21, rue d'Artois, F-75008 PARIS
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Risk Assessment Of Aging Power Transformers In The Transmission Network

M. FLECKENSTEIN
TU Darmstadt
Germany

C. NEUMANN
TU Darmstadt
Germany

G. BALZER
TU Darmstadt
Germany

SUMMARY

The report of CIGRE WG A 2.37 "Transformer Reliability Survey" shows that the failure risk of a power transformer (PTR) in the 380 kV extra high voltage level increases significantly above the age of 30 years. Previous risk assessments for this transmission level show that about one third of the total risk is accounted for the asset group power transformer. With these recent figures this share has further increased. In addition, the predicted higher number of switching operations of the tap changer due to higher transmission network utilizations, which are e.g. caused by increased feed-in of renewable energies, a further intensification should be expected. The fact that the power transformer is the most capital-intensive asset, highest attention in asset management should be spent on this asset group.

This paper presents the implications of these new findings on the risk assessment with a representative transmission network model, which is based on the data of a German transmission system operator. In addition an investment strategy developer for power transformers is shown to illustrate the effects of partial refurbishment or replacement on the overall network risk. The network and individual asset risk is determined with various load flow situations, lifecycle costs and age-dependent failure rates. These data are compressed to a single key figure by using a Value at Risk method. The investment strategy developer, which uses a multiple choice knapsack problem optimizer, determines the decisions for the individual power transformer if a partial refurbishment, replacement or usual treatment should be taken into account to get the minimum network risk for a limited investment budget. The target figures of the strategy developer are the reliability & availability of the overall transmission network and the investment budget. This optimum budget usage is found with the branch-and-bound algorithm of Sinha & Zolters.

The technical and economic impact of partial refurbishment is dependent on the age as well as on the position of the power transformers in the network. The replacement of tap changer and the bushings at power transformers in mid-age (between 20 – 30 years) is a promising investment in asset base and network risk & availability in many cases. In contrast a partial refurbishment of PTR with an age of more than 40 years is not recommended in any case.

The most important measure is still the timely replacement of power transformers at the end of life. These have the highest risks, irrespective of local positioning in the system, for the transmission system.

KEYWORDS

ASSET MANAGEMENT, RISK ASSESSMENT, POWER TRANSFORMER

Marco.Fleckenstein@eev.tu-darmstadt.de

1. Introduction

The energy market liberalization in 1998 has started a rethinking process among the transmission system operators (TSO) in Europe which has not finished so far. The unbundling of the four major electrical power supply companies in Germany into power generation, distribution and transmission and the removal of their territorial monopolies has completely changed this business sector. All these parts of the electricity market are reliant to generate positive economic figures to survive. The former common cross-subsidies are prohibited by this legislation [1]. The revenue cannot be increased by higher network charges, these are limited by law. Thus investments and operating costs must wisely be minimized so that the transmission network still has a very high availability while a high return for shareholders can be generated. To achieve this goal it must be sought after the Pareto front of expenditure and network availability [2].

The power transformers (PTR) are the assets in the 380 kV level with the highest CAPEX & OPEX and will tax-write off over 50 years. Therefore a very detailed risk assessment is useful to keep the power transformer budget or to improve the network availability. In the WG A 2.37 "Transformer Reliability Survey" current failure statistics on PTR of the German TSOs were evaluated. It is found that one third of PTR must be scrapped after a major failure [3]. With CAPEX of 3 – 11 million € per PTR this must be considered in the risk assessment of the overall network and a refurbishment of older PTR must be questioned critically.

The following sections show the data for the power transformers, the transmission network model and determination of the asset- & overall network risk. Finally, the results and an outlook on upcoming work are presented.

