SOLUTIONS FOR THE CONNECTION AND OPERATION OF DISTRIBUTED GENERATION

by

Allan Collinson, Fangtao Dai, Andy Beddoes and John Crabtree

(EA Technology Ltd)

Prepared under the DTI New & Renewable Energy Programme

July 2003
Introduction

A key objective for Workstream 3 (WS3) is to establish how to facilitate the connection to the distribution networks of distributed generation, without driving high reinforcement costs and without impairing the quality of supply to load customers.

The first stage of this project, to identify basic active network management solutions, was completed in 2002, with a report providing a first-pass review of currently available technical solutions. These solutions are either currently being used by Distribution Network Operators (DNOs) and distributed generators to overcome the technical issues associated with connecting distributed generation to electricity distribution networks, or are regarded as being available for deployment in the near future.

The solutions can be categorised in terms of managing fault levels, voltage levels and network power flows.

The focus of stage 1 of this project was to identify solutions that could be implemented in the short term, prior to 2005. Solutions that were considered to need significant changes to regulatory or commercial frameworks or required significant additional research and development were identified as longer-term solutions, outside the scope of this project, and were passed to Workstream 5 (WS5) which is looking at longer term solutions.

The objective of the second stage of this project has been to build on work of stage one, and further define the short-term solutions. This has been achieved by establishing the scope and extent of the issues associated with implementing the solution and then applying rollout strategies as appropriate.

Where there was agreement within Workstream 3 that the implementation issues for the particular solution could be readily addressed, the solution has been further described or developed. Where evidence of current network operator or generator practice exists, case studies have been presented, although for several of the solutions these have been difficult to find. Several references are made to other substantial projects, reflecting the position that several solutions are becoming available, rather than actually in broad use. In total these approaches provide the basis for the introduction of the solutions across GB.

Some of the solutions are straightforward and require no further description. Two groups of solutions will benefit from further guidance being prepared for application by the DNO Planning Engineer, and work on these has been put in hand. The two areas are the use of power flow management techniques for single generators (Table 3, Solutions 3a & 3b) and a range of voltage control solutions (Table 2, Solutions 3,4,5 & 6).

Three of the voltage control solutions (6,7 & 8) will require further information to come from proposed trials and development. Guidance for the application of Solution 6 on Cancellation CTs will be provided, and will be updated as information comes in from proposed future trials. Solutions 7 & 8 on Virtual VTs and active voltage control will require further information before planning engineer guidance can be prepared. Further information on these two will be provided from application of the VATech/Reyrolle MicroTapp product and the GenAVC trials.
respectively. The initial guidance on the earlier solutions can then be extended to include these.

In the case of three solutions for managing fault levels, (Table 1, solutions 4b, 5 & 6), the solutions were identified as having merit, but there were technical, commercial or regulatory issues that needed to be further understood and developed. Terms of Reference have been prepared for further study to better quantify the risks and reduce the uncertainty.

Solutions 4a & 4b for power flow management using both intertripping and short term ratings for networks comprising multiple generation sites, will be taken forward by Workstream 5, which is ready to develop a broader project incorporating this area.

**Recommendations & Way Forward**

The proposals for taking the solutions forward have been described above. The EATL report made four main recommendations and these are discussed here.

1. **To continue to promote the implementable solutions described in this report.**
   This paper has been presented to the EA Distributed Generation Support Group, recommending adoption of the implementable solutions by the DNOs. Where required, guidance will be prepared for the DNO Planning Engineers. It is expected that these solutions will be considered and discussed between DNO and Generator in connection applications.

   This report has been published on the DGCG website.

2. **To progress the further work required for the other solutions requiring further work.**
   Terms of Reference are being prepared and the process of placing contracts is underway for three solutions for managing fault levels.

   Trials to progress the understanding of the application of three voltage control solutions will be overseen by WS5, and thereafter written up into the extended voltage control guidance for Planning Engineers.

3. **To develop and confirm the process by which the evolving best practice within the industry can continue to be captured and disseminated.**
   The report will be referenced in the proposed FES Connection Guide. Continuing development may be managed under a DCRP programme.

4. **To encourage pilot projects where solutions have yet to be demonstrated.**
   Discussions will take place with FES as to which solutions would benefit from further trials. The three voltage control solutions fall into this category. Some of the fault level solutions may also require some trials for monitoring and experience of application.

Liaison will continue with WS5 on ‘Long Term Solutions’ to ensure an effective linkage of work, such that each solutions is progressed seamlessly across the two workstreams.
There are a number of regulatory issues to be addressed for those solutions that call for DNOs to operate their networks in a different manner to current practice. The issues will be raised and discussed in Workstream 3.
### Table 1: Short-term solutions for fault level management

<table>
<thead>
<tr>
<th>No.</th>
<th>Short-term solution for fault level management</th>
<th>Roll-out Strategy</th>
<th>Further Work</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Uprate network (replace switchgear)</td>
<td>1</td>
<td>None</td>
</tr>
<tr>
<td>2</td>
<td>Increase impedance of components</td>
<td>1</td>
<td>None</td>
</tr>
<tr>
<td>3a</td>
<td>Converter technology for wind turbines</td>
<td>1</td>
<td>None</td>
</tr>
<tr>
<td>3b</td>
<td>Converter technology for other generator types</td>
<td>Long-term</td>
<td>WS5</td>
</tr>
<tr>
<td>4a</td>
<td>Network reconfiguration (moving open points)</td>
<td>1</td>
<td>None</td>
</tr>
<tr>
<td>4b</td>
<td>Network reconfiguration (network splitting)</td>
<td>2</td>
<td>Terms of Ref (ToR)</td>
</tr>
<tr>
<td>5</td>
<td>Is Limiter</td>
<td>2</td>
<td>ToR</td>
</tr>
<tr>
<td>6</td>
<td>Sequential switching</td>
<td>2</td>
<td>ToR</td>
</tr>
<tr>
<td>7</td>
<td>Fault level management procedures, e.g. consistent interpretation of ER G74</td>
<td>1</td>
<td>Statements In LTDS</td>
</tr>
<tr>
<td>8</td>
<td>Active fault level management, e.g. re-configuration of the network. Based on actual generator presence and calculated fault levels</td>
<td>Long-term</td>
<td>WS5</td>
</tr>
</tbody>
</table>

### Table 2: Short-term solutions for voltage control

<table>
<thead>
<tr>
<th>No.</th>
<th>Short term solutions for voltage control</th>
<th>Rollout Scenario</th>
<th>Further Work</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Line re-conductoring</td>
<td>1</td>
<td>None</td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>Build a dedicated line or network</td>
<td>1</td>
<td>None</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>Generator reactive power control</td>
<td>1</td>
<td>Guidance</td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>Generator real power control</td>
<td>1</td>
<td>Guidance</td>
<td></td>
</tr>
<tr>
<td>5</td>
<td>Line voltage regulation e.g. a single regulator on a circuit</td>
<td>1</td>
<td>Guidance</td>
<td>Refer to K/EL/00302/00/00/REP</td>
</tr>
<tr>
<td>6</td>
<td>Cancellation CTs (Current Transformers)</td>
<td>1</td>
<td>Guidance</td>
<td>Further trials proposed in WS5</td>
</tr>
<tr>
<td>7</td>
<td>Virtual VT (Voltage Transformer)</td>
<td>1</td>
<td>Further trials proposed in WS5</td>
<td>Refer to VATech / Reyrolle MicroTAPP</td>
</tr>
<tr>
<td>8</td>
<td>Active voltage control e.g. remote voltage sensing Associated with a single generator</td>
<td>Long Term</td>
<td>WS5</td>
<td>Refer to GenAVC trials</td>
</tr>
</tbody>
</table>
Table 3: Short-term solutions for power flow management

<table>
<thead>
<tr>
<th>No.</th>
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<th>Roll-out Strategy</th>
<th>Further Work</th>
</tr>
</thead>
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<tr>
<td>1</td>
<td>Network Enhancement</td>
<td>1</td>
<td>None</td>
</tr>
<tr>
<td>2</td>
<td>Pre-fault Constraint</td>
<td>1</td>
<td>None</td>
</tr>
<tr>
<td>3a</td>
<td>Post-fault Constraint (intertripping) – single generator</td>
<td>1</td>
<td>Guidance</td>
</tr>
<tr>
<td>3b</td>
<td>Post-fault Constraint (dynamic, incl use of short-term ratings) – single generator</td>
<td>1</td>
<td>Guidance</td>
</tr>
<tr>
<td>4a</td>
<td>Post-fault Constraint (intertripping) – multiple generators</td>
<td>2</td>
<td>Develop in WS5</td>
</tr>
<tr>
<td>4b</td>
<td>Post-fault Constraint (dynamic, incl use of short-term ratings) – multiple generators</td>
<td>2</td>
<td>Develop in WS5</td>
</tr>
</tbody>
</table>

Table 4: Long term solutions previously identified in Stage 1 and passed to WS5

<table>
<thead>
<tr>
<th>Long term solutions for fault level management</th>
</tr>
</thead>
<tbody>
<tr>
<td>Non-linear limiting impedances</td>
</tr>
<tr>
<td>Add superconducting devices</td>
</tr>
<tr>
<td>Add switching devices – Solid–State &amp; low tech</td>
</tr>
<tr>
<td>Modify Fault Level Design Procedures (Review of G74: Long Term)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Long term solutions for solutions for voltage control</th>
</tr>
</thead>
<tbody>
<tr>
<td>Voltage Regulator (Integrated regulator: Long term)</td>
</tr>
<tr>
<td>StatCom</td>
</tr>
<tr>
<td>Active network voltage control</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Long term solution for power flow management</th>
</tr>
</thead>
<tbody>
<tr>
<td>Demand-Side Management</td>
</tr>
</tbody>
</table>
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K/EL/00303/00/01/REP
URN 03/

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The work described in this report was carried out under contract as part of the DTI New and Renewable Energy Programme, which is managed by Future Energy Solutions. The views and judgements expressed in this report are those of the contractor and do not necessarily reflect those of the DTI or Future Energy Solutions.

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1 Introduction

The term Distributed Generation (DG) embraces all electricity generation plants connected to a distribution network. However, many distributed generation plants employ smaller generators, producing electricity from renewable energy sources (i.e. wind, hydro, biomass, solar, etc.) or are small-scale combined heat and power (CHP) plants. These plants are often connected to essentially passive distribution systems at 33kV and below. It is at this level that new connection solutions are required and this forms the focus of this report.

The growth of distributed generation has increased since the privatisation of the ESI in 1990 and is now being further encouraged by the Governments’ climate change objectives. The Government’s 2010 targets for renewable and CHP generation, much of which will be DG, are:

- to produce 10% of the UK’s energy needs from renewable sources;
- to reach a total of 10GW of CHP generating capacity (an approximate doubling of current capacity).

These targets have been reinforced by the Government’s recent Energy White Paper. Aimed at creating a “low carbon economy”, the Government’s new energy policy will demand new thinking about energy supply. This in turn will lead to significant changes for electricity distribution networks in the UK.

Historically, the growth of distributed generation capacity in the UK has been restricted by three key factors:

- difficulties in obtaining planning consent;
- insufficient financial incentives;
- connection to the network.

The planning consents and financial incentives are being addressed elsewhere, and so this report is focused on the network connection issues.

Existing distribution networks have not been designed to accept extensive distributed generation. New technical challenges are presented in accommodating distributed generation onto the networks without incurring high reinforcement costs, and in ensuring that existing load customers are not adversely affected. In addition, until recently, the electricity industry’s commercial and regulatory framework has evolved without much consideration of its impact on the growth of distributed generation. Thus, significant technical, commercial and regulatory change will be required in order to achieve the targeted growth in distributed generation.

A superficial glance at some of our European neighbours, especially Germany and Denmark, shows that significant levels of distributed generation can be accommodated within electricity distribution networks. In Germany, generation capacity has recently been growing at approximately 1 GW per annum, with now over 10 GW of wind power having been installed. This equates to approximately 4% of total electricity consumption in Germany. In Denmark, wind generation capacity had reached over 2.5 GW by the end of 2001, against a total maximum demand of 6 GW. This significant growth rate in these two countries is primarily due to a supportive planning process combined with high levels of financial incentives for
generators. However, the financial cost to electricity consumers of achieving this growth has been high. It has also led to systems in those countries being overly reinforced.

In contrast, whilst the UK Government has similar aspirations for the growth in distributed generation capacity, it also wishes to minimise the economic impact on customers. Therefore the Government, in collaboration with the industry Regulator (Ofgem), is encouraging the use of innovation. The use of novel approaches is being encouraged to overcome the network connection issues, where the objective is to develop cost-effective solutions for the network connection of distributed generators. Thus, the concept of “Active Network Management” is being applied to network planning and operational processes in a move away from the conventional “fit and forget” network design methodology and towards a higher degree of network operational management. This transition from “fit and forget” to “active” networks is likely to be evolutionary rather than revolutionary. The first steps in this process involve the application of so-called “basic active network management” techniques in the short-term\(^1\), possibly leading to “full active management” in the longer term.

The challenge facing the UK electricity industry is to facilitate a major increase in the connection and operation of distributed generation capacity to match the environmental aspirations of the UK Government. This report forms part of the ongoing process to develop innovative technical solutions to the connection of distributed generation within UK distribution networks. This involves developing basic active management techniques which can be applied in the short term.

\(^1\) In the context of this work, “Short Term” is considered to relate to network solutions which can be “quickly implemented”, rather than “as a “temporary” short term measure.
1.1 **Background**

In order to implement the recommendations of the January 2001 DTI/Ofgem report on Embedded Generation, a Distributed Generation Co-ordinating Group together with a supporting Technical Steering Group (TSG) has been established. A number of workstreams have been defined by the TSG. One of these workstreams, Workstream 3 (WS3), is focused on short-term network solutions. A key issue to be addressed by WS3 is to establish how to facilitate the anticipated increase in the amount of energy generated from distributed generation. This is likely to be achieved by a combination of increasing the amount of generation plant connected to distribution networks and by increasing the amount of energy generated from new and existing plant by increasing the degree of network and/or generation management. This approach is broadly referred to as “basic active network management”.

The first stage of this project, to identify basic active network management solutions, has been completed. The Stage 1 report [1] provided a first-pass review of currently available solutions. The solutions are either currently being used by Distribution Network Operators (DNOs) and distributed generators to overcome the technical issues associated with connecting distributed generation to electricity distribution networks, or could be used in the near future.

