Evaluation of the customer value of component redundancy in electrical distribution systems

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Abstract—A new regulatory model for the Swedish electrical distribution system operators has been proposed, and is now being implemented. The model is referred to as the Network Performance Assessment Model (NPAM). The NPAM is based on fictive *reference networks*. These emanate from a radial network that is reinforced with redundant components if it increases the customer value more than required investment cost for higher system reliability. The NPAM involves a paradigm shift for the Swedish DSO from a system based on compensation for costs to one based on performance. Evidently, it is of great importance to both the regulator and the different DSOs to evaluate how well the NPAM calculates the performance i.e. the customer values. The aim for this paper is to take a first step in this process; by putting light on how these *redundant reference networks* are created and used for the NPAM. In order to do this a comparative study has been made for a small test system where two different approaches are used for identifying the resulting redundant reference network for a system. The NPAM approach uses a Monte Carlo simulation technique, and the comparative approach uses an analytical based reliability assessment tool RADPOW, developed at KTH.

***Index Terms*—Customer value, Electrical distribution systems, Network Performance Assessment Model, Outage cost, Power systems, Probability, Performance based regulation, Redundancy, Reference networks and Reliability.**

I. INTRODUCTION

Electrical energy customers generally require high availability in the power supply. However, if, as for other goods, the customer were to pay a price for electricity corresponding to the customer value, different customers, such as industrial or household, would have different values for energy not supplied Consequently, there would be different set of prices for power supply from a customer point of view. From the perspective of the electrical distribution system operator (DSO), there is a cost for operation and maintenance of the electrical distribution system, to balance against the requirements for system reliability and the profit for the stakeholders. In a perfect market environment, a balance would be reached where customers select the DSO with the best price for the required customer value. However, the infrastructure for the electrical distribution system is in most cases still under a monopoly. To manage this situation the authorities apply different regulatory tools. In Sweden, a regulatory tool is being introduced by the Swedish energy agency (STEM), referred to as the Network Performance Assessment Model (NPAM) [1]- [4].

The NPAM aims to regulate the network tariffs, i.e. the price that the DSO charges the power supply customers, based on the customer value. An increase in network tariffs should then only be valid if it creates higher customer value, e.g. by increased system reliability. It is important to realize, however, that an increase in system reliability does not necessarily lead to a corresponding increase in customer value. The increase in customer value might be lower than the cost of increasing the reliability and the DSO will not be completely compensated by the network tariffs. Another purpose of the NPAM is to compare tariffs between different DSO depending on their electrical distribution system and corresponding customer value.

The NPAM is based on *reference networks*. A *reference network* is a fictive electrical distribution system that is defined from a set of *objective prerequisites* such as location of customers. Moreover, the *reference networks* emanate from a radial network that has been reinforced with redundant components e.g. feeders in parallel. The principle when creating the redundancy for the *reference networks* was that the investments for improving the system reliability are motivated only if this increases the customer value more than the required cost for higher reliability.

The ongoing introduction of NPAM involves a paradigm shift for the Swedish DSO from a system based on compensation for costs to one based on performance. Evidently, it is of great importance to both the regulator and the different DSOs to evaluate how well the NPAM calculates the performance i.e. the customer values.

This paper aims to take a first step in this process by investigating the issue of system reliability. More specifically, the paper addresses the question of how system redundancy is created for the *reference networks* and compares it with a general reliability model for electrical distribution systems, using the reliability assessment tool RADPOW, developed at KTH [5],[6].

II. NETWORK PERFORMANCE ASSESSMENT MODEL NPAM

A. Background to NPAM

In 1996 the Swedish electricity market was re-regulated and a new regulating authority STEM was established. The re-regulation meant that trading with electricity was exposed to competition and that the net service henceforth constituted a monopoly, with responsibilities as well as privileges. For a DSO this meant being responsible for all electric distribution

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in a geographically well-defined area, offering all customers a connection and setting network tariffs that included a reasonable profit.

Following the re-regulation, the network tariffs for electricity supply in Sweden increased. Despite several attempts by STEM to keep the network tariffs down, for instance, through price freezing, no solution was found. There was therefore an urgent need to find another or a new regulation paradigm.

In 1998, one of the authors of this article [1] was commissioned by STEM to propose a new regulation model for the DSO. The model was to be based on self-regulation and was to give incentives to increase cost-efficiency in the electrical distribution systems. Moreover, the model should be accepted by the customers and different DSOs. Finally, there should be full insight into the model.

The first approach was to use one of the existing models and adapt it to Swedish conditions. However, when no suitable model was found, it was decided to develop a new model. The primary drawback of the existing models was that they were based on the actual electrical distribution systems, and that they did not take into account the efficiency of these networks [1].

