Abstract—Balancing cost-effectiveness and quality of service is one of the most important tasks for network companies in the deregulated environment. It is widely recognized that interruption costs is a relevant expression for the inconvenience customers feel when service is interrupted and that adequate assessment of such costs is crucial when they are used quantitatively in cost-benefit analyses. In this paper we demonstrate by a distribution system example that typical time variations of component failure rate, repair time, load and specific interruption costs can have a significant impact on the estimated annual interruption cost for delivery points in the system. This observation is possible by a model that can handle such time variations including correlation between the parameters. An interesting application of this model is to quantify the consequence of for example moving planned maintenance to periods when the load and the interruption cost is low.

Index Terms—energy not supplied, interruption costs, power system economics, power system reliability

I. INTRODUCTION

Around the world there is an increased focus on the quality of service as well as cost-effectiveness. The last aspect might over time lead to declined reliability of supply. To counteract such possible consequences, there is a trend that the distribution network companies become subject to regulation considering quality of service [1]. One example is the Norwegian regulation scheme CENS ('Cost of Energy Not Supplied') where the network companies’ revenue caps are adjusted in accordance with the customers’ interruption costs [2]. For each network company the expected amount of CENS is determined as the product of the annual expected energy not supplied (ENS) and a specific interruption cost (c) in NOK/kWhENS. Therefore, to obtain a credible quality regulation scheme, adequate interruption cost assessment becomes very important.

By the introduction of CENS from 2001, the customer interruption costs have become essential risk factors for the network companies. The main objective of CENS is to give the companies incentives to build, operate and maintain the power system in a socio-economic optimal way [2]. In this context it is of high importance to be able to predict future interruption costs, using methods for reliability assessment. Methods taking time variation in the different input parameters into account are previously developed and described in e.g. [5, 9]. These are both analytical and Monte Carlo methods. The models are able to represent time variation in failure rates, repair times and specific interruption costs as well as loads. An analytical approach is described in [5] using statistical based time dependent patterns of the failure rates. In [6] a comparison is given of this approach with a time sequential simulation approach where the failure rates are represented for different weather states. These two approaches were demonstrated for a transmission system and local area in the south of Norway. It is found that the time variation may be of high importance in transmission systems as there might be a positive correlation between the failure rate and the peak load periods, increasing the probability of interruptions to end consumers.

This paper addresses interruption cost assessment in distribution systems and the impact of taking time variation of the different parameters into account. The CENS arrangement is described in [2, 3]. A brief description is given of the methods for interruption cost assessment where time of occurrence of interruptions is taken into account. Examples of time variations in the input data are presented. The effect on expected energy not supplied (EENS) and the annual interruption cost (EIC) is demonstrated for a 12 kV distribution system in the supply area of Trondheim Energy Company (TEV).

II. INTERRUPTION COST ASSESSMENT

The CENS arrangement comprises long interruptions (> 3 minutes) due to forced outages and planned disconnections in electrical installations > 1 kV. The customers are divided into two groups: Residential/Agricultural and Commercial/Industrial end-users. The regulation authority has decided that in the first stage constant specific costs equal to 4 NOK/kWhENS and 50 NOK/kWhENS respectively should be used for non-notified interruptions. For interruptions where customers are given advance notice, the cost figures are reduced to 3 NOK/kWhENS and 35 NOK/kWhENS respectively.
These cost rates are based on the information from a customer survey performed in 1989 – 1991 [1, 10]. However, they do not reflect the annual, weekly and daily variation in the interruption cost. The CENS cost assessment is described in [7] where it is pointed out that the interruption costs depend on the time when an interruption occurs, see the example for industrial customers in Figure 1.

![Figure 1](image)

Figure 1. Daily variation in interruption cost for the industrial sector in Norway. Deviation in % from the cost in NOK per interruption at reference time: Thursday in January at 10 am.

Neglecting the time variation in the specific interruption costs (NOK/kWh\text{ENS}) may significantly influence the calculation of the annual interruption costs. Using the constant cost figures the total annual CENS amount for Norway can be estimated to about 710 million NOK (based on five years of interruption statistics). Information as shown in Figure 1 can be used together with typical load curves to determine annual average cost rates [7], see below. In that case a rough estimate of the annual CENS-amount for Norway would be about 960 million NOK (35 % higher). This example indicates that the time variation in the interruption cost may be significant in the assessment of the annual interruption cost.