2. Details to Aging Power Transformers

The transmission network model (TNM), which will be presented in the third section, includes 103 power transformers which connect the 380 kV level with the 220 kV sub-transmission level and the 110 kV network groups [4]. The evaluation of various sources shows that only the renewal of the tap changer and the bushings of a power transformer can be accomplished on site. This can be done with 20 percent of the original price [5]. All other measures which are concerned to the core & magnetic circuit or the windings of the PTR have to be done at the manufacturer or any specialized repair shop and can generate costs up to 80 percent of a new PTR [6]. The alterations in the core can be detected by measuring and monitoring systems and are used for an estimation of the lifetime end to order a new PTR in time [7][8]. The transport of such a transformer should only be done in exceptional cases. With every transport new problems with the transformer can occur or it is often just uneconomical regarding to the financial residual value [5][6]. The partial refurbishment with replacement of tap changer and bushings are used in the further considerations.

The age-dependent failure rates due to CIGRE and the association of German TSOs (VDN) are shown in Figure 1. In addition the curve "CIGRE + Refurbishment" is shown in the diagram, which represents the resulting failure rate by a refurbishment in that given year. With the red and green dot is displayed the changes in the failure rate by such a measure. A refurbishment of an asset aged 35 years (red point) would lead to a "virtual age" of 28 years (green point).

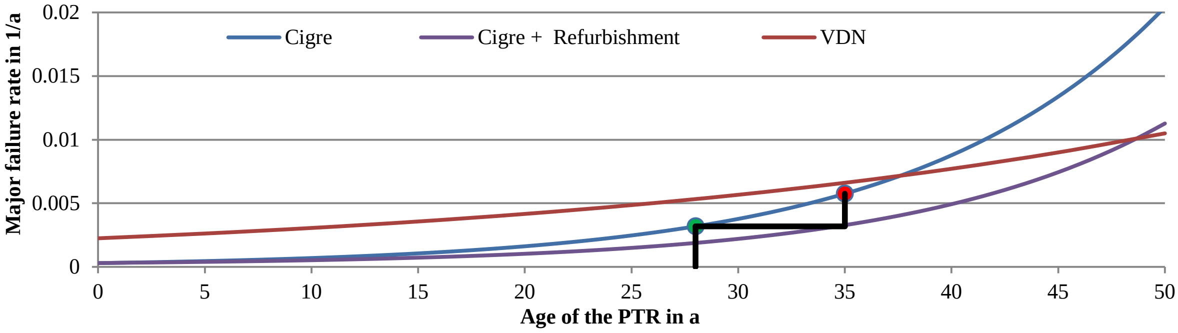

Figure 1 : Age-dependent major failure rates for PTR.

The previously used age-dependent failure rates for that asset group, are based on Data of a TSO and the statistics of the German association of transmission system operators (VDN). These are on average ten percent higher than the determined values of WG A 2.37 (CIGRE). But the CIGRE characteristic has a stronger age dependency. The change in the failure rates of the CIGRE characteristic by replacing the bushings and the tap changer can be determined by equation 1. With t_{PTR}, t_{BH} and t_{TAP} the age of the transformer, bushings and tap changer are specified. Fundamental for this equation is the assumption, that an equal distribution of the cause of failure over the lifetime is given.

$$H_{\mathrm{PTR}}(t) = 163.5 \cdot 10^{-6} \cdot e^{0.0844 \cdot t_{\mathrm{PTR}}} + 101.7 \cdot 10^{-6} \cdot e^{0.0844 \cdot t_{\mathrm{TAP}}} + 34.8 \cdot 10^{-6} \cdot e^{0.0844 \cdot t_{\mathrm{BH}}} \qquad (1)$$

The refurbishment has also an influence on the expected future repair costs. Figure 2 shows the cumulative histogram of the expected costs for a 380 kV / 220 kV PTR with a logarithmic scale. In the case of a major failure, scrapping of the PTR must be expected with 36 percent [2]. More than 70 percent of scrapping failures are in magnetic circuit, core or windings. After replacing that mentioned components, tap changer and bushings, in a future failure, which has scrapping as consequence, the manufacturer of this component is in recourse, if their components are responsible for the outage. The mean repair costs are in average indicated with 50,000 €. For the investment costs (CAPEX) of the PTR the following values are used, which should be considered as mean values:

PTR 380 kV / 110 kV (350 MVA)	3,500,000 €
PTR 380 kV / 220 kV (1000 MVA)	9,000,000 €

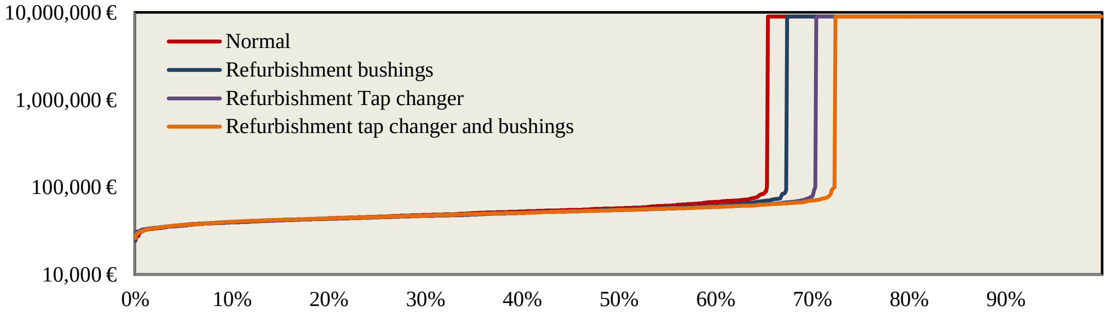

Figure 2: Cumulative histograms of repair costs of a 380 kV/ 220 kV power transformer.

The age distribution of the PTR in the investigated transmission system model is shown in Figure 3. It shows that the power transformer fleet has experienced overcome a large replacement in the last decade. The majority of the 380 kV / 110 kV - PTR are aged between 5 - 15 years.

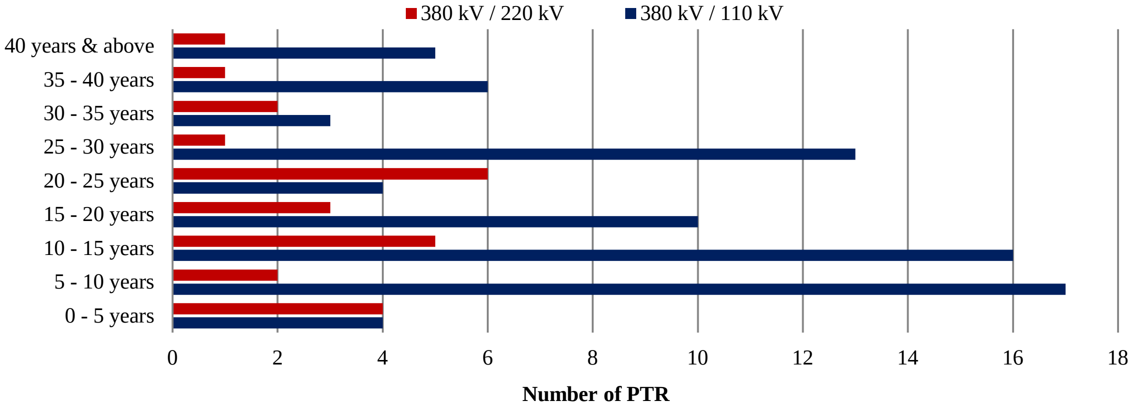

Figure 3: Age distribution of power transformer.

3. The Transmission Network Model

The transmission network model (TNM) which is used for demonstration is implemented with the commercial network simulation software NEPLAN [9]. It includes the entire 380 kV-, 220 kV-voltage level and ends with the vertical feed-in to the 110 kV network groups.

The investment-strategies with different budgets are developed for all power transformers in the highest voltage level. This 380 kV network is directly supplied by 30 power plant units with a maximum net production of 18 GW [10]. The different layouts of the 60 substations are modeled in detail. Ten coupling points are the connections to neighboring German or European TSOs. The total transmission capacity of these connection points is around 29 GVA [11]. The coupling points have no additional restriction besides the transmission capacity of the connecting transmission lines. The voltage angles at the slack nodes, representing the neighboring transmission system, are set to zero, which is considered as the neutral case.