The technical solutions can be categorised in terms of:

- managing fault levels;
- controlling network voltage levels;
- managing network power flows.

The focus of the previous work was to identify solutions that could be implemented in the short term. Solutions that were considered to need significant changes to regulatory or commercial frameworks or required significant additional research and development were identified as longer-term solutions and therefore outside the scope of this project.

1.2 **Objectives**

The objective of this report is to build on the work previously carried out, and further define the short-term solutions identified. This has been achieved by establishing the scope and extent of the issues associated with implementing the solution and then applying an appropriate rollout strategy. Two potential rollout strategies for the solutions have been identified:

**Rollout strategy 1**—where there is an agreement within Workstream 3 that the implementation issues for the particular solution can be readily addressed, the solution is explained. Where evidence of current network operator or generator practice exists, case studies are presented, and where relevant, references are made to other work. This provides a basis for the introduction of the solution into other DNOs.
Rollout strategy 2- where a solution is identified as having merit, but there are technical, commercial or regulatory issues that need to be further understood and developed, recommendations for further study will be made to better quantify the risks and reduce the uncertainty.

1.3 Methodology

This study was divided into three main tasks:

Task 1: Comparison of short-term solutions against assessment criteria;
Task 2: Description of solutions for “Rollout strategy 1”;
Task 3: Recommendations for further study of the “Rollout strategy 2” solutions.

The first task involved a comparison of the short-term solutions identified in the previous study [1] against a set of assessment criteria defined by the Workstream 3 members. The assessment criteria are contained in Appendix I and can be generally classified as:

- implications for customers;
- implications for distributed generators;
- implications for distribution network operators.

The assessment is considered in relatively simple terms in order to establish the appropriate rollout strategy for the solution, e.g.:

- no impact;
- insignificant impact, i.e. small enough to be considered acceptable;
- Impact potentially large enough to merit further quantitative analysis.

Whilst each solution is compared against all the assessment criteria, this report only discusses those issues that do not result in a “nil” or “insignificant” response. The more significant assessment criteria tend to be related to quality of supply/power quality issues or safety issues. In this context, quality of supply normally relates to supply interruptions (e.g., Customer Interruptions (CIs), Customer Minutes Lost (CMLs) and transient interruptions), whilst power quality relates to the electrical waveform (e.g. voltage dips, voltage swells, harmonics, flicker, voltage step changes, etc.)

The second task focused on those solutions where it was agreed that the first of the rollout strategies applies. Solutions falling into this category are explained theoretically and where evidence of current network operator or generator practice exists, case studies are presented as an illustrative application of the solution, with the aim of facilitating the introduction of the solution into other DNOs.

Guidance given in this report on the implementation of the solutions is based on feedback obtained from DNOs and Generators. A simple questionnaire survey was carried out, backed up with discussions at several Workstream 3 meetings. The intention was to establish indicative costs for each solution, especially the current “benchmark” solutions of network enhancement and reinforcement. The survey would also indicate the current level of uptake of each solution to illustrate the extent to which “good” engineering practice has had a chance to evolve into industry “best practice”. The questionnaire was answered by eight network
operating companies, representing thirteen of the network operator licence areas in the UK. Responses were also received from four generator operators. A summary of the questionnaire responses is given in Appendix II.

The third task focused on those solutions where it was agreed with the Workstream 3 members that the second of the roll out strategies applies. The task identifies the issues that warrant further work and develops additional terms of reference for the subsequent pieces of work that will be required to implement this set of solutions.

1.4 Overview of the solutions

For ease of description, the solutions have been categorised in terms of:
- fault level management;
- voltage control;
- power flow management.

A chapter of the report is dedicated to each of these categories. Identified short term solutions from Stage 1 of the study are listed in the following tables, which also identify the appropriate rollout strategies.

**Table 1: Short-term solutions for fault level management**

<table>
<thead>
<tr>
<th>No.</th>
<th>Short-term solution for fault level management</th>
<th>Roll-out Strategy</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Uprate network (replace switchgear)</td>
<td>1</td>
</tr>
<tr>
<td>2</td>
<td>Increase impedance of components</td>
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<td>3b</td>
<td>Converter technology for other generator types</td>
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</tr>
<tr>
<td>4a</td>
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<tr>
<td>4b</td>
<td>Network reconfiguration (network splitting)</td>
<td>2</td>
</tr>
<tr>
<td>5</td>
<td>Is Limiter</td>
<td>2</td>
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<tr>
<td>7</td>
<td>Fault level management procedures, e.g. consistent interpretation of ER G74</td>
<td>1</td>
</tr>
<tr>
<td>8</td>
<td>Active fault level management, e.g. re-configuration of the network based on actual generator presence and calculated fault levels</td>
<td>Long-term</td>
</tr>
</tbody>
</table>
Table 2: Short-term solutions for voltage control

<table>
<thead>
<tr>
<th>No.</th>
<th>Short term solutions for voltage control</th>
<th>Rollout Scenario</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Line re-conductoring</td>
<td>1</td>
</tr>
<tr>
<td>2</td>
<td>Build a dedicated line or network</td>
<td>1</td>
</tr>
<tr>
<td>3</td>
<td>Generator reactive power control</td>
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<td>Generator real power control</td>
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</tr>
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<td>8</td>
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<td>2&lt;sup&gt;2&lt;/sup&gt;</td>
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Table 3: Short-term solutions for power flow management

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<tr>
<td>2</td>
<td>Pre-fault Constraint</td>
<td>1</td>
</tr>
<tr>
<td>3a</td>
<td>Post-fault Constraint (intertripping) – single generator</td>
<td>1</td>
</tr>
<tr>
<td>3b</td>
<td>Post-fault Constraint (dynamic, including use of short-term ratings) – single generator</td>
<td>1</td>
</tr>
<tr>
<td>4a</td>
<td>Post-fault Constraint (intertripping) – multiple generators</td>
<td>2</td>
</tr>
<tr>
<td>4b</td>
<td>Post-fault Constraint (dynamic, including use of short-term ratings) – multiple generators</td>
<td>2</td>
</tr>
</tbody>
</table>

Clearly, some solutions represent current network operator practice, whilst other solutions have issues associated with them which need to be better understood. In addition, there are some solutions which have elements which are currently being used but would benefit from further effort being applied, such as further validation, training or the development of design procedures, in order to broaden their potential use. It is anticipated that the more innovative solutions described in this report will eventually be taken on board formally by the electricity industry as the solutions evolve and become suitably refined. For instance, the industry is discussing the possibility of adopting a technical “Connection Guide”, the governance of which will allow for regular reviews and updates.

The following sections develop the general understanding of these solutions. They are explained theoretically and an analysis of the implications for each of the main stakeholders is provided. Where appropriate, examples for the “Rollout Scenario 1” solutions are given, whilst the outstanding issues for the “Rollout Scenario 2” solutions are highlighted. An indication of the relative state of development of each solution is also given.

Solutions labelled as “long term” in the above tables have been passed on to the TSG Workstream 5 for consideration. Also, in the first stage report, those solutions that were

<sup>2</sup> This is being addressed as with FES Project 271, see Appendix III
identified as long term (from tables 1, 2 and 4 of ETSU K/EL/00303/00/00/REP³
‘Identification of outline solutions for the connection and operation of distributed generation’ are also highlighted in Table 4 for completeness. These solutions are also under consideration by the TSG.

Table 4: Long term solutions previously identified in Stage 1

<table>
<thead>
<tr>
<th>Long term solutions for fault level management</th>
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<tr>
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</tr>
<tr>
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³ For information, a list of relevant DTI/FES-supported activities (recently completed, ongoing and planned) is given in Appendix III).
2 Fault level management

Distributed generation from both synchronous and asynchronous machines makes a contribution to fault levels. Thus, the connection of distributed generation to the network could cause a distribution network, which happens to be close to its fault level limit, to exceed it. The risks when fault levels are exceeded are of damage and failure of the plant, with consequent risk of injury to personnel and interruption to supplies.

The following sections describe the various solutions available to help manage fault levels, giving an indication of the implications for each of the major stakeholders and also giving examples, where appropriate.

2.1 Uprate network components

Where fault levels are close to existing limits, the most immediate issue raised by the addition of distributed generation to the network is that circuit breaker ratings are likely to be exceeded. Circuit breakers associated with the connection may then have to be uprated. Whilst it is sometimes possible to uprate the capability of existing equipment to increase the fault level capability of the network, it is more normal that network equipment has to be replaced with equipment having a higher design rating. The need for uprating can be even more extensive if cable networks and switchgear relatively close to the connection point are affected (a particular issue for meshed networks) and/or where there are existing customers, connected to the same network, whose plant may also need uprating. The cost of these network upgrades can seriously affect the commercial viability of a distribution generation scheme if all the costs are passed onto the generator in the form of a “deep” connection charge. This is seen as particularly unfair if the resultant network upgrade creates additional fault level headroom on the network which is subsequently used by other distributed generators connecting to the network.

In other situations, the switchgear may already have been uprated and therefore cannot be uprated further. Hence increasing the capability of the network would require replacement of equipment. The timing of asset replacement can take place either when plant ratings are about to be exceeded (i.e. when a request for connection is received) or as a part of longer-term asset replacement programmes (i.e. as a company policy accepted by the Regulator in anticipation of future generator connections).

It may be difficult to assess the feasibility of uprating equipment for the following reasons:

- the fault current capability of installed older equipment (including cables and transformers) may not be ascertainable.
- the manufacturers of installed older equipment (including circuit breakers, cables and transformers) may no longer be in business, or unable (or unwilling) to advise on the feasibility of uprating or to confirm the actual capability of the equipment.

These factors may make larger scale replacement the only uprating method.

The solution of uprating network components has been evaluated against the Workstream 3 assessment criteria and the following implications have been identified:
Implications for customers

• The upgrading of network equipment may facilitate the connection of generator capacity to a level that will lead to short circuit levels exceeding the capacity of customer equipment. The increase of fault level imposed on customer plant may require the customer to change primary equipment, protective devices or settings if the increase is material.
• Customers may experience disruption to supplies or an increase in risk of supply failure during implementation of network upgrades. It may be possible to minimise these risks by co-ordinating works with particular customers or by implementing network upgrades during the summer.
• The solution could discriminate against existing connected customers because they are more likely to have plant and equipment that requires replacement or modification.
• The solution increases the potential for increased fault damage from the passage of short circuit currents. Appropriate re-engineering of customer protection equipment should mitigate this risk.
• The existing connection agreements will need to be reviewed from a legal perspective to confirm the legal position regarding the costs of changing customers’ equipment.

Implications for distributed generators

• The solution facilitates the installation of additional generation capacity but with increased connection cost. This may change with Ofgem’s proposals for shallower connections.
• The solution may require an interaction with other distributed generators, particularly where there is a requirement for enhancements of distributed generators’ plant.
• The solution increases the potential for increased fault damage from the passage of short circuit currents. Appropriate re-engineering of generator protection equipment should mitigate this risk.

Implications for distribution network operators

• The solution would require the DNO to change equipment, protective devices or settings.
• Under the current charging regime, the DNO would not fund this capital investment, although it would adopt the assets. These assets may also provide benefits for the connection of other load or generation customers.
• Under a shallow connection policy, the DNO could be faced with the capital investment costs, with these costs outweighing the benefit of the connected generation.
• The solution may involve some disruption to customers during implementation and therefore will affect network operator performance indices.
• There are regulatory risks associated with the interpretation of existing connection agreements in relation to the funding of customer plant replacement.
• Discussion will be required with other distributed generators and customers.
• Asset replacement could result in equipment that is not that old (i.e. recently replaced) being changed well before its end of life.

The traditional solution of uprating the network provides a “benchmark” against which other solutions can be assessed. The key issue is the high cost of replacing the switchgear and other network equipment, especially when switchgear at several substations is affected. The costs of implementing the solution are different at different voltage levels. An indication of relative benchmark costs are given in Appendix II.
2.2 Increase impedance of components

It is possible to specify a higher impedance for certain network and generator components (e.g. substation transformers, generator impedance). This will reduce the fault level and is a low cost solution for new installations, but is more costly or impracticable as a retro-fit option. New components such as fault limiting reactors can also be introduced into the network to increase network impedances. The addition of series reactors to link bus sections uses established technology. Their insertion can allow a re-assessment of the engineering compromises involved between fault level, power quality, system losses, source impedance and security. Reactors may also be used at other network locations, either to limit infeed from a single source (generator or network transformer) or to add impedance to the interconnectors between network areas. These three approaches are examined in more detail below.

Increasing generator impedance

The majority of megawatt-scale generators are designed to have a low source impedance since they are primarily intended for stand-alone (i.e. non grid-connected) applications. This is to ensure, amongst other things, that adequate current can be supplied for the starting of induction motor loads. Therefore, there is some scope to increase the generator impedance at the design stage for grid-connected generator applications. There are costs associated with using non-standard generator designs, but over time the standard generator impedances could increase towards a higher limit. There are however technical constraints, primarily associated with losses and stability criteria, which limit the fault level reduction from distributed generators to approximately 10 to 20%, depending on generator size.

Increasing transformer impedance

Increasing network transformer impedances is normally done by swapping out grid and primary transformers for higher impedance units. The impedance of transformers currently used on the network represent a balance of factors including maintaining certain fault levels, network losses, tap changer capability, voltage step changes and the performance of protection schemes. A number of these factors provide technical limits to increasing the impedance of network transformers. For example, the impedance of 12/24MVA 33/11kV transformers tend to be limited to 100% on 100MVA base by the performance of protection systems. There is, however, some scope in many situations to increase the transformer impedance. Adopting such an approach as a strategy makes most sense as part of a rolling programme of asset replacement over the next 10-20 years. This would then provide an additional fault level margin for distributed generation. However, if transformers were replaced with high impedance units before the generation plant was connected, networks would then be sub-optimal for load customers. In addition, until there was a sufficiently diverse portfolio of generators connected to maintain fault levels at an acceptable level, networks would be sub-optimal at any time when the generators are inactive. Note also that whilst increasing transformer impedances may mitigate fault level problems, it exacerbates the voltage control problem, losses and distributed generator stability problems.
**Inserting impedance devices**

As an alternative to traditional methods of introducing network impedance, it is possible to install new impedances into various locations in distribution networks. There are a limited number of examples of this being done in the UK, mainly within industrial sites with on-site generation.

