TECHNICAL FEASIBILITY AND COST BENEFIT ANALYSIS OF NETWORK LOSS REDUCTION OPPORTUNITIES IN THE UK ISLE OF WIGHT 11 KV NETWORK

Sarat Chandra VEGUNTA, Mick BARLOW  
S&C Electric Europe Ltd – UK  
sarat.vegunta@sandc.com

David HAWKINS  
LIG Consultancy  
davehawkins@iee.org

Alistair STEELE, Stewart A REID  
Southern Electric Power Distribution plc – UK  
alistair.steele@sse.com

ABSTRACT

This paper summarizes the technical feasibility and cost benefit analysis of a range of electrical losses reduction interventions in the Isle of Wight (IoW) 11 kV distribution network in the UK.

INTRODUCTION

Electrical losses represent about 6% of the total energy transmitted in the UK distribution system [1]; these losses currently cost around £1 billion a year and account for 1.5% of all greenhouse gas emissions in the UK [2]. Distribution Network Operators (DNO) in the UK are obliged to design and operate their networks efficiently [3][4] and participate in reducing the carbon footprint of their operations, thus helping reduce cost to customers and the UK reach its carbon reduction targets by 2020. Traditionally, DNOs in the UK have reduced losses through long-term asset management, replacing end of life assets with energy efficient models; with the introduction of the EU’s Ecodesign Directive 2009/125/EC in 2009 [4], this has become mandatory for utilities. In addition, the UK’s gas and electricity regulator ‘Ofgem’, recognizing the importance of network loss reduction, has included a new licence obligation on DNOs to reduce losses to “as low as reasonably practical” from April 2015.

This paper summarizes a technical feasibility study and cost benefit analysis of potential network interventions to reduce 11 kV distribution network electrical losses. A comprehensive set of network interventions were considered, studying each intervention’s technical and cost-benefits benchmarked against a Business as Usual (BaU) network.

NETWORK MODELLING

Isle of Wight Network Model

Isle of Wight is the second largest island of England, and is located in the English Channel about the coast of Hampshire and is separated from mainland Great Britain by the Solent. The IoW island electrical network (wholly owned and operated by SSEPD Ltd) is supplied from the UK mainland via a 132 kV ring circuit, connecting the 132 kV Fawley Central Grid Supply Point (GSP) and 132 kV Langley GSP on the mainland with the 132 kV Cowes and 132 kV Wootton Common GSPs on the island. Its 11 kV network is an extensive part of SSEPD’s Medium Voltage (MV) distribution network, connecting local private loads/generators, commercial, small-scale industrial and domestic load centres. An electrical network model of this network was developed in DIgSILENT PowerFactory software as detailed in Fig. 1.

Half-hourly 11 kV load data at each of IoW’s primary substation feeders for the entire year was used in the model with feeder power factors assumed to be typical (0.95 lagging/inductive). Each half-hour feeder load was distributed among the 11 kV/LV substations along the feeder; and was maintained the same for each considered intervention. Two typical days (weekday and weekend) of feeder load data for each of the four seasons (winter, spring/autumn, summer and high summer) in a year were used to generate annual study results while maintaining computation time at a reasonable level.

Considered Network Interventions

- Case 1: Base network configuration.
- Case 2: Network automatic reconfiguration.
- Case 3: Meshed network operation.
- Case 4: Transformer automatic switching.
- Case 5: Incorporating energy storage using either Lithium ion (Li-ion) (5a) or Sodium Sulphur (NaS) (5b) based storage.
- Case 6: Conservation Voltage Reduction (CVR). Case 6a: load without voltage dependency and Case 6b: load with unity voltage dependency.
- Case 7: Network voltage upgrade.
- Case 8: Combination of Case 3 and Case 4; the two most favourable cases from a Return on Investment.
(RoI) point of view.