Will the interruption cost assessment in distribution systems be further influenced by the time dependent variation in failure rates, repair times and loads? These aspects can be studied using the models described in [5]. The expected annual energy not supplied (EENS) and annual interruption costs (EIC) due to forced outages are in the classical approach determined by the product of the expected values of the input parameters. It is shown in [8] that in distribution systems the time dependent correlation among the input variables can be handled by correction factors. The assessment of these correction factors is described in [5, 8]. Three different approaches for estimation of EIC for a load point is given in Equation (1):

\[
\begin{align*}
EIC_1 &= \lambda P r c_{\text{ENS}} \\
EIC_2 &= \lambda P r c \\
EIC_3 &= \lambda P r c k_{\text{pre}} \\
\end{align*}
\]

where

- \( \lambda \) = annual number of interruptions at the delivery point (numbers per year)
- \( p \) = annual average load at the delivery point (kWh/hour)
- \( r \) = average interruption time at the delivery point (hours/interruption)
- \( c_{\text{ENS}} \) = cost rate used for EENS (NOK/kWh\text{ENS})
- \( c \) = annual average cost rate (NOK/kWh\text{ENS})
- \( k_{\text{pre}} \) = correction factor (handling time variation) for the annual interruption cost

In the first expression \( EIC_1 \) is determined by the product of the expected ENS and constant CENS-rates. The second expression is the classical approach using the expected value \( 'c' \) (annual average) for the cost rate. In the third expression, the time of occurrence of interruptions is considered. That is, the time dependent correlation among the input variables is handled by the factor \( k_{\text{pre}} \). If this factor appears to be significantly different from 1.0, the classical calculation method (EIC2) will give inaccurate results for EIC. Similar expressions can be established for EENS [5, 8].

Equation (2) gives an expression for the annual average interruption cost rate \( 'c' \) for a customer group [7]:

\[
c = \frac{c_{\text{ref}}}{{f}_c} \frac{P_{\text{ref}}}{P}
\]

where

- \( c \) = annual average cost rate (NOK/kWh\text{ENS})
- \( c_{\text{ref}} \) = cost rate at reference time (Thu in Jan at 10 am)
- \( {f}_c \) = resulting correction factor for the cost in NOK/interruption
- \( P_{\text{ref}} \) = load at reference time (kWh/hour)
- \( P \) = annual average load (kWh/hour)

The correction factor \( {f}_c \) is a relative factor handling the resulting relative time variation in the interruption cost [5, 7]. The factor gives the deviation in the annual average cost from the cost estimated at the reference time in the customer survey. The expression for the annual average cost rate in NOK/kWh\text{ENS} therefore includes the relation between the load at the reference time and the annual average load (for a given interruption duration). Equation 2 and the expression for \( EIC_2 \) handle only the time variation in the interruption cost, while the resulting time dependent correlation among the variables is handled by the correction factor \( k_{\text{pre}} \) (in \( EIC_3 \)).

III. THE DISTRIBUTION CASE

A 12 kV feeder in the TEV distribution system is used to study the impact of the time variation, see Figure 2. The network consists of an overhead part supplying residential customers only and an underground cable part supplying some residential customers, some large commercial customers and a few industrial customers. It is a total of 28 delivery points (distribution transformers) in the network. The maximum load was 4.2 MW in 1995, where 90 % is supplied by the cable network.
The importance of taking time dependent correlation into account is demonstrated in this chapter for three delivery points, one residential (N3), one commercial (N7) and one industrial (N14) in the cable part of the system.

A. Time variation

There are essentially four parameters that determine the annual interruption costs: Failure rates (or number of planned disconnections), repair time, load and interruption cost rates. The fault statistics show that the failure rates and durations have cyclical patterns due to seasonal/climatical and social variations. A large portion of the incidents occurs in periods when the load as well as the interruption cost is high. TEV's fault and interruption statistics for the period 1995-2000 shows for instance that 50% of the forced outages and 80% of the planned disconnections occur during working hours (08-16), see Figure 3. As much as 97% of the planned disconnections are performed on working days (Mon - Fri), while 78% of the forced outages occur in the same period of the week.

The table shows that there is a strong positive correlation between the number of incidents and the absolute interruption cost (in NOK/interruption) on a weekly and daily basis. On the other hand there is a negative correlation between duration and cost in some periods, meaning that interruptions with the longest durations often take place in low load and low cost periods. For planned disconnections there is a relatively strong negative correlation on a monthly basis between duration and cost. Positive correlation between some variables may therefore be counteracted by negative correlation between others. The resulting time dependent correlation is discussed in the following sections.

B. Forced outages

Table 2 gives the cost and load data for the chosen delivery points. The correction factors taking the time dependent variation into account, and results for EENS<sub>2</sub> and EIC<sub>2</sub> due to forced outages are also shown in the table. The delivery points experience on average 1.2 interruptions per year due to forced outages.
interruptions, while the annual interruption time is 0.7 hour/year.

