaced before failure for energy efficiency reasons alone. If it is not related to a substantial change in the load profile or the voltage level, energy efficiency will rarely trigger replacement, even if it substantially reduces the life-cycle cost and carbon footprint. In this Application Note, we will show how to assess whether such an early replacement would be a sound decision.

For more on distribution transformer energy efficiency, see Appendix 2 and [9].

2) To improve the reliability of supply

A transformer breakdown can compromise productivity, customer service, and even safety.

A back-up transformer will be installed if running this risk is unacceptable. However, this is only done for highly critical loads, since transformers are known to be very reliable and the cost of a back-up transformer is substantial.

In all the other cases, transformer failure will lead to an unexpected power cut for all of the connected loads. To avoid such an interruption and the related financial losses, it is a good idea to carry out maintenance measurements to monitor insulation degradation, in order to replace the transformer when reliability drops below a particular threshold.

For reliability reasons alone, rewinding the transformer (or other types of substantial repair actions) can be a good alternative to an early replacement. However, an early replacement has the advantage that it improves the energy efficiency of the transformer along with its reliability. For this reason, an early replacement will in the large majority of cases result in a lower life cycle cost compared to rewinding.

3) Because of a change in load profile

Since transformers have a long life expectancy, it will often occur that a higher power load needs to be connected than what the transformer was originally designed for. Even if this higher load is still within the transformer's standards, both the energy efficiency and the reliability will be affected to some extent. The connection of a new and regular load is therefore a good opportunity for action.

Two types of action are possible: either install an additional transformer and spread the load over the old and the new one, or retire the old one and replacing it by a new transformer with a larger capacity (or by two new transformers with a joined capacity that is equally large).

[1] SEV/Electrosuisse: Swiss Association for Electrical Engineering, Power and Information Technologies VSE: Association of Swiss Electricity Utility Companies

[2] Borer Edi: Ersatz von Transformatoren-Veteranen macht sich bezahlt *[Replacing old transformers does pay]*, in Bulletin SEV/VSE, vol. 4/1999, p. 31

The options with two parallel transformers have the advantage of having a spare transformer available should one of them fail. In such a situation, the transformer that remains functional will be overloaded. However running a transformer at overload for a limited time adds little to its overall ageing.

Note that from the point of view of energy efficiency alone, one large transformer will be more energy efficient than two smaller transformers with a joint power rate that is equal to the larger one.

4) Because of a change in voltage level

A 10% increase in the voltage level can lead to an increase in the no-load losses of 25 to 60%. This can be a good reason to opt for an early retirement of a transformer, replacing it by one that has been chosen appropriately for the new voltage level. Such a replacement is at the same time a good opportunity to further reduce transformer losses.

In 1995, for example, continental Europe changed from a 220/380V nominal rated low voltage level to one that is rated 230/400 V. As a result, all transformers in the low voltage network were slightly over-excited. They still operated within standards, but the over-excitation resulted in a dramatic increase of no-load losses because the design had been optimized for the previous voltage level. It was therefore worthwhile to consider an early retirement of those transformers.

5) To comply with environmental and fire safety regulations

Two main kinds of environmental regulation can affect transformer use: those related to noise regulation and those related to limitations on the type of chemicals added to the oil. Fire safety restrictions are also to be considered.

- Transformers make a soft but constant humming **noise**. This noise level varies with the no-load losses of the transformer. The international standard EN50464 stipulates maximum noise levels according to the power and the efficiency level of the transformer. These noise levels range between 39 and 55 db(A) for a 50 kVA transformer and between 63 and 81 db(A) for a 2,500 kVA transformer. When a transformer ages and no-load losses increase, the noise levels can surpass these standards.
  Moreover, even if a transformer complies with international standards, the noise level can still be too high to meet local regulations in some countries or regions. In certain types of environments, such as residential neighbourhoods, limitations for a constant noise are often severe, even to the level of being ummeasurable. In many countries, noise regulations in industrial environments have also become stricter in recent years.
  Complying with these noise regulations can be a reason for replacing an old transformer by a new and less noisy unit. Since this new transformer will have higher efficiency, such a replacement will often turn out to be financially advantageous.
- Over the course of several decades (roughly between 1930 and 1980), **PCBs** were used for transformer insulation because they functioned as a fire inhibitor as well. However, PCBs do not break down when released into the environment but accumulate in the tissues of plants and animals, which can lead to adverse health effects. When burned, PCBs can form highly toxic products, such as chlorinated dioxins and chlorinated dibenzofurans. Most countries or regions in the world therefore adopted regulations for phasing out the use of PCBs. In the meantime, all transformers containing PCBs should have been replaced with new ones without PCBs.
- Now that PCBs as fire inhibitors have disappeared from the market, complying with **fire safety regulation** has become more difficult. In closed environments, such as a basement, or in industrial environments with a high fire risk, regulations require the use of dry transformer types instead of oil-immersed ones. Complying with this regulation can also be a reason for transformer replacement.

BEST PRACTICE REPLACEMENT CYCLE

What is the best moment to replace a distribution transformer, from a financial point of view, taking the cost of energy losses, failure risk and maintenance into account, as well as the investment cost and the residual value of the transformer at the moment of retirement? The optimal replacement cycle can be determined by calculating the **Equivalent Annual Cost** (EAC) of the transformer and searching for the minimum.

In the EAC, all cost components are re-calculated to the present monetary value. It takes an **Annuity Factor** (AF) into account, which should be based on a carefully chosen discount rate. This AF can then be calculated as follows:

$$\boldsymbol{AF\ (i,n) = \frac{1 - \frac{1}{(1+i)^n}}{i}}$$

i = annual discount rate
n = number of years in the life cycle of the transformer

The EAC of a transformer consists of two main terms:

1) One cost term decreases with increasing life cycle, namely:

$$\boldsymbol{\frac{(New\ tranformer\ investment\ cost)}{AF(i,n) * \ n}}$$

The longer the replacement cycle, the more the investment can be spread over the entire period and the lower its influence on the annual cost will be.