![Diagram of impedance devices](image)

**Figure 2.1: Typical applications of current limiting impedance devices**

Three typical examples of possible locations for inserting impedance devices into networks are shown in Figure 2.1. Figure 2.1(a) shows a reactor used to connect two busbar sections together, Figure 2.1(b) shows a reactor used in series with a generator and Figure 2.1(c) shows a unit transformer-connected generator.

The main disadvantage of the impedance device is the presence of high reactive impedance in normal operation. This could increase the voltage variations delivered to customers under fluctuating load conditions and also influence the effective operation of tap-changing transformers. Step voltage changes under fault conditions could also increase. The reactors are also physically quite large and so there may be some difficulties in accommodating them within typical substations.

There are many examples where a reactor has been used at the generator site to reduce the fault level. In some cases, this has caused an excessive voltage drop on-site. This problem can be mitigated by the use of automatic switching capacitor banks and careful management of reactive power flows across the reactor.

The solution of increasing component impedances has been evaluated against the Workstream 3 assessment criteria and the following implications have been identified:

**Implications for customers**

- If the modification is to the network, customers may experience disruption to supplies or an increase in risk of supply failure during implementation of network upgrades. It may be possible to minimise these risks by co-ordinating works with particular customers. Modifications at generator sites only do not affect customers.
- Increasing network impedance can require the customer to review his protection arrangements, or in some cases to replace protection equipment.
- Increasing impedance of components generally decreases the power quality experienced by customers.
- The solution may lead to less fault damage resulting from a change of short circuit current provided that the protection operating time does not significantly increase.

**Implications for distributed generators**
• The solution involves disruption to supplies during implementation if the solution takes place at the generator site.
• The solution results in an increase in network impedance which will increase background voltage fluctuations.
• Increasing the impedance of the generator connection could affect internal losses within the distributed generators system and cause voltage control problems, depending on where the increase in impedance is located.
• Increasing the impedance within the network and connection is also likely to introduce issues for generator stability.

Implications for distribution network operators
• The solution may require the distributor to change equipment, probably protective devices or settings in some situations.
• The solution may affect the voltage profile on circuits.
• The solution results in an increase in background voltage fluctuation.
• The solution may lead to an increase in network losses for which the distributor may experience a financial penalty under the current regulatory framework.

In summary, inserting additional series impedances is a logical solution to counteract the effects on network fault levels of increasing the number of current sources within the network. Increasing component impedances is most cost-effective when applied at the design stage rather than as a retro-fit option. Fault limiting reactors currently appear to be more widely used on private co-generation sites rather than on public distribution networks. Greater consideration should be given to applying this solution on DNO networks, although its suitability will be dependent on local circumstances.
2.3 Converter technology for wind turbines

Increasingly, distributed generators are becoming available which use a power electronics converter interface. This is partly due to a number of DC source distributed generators becoming available (such as fuel cells and photovoltaics) as well as some distributed generators which benefit from operating at variable speed (e.g. variable speed wind turbines) or non-synchronous speed (e.g. micro-turbines). Power inverters provide a much lower fault current contribution than either synchronous or asynchronous machines. Thus, although the power electronics converter increases the cost of the generator, the extra cost could be outweighed by the benefits of reduced fault current contribution. It is also worth noting that converter technologies can also bring additional benefits in terms of power factor and voltage control.

Two types of wind turbine generator are currently available which have a power electronics interface. These are the synchronous generator and the doubly fed induction generator.

As further information, previous work in relation to converter interfaces can be found in project K/EL/00273/REP, carried out under the current DTI/FES programme.

The synchronous generator

Figure 2.2 shows the connection of a direct drive, multi-pole generator to a network through a converter [2]. The generator is directly excited but not synchronised to the power network. This arrangement does not require a gearbox – a mechanical component requiring frequent maintenance and the cause of many of the mechanical failures in wind turbine generator applications. The generator AC output is rectified to DC and converted to mains frequency by the power converter. The control of the power electronic switching devices in the converter controls the power output. When a fault on the network is detected by the converter protection, the switching devices can be rapidly turned off by the control circuit. Equipment of this type can generally prevent fault level contribution in switchgear breaking timescales (>100ms) and limit fault level contributions in switchgear making timescales (10ms).

![Figure 2.2: Direct drive non-synchronous generator connected through a converter](image)
Doubly-fed induction generator

The doubly-fed induction generator (DFIG) shown in Figure 2.3 was primarily designed and developed for wind generator applications [3]. This type of generator is variable speed, enabling more efficient operation over a wider range of wind speeds. The DFIG machine is essentially an asynchronous machine, but instead of the rotor windings being shorted (as in a “squirrel-cage” induction machine), they are arranged to allow an AC current to be injected into the rotor, via the power converter. By varying the phase and frequency of the rotor excitation it is possible to optimise the energy conversion. The power depends on the wind speed, through the rotational speed of the wind turbine, and a control system that generates a power set point based on the actual rotor speed. Thus, actual power depends both on rotor speed and the control of the rotor excitation via the power electronic converter.

The power electronics converter is rated at approximately 40% of the machine rating. Under fault conditions, a short-circuit “crowbar” is applied to the rotor windings in order to protect the power electronics from the excess current flow, which could otherwise be several times the machine rating, damaging the power electronic devices. Essentially, shorting the rotor windings means that the DFIG reverts to a conventional induction machine, which is then likely to be operating in an unstable region. Therefore, the main circuit breaker is immediately tripped and the turbine shuts down. The crowbar protection operates very quickly (i.e. within approximately 5 milliseconds) and the circuit breaker is tripped immediately. Therefore, although there is a contribution to fault current in switchgear make timescales, it is removed by the circuit breaker very quickly (i.e. typically within 120 milliseconds) such that the DFIG machine has the potential to avoid contributing to switchgear break duties.

An additional feature of the DFIG machine is that the generator power factor can be controlled. Although limited, this does give some facility to provide local network voltage control. This can obviate the need for local power factor correction capacitors that would normally be required with a conventional fixed speed induction generator.

![Figure 2.3: Schematic diagram of a doubly-fed generator wind turbine](image)
Converter technologies have been evaluated against the Workstream 3 assessment criteria and the following implications have been identified:

**Implications for customers**
- The solution may result in an increase in harmonics and therefore may require a harmonic assessment and local customer consent prior to implementation.

**Implications for distributed generators**
- The solution is potentially suitable for all types of generator, although is currently generally used only for photovoltaic systems, microturbines, fuel cells, doubly-fed induction machines and inverter-connected synchronous wind turbines.
- The solution results in an increase in background harmonics.
- The solution requires additional generator capital investment.
- The solution involves disruption to generator processes and generator business during implementation for retrofit applications.
- The solution may have implications for protection of the generator due to fault performance change of the technology

**Implications for distribution network operators**
- The solution may result in an increase in background harmonics.

Power electronics is an area of rapid technological development. The power ratings of devices is being continually increased, whilst the costs are reducing. Also, the additional controllability of the power devices is being exploited to improve sub-system performance and provide additional system functionality. It is important to keep abreast of current developments associated with the existing prime mover applications. In addition, consideration should be given to applying power converter technology to other prime movers, such as CHP generation plant.
2.4 Network reconfiguration

Distribution networks are designed to allow their connectivity to be altered, either in response to a fault or to allow a section of network to be isolated for maintenance purposes. Thus, distribution networks contain switchgear which is either used to provide additional connectivity (a normally-open switch) or isolation (a normally-closed switch). Normally-open switches are often found at the furthest point of an open ring or at a point where two feeders could interconnect adjacent substations. This topology is illustrated in Figure 2.4.

Figure 2.4. Typical 11kV network configurations

2.4a Options for reconfiguring networks

Reconfiguration of the network can reduce fault levels by either changing the fault current paths or reducing the number of network feeds through parallel paths. One of the simplest ways to change the fault current path is to simply move the normally-open point (i.e. close the normally-open point and open an associated normally-closed switch). In this way, the generator may electrically become farther away from the substation and therefore the fault
infeed to the switchgear becomes less. Alternatively moving the normally-open points could be used as part of a network connection design to connect a generator to part of an adjacent network where fault levels were not an issue. These are established normal practices within network operators.

Alternatively, the number of parallel paths can be reduced in networks comprising radial transformer feeder arrangements (rather than interconnected meshes), without physical network change, using network splitting configurations. These are generally referred to as:

- operating with the bus section circuit breaker open
- operating a transformer circuit breaker in open standby

In both cases, an auto-close scheme would be needed to close the breaker for upstream faults.

### 2.4b Network Splitting

Network splitting can significantly reduce the fault level at a busbar. However, this action will also increase system losses, harmonic voltage levels, voltage dips and flicker and will reduce power quality in general because of the increased source impedance. Also, the risk of supply failure would increase, as would the number of transient interruptions seen by customers. It is important to note that once a number of generator connections have been permitted following the permanent opening of the bus section, the options for restoring the substation configuration, should the resulting power quality prove to be unacceptable, could be expensive.

Another issue to be considered with this solution is that the busbar sections have to be coupled prior to a transformer being switched out for maintenance. This usually requires generation to be constrained off for this period.

The solution of reconfiguring networks either by changing the relative positions of existing normally open or normally closed switched or ‘splitting’ normally closed parts of the network has been evaluated against the Workstream 3 assessment criteria and the following implications have been identified:

#### Implications for customers

- Network splitting increases the network source impedance and therefore has an adverse effect on power quality. Although the number of voltage dips due to network disturbances is generally reduced, their magnitude increases, increasing the likelihood that sensitive electrical equipment will trip.
- Network splitting may lead to an increase in customer interruptions, customer minutes lost and short term/transient interruptions.

#### Implications for distributed generators

- Network splitting results in lower firm capacity for generation, and may lead to increased short term interruptions that compromise operating arrangements with existing distributed generators.
- The stability of distributed generators could be affected due to reduced system short circuit levels by network splitting.

#### Implications for distribution network operators
• Network splitting requires the distributor to change equipment and protective devices used for the operation of reconfiguration. There could be risks from auto-switching failure.
• Power quality generally will become worse due to increased system impedance.
• The distributor may be exposed to increased liability for additional disruption against which claims for damage and loss of business may result.
• Moving the open point on a radial network will have implications for voltage control and would tend to increase exposure to IIP and losses if open points were moved to sub-optimal network locations.
• Moving the open point within a network also may have power quality implications on those customers who are moved further from the substation (due to increased impedance). Conversely, customers who are closer to the substation from moving the network open points may benefit.

The network splitting configurations provide significant reductions in network fault level, but raise many additional issues which will need to be considered and addressed before these solutions can be taken forward. Specific attention should be given to the methods of mitigating the impacts of splitting low voltage systems, particularly in preventing or minimising supply interruptability, and in quantifying the fault level benefit versus the cost and performance impact for network splitting.

Splitting the network represents a major change to the way in which networks are designed and operated. There are a number of ways in which a network can be split each of which will have different reductions in fault level and impact on customers. In addition, there are technical options that could be used to mitigate any adverse impact yet still deliver a reduced fault level. A key aspect of any future study would be to identify these options and assess the potential they have for reducing any adverse impact of network splitting. The aim is to analyse the options for striking a balance between fault level reduction, impact on customers and the cost of reasonable mitigation measures.
2.5  *Is Limiter*

The above solutions are designed to permanently increase the network impedance, either by increasing the impedance of network components or reducing the number of parallel current paths. It is possible to increase the network impedance only at the time when the impedance of the network needs to be increased i.e. at the time when fault current flows. This can be achieved by the use of a device known as an Is limiter – a fault current limiting device. The key advantage of using such a device is that it retains the existing low network impedance under normal network conditions, and hence avoids any of the problems associated with increasing network security risks, losses and voltage control associated with permanently increasing network impedance. There are a number of possible locations for using Is limiters in networks, the most obvious positions being in series with a bus section circuit breaker, or in series with a dedicated generator connection.

An Is limiter is shown in Figure 2.5. The Is limiter senses the rapid rise in network current associated with a network fault and fires a pyrotechnic charge to open the main current path. The current is limited and then cleared by a parallel fuse. Is limiters operate very rapidly and disconnect the current before the first current peak (10ms) such that they can be effective in eliminating fault current flowing through the device in circuit making and breaking timescales.

![Is limiter diagram](image-url)

**Figure 2.5: An Is limiter**

Fitting an Is limiter to an existing switchboard may not be straightforward as space in many substations is limited. Additional isolation and earthing switches are required in order that the devices can be replaced after operation. As the Is modules must be replaced after each operation there are issues of operating costs and the time delays between their operation and replacement.

The Is limiter has been evaluated against the Workstream 3 assessment criteria and the following implications have been identified:

**Implications for customers**
• Depending where the equipment is installed, the solution may lead to an increase in CI, CML and short term/transient interruptions due to possible nuisance tripping.
• The solution may lead to less fault damage resulting from a change of short circuit currents.

Implications for distributed generators
• The solution leads to an increase in interruptions and unavailability of the connection if installed on the generator terminals.
• The solution may involve disruption to generator processes and generator business during implementation if the Is limiter is located at the generator site.

Implications for distribution network operators
• If installed on the DNO network, the solution requires the distributor to install the equipment which requires physical space on site for the equipment, network connections, isolation and earthing facilities and possibly a bypass circuit beaker.
• The solution requires capital investment and triggers network operator ongoing operational costs in operating and maintaining an additional piece of equipment.
• Depending on the location of the equipment on the network, mal-operation could give rise to an increase in CI and CML.
• The solution may require a departure from the standard safety philosophy for electricity networks as it is not fail safe technology.

The Is limiter is being used on some industrial sites in the UK, but on nowhere near the scale that it has been used in Germany. This is because the UK DNOs have several concerns over the use of Is Limiters, primarily linked to safety:

1) the Is Limiter is not intrinsically safe (i.e. fail-safe);
2) the integrity of the triggering supply;
3) the inability to functionally test the equipment;
4) the lack of an associated ‘back up’ system;
5) concerns expressed in the Distribution Code relating to the use of this type of equipment.