Technical Assumptions

- Base network configuration (BaU network): All 11 and 33 kV network switches were assumed to be fixed (open/closed) during studies.
- Network automatic reconfiguration: This was a variation of the meshed network operation (Case 3) where a Normally Open Point (NOP) was relocated through the deployment of remote control (involving some means of group or centralised logic and control) switchgear. CBA studies did not include the cost of specialized software (e.g. sequence switching scripting by DMS) that enables continuous network reconfiguration.
- Network meshed operation: All IoW 11 kV network switches were assumed to operate ‘closed’.
- Transformer automatic switching: Assesses the effectiveness of de-energising one of a pair of 33/11 kV transformers when this delivers a net losses reduction. Additional 33 kV switchgear was included where required.
- Incorporating energy storage: Energy storage devices were strategically placed close to load centres along 20% of feeders that exhibit highest electrical losses. There will be no short-circuit contribution from battery storage systems. Feeder load forecasting was assumed available.
- CVR: Inline Voltage Regulators (VR) were placed on 20% of feeders with highest electrical losses close to load centres. The study did not include costs for any specialized software/controllers.
- Network voltage upgrade from 11 to 22 kV was considered. For overhead line circuits, it was assumed that only the cross-arms and insulators will be replaced. Replacement cable circuits were included at typical budget costs. For primary and secondary transformers, when upgrading from 11 to 22 kV, only the MV voltage rating on these transformers was changed with the remaining electrical parameters maintained the same.
- Network meshed operation with transformer automatic switching: Considers combination of assumptions for Case 3 and 4.

CBA Assumptions

- The CBA used the Ofgem RIIO-ED1 CBA spreadsheet [6]. Costs of equipment and related works to implement each intervention was based on both publically and internal available data.
- A 45-year assessment period (2016 to 2060) was assumed. The capital cost to refresh switchgear was included where appropriate.
- Discount rates at 3.5% Social Rate of Time Preference for ≤30 years and 3% for >30 years.
- Per MWh loss value (10 gCO2e/kWh by year 2050) over the study period was set according to the OFGEM/DECC forecast for electricity supply decarbonisation [6].

STUDY METHODOLOGY

The methodology used in undertaking studies presented here are given below.

Technical and Cost-Benefit Metrics

For each case study or intervention, time dependent load-flow and short-circuit studies were undertaken for the selected annual representative days. The study results were aggregated and annualised. Other network operational and performance aspects (also listed below) were captured for each network intervention based on authors’ expert opinion. The CBA performance metrics (listed below) for each intervention were assessed for three network load growth rates (low, medium, and high).

Network technical metrics, based on:
- Detailed studies: Power losses, voltage profile, equipment thermal loading, short-circuit level.
- Expert opinion: voltage step-change, reliability and protection, risks and constraints.

Cost-benefit metrics, based on:
- Ofgem CBA spreadsheet: capital investment, avoidable DNO costs, non-DNO benefits, and net (and cumulative) benefits.

Technical Assessment Methodology

- The base network model consists of existing network 11 kV load and DG levels.
- The base network configuration model was adopted and intervention specific assumptions and modelling aspects were applied individually.
- Half-hourly load-flow and short-circuit simulations were undertaken for eight representative days.
- Network performance metrics were obtained and aggregated, and potential network operational risks, violations, constraints and additional equipment were identified; outputs from this assessment were then used in CBA studies.
- Technical analysis and CBA outputs for each intervention were then compared against those obtained from BaU network.

RESULTS AND DISCUSSION

Analysis results from the technical and CBA studies are summarised below.

Case 2: Network Automatic Reconfiguration

In comparison to the base case, no more than a 0.7% reduction in overall losses was achieved over 45 years. The value of these losses was significantly reduced through the need to deploy high-speed 11 kV pole-mounted or pad-mounted switchgear plus control equipment. In addition, the increase in overall fault
levels, may reduce the opportunity to connect additional DG at MV.

Depending on the level of considered network loss growth rates, the 45-year carbon savings were estimated to range between 1.7 and 3.0 ktCO2e. Over the 45-year study period this intervention resulted in a negative RoI.