The 220 kV transmission network is only schematically modeled in the TNM. This sub-transmission level is not considered with reliability values. It is necessary for the simulation to achieve realistic load flows in the analyzed 380 kV level. Four coupling points to other TSOs in the 220 kV level are included in the TNM. The total transmission capacity of these couplings is around 4 GVA [11].

The 110 kV network groups are the vertical load of the transmission system model. These are directly supplied by the 220 kV and 380 kV levels through power transformers. Power plants which supply directly the 110 kV network groups are not considered in the model. This voltage level has 34 separated utility network groups and eight industrial network groups. These have no direct connection in this voltage level between each other. Every group is supplied at least by three to a maximum of eleven power transformers. The peak load of each network group varies between 250 MW and 1200 MW. The power factor is set to $\cos\varphi = 0.95$ in all 110 kV network groups.

The 61 power plant units which feed-in in the 380 kV and the 220 kV transmission network have a gross output of 30.16 GW [10]. The different power plants with their individual characteristics e.g. power gradients and auxiliary power are taken into account in the TNM [12].

4. Risk Assessment & Risk-oriented Investment Decision Method

The *risk-oriented investment decision method* comprises three main parts. The availability & reliability calculations determine the impact of the individual power transformer outages during different load flow scenarios. To bundle this amount of values to one risk figure per asset the Value at Risk method (VaR) is used, which generates their asset outage combinations with a Monte Carlo simulation. The VaR is the ideal figure for the *risk assessment*. This value indicates which maximum financial risk can be expected by that asset to a confidence interval of 95 percent.

The multiple choice knapsack problem theory is used, to determine the optimal investment strategy for the minimal network risk to a restricted budget.

4.1 The availability & reliability calculations

Ten representative load flows in the TNM are taken into account. With that database all typical load situations of the TNM are considered. A surplus of generation is achieved by all of these load scenarios. This TSO is long at any time in the year and exports its surplus to the neighboring TSOs via the coupling points. The consequences of the individual asset outage are strongly dependent on the load situation of the TNM [12]. The effects of the individual asset i outage on the transmission network by the different load situation m is determined. For the assets in the highest voltage level, these four values are calculated by the availability calculation:

$T_{\mathrm{ND}}(i,m)$	outage duration of non-delivered power in h
$T_{\mathrm{NS}}(i,m)$	outage duration of non-supplied power in h
$P_{\mathrm{ND}}(i,m)$	non-delivered power in MW
$P_{\mathrm{NS}}(i,m)$	non-supplied power in MW

4.2 Asset & network risk determination

These four values for all assets are listed in a database and are necessary to determine the individual asset risk $R(i,m,s)$ and network risk $R_{\mathrm{S}}(s)$. The financial variables are also important for the single asset- and network risk determination. The specific data for the power transformer are given in the second section. The single asset risk determination $R(i,m,s)$, equation 2, consists of the repair risk $R_{\mathrm{R}}(i,m,s)$, non-delivered energy risk $R_{\mathrm{ND}}(i,m,s)$ and the non-supplied energy risk $R_{\mathrm{NS}}(i,m,s)$ which all have the unit €. All costs are repeatedly considered by the Monte Carlo Simulation in each simulation round *s* for asset *i*. The load scenario is determined at random for all assets individually per simulation round.

$$R(i,m,s) = R_{\mathrm{R}}(i,m,s) + R_{\mathrm{ND}}(i,m,s) + R_{\mathrm{NS}}(i,m,s) \tag{2}$$

These three parts of the asset risk are determined with the equations 3 – 5. The individual outage rate *H(i,s)* is also re-determined per simulation round because each asset group is divided in eight different age groups with a corresponding outage rate (e.g. 0 – 5 years). To account this simplification and usual variation in outage rates per asset any age-dependent outage rate is combined with a distribution function with an assumed standard deviation of ten percent. The repair cost C_{R} of the individual asset is re-determined for each simulation round. The determination is made randomly out of the related histogram, with or without refurbishment, shown in Figure 2. For a new PTR the scrapping risk is eliminated in the calculations.