The proposed regulation model, i.e. NPAM, meant a change in perspective from a company to a consumer focus, with performance-based regulation. From the consumer perspective, the cost is based on the value to the consumer, in contrast to the cost for the DSO. As a result of this new customer perspective, the legislation had to be changed [7].

B. Overall description of the NPAM

1) Customer values

The fundamental starting point of the NPAM is much the same as if it were active in a competitive market. The goal is to calculate the customer values produced by the DSO and sold to the customers. The DSO will be allowed – within the monopoly framework – to be paid for these customer values. The customer values are based on average costs. Moreover, these costs are based on the estimated cost for an electrical distribution system that would be built today with known technology, e.g. it is assumed that underground cables are used rather than overhead lines.

The customer values are separated into a value chain, as illustrated in Fig. 1. The *connection* is the subscription at a distinct location with power supply required at all times. The *connection reliability* is the measured reliability at the connection point. The *delivery* is the actual delivery of energy, i.e., excluding losses. The *grid administration* is the value created for the customer through the delivery of energy, for instance, or fair measurement of energy, and by charging for the connection and supply. The sum of the customer values is referred to as the *Network Performance Assessment* (NPA). This value is then compared with the payment from the customers.

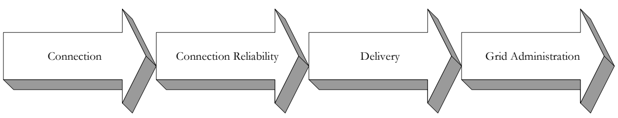

Fig. 1. The *Customer value* chain in the NPAM

2) Objective prerequisites

The *objective prerequisites* are based on pretreatments of the Swedish law [1], and summarize conditions “all circumstances that can not be influenced” for a DSO within their concession area. There are four *objective prerequisites* for a node as follows: geographical position, maximum load to or from a node, the time distribution of the load, and the nominal voltage level required.

Customers have different requirements according to their location and capacity demand. On one hand, urban customers could be easy to connect, since many customers can share the same cable. On the other hand, connecting rural customers might require long cables that cannot be shared with other customers. Moreover, the power demand differs and is variable throughout the day. The conditions for customers are consequently different and therefore also different for the DSOs. This is an important note since all DSOs are obliged to supply the power demanded at an arbitrary location within their concession area.

3) Reference network - radial and with redundancy

The *connection* in the customer value chain is assessed through a *reference network*. The *reference network* is an artificial network that is created from the *objective prerequisites*. It was initially created as a pure radial network. The network is then adjusted to a redundant network where redundancy has been extended, based on a balance between investment cost for DSO and reduced outage cost for customers. The approach for defining the redundancy for the *reference network* follows in a subsequent chapter.

It is important to distinguish between the process of defining the redundant *reference network*, which is based on reliability assessment, and the use of the result for the NPAM. The results from the reliability assessment are standard cost functions, used to provide a quality increase for the *radial reference networks*. This implies that the customer value for the redundant *reference network* corresponds to extra line length that the DSO in turn would be paid for. The amount of extra line length depends on the network level and average density in [feeder meter/customers]. The approach for defining these corresponding lengths is presented in [1] and will not be treated in this paper.

4) Reliability in terms of expected or attained performance

The NPAM distinguishes between two different measures for reliability and outage cost. These are the *expected reliability, which* is the resulting performance for the *reference network,* and the *attained reliability*, which is the measured reliability for the real network. If the *attained reliability* is less than the *expected reliability,* there will be a reduction in the assessment of customer value. The assessment of the *attained reliability* and the *expected reliability* is in close relation to the assessment of redundancy for the *reference network.*.

C. Result from test of NPAM

Table 1 shows results from a test of NPAM in 2002 on 114 companies and 2.7 million customers. (Compare with the total number of DSOs in Sweden of 259 with approx 5.3 million customers.) Results are shown for each *customer value*, and the total sum of values, i.e. NPA, is compared with the revenue, i.e. what the customers have paid. The final result indicates a 19% overcharge, i.e. a debiting rate of 1.19. This is of course a conservative result and has been the topic of much discussion. In general, a debiting rate over 1 implies that customers are overcharged for the service provided.

TABLE 1
RESULTS FROM TEST OF THE NPAM

Customer values	**Result per customer***	**% of NPA**
Connection radial Reference network	SEK 1,297	46 %
Connection redundancy	SEK 336	12 %
Reliability	SEK -129	- 5 %
Delivery	SEK 170	6 %
Administration	SEK 341	12 %
Services from superior grid	SEK 826	29 %
Total customer values (NPA)*	SEK 2,841	100 %
Revenue	SEK 3,389	119 %
Debiting rate = Revenue/NPA	**1.19**	**19%**

10 SEK~ 1 Euros.

III. RELIABILITY ASSESSMENT TECHNIQUES AND REDUNDANCY

A. Redundancy to improve system reliability

All technical systems are exposed to randomly occurring failure events. For a system composed of components, this implies that the individual components have a probability of failure, resulting in the total system reliability.