The safety concerns are generally shared by the Health and Safety Executive. Given the safety concerns associated with the use of Is limiters, further work is required to assess the suitability of this type of equipment for use within public distribution networks. This would naturally involve input from the Health and Safety Executive (HSE). Assuming that this assessment proves to be positive, further work would then be required to establish the most appropriate means of employing them as an integral part of distribution network design. As further information, previous work in relation to Is limiters can be found in the recent project K/EL/00304/REP, carried out under the DTI/FES programme.
2.6 Sequential switching

Sequential switching is a method by which the multiple sources contributing to any fault current are separated prior to the clearance of the faulted section. The sequential switching concept is explained in Figure 2.6. In this example, three separate components can be seen to contribute to the fault current; Transformer 1, Transformer 2 and Generator 1. Ordinarily, the protection would be arranged such that Circuit Breaker 5 would clear the fault directly. However, the additional fault contribution introduced by Generator 1 could mean the fault current flowing through Circuit Breaker 5 exceeds its rating. In this case, operation of Circuit Breaker 5 could be inhibited until either Circuit Breaker 1, Circuit Breaker 2, Circuit Breaker 3 or Circuit Breaker 6 is operated.

In this way, the generator connection can be accommodated without the need to uprate the circuit breakers. Sequential switching has been evaluated against the Workstream 3 assessment criteria and the following implications have been identified:

Implications for customers
- There is negligible impact on customers.

Implications for distributed generators
• The solution reduces the generator connection costs relative to the additional connected capacity achievable.
• The solution increases protection clearance times which will tend to reduce generator stability.

Implications for distribution network operators
• The solution requires the distributor to change protection schemes. The new protection schemes for sequential switching trigger network operator ongoing additional operational costs in operating and maintaining the installation.
• There is risk of failure of the sequential switching schemes. In the case of failure of sequential switching, circuit breakers are exposed to fault currents potentially exceeding their rating. This increases the risks to both people and equipment.
• If the solution is reversed further network operator operational costs will be involved to revert to previous basis of operation.
• The solution will lead to the need for modified distribution protection systems to assure grading and operation.

A sequential switching application in 132kV networks
An example has been found where sequential switching was used as a temporary solution to limit fault levels in a 132kV network. There is also the potential to adapt the method for use in 33kV and 11kV networks.

The system diagram of the application is shown in Figure 2.7. The distributed generator is connected to the 33kV network.

![Figure 2.7: Network diagram for application of sequential switching](image)

There was a need for Supergrid Transformer (SGT) reinforcement at the South 400/132 kV Substation. However this coincided with an application for connection of an embedded generator in the East network. The combined fault infeed from the new SGT and the embedded generation increased the prospective fault levels significantly beyond the rating of the existing 132 kV switchgear at all three sites.
It became imperative to investigate methods of deferring major capital expenditure at these sites until a firm strategy for future development could be clearly defined. A sequential trip scheme at the East substation was proposed to ensure that the sources of fault infeed were separated before the faulty feeder circuit breaker tripped to clear the fault.

At the East substation, the double busbar 132 kV substation was operated with the main bus section circuit breaker and both bus couplers closed. The bus-section disconnectors in the reserve busbar were operated normally-open, so that if one of the bus couplers were operated one section of busbar would be separated from the rest of the board. The East substation was supplied by two feeders from the South substation and four feeders from North substation. The two infeeds from the South substation were connected to one of the sections of reserve busbar and its bus coupler was included in the sequential trip scheme.

The sequential trip scheme was initiated by high-set earth fault relays on all outgoing feeder circuits, which tripped the appropriate bus coupler instantaneously and segregated the infeeds from the South substation to supply two out of four local Grid Transformers. All feeder circuit breakers had a 100 millisecond time delay incorporated into their trip circuits. These time delays were in-circuit for all fault types and ensured that dc offsets and induction motor infeeds were negligible by the time the circuit breaker operated to clear the fault, even for three phase faults.

The bus-coupler was automatically reclosed after a suitable time delay to allow for delayed-auto-reclose of the faulty feeder. This ensured that make duties were contained within the switchgear rating. Manual closure of feeder circuit breakers at the East substation also required manual separation of the infeeds from South and North before re-energisation of any outgoing feeder.

Whilst the scheme had to be extended to cover three phase faults on some circuits, and single phase faults on some of the infeeds, when the embedded generation was increased, it proved satisfactory until the switchgear was replaced, and the network configuration improved, in 2000/2001.

One of the major concerns during this period was the risk of generator instability due to the increased fault clearance times. This required careful liaison between the embedded generator and the network operator to ensure that planned outages imposed minimal constraints on generation patterns.

**Further work required for the sequential switching solution**

There are a small number of examples where sequential switching techniques have been incorporated into protection schemes used in the UK. However, its application raises several important issues:

- **Safety** – sequential switching introduces more risk to network plant, network personnel and the public than ensuring that switchgear has an appropriate rating. The safety risks arise because there is the risk that a sequential switching scheme fails to prevent a circuit breaker opening before the fault current has been reduced sufficiently. In addition, the overall fault clearance times increase, hence increasing the safety risks at the point of fault. Therefore, if safety is considered in absolute terms, the solution is not acceptable because of the increased risk. However, if a risk assessment approach is adopted, this may show the additional risks to be acceptably small under certain circumstances. There is a clear linkage here to the ESQ&C Regulations particularly 3(1), 6 and 23(1).
- **Complexity** – the use of sequential switching introduces additional complexity into network design and operation, particularly if equipment at more than one site is involved. This inevitably increases the risk of customer supply failure due to technical failure or operator misjudgement. Any design, maintenance or operational work would require the resources of engineers or technicians with increased knowledge and skills in order to minimise the risks of mal-operation.

- **Suitability** – the deliberate introduction of a protection operation time delay introduces technical issues for both network operators and distributed generators. For network operators, it means that the fault is present for longer, causing additional stress and damage to network components. Similarly, longer fault clearance times could cause problems related to the critical clearance times for distributed generation, which often requires fast protection operation in order to avoid generator stability problems.

Additional activities should be carried out to address these issues.
2.7 **Fault level management procedures**

There is some scope for increasing the transparency of the fault level calculations carried out by DNOs to allow distributed generators to better understand the calculation of the fault level contribution of their distributed generator. Engineering Recommendation ER G74 is recommended as the standard methodology for implementing the IEC 909 standard for UK fault level calculations. Engineering Technical Recommendation ETR 120 is the associated application guide.

The implication of this solution is that companies across the country have applied ER G74 to their networks in ways that differ, either within its guidelines or extending them, or that the companies have developed other methods for managing fault levels, possibly with reference to IEC 909.

The aim is to produce a uniform approach across the country to the assessment of fault levels and the potential impact of new generation on them. It is likely that the minimum size of network to be modelled and the factors used for aggregating the effects of components beyond the detailed modelling section will become more uniform. However, they will not become the same as they must reflect the nature and parameters of the differing local networks. The need and requirement to harmonise fault level management procedures is supported and recognised within the Electricity Association Operations and Systems Group (OSG) Sub-Group 4. Here, work has been undertaken in developing a common approach to the assessment of short circuit levels (consistent with ER G74 and ETR 120) and the use of quantified risk assessment techniques. The adoption of such work would help to promote the needed transparency and understanding to all parties.

**Implications for customers**
None.

**Implications for distributed generators**
- The information required of the prospective generator would become more uniform across the country.
- A consistent policy would not change the ability of the network to accept new generation. However, on average, there would probably be a tendency for the assessment to be made more rigorous, accurate and transparent.

**Implications for distribution network operators**
- Effort would be required initially to develop and codify the policy covering fault level assessment.
- The aim of the policy changes should be to at least clarify and probably simplify the process. This would lead to a reduction in required engineering effort in the assessment studies and other related tasks.

In conclusion, there are discussions taking place within the electricity industry to ensure a consistent interpretation of calculation and measurement of fault level.
2.8 Active fault level management

The management of fault level could be carried out within operational as well as planning timescales by developing the evolution of the network from “fit and forget” to “actively managed”. Basic active fault level management could encompass simple activities such as the moving of network open points, as previously described. However, more dynamic and active fault level management would require much more flexible networks. It is difficult to make physical changes to the network and so the flexibility is most effectively created by changes in network operation and planning. This approach is seen as a logical reaction to the introduction of significant local generation, which introduces significant variations in network parameters such as fault level as distributed generators go on and off line. This situation is in contrast to that previously where the network loads changed but the network configuration and fault level generally remained stable.

Many of the solutions to fault levels previously described, such as network splitting, Is limiters, reactors and sequential switching, can be used in conjunction with traditional network reinforcement techniques to make networks more flexible. Active fault level management then becomes the process of integrating the solutions together into a single coherent network design approach.

The move from a ‘fit-and-forget’ philosophy to a ‘managed’ approach would also benefit from increased network data, such as could be provided by fault level monitoring. The fault level monitoring provides closed loop feedback for the active fault level management and the corrective actions would include many of the solutions previously described.

Implications for customers
• The solution leads to less fault damage resulting from a change of short circuit currents.

Implications for distributed generators
• The solution requires the generator to modify the technical design of the control equipment in order to carry out possible generator curtailment.
• The solution reduces the generator connection costs relative to the additional connected capacity achievable.
• The solution requires additional generator capital investment for the control schemes.
• The solution will trigger generator ongoing additional operational costs and the implications of any operational constraints.
• The solution may require co-ordination for the application with more than one generator. Co-ordination with other distributed generators is also required for commercial arrangements.

Implications for distribution network operators
• The solution requires the distributor to install monitoring and controlling equipment which will have to be reversed if the solution is reversed.
• The solution represents a significant departure from current network design from which it would be difficult to reverse.
• The solution will also trigger distributor additional operational costs for the requisite measurement and control devices. The distributor would incur further operational costs to revert to the previous basis of operation.
• The benefits of the solution may have to be secured under contract. If more than one generator is involved the rights of the benefits will be shared between distributed generators. The new connectee may cause constraint upon existing connections.

Thus, this solution has merit, but there are technical, commercial or regulatory issues that need to be further understood and developed. This solution is closely linked to many of the more sophisticated fault level solutions previously described and so the application of active fault level management techniques would follow on logically after these solutions, especially network splitting, Is limiters and sequential switching, have been studied. Therefore, it is recommended that further study of this solution awaits the completion of these other studies. Finally, active management has a potentially broad scope and would be expected to deliver benefits beyond the control of fault level.
3 Voltage control

The voltage (V) at the remote end of a feeder is determined by both the source voltage (E) and the voltage difference (+ve or –ve) along that feeder. This voltage difference (ΔV) along a feeder is influenced by various factors, these being:

- the line resistance, R
- the line reactance, X
- the reactive power flow, Q
- the real power flow, P

This results in the typical voltage drop equation [4]:

\[ E - V \approx \frac{RP + QX}{V} = \Delta V \]

Therefore, network voltages can be managed in “planning” timescales by altering R and X or in “operational” timescales by controlling P and Q. It is interesting to note that if the generator is exporting real power (P), at the same time that it is importing reactive power (Q), the voltage change can be minimised. This is especially true in networks which have a large X/R ratio (i.e. overhead line networks).

In practice, solutions to voltage control problems include:

- line re-conductoring;
- build a dedicated line or network;
- generator reactive power control;
- generator real power control;
- line voltage regulation e.g. a single regulator on a circuit;
- cancellation CTs;
- virtual VT;
- active voltage control.

The following section describes these solutions. Where possible, examples of these voltage control solutions and their application in real networks have been included. Furthermore, other views on the solutions, based on a common understanding of the technology and published information, are also included.

As further information, previous work in relation to voltage regulation and control can be found in project K/EL/00230/REP, carried out under the DTI/FES programme 2001.
3.1 Line re-conductoring

Re-conductoring a circuit with a lower resistance cable or overhead line improves the voltage regulation along that circuit. This improvement is a direct result of the lower network resistance, and therefore increases the amount of distributed generation which can be connected. Such a solution, however, clearly has associated costs.

Line re-conductoring could be carried out at a time of scheduled asset replacement, where the marginal cost of using higher rated cables or lines may not be so great. Also, new networks have the option of using different design criteria, such as incorporating network designs with shorter cable lengths (but more, smaller transformers). Such an approach needs further study to quantify the costs and benefits and to optimise the design. The cost framework (i.e. regulatory incentives) would also need to be examined.

The line re-conductoring voltage control solution has been evaluated against the Workstream 3 assessment criteria and the following implications have been identified:

Implications for customers
- In terms of power quality, the solution leads to a reduction in customer interruptions, customer minutes lost and short term/transient interruptions as the line is generally refurbished as it is re-conducted.
- During the implementation, there may be some disruption to supplies.

Implications for distributed generators
- The solution leads to a reduction in connection interruptions, as a result of an increase in the availability of the connection.
- The solution will increase available network capacity and this is of benefit to Distributed Generators.
- The solution will result in improved power quality.
- The solution increases the generator connection costs if deep connection charging is used. This may change with Ofgem’s proposals for shallower connections.

Implications for distribution network operators
- The solution requires the distributor to change conductor, and hence voltage profile on the circuits will be improved.
- The solution will result in improved power quality.
- The solution will result in lower losses.
- The re-conductoring of a line has implications for DNO’s as the adoption of the asset (re-conducted line) by DNO’s means that it can be utilised for the connection of additional customers.
- The solution could, however, exacerbate fault level problems.
- The solution results in positive CI and CML impact which may benefit the distributor under the current regulation.

This is a “benchmark” solution and one of the key issues for implementing such a solution is the cost, and these are different for the different voltage levels. The costs are summarised in Appendix II.
Line re-conductoring is a solution that can be readily adopted in the short term, but the introduction of new network design philosophies could and should be considered in the longer term perspective. These philosophies include:

i) increasing the extent of the higher voltage networks, combined with the use of more, smaller, transformation nodes.

ii) extending the extent of voltage control within networks, possibly as far as the LV network.

Such concepts are beyond the scope of this report, but are recommended for further study.
3.2 **Build a dedicated line or network**

Building a dedicated line or network for the connection of generation is effectively separating load customers from generation customers. This approach has merits under certain circumstances, for example, when the load density is low relative to the local distributed generation resource. The advantage of this arrangement is that normal load customers are not subject to the voltage conditions arising from generation. This approach enables the DNO to agree voltage limits outside statutory limits with the generator. These so-called “reception networks” may be particularly applicable in rural networks with few load customers, but many potential generation customers in the form of windfarms, small-scale hydro and biomass generation schemes.

