

Multiobjective Maintenance Policy for a Distribution System an Application Study

P. Hilber, *Graduate Student Member, IEEE*, and L. Bertling, *Member, IEEE*

Abstract—Maintenance managers of today’s electrical distribution systems are faced with the problem of where their maintenance resources will be utilized best. In previous work the authors have developed a method for maintenance policy optimization for electrical networks. This paper presents results from an application study performed for a distribution system, including both urban and rural parts, for this method. A basic optimization is performed in order to find the right level of maintenance for the involved components with respect to customer interruption costs and maintenance budget. For the rural parts of the system the conclusion is that intensified tree trimmings is the most beneficial maintenance activity. While for the urban parts the maintenance should be focused towards customer intense areas. Furthermore, it becomes clear, especially for the urban part of the system, that the operation mode of the network becomes important. The method presented helps the managers to prioritize their maintenance to the places where it will result in the best system performance.

Index Terms—Asset management, Component reliability importance, Maintenance, Multiobjective optimization, Power distribution systems.

I. INTRODUCTION

MAXIMUM asset performance is one of the major goals for distribution system operators. To reach this goal minimal life cycle cost and maintenance optimization becomes crucial while meeting demands from customers and regulators. Consequently one of the fundamental objectives is to relate maintenance to system reliability performance in an efficient and effective way. This is the aim of several maintenance methods such as the Reliability Centered Maintenance method [1] and its further developed methods, such as the Reliability Centered Asset Management [2]. In this context it becomes crucial to find a solution to the problem of optimal balance between corrective and preventive maintenance. In the work prior to this paper a method has been developed as an answer to these needs [3].

This paper takes the concept presented in [3] and applies it to a distribution system in Sweden. The multiobjective approach puts the customer interruption on one side and the maintenance budget of the distribution system operator (DSO) on the other. Thus, the proposed method provides a span of optimal solutions that the decision maker can choose among,

each with different expected outcomes for maintenance budget and customers. The multiobjective optimization, taking the reliability from several load and supply points into account is relatively new, see [3] and [4] for a review of related methods.

II. MULTIOBJECTIVE OPTIMIZATION

A. Multiobjective approach to the optimization problem

The task of finding the optimal balance of preventive and corrective maintenance is approached as a multicriteria/multiobjective optimization problem. On one hand, we have the customers’ demands for power delivery and on the other hand we have the maintenance cost for the DSO. In this study, we have chosen to use the total customer interruption cost as the measure of distribution system performance from the customer perspective. The maintenance costs are closely related to the analyzed distribution system, its components, structure and available resources.

It is possible to extend the multiobjective approach by studying every load point’s availability as an individual objective. Some cases might, for example, call for pure Pareto improvements [5], where all customers are viewed separately, i.e. improvements that reduce costs or at least keep costs at current levels for all parties involved. To study all customers independently, with requirements on Pareto improvements, narrows down the feasible solution space. Furthermore, with more objectives, the solution space fast becomes difficult to grasp with the increasing number of load points.

It is important to note that the two objectives (customer interruption cost and cost of maintenance) do not entirely point the solution in to two different directions, in the solution space, since the cost of corrective maintenance to a certain degree correlates with the customers’ inconvenience.

1) Objective function

A scaling between the customer interruption cost and the maintenance cost of the distribution system is introduced. This scaling is varied in order to obtain a number of non-dominated solutions with specific tradeoff between customers and DSO. The objective function of the optimization is presented in (1).

$$\min s * C^{IC} + C^{CM} + C^{PM} \quad [€/yr] \quad (1)$$

where C^{IC} [€/yr] is the expected yearly system customer interruption cost, C^{CM} [€/yr] the cost of corrective maintenance, C^{PM} [€/yr] the cost of preventive maintenance and s is the scale factor (tradeoff). The unit of the scale factor, s , becomes DSO money per unit of customer money and constitutes a translation of the expected customer interruption

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P. Hilber and L. Bertling are with KTH (Royal Institute of Technology), School of Electrical Engineering, Stockholm, Sweden. Corresponding author: P. Hilber, phone: +46 8 790 77 72; e-mail: hilber@kth.se.

costs into terms of DSO costs. In this study the value of s is varied between 0.05 and 1200, the lower value is used for inclusion of the most cost efficient maintenance activities while the higher value is used in order to include all maintenance actions in the solution. C^{IC} , see (2), depends on the maintenance strategy. The values of C^{CM} and C^{PM} are based on the maintenance strategy; for this paper, these costs are discussed in the case study. The three different costs in the objective function depend on the distribution system and its components. C^{IC} is calculated according to (2) [6].

$$C^{IC} = \sum_L \lambda_L (k_L P_L + c_L P_L r_L) \quad [\text{€/yr}] \quad (2)$$

where C^{IC} is the total expected yearly customer interruption cost for the system, P_L [kW] average power, λ_L [f/yr] and r_L [h/f] are reliability indices for every load point L , and k_L [€/f, kW] and c_L [€/kWh] are cost constants representing the customer types and composition for every load point L .