The level of system reliability could be changed in different ways. Technically, changes could be made in either the system or the components. Examples of changes in the system are: keeping the system as simple as possible or using redundancy. Moreover, the redundancy could be either active or in standby [8]. Active redundancy means that all components are in operation. Standby redundancy means that after a component has failed, the redundant component is brought into operation. Examples of changes in the component are: increasing the reliability of the components, or maintaining different types, including correcting or preventing failures. The reliability analysis included in this paper focuses on the first group of principles that involves system improvements by active component redundancy.

Examples of active component redundancy for an electrical distribution system are: transformers or lines in parallel. Standby redundancy is exemplified by a normally open path that would be closed when the normal feeding path has failed, i.e. a meshed system.

The amount of redundancy that is built into an electrical distribution system is formulated in different practice and technical standards. However, ultimately it should be the customer's willingness to pay that defines the extension of redundancy. In other words, the redundancy level should be increased as long as the cost of increasing the level of redundancy is less than the gain by lowering the estimated outage cost for an interruption. However, this is a complicated task: it involves finding the optimal point for system redundancy.

B. Analytical tool for reliability assessment RADPOW

To evaluate the customer value of system redundancy, the focus of this paper, reliability assessment tools are needed. These tools can relate the impact of component reliability to the system reliability that in turn defines the customer value at different load points.

For this study, a computer program RADPOW (Reliability Assessment of Distribution POWer systems) is used for the reliability analysis. RADPOW was developed by the Centre of Excellence in Electrical Engineering at KTH [5], [6]. The tool includes an analytical approach to the reliability predictions. The mathematical model is based on the generally known techniques of network modeling and the minimal cut set (load-point-driven) approach.

There are four types of input data to RADPOW: network topology data, customer and power data, component reliability data and load flow data.

There are two main types of output data from:

1. Load point indices i.e. measures of reliability at each load point (load-point indices) including:
   - failure rate [interruptions/year] = [int./yr],
   - average outage duration [hours] = [h],
   - annual expected outage time (unavailability) [h/yr], and
   - expected energy not supplied [kWh/yr]
2. System indices i.e. measures of reliability for the overall system, including:
   - SAIFI [expected number of interruptions/yr, customer],
   - SAIDI [average outage duration per customer, h/yr, customer],
   - CAIDI [average total outage duration, h/interruption], and
   - EENS [expected energy not supplied, kWh/yr, customer].

The main feature of RADPOW is that it includes the ability to analyze general distribution systems (including meshed systems), to maintain the network structure in the analysis, to allow implementation in the object-oriented language C++, and to allow the representation of different functions as separate modules.

IV. CALCULATION OF REDUNDANCY IN REFERENCE NETWORK

A. Outage cost and annual investment cost

The *outage cost* has an essential function in the NPAM. It shows how well the DSO has fulfilled the customer expectations. The starting point for the model is on one hand, the customers' readiness to pay for redundancy in the network and on the other hand, an estimation of how well the DSOs have been able to live up to the customers' demand for low outage costs. The fundamental approach is that redundancy should be extended as long as the customers are willing to pay for this.

B. Calculation of redundancy for the reference system

In the NPAM, the valued outage cost for a pure radial network is expressed as the *annual network cost* (a_{annual}) and the *expected outage cost* (a_{outage}). In Fig. 2, this cost is shown as point A.

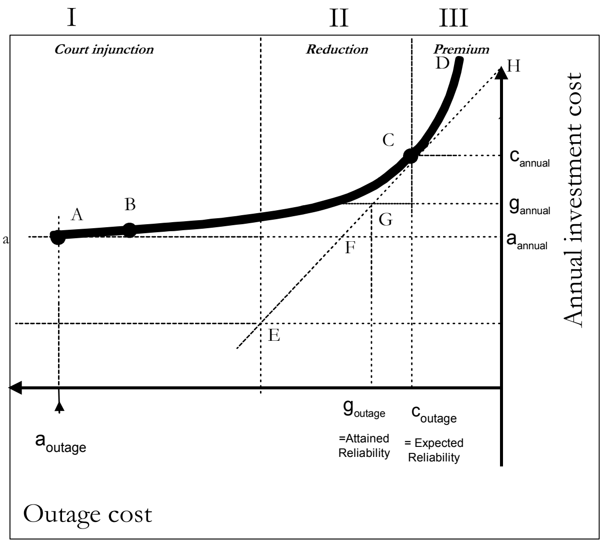

Fig. 2. Outage cost versus annual network costs.

