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Value Quantification of State-of-the-Art Condition Monitoring in 400kV Transmission System Substations

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SUMMARY

Digital substation and its monitoring systems is an "en vogue" topic again these days in the power engineering community. Many system providers have put it back on the agenda and started their promotion to sell their new holistic product offerings for substations. On the other hand, the transmission system operators (TSO) are still not completely convinced to replace/retrofit substations with "digital/sensored" equipment, because the added value is not visible on the first view and many other subjects have a higher priority for TSO/DSO.

To determine the economic added value of monitoring systems within digital substations, a Transmission Network Model (TNM) based on data from a German TSO was used in a grid calculation tool with various scenarios of improved reliability and availability values. Based on these values, the risk OPEX for the next 10 years will be calculated for all equipment in the 400 kV switchgear. For the sake of simplification, this paper only illustrates the monitoring systems for power transformers and circuit breakers in the 400 kV level.

A value-at-risk method is used to estimate the different risk costs of the assets. This methodology considers repair, replacement and lost revenue costs by considering various occurrence moments of the asset outages.

Based on the net present value with a 10-year period, it is determined, if a "digitization" of the substations makes economic sense. Therefore, it is applied a variation of penalty fees for non-delivered or feed-in electrical energy and span of prices for the sensor application. The results show a strong dependency on the revenue losses due to energy not delivered, transferred or fed in, which are also related to the penalty fees. Mission-critical substations always benefit from condition monitoring.

KEYWORDS

ASSET MANAGEMENT, CONDITION MONITORING, DIGITAL SUBSTATION, VALUE QUANTIFICATION

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1. Introduction

The German way against "global climate change" is unique. In 2011, directly after the Fukushima disaster, the German government decided to accelerate the shutdown of nuclear power plants with the last plant being out of service by 2022 [1]. Due to the public pressure the German government also committed in 2019 to retire all lignite and hard coal power plants by 2038 [2]. Furthermore, the regulation of network charges is tough to budgeting investments cost for the electrical transmission and distribution systems and as a further side condition the feed-in of unregulated renewables is further increasing [3]. Nevertheless, the TSO and DSO must adapt and expand the electrical network for current feed-in modifications and future requirements. The application of sensors for monitoring the equipment condition, has moved back to the agenda of many stakeholders of the power system community after the price collapse of these various technologies within digital substations and its data infrastructure [4]. This paper shows where and at what prices an added value exists for the operators of such facilities. The methodology which was applied was already used for development of maintenance strategies and other asset management tasks.

2. Basics for substation equipment risk determination

The benefits of digital substations are demonstrated with a transmission system model and an OPEX-Risk cost assessment which is based on a Value-at-Risk Methodology by using Monte Carlo Simulations to consider several equipment failure scenarios. The next subsections explain the fundamental methodology to determine the risk associated with substation equipment [5].

2.1. Transmission System Model

The transmission network model (TNM) employed for this demonstration consists of three voltage levels and is based on a subsection of the structure of a German TSO. It has been created within the electrical power system software and contains 400 kV, 220 kV voltage level and ends with the vertical feeding into the 110 kV network groups. These groups are summarized as an aggregated load, which are used to simulate realistic load scenarios [6].

The highest voltage level is the 400 kV system and core of the TNM. The observed assets are in the substations of this voltage level. TNM includes 60 substations, 23 power station connection points, and ten coupling points to neighboring TSOs. The 400 kV network has a direct feed-in by 30 power plant units with a net production of 18 GW [6].

Various types of substations are considered by modelling the network model. The structure of each substation is reproduced in detail and is provided with the real switching settings which are important for the reliability and availability calculations. TNM also considers the horizontal load. The transmission capacities of the overhead lines are assumed as the only limiting boundary condition in the regarded scenario. The voltage angles at the slack nodes, representing the neighboring transmission system, are set to zero, which is the ideal case and has a transfer capacity to other TSOs of around 29 GVA [7].

Age depended outage rates H are applied for the 400 kV assets within substations. An exception was only made for the power plant connections. These are considered as ideal because these are on duty of the power plant operators by German law.
Additionally, it should be noted that the outage rates of pantograph disconnectors are included in the values of the bus bars, which are bay dependent. Figure 1 shows the age-dependent outage rates $H_{AGE}(t)$ of each busbar BB, circuit breaker (CB), disconnector (DIS), and power transformer (PTR). A secondary axis for the power transformer is inserted on the left side. Each asset group consequently has eight different failure rates. The individual financial characteristics of the assets are shown for clarity in the results section.

