ISLANDED OPERATION OF DISTRIBUTION NETWORKS

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This work was commissioned and managed by the DTI's Distributed Generation Programme in support of the Technical Steering Group (TSG) of the Distributed Generation Co-ordinating Group (DGCG). The DGCG is jointly chaired by DTI and Ofgem, and further information can be found at www.distributed-generation.gov.uk

Contractor

Econnect Ltd

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Project Steering Group Summary

Introduction and Background:

In support of DGCG TSG, Workstream 5, the Department of Trade and Industry's New and Renewable Energy Programme commissioned Econnect to undertake an investigation and report on the potential for Islanded Operation of Distribution Networks. The work was to be carried out from a distributed generation (DG) and Distribution Network Operator's prospective. The final report is titled 'Islanded Operation of Distribution Networks'.

The investigation was undertaken during the second and third quarter of 2004. In carrying out the study, Econnect consulted a number of Distribution Network Operators and OFGEM. A P05 project steering group was set up to review the interim report at the end of Phase 1, confirm selection of the case studies and review the final report at the end of Phase 2.

The combined final report was submitted to Future Energy Solutions (FES) in October 2004. FES is the DTI's New & Renewable Energy Programme's managing contractor.

Aims and Scope of Study:

The aim of the study was to assess the benefits and risks, to distribution networks and their users, of generator islanding and to identify regulatory, commercial and technical changes required to facilitate islanding operation.

Phase 1 of the work was to include the following:

1. Brief review of published literature to provide a status of the subject, and if available identify possible solutions offered by previous authors to islanding issues.

2. Identify UK generators which could operate as part of an island network within the existing regulatory, technical and safety framework.

Phase 2 of the study was to include the following:

3. Detailed examination of case studies selected from above.

4. Define changes and make recommendations that would be required to industry procedures, design standards and operational processes to facilitate safe reliable operation of islanding.

5. Provide an indication of the costs and benefits to both the network operators and generators of islanding based on the expected growth of integration.

Two case studies, based on existing networks, were selected. Technical and commercial analyses were carried out on the selected case studies. The scenarios to be investigated were of medium term up to 2010.

Findings/Conclusion:

- The studies confirmed that there were only a small number of locations on distribution networks where islanding support would be commercially viable.

Conclusion of Steering Group:

- The Workstream 5 project steering group concluded that no clear case for widespread islanding could be demonstrated from the limited number of case studies. The Group's summaries were as follows:

    a. The probability of credible faults that could lead to islanding is likely to be very small and tends to reduce the economic justification for islanding as mentioned in the report.

    b. The report assumes that in the future islanding will be carried out by embedded generation built for other reasons and therefore the costs of construction, operation and maintenance of generating plant will not be solely attributed to islanding. The costs for conversion of this generating plant to support islanding have been estimated and included in the economics. Similar considerations for installing and operating generators specifically for islanding support were outside the scope of the study.

    c. At present islanding is still not likely to be commercially attractive, but may be in the future.

    d. There are technical issues which can be resolved at a cost. With islanding demonstrations and with more DG connected to the network, these costs are likely to fall

- The technical studies have identified the need to review parts of the Electricity Safety, Quality and Continuity Regulations and taking the opportunity to recognise islanding when relevant Engineering Recommendations are next reviewed.

Next Steps: The Technical Architecture Project could provide a good opportunity to develop systems that could facilitate islanding; however it is important that it should be considered realistically against the wider picture in the development of future networks beyond 2010.

The commercial case for islanding is reviewed when there is a greater amount of DG connected to the network that is actively managed, and which potentially includes the provision of Ancillary Services through network support.

Lastly, it is recommended in the report that a demonstration project could be initiated under the auspices of the Registered Power Zone arrangements to discover the value of islanding capabilities of DGs.

B N Hamzah
Project Manager, TSG WS5 P05
1st December 2004

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1 Executive summary

This report details the work undertaken for the investigation into the technical, commercial and regulatory benefits and risks from the operation of distributed generation (DG) to power an islanded section of distribution network.

This work has been commissioned by the DTI on behalf of Work Stream 5 (WS5) of the Technical Steering Group (TSG) to the Distributed Generation Co-ordinating Group. The end objective of the study is to provide a targeted benefit and risk analysis on DG islanding, based on case studies of actual network configurations, by examining the required regulatory, commercial and technical changes to allow islanding to occur. The aims of Phase 1 were to

- Review existing literature on the topic;
- Consult with selected Distribution Network Operators (DNOs), Ofgem and others to obtain their views on islanding;
- Establish and define commercial and technical criteria and drivers;
- Define the methodology and scope for the Phase 2 work, to submit a report and meet with TSG Work Streams and obtain approval of methodology.

The aims of Phase 2 of the study were to

- Meet with the DNOs to identify and agree two case studies for consideration;
- Model the case studies in order to quantify the technical and commercial risks, benefits, and costs of islanding;
- Produce a case implementation plan for each case study;
- Produce the final report.

