ASSESSMENT OF COST RELATED RELIABILITY OF POWER SYSTEMS

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ABSTRACT

Cost/benefit analysis of power systems is becoming an essential factor in the determination of system reinforcement and expansion projects, due to the impact of electric utility deregulation and market competition. Economics play a major role in the application of reliability concepts and the attainment of an acceptable level of reliability. Inadequate reliability of electric power supply ultimately costs the customers much more than good reliability. It is therefore important to determine the optimal reliability level at which the reliability investment achieves the best results in reducing the customer damage costs due to power supply interruptions.

This paper describes the basis concepts required for system reliability cost/benefit analysis. The basic approach is to minimize a total cost composed of the overall investment cost and the customer damage cost. The customer damage cost is a function of interruption frequency, duration, load lost, location, and other societal effects.

System studies conducted on a part of Alexandria electricity distribution network are presented which provide insight into the variation of the indices with different system factors.

INTRODUCTION

Power system planning is traditionally based on deterministic criteria. A generally used criterion is that the loss of any single generating unit or transmission line should not cause load interruption. This criterion does not explicitly consider the probability of component failures and the value of service to customers. It can therefore result in overbuilt systems due to low probability events.

The criterion provides no economic input to the cost associated with a particular expansion plan in terms of the value of service provided to customers. Deterministic approaches are not sufficiently responsive to conflicting factors in the emerging competitive power supply environment.

System reliability normally increases with investment cost. On the other hand, the customer damage cost decreases as the reliability level increases. The total cost is the sum of the project and customer damage costs. This total cost exhibits a minimum, at which an optimum or target level of reliability is achieved.

The cost/benefit approach uses the total cost as a basis for ranking the system expansion alternatives. The approach can be: minimize the total cost which is the sum of investment cost and the customer damage cost. Where, the investment cost includes the capital cost and the operation/maintenance cost, the customer damage cost reflects the value of unsupplied energy.

The investment cost is basically deterministic in nature and can be obtained using well-established methods. The customer damage cost is conceptually the aggregated value the customers are willing to pay to avoid load interruptions or voltage standard violations, and is a function of interruption frequency, duration, load lost, location and other social effects.

The calculation of the customer damage cost is a necessary and complex task in reliability cost/benefit analysis. The technique to calculate the customer damage cost and the application of the technique are developed and illustrated. The data for calculating the customer damage costs used in this paper come from the surveys conducted by Alexandria Electricity Distribution Company (AEDC).

CONCEPT OF CUSTOMER DAMAGE FUNCTION

A customer damage function (CDF) provides the interruption cost versus interruption duration for a specified group of customers.

Table 1 shows interruption cost data in the form of sector CDF. Five sectors were identified for data collection. The five sectors are: industrial, commercial, government& institutions, residential and agricultural

<table>
<thead>
<tr>
<th>User sector</th>
<th>Interruption duration</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>1 min</td>
</tr>
<tr>
<td>Industrial</td>
<td>6.26</td>
</tr>
<tr>
<td>Commercial</td>
<td>1.26</td>
</tr>
<tr>
<td>Gov.&amp; Inst.</td>
<td>0.19</td>
</tr>
<tr>
<td>Residential</td>
<td>0.01</td>
</tr>
<tr>
<td>Agricultural</td>
<td>0.23</td>
</tr>
</tbody>
</table>

The five sectors are graphically shown in Fig.1

The Composite Customer Damage Function (CCDF) represents the total interruption cost as a function of the interruption duration for the combined customers in a particular service area.

The CCDF for a service area is obtained by weighting the sector CDF by the customer load composition for that area.
Fig.1. Sector customer damage functions (LE/kW)

The customer load compositions in terms of peak load and energy consumption percentages must be known in order to obtain the CCDF for the combined customers. The annual peak load percentage is usually used for weighting short durations (below 1 hour), and the annual energy consumption percentage is used for weighting the longer durations.

Table 2 shows the load compositions in terms of:
1- The annual peak percentage
2- The energy consumption percentage
For a part of Alexandria Electrical System.

Table 2 Load Compositions for the study area

<table>
<thead>
<tr>
<th>User Sector</th>
<th>Sector Peak%</th>
<th>Sector Energy %</th>
</tr>
</thead>
<tbody>
<tr>
<td>Industrial</td>
<td>25</td>
<td>28</td>
</tr>
<tr>
<td>Commercial</td>
<td>8</td>
<td>7</td>
</tr>
<tr>
<td>Gov.&amp; Inst.</td>
<td>6</td>
<td>9</td>
</tr>
<tr>
<td>Residential</td>
<td>57</td>
<td>53</td>
</tr>
<tr>
<td>Agricultural</td>
<td>4</td>
<td>3</td>
</tr>
</tbody>
</table>

The Composite Customer Damage Function (CCDF) for the study area is obtained as shown in Table 3, and is shown graphically in Fig.2.