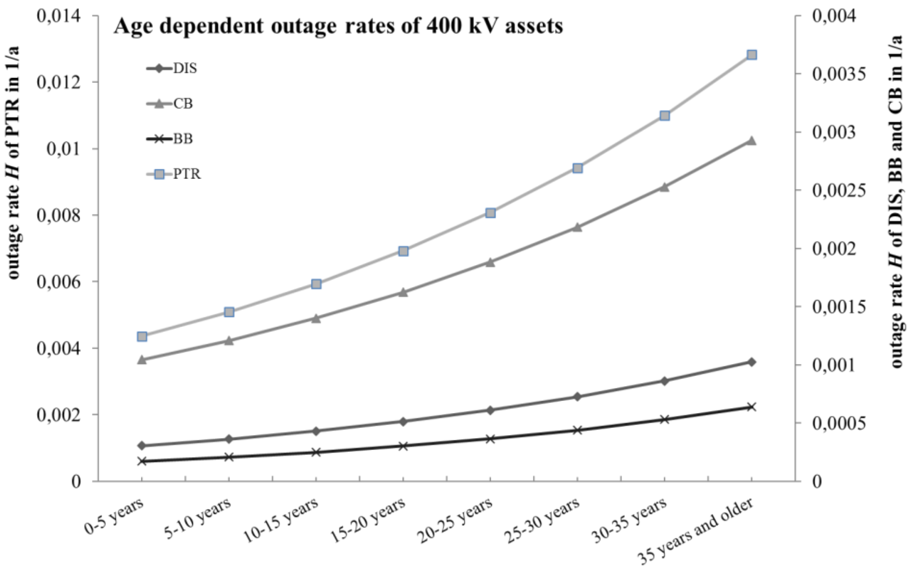

Figure 1: Age distribution & dependent outage rates of the assets. [5][7].

The 220 kV transmission system is only modelled schematically and its assets' outage impacts are not simulated itself in reliability and availability calculations. But this level is necessary to get realistic power flow conditions in the 400 kV transmission system. The 110 kV network groups are also partly supplied by 220 kV/110 kV power transformers. In total 31 power plant units with a total net output of 10 GW are connected to the 220 kV network. It also has four coupling points to other TSOs, with a total transmission capacity of around 4 GVA [5]. The 110 kV network groups represent the vertical load of the transmission system model. These are supplied by the 220 kV and 400 kV networks through power transformers. Power plants feeding directly into the 110 kV groups are not part of the model. This voltage level is separated into 34 network groups and eight industrial network groups and have a peak load of between 250 and 1200 MW.

The power plant units are implemented with different characteristics and their individual dynamic performance in the model. Therefore, different power gradients inherent to the various types of power plants, as well as their share of auxiliary power, are considered in the reliability and availability calculations. The gross output of all power plant units is around 30 GW [8].

Ten typical load flow scenarios are used for these simulations with their different vertical load and power plant scheduling, based on an analysis of the sorted annual vertical load curve of the transmission system. The actual generation capacity of power plants always exceeds the consumption of the 110 kV network groups. The surplus/shortfall of energy is imported/exported from the neighboring transmission systems.

The schedules of the different types of power plants are determined by their typical operating hours. For instance, gas power plants have fewer hours of operation, due to their high operating costs. A portion of the gas power however remains constant at the power plants, as these are operated with mine gas. These are promoted by the Renewal Energy Act (EEG) and may therefore always remain in operation [8].

2.2. OPEX-risk costs determination of 400kV-Assets in substations

The determination of OPEX-risk costs contains the shortfall of revenue costs of individual assets, which is based on the results of reliability and availability calculations multiplied with energy costs and the typical follow-up costs e.g. repair/replacement costs K_R.

An overview of the determination of OPEX-risk costs is illustrated in Figure 2. This process is repeated many times within a Monte Carlo simulation. To clip out extreme values, which are generated by the combination of variety of distribution functions, a *Value at Risk* (VaR) evaluation of the data series is applied. Sorting the list of substations by their VaR then yields their priority list [10][11]. The three green boxes illustrate the main input parameters: repair costs, reliability values

(Duration T of non-delivered or non-feed-in energy, Power P of non-delivered or non-feed-in energy) and outage rate H. For every asset group a distribution function with repair costs is implemented. The cost of repair for any asset i is randomly re-drawn from this distribution for each simulation s. The characteristic values of the distribution functions of each asset groups are presented in the results section. The green box "Reliability values" includes the database consisting of the reliability and availability results under all load flow situations of the assets. By randomly re-drawing a value in each simulation, different times of outage occurrence and the effects of the individual assets are considered.