2) A second cost term increases with increasing life cycle, namely:

$$\boldsymbol{(Average\ annual\ running\ cost) - \frac{(Old\ transformer\ residual\ value)}{AF\ (i,n) * \ n}}$$

The average annual running cost will increase with increasing the life cycle, because the energy losses, maintenance costs, and failure risks increase with transformer ageing. The residual value of the transformer appears as a negative cost and consequently also increases with increasing the life cycle.

The transformer will have a minimum EAC at a life cycle length n where the increasing and the decreasing part of the equation equal each other.

Transformer vendors and manufacturers will be more than willing to help calculate the transformer investment cost. The cost of regular distribution transformers can be found in catalogues. For larger power transformers, a transformer manufacturer should be asked for a quotation. If a repair scenario is being considered, the repair cost should be added to the investment cost.

The residual value of the old transformer is slightly more difficult to calculate. A precise calculation can be complex, but a good approximation can be made by multiplying the weights of copper and steel in the transformer with copper and steel prices. The copper price is highly volatile, making it difficult to make long-term predictions. However, as we will see later, a reasonable prediction of one year ahead can be sufficient.

The most difficult term to estimate consists of the average annual running costs. The main elements in this cost are the **energy losses**, the **maintenance cost**, and the **reliability penalty**.

ESTIMATING THE RUNNING COST

COST OF ENERGY LOSSES

The annual cost of the energy losses consists of two parts: the no-load losses and the load losses.

The cost of the annual **no-load losses** (also called iron losses) is the most straightforward to calculate. The power of these losses is listed in the data sheet of the transformer. This figure needs to be multiplied by 8,760 (number of hours in a year) and by the electricity price to derive the cost of the energy losses.

The **load losses** (also called copper losses) are more complex, since it requires an accurate estimate of the loading and loading time of the transformer. For simplicity reasons, it would be attractive to calculate with an average load. This is not recommended, because the load losses are not linear to the load, but vary by the square of the load current. Take for example a transformer with rated copper losses of 8 kW at nominal load. At half the load, these losses will only be 0.25 x 8 kW = 2 kW. Consequently, one hour at full load and one hour at standstill results in 8 kWh of load losses, while two hours running at half the load results in only 4 kWh of losses[3].

The ideal would be to calculate with the exact load profile over the entire year, but this is difficult to predict in most cases. A good compromise is to estimate the annual number of hours the transformer will work at or near a certain percentage of loading. For example:

- A hours unloaded
- B hours around 25% of the nominal load
- C hours around 50% of the nominal load
- D hours around 75% of the nominal load
- E hours at the nominal load

The load losses that are calculated using this approximation should then be multiplied by the electricity cost in order to know the annual cost of the load losses.

Note that the load losses are not always rated as such on the data sheet. In general, the nominal power (e.g. 1,000 kVA), and the no-load losses (e.g. 2 kW) are rated, as well as the overall efficiency at nominal load (e.g. 98%). Out of the latter, the total losses at nominal load can be calculated [(1-0.98) x 1000 kVA] = 20 kVA). Deduct the no-load losses from this figure to calculate the load losses at nominal load (20 kVA-2 kVA = 18 kVA).

The losses mentioned on the transformer rating plate are valid at nominal frequency (50 Hz). However, many loads draw **harmonic currents** which will increase the load losses of the transformer. See [9] Application Note Distribution Transformers, chapter *Evil Loads* for a detailed description of harmonic currents and how to

[3] This is also the reason why, during the design or purchase phase of the transformer, it is better to over-estimate than to under-estimate the load. For more on the energy efficiency of transformers, see Appendix 2.

calculate the influence on the transformer losses. For an average load mix in transmission and distribution networks, a conservative estimate is to add 10% to the load losses for the harmonic currents. However, for transformers connecting premises with a high level of inductive loads, transformer load losses can rise much higher than that. See [9] Application Note—Distribution Transformers for how to calculate the transformer power rate in such cases.

COST OF MAINTENANCE

Maintenance best practices for a distribution transformer consist initially of a series of small inspections. These should include a monthly inspection of connections, fuses, bushings, the oil level, the breather and the diaphragm, and a quarterly verification and adjustment of voltage levels and load balancing [4]. These inspections can lead to small repair actions, but their cost relative to the Total Cost of Ownership (TCO) of the transformer will never amount to a significant level and will remain more or less stable over the years. Consequently, they can be ignored when calculating the best moment for replacement.

The following actions are crucial to assess the condition of the transformer[4]. Their frequency will be increased in case of a degrading condition, they can lead to significant repair actions, and their results have to be taken into account in the reliability estimation (see further).

- Verification of the insulation resistance, compared to the values at the time of commissioning (~2 times a year).
- Checking the water content and executing a crackle test on oil samples (~each year). In case the test indicates deterioration, a di-electric strength test can be performed. In the event of over-contamination, the transformer oil should be drained and dehydrated, or replaced.
- Removing and investigating the oil sludge (~every 2 years). In case the acidity of the sludge is more than 0.5 mgKOH/g[5], the oil should be reconditioned. If the acidity surpasses 1 mgKOH/g, oil inhibitors should be added.
- A complete overhaul of the transformer (~each 5-10 years).

The cost of these maintenance actions will be higher for a transformer that has been in service for many years, than for a newly purchased transformer. To make an accurate estimate of the Average Annual Running Cost of the transformer, the precise frequency and cost of those actions should be requested from the maintenance department. In a CIRED study, the average cost of inspections and overhauls on transmission and distribution network transformers has been estimated to be 1% of their Equivalent Annual Cost [5]. This can easily increase to 4% for transformers which have been in service for more than 20 years and/or for transformers in poor condition.