B. Component reliability importance index, I^H

The idea behind component reliability importance indices is to identify components whose reliability have a significant impact on the system performance. Hence these indices are useful for maintenance optimization. The authors have previously presented a number of component reliability importance indices in [7] and [8]. The indices are adapted to power systems by studying the customer interruption cost with respect to component reliability. In the present study we utilize the interruption cost based index (or hazard rate index), defined as follows [8]:

$$I_i^H = \frac{\partial C^{IC}}{\partial \lambda_i} \quad [\text{€/f}] \quad (3)$$

where C^{IC} [€/yr] is total yearly customer interruption cost and λ_i [f/yr] component i 's failure rate. The index identifies components that are critical for the system with respect to their individual impact on total interruption cost with changes in component failure rate [7]. One interpretation of I^H is that it corresponds to the total expected interruption cost (for all load points) that would occur if component i failed. Hence, if there were one maintenance action available, which would result in the same absolute change in failure rate for any component in the network, I^H would then be the adequate index to use for a prioritization of what component the action should be performed on.

C. Value of maintenance actions

The value of every maintenance action is approximated according to the following equation:

$$P_{i,j} \approx \Delta \lambda_{i,j} C_i^{CM} + \Delta C_{i,j}^{PM} + s \Delta \lambda_{i,j} I_i^H \quad [\text{€/yr, action}] \quad (4)$$

where $P_{i,j}$ is the expected change of the objective function if maintenance alternative j is implemented for component i , s is the scale factor of customer interruption costs, λ is the component failure rate, and Δ denotes the change from the

current maintenance policy in the optimization process. C_i^{CM} corresponds to the expected corrective maintenance cost that a failure of component i incurs for the DSO. ΔC^{PM} depends on the cost difference of introducing the studied maintenance action compared to the current policy. Equation (4) is approximate since the last term is an approximation of how the customer interruption cost will change.

D. Optimization

In [3] a method is presented on how to calculate a number of efficient maintenance solutions with the help of equations closely related to (1)-(4). However, in the case presented below the reliability model is so much simplified compared to the case presented in [3], that the whole optimization approach can be replaced by a sorting of maintenance activities. The sorting is based on (4) and constitutes the actual optimization in this case.

E. Results and selection of optimum

The suggested method will deliver a number of optimal points, exemplified in the case study below. These points will be located on the Pareto border and are all optimal from a specific point of view. The solution that is selected by the decision maker depends on many factors such as the current status and behavior of the distribution system. The different solutions provide the decision maker with important information on the expected consequences of the different maintenance policies.

F. Differences compared to RCM

The Reliability Centred Method (RCM) [1] prioritizes preventive maintenance tasks based on their impact on identified equipment or events. The method focus on the most critical equipment or events followed by preventive actions directed to these. The suggested approach, in this paper, is to consider effects of preventive maintenance simultaneously with the expected outcome in terms of corrective maintenance and objective fulfillment (power delivery to customers). I.e. the efficiency of considered maintenance activities are taken into account directly. Both methods have their pros and cons. The major problem with the latter is that it is difficult to identify the effects of preventive maintenance and hence establish a value of efficiency. Furthermore, the method might suggest maintenance actions that are not directed towards the highest risks, which could be considered unethical.

III. CASE STUDY

To demonstrate the suggested method we have studied the 11 kV distribution system of Kristinehamns Energi, a local utility with 10 900 customers. The distribution system covers the town of Kristinehamn (the urban system) and the surrounding countryside up to a radius of about 10 km (the rural system). Within the city there are 231 stations which mainly are fed by underground cables while the seven lines that feed the rural part of the system mainly consist of overhead lines. It is important to point out that the urban system is significantly bigger in terms of customers. The utility has no production of its own, and draws approximately

230 GWh per year from the overlying, regional network, through two receiving transformer stations. [9]

The purpose of this paper is to answer the following questions:

1. How should maintenance be prioritized between rural and urban parts?
2. Where will the maintenance payoff be highest?
3. Given that the overhead lines have to be replaced with underground cables, in which order should the lines be replaced?