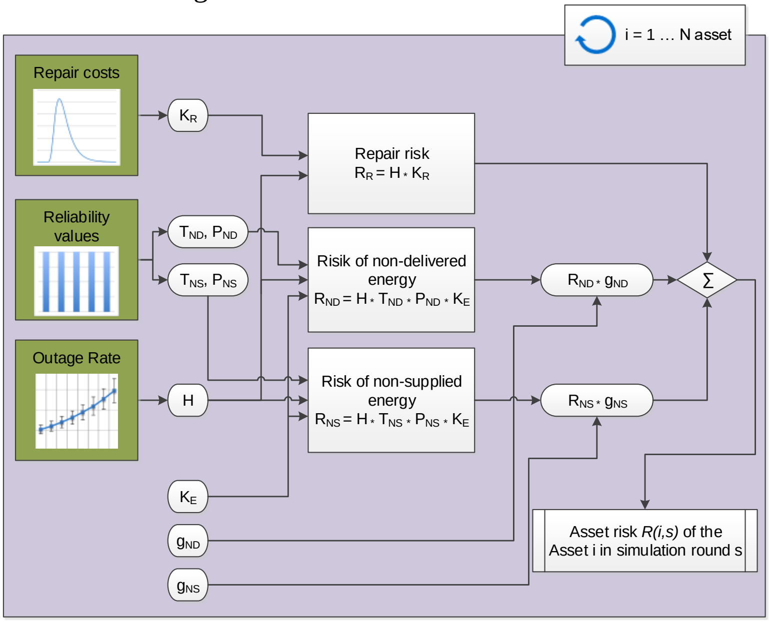

Figure 2: Structure of asset risk $R(i, s)$ determination [11].

The third green box is the outage rate. These outage rates of the assets are age dependent, as described in subsection 2.1. Additionally, the outage rate $H(i, s)$ is varied in each simulation s according to a normal distribution with a standard deviation of ten percent around the mean given by its age dependent value.
Three further variables are required for the asset risk determination. The revenue loss by non-supplied or non-delivered energy is specified by energy costs K_E in €/MWh. With correction factors g_{ND} and g_{NS} penalty payments can be considered for non-delivered or non-supplied energy. The asset risk $R(i, s)$ of simulation round s is finally determined as the sum of the repair risk R_R, the risk of non-delivered energy R_{ND} and the risk of non-supplied energy R_{NS}.
Due to the use of many distribution functions and randomly selected features a great number of simulations are required to minimize the impact of exceptional combinations.
After the determination of all individual OPEX- risk costs in a simulation round, these values are assigned to its substation and capture the overall substation risk of the round. The substation risks for each substation are formed from the summarization of the risk of all assets that are associated with it. The Monte Carlo Simulation repeats this process M times. The overall evaluation of the individual simulation runs in the Monte Carlo simulation is performed again according to the VaR method. In this method, risk values are sorted by their magnitude and the confidence area is determined using a specified confidence interval. With this interval, the extremes are filtered which result from unfortunate combinations of distribution functions. A confidence interval of 0.95 and 10,000 simulation rounds are used, which are standard values in VaR calculations [10].

2.3. Applied key figures of condition monitoring

To determine the value of condition monitoring in these 400 kV substations, some assumptions are made. On the one hand, the impact of the monitoring, and on the other hand, the costs of monitoring with its sensor application must be estimated.

Many significant publications were done within CIGRE, covering the topic asset monitoring for high voltage equipment [12][13][14]. According to these documents, failure rates for power transformers can be reduced significantly, as shown in Figure 3.

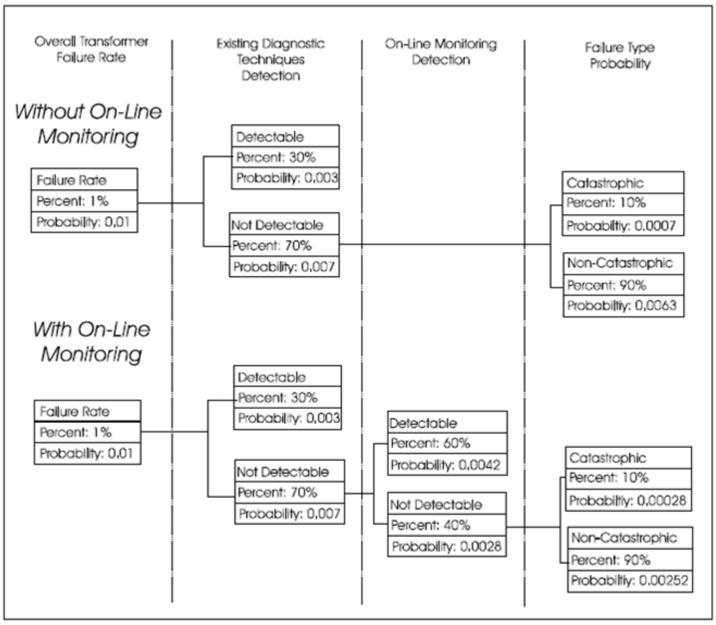

Figure 3: Standard failure probability tree for power transformer [12].