COST OF RISK OF FAILURE

The reliability penalty of a transformer can be calculated by multiplying the cost of failure by the probability of failure:

[4] A more extensive condition monitoring is usually too expensive for distribution transformers, and is consequently only executed on power transformers.

[5] The Total Base Number, which is a measure of the level of base in the oil. It is determined by measuring the amount of Potassium Hydroxide in mg taken to neutralize the base reserve in 1 gram of oil (mg KOH/g).

$$C_{reliability} = C_{failure} * P_{failure}$$

The cost of failure $C_{failure}$ has many different aspects, some of which are easier to calculate than others. In any case (except if there is a back-up transformer), there will be a production loss. Industrial facilities may also experience damage to equipment, waste of raw materials, and loss of work in progress during an outage. Indirect consequences can be supply delays, penalties, re-imbursements, and loss of image.

During a scheduled replacement of a transformer, the load will also experience an outage, but this will be shorter and the fact that it is predicted reduces the cost of its consequences. This cost will be a degree of magnitude lower compared to that of a transformer failure.

In the 2007 KEMA Consulting Report, *Quality of Supply and market regulation; survey within Europe* (2007), power outages in industry and commerce have been estimated to cost 1-10 USD/kWh.

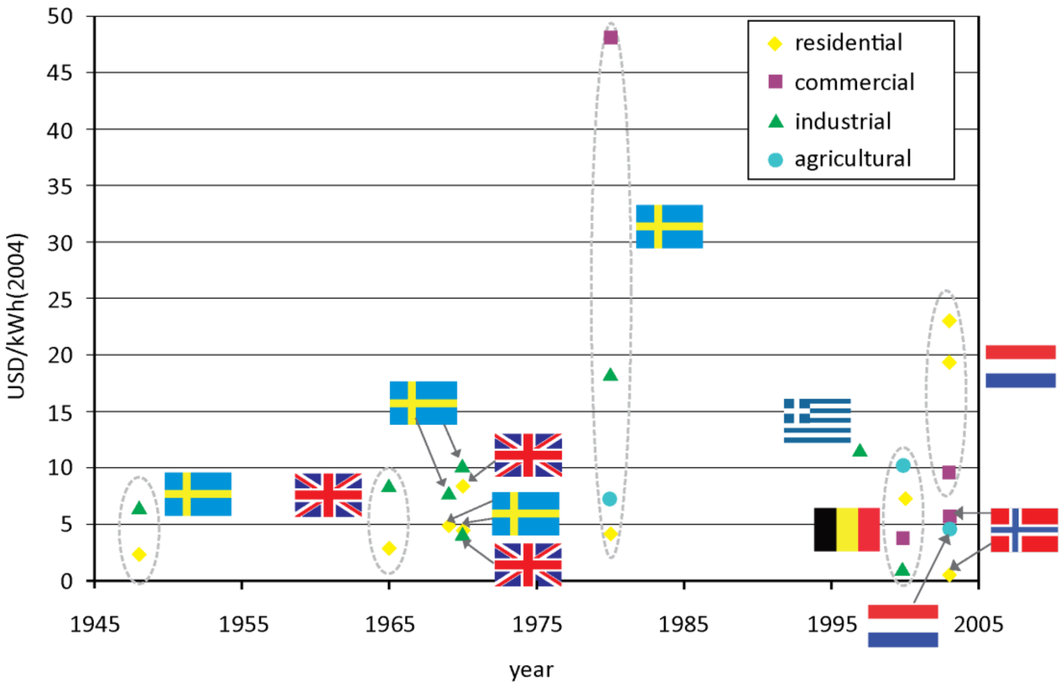

Figure 1—Outage costs from European surveys, KEMA 2007.

An alternative method of expressing interruption costs is to draw the monetary loss per lost load over time. This is quite reasonable and is more accurate, particularly if the damage has a different intensity over time. Typically, customer damage functions are not linear but have an S shape: the damage per kW remains flat until a critical moment arrives and the function rises then steeply until it reaches a higher plateau where the costs level off again. In such cases, loss per kW may have very different values depending upon the duration of the interruption. Some examples are illustrated by a Dutch survey undertaken by KEMA.

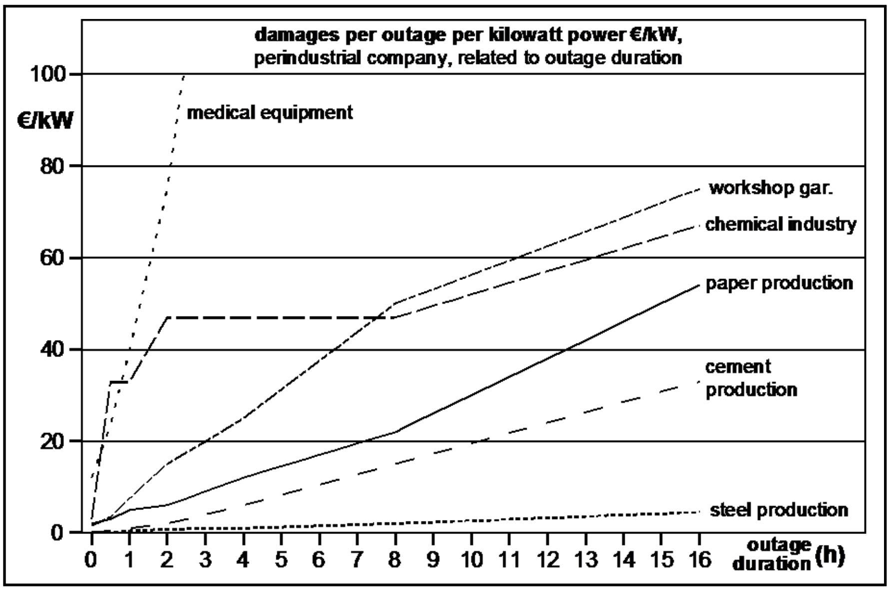

Figure 2—Interruption costs as a function of outage duration for various industrial sectors, KEMA 2005.