In the next step, the radial grid is considered with respect to finding the best motivated redundancy. The resulting redundant network, will give an increase in annual network cost as well as a decrease in expected outage cost. Fig. 2 illustrates this action as a move from point A to point B. If all profitable redundancy alternatives are gradually introduced into the network in order of preference for profitability, the relation between the annual network cost and the expected outage cost gradually changes from point B to point C in the figure. Every profitable measure put into practice has a lower annual cost for the network owner than the value of the decreasing outage cost for the customer. In a network with low reliability, inexpensive measures (low additional annual cost) have great influence on e*xpected outage cost*. The higher the reliability it achieves in the network, the lower the profitability for additional redundancy. The least profitable of the redundancy alternatives are those that have the same annual cost as the resulting decrease in outage cost. These are the measures found close to point C in the figure. Point C is the point where the network can perform *expected reliability* (c_{outage}). Ideally, every company should have a network that performs *expected reliability*. Consequently, point C is referred to as the solution with optimal redundancy in the network.

To the right of point C in the figure, no further measures for improved reliability for the network should be taken. Such measures have a higher annual cost than the value of the improved reliability and cannot be motivated and are unlikely to be accepted by the customers.

The line between point A and point C in the figure represents the redundant network calculated by the model. This reduction occurs along the line E-F-G-C. The slope of this function is 45 degrees at point C for *expected reliability* because there the costs for improving the reliability (c_{annual}) and the customers' outage assessment (c_{outage}) of improved reliability coincide.

The relation between increased annual costs in a network and decreased outage cost is a matter of principle for all networks. The difference between different networks is the radial network's own inherent reliability function. This also leads to a variation in the extent of redundancy adjustment with respect to the grid density as well as the number of grid levels in different networks. This, in turn, results in a variation in the expected outage cost between different networks with respect to the density.

C. Implication of the cost model and its stages

From Fig. 2 it is possible to conduct a discussion about what should be valid in the different stages of I-III. Point C expresses the optimal solution where the company has built its redundant network according to the customer value and runs the network such that the customer receives the required reliability i.e. the *expected reliability* equals the required reliability. However, to the left of point C i.e. in *stage II,* the companies that fail to deliver *expected reliability* are given a reduction based on the achieved customer value compared with expected reliability. At point G this reduction is defined by g_{outage}-$c_{outage.,}$, in accordance with Fig. 2. The resulting annual investment cost in point G is consequently given by $g_{annual} = c_{annual} - (g_{outage}-c_{outage})$. The reduction may be so large that the DSO receives no compensation for its redundancy, i.e. when point F is reached and the annual investment cost for a pure radial system is reached ($a_{annaual}$).

If the *attained reliability* is even lower than at point F, i.e. in *stage I*, the reductions continue down along the line F-E. At some point, a condition occurs in which the reduction could not be considered as linear, and continuous reductions to the same extent would clearly be unreasonable. If it has not happened before it will happen when the deduction equals the *network performance assessment* value from the radial network, i.e. when the NPA=0. Continuous deductions would lead to the DSO being in debt to the customer. Then we are far outside the model's regulation area. In *stage I* we are outside the model's regulation limit and other actions than reductions must be considered. In *stage III* it is not obvious what should be done. Even a reliability that is higher than the required reliability i.e. the *expected reliability* is of value to the customer. The customers will benefit from this improved reliability; however, the marginal improvement is less than the cost to produce it. So far the Swedish regulator will give no premium to DSO with a reliability exceeding the *expected reliability*. It could, however, be argued that the customers have benefits from the extra reliability, and are willing to pay for this along the line C-H.

D. Approach to obtaining the redundant reference network

The *reference network* in NPAM has been defined using probabilistic methods. The generally known function, Weibull distribution, has been used for modeling failure occurrences for components in the system. Components are in one of three states: in operation, in service or in failure. Sequential Monte Carlo simulation has been used to model the expected behavior of the system. The *reference network* for the NPAM has been calculated in five steps as follows:

1. The *attained reliability, (*g_{outage}), is calculated from reported outage statistics for the DSO and their total number of customers.
2. Based on input data to NPAM, a fictive radial network is created. A Monte Carlo simulation is performed for the radial system, including the effect of failure occurrences

and planned maintenance for feeders, and the resulting outage cost is evaluated, i.e. a_{outage}.
3. Different alternatives for redundancy are investigated for the radial network and the feeder lengths. Those redundancy alternatives that could be estimated to be beneficial are studied further. For each of these alternatives the resulting outage cost is evaluated from simulation studies. From a resulting list of possible redundancy solutions, the first one, profitability, is selected, i.e. where the gain in outage costs is higher than the required annual cost for investment in redundancy.
4. The radial network is simulated including failure occurrences for transformers, and possible solutions for redundancy of transformers. The resulting outage cost is compared with the required annual investment cost.
5. Simulation is performed for the resulting redundant *reference network* system including possible redundancy for feeders and transformers. The resulting *expected reliability* is calculated (c_{outage}).

