RISK ANALYSIS FOR POWER SYSTEMS - OVERVIEW AND POTENTIAL BENEFITS

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ABSTRACT

This paper provides a mapping and sample of recently developed risk assessment techniques that are available for the distribution system operator. Three estimates on the value of more detailed risk analysis are described. I.e. component reliability importance indices can be used to diversify the maintenance efforts, gaining better expected system performance at no cost. Furthermore, components that are assumed to be relatively harmless (based on average values) are identified as critical for longer interruptions. Finally it is shown that losses in a transformer are critical in the decision on transformer lifetime.

INTRODUCTION

Risk assessment is an important tool for the distribution system operator (DSO). Typically the risks that occur are financial (regulation, varying interest rates and energy price), environmental, and/or age related mechanisms. One example of the outcome of these risks is the storm Gudrun, hitting Sweden January 2005. Prior the storm, work had begun towards securing the rural overhead line systems against severe weather, often by replacement with covered overhead lines. Simultaneously a work towards a compensation model and threshold values for reliability indices for customers was in progress. But the storm had significant impact, primarily on the overhead line system, causing immense outages, and secondarily resulting in a strong political pressure with long term results such as:

• Forced investments in underground cables, resulting in higher risks for the cable system (that may appear with age). Furthermore, cable investments are made in terrains traditionally not considered as suitable for underground cables.
• Increased regulatory pressure, cancelling the value of previous planning and work towards “self”-regulation.
• Financially, a forced investment put constraints on other investments in the power system, especially with the background of the economical crises, starting in 2008.

The storm Gudrun exemplifies the above mentioned risks, developed into a real outcome. The aim of risk analysis is to identify contributors to these risks and to evaluate the different strategies that can be taken to meet them, by reducing the probability that these causes major negative consequences if an event occurs. Examples of important aspects, studied at KTH, Sweden, to include in the power system risk analysis are: (i) preventive and corrective maintenance [1], (ii) life time modelling [2], (iii) monitoring and diagnostics [3], (iv) protection system configuration [4], (v) weather effects [5], [6], (vi) ICT (hardware and software) [6] and (vii) antagonistic attacks with e.g. intentional electromagnetic interference [7].

RISK ANALYSIS RESEARCH, BACKGROUND

According to Swedish law, every DSO is obliged to annually provide the regulator with a risk- and vulnerability analysis on the reliability [8]. Including an action plan on how the reliability shall be improved. This combined with a performance based tariff regulation has justified the startup of several development- and research projects on risk management of power distribution systems [9]. One example is the Swedish “risk analysis program”, which funds several projects including two Ph.D. projects [5], [10].

Maintenance costs combined with extreme demand on safety, and complex structures motivates the development of a systematic asset management planning. At KTH there is a continuous development of a concept called Reliability-Centered Asset Management (RCAM) to address these issues. RCAM can partially be viewed as a quantitative development of Reliability Centered Maintenance (RCM), which is an advanced form of preventive maintenance planning, first developed by the aircraft industry [11]. This paper continues with a discussion on different levels of modelling for risk assessment and then presents examples, from the RCAM research, of the potential benefits with a more detailed risk assessment.

RISK METHOD MAPPING

Quantitative risk analysis of power systems involves several steps, where one is the probabilistic reliability modelling. The goal is to predict system reliability indices, e.g. SAIDI, SAIFI, which provides a measure of the system’s reliability performance. The model input data are component reliability, system topology, customer data, etc. Development of probabilistic reliability models and methods for power systems have been a major research topic during the last decades [12],[13], and the following two sections provide an introduction to the subject.

Component reliability model

A component is defined as a piece of electrical or mechanical equipment viewed as an entity for the purpose of reliability evaluation [14]. Typical components are here e.g. overhead lines, cables, transformers, generators and circuit breakers. Generally a two state model, with an up- and down state, is used to model a repairable component’s function of transferring a certain amount of power. The expected failure rate and repair time are two model parameters that are estimated given historical failure data for the component type. The component model can include several failure modes with e.g. long and short failures and planned maintenance. Switching components (e.g. breakers) may also include failure modes for function fault (e.g. breaker is stuck) and erratic operation.

System reliability modelling

A system is a group of components connected or associated in a fixed configuration to perform a specified function [14]. Power system reliability models are based on established network theory that has been extended with properties of electrical systems. Three such properties are (i) several input (feeder) and output (load point) nodes, (ii) bi-directional power flows in branches, (iii) active component failures (e.g. short circuit) may trigger protection devices that disconnect a number components and load points.

Several evaluation methods and electrical models exist where the choice and complexity is dependent on the size and topology of the system. E.g. distribution systems are generally operated in a radial configuration, whereas transmission systems are meshed, and this requires different approaches. TABLE I shows a summary of typical choices of evaluation methods and electrical models for different systems.

A. General evaluation method

The methods can be divided into analytical (A1-A3) and simulation methods (A4):

A1. Markov modelling: Every system state and the transitions between them are modelled and the result is the steady state probabilities for each state.

A2. Series and parallel network equivalents: The system is reduced to series and parallel structures enabling approximate analytical expressions for the reliability.