Suppose the company that experiences the transformer failure has a service contract with an energy provider, which ensures the replacement of the failing transformer by an emergency unit within 8 hours. This means the outage will cost the company between 1 and 50 €/kW[6], typically around 20 €/kW.

Risk of failure for the transformer depends upon:

- The placement of the transformer within the network and the related short circuit current. The higher the short circuit current, the greater the chance that a fault in the network will cause the transformer to fail (29.43% of failure causes [7]).
- The risk of lightning strikes on, or close to, the network in which the transformer is connected (17.32% of failure causes [7]).
- The state of the transformer. This is a result of, on one side, how much operational stress the transformer undergoes (harmonics, frequent shutdowns and start-ups, temporary over-voltages and surges due to switching operations, et cetera) and, on the other side, how well the transformer is designed and built to cope with such stress.

A first rough estimation for an average situation can be made by using failure statistics of the particular type and power of transformer, in which the risk of failure is expressed according to the age. However, such statistics might not be freely available on the internet. The following is a typical failure rate distribution for a distribution transformer [8]:

[6] The case of a hospital (involving medical equipment) is not relevant here. If the electricity supply is that critical, a back-up transformer and a UPS will almost certainly be in place and the transformer failure will not lead to an interruption in the load.

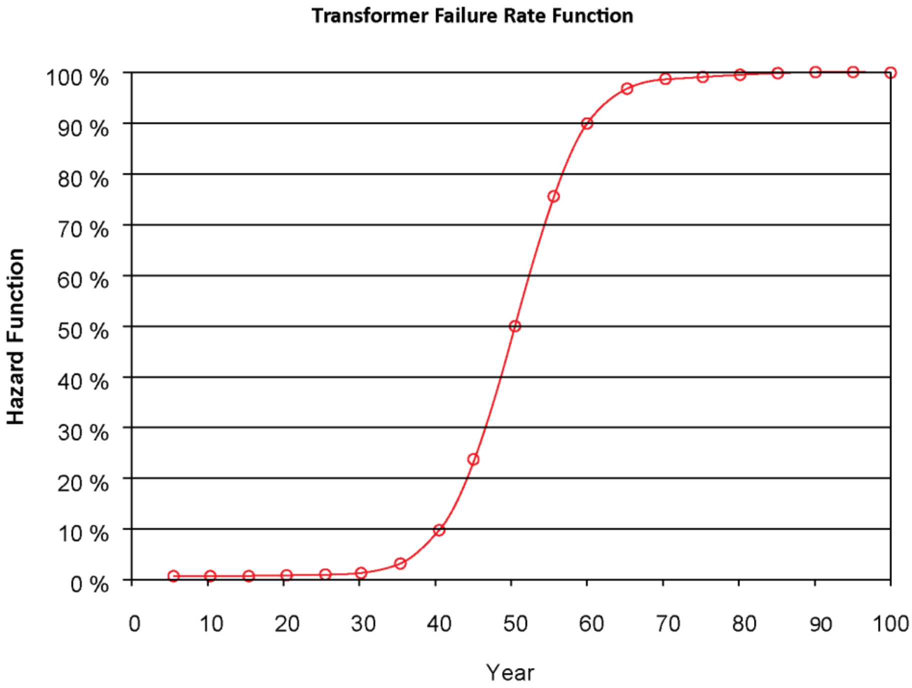

Figure 3—A typical distribution transformer failure rate function.

Translated into annual risk of failure, we could make the following categories

- Highly safe, 0-1% risk of failure per year (typically 0-20 year-old transformer)
- Safe, 1-2% risk of failure per year (typically 20-30 year-old transformer)
- Fairly safe, 2-10% risk of failure per year (typically 30-40 year-old transformer)
- In risk, 10-50% risk of failure per year (typically 40-50 year-old transformer)
- High risk, > 50% risk of failure per year (typically a more than 50 year-old transformer)

A correction factor for these figures can be added for areas with very high or very low risk of lightning strikes. A rough approximate correction will be sufficient. Maps with the average number of lightning strikes per square kilometre or mile can be found on the internet or requested from meteorological institutes. The following is an example of such a map from the US:

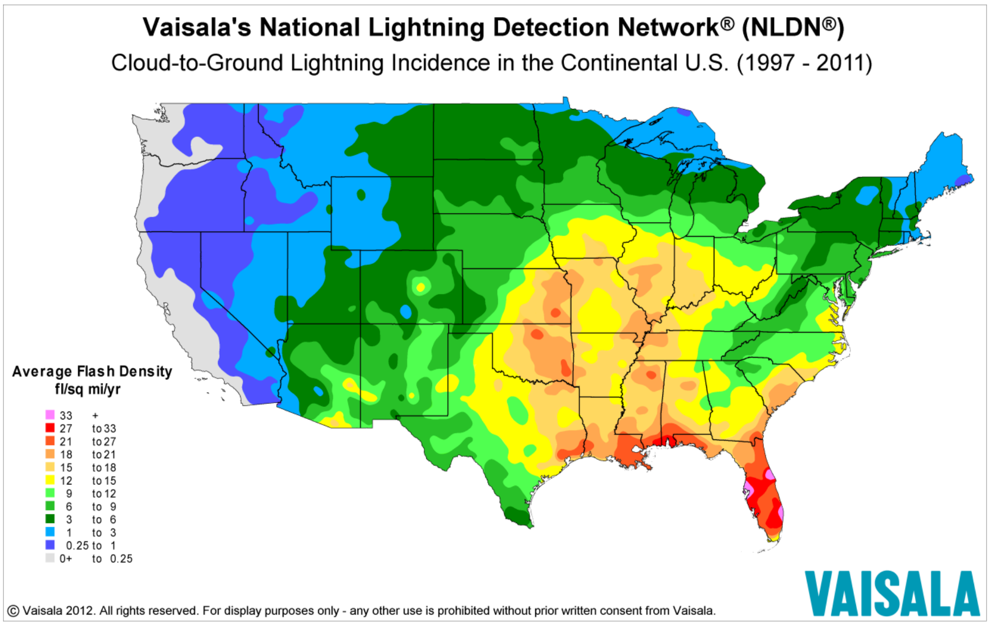

Figure 4—Average lightning incidence density in the US.