V. TEST SYSTEM AND RESULTS FROM NPAM AND RADPOW

This section shows selected results from analysis of a test system both with NPAM and with RADPOW. Note that the analysis for the *reference network* relates to input data to the NPAM. The main purpose is to illustrate the approaches and the implications of redundant reference network.

A. The Test system and the redundant reference network

A fictive network has been identified at the 10kV and 0.4 kV level, which corresponds to the network level 1 and level 2 in the NPAM. Table 2 presents input data for the Test system to the NPAM. The 10kV network is supplied from one feeding point and is connected to three 0.4kV networks.

A redundant *reference network* was identified from simulations following the previously presented approach. Fig. 3 illustrates the resulting reference network for the Test system. Note that this system has one redundancy for the *10* kV feeder between point *c5* and *c7*. The redundant feeder corresponds to an extra length of 48% at the 10kV level. In NPAM the corresponding need for redundancy is presented per customer density. Table 2 gives a system average customer density for the Test system of 8 meters/customer. This density at 10kV level, i.e. level 2, result in 20% extra feeder length according with [1].

B. Results from the NPAM for the Test system

Table 3 shows results from the NPAM and calculation of outage costs and annual investments at the different points A-C. Since this system has only one redundant component, B=C. C represents the redundant system with the two feeders between c5 and c7. The table also includes results from the same study of NPAM that was presented in Table 1.

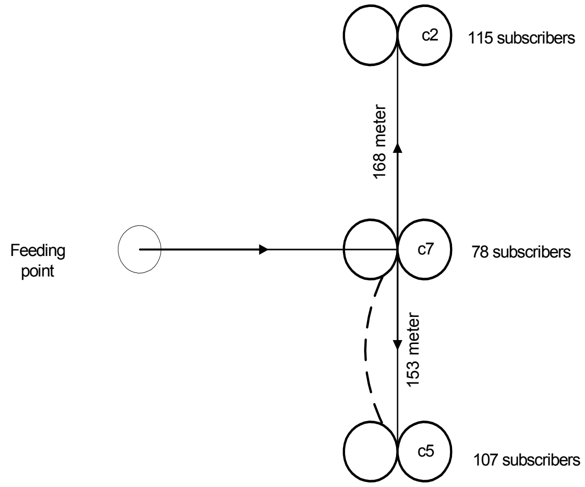

Fig. 3. Reference network for the Test system with resulting redundancy for the feeder c7 and c5.

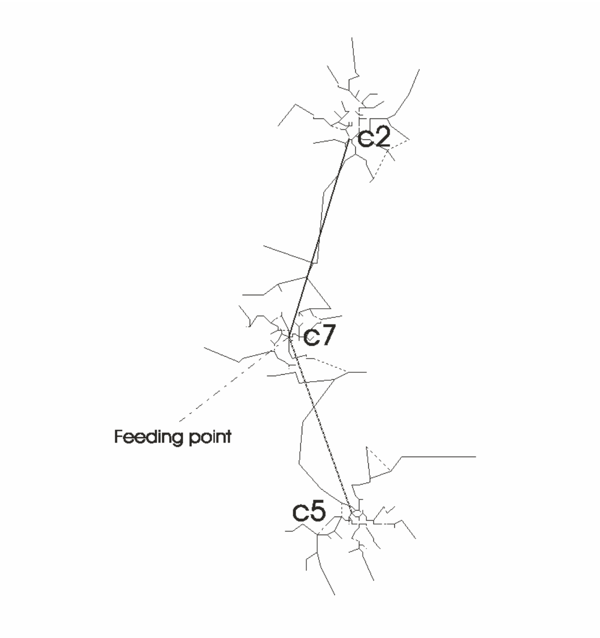

Fig. 4. Network at 0.4 kV and 10 kV level in NPAM for the Test system.