The data presented in this chapter are based on [6], [9], [10], and interviews with the DSO.

A. Power System Components

This subchapter discusses the components included in the model. The model decisions are based on failure statistics, gathered for a period of 10 years [9].

1) Overhead Line System

Of the total 226 recorded failures on the 11kV network for the studied time period, 132 failures were due to the 104 km of overhead lines and 32 failures due to 99 pole mounted stations (transformers). Overhead lines have a failure rate of 0.16f/yr,km in forest and 0.062f/yr,km in forest free areas. for the studied time period.

2) Stations (secondary substations)

25 failures due to 231 secondary substations (stations) over 10 years correspond to 0.011 f/yr and station. The yearly inspections have resulted in a list for the stations of outstanding maintenance activities. I.e. defects that are not critical, but given time and resources these issues would be corrected since they eventually may cause interruptions.

3) Underground cables

Through 10 years and 170 km of cable there were a total of 14 failures, 6 due to digging. The remaining 8 failures are related to the status of the cables and/or how they are operated/handled. Below one failure per year for 170 km of cable (0.005 f/yr) is not likely to be improved by maintenance. Hence, the cables are considered as impossible to improve in the model.

B. Reliability model

High redundancy, within the city, and closed loop or radial feeding for the overhead line systems combined with manual switching, in case of failure, leads to a relatively simple reliability model.

1) System outline

The basic outline of the system is five substations with a total of 20 outgoing feeders with automated relay activated circuit breakers. These breakers operate automatically when a failure is detected. Additional relay activated breakers are connected to the feeding end of each of the seven overhead lines. Seven of the twenty feeders have an overhead line connected to it.

The redundancy within the urban parts is so high that the prime interruption duration contribution is the manual switching time, approximately 1h in case of failure. Impact of second order failures is very small mainly due to the relatively short average repair time, approximately 3h, [6], and after restructuring of the network a smaller part, if any, is without

power. All but one station in the city has secondary feeding points and many stations have three alternative feeding points.

For the rural overhead line system a failure brings down the whole line for approximately one hour and the part of the line downstream of the failure for 3 hours [9], if its not possible to close a loop further downstream [10]. Four of the seven overhead lines have a secondary feeding point.

2) Model

The urban part of the system is modeled according to the outline. A failure brings down all stations downstream and upstream to the feeding point to the automated breakers for one hour. Second order failures are neglected since their contribution to the “unreliability” is low.

Failures in the rural overhead lines are modeled as a 2 hour breakdown of the whole line. For a more precise model of one of the overhead lines see [10].

All components and customers are, hence, grouped into 27 groups. 20 groups for each of the outgoing feeders for the urban system and 7 groups for the overhead lines.

C. Maintenance activities

To identify what activities that might be classified as maintenance in a company is complicated. In this paper actions intended to maintain or increase the reliability of the distribution system are included into the scope. E.g. reinvestment in stations, connecting two overhead lines by building an additional overhead line and naturally the more traditional activities as revision, replacement, inspections and service.

1) Increased tree trimming

Going from trimming one line per year and seven overhead lines, i.e. tree trimming every 7th year, to trimming every 3rd year. The cost of this is initially €10 000 spread over the first three year period, when moving to the new interval, this is the cost for trimming 35 km extra. Henceforth, the cost is considered to be the same as before due to easier trimming (it is significantly easier to trim after 3 years). The expected result of this is a reduction by 47% of the tree related failures. Approximately 2.9 failures per year, this figure is based on failure statistics separated on tree related failures and identification of the ratio of failures within 0-3 years and 4-7 years from the trimming. Even though this cost is considered a one time cost it is modeled as € 1 000 per year, this cost includes capital cost and a margin for higher trimming costs.

2) Thermography

Every year approximately 100 stations are inspected with assistance from an ir-camera. Identifying 8-10 cases of partial discharges in the circuit breakers. The cost of the thermography is €2200 and the maintenance following €100 - €500 for maintenance or revision per identified breaker. The reliability benefit is avoiding a failure within 5 years per improved breaker. I.e. a failure rate of 0.2 failures per year is reduced to zero.

3) Inspections

Inspections lead to maintenance activities in the magnitude of €10 000 per year and involves many minor actions for several of the stations. This is currently not modeled more than to the extent that the cost is included. Some of the results presented later in the paper do, however, indicate where changes in inspection intervals could be considered.