### Table 2
**DATA AND RESULTS FOR THE EXISTING SITUATION (2000), FORCED OUTAGES**

<table>
<thead>
<tr>
<th>Delivery point</th>
<th>N3 Res</th>
<th>N7 Com</th>
<th>N14 Ind</th>
</tr>
</thead>
<tbody>
<tr>
<td>CENS-rate NOK/kWh&lt;sub&gt;EENS&lt;/sub&gt;</td>
<td>4</td>
<td>50</td>
<td>50</td>
</tr>
<tr>
<td>f&lt;sub&gt;0&lt;/sub&gt;</td>
<td>0.51</td>
<td>0.84</td>
<td>0.75</td>
</tr>
<tr>
<td>P&lt;sub&gt;av&lt;/sub&gt;/P&lt;sub&gt;0&lt;/sub&gt;</td>
<td>1.96</td>
<td>1.84</td>
<td>1.99</td>
</tr>
<tr>
<td>Average load in 2000 (P in kWh)</td>
<td>110</td>
<td>210</td>
<td>190</td>
</tr>
<tr>
<td>EENS&lt;sub&gt;1&lt;/sub&gt; (kWh/year)</td>
<td>78</td>
<td>150</td>
<td>135</td>
</tr>
<tr>
<td>EIC&lt;sub&gt;c&lt;/sub&gt; (NOK/year)</td>
<td>313</td>
<td>111538</td>
<td>8074</td>
</tr>
<tr>
<td>k&lt;sub&gt;Pav&lt;/sub&gt; (Eq. (2))</td>
<td>1.15</td>
<td>1.16</td>
<td>1.13</td>
</tr>
<tr>
<td>k&lt;sub&gt;Pr&lt;/sub&gt;</td>
<td>1.15</td>
<td>1.08</td>
<td>1.09</td>
</tr>
</tbody>
</table>

1) 8 NOK

The relative annual interruption costs using the three different approaches in Equation (1), are shown in Figure 5 for forced outages. The annual average cost ‘c’ is found using Eq. (2) with CENS-rates and the relative cost and load variation from Table 2.

Figure 5 shows that the estimate of the annual interruption cost EIC<sub>c</sub> (see Eq. (1)) is more than 50 % higher for the commercial load than EIC<sub>c</sub> (the CENS-cost). The difference is 20 % for the industrial load, while there is no difference for the residential load. This is due to the assumption of a constant annual cost rate for these kinds of loads. These results indicate that the CENS arrangement significantly underestimates the annual interruption cost. The additional time dependent correlation between the variables is however less important.

As can be observed from Table 2 and Fig. 5, this correlation counts for about 8 - 16 % for EENS<sub>1</sub> and EIC<sub>c</sub> (compared to EENS<sub>2</sub> and EIC<sub>c</sub>) due to forced outages, for these examples. This means that the factors k<sub>Pav</sub> and k<sub>Pr</sub> equals about 1.08 – 1.16. Using other data one might reach different conclusions. It is therefore interesting to note that in the study reported in [9] the authors have found a significant impact on the expected energy not supplied and the annual interruption cost, especially from time varying restoration times in different weather states (looking at forced outages).

### C. Planned disconnections

Planned disconnections are accomplished to perform maintenance work, repair and so on. The customers are usually notified in advance. If so, the CENS arrangement allows for lower cost rates [2]. If we look at the time variation in planned disconnections we get somewhat different results from the previous section. Table 3 gives the cost rates and results for the three delivery points. It is assumed that the relative cost variation is equal to the variation caused by forced outages, and it is assumed that the customers are given advance notice. The delivery points experience on average 1.1 interruptions per year due to planned disconnections, while the annual interruption time is 1 hour/year.

### Table 3
**DATA AND RESULTS FOR THE EXISTING SITUATION (2000), PLANNED DISCONNECTIONS**

<table>
<thead>
<tr>
<th>Delivery point</th>
<th>N3 Res</th>
<th>N7 Com</th>
<th>N14 Ind</th>
</tr>
</thead>
<tbody>
<tr>
<td>CENS-rate NOK/kWh&lt;sub&gt;EENS&lt;/sub&gt;</td>
<td>3</td>
<td>35</td>
<td>35</td>
</tr>
<tr>
<td>EENS&lt;sub&gt;1&lt;/sub&gt; (kWh/year)</td>
<td>105</td>
<td>200</td>
<td>180</td>
</tr>
<tr>
<td>EIC&lt;sub&gt;c&lt;/sub&gt; (NOK/year)</td>
<td>314</td>
<td>10847</td>
<td>7616</td>
</tr>
<tr>
<td>k&lt;sub&gt;Pav&lt;/sub&gt;</td>
<td>1.12</td>
<td>1.21</td>
<td>1.41</td>
</tr>
<tr>
<td>k&lt;sub&gt;Pr&lt;/sub&gt;</td>
<td>1.12</td>
<td>1.23</td>
<td>1.27</td>
</tr>
</tbody>
</table>

1) 8 NOK.