Table3.CCDF in (LE/kW) for the study area

<table>
<thead>
<tr>
<th>AEDC Study Area</th>
<th>Interruption duration</th>
<th>Total Customer Cost (LE/kW)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>1 min</td>
<td>20 min</td>
</tr>
<tr>
<td>Industrial</td>
<td>6.26</td>
<td>0.25</td>
</tr>
<tr>
<td>Commercial</td>
<td>1.26</td>
<td>0.08</td>
</tr>
<tr>
<td>Gov.&amp; Inst.</td>
<td>0.19</td>
<td>0.06</td>
</tr>
<tr>
<td>Residential</td>
<td>0.01</td>
<td>0.57</td>
</tr>
<tr>
<td>Agricultural</td>
<td>0.23</td>
<td>0.04</td>
</tr>
<tr>
<td>Total Customer Cost (LE/kW)</td>
<td>1.69</td>
<td>4.51</td>
</tr>
</tbody>
</table>
incorporated in the calculation. In this direct approach, the available capacity at the system state $s_i$ is first obtained and then combined with the load duration curve to obtain the expected load curtailment.

The equation for the EENS using the direct approach is:

$$EENS = \sum_{s_i \in S} \left( \frac{P_{s_i}}{\sum_{L_j > C_{s_i}} (L_j - C_{s_i})} \right) \text{MWh / year} \quad (4)$$

Where:

- $S$: the set of all investigated system states
- $L_j$: the hourly peak load in one year at a specific load bus in system state $s_i$
- $C_{s_i}$: the available capacity at the specific load bus in system state $s_i$.

The equation for the annual ECOST can be derived from the annual EENS equation in the same way as that for the annualized ECOST. In this situation, as the system state $s_i$ is not a complete failure state using a single constant load, the expected system state failure duration $d_{f,s_i}$ is used for the interruption cost calculation.

The annual ECOST is given by:

$$ECOST = \sum_{s_i \in S} \left( \frac{\mu_{s_i} + \lambda_{s_i}}{L_j > C_{s_i}} \right) \left( d_{f,s_i} \left( L_j - C_{s_i} \right) \right) / 8760 \text{ kLE/year} \quad (5)$$

Where:

- $d_{f,s_i} = \sum_{L_j > C_{s_i}} \left( \frac{\mu_{s_i} + \lambda_{s_i}}{C_{s_i}} \right)$ is the hours in which the load is greater than the available capacity at a specific load bus in system state $s_i$.

The ECOST analysis was applied to a part of Alexandria Electrical system. The results are shown in Fig.3. Fig.3. shows the system ECOST at different load levels for the part of Alexandria electrical system.

The graph shows that the system ECOST decreases rapidly when the load level decreases from 260 to 208 MW and does not vary significantly when the load level decreases from 208 to 130 MW.

### INTERRUPTED ENERGY ASSESSMENT RATE (IEAR)

An often used index in reliability cost analysis is the interrupted energy assessment rate (IEAR), which is calculated as the ratio of ECOST and EENS.

$$IEAR = \frac{ECOST}{EENS} \text{ (LE / kWh) } \quad (6)$$

The IEAR is a convenient and readily understandable index, which provides a momentary evaluation of energy deficiencies for the system from a customer damage cost point of view.

The results of IEAR analysis for the part of Alexandria electrical system are shown in Fig.4.

Fig.4. indicates that the IEAR index is quite stable with respect to load level variations.

### CONCLUSIONS

The paper illustrates the essential techniques and philosophy of reliability cost/benefit analysis in power systems. The customer damage cost is a function of interruption frequency, duration, load lost, location and other societal effects.

The paper illustrates the calculation of the ECOST (Expected Customer Damage Cost) and related IEAR (Interrupted Energy Assessment rate) indices in power systems.

The data used to calculate the ECOST and IEAR come from surveys conducted by the study group. The ECOST and IEAR of a part of Alexandria electrical system were calculated for the system under various conditions. The
The results show that the ECOST decreases rapidly with reduction in load level. The ECOST can be very large and very sensitive to system load level variations, when the system load level is relatively high. The system studies show that the IEAR index does not change significantly with variation in system load level.

REFERENCES