4) Replacement of Station

To completely replace a station cost from €65 000-€110 000. The benefits are significant, e.g. several circuit breakers are improved, i.e. modeled as avoiding one failure per year. This high value is used since the action only is considered for significantly degraded stations. It is important to note that this action many times is necessary due to regulations. In the reliability model this is taken into account in the following way: It is assumed that the station was due to replacement within 5 years. Hence the cost of an earlier replacement is only based on depreciation for five years and expected lifetime of 30 years (on the financial side the depreciation time is shorter). Price € 11 000 - € 18 500 for replacement, corresponding cost in the model: €1 800 – € 3 100.

5) Replacing overhead lines with underground cables

A previous paper, [10], discusses the costs of replacing overhead lines with underground cables. The cost of replacing an overhead line with cable is set to €27 000 per km, including replacements of transformers. The overhead lines have a failure rate of 0.16 f/km,yr in forested areas and 0.062 in open areas. When replaced with underground cables the failures are reduced to 0.0082 f/km,yr.

As discussed earlier the cost of replacement can be considered lower if a necessary replacement is anticipated. This case is accommodated into the model by an assumption that all overhead lines will need replacement within a relatively close future. The cost per km and year is based on an expected lifetime of 30 years and the cost is reduced to 1/30 per year i.e. €900 per km and year. The difference compared to the station replacement is that the cost used in this approach comes from only one year, this since it is expected that the cables consistently will improve the reliability, through the years to come after the replacement.

D. Approach

The approach is to calculate the importance index, I^H , for all 27 groups and to utilize this index in the optimization. Combined with the maintenance actions, described above, it is possible to commence the optimization, given that the corrective maintenance is excluded from the model. The reason for not including corrective maintenance is limited time for the study, combined with the assumption that the expected changes in corrective maintenance will be relatively small, compared to the changes in customer interruption cost and preventive maintenance cost. It is however important to point out that if the corrective maintenance were to be included it would reduce the cost of maintenance.

With the available maintenance actions presented we need to establish values for the customer interruption cost index. This is achieved through classification of the customers [Residential, Commercial, Industry, Agricultural] connected to every feeder and estimates on the values of their interruption costs, see [10] and [11], for example and data. In Table I the customer interruption cost in case of a failure, I^H , can be seen. These values can be used directly when comparing the same type of maintenance for different parts of the distribution system. The structure of the distribution system specifies that all components connected to a feeder get

the same importance. Hence it becomes interesting to compare components that are connected to different feeders.

TABLE I
COMPONENT RELIABILITY IMPORTANCE

Feeder group / overhead line	I^H Customer interruption cost [€/int.]	Connected overhead line
T2_3	54616	
T1_221	33478	TL3
T3_29	22278	
T3_23	18130	
T1_25	10722	
T2_2	8010	
T3_10	7076	TL4
T2_23	6516	
T1_12	6358	TL6, TL7
T3_9	5765	
T1_11	5391	
T1_24	4664	
T3_24	3666	TL5
T3_3	3581	
TL6	2957	
T3_4	1803	
TL3	1321	
TL1	978	
TL5	930	
T1_33	846	TL1
T1_32	529	TL2
TL4	478	
TL7	432	
T0_0	133	
T3_0	31	
T1_26	22	

TL denotes an overhead line. Note that the overhead line TL1 has a higher value than the feeder to which it is connected. This is due to longer interruptions in the overhead line system, even though there are more customers than those connected to the overhead line.

The operation mode becomes important due to the structure of the network. It is possible to change the default connection for many stations. In terms of the presented model this would result in changed reliability importance for the concerned feeders. In these considerations many factors have to be included, for example peak power consumption and max current in utilized feeders.

Based on the values in Table I and the maintenance actions it is now possible to construct a list sorted on customer interruption cost savings per preventive maintenance expenditure. This sorted list basically constitutes the Pareto border with values for changes in preventive maintenance budget and expected customer interruption costs. The DSO has now to choose the most suitable level of preventive maintenance.

IV. RESULTS

Results from three different cases are presented. For every case the Pareto border is drawn, every point representing an optima given a specific scale. The different solutions were obtained by starting with the most beneficial maintenance action in the solution and then adding the next best, resulting in the next optima. This method, of adding the next action, is continued until no more actions are available.

A. Case 1

The first case is built on the assumption that it is possible to perform the maintenance activities on the most important parts of the distribution system. Furthermore it is assumed that the overhead lines are in good condition.