TABLE 2
INPUT DATA FOR THE TEST SYSTEM TO THE NPAM

Corresponding Load point number in RADPOW	Lp 1	Lp2	Lp3
Transformer identification	c2	c5	C7
Transformer power	889 kVA	886 kVA	715 kVA
Transformer current	50,4 A	50,2 A	40,5 A
Nominal voltage	10,797 kV	10,798 kV	10,800 kV
Annual Energy	3,31 MWh	3,29 MWh	2,54 MWh
No of 0,4 kV subscribers	115	107	78
Line length 10 kV	168	153	0
Total line length in the local grid	919 m	863 m	379 m
Average density (meters/subscriber)	9.5	9.5	4.9

TABLE 3
RESULTS FROM THE NPMA

Cost [öre*/kWh]	System	
	Test system	Full scale test
a_{outage}	0.93 (0.4 kV: 0.67 and 10 kV: 0.26)	5.48
a_{annual}	3.91 (0.4 kV: 2.04 and 10 kV: 1.87)	6.89
g_{outage}	0.30	1.67
g_{annual} **	4.09	7.63
c_{outage}	0.13 (0.4 kV: 0.05 and 10 kV: 0.08)	0.62
c_{annual}	4.26 (0.4 kV: 2.26 and 10 kV: 2.00)	8.68

* 100 öre = 1 SEK and 10 SEK ~ approximately 1 Euros.

** c_{annual}-(g_{outage}-c_{outage})

C. Modeling of the Test system for assessment with RADPOW

1) Input data and network reliability model to RADPOW

Each 10kV feeder in the Test system has around 100 subscribers at 0.4kV level. Fig 5. shows a network model for the Test system including eight component types: 10kV lines, 0.4 kV lines, and transformers. It is assumed that the system has a perfect protection system including breakers and transformers with zero probability of failure.

The Test system is modeled with three load points, which have around *100* subscribers at the *0.4* kV level and components *c3*, *c6* and *c8* represent each a *0.4* kV network. Consequently, the complete network model with all set of lines at *0.4* kV would result in a very extensive model, although the Test system is a small system. Failure statistics show that it is generally the 10kV level that contributes most to the load point unavailability [9]. Moreover, the results from the NPAM model for the Test system showed that it was the 10kV level that contributed most to the customer value, i.e. the voltage level where redundancy could be motivated. Considering these two aspects, and the fact that the purpose of this study is illustrative rather than to calculate reliability for a specific system, it was decided to include failures only at the 10kV level.

Fig 5. shows the resulting reliability model that was used for the reliability assessment with RADPOW. The reliability model includes two 10kV lines c1 and c4. Consequently, there are three alternatives, as shown in the figure, to create redundancy:

1. parallel component for c1 (c1’)
2. parallel component for c4 (c4’)
3. coupling between Lp1 and Lp2 (c14’)

Table 4 presents the input data used for the three different sets of components in the model. All data is from [4].

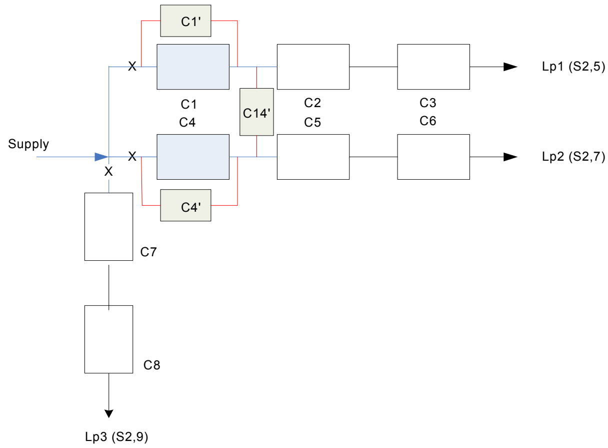

Fig. 5. Network model for the Test system for assessment with RADPOW

TABLE 4
COMPONENT RELIABILITY INPUT DATA FOR THE TEST SYSTEM TO RADPOW

Component of type line 10kV		Failure rate** [int./yr]	Duration*** [hours]
No	Length		
c1, c1’	168 m	0.0226	3.2833
c4,c4’	153 m	0.0205	3.2833
c14’	c1+c4* =321 m	0.0431	3.8333

*approximation since the actual length is unknown

**from mean time to failure of 218.95 years for an average line of 34 meter i.e. 0.000134 interruptions/year, meter from NPAM [4].

*** from mean down time and input data to NNM of 197hours for lines and 13800 seconds [4].

D. Result from reliability assessment with RADPOW

Table 5 summarizes the result from reliability assessment with RADPOW for the Test system and the base case with a radial distribution system. The result shows on the reliability characteristic of the analyzed system. However, for a comparison with results from the NPAM, these results need to be translated into economic terms, which will be considered in the next section.

TABLE 5
RESULTS* FROM RELIABILITY ASSESSMENT WITH RADPOW FOR THE TEST SYSTEM AND RELIABILITY MODEL FOR THE 10KV COMPONENTS

Load point	Failure rate [int./yr]	Duration [hours]	Unavailability [hours/yr]
Lp1	0.0226	3.28	0.0741
Lp2	0.0205	3.28	0.0675
Lp3	0.000	-	0.000
System index*			
SAIFI = 0.01598		SAIDI = 0.05247	
CAIDI = 3.2833		ASAI = 0.999994	

*Only including failures for 10kV lines.