The literature review and meetings with DNOs and Ofgem, as covered in Section 3 (and at Appendices A and B) confirmed that islanding could be implemented from a technical standpoint. Very few examples of current islanding operations were found, and most of these related to geographic islands where islanded operation of diesel generators had been the normal supply arrangement. When sub sea cables had been laid to join these islands to the mainland distribution network, the ability of the remote island network to operate in islanded mode had been maintained. The benefits of islanding on these islands can be clearly seen on examining the relative vulnerability of sub sea cables coupled with anticipated repair times of weeks.

Sections 4 and 5 provide detailed technical criteria and related issues of operating DG within islands. The general conclusion is that, provided the identified criteria can be met, islands can be operated in a safe and satisfactory manner. There will be capital and revenue cost implications to meet the necessary criteria for both the DG and the DNO, and there will be significant variations in these costs between possible sites of application and the size and type of DG. It is therefore clear that there must be suitable financial benefits in order that the DNOs and DG owners can expect to receive an acceptable return on their investment.

In Section 6, the impacts of islanded operation on trading and settlement are reviewed. It was considered that the position of suppliers would be fairly neutral to the issues of islanded DG, and it was not possible to identify drivers to cause suppliers to promote DG islands. This situation was not helped by the use of profiling for non half-hourly metered customers.

Section 7 concentrated on the benefits of DG islanded operation to customers and to all the other stakeholders, including society in general, suppliers, DNOs, DG developers and generator manufacturers. Many benefits were identified, and a driver identified for further consideration was that of possible scenarios for the future (e.g. impact of fuel shortages, terrorism etc).

A proposed outline methodology for the selection of case studies for further investigation was described in section 8. The approach taken attempts to resolve the wide variations in islanding options so that the final selection can give the maximum value for the industry and its stakeholders. The methodology should allow each potential islanding network configuration/situation to be scored for a variety of factors to achieve a comparative score for each configuration, and enable selection of the most effective network configuration for further analysis.

Five possible systems for islanding were considered at the WS5 peer review meeting on the 9th June 2004 and put through the case selection methodology. The two systems, whose characteristics are described in Section 9, chosen for modelling were:

a) The common mode failure of sole twin 33KV feeders, which would cause islanding of a primary substation 11kV busbars that had no 11kV interconnection;

b) The loss of a single transformer feeder primary resulting in the islanding of an 11kV network.

These two examples were selected in order to enable the principles of islanding to be presented, rather than being typical primary substations on distribution networks.

Technical models of these two systems were then created using Simulink and three scenarios were applied, which would put each system under high stress (with large load swings) immediately post the islanding event. Results are shown in Section 10. The outputs showed that the DG and the induction motor loads within the two systems remained stable following the islanding event, although voltage and frequency exceeded the acceptable limits laid down in the Electricity Safety Quality and Continuity Regulations, Engineering Recommendation G59, and the BS EN 50160 standard. The use of frequency sensitive load controllers within the island to both add and shed load according to the scenario, helped to damp the voltage and frequency excursions, and bring them within acceptable limits. Analysis of the fault levels pre and post islanding show that despite the short term boost provided by the generator AVRs, the fault levels in the islanded network are approximately half those of the grid connected network, and these reduced fault levels would require an adjustment to protection settings on the islanded network to ensure correct protection operation in the island, post the islanding operation.

To assess the commercial incentive for islanding, the costs to the two DNOs of the two case study credible faults were assessed. These costs are discussed in Section 11. The credible common mode failure chosen for System A was the double circuit loss of several poles and spans of the 33kV feeder due to an extreme weather event requiring a restoration time of two days (an unusual and worst case scenario). In order to make a cost comparison, the alternative chosen to using the DG to provide seamless islanding was to reinforce the network through an 11kV interconnection. The financial analysis showed that should such a fault occur then the penalties for two days interruption of supply could be significant for the DNO in question, even assuming negligible compensation for the DG. The costs of reinforcement were also high and approximately equal to the possible penalty total, although there are other, significant, benefits to the network for future growth with the 11kV interconnection as it increases the firm capacity of the network. There could be a case for islanded operation here, if it could be provided at a cost that appreciably undercut the cost of reinforcement, and hence could be more reasonably offset against the perceived risk. Perceived risk is affected by the probability of such an outage.

The credible fault chosen for System B was the loss of the single incoming 33kV undersea cable to the 11kV network with a restoration time of 30 days. The alternative solution to seamless islanding using DG was the installation of a parallel-connected 33kV sub sea cable and the importation of standby generation post fault. In this scenario the penalties imposed on the DNO are potentially extremely large. The high cost of a second cable link means the only realistic alternative to in-situ DG based islanding is the more reasonable cost of importing standby generators to supply the islanded load. In this comparison it was assumed that the supplies from the standby generators would be immediately available following the fault. In practice there would be a considerable time interval and associated cost penalties incurred between fault occurrence and obtaining supplies from the standby generators, There is a case, therefore, for in-situ DG supplying the load, once this section of the network becomes islanded.