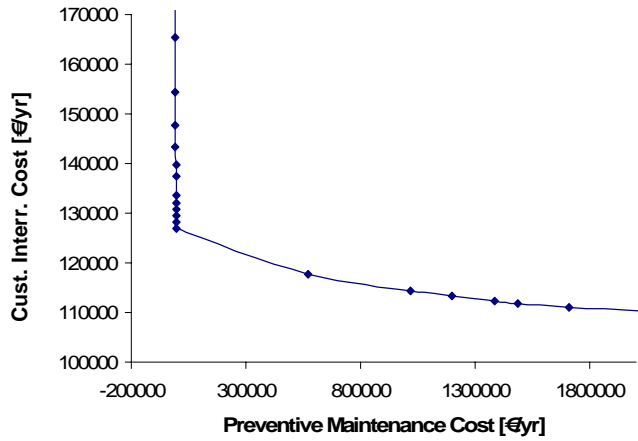


Fig 1. Pareto border for case 1, “healthy” overhead lines and maintenance performed on the most important components. The preventive maintenance cost is the change in cost compared to today’s budget.

The result is that a station is replaced as the first action followed by thermography, and related actions, performed on stations of high reliability importance. The first action to be performed on the overhead line system is the increased tree trimming, and this action is in the middle of the thermography. In Fig 1 a knee can be seen when all actions on the urban parts are performed as well as the tree trimming. The next action after the knee is replacement of a rather long section of overhead line in forest, for line TL6.

B. Case 2

In this case it is assumed that the overhead lines will need replacement within a close future and the cost used in the calculations is the replacement cost divided by the expected life of the underground cable. Hence this is more of a yearly cost, caused by a premature replacement of the overhead line. In this case all maintenance actions become more equal but the exact same pattern/order of maintenance actions present themselves. See Fig 2.

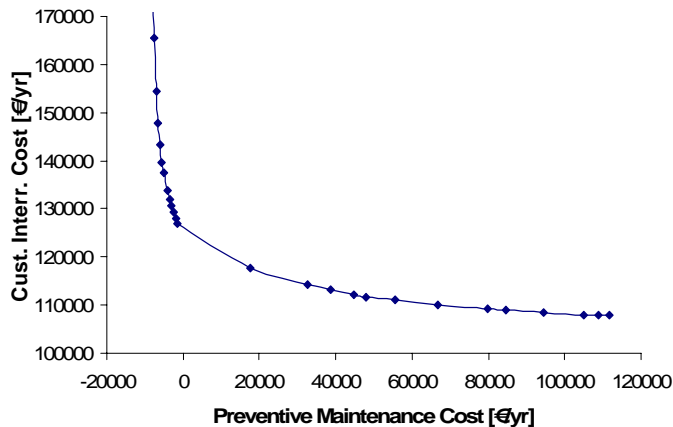


Fig 2. Pareto border for case 2, aged overhead lines and maintenance performed on the most important components. The preventive maintenance cost is the change in cost compared to today’s budget.

C. Case 3

In the last case it is recognized that many of the maintenance actions cannot be performed on the same components year after year with the expected same outcome (high performance). For example it is expected that the thermography might be suitable to perform every 3rd year. In order to simulate this system behavior the available maintenance actions are randomly distributed over the urban system. The actions for the rural system remain the same. The result can be seen in Fig 3. This simulation puts the increased tree trimming higher in the ranking and in some cases it becomes motivated to replace overhead line segments (with cable) prior to perform work within the city.

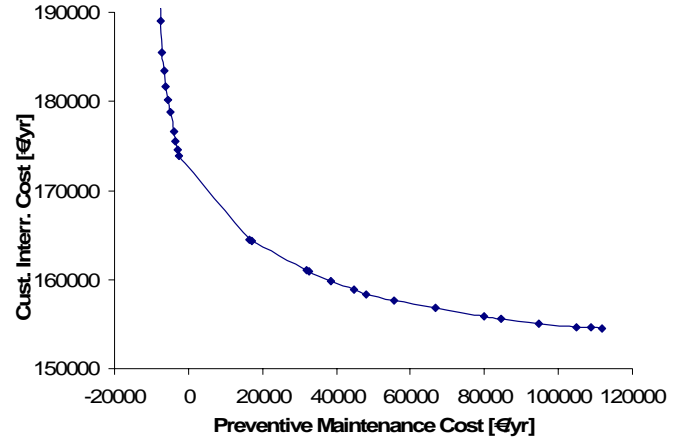


Fig 3. Pareto border for case 3, aged overhead lines and maintenance is performed on randomly selected components. The preventive maintenance cost is the change in cost compared to today’s budget.