Since the network would be designed specifically for the needs of the distributed generation, this solution should provide the minimum barrier in terms of technical difficulty, but it can be an expensive option unless all the network capacity is utilised.

The building of a dedicated line as a voltage control solution has been evaluated against the Workstream 3 assessment criteria and the following implications have been identified:

**Implications for customers**

The solution results in negligible impacts on customers as it is implemented as dedicated lines to the distributed generation.

**Implications for distributed generators**

- The solution leads to a significant reduction in network capacity constraints due to the physical increase in local network capacity.
- The cost of building a dedicated line may be high. However, considering the additional connected capacity achievable, and otherwise higher levels of interruptions, generator connection costs could be justified for concentrated resources.
- The solution could lead to commercial implications for the sharing of costs between a number of generators.

**Implications for distribution network operators**

- The difference between the generation capacity and adjacent demand will determine whether there is any significant change to the voltage profiles upstream. The substation voltage control will be affected if the generator export causes reverse power flow.
- Environmental aspects and requirements for planning consent may have implications for this solution.

This is also a “benchmark” solution. The building of a dedicated line or network for the connection of generation has been used with some success in Germany. The option of introducing additional capacity by installing a dedicated line or network is one clearly within the present “Toolbox”, and could be construed a relatively simple to implement. Such a solution however would have particular merits within specific UK geographical areas, as identified in Ofgem’s idea of “Power Zones”. “Power Zones” could be described, in summary, as the concept of “generator-friendly” networks.

As outlined with the previous solution, one of the key issues in its implementation is that of cost. The costs of implementing the solution are given in Appendix II.
3.3 Generator reactive power control

Reactive power control is a technique commonly used in transmission networks to maintain voltage profiles along a line. Generally speaking, transmission lines tend to be longer than distribution lines and their X/R ratio higher. This means that reactive power control is not so effective within distribution networks, but nevertheless can provide some benefits. Presently, however, it is normal practice for DNOs to require distributed generators to operate at (or close to) unity power factor since this has a governing influence on the reactive power.

Reactive power control for conventional generation can be at the distributed generator, or at the connection point of several distributed generators to the network. Switched capacitor & reactor banks, transformer tap changers, SVCs or statcoms can be used, giving a wide range of options.

A practical example might be a windfarm with asynchronous generators. These would normally require power factor correction capacitors to be fitted to provide for generator starting. The capacitors would remain connected to allow the windfarm to operate close to unity power factor. However, if the capacitors were switched out after the windfarm had started, then the windfarm would import reactive power, helping to maintain a flatter voltage profile on the network. However, this could also give rise to a poor power factor condition on the remainder of the network and hence voltage control problems. Obviously, system studies would be required in any particular case to assess the possibility, but it is a very cost-effective solution when it can be applied. Increased reactive power flow also influences the network loading and could reduce the network capacity available.

The control of generator reactive power as a voltage control solution has been evaluated against the Workstream 3 assessment criteria and the following implications have been identified:

Implications for customers
- The solution has negligible impact on customers.

Implications for distributed generators
- The solution is dependent on the generation technology. For synchronous machines the reactive power control is achieved by excitation control, for asynchronous generators the control is through capacitor switching and for DFIG machines the power factor and voltage control is provided by the DFIG’s ac/dc & dc/ac converters and controller. The control is limited by the reactive power capacity for the generation technologies.
- The solution results in a reduction in generation constraint, though the reduction depends on the reactive power capacity and the generator size. The solution reduces the generator connection costs relative to the additional connected capacity achieved for small to medium generators. For higher capacity generators, the effectiveness of the solution is limited.
- The solution may trigger generator ongoing additional operational costs in operating their installation with the implemented solution.
- The solution may result in more reactive power flow, which is constrained by the operational regulations put in place by the network operator.
- There are also commercial implications in terms of reactive power charging.
Implications for distribution network operators

- The solution will change the voltage profile on circuits. It may require a review of voltage control systems as the solution changes the PF (Power Factor) of the feeder, which may cause problems for On-Line Tap Changer (OLTC) control.
- The solution will be constrained as the existing planning regulations put limits on the power factor of distributed generators.
- An increase in network losses will result because of the resulting poor power factor.
- The solution may have implications on the performance of existing and future network assets in accommodating higher reactive power levels within the network.

At least one company has looked at increasing the generator reactive power import as an alternative to upgrading the distribution feeder for a small selection of Distributed Generation schemes. In these instances, the scheme was connected at 33kV and the network operator requested the generator to operate at a fixed power factor (importing reactive power) of 0.9. This would ensure that the voltage of the system was below the allowable 1.012pu voltage at times of minimum demand. Operating at this power factor for all other demand periods, whilst maintaining the voltage within limits, was understood to leave the scheme importing more reactive power than necessary. The logical solution was to permit the generator to control its reactive power import so as to maintain the voltage below 1.012pu. This does however have implications on the charges for the reactive power and how they are best determined. At minimum load, it is important to note the significance of adhering to an upper voltage limit set point. This is critical as directly connected customers whose fixed tap transformers and incorporated voltage boost could cause the LV side to exceed statutory limits.

Other practices of reactive power control to increase a wind farm’s capacity, without reinforcing the connection, are also being implemented. With the correct reduction in power factor, and validation against load duration curves for the load centres, operating a generator at a reduced power factor reduces the chances of an excessive voltage at other customers’ connections. Reactive power import however may be a significant chargeable cost to a project and so would need to be considered.
3.4 Generator real power control

Control of the generator power output can be a way of enabling more generation to be connected and increasing the overall financial performance of a development. If the level and frequency of generator curtailment is relatively small, then this can be a very attractive solution. In principle, real power control could be carried out in “real time”, although it could also be achieved more coarsely using a simple seasonal control.

Consideration would have to be given to the market implications of constraining energy. Constraining the outputs of more than one local generator adds both flexibility and complexity. For example, the management of distributed generators competing for available network capacity adds complexity, but the available options (i.e. which generator to curtail, to what extent and when) adds flexibility. Therefore, the control of a single generator is a short term solution, whilst the control of multiple distributed generators is likely to require further consideration.

The control of generator real power as a voltage control solution has been evaluated against the Workstream 3 assessment criteria and the following implications have been identified:

Implications for customers
- The solution results in negligible impact on customers.

Implications for distributed generators
- The constraining of energy output affects the economics of the generation site
- The solution is dependent on the generation technology. For synchronous generators, control can be achieved through the prime mover. In the case of fixed speed wind generators, it can be done through pitch control. For doubly fed wind generators, real power output can be adjusted in a certain range of control by electronic control. There is a need to monitor the voltage in order to issue the control when necessary.
- There may be a reduction in the availability depending on the size of generator. The solution reduces the connection costs relative to the additional connected capacity achievable.
- The solution triggers the generator’s ongoing additional operational costs in operating their installation with the implemented solution.
- The solution requires changes to generator equipment for some generation technologies in order to monitor the voltage and carry out real power control.
- The solution may become complicated for multiple generators both technically and commercially.
- As energy storage becomes more of a viable option, the solution would become more attractive.

Implications for distribution network operators
- The solution may have some commercial & legal implications if there are several Distributed Generators in play.
- The enhanced headroom is limited by the real power control capacity.
Overvoltage can be prevented by generator real power control or generation constraint. No schemes currently in operation have been identified, although several wind farms are being developed with real power control, with the generator effectively being offered a shallow connection. The constraint mechanism has not yet been defined in these examples, but is likely to be simple in technical implementation (i.e. simple on/off control).
3.5 **Line voltage regulation e.g. a single regulator on a circuit**

The use of line voltage regulators can be viewed as an extension to active voltage control on the distribution network. Line voltage regulators can be placed strategically within a feeder, such that the voltage regulator and the generator work together to control the downstream voltage, whilst the existing substation OLTC and Automatic Voltage Control scheme (AVC) controls the rest of the passive network in the conventional manner. Line voltage regulators are used by several DNOs to help manage voltage profiles on long feeders. However, the use of voltage regulators in conjunction with distributed generation is a fairly recent application in the UK.

Line voltage regulation has been used in an 11kV rural radial network in a demonstration project in Scottish Power / Manweb [5]. The principal limiting factor to connection of “wind clusters” is voltage regulation rather than line rating or fault level in this application.

In Scottish Power / Manweb, the limit for connection of any generator to the 11kV rural network without network change can be described by an empirical formula and general rule of thumb:

\[
\text{Generator capacity (MVA) } \times \text{ distance from substation (km)} \leq 4
\]

That is to say, a 1MVA generator could be connected 4km, a 2MVA generator could be connected 2km, or a 4MVA generator could be connected 1km from the substation. Above the limit, network studies have to be carried out, and appropriate measures have to be taken based on the study results.

In this project, the generator operator wanted to increase the generation capacity from 600kW to 2.3MW (1×600kW FSIG + 2×850kW DFIG). The generator site is 12km away from the primary substation, and hence 2.3MW exceeds the limit from the empirical “4MVA.km” rule. This would cause an unacceptable voltage control problem in the immediate vicinity. The conventional solution in this case would be a change from 11kV to 33kV connection. Typical rural 33kV connection costs are in the region of £500k to £1M compared to the cost of connection at 11kV (£50k to £100k).

To be able to connect the proposed new turbines at 11kV, in-line voltage regulation has been installed on the main overhead line to prevent the voltage rising above statutory limits. The application uses a pair of single in-line voltage regulators which cost approximately £20,000 each. They were sited on the main line near to the tapping point where the spur line to the wind turbines connects. As an additional measure, the power factor of the two DFIG generators was fixed at 0.95 (importing VArS) rather than unity. Figure 3.1 shows the layout.
To monitor the operation, the voltages at strategic points and power flow were monitored by the SCADA system. The monitoring points are primary substation, voltage regulator and Distributed Generation site. Monitored and simulated results showed that network voltages are within the required limits under all conditions including summer loads and maximum generation, and the solution is viable from a voltage control perspective.

However, the reverse power flow through the primary substation at times of maximum generation and minimum load cause the voltage on the primary substation busbar to be reduced. This undesirable side effect is a consequence of the “negative reactance compounding” voltage control scheme used within the AVC controller.

The application also suggests that the solution can be better utilised by optimising the voltage control settings at the primary substation, voltage regulator and generators. Optimisation of the voltage control strategy should further increase the capacity of the network to accept distributed generation. Optimisation should also allow the generator to operate close to unity power factor, thereby reducing the generator’s reactive power charges and network losses.

The use of line voltage regulators as a voltage control solution has been evaluated against the Workstream 3 assessment criteria and the following implications have been identified:

**Implications for customers**
- The solution may involve some disruption to supplies during implementation.
- This solution could increase CI and CML due to the increased number of network components.

**Implications for distributed generators**
• The solution leads to a reduction in generation curtailment and therefore an increase in availability of the connection.
• The solution reduces the generator connection costs relative to the additional connected capacity achievable.

Implications for distribution network operators
• The addition of voltage regulation may affect protective devices and require change of settings due to the addition of extra impedance.
• The solution will affect the voltage profile on the circuits, especially near the location of the voltage regulator due to the step change of regulation.
• The solution may involve some disruption during implementation.
• The solution triggers ongoing additional operational costs for the distributor in maintaining the regulator, although with a deep connection charge it is likely that the Distributed Generator will pay for the installation of the equipment and also for its O+M. There may also be a need to change the regulator settings between summer and winter.
• The solution leads to an increase in network losses for which the distributor will be liable under current regulation. This would mainly be the regulator losses.

Experience is still developing concerning the interactions between the OLTC AVC, the voltage regulator and the generator controller. It is recommended that further studies be carried out to develop an optimised design methodology for the application of voltage regulators in conjunction with distributed generation. Also, continued monitoring of DNO experiences to maintain best practice is recommended.
3.6 Cancellation CTs

The use of Cancellation Current Transformers (CTs) is a means to modify the OLTC AVC arrangements. Cancellation CTs can be used to remove the feeder with generation connected to it from the AVC control mechanism when Line Drop Compensation (LDC) is used. Cancellation CTs and their interface to the Voltage Control Relay (VCR) are already available from manufacturers (e.g. load exclusion module from VA Tech)[7]. The application of the technique would be limited by the number of circuits that could be ‘excluded’ from the control scheme whilst still maintaining voltage control on the remaining feeders.

Distributed generators can be embedded remote from the busbar and supply part or the entire feeder load. Figure 3.2 shows an illustration of a generator connected to supply the feeder load. The generator reactive load is supplied from the source through the transformer, with the result that the transformer contributes a smaller load to the busbar, at a lower power factor due to the increase in reactive current.

As the real load has reduced, the LDC effect is reduced causing the LDC boost voltage effect to be reduced. As the voltage control is in TAPP\(^4\) mode the decrease of power factor causes an error in the VCR target voltage that results in a further reduction in voltage. When the generator is running then the busbar voltage is reduced.

If the generator contributes insignificantly relative to the transformer, the effect on the VCR will not be significant. However, if the generator causes a significant change to both the transformer load and power factor, steps can be taken to exclude feeder load A from the transformer current applied to the VCR CT input. The transformer load will now ignore the effect of all generation connected along feeder A.

This can be achieved by use of a “Load Exclusion Module” (LEM). This module subtracts load A from the current measured by the VCR CT. The current seen by the VCR will now be of the correct power factor and the LDC effect will be slightly reduced (since it does not include load A). This can be corrected by a small increase to the LDC setting.

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\(^4\) TAPP is a voltage control protocol to permit the improved Tap-changer operation of parallel connected transformers, with a view to minimising reactive circulating currents.
The use of cancellation CTs as a voltage control solution has been evaluated against the Workstream 3 assessment criteria and the following implications have been identified:

Implications for customers
- The solution has negligible impact on customers unless the solution is applied to too many feeders on a single substation.

Implications for distributed generators
- The solution leads to a reduction in generation curtailment, especially in the case of large distributed generators connected through a dedicated line. The solution, however, is limited in the number of feeders on a single substation to which it can be applied.
- The solution reduces connection costs because of the increased allowed generation capacity.

Implications for distribution network operators
- The solution requires the distributor to change the hard wiring of OLTC AVC.
- The solution will change the voltage profile on the circuits. The solution will probably require a review of voltage control policy in order to validate the solution.