Section 12 provides a detailed implementation plan for the two case studies considered. These implementation plans cover issues of power balance, synchronisation, earthing, network protection, G59 protection, network operation and communications.

The commercial and regulatory drivers and incentives that could make islanded operation an attractive proposition for both Distributed Generators, Distributed Network Operators, suppliers, and not least customers, effectively fall into three broad groups, as discussed in Section 13. These are infrastructure, services, and market. The infrastructure drivers revolve around the DG providing network support, whilst the services drivers look at boosting the financial penalties the DNO face for Customer Interruptions (CI) and network unavailability. The market driver highlights the fact that there is a sales opportunity for seamless islanding already, though the DNO, DG, and suppliers are unable to compete in it at present.

It appears feasible to implement schemes that will allow DG operation of islanded networks with apparent seamless transfer (as perceived by the customer). The costs associated with retro fitting the necessary protection and control are high and will almost certainly be an obstacle to rollout programmes. The relative geographic arrangement of DG and primary substation impacts significantly on these costs. Taking a high level “Technical Architecture” type vision, then relatively low cost provisions could be included into the initial DG connections and future DNO reinforcements to minimise costs for subsequently ensuring islanding capability.

The recommendations of this report are

- It is probable that the ESI Engineering Recommendation documents G59/1 and G75, together with Engineering Technical Report 113/1 will be updated soon in the light of the new Grid Codes that are being developed to ensure grid stability during, and following, a major fault on the transmission network. This will ensure a common approach is applied which will benefit overall network stability and resilience. It is recommended that such an update should consider Technical Architecture issues, including the deliberate provision for DG operated islands.
- It is clear that the limits for frequency and voltage excursions laid down in ESQCR are too stringent to allow seamless islanding to occur and that a more probabilistic approach, similar to that used for EN 50160 would need to be developed to accommodate such events, although not necessarily with the same limits.
- That the commercial case for islanding is not pursued until more DG becomes connected and plays a more active role in the operation of both Distribution and Transmission networks, first through the provision of Ancillary Services, and then through network support.
- Although at present there is no commercial reason to take islanding forward, to enable a long term strategy for the technical architecture of future distribution networks to be formulated there is value in gaining further experience of the requirements for successful islanding on actual distribution networks. To enable this it is recommended that a demonstration project should be set up on a section of DNO network under the auspices of the Registered Power Zone arrangements, which incentivise the DNO to designate an area of network in which high quality innovation projects facilitate the added value connection of distributed generation (DG).

- The issue of DG operated islanded operation be included in the brief of the Technical Architecture think-tank so that the route map that may be developed in the near future adequately considers the long-term technical requirements for DNO networks for 2024 and beyond.

2 Introduction

2.1 Background to study

The purpose of this study was to examine how islanding of Distributed Generation (DG) can be accommodated and if so, under what conditions. The study was commissioned by the Department for Trade and Industry (DTI) at the request of Work Stream 5 (WS5) of the Technical Steering Group to the Distributed Generation Co-ordinating Group. The remit of WS5 is to examine the long-term network concepts and options for DG and how the UK network will integrate growing amounts of DG over the next few years.

2.2 Structure of study

The study comprised 2 phases with the ultimate deliverable being to make recommendations for technical and commercial changes required to make the networks of two case studies to be "island ready".

Phase 1 comprised several elements.

- Literature review
- Consultation
- Establish and define commercial and technical criteria and drivers
- Definition of the scope of Phase 2 work, submit report, meet TSG work streams and obtain approval of the methodology (for Phase 2)

Phase 2 work leading up to the final report included

- Meeting with Distribution Network Operators (DNOs), identification of case studies, interim report and presentation to WS5
- Model Case Studies, quantify technical and commercial risks, benefits and costs
- Produce case implementation plan for each case study
- Final report

2.3 Islanding

It is appropriate to define the term "islanding" at this stage. Islanding is the generic term used to describe a scenario where a section of a transmission or distribution network, which contains distributed generation (DG), is separated from the main transmission or distribution grid. Subsequent to this separation, the DG continues (or is restarted) to power the loads trapped within the island.

Current cultures in the design and operation of networks discourage the operation of these islands for safety and security reasons. However, as the amount of DG increases, it is appropriate to review this policy, especially as there are potential benefits to customers, DNOs and generators. This study examined if islanding can be safely and satisfactorily accommodated within UK distribution networks and under what conditions. It aimed to address the attendant benefits and risks from technical, commercial and regulatory aspects.

Islands involving transmission networks are excluded from this work.

3 Literature review and consultation

3.1 Literature review

This study began with a review of relevant literature covering all relevant technical, commercial and regulatory publications as indicated in the references. Particular focus was put on the commercial drivers, as these are crucial for any developments to be justified, especially