On the average, lightning strikes account for 17 per cent of transformer failures [7]. Suppose the transformer is located in an area with more than twice the average amount of lightning, for instance more than 20 lightning strikes per square mile per year or more than 7 per square kilometre. This means the failure risk should be increased by roughly 20%. Suppose the transformer is located in an area with less than half the average number of lightning strikes, for instance less than 3 lightning strikes per square mile per year or less than 1 per square kilometre. This means the failure risk should be reduced by roughly 10%.

A similarly approximate correction can be made in case the possible short circuit current relative to the rated current is higher than average. This depends on how the circuit and its loads and protections have been applied. See [9] for the method of calculating this short circuit current. However, assessing its influence on the transformer failure risk is a difficult task, as it will not be linear. Actually, this influence is subject to scientific research and novel assessment methodologies are being developed (see [10]). Very roughly, it is wise to increase the failure risk by 50% in case a high short circuit current can occur in the network.

Even more difficult to assess is the influence of operational stress (harmonics, frequent shutdowns and start-ups, temporary over-voltages and surges due to switching operations, et cetera) on the transformer. First, the operational data are not always readily available, and second, each transformer model and even each particular transformer will age differently under similar operational circumstances. In the event that the transformer reacts poorly to the operational circumstances to which it is subjected, the failure hazard can easily double compared to the published failure rate function. Maintenance measurements are indispensable in determining whether that is the case. An exact estimation of its condition and ageing can only be made by assessing the quality of the dielectric insulation of the transformer (oil + paper).

The quality of this insulation can deteriorate due to two phenomena: oil oxidation and paper depolymerization.

1. Oil oxidation. This is accelerated by the presence of oxygen and moisture in the oil, and by increased temperature levels. Oil oxidation results in acidic materials being present in the oil, and eventually in sludge. Useful measurements are water content (preventive), presence of acidic materials, and presence of sludge particles. Oxidation can be restricted by oxidation inhibitors. They only function

for a limited period of time, after which a new inhibitor has to be added, or the oil bath must be replaced.

2. Paper degradation. This is accelerated by increased temperature levels and by the presence in the oil of moisture and acidic materials (formed by oil oxidation). When paper degrades, its cellulose molecular chains shorten. Furan derivatives, as well as CO and CO_2 gasses are released into the oil. Useful measurements are the water content of the oil (preventive), acidic materials in the oil (preventive), a Dissolved Gas Analysis (DGA) of the oil, the concentration of furan derivatives in the oil, and the degree of polymerization (DG) of the insulating paper at critical spots.

Choosing the right set of measurements and measurement interpretation are tasks for transformer oil specialists.

MAKING A REALISTIC ESTIMATE

In the previous chapter we explained how to estimate all the terms and sub-terms of the **Equivalent Annual Cost** (EAC). The optimal replacement cycle n is the number of years for which the EAC goes through a minimum. To make this calculation, however, the average annual running cost has to be estimated over the entire life-cycle of the transformer. This is a difficult task, requiring many assumptions about the future and the past. A more pragmatic approach is to calculate the better of two options: replace the existing transformer now, or let it function for (at least) one more year. In this way, only the EAC of the following year has to be taken into account.

The EAC in the event that the transformer will be replaced, can be calculated as follows:

$$\frac{(\boldsymbol{Investment\ cost})}{\boldsymbol{AF(i,n) *\ n}} - \frac{(\boldsymbol{Residual\ value\ today})}{\boldsymbol{AF(i,n) *\ n}} + \boldsymbol{Running\ cost\ next\ y\ new}$$

The EAC in the event that the transformer will remain in place at least one more year, can be calculated as follows:

$$\frac{(\boldsymbol{Investment\ cost})}{\boldsymbol{AF(i,n+1) *\ (n+1)}} - \frac{(\boldsymbol{Residual\ value\ next\ y})}{\boldsymbol{AF(i,n+1) *\ (n+1)}} + \boldsymbol{Running\ cost\ next\ y\ old}$$

The EAC in the event of a transformer rewinding (or other substantial repair action), can be calculated as follows:

$$\frac{(\boldsymbol{Investment + repair\ cost})}{\boldsymbol{AF(i,n+1) *\ (n+1)}} - \frac{(\boldsymbol{Residual\ value\ next\ y})}{\boldsymbol{AF(i,n+1) *\ (n+1)}} + \boldsymbol{Running\ cost\ next\ y\ after\ repair}$$

With n = the age of the transformer, and the running cost for next year calculated as follows:

$$\boldsymbol{Running\ cost\ next\ y} \\ = \boldsymbol{no\ load\ losses + load\ losses + \ maintenance\ cost + cost\ of\ failure\ risk}$$

The best decision will be the one with the lowest EAC.

Since it is only the difference in EAC that counts, terms in the annual running cost for which this difference is estimated to be small can be left out. For instance, suppose the new transformer mainly improves the reliability, and the energy efficiency stays more or less similar to the old model. In that case, the running costs can be limited to the cost of failure risk. Suppose, on the contrary, that the new transformer mainly improves the energy efficiency, and the reliability stays at the same level. In that case, the running costs can be limited to the energy efficiency.