One network operator is known to have several primary substations whereby one circuit containing a generator is subtracted from the substation AVC/LDC scheme and other DNOs are considering its use. The solution is complementary to the previously described solution (in-line voltage regulators). It is recommended that a combined study is carried out to establish the optimum balance between the use of AVC voltage control (including LDC or negative reactance compounding), cancellation CTs, in-line voltage regulators and generator real/reactive power control.
3.7 Virtual VT

A further option is to use the MicroTAPP relay with a Virtual VT [7]. With this option, control of the voltage on the primary-side of the Primary transformer is achieved, with the voltage on the secondary-side controlled by the connected generation. The implications of this scheme, where the local voltage is controlled by local distributed generators, are technical, commercial and regulatory.

The VATech Reyrolle MicroTAPP voltage control relay (VCR) can be provided with functionality that will allow effective control to be exercised on either side of the transformer using a single fixed voltage transformer and includes load related voltage regulation.

Figure 3.3 shows a normal arrangement for a voltage regulation system that employs a MicroTAPP relay taking a voltage and current measurement input from the network side of the power transformer. Any adjustments to the target voltage level are initiated by the VCR to drive a tap-changing mechanism that may be connected to either the ‘primary’ or ‘secondary’ windings of the power transformer.

![Figure 3.3: Normal operation of AVC control](image)

If the network running arrangement is such that the use of generation makes it desirable for the controlled network to be changed from one side to the other, automatic voltage control may not be possible as shown by Figure 3.4.
Figure 3.4: AVC control of the voltage at the other side of transformer

The advanced functionality of the MicroTAPP uses algorithms that enable the terminal voltage of the non-measured side of the power transformer to be calculated and effective control to be carried out without a requirement for any additional inputs.

The use of such an arrangement as a voltage control solution has been evaluated against the Workstream 3 assessment criteria and the following implications have been identified:

**Implications for customers**
- The solution results in a reduction in background voltage fluctuations for customers connected on feeders other than the generation feeder.

**Implications for distributed generators**
- The solution leads to a reduction in generator curtailment.

**Implications for distribution network operators**
- The solution requires the distributor to change the operation mode of the OLTC AVC according to the generator production and substation loading.
- The solution will change the voltage profile on the circuits and therefore will require a review of voltage control policy in order to validate the solution.
- In the context of the solution the new connectee may cause constraint upon existing connections.

Application of the advanced settings is dependent upon particular operational situations. As an example, consider a network where a local generation scheme supplies local load network which is also supplied by a long line from a remote source, Figures 3.5 and 3.6.
Figure 3.5: Virtual VT application example

If the generation is active and the network is heavily loaded, voltage control is switched over to take control of the incoming voltage at load site A (see Figure 3.6) while the generation is configured to maintain the voltage on the local busbar. The incoming voltage at load sites B and C are supported by load site A and offset the line voltage drop from the source. Under light loading or during generation down time, the VCR at load site A would be switched to take control of the voltage level at the local busbar.

Figure 3.6: AVC taking control of the incoming voltage
### 3.8 Active voltage control with remote sensing

An area-based voltage control system with remote sensing could be used for active voltage management of a distribution network. To give an idea of an area-based voltage control method with remote voltage sensing, the following explanation, based on material provided by Econnect [8], outlines this concept.

**Voltage Controller Description**

Figure 3.7 is a functional diagram of the voltage controller. There are two main blocks within the system, these being the state estimation and control functions. The measurements, estimates and AVC relay target voltage, shown with black arrows, are real-time signals. The other inputs, shown with white arrows, are off-line data.

**State estimation block**

This calculates the expected value and standard deviation of the voltage magnitude at each node on the network under control. To do this it uses voltage and power measurements, historical load data and network data such as topology and conductor impedances. It uses a weighted least squares algorithm, solved using the Newton Raphson method, which also calculates the state variable standard deviations. These voltage magnitude estimates are passed to the control block.

**Control block**

This checks that each estimate is within its ‘control range’. The control range for each node is defined as the range of acceptable values for its voltage magnitude estimate. If an estimate falls outside its control range, the control block alters the AVC relay target voltage to initiate a tap change operation, so ensuring that all customer voltages remain within statutory limits. Real-time measurements are taken both at the primary substation and at remote sites on the network, such as generator points of connection or nodes where large voltage variations are expected. As an AVC relay typically operates after a delay of between thirty seconds and two minutes, the remote measurements are communicated to the controller every few seconds. Low power radio or public data networks are considered suitable communications technologies.
If the voltage controller loses communications or fails, the AVC relay reverts to autonomous operation. This is achieved using a hardware refresh of the AVC relay target voltage input, which returns the target voltage to a set value in the absence of an input from the controller.

As the voltage controller allows the capacity of distributed generators to be increased, in the event of voltage controller failure, it is possible for a generator to cause an over voltage. Installing an over-voltage relay at each generator point of connection can prevent this.

The state estimation algorithm models the node voltage magnitude estimates as Normal and calculates an expected value and standard deviation for each node. Since the real-time measurements are much more accurate than pseudo measurements, the addition of real-time measurements improves the state estimate accuracy. However, as real-time measurements are expensive, it is desirable to use the minimum number necessary to provide an acceptable control range.

The controller’s main features, however, remain the statistical state estimation and control of a network, based on measured and estimated data, ensuring that all the network nodes stay within the statutory limits.

The use of area-based voltage control has been evaluated against the Workstream 3 assessment criteria and the following implications have been identified:

**Implications for customers**
- This solution may require the installation of monitoring equipment at customer sites.

**Implications for distributed generators**
- The solution leads to a reduction in generation curtailment.
- The solution may involve additional monitoring cost to be provided by distributed generators for the solution’s implementation.

**Implications for distribution network operators**
- The solution requires the distributor to introduce additional monitoring and control equipment into the network.
- The problems of voltage unbalance within the network may introduce problems with the solution’s operation.

In order to develop this innovative solution, the DTI funded a project “Active Network Management” which is being carried out jointly by Econnect, Hathaway, UMIST, 24 Seven and United Utilities. The implementation of such schemes are important in helping to realise the solutions today. To facilitate this, Econnect is working on a controller and product called GenAVC. This is being developed for active voltage control and Econnect is planning to install two basic active network management controllers on 24 Seven’s and UU’s networks in 2003. The GenAVC system will be installed on two real networks in this demonstration project and so the units will operate in monitoring mode for a year, with the control unit disabled. The control algorithms will be activated once confidence has been established during this monitoring period.
4 Power flow management

One of the roles of a network operator is to manage the risks associated with network power flows. For example, power flow becomes a risk management issue when the distributed generation capacity connected to the network could exceed the firm capacity of the upstream network to which it is connected. Under these circumstances, network assets are at risk of being operated above their rating (and therefore failing) following a circuit outage. Therefore, network power flow management takes into account the capacity and security of the network for both normal operation and following a circuit outage. A First Circuit Outage (FCO) event can be either be a planned event (e.g. due to network maintenance or network development) or unplanned (due to faults). A Second Circuit Outage (SCO) event almost always refers to a fault occurring during a planned circuit outage.

The short-term solutions identified in a previous stage of the study are:

- network Enhancement;
- pre-fault Constraint;
- post-fault Constraint (intertripping);
- post-fault Constraint (dynamic, including use of short-term ratings).

In addition, whilst Demand-Side Management (DSM) is still considered to be a long-term solution, some additional comments about DSM are given at the end of this section.

As further information, previous work in relation to intertripping can be found in project K/EL/00235/REP, carried out under the DTI/FES programme 2001.

4.1 Network enhancement

Conventional network planning and design is based on a “fit and forget” methodology, with network reinforcement taking place to allow full generator output under normal network operating conditions. Where dual circuits are present, such as a typical 33kV radial feeder network, reinforcement is normally carried out when necessary to allow the generator to continue to operate at full power under FCO conditions.

The network enhancement power flow management solution has been evaluated against the Workstream 3 assessment criteria and the following implications have been identified:

Implications for Customers

- Network enhancements to accommodate more distributed generation generally also have benefits for load customers.
- Network upgrades can normally be accommodated without interrupting supplies to customers (e.g. the building of new network or upgrading existing network during the summer months, when networks are more lightly loaded). Exceptions to this include rural overhead rebuild – it is usual for such projects to involve shutdowns.
- Power quality and quality of supply issues are generally improved.
Implications for Distributed Generators

- Deep connection costs are the main concern for distributed generators. A move towards shallow(ish) charging in the future would mitigate this.
- Network enhancement generally brings benefit to distributed generators in terms of increased power export capability, improved quality of supply and power quality.
- Also, short-circuit levels may also be increased (up to the design limit of the network), thereby increasing generator stability.
- If the network enhancement involves the construction of new lines, this could have planning implications.

Implications for Distribution Network Operators

- Network enhancement is a traditional approach for network operators and so the technical issues are well understood.
- Quality of supply and power quality generally improve.
- Network enhancement normally provides sufficient additional capacity to meet all needs for a significant period into the future.
- The costs for network re-inforcement are currently recovered from distributed generators in the form of a deep connection charge. A change to this approach could facilitate otherwise financially non-viable projects, with a consequential increase in DNOs capital requirements.
- Short circuit levels do tend to rise and so fault level issues could become important if fault levels are already close to plant ratings.

In summary, whilst network enhancement is a technically attractive solution it is also very costly. Thus, alternative methods need to be considered and used whenever possible.

4.2 Pre-fault constraints

A “pre-fault constraint” describes the criteria against which a network operator will assess the acceptable level of export, in anticipation of, and to cater for, the next outage regardless of whether the system is intact or depleted. If a “pre-fault constraint” is applied, this means that at the planning stage (i.e. under normal system conditions), the generation connection capacity is limited to the FCO (i.e. firm) rating of the network and the constraint is implicit.

Similarly, under a pre-fault constraint, the generator is constrained to the network “second circuit outage” capacity following the FCO. If a constraint for the SCO condition is applied, a generator is required to either reduce its output power or even shut down completely. In this way, the network is not placed at risk should a second circuit outage occur. Unfortunately, the second circuit outage capacity may place significant restrictions on the generator output. For example, a second circuit outage on a dual circuit supply in a rural network would almost certainly mean the generator would need to disconnect from the network. It is the extent to which the generator is constrained that determines the need for network reinforcement. In principle, pre-fault constraints could be carried out in “real time”, although it could also be achieved more coarsely via seasonal control.

The pre-fault constraint power flow management solution has been evaluated against the Workstream 3 assessment criteria and the following implications have been identified:
Implications for Customers

• This solution is neutral to load customers.

Implications for Generators

• The solution can significantly restrict output from distributed generation, depending on the network capacity under a FCO condition and the frequency and duration of the subsequent constraint periods.
• The constraint frequency and duration cannot be predicted accurately beforehand and so distributed generators face significant risk and uncertainty with respect to forecasting their generation output.
• A constraint can be relieved by enhancing the network capacity.

Implications for Distribution Network Operators

• This solution is also neutral to network operators, since the generation is currently not relied upon for security of supply and is disconnected during periods when the network’s capability is temporarily reduced.
• The means for implementing the constraint would be defined in the connection agreement.
• The solution reduces the potential for distributed generation to contribute to network security. Suggested changes to the P2/5 planning standard would recognise some contribution to security from distributed generation.
• There can be an overhead on DNOs in assessing the applicable pre-fault constraint to be applied. This can be done once at connection time, or more frequently down to real time.

In the past, Generators have considered the option of reducing output capacity in anticipation of (and to cater for) the next circuit outage condition rather than face the high reinforcement costs of achieving full output during this condition. However, this approach reflects a risk-averse nature in network operators.

There are other power flow management solutions which do not place such an onerous constraint on the generator, although the risk to the network operator’s network is increased slightly. However, the increased risk is believed to be manageable, and will therefore be taken on board by network operators if they are incentivised to do so. These solutions are known as post-fault constraints, as opposed to pre-fault constraints.
4.3 Post-fault constraints

As its name implies, a post-fault constraint is applied after a circuit outage has occurred rather than being applied “in anticipation” of an outage. In this way, the frequency of application of the constraint is much reduced. However, given the risk to the network should a constraint not be implemented when needed, a reliable method of safeguarding the integrity of the network is required. A constraint can be applied in the form of an intertrip or as a generator power reduction.

Power flow management is best shown using an example. A simple illustration of power flow is given in Figure 4.1.

**Figure 4.1: Network power flows**

In this example, the size of the generator that could be accommodated on the network would normally be restricted by conventional network design methodology to the firm capacity of the 11kV busbar, which in this case is 12MVA. In addition, if a pre-fault constraint was applied, the generator would have to disconnect following a FCO, (planned or unplanned) in anticipation of the SCO. The connection of a generator larger than 12MVA would normally be achieved either by connecting the generator at a higher voltage level or by reinforcing the network (by the addition of a transformer and/or addition of a 33kV circuit) in order to increase the network firm capacity.
A slight increase in generator connection capacity can be achieved by taking into account the local load on the Primary substation. If the substation minimum load is used, the generation connection capacity can be increased to 14MVA (i.e. 12+1+1). This could be further refined by the use of summer and winter minimum loads, where a winter minimum load of 2MVA per feeder would increase the maximum connectable generation still further to 16MVA (12+2+2), with a constraint to 14MVA applied during the summer months. Such an arrangement could be encapsulated as an appended schedule in the Generator Connection Agreement, with a simple “manual” operational implementation, such as a telephone call or fax to the Generator to enforce (or remove) the constraint.

However, the most significant increase in generator connection capacity can be achieved if the non-firm capacity of the substation is used. This requires the use of post-fault constraints rather than pre-fault constraints. In this case, the connection capacity could be increased to 24MVA for normal network operating conditions. This limit could be increased even further if the magnitude of the local load is also taken into account.

Using post-fault constraints, the output of the generator is reduced to the “firm” capacity (plus any allowance for the local load) following a “FCO” condition (i.e. 12 to 16 MVA if an allowance is made for local load). This generator reduction can be achieved in several ways, depending on the local circumstances. Three methods are described here, although other variations exist and additional refinements are always possible. These methods are:

- direct intertripping;
- generator trip based on power flow measurements;
- generator power output control based on power flow measurements.