E. Economic assessment for the Test system based on results from reliability assessment with RADPOW

1) Outage Cost

The outage cost has been evaluated in similar way to that in the NPAM. The outage cost in the NPAM depends on the average density, i.e. meter/subscriber. Figure 13, in [1] shows the values used for the NPAM (based on customer interruption cost from Swedish utilities, included in the Cigré report [9]). Moreover, the cost is separated into non-announced or announced outages, and is given in the form: x SEK/kW and y

SEK /kWh. This study has only considered the non announced outages: those that occur randomly.

The outage cost is calculated with mean values of system specific data as follows:

$$outage\ \cos t = \begin{pmatrix} x \cdot \text{supplied energy} \cdot (SAIFI/8760) + \\ y \cdot SAIDI \cdot (\text{supplied energy}/8760) \end{pmatrix} \quad (1)$$

where x kr/kW and y kr/kWh, and supplied energy is the total served energy per year.

The outage cost for the Test system can be calculated as follows. From Table 2 it is given that the Test system has: supplied energy of 9 140 000 kWh, and that the average density is 8 meter/subscriber. This density gives from Figure 13, in [1], that x=22 kr/kW and y=110 kr/kWh. The system index is calculated with RADPOW. Input in (1) gives that the outage cost is approximately= 23 000*(SAIFI + 5*SAIDI). For the base case system, i.e. the radial system, the resulting outage cost, in [SEK/år], can then be calculated as follows: $23000 \cdot (0.01598 + 5 \cdot 0.05247) \approx 6402 SEK/yr$.

2) Summary of proposed approach

The approach aims to investigate the possible economic benefit of introducing different redundancy alternatives for the system. A *comparative figure* is defined as follows:

$$comparative\ figure = \frac{marginal\ benefit}{marginal\ \cos t} \quad (2)$$

where Marginal benefit = reduced outage cost due to activity per year and Marginal cost = yearly cost to apply the activity.

Those alternatives that have a *comparative figure* >1 are defined as economically beneficial.

The approach to identifying the optimal distribution system is as follows:

1. Calculate the system interruption cost i.e. *expected outage cost.* The first time this step is entered, the base case is evaluated, i.e. the radial distribution system (a_{outage}).
2. Test different possible activities for system redundancy for the system.
3. Investigate if there are one or more of the activities from Step 2 that result in a *comparative figure* >1.
    - if NO then it is not beneficial to improve the system redundancy GOTO Step 5.
    - if YES apply the activity with highest *comparative figure*. The outage cost for the system = outage cost for the system after this activity has been introduced, i.e. the new system. The first time this step is entered (b_{outage}) is evaluated.
4. Repeat the analysis for the new system GOTO Step 1.
5. The outage cost for the resulting system equals the *expected outage cost* (c_{outage}).

3) Application of approach for the Test system

Table 6 summarizes the results when calculating the effect of introducing different alternative redundancy alternatives, i.e., the result after Step 3 in the approach.

The alternatives that have been studied imply the introduction of further feeder length. Consequently, the marginal cost can be calculated from the cost of introducing 1 meter feeder per year. For the following studies this cost has been assumed to be 19.5 SEK/meter.

An example of the calculation procedure is presented for alternative c1'. Component c1 is a 10kV feeder of 168 m supplying Load point 1. This alternative implies that a redundant component is introduced with the same characteristic as c1. A reliability model for this new system is implemented in RADPOW. From a reliability assessment with RADPOW, the resulting system index for the new system gives the output of SAIFI=0.02407 and SAIDI =0.00733. From (1) the resulting *outage cost* can be calculated as 2 937 SEK/yr. The *marginal benefit* is given by: 6 402 – 2 937 = 3 465 SEK/yr, the *marginal cost* = 19.5*168=3 275 SEK/yr, and the resulting *comparative figure* is given by = 3 465/3 275 = 1.058.

TABLE 6
RESULTS FROM ANALYZING DIFFERENT ALTERNATIVES FOR REDUNDANCY FOR THE TEST SYSTEM AND 10KV LEVEL WITH USE OF RADPOW

Alt.	Outage cost [SEK/yr]	Marginal benefit [SEK/yr]	Marginal cost [SEK/yr]	Comparative figure
C1'	2 937	3 465	3 275	1.058
C4'	3 457	2 945	3 152	0.9873
C14'	~0	6 402	6 260	1.023

The *comparative figures* presented in Table 6 can be used to rank the alternative solutions for system redundancy as follows:

c1' = 1.058
c14' = 1.023
c4' = 0.9873

The conclusion is that c1' and c14' are beneficial redundancy improvements in the Test system. The solution is that redundancy should be included for the 10Kv line, c1, with resulting *outage cost* of 2 937 SEK/yr (b_{outage}). The redundant feeder corresponds to an extra length of 78% at the 10kV level. The next step is to evaluate if there are any beneficial redundancy alternatives for the new system, i.e. Step 4 in the approach.