CALCULATION EXAMPLE

To illustrate this principle, we will now calculate an example with fictional figures. Suppose a transformer of 1,000 kVA at 20 years of age. Is it the right moment to replace it by a new and more efficient one now, or is it better to wait for at least one more year? Assume the following data:

- Transformer purchase cost: **€20,000**
- Transformer residual value (now and in one year): **€2,000**
- Discount rate: 8%
  → Annuity factor when keeping old transformer (life 21 years): 1.250
  → Annuity factor when replacing with new transformer (life 20 years): 1.249
- Electricity cost: 0.1 €/kWh
- No load losses old transformer: 2 kW x 8760 h x 0.1 €/kWh = **€1,752**
- No load losses new transformer: 1 kW x 8760 h x 0.1 €/kWh = **€876**
- Load losses at nominal load old transformer: 8 kW + 10% for harmonics = 8.8 kW
- Load losses at nominal load new transformer: 4 kW + 10% for harmonics = 4.4 kW
- Loading: 5% of time at nominal load, 20% of time at 75% of the load, 40% of time at 50% of the load, 30% of time at 25% of the load and 5% of time unloaded

Load (% of nominal)	Hours	Electr. cost	Losses old (kW)	Losses new (kW)	Subtotal old (€)	Subtotal new (€)
100%	8760 x 0.05 = 438 h	0.1 €/kWh	8.80	4.40	385.44	192.72
75%	8760 x 0.2 = 1752 h	0.1 €/kWh	4.95	2.47	867.24	432.74
50%	8760 x 0.4 = 3504 h	0.1 €/kWh	2.20	1.10	770.88	385.44
25%	8760 x 0.3 = 2628 h	0.1 €/kWh	0.55	0.27	144.54	70.96
0%	8760 x 0.05 = 438 h	0.1 €/kWh	0.00	0.00	0.00	0.00
					2168.1	**1081.86**

Table 1—Calculating the load losses

- Annual maintenance cost old transformer: 4% of purchase cost = **€800**
- Annual maintenance cost new transformer: 1% of purchase cost = **€200**
- Risk estimate of outage old transformer: 1%
- Risk estimate of outage new transformer: 0%
- Penalty for area with high risk of lightning strikes: 20% of outage risk, resulting in a total outage risk estimate of 1.2%
- Cost of outage: 20 €/kVA
- Total cost of failure risk old transformer: 1,000 kVA x 20 €/kVA x 0.012 = **€240**

This leads to the following result:

	Keeping old transformer to next year (€)	Replacing by new transformer now (€)
Annual investment cost /AF	762.51	800.00
Annual rest value /AF	-76.25	-80.00
No-load losses	1752.00	876.00
Load losses	2168.10	1081.86
Maintenance cost	800.00	200.00
Reliability penalty	240.00	0.00
EAC	**5646.36**	**2877.86**

Table 2—Calculating the EAC.

In this case it is better to replace the transformer with a new one. The old transformer has an EAC that is almost twice as big as the EAC of the new transformer.

Conclusion

By estimating the Equivalent Annual Cost (EAC) of the upcoming year, it can be assessed whether, from a life cycle costing point of view, it is worthwhile to leave a distribution transformer in place for at least one more year, or it is better to replace it by a new, more efficient, and more reliable model. An accurate estimation of the load losses is critical in this assessment. This requires a good prediction of the loading pattern. A sound evaluation of the risk of failure, depending on the ageing state of the transformer, is also crucial. This will require the correct interpretation of maintenance measurements. For transformers that are under 30 years old and in normal condition, the energy losses will dominate the EAC. The replacement issue mainly comes down to the question whether the energy efficiency can be improved sufficiently to reduce the life-cycle cost of the transformer. As the cost of the energy losses mount up to a multiple of the investment cost of the transformer, a minor energy efficiency gain can already be enough to justify replacement. For older or more worn-out transformers, the failure risk can become the dominant term of the EAC, calling for replacement.

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APPENDIX 1: TRANSFORMER EFFICIENCY[7]

A study conducted for the EU and supported by the European Copper Institute and KEMA[8] (among others) estimated that about 22 TWh per year could be saved in the European Union through the use of energy-efficient distribution transformers. This corresponds to an annual reduction in carbon dioxide emissions of 9 million tonnes, equivalent to 4% of the European Union's Kyoto targets[9].

		Oil-immersed transformer						
Power rating	rel. short-circuit volt.	Load losses						Cast resin
		List C_K		List B_K		List A_K		HD538
		≤24kV	≤36kV	≤24kV	≤36kV	≤24kV	≤36kV	≤12kV
S_N	u_k	P_K	P_K	P_K	P_K	P_K	P_K	P_K
50kVA	4%	1100W	1450W	875W	1250W	750W	1050W	
100kVA	4%	1750W	2350W	1475W	1950W	1250W	1650W	2000W
160kVA	4%	2350W	3350W	2000W	2550W	1700W	2150W	2700W
250kVA	4%	3250W	4250W	2750W	3500W	2350W	3000W	3500W
315kVA	4%	3900W		3250W		2800W		
400kVA	4%	4600W	6200W	3850W	4900W	3250W	4150W	4900W
500kVA	4%	5500W		4600W		3900W		
630kVA	4%	6500W	8800W	5400W	6500W	4600W	5500W	7300W
630kVA	6%	6750W		5600W		4800W		7600W
800kVA	6%	8400W	10500W	7000W	8400W	6000W	7000W	
1000kVA	6%	10500W	13000W	9000W	10500W	7600W	8900W	10000W
1250kVA	6%	13500W	16000W	11000W	13500W	9500W	11500W	
1600kVA	6%	17000W	19200W	14000W	17000W	12000W	14500W	14000W
2000kVA	6%	21000W	24000W	18000W	21000W	15000W	18000W	
2500kVA	6%	26500W	29400W	22000W	26500W	18500W	22500W	21000W

Table 3—Load losses in standardized distribution transformers.