$$R_{\mathrm{ND}}(i,m,s) = C_{\mathrm{E}} \cdot P_{\mathrm{ND}}(i,m) \cdot T_{\mathrm{ND}}(i,m) \cdot H(i,s) \tag{3}$$
$$R_{\mathrm{NS}}(i,m,s) = C_{\mathrm{E}} \cdot P_{\mathrm{NS}}(i,m) \cdot T_{\mathrm{NS}}(i,m) \cdot H(i,s) \tag{4}$$
$$R_{\mathrm{R}}(i,s) = C_{\mathrm{R}}(i,s) \cdot H(i,s) \tag{5}$$

The age-dependent major failure rates *H(i,s)* of the different asset groups are determined by exponential functions for the asset groups bus bar, circuit breaker, disconnector and overhead line. These are determined by using a combination of the asset age distributions and the VDN statistics [13]. For the power transformer the CIGRE values, mentioned in the second section, are used.
The network risk $R_{\mathrm{S}}(s)$ per simulation round is determined by equation 6 and indicates which total outage costs are expected in that simulation round *s* with all assets *N*.

$$R_{\mathrm{S}}(s) = \sum_{i=1}^{N} R(i,m,s) \tag{6}$$

The Monte Carlo simulation is performed with 10,000 simulation rounds. A sensitivity analysis has shown that a higher number of simulation rounds does not significantly alter the results [14]. Figure 4 shows the structure of the VaR determination of the individual asset *V(i)* and the network risk *V*. The Value at Risk is determined by sorting the values by size and to pick the value at the confidence interval. In the subsequent calculations, the common confidence interval of 0.95 is chosen [15][16].

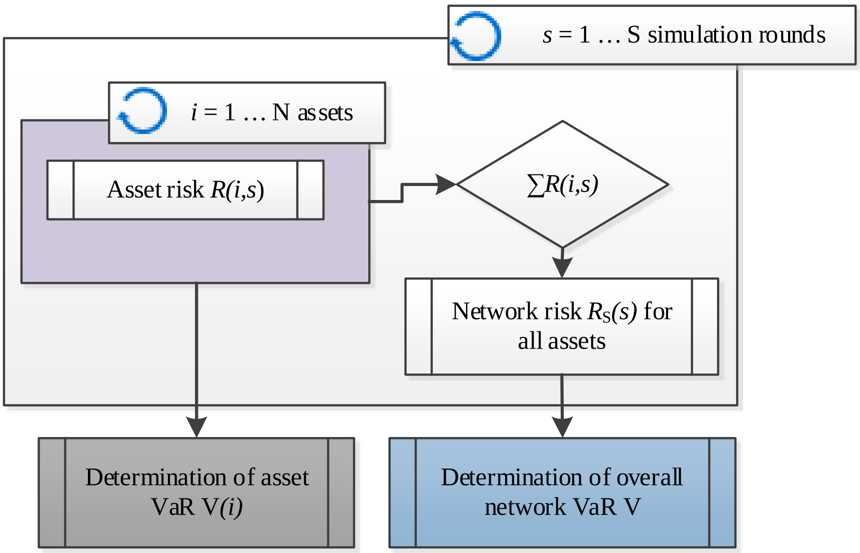

Figure 4: Asset & network risk determination.