In the latter two cases some form of backup system would be required to cater for failure of the main control system.
4.3.1 Direct intertripping

Implementation of post-fault constraint using direct intertripping is shown in Figure 4.2. Here, the generator circuit breaker is tripped in the event of any of the upstream breakers tripping (caused by either the loss of a 33/11 kV transformer or fault on either 33 kV feeder). In some cases the intertripping scheme can be simplified if there are no 33 kV circuit breakers at the Primary substation or if there is some intertripping provided as part of the existing protection system. The use of intertripping has the potential for fast response but its overall reliability is dependent on the reliability of the communications links between the remote circuit breakers and the generator breaker. Dedicated hard-wired pilot wires offer the most reliable communications solution, but this is often not practical due to cost.

The most commonly used communication link is a BT phone line. However, these can prove to be unreliable, especially in remote, rural areas. Their cost can also be expensive. As a consequence, satellite-based communication has been used in some remote rural locations in the UK. During periods when the intertripping scheme is out of service (e.g. due to scheme maintenance or communications failure), the generator will need to be operated according to the pre-fault constraint approach in order to protect the network from potential operation beyond its thermal rating. Also, experience has shown that in practice some false tripping of the intertrip scheme can occur.

![Figure 4.2: Generator power flow control based on intertripping](image-url)
4.3.2 Generator trip based on power flow measurements

In some situations (i.e. when the generator power reduction requirement is not so urgent or a direct inter-tripping scheme becomes overly complex) it may be possible to implement the generator trip based on power flow measurements at a single site, in this case, the Primary substation. This implementation is shown in Figure 4.3. The principle of this approach is to measure the net export of power through the two primary transformers, thus taking into account the generator output and the load demands. If the net export is less than the network capacity, no trip is necessary on the loss of the first circuit. The trip is only armed when the net export capacity is greater than the network firm capacity. Real and reactive power flows should be considered.

Figure 4.3: Generator trip based on power flow measurements.
A more dynamic form of power flow control could take into account the short-term power ratings of network plant, such as feeders and transformers, as well as the actual levels of load in order to directly influence the generator power output. This would minimise any operational generator constraint, thereby maximising the exported energy from the generator. The implementation of a generator power reduction scheme is shown in Figure 4.4. In this arrangement, the power flow through the 33/11kV transformers (and 33kV feeders) is monitored to ensure that it remains within plant ratings. The short-term plant ratings can also be taken into account to allow the generator time to reduce its output power in a controlled manner should a sudden change occur in network capacity (i.e. due to a circuit outage).

If short term ratings are NOT used in establishing the design parameters, then there is some latitude to use these in the event that the control system fails and a backup process has to be called in to play. However, if short term ratings are used in designing the operating parameters, then they are NOT available to be used in the event that the main control system fails. In this case, it is far more likely that an intertripping scheme would be required. For example, as a backup, a generator trip signal could be initiated by the substation power monitoring system should the power flow exceed the network plant short-term ratings. However, in some cases it may be more appropriate to employ a completely independent backup scheme.
The backup system is needed to ensure that network equipment is not exposed to power flows above its capability in the event that the generator fails to implement the constraint. The requirement for a system to cater for this situation is dependent on the capability of the network to withstand the higher power flows before damage occurs. If the power flows exceed the short term rating of the network equipment, as is likely given that the system has the potential to exploit the maximum capability of the network, immediate intertripping would be required. If the power could be accommodated for a period of several hours before damage occurs, a simpler, more manual system may be more appropriate.

Also, whilst not essential, monitoring of the power flow on the generator’s 11kV feeder would give additional flexibility in the power flow control strategy. For example, it would give a direct indication of the generator's response to any change in constraint conditions.

It should be remembered that these example are only considering power flows. In a real situation, voltage control and fault levels are also likely to need consideration in conjunction with the power flow issues.

The practical implementation of any generator power reduction scheme is likely to be more involved than the simple examples previously described, due to any specific local factors. Therefore, the viability of any scheme will need to be judged on its own merits. In practice, the nature of the local historical development will have a strong influence on the design of any power deduction scheme. For example, intertripping schemes become very complex very quickly within meshed or interconnected networks.

Power flow management in the form of generator power reduction and/or intertripping is a technically viable alternative to network reinforcement in many circumstances. However, there are implications at both the “planning” and “operational” level. The main issues can be summarised as:

**Implications for Customers**
- Possibility of a slight increase in number of voltage step changes, due to generator trips. Most frequent intertrip operation will occur in areas with high incidents of network faults.

**Implications for Distributed Generators**
- This solution can be applied to CHP generators, although there may still be demand for the CHP plant’s heat output.
- This is a cost-effective solution, at the expense of increased curtailment of the generation compared to network reinforcement.
- This solution reduces any potential contribution to security of supply from the generator.
- Intertripping will also increase the number of voltage step changes (and voltage vector shifts). This may cause increased occurrences of nuisance tripping caused by the mal-discrimination of loss-of-mains protection.

**Implications for Distribution Network Operators**
• The technical and commercial complexity of an intertripping scheme increases rapidly as the number of distributed generators and the number of network ‘ends’ increases. The number of network ‘ends’ is influenced by network design philosophies.
• Maintenance of the intertripping scheme, particularly unplanned maintenance due to communication link service-provider issues needs to be taken into account.
• Methods for providing backup of the intertrip scheme need to be considered, since the failure of a generation reduction scheme when needed, is likely to have serious safety implications.
• Guidance or rules need to be developed to provide “ranking” of schemes when more than one generator operator is involved.
4.3.4 A real example of post-fault constraints using intertripping

Figure 4.5 shows an example of an actual intertripping scheme. The scheme is located in a rural area with significant hydro and wind generation. With the exception of one significant load centre, the scheme is located some distance from populated areas. Thus, the distribution network is particularly sparse in the region.

Figure 4.5: Example of a real intertripping scheme for generator power flow control
Substation 1 and Substation 2 are interconnected at 33 kV and are located some 12 miles apart, with each substation having a single 45 MVA 132/33 kV transformer. The incoming 132 kV feeders are both long overhead lines, each approximately 50 miles in length. Historically, the first substation was installed to supply the main load centre, whilst the second substation was installed to provide export capacity for the large hydro power station. The diagram shows intertrip “Scheme A”, which is a conventional intertrip protection scheme, which pre-dates the connection of any of the wind farms.

The hydro station was installed prior to electricity privatisation in 1989 and so has inherited rights to operate unconstrained (system normal). However, the three wind farms were constructed with support from the non-fossil fuel obligation (NFFO) at various times during the 1990’s. The 6 MW wind farm was connected first and was able to operate unconstrained within the available network firm capacity. However, the next generator to connect was the 12 MW wind farm. This caused power flows to exceed the firm capacity of the 132 kV network and so the first part of the Scheme B intertrip was introduced. The 3 MW wind farm was the next to connect and so the Scheme B intertrip was extended to include this wind farm. More recently, the original 6 MW wind farm increased its capacity to 9 MW. This increase caused the power flow in the 33 kV interconnecting network to exceed its rating. Thus, the Scheme 3 intertrip scheme was introduced and is applied only to the extra 3 MW of generation capacity.

Thus, it can be seen that the local network contains three functional intertripping schemes, described here as Scheme A, Scheme B and Scheme C. Scheme A is a conventional intertrip protection scheme and so is not described in any detail here. However, the Scheme B intertrip was installed to manage the power flows associated with the 132kV feeders and 132/33kV transformers, whilst the Scheme C intertrip is for power flow management within the 33 kV network. These two schemes are described in more detail below.

The scheme B intertrip consists of two independent halves (B1 & B2), triggered by directional overcurrent relays which are monitoring each of the two substation transformers. A 200msec time delay is used to avoid intertripping on transient faults on the 132kV overhead line. The intertrip can also be triggered by the 132 kV feeder protection. The intertrip signal to the 12 MW wind farm uses a BT line, whilst the 3 MW wind farm can be disconnected by tripping the Substation 2 circuit breaker. The two intertrip halves are linked together using “triangulation”, i.e. additional direct BT communication links between the two substations which provides increased communication security.

As an added complication, the power flows through the 33 kV network between the generation, which is predominately connected to Substation 2, and the load, which is predominately connected to Substation 1, can cause excessive power flows within the 33 kV network. Hence, the need for the additional intertrip scheme (Scheme C), monitoring the substation interconnecting circuits. The trip level is set at 18MVA (summer rating), with a 60 second time delay to allow the generator time to reduce to a total unconstrained level of 6MW.

An important point to note is that should the intertrip scheme fail to operate when required, this could result in a cascade failure of both circuits, whereby the failure of one circuit causes an overload failure of the second circuit. The consequential risk is therefore very high.
In summary, key features of the example include:

- rural location with excellent renewable resources but limited local load and network;
- an older hydro generation site with inherited unconstrained rights;
- incremental evolution of new generator connections;
- expansion of generation capacity at existing sites.

Key features of the intertripping schemes include:

- separation of the “protection” from the “control” intertripping schemes;
- separate intertripping schemes for the 132 kV and the 33 kV power flow control;
- “triangulation” of the intertripping signalling between the substations for increased communications security;
- use of BT lines for the intertrip signalling to the remote sites;
- the introduction of appropriate time delays is important to optimise system performance;
- consequential risk of cascade failure is very high.

Experience to date has shown that the BT lines have proven to be less reliable than anticipated, with communication failures often co-inciding with network failures (i.e. both failures caused by adverse weather conditions). Also, as more and more generation capacity is connected in the region, the timing issues associated with the protection and intertripping schemes become more and more important. This means that the whole scheme has to be re-assessed each time a new generator needs to be accommodated. This incurs additional engineering effort.

Further generation sites are appearing in this particular area. For example, a connection is currently being developed for a 58 MW wind farm to connect to the 132 kV network, close to Substation 1. This connection will introduce additional complexities for determining power flows and generator constraints in the local network.

One option that has not been possible to explore in the past, but may be appropriate to consider in the future, is to investigate how complementary generation technologies, such as hydro and wind, can be operated co-operatively in order to maximise the utilisation of the available network capacity. This introduces additional commercial and regulatory issues as well as technical considerations and so this is beyond the scope of this report. This example has the potential to be developed in the future within Ofgem’s “Power Zone” concept, whereby certain regulatory issues can be ring-fenced. This would reduce the levels of commercial risk, thereby facilitating a more innovative approach.
4.4 Power flow management in interconnected networks

The design approach used in interconnected networks is different to radial network design and therefore the implementation of power flow management is slightly different. In traditional radial networks, primary transformers are located in pairs. However, in interconnected networks, single transformer substations are typically connected together in groups of three, four or five. If more power capacity is required, additional transformers are inserted into a new node in the network. If this insertion creates a group with six transformers, this group is then split to create two groups of three. In this way, interconnected networks are designed to cope well with a certain level of “organic” growth and in this way manage fault levels and power flow “automatically”. However, interconnected networks tend to work with smaller unit sizes (i.e. single 7MVA transformers as opposed to 12+12MVA transformer pairs) and so the scope for increasing generator connection capacity at single nodes is more limited.

The use of intertripping within an interconnected network also increases the risk of introducing a cascade failure within the network. The failure of an intertripping scheme to operate would place other parts of the network under stress, causing additional circuit trips and subsequent loss of network capacity, resulting in additional stress to the network and even more circuit trips.

4.5 Future refinements for power flow management techniques

Whilst it is agreed that power flow management in the form of intertripping and post-fault generator constraints can be applied immediately, some future activities are required to refine some of the technicalities. Issues beyond the scope of this study include:

- The use of novel control and communication possibilities;
- Alternative commercial and regulatory treatment of constraints;
- Definition of the requirements for redundancy (i.e. backup systems) to reduce the consequential network risk in the event of a power management system failure to function;
- Contribution to security (i.e. linkage to the application any future revisions to ER P2/5);
- The technical, commercial and regulatory factors that provide the criteria for network reinforcement;
- Acceptable levels of generation which could be at risk of being tripped;
- The extent of acceptable complexity of any intertripping scheme;
- Priority order (ranking) of the application of output constraint when multiple generators are present.

4.6 Demand-side management

Power flows can also be controlled by the management of demand as well as generation. It is normally easier to shed load than it is to ask load to increase on request. Unfortunately, network constraints normally require an increase in local load rather than a decrease. However, developments are taking place in the field of utility-scale energy storage, which could provide the necessary functionality. Whilst this is an option for the longer term, it should be possible to implement simple demand-side management schemes relatively easily, using similar techniques to those described for generator power reduction.
5 Conclusions

The evolution of electricity distribution networks is a continuous process. However, the network is now entering a new phase of that evolution and will be required to accommodate distributed generation whilst maintaining or improving the quality of supply and power quality to load customers. The nature of the distribution network, characterised by large physical assets with long operational lifetimes, means that any fundamental physical changes to the network necessarily take place over extended periods of time. Thus, it takes some time for changes in fundamental network design practices to permeate through into physical changes to the network. However, changes to operational practices, driven by commercial or regulatory incentives, can produce significantly faster effects. The evolution of the network will be driven by new network management principles, created by new commercial and regulatory incentives and underpinned by new network design philosophies.

This report has outlined some of the operational and design changes that are currently taking place (or currently under consideration) in the UK to accommodate the connection and operation of distributed generation. Given the dynamic nature of change, the various solutions are at different stages of evaluation within network operators in terms of revising the relevant network design and operational practices. This report has endeavoured to document these practices in order to facilitate a more rapid and even take-up of these new techniques across UK network operating companies.

Of the three technical areas examined in this report, the voltage control solutions are perhaps the most refined. These voltage control solutions relate well to each other, in effect providing a package of incremental solutions as the need arises. For example, it is possible to see a natural progression from the application of a single voltage regulator to accommodating a single small wind farm on a remote 11kV feeder. The development would extend to the additional use of cancellation CTs and generator real/reactive power control as the size and number of turbines increases within a local network area, culminating in a significant amount of generation being managed by an area-based voltage control system. The order of application is not necessarily fixed in this way, but this does illustrate the incremental application of the solutions.

![Figure 5.1: Incremental application of voltage control solutions](image)

Fault level management presents particular challenges because of the inherent health and safety implications of ensuring that switchgear is operated within its fault current handling capabilities. In addition, any significant changes in the way networks are designed could have an impact on customers’ quality of supply and power quality. Several short-term
solutions which are being used now or could start to be used on a more widespread basis have been identified, including increasing component impedances, the use of inverter technologies for wind turbines, moving network open points and consistent use of Engineering Recommendation G74.