[7] For a more detailed description of distribution transformer efficiency, see [9] *Cu0143 Application Note—Distribution Transformers*

[8] www.kema.nl

[9] Verlustminimierte Trafos können EU helfe *[Loss-minimized transformers can help the EU]*, in etz, vol. 9/2000

Power rating	rel. short-circuit volt.	No-load losses oil-immersed transformer							
		List D_0		List C_0		List B_0		List A_0	
		≤24kV		≤24kV		≤24kV		≤24kV	
S_N	u_k	P_0	Noise	P_0	Noise	P_0	Noise	P_0	Noise
50kVA	4%	145W	50dB(A)	125W	47dB(A)	110W	42dB(A)	90W	39dB(A)
100kVA	4%	260W	54dB(A)	210W	49dB(A)	180W	44dB(A)	145W	41dB(A)
160kVA	4%	375W	57dB(A)	300W	52dB(A)	260W	47dB(A)	210W	44dB(A)
250kVA	4%	530W	60dB(A)	425W	55dB(A)	360W	50dB(A)	300W	47dB(A)
315kVA	4%	630W	61dB(A)	520W	57dB(A)	440W	52dB(A)	360W	49dB(A)
400kVA	4%	750W	63dB(A)	610W	58dB(A)	520W	53dB(A)	430W	50dB(A)
500kVA	4%	880W	64dB(A)	720W	59dB(A)	610W	54dB(A)	510W	51dB(A)
630kVA	4%	1030W	65dB(A)	860W	60dB(A)	730W	55dB(A)	600W	52dB(A)
630kVA	6%	940W	65dB(A)	800W	60dB(A)	680W	55dB(A)	560W	52dB(A)
800kVA	6%	1150W	66dB(A)	930W	61dB(A)	800W	56dB(A)	650W	53dB(A)
1000kVA	6%	1400W	68dB(A)	1100W	63dB(A)	940W	58dB(A)	770W	55dB(A)
1250kVA	6%	1750W	69dB(A)	1350W	64dB(A)	1150W	59dB(A)	950W	56dB(A)
1600kVA	6%	2200W	71dB(A)	1700W	66dB(A)	1450W	61dB(A)	1200W	58dB(A)
2000kVA	6%	2700W	73dB(A)	2100W	68dB(A)	1800W	63dB(A)	1450W	60dB(A)
2500kVA	6%	3200W	76dB(A)	2500W	71dB(A)	2150W	66dB(A)	1750W	63dB(A)

Table 4—No-load losses and noise levels in standardized distribution transformers up to 24 kV.

Power rating	rel. short-circuit volt.	No-load losses oil-immersed transformer						Cast resin
		List C_{036}		List B_{036}		List A_{036}		HD538
		≤36kV		≤36kV		≤36kV		≤12kV
S_N	u_k	P_0	Noise	P_0	Noise	P_0	Noise	P_0
50kVA	4%	230W	52dB(A)	190W	52dB(A)	160W	50dB(A)	
100kVA	4%	380W	56dB(A)	320W	56dB(A)	270W	54dB(A)	440W
160kVA	4%	520W	59dB(A)	460W	59dB(A)	390W	57dB(A)	610W
250kVA	4%	780W	62dB(A)	650W	62dB(A)	550W	60dB(A)	820W
315kVA	4%							
400kVA	4%	1120W	65dB(A)	930W	65dB(A)	790W	63dB(A)	1150W
500kVA	4%							
630kVA	4%	1450W	67dB(A)	1300W	67dB(A)	1100W	65dB(A)	1500W
630kVA	6%							1370W
800kVA	6%	1700W	68dB(A)	1450W	68dB(A)	1300W	66dB(A)	
1000kVA	6%	2000W	68dB(A)	1700W	68dB(A)	1450W	67dB(A)	2000W
1250kVA	6%	2400W	70dB(A)	2100W	70dB(A)	1750W	68dB(A)	
1600kVA	6%	2800W	71dB(A)	2600W	71dB(A)	2200W	69dB(A)	2800W
2000kVA	6%	3400W	73dB(A)	3150W	73dB(A)	2700W	71dB(A)	
2500kVA	6%	4100W	76dB(A)	3800W	76dB(A)	3200W	73dB(A)	4300W

Table 5—No-load losses and noise levels in standardized distribution transformers in the 24 kV to 36 kV range and in cast-resin transformers up to 12 kV.

Looked at superficially, the above data might seem to suggest that there is no real need to do anything, since the efficiencies of distribution transformers are not only very high, they are also standardized. It may seem that choosing the most economical transformer involves little more than selecting a transformer with a class CC' rating (in the old European Harmonization Document 428) or with an A_0A_K (in the new EN 50464).

In the new EN 50464-1:2011-04, each of the four load loss lists can in principle be combined with every one of the five no-load loss lists. The relative weight given to load losses and no-load losses in the design of a transformer can therefore be determined by the respective application. The design choices made will also affect the transformer's operational behaviour, particularly its losses. For instance, optimum efficiency can be achieved at a load factor of 24% or at 47%, depending upon the design (see Figure 5).