4) Other possible redundancy alternatives

Other possible alternatives for system redundancy would be introducing redundancy for transformers, or supplying from other distribution systems from a normally open point.

The alternative of introducing a redundant transformer has been studied. Component c2 was selected since it supplies the largest number of customers compared with the other transformer, i.e. c5 and c7. The result showed that the marginal benefit is not comparable with the investment cost of investing in a new transformer. The conclusion was, therefore, that introducing redundant transformers is not a beneficial alternative for the Test system. It is interesting to note that this result agrees with the result for the NPMA study for the Test system, where it was not efficient to include redundant transformers. The result can also be compared with general results from NPAM where the 0.4/10 kV transformers are never redundant, and the 10/70 kV and higher transformers voltage are always redundant [1].

5) Application for the Test system with redundancy

Reliability assessment with RADPOW for the new system gives that: SAIDI = 0.02407 and SAIFI = 0.00733. The resulting *outage cost* is then calculated as: 2 937 SEK/yr.

The different alternatives for redundancy are as follows:

1. parallel component for c1 (c1')
2. parallel component for c4 (c4')
3. coupling between Lp1 and Lp2 (c14')

Alternative 1 has already been incorporated and including further components in parallel would only yield a small improvement but still require the same investment cost. This alternative is consequently not beneficial.

Alternative 2 was not beneficial for the radial Test system, and would therefore not be beneficial for the redundant Test system.

Alternative 3, to include a new line between load point 1 and load point 2, is analyzed. Results from reliability assessment with RADPOW give that: both system index and outage cost are close to zero. The *marginal benefit* is then given by: 2 937 SEK/yr, and the *marginal cost* = 220,6*321 = 6 260 SEK/yr, and the resulting *comparative figure* is given by = 2´937/6´260 = 0.469.

Consequently, there are no economically beneficial alternatives to extend the redundancy for the Test system than the first activity, i.e. redundancy for line c1.

In accordance with Step 5 in the approach, the resulting *outage cost* for the resulting system now equals the *expected outage cost* (c_{outage}) = 2 973 SEK/yr. Observe that for this example the points c_{outage} and b_{outage} coincide since there is only one beneficial redundancy activity for the system.

F. Concluding remarks for the analysis of the Test system

The conclusion from the reliability and cost assessment for the Test system, from both calculation models, is that the optimal component type for redundancy is the 10kV line, i.e. the solution that gives the right customer value. Moreover, the optimal component for which to include redundancy is: component c4, from the NPAM analysis, and component c1 from the RADPOW analysis.

There might be numerous arguments against these models yielding the equivalent numerical result, and also against the NPAM model giving a true picture of a real network. For example, the Monte Carlo simulation methods used for the NPAM model would have large uncertainties in results when analyzing small systems like this. Moreover, the result is very sensitive to the cost parameters employed, as in this example, the cost per line length. Other arguments could be that the reliability model for the NPAM and the RADPOW analysis differs; for instance, in RADPOW each component is represented by its own failure rate and outage time, but in NPAM some functions are built into the system model, like the breaker function. For this simple Test system, however these aspects were not included.

VI. Conclusions

This paper has illustrated the role played by the NPAM with respect to identifying a *redundant reference network*. Moreover, this implies identifying the optimal redundancy for the system related to customer value.

The application study for the small Test system and the comparative study using the RADPOW tool, has put light on how the *redundant reference networks* are created and used for the NPAM. Although no general conclusions can be drawn from the numerical results due to the simplicity of the test system and the differences in reliability models – they demonstrate the reliability assessment theory behind NPAM which it in it self is a significant contribution. For future studies it would be of great interest to expand the test system into a real distribution system for further investigations evaluating the NPAM.

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VIII. Biographies

Lina Bertling (S'98-M'02) received the Ph.D., and Tech. Lic. degree in electric power systems in 2002 respectively 1999, from the Department of Electrical Engineering and the M.Sc. degree in Systems engineering in 1997, all from the Royal Institute of Technology (KTH), Stockholm, Sweden. She is currently engaged at KTH as Research Associate and Project Leader of the research program on Asset management in power systems. Her research interests are in reliability assessment of power systems, component reliability modelling and reliability centered maintenance methods.

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