However, many of the potential solutions have significant issues associated with them, and require a better understanding before they can be generally applied within UK distribution networks. These include the use of different network splitting topologies (i.e. open bus sections or transformer breaker on open standby), the use of Is limiters and the application of sequential switching. Additional work has been defined for these solutions, leading to further studies aimed at addressing both the network performance and risks and the health and safety issues. As the number of applicable fault level solutions increase, the flexibility of the network will also increase. This will lead the way to more advanced active fault level management techniques as the solutions become integrated into conventional network design techniques.

Power flow management tends to be an issue where there is a significant concentration of renewable resource for generation and this often coincides with areas of a weak network. The major step forward proposed here is the move away from “pre-fault” constraints to “post-fault” actions, with the application of constraint taking the form of either intertripping or generator power reduction. The power flow management solutions described in this report can generally be applied to single generator operators. However, the presence of multiple generator operators introduces “third party” regulatory and commercial implications. The scope of these additional implications has been defined.

Finally, although the solutions have been described separately in this report, issues of fault level, voltage control and power flows are often inter-dependent and in practice will need to be considered concurrently in any real application.

6 Recommendations

The main recommendations from this study are:

- to continue to promote the solutions described in this report;
- to progress the immediate further work identified in this study;
- to develop and confirm the process by which the evolving best practice within the industry can be continued to be captured and disseminated;
- to encourage pilot projects where solutions have yet to be demonstrated.

Solutions which have shown particular merit for their relative ability to solve real problems include:

- increasing impedances of components (transformers, generators and inserting reactors);
- converter technologies for wind turbine generators;
- generator real/reactive power control;
- line voltage regulation;
- cancellation CTs;
- post fault constraints (intertripping and generator power reduction).
Many of the more effective solutions, especially those related to fault level, require further work in order to address quality of supply or safety issues that their implementation might introduce. Solutions fitting into this category include:

- area-based voltage control;
- the use of the Is limiter;
- the application of sequential switching;
- the introduction of “split network” configurations;
- post fault constraints for multiple generators.

The work on area-based voltage control is being addressed by the DTI/FES supported project described in this report. However, the further work identified in this study for the other solutions should be progressed immediately.

Following this, further consideration will be needed to carry forward some of the more innovative solutions from the theoretical stage to the implementation stage. This will best be achieved by the setting up of significant field trials or demonstration projects. There is the potential for the more innovative solutions to be developed in the future within Ofgem’s generator-friendly “Power Zone” concept. This is yet to be fully developed, but could reduce the levels of commercial risk, thereby facilitating a more innovative approach. Such a demonstration would encapsulate and integrate many of the solutions discussed in this report under the collective banner of active network management. This would include:

- active fault level management;
- active voltage control;
- active power flow management.

Finally, it is important that as the solutions develop and become more refined, that “best practice” engineering continues to be captured and disseminated within the industry. Therefore, it is further recommended that a framework is established to ensure that this can continue to occur.
References

4. BM Weedy, “Electric Power Systems”.

Acknowledgements

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# Appendix I – Assessment criteria

## IMPLICATIONS FOR CUSTOMERS

<table>
<thead>
<tr>
<th>Ref.</th>
<th>Category</th>
<th>Key Questions to ask against each Solution (with sub-ref.)</th>
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</table>
| C1   | TECHNICAL      | 1. Does the solution provide dg capacity to a level that will lead to short circuit levels exceeding the capability of customer equipment, when compared against national planning standards or commercially agreed terms.  
2. Could the solution require the customer to change primary equipment, protective devices or settings |
|      |                | 1. Does the solution lead to a reduction or increase in Customer Interruptions.  
2. Does the solution lead to a reduction or increase in Customer Minutes Lost.  
3. Does the solution lead to a reduction or increase in short term / transient interruptions  
4. Does the solution lead to a reduction or increase in multiple interruptions.  
5. Does the solution involve disruption to supplies during implementation.  
6. Does the solution result in a reduction or increased in background voltage fluctuations.  
7. Does the solution result in a reduction or increase in the duration or depth of voltage fluctuations.  
8. Does the solution result in a reduction or increase in harmonics  
9. Does the solution result in a reduction or increased in background fault levels to an extent that prevents normal operation (e.g. motor starting) |
| C3   | FINANCIAL (CAPEX) | 1. Does the implementation of the solution trigger customer capital investment requirements to adjust their installations to cater for any implications.                                                                                     |
## IMPLICATIONS FOR CUSTOMERS

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<th>Ref.</th>
<th>Category</th>
<th>Key Questions to ask against each Solution (with sub-ref.)</th>
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<tbody>
<tr>
<td>C5</td>
<td>REGULATORY</td>
<td>1. Will the solution be constrained within existing network planning limits to which existing customers based their equipment ratings.</td>
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</tbody>
</table>
| C8   | SAFETY   | 1. Will the solution lead to more or less fault damage resulting from a change of short circuit currents or changes in fault duration time.  
2. Does the solution result in customer protection systems not grading or not operating.  
3. Does the solution result in faster or slower operation of safety systems. |
<table>
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<th>Ref.</th>
<th>Category</th>
<th>Key Questions to ask against each Solution (with sub-ref.)</th>
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</table>
| G1   | TECHNICAL                                   | 1. Is the solution dependent on the generation technology or limited by the generation technology  
2. Will the solution require the generator to modify the technical design of his equipment.  
3. Will the solution require other generators to change protective devices or settings. |
| G2   | QUALITY OF SUPPLY                            | 1. Does the solution lead to a reduction or increase in Connectivity Interruptions.  
2. Does the solution lead to a reduction or increase in availability of the connection.  
3. Does the solution lead to a reduction or increase in short term / transient interruptions to connectivity.  
4. Does the solution lead to a reduction or increase in multiple interruptions to connectivity.  
5. Does the solution involve disruption to supplies during implementation.  
6. Does the solution result in a reduction or increased in background voltage fluctuations.  
7. Does the solution result in increase the duration or depth of voltage fluctuations.  
8. Does the solution result in a reduction or increased in background harmonics.  
9. Does the solution result in a reduction or increased in background fault levels to an extent that has a detrimental effect on normal and transient operation (e.g. loss of steady state or transient stability) |
| G3   | FINANCIAL (CAPEX)                            | 1. Does the solution increase or reduce generator connection costs (excl DNO costs) relative to the additional connected capacity achievable.                                                                                                                                                                      |
| G4   | FINANCIAL (OPEX)                             | 1. Does the solution trigger generators ongoing additional operational costs in operating their installation with the implemented solution (settings, training, method of operation etc.).                                                                                                               |
| G5   | REGULATORY                                  | 1. Will the solution be constrained within existing network planning limits to which existing generators based their equipment ratings.                                                                                                                   |
| G8   | SAFETY                                       | 1. Will the solution lead to more or less fault damage resulting from a change of short circuit currents or changes in fault duration time.  
2. Does the solution result in generator protection systems not grading or not operating.  
3. Does the solution result in faster or slower operation of safety systems |
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<td></td>
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<td>D1  TECHNICAL</td>
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<tr>
<td></td>
<td></td>
<td>1.  Does the solution lead to short circuit levels exceeding the capability of distribution equipment.</td>
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<tr>
<td></td>
<td></td>
<td>2.  Does the solution require operational practices to be implemented to avoid short circuit levels exceeding the capability of distribution equipment.</td>
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<td>3.  Does the solution require the distributor to change equipment, protective devices or settings.</td>
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<td>4.  Will the solution affect voltage profile on circuits</td>
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<td></td>
<td>5.  Will the solution require a review of voltage control systems.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>6.  Is the solution scaleable or is the enhanced headroom limited. Will the solution lead to the need for more complex distributor monitoring and communication and control systems.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>7.  Will the solution result in slower operation of distributor safety systems</td>
</tr>
<tr>
<td></td>
<td></td>
<td>D2  QUALITY OF SUPPLY</td>
</tr>
<tr>
<td></td>
<td></td>
<td>1.  Does the solution result in a reduction or increased in background voltage fluctuations requiring review of distribution plant</td>
</tr>
<tr>
<td></td>
<td></td>
<td>2.  Does the solution result in a reduction or increased in background harmonics requiring review of distribution plant.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>D3  FINANCIAL (CAPEX)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>1.  Does the solution trigger distributor capital investment to adjust networks for the solution being catered for.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>D4  FINANCIAL (OPEX)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>1.  Does the solution trigger distributor ongoing additional operational costs in operating their installation with the implemented solution (settings, training, method of operation etc.).</td>
</tr>
<tr>
<td></td>
<td></td>
<td>D5  REGULATORY</td>
</tr>
<tr>
<td></td>
<td></td>
<td>1.  Will the solution be constrained within existing network planning limits to which distributors based their equipment ratings and advise customers.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>D6  COMMERCIAL</td>
</tr>
<tr>
<td></td>
<td></td>
<td>1.  Will the solution lead to a condition where distributor has conflict with either statutory or ‘good industry practice’ compliance issues or existing commercial arrangements.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>D8  SAFETY</td>
</tr>
<tr>
<td></td>
<td></td>
<td>1.  Will the solution lead to the need for enhanced distribution equipment ratings.</td>
</tr>
<tr>
<td><strong>IMPLICATIONS FOR DISTRIBUTION NETWORK OPERATORS</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>---------------------------------------------------</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2. Will the solution lead to the need for modified distribution protection systems to assure grading or operation.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>3. Does the solution require a departure from the standard safety philosophy for electricity networks</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Appendix II – Benchmark costs of solutions

The network operator and generator communities were surveyed using a simple questionnaire in order to obtain approximate benchmark costs for the various solutions. Some solutions have more established implementation than others and so the accuracy of the cost information in the table is not necessarily consistent. Also, the absolute cost values are subject to individual variations, due to undefined means of calculation. However, notwithstanding these limitations, the cost table does provide value as a qualitative benchmark of the relative costs of the solutions.

Determining such costs is always a difficult task, with determining exact costs even more of a difficulty since distribution networks are not homogeneous. An indication therefore of the relative costs is a more realistic and helpful indicator. To enable this comparison, the costs of the solution are divided into the following price ranges:

<table>
<thead>
<tr>
<th>Cost</th>
<th>Range</th>
</tr>
</thead>
<tbody>
<tr>
<td>Low (L)</td>
<td>Less than £20,000</td>
</tr>
<tr>
<td>Medium (M)</td>
<td>£20,000 to £50,000</td>
</tr>
<tr>
<td>High (H)</td>
<td>£50,000 to £200,000</td>
</tr>
<tr>
<td>Very High (VH)</td>
<td>Over £200,000</td>
</tr>
</tbody>
</table>

Based on the responses from 8 DNOs and 4 generator operators to the questionnaire, the costs are summarised in the following table. The costs are given in either a “per km”, “per MVA”, “per item” or “per scheme” basis, as appropriate. Each questionnaire response has been translated into an “X” in the table. The more X’s in one table cell means more consensus in the responses. The more scattered the X’s implies different opinions between the respondents.
Several supplementary points came out of the questionnaire which are worthy of mention.

These include:

- In addition to the cost/km, there are significant fixed costs associated with installing overhead lines and cables.
- For overhead lines and underground cables, the cost per km increases as the voltage level increases. However, in addition, the relative connection cost at higher voltage levels tend to increase even more because the amount of physical network decreases as the voltage level increases, typically resulting in the need for longer interconnections at the higher voltages.
- The uprating of switchgear is shown on a “per item”. In practice, it is likely that all the switchgear within the substation will need to be uprated. The cost becomes even greater if several substations are affected.
- Although the cost of an Is limiter is similar to a circuit breaker, the Is limiter is a single-shot device. Also, the current Is limiter does not fit into a standard switchboard panel – it needs a separate enclosure, with associated isolating switches to permit component replacement and therefore the cost of implementation is likely to be significantly more than the cost of the Is limiter itself.
## Appendix III – Related DTI/FES activities

<table>
<thead>
<tr>
<th>Study Title</th>
<th>K/EL/00***/REP</th>
<th>Date of Publication &amp; Status</th>
<th>Contractor</th>
</tr>
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<tbody>
<tr>
<td>Overcoming Barriers to Scheduling of Embedded Generation to support Distribution Networks</td>
<td>217</td>
<td>2000</td>
<td>E A Technology</td>
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<tr>
<td>Methods To Accommodate Embedded Generation on Existing Networks without Degrading Voltage Regulation</td>
<td>230</td>
<td>2001</td>
<td>EA Technology</td>
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<tr>
<td>Likely changes to network design, function and management as a result of significant embedded generation</td>
<td>231</td>
<td>2001</td>
<td>EA Technology</td>
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<tr>
<td>Embedded Generation on Actively Managed Networks</td>
<td>233</td>
<td>2001</td>
<td>Power Technologies Limited</td>
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<tr>
<td>Generator inter-tripping for Network Protection</td>
<td>235</td>
<td>2001</td>
<td>Econnect</td>
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<tr>
<td>Distribution Management Systems</td>
<td>262</td>
<td>2002</td>
<td>UMIST</td>
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<tr>
<td>Monitoring Fault In-Feed</td>
<td>269</td>
<td>On-going</td>
<td>EATL</td>
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<tr>
<td>Technical Solutions to Enable Embedded Generation Growth</td>
<td>278</td>
<td>2002</td>
<td>UMITEK</td>
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<td>Stability of Networks with Distributed Generation and Power Converter Interfaces</td>
<td>273</td>
<td>On-going</td>
<td>Alstom</td>
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<td>Active Local Distribution Network Management for Embedded Generation</td>
<td>271</td>
<td>Starting</td>
<td>Econnect</td>
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<tr>
<td>High Temperature Super-conducting Fault Current Limiter</td>
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<td>Starting</td>
<td>V A Tech</td>
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<tr>
<td>An Innovative Voltage Control for Wind Turbine Clusters</td>
<td>recommended</td>
<td></td>
<td>SP Power Systems</td>
</tr>
<tr>
<td>Network Management for Active Dist Networks – Feasibility Study</td>
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<td>SP Power Systems</td>
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<tr>
<td>Renewable energy and active Network Management</td>
<td>311</td>
<td>approved</td>
<td>SSE</td>
</tr>
<tr>
<td>Is Limiter risk assessment</td>
<td>tendering</td>
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</tr>
<tr>
<td>Optimisation of an Innovative Voltage control for wind turbine clusters</td>
<td>-</td>
<td>proposed</td>
<td>SP Power Systems</td>
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