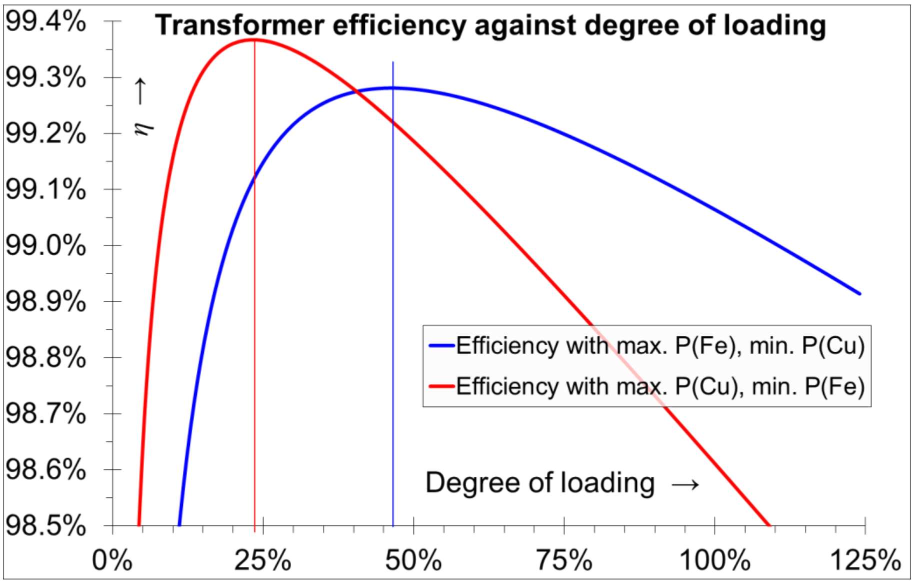

Figure 5—The operational characteristics of the transformer depend upon whether one minimizes the no-load (iron, Fe) losses or the load (copper, Cu) losses, as shown here in a comparison of the A_0D_K and E_0A_K classes for a 1,000 kVA transformer using data from Table 3 and Table 4.

Unfortunately, splitting a 1,250 kVA transformer into two units with a power rating of 630 kVA each results in a slight rise in all losses irrespective of the size of the load. Nevertheless, the beneficial redundancy achieved means that this sort of splitting is frequently utilized in practice. With two smaller transformers, there is also the option of switching one of the transformers off during light-load periods and thus reducing the losses during these periods to below the level that would be incurred if a single larger transformer were used. Of course, both sides of the transformer have to be disconnected from the power supply. If only one side is disconnected, the transformer remains excited and no-load losses continue to be incurred.

Appendix 2: Choosing the discount rate[10]

The discount rate represents the time value of money. However, inflation also contributes to the fact that money loses value over time. A **nominal discount rate** includes inflation into the figure. The **real discount rate** does not include inflation. The real discount rate will always be smaller than the nominal discount rate, unless in the rare case of deflation. When a choice needs to be made between different alternatives, inflation often has about the same influence on each of them, so it can be discarded.

Many specialists agree that the real discount rate should reflect the investor's **opportunity cost of capital**. Opportunity cost of capital reflects that capital employed to make an investment in energy efficiency measures does not come for free: either it is borrowed capital (debt) or own capital (equity). Both debtors and shareholders will expect a certain return from their money and will only keep providing you with funds when you meet their expectations.

An **accepted benchmark** for the opportunity cost of capital—and thus for the discount rate—is the **Weighted Average Cost of Capital** (abbreviated as **WACC**). WACC is calculated as the rate that a company should pay on average to the owners of its capital. For a company with only shareholders and debtors, WACC is calculated as follows:

$$\boldsymbol{WACC = \frac{D}{E+D} R_d (1-t) + \frac{E}{E+D} R_e}$$

In this formula,

- E represents the market value of the equity
- D is the total debt
- R_d is the interest paid on debt
- t is your company's tax rate (expressing the fact that interests on loans are tax deductible)
- R_e is the return that your shareholders expect (the most difficult parameter to determine)

In a risky business context, a company's WACC will be bigger since both shareholders and debtors expect a greater return, while in a stable business context, a company's WACC will be smaller. Since WACC depends heavily upon the risk level of the activities, a company that operates in different industries can have a different WACC per industry.

This formula appears simple, but the great challenge lies in determining R_e. A popular approach among financial experts is the **Capital Asset Pricing Model (CAPM)**, in which R_e is determined as $\boldsymbol{R_e = R_0 + \beta \times R_p}$, with R_0 the risk free rate (e.g. 10-year German treasury bonds, around 2% in December 2011), β the company-specific Beta-factor and R_P a risk premium of typically 3 to 5%. The Beta-factor reflects how the returns of the company correspond to market fluctuations.

WACC calculations are not an exact science: different specialists might come up with a different R_e (and thus a different WACC) for the same company. The WACC can be applied in the following way:

[10] For a more detailed description of Life Cycle Costing and the choice of the discount rate, see [11] *Cu0146 Application Note—Life Cycle Costing: the basics*

1. If your company is **publicly listed** on a stock market, your financial department should have an estimate for your company's WACC, since it can be calculated from financial data they are required to publish.
2. If your company is **not publicly listed**, you can try to determine WACC yourself by collecting information about the parameters used in the formula above. However, you will probably not have the time or the background to carry out this complex financial analysis. If your financial department cannot help, we suggest the following pragmatic approach:
   - The absolute minimum WACC is around 4%, the so-called social discount rate applicable for long-term social planning. In general, a WACC is seldom below 7% or above 20%.
   - The WACC of similar companies active in the same industry and with a similar risk profile can be indicative, as WACC is somewhat comparable within industries. Some industry-wide estimates for cost of capital determined by Professor Damodaran of NYU Stern Business School are provided in Table 4. This 2009 data is based entirely on U.S. companies. Take this value as a benchmark and increase it by a few % if you estimate that your company has a higher risk profile than average, or decrease it if you think the opposite is true. You can also find examples of companies listed on U.S. stock markets on this website: http://thatswacc.com/.

Aerospace/Defense	8.51%	Drug	8.52%
Auto & Truck	8.58%	Food Processing	7.16%
Auto Parts	9.91%	Paper/Forest Products	9.24%
Beverage	8.15%	Petroleum (Integrated)	8.63%
Building Materials	8.57%	Petroleum (Producing)	8.48%
Chemical (Basic)	8.70%	Steel (Integrated)	10.27%
Chemical (Diversified)	9.10%	Steel (General)	9.54%
Chemical (Specialty)	8.88%		

Table 6—Average cost of capital for some selected industrial sectors. (Source: http://pages.stern.nyu.edu/~adamodar/)