Figure 6 shows the relative interruption costs from Eq. (1) caused by planned disconnections, for the commercial and industrial delivery points. The relative difference between EIC<sub>c</sub> and EIC<sub>c</sub> is the same as in Fig. 5 due to the above assumption of equal relative time variation. The figure and Table 3 however, clearly indicates that the additional time dependent correlation is of high importance for planned disconnections. The correction factors are now in the range of 1.2 – 1.4 for EENS<sub>1</sub> and EIC<sub>c</sub>, giving about 20 % higher annual interruption costs and up to 20 – 40 % higher EENS compared to the estimates of EIC<sub>c</sub> and EENS<sub>2</sub> respectively. The reason for these results for planned disconnections can be found from the TEV statistics (see Fig. 3) and the fact that the planned disconnections have been conducted during the heavy
load periods when the interruption costs are highest. This is illustrated in Figure 7 for the commercial load, marking that about 50% of the interruption cost occur during the period from 08 – 12 a.m.

To answer the above question this societal benefit will have to be traded off against the extra cost of letting the crew work in the afternoon and during the night instead. This is not further investigated in this case, but the example illustrates that it is important to take time variation into account in the interruption cost assessment to find the socio-economic optimal solutions. The methods reported in [5-8] can be used to investigate the impact of time variation.

IV. DISCUSSION AND CONCLUSIONS

Using the constant interruption cost rates (CENS) will significantly underestimate the annual interruption cost compared to taking the average cost variation into account. Neglecting this variation with time of occurrence of interruptions may lead to a mismatch between business economics and socio-economic criteria. However, the additional time dependent correlation among the different variables seems to be of less importance for interruptions due to forced outages (8-15%). For planned disconnections the additional time dependent correlation accounts for up to 27% for the commercial load. Using other data one might reach different conclusions.

Balancing cost-effectiveness and quality of service is one of the most important tasks for network companies in the deregulated environment. It is widely recognized that interruption costs is a relevant expression for the inconvenience customers feel when service is interrupted and that adequate assessment of such costs is crucial when they are used quantitatively in cost-benefit analyses. From the Norwegian interruption cost survey we found significant time dependence of the costs, for non-notified as well as for notified interruptions. Typical average time dependent patterns are also found from component fault and repair statistics, and it is well known that load varies with time. Therefore, to make a realistic assessment of annual interruption costs the possible influence of these time dependent patterns, including correlation should be investigated.

In this paper we have used data for a typical 12 kV distribution system in Norway. For comparison three alternative calculations are made:

1. The simplified quality regulation scheme implemented by the Norwegian regulator from January 2001 (CENS). No time dependence is included in the calculation.
2. Only time dependence of interruption costs is included, together with average values of the other parameters.
3. Time dependent correlation between failure rate, repair time, load and interruption costs is taken into account.

Except may be for residential consumers it is quite clear that ignoring time dependence and correlation leads to significant
underestimation of annual interruption costs. For commercial and industrial consumers correlation seems to have significant impact, particularly for planned interruptions.

Moving planned maintenance to nights and weekends when customer interruption costs are considerably lower may be an instrument to reduce these costs, and the results shown in the paper support this idea. It should be noted that this maintenance policy is assumed to increase the costs for the company, and in this paper we have not included this aspect.

Anyway, using the available data from Trondheim Energy Company we have found that influence from time dependence and correlation is significant. Having a model that can take this into account is a necessity to analyse and compare different maintenance policies and also to make a realistic assessment of annual interruption costs in general.

We believe that in the future the regulation schemes implemented by the regulator in order to counteract a possible degradation of quality due to cost-effectiveness will have to include adequate models for interruption cost assessment. The current scheme introduced in Norway is only a first beginning, and as can be seen from the analysis in this paper the scheme is too simplified. But the fact that it has been put in operation has already had a remarkable impact on the way the companies are thinking about the future. Reliability and associated costs are now issues that are being quantitatively implemented in decision processes. We also believe this is a worldwide tendency as data collection schemes and models to apply these data are being further developed. The recently published CIGRE Report [1] provides a basic reference for future international co-operation and work within this area.

VI. REFERENCES

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VI. BIOGRAPHIES

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