Case 2 and 3 can be interpreted as follows; the first year the maintenance should be performed according to case 2, but following years will likely produce optima’s more resembling case 3.

D. Selection of maintenance policy

In Fig 1-3 the Pareto border can be seen given the assumed maintenance actions. With the help of this information the DSO has a good overview over the alternatives, and can select the most suitable alternative.

For the last case the order of maintenance actions are presented below, highest priority first, line followed by left to right, aggregated to type of action (overhead line - OHL):

1. Thermograph T1_221 and T3_23
2. Increase tree trimming
3. Replace a degraded station at T2_2
4. Thermograph T2_2, T2_23, T3_9, T1_11, T1_24 and T3_3
5. Replace old OHL in forest with cable for TL6
6. Thermograph T1_33
7. Replace old OHL in forest with cable for TL3
8. Thermograph T1_32
9. Replace old OHL in open area with cable for TL6
10. General replace old OHLs in forest areas with cables
11. General replace old OHLs in open areas with cables

It is now up to the DSO to choose the level of maintenance; should the normal budget be exceeded in order to lower the customer inconvenience? Exceeding the budget reduces the maintenance payoff but may still be beneficial, for example when considering regulatory issues.

E. Summary, results

Looking back at the three questions presented in III. The answer to number one, “How should maintenance be prioritized between rural and urban parts?” seems pretty clear, in the presented case study. The urban part should be prioritized. But it is important to note that the major reason for this is that the urban feeders have more customers and a higher interruption cost. Hence, the conclusion is that as long as the rural parts are relatively small the focus should be on the urban parts of the system. The answer to the next question, regarding best maintenance payoff, is related to the first question, it can for example be seen that the increased tree trimming (a very cost efficient maintenance action) is in the middle of all urban related maintenance actions. Hence an efficient maintenance action is valuable, even when performed on areas with relative low reliability importance. The advantage of the presented method is that in a systematic way these actions as well as important parts of the network are identified. Regarding the replacement of overhead lines, the conclusion for the case is that in order to consider replacement, the overhead lines need to be aged/ degraded and be due for replacement within a relatively short time period. Even then the focus should be on important lines and specifically important segments in forested areas.

V. CONCLUSIONS

A previously developed method is here adapted to a real case and tested with genuine maintenance data. The most significant contribution is to show on the possibility to perform such calculation. The method enables the DSO to, in a systematic manner, identify how maintenance should be prioritized, by identification of where the maintenance payoff is the highest. Furthermore the method gives indications on the replacement order of overhead line segments with underground cables. Additionally one economical concept is introduced, i.e. a relatively low cost for early replacement, when replacement is imminent.

Given the assumptions made in this paper the following can be recommended: Preventive maintenance within the city should be high priority especially to equipment connected to important feeders. In addition, it is interesting to identify more preventive maintenance actions within the city. Furthermore, aged overhead lines in forest to relatively important areas should be considered for replacement.

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VIII. BIOGRAPHIES

Patrik Hilber (GS'02) was born in Stockholm in 1975. In 2000 Patrik received the degree of M.Sc. in Systems Engineering and in 2005 the degree of Tech. Licentiate in Electrical Engineering, both from KTH (Royal Institute of Technology), Stockholm, Sweden.

Since 2002 he has been employed as a Ph.D. student within the RCAM research group at the School of Electrical Engineering, KTH, Stockholm, Sweden. During part of 2005 and 2006 he visited INESC Porto, Portugal, as a guest researcher. Patrik has industrial experience of optimization from previous employments, within the field of logistics optimization (1999-2002).

Lina Bertling Lina Bertling (S'98-M'02) is Associate Professor at KTH School of Electrical Engineering and Assistant Research Director at Svenska Kraftnät, Stockholm, Sweden. She received her Ph.D. in Electric power systems in 2002, and was a visiting postdoctoral student at the University of Toronto, associated with Kinectrics Inc. 2002/2003 her research interests are in; reliability assessment and modeling, and maintenance planning for electric power systems and equipments. She was the general chair of the 9th International conference on probabilistic methods applied to power systems (PMAPS) in Stockholm, in 2006. Dr. Bertling is the secretary of the IEEE Sweden Section, and the IEEE PES Subcommittee on Risk, Reliability, and Probability Applications (RRPA). She is reviewer for several journals, and is engaged as an evaluator by the EU commission. She is a member of the Royal Swedish Academy of Engineering Sciences, and the Industrial Research Group during 2007-2009.