### Table 1 - Annualized Network Intervention Technical Performance

<table>
<thead>
<tr>
<th>Metric</th>
<th>Intervention Metric Performance for Compared Cases</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Case 1</td>
</tr>
<tr>
<td></td>
<td></td>
</tr>
<tr>
<td>Electric Load Energy Cost [ Cov ]</td>
<td>588.29</td>
</tr>
<tr>
<td></td>
<td>100%</td>
</tr>
<tr>
<td>Electric load **</td>
<td>0.9%</td>
</tr>
<tr>
<td>Carbon emissions [ tCO2e ]</td>
<td>1.0%</td>
</tr>
<tr>
<td>Voltage profile **</td>
<td>0.07%</td>
</tr>
<tr>
<td>Max. Transmission Loss [ kV ]</td>
<td>57.27</td>
</tr>
<tr>
<td>Short circuit currents **</td>
<td>0.0%</td>
</tr>
</tbody>
</table>

* Values in % (blue text) were calculated as: $\text{[Case/Case 1]} \times 100$

** Positive % value indicates reduction in metric value from the base case, and a negative value for increase.

### Case 3: Network Meshed Operation

This intervention was identified to be among those achieving high network loss savings. In comparison with the base case, a 1.7% reduction in 45-year losses on the study network was estimated. The net value of these losses will be reduced where additional network CAPEX are required to enable this intervention. A meshed arrangement may also increase overall fault levels, reducing the opportunity to connect additional DG.

This intervention will require the lowest investment among all study cases, estimated at £0.07 million accounting for upgrading two existing 11 kV switches, due to fault level. The cumulative benefits NPVs range between £0.8 and £1.4 million. However, the results show that the intervention has the best RoI among considered interventions. The carbon savings are estimated to range between 4.0 and 7.1 ktCO2e. Investment payback occurs between 4 and 5 years after the CBA base year 2016.

### Case 4: Transformer Automatic Switching

Results indicate potential annual savings of 9% of 11 kV network electrical losses. Fault levels are generally lower throughout the MV network and this may mean that additional distributed generation can be connected without reinforcement. However, repeated energisation or de-energisation of system transformers may lead to a reduction in asset lifetime, voltage disturbances and short-term interruptions. This requires further analysis, and more detailed costs assessment of any additional 33kV switchgear, SCADA/DMS sequence switching, and on-line transformer monitoring.

The intervention will require a moderate investment of £0.8 million, with cumulative benefits NPVs ranging between £2.9 to 7.4 million. The carbon savings are estimated at between 21.8 and 38.5 ktCO2e. Investment payback occurs between 8 and 9 years after the base year 2016.

### Case 5: Incorporating Energy Storage

A generic storage model was created in PowerFactory and two different technology costs were modelled in the CBA (Li-ion and NaS). This means there is one estimate of technical benefits (losses, etc. for Case 5 in Table 1) with two estimates of commercial impact (costs, etc. for Case 5 in Table 2).

The study estimates that the gross annual demand increases by 650 MWh, while the losses decrease by 114 MWh. This is the lowest loss saving achieved in considered scenarios (Case 2 to 8). In order to achieve this reduction in losses, ranging from 1 to 9 MWh, are required. These storage units are less than 100% efficient, therefore, the total annual demand on the island increases above that for the base case.

From the network fault performance point of view, the battery storage units were assumed neither to provide any additional interruption or cause any change in network reliability. In practice it is likely that additional battery storage devices may give rise to additional interruptions.

This intervention is also among the most expensive investment options, ranging between £65 to £145 million depending on the type of storage technology (Li-ion or NaS) selected. The cumulative benefits NPV over 45-years is negative. In addition, the cumulative carbon saving achieved using this intervention is the lowest.
among all considered interventions, ranging between 1.0 and 1.8 ktCO2e. The results for this intervention, from a network losses reduction point of view, have shown no RoI during the considered 45-year assessment period. To deploy storage just for loss reduction would be uneconomic and it would be necessary to realise additional revenue streams to make storage viable.