4.3 Risk-minimizing multiple-choice knapsack problem strategy

The risk oriented investment decision method is implemented with a risk-minimizing multiple-choice knapsack problem strategy, which has to meet a given limited budget LB to achieve the minimal overall network risk V. The main equation and the three constraint condition equations for the description of the problem can be found in the equations 7 - 10. In the main equation, equation 7, it is searched for the minimum VaR, which is the summarization of the asset VaR *V(i)* depending on the one of the three activities *j*. These three activities are named and described in the next subsection. The network risk *V* is not equal to the VaR. After finding the best strategy, the VaR for this is re-determined. The binary variable x_{ij} indicates which activity *j* is used for which asset *i*. For each asset, an activity must be selected, equation 9, and partly usage of activity per asset is not allowed, equation 10. Another side condition is that the costs per asset which are determined by the selected activity are not allowed to exceed the specified budget LB, equation 7. For an efficient solution of the equations the solution algorithm of Sinha and Zolters is used. This is characterized by the fact that it finds an almost optimal solution quickly and easily [17].

$$Min\,VaR = \sum_{i=1}^{N}\sum_{j=1}^{3} V_{ij} \cdot x_{ij} \tag{7}$$

$$\sum_{i=1}^{N}\sum_{j=1}^{3} C_{ij} \cdot x_{ij} \leq \mathrm{LB} \tag{8}$$

$$\sum_{j=1}^{3} x_{ij} = 1 \tag{9}$$

$$x_{ij} \in \{0,1\} \tag{10}$$

4.4 Different activities of PTR investment strategies

The risk oriented investment strategy developer has three different activities for the assets to choose from. These cause different costs and effects on the availability of the assets. These activities are as follows:

- Replacement (RP)
- Refurbishment (RF)
- Usual Treatment (UT)

The activity *replacement* (RP) performs an immediate renewal of the power transformer. The activity *refurbishment* (RF) provides that the power transformer will be renewed intensively as mentioned in the second section. The tap changer and the bushings of the power transformer will be replaced. 20 percent of the original price for a new power transformer is expected to fulfill these operations. These costs are allocated to the CAPEX. The third activity is the *usual treatment* (UT). In this case, the asset only runs through a normal inspection. No renewal measure is covered by that activity. It is assumed that the reliability characteristics will not change and no CAPEX are used for that asset.

5. Results

A comparison of the overall risks *V* of the TMN with the VDN and CIGRE values for the PTR shows that the risk to the CIGRE values is significantly higher. The overall risk with the new findings of the WG A2.37 is around 20 percent higher. The majority of this change is the recent consideration of scrapping in the repair risk and the higher failure rates of the PTR with an age above 35 years. Taking this not into account, comparison the risks with different failure rates, still yields a higher overall risk of 6.5 percent with the CIGRE values. The risk of the asset group PTR was thus underestimated.

Figure 5 shows the possible reduction of the overall risk *V* with different CAPEX budgets for PTRs. The status quo with usual treatment for all PTR is represented by the red dot. The results show that up to a total investment of 49.45 million € a linear reduction of the overall risk is possible, which is roughly equivalent to 10 percent of the replacement value of all PTR. The overall network risk reduction with this investment volume is 11.7 percent. Higher investments in PTR allow only a minimal further reduction of the overall risk.

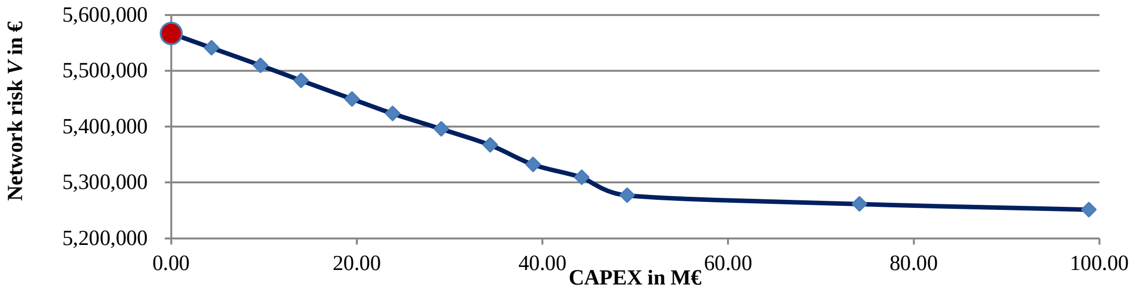

Figure 5 : Change in network risk *V* regarding to CAPEX-budget.