The reliability values, which are shown in Figure 3, are applied together with the age-dependent outage rates for the power transformer of section 2.1, to show the impact on the OPEX-risk costs.
For determining the improvement of circuit breaker availability, the key parameter for monitoring are gas density, motor drive current and cabinet heater supervision [15]. Increasing the reliability of the circuit breaker with Condition Monitoring, no public figures are yet available. In this paper, the assumption has been made that the outage rate will be halved.
As a basic assumption for the costs of condition monitoring, basic costs of 60k€ for the power transformer and 15k€ for the circuit breaker were considered. These values relate only to the sensors and does not include the data connection, engineering and other costs, which are heavily dependent on the individual network operator. Due to the high skepticism about these technologies, the depreciation period is set to ten years.

3. Execution of scenarios

For illustration of the results, the number of substations is reduced to twelve. Table 1 lists these substations acronyms, along with their layout and numbers of power transformers (PTR) and circuit breakers (CB).

Table 1: Substation key data

SUBSTATION ACRONYM	**LAYOUT**	**PTR**	**CB**	**SUBSTATION ACRONYM**	**LAYOUT**	**PTR**	**CB**
BI	H4	2	4	**LB**	DBT	3	8
BU	TBT	4	12	**MB**	DBT	0	6
DT	H3	1	3	**SB**	ET	1	1
ED	DBT	1	6	**UC**	DBT	3	10
KO	DB	1	4	**UR**	DBT	8	3
KR	DB	3	7	**WT**	TBT	3	10

Layout Acronyms:

DBT	Double Busbar with Transfer Busbar	TBT	Trible Busbar with Transfer Busbar
H4	H-Connection with 4-Breakers	H3	H-Connection with 3-Breakers
DB	Double Busbar	ET	External Transformer

The substation risk values regarding the age-depended outage rates of the assets for these 12 substations are considered with the methodology, which is presented in the second section. For the application of monitoring systems, associated outage values (see subsection 2.3) are applied and the risk determination of substation was performed with the modified values. Additional scenarios have been developed, to show different investment strategies respectively to show the best case, if it is decided to replace the whole substation and equip all PTR and CB with monitoring systems. The applied scenarios are:

Regular	Status Quo of current equipment
Intensive	Improved behavior of equipment if all assets will be refurbished
NEW	Replacement of primary equipment inside of the substation
Online Regular	Retrofit of current CB's and PTR's in the substation with sensors
Online New	Replacement of all CB's and PTR's in the substation and installation of sensors

3.1. Annual OPEX-Substation risk costs comparison

This subsection shows the annual OPEX-substation risk costs for all five scenarios with 50€ per MWh of non-delivered or non-feeded-in energy costs, per asset outages within specific substation. Figure 4 illustrates that risks for all described scenarios. The annual risks vary greatly among the regarded substations. The number of equipment is an essential but is not the dominant reason for the massive gap between the highest risk (260 k€) and the lowest one (6 k€). It can be seen the implementation of sensors significantly mitigate the risk. For example, the annual risk of substation BU, which has the highest risk, was reduced from 260 k€/a to 82 k€/a by a full refurbishment.

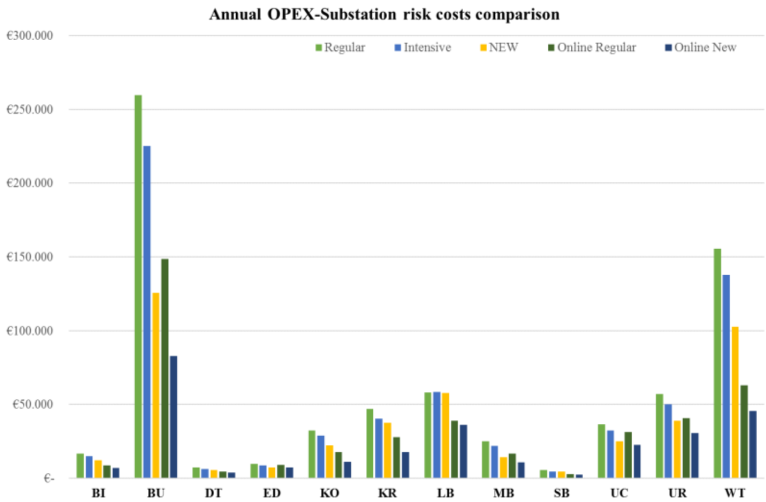

Figure 4: Annual substation risk costs by scenario

It is worth noting that in BU the substation has been renewed within the last five years. This explains the result gap between NEW and the other OPEX Substation risk costs for this plant. For the substation BI, DT, ED and SB the condition monitoring has no significant importance. These facilities have a high redundancy and have only repair/replacement cost risk. The share of loss of revenue with energy costs of 50 €/MWh is minimal. Due to that situation an investment for additional equipment has a lower priority.