**Case 6: Conservation Voltage Reduction**
Non-voltage dependent load case (Case 6a) increases total annual demand by about 0.2% (estimated 806 MWh) with a decrease in calculated annual losses of 634 MWh. Voltage dependent load modelling (Case 6b) decreases total annual demand by 14.6 GWh, or 2.5%, while estimated annual losses were calculated to decrease by 1.4GWh.

This intervention will require a moderate investment of about £0.8 million. Depending on actual load voltage dependency and network losses growth during the 45-years, the cumulative benefits NPV can range between £0.03 million and £3.8 million. The carbon savings were estimated to range between 5.8 and 22.7 ktCO2e. With no load voltage dependency, a positive RoI only occurs with the high network loss growth rate. For near unity load voltage dependency, payback is expected to occur between 12 and 17 years after project commencement.

**Case 7: Network Voltage Upgrade**
This intervention is among the most effective in network losses and carbon savings from the base case and those indicating a positive RoI over reasonable timescales. However, some feeders may be totally or mostly overhead and this may also fit with reinforcement for renewable generation which is more likely in rural regions, e.g. PV farms and wind turbines. Although, the intervention offers significant savings in network losses savings compared to any other considered intervention (Case 2 to 8), the high investment costs outweigh any cumulative benefits over the 45-year period, with no expected RoI.

**Case 8: Meshed Network Operation with Transformer Automatic Switching**
This study is derived by combining the annualised results of meshed network operation (Case 3) and transformer automatic switching (Case 4). This intervention is the best of considered interventions from a losses reduction, carbon savings, and RoI point of view.

Further benefits of this case compared with transformer automatic switching case acting alone could include:
- Minimal impact on customer network performance during 11 kV feeder faults provided that the high-speed circuit breaker installed at the NOP will operate quicker than any ‘traditional’ feeder protection. This means that all feeder faults can continue to be treated as an open-ended protection scheme. This assumption requires further review.
- Minimal impact on customer network performance during system transformer failure. Each transformer will be operated in parallel with a neighbouring 33/11 kV substation, which will ensure the continuity of supply, albeit with a voltage depression at the time of transformer failure. Further analysis is required to confirm the severity of any voltage transients.

**DG Impact on Intervention Performance**
The impact of additional DG on interventions’ performance was studied. Addition of DG was found to increase total annual 11 kV electrical losses. Modelling of the embedded generation in Phase 2 studies was based on a best-guess of the point (and voltage) of connection to SSEPD’s network. This has given rise to possible voltage and overload issues, which would be resolved as a part of any new connection arrangement. However, the overall result with additional DG (losses and improvements due to interventions) in IoW 11 kV network is expected to remain similar to those with interventions discussed with existing load and DG levels.

**CONCLUSIONS**
Several interventions that indicate a positive RoI over reasonable timescales were identified. Among these, network interventions with significant electrical loss and carbon savings from the base case and those indicating a positive RoI were identified as following: meshed network operation with transformer automatic switching (Case 8), transformer automatic switching (Case 4), and CVR with unity voltage load dependency (Case 6b). The greatest loss reduction was found to be achieved in Case 7 (22 kV network upgrade), but the overall cost would likely prohibit this approach. Network meshed operation (Case 3) was found to give the quickest RoI, although the expected RoI and sensitivity to higher network losses growth rates is low. In comparison, Case 8 represents the same network intervention in combination with transformer automatic switching (Case 4) and is expected to give a greater RoI and improved sensitivity to higher network losses growth rates.

Among considered interventions, the transformer automatic switching (Case 4) alone or its combination (Case 8) with the meshed network operation case is found to be the optimal intervention solution (accounting for
both network technical and cost-benefit metrics offered by these interventions) in reducing 11 kV network losses.

REFERENCES