In Figure 6, the allocations of costs according to the activities of the various CAPEX-budgets until 49.45 million € are shown. The low budgets suggest a replacing the PTR at the end of life, age greater 40 years. The rest of the budget is filled with refurbishments of PTR in the age range of 30 - 40 years. As the first acts the optimizer recommends the replacement of two 380 kV / 220 kV power transformers which are located in a substation that has as well the feed-in of a large lignite power plant. The replacement of the 380kV / 110 kV - PTR is generally of minor importance.

The majority of refurbishments are also applied to the 380 kV /220 kV power transformers. Only two 380 kV / 110 kV - PTR will be recommended at all for that measure up to budget of 49.13 million €. With the budget of 39 million €, all PTRs are replaced (RP) with an age greater than 40 years. Previously refurbishments (RF) are preferred in PTR with an age of 30 - 40 years. With the higher budgets refurbishments of the PTR in the age range 25 - 30 years are carried out. By only limited improvement in the failure rates, the overall result may be marginally affected only.

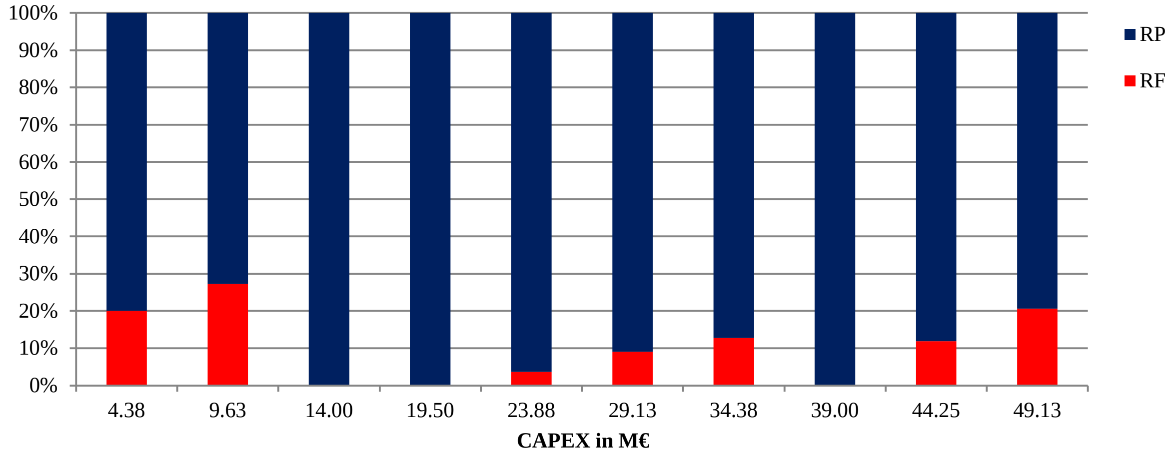

Figure 6: Share of the CAPEX by activities.

6. Conclusion & Further Work

The results show that refurbishment of PTR with an age between 30 - 40 years are a good possibility for the risk reduction of the overall transmission network. However, the best investment for risk reduction is to replace the PTR that have reached the end of lifetime. The refurbishment of this old PTR, aged greater than 40 years, is never chosen by the optimizer in any case. The residual risk through scrapping by major failures in the core is much too high for such expenditure.

Furthermore, it should be noted that the 380 kV/ 220 kV power transformers generally have a higher impact on the overall network risk of this transmission network model, than the 380 kV/ 110 kV. For these PTR the redundancy is much higher for both rural and urban 110 kV network groups.

Through the current legal situation a refurbishment of PTRs is economically unattractive in Germany. The amount invested for refurbishment measures must not be assigned to the CAPEX. These are "only" considered as OPEX for the asset. These costs, however, are not allowed to be considered as a fiscal investment in the transmission network for the network charge calculation. An increase in the carrying amount of the asset will not take place [18].

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