A3. State enumeration: All single and multiple component failures (normally combinations of two) are evaluated to determine the system reliability on the system.

A4. Monte Carlo simulation: The system is subjected to a large number of random experiments in order to evaluate the expected reliability indices.

B. Electrical model

The impact on the systems load points needs to be evaluated for each outage (one or more component failures). Three general approaches (with increasing complexity) can be used:

B1. Connection check: Load point is in function if there is one or more a paths between feeder and load point. The path is assumed to always handle the power flow.

B2. Simple network flow model: Each component's loading is estimated by summarizing each branches associated loads.

B3. DC or AC load flow (LF): The active power flows are determined by solving non-linear equations given the components' impedances and the load point data. The AC LF also gives the reactive power flows.

TABLE I – Typical evaluation methods and electrical models for different systems of study

	A. Evaluation				B. Electrical		
Method / System to model	1. Markov	2. Series/Parallel	3. Enumeration	4. Monte Carlo	1. Connection	2. Network flow	3. DC or AC LF
Small subsystem	x	x			x		
Distribution, radial		x			x		
Distribution w. red		x		x	x	x	
Sub-transmission			x	x		x	x
Transmission			x	x			x

COMPONENT IMPORTANCE EVALUATION

Component reliability importance indices are useful for prioritization of components as part of a system, especially when considering maintenance activities and/or investment in new equipment [15]. Traditional component reliability importance indices were developed for systems with one input and one output point, which not captures the general function of electrical networks [1]. The indices, presented below, utilize the concept of reliability worth and traditional power system reliability measures (e.g. SAIDI and SAIFI) as measure of system reliability in order to establish the importance of the components. These measures of reliability works over several supply and load points and does for example enable comparisons between components dedicated to different load points as well as components from different systems. The indices are calculated for changes in failure rate and repair time. Three major groups of indices can be calculated:

1. Importance of the individual component's failure rate.
2. Importance of the individual component's repair time.
3. Maintenance potential, i.e. how the system measures would be affected by an always available component (failure free).

For three groups component importance is established with respect to a system index (e.g. SAIDI and/or SAIFI). In an application study presented in [1] it can be seen that several components almost never cause customer outages, while the system is very sensitive to a few critical components. This identification can be used in maintenance planning, i.e. by moving resources to the components of highest importance. In [1] it is shown that even if this resource reallocation doubles the failure rate for neglected components and only reduce failure rate with 10% for the critical components, the resource allocation results in a 10% reduction in customer interruption costs (for the specific case study).

CONSEQUENCE REDUCTION

Sweden has legalization for outages ≥12h and a functional requirement from 2011, that interruptions ≥24h not are tolerated. Consequently, 12 and 24 hours are important limits for Swedish DSOs in maintenance and investment planning [10]. TABLE I [16] summarize the model for determining customer outage compensation and damages to affected customers.

TABLE II Consequences of outages ≥12 hours

Length of interruption	Compensation to customer	Minimum compensation[1]
12-24 hours	12.5 % of α	2 % of β
Following 24 hour periods	+ 25 % of $\alpha + \gamma$	+ 2 % of β
…	…	…
Max	300 % of $\alpha + \gamma$	-

α = Individual customer's annual network tariff, β = Yearly set base amount (42 400 SEK 2010), γ = Risk of further consequences of breaking the law. [1]Is always set to even 100 SEK values, rounded up → 2 % of β is rounded to 900 SEK (~100 € / ~130$)

Fig. 1 illustrates results from an ongoing application study showing the expected number of outages ≥12h as a function of changed mean outage time. The current probability is 136 12h+ outages per year and 1 000 customers. If an investment is estimated to reduce the average outage time with 1 hour, this value will decrease to 121, while the opposite will increase the value to 151 long outages per year and 1 000 customers.

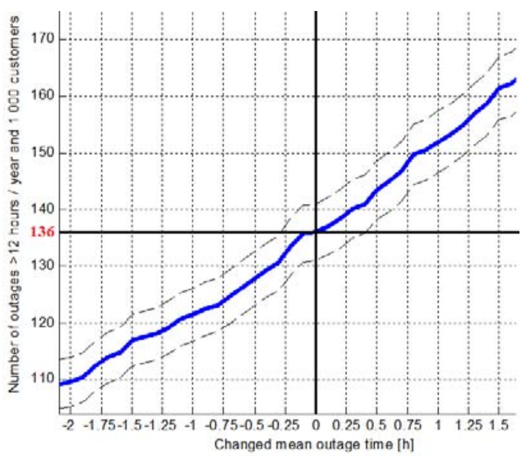

Fig. 1 Number of outages≥12h as a function of changed average outage time including 95 % confidence interval.