3.2. Net present value determination for a ten-year period.

The reduction of operational risks always has impact on the investment costs. In Figure 5, the development of the total net present values (NPV) is shown for different loss of revenues. In this case a variation of energy costs for non-delivered or non-feed-in energy was done between 50 €/MWh and

300 €/MWh. The results are shown accumulated from left to right. This means that the results of WT include the results of BU for all scenarios. Thus, the results could be considered for high price areas, or for countries which have high penalties; e.g., non-services of power purchase agreements (PPA) or any other non-delivery.
The order of importance of the substation was used for the sequence of condition monitoring and respectively for the investment. The diagram shows that the total NPV is strongly depended on the penalty fee for non-delivered and supplied energy. Assuming low penalties the investment in sensors can only be recommended for the most important substations. For energy costs of 100 €/MWh and higher, investment can however be recommended for all substations.

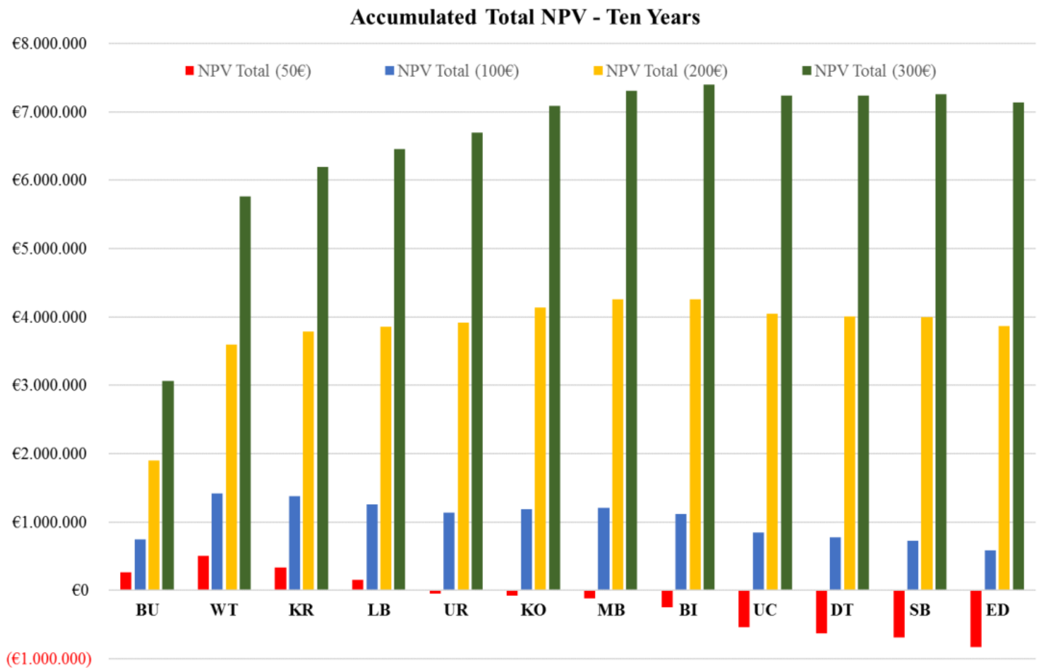

Figure 5: Net present value of the substations.

4. Conclusion

The use of sensors for switchgear is an excellent opportunity to increase the availability and the service life. Even with minor penalties, a return of investment for the major switchgear can be achieved within 10 years. This result is very impressive, since redundancy is very high within the maximum voltage level compared to the lower levels.
The reduction of operational risk is only a partial aspect. Other options such as the adjustment of the maintenance, which is not shown in this paper, or the extended life of the equipment and the resulting shift of investment costs are not considered here.
In this paper, only figures with the state of the art are used in terms of condition monitoring. New publications show that even more will be possible in the area of circuit breakers and power transformers soon [15][16]. Furthermore, a condition monitoring for surge arresters promises additional advantages. Although this component is considered one of the cheaper components in a substation, its failure has a significant impact on the "valuable" assets [17].

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