DETAILED RELIABILITY DATA

Good and comprehensive input data are expensive and sophisticated analysis based on detailed data demands further resources. A common solution is to use mean values (of e.g. failure rates), which is the case in e.g. the calculation of well established indices such as SAIDI [15], [12]. However, there are significant disadvantages connected to using mean values in analysis. For example: Using mean restoration time does not take into account the behavior of consequences as seen in TABLE II. Four different approaches to handle mean values:

1. Only use one mean value:
   + Easy manageable and well established models.
   - Discussed above.
2. Estimate a statistical (e.g. exponential) distribution based on a single mean value:
   + Capture all consequences, data easy available.
   - More knowledge-intensive, the distribution is not always a suitable description of the real behavior.
3. Dividing the failures into categories:
   +Relatively simple, easy to adjust the complexity according to purpose.
   - More work with data collection and processing, discrete model, not spanning all possible events.
4. Estimate the real distribution:
   + Gives results close to the reality.
   - Complex, costly and time consuming.

TABLE III provides an example of the 3rd approach dividing outages into two failure categories. The failure rates based on over 50 000 historical outages over 8 years. The ≥12h values stems from rare events, affecting system reliability indices to a small extent. The result is that the events causing these longer interruptions could be missed when the DSO works towards better reliability indices based on average values. When looking at average values at the 0.4kV level it might be assumed that cables causes more ≥12h interruptions, but as seen in the table the over-head lines are more problematic. This illustrates the value of applying the 3rd approach, i.e. if our main concern is long interruptions, then we should focus on overhead lines.

TABLE III Failure rates divided into short (0.05-12 hours) and long interruptions (≥12 hours)

Component	Failure rate[1]	[%][3]	Failure rate[2]	[%][3]
OH line 0.4 kV	0.0668 ±0.0025	0.8	0.0150 ±0.0012	3.4
OH line 10 kV	0.1169 ±0.0027	61.3	0.0086 ±0.0008	92.2
Cable 0.4 kV	0.0395 ±0.0014	1.1	0.0034 ±0.0004	0.5
Cable 10 kV	0.0281 ±0.0020	7.0	0.0002 ±0.0002	0.4
Sec. sub station	0.0107 ±0.0007	3.8	0.0006 ±0.0002	0.2
Other/unknown	-	26.1	-	3.3

[1]Number of outage 0.05-12 hours/year, km/station with 95 % confident int.
[2]Num. of customer outage ≥12 hours/year, km/station with 95 % conf. int.
[3]Contribution to total outage time caused by the category of failure

TRANSFORMER REPLACEMENT

The single act of a transformer replacement should involve risk assessment. This could allow the DSO to postpone the replacement and thus allow further benefits such as those emerging from investment optimization. This since the transformer is one of the most cost intensive components in the power system considering manufacturing and consequences of an outage. Transformers should be utilized at an appropriate level of risk. To achieve a quantitative measure of the risk associated with having a transformer operating a stochastic expression for the lifetime can be used. One approach to the risk measure is the use of Bayesian statistics. A method that can combine valuable knowledge about the operating transformers with available reliability data into a probability density function of the failure intensity [2]. The failure intensity can then be used in risk assessments and for establishing remaining lifetime of the transformer.

Delaying investment

For a 3 million SEK distribution transformer [17], the net present value for an investment one year from now, assuming a rate of return of 5 percent, is 2.86 MSEK (0.95238·3.0). By postponing the investment one year, the saved capital is then 140 kSEK. Further, assume that the cost increase of the transformer is 20 kSEK. Still there is a potential to save capital from delaying the investment.

Transformer loss evaluation cost

A consequence of postponing a transformer replacement is the absent improvement of transformer performance. The cost of this is the cost of the difference in energy losses of the old and the new transformer. In Fig. 2 a study of the losses in 230 transformers on levels 400, 220, 130 och 70 kV, is seen. Assuming a similar behavior for 33/11 kV, 20 MVA transformers, and assuming a performance improvement by 0.2% of the rated power. Then, the cost of postponing the replacement one year is 175kSEK (650·0.002·20·8760). Based on an energy price of 500 SEK/MWh. Breakeven with the delayed investment (120kSEK) is reached at 342 SEK/MWh (35EUR/MWh).

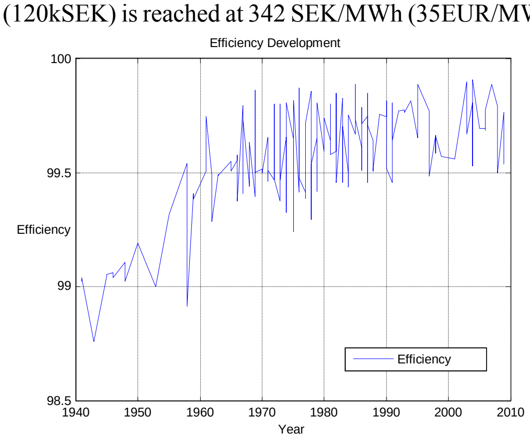

Fig. 2 Efficiency as a function of age.

In conclusion economical boundaries dictate much of the decision on transformer lifetime. Interest rates and cost of energy losses are important parameters that have to be put against technical lifetime analysis in the decision process.

CONCLUSION

In this paper we have presented a number of different perspectives on how advanced risk and reliability methods can improve power system analysis. It is the authors' shared belief that by collecting more detailed data and utilize this information in analyses a performance increase of the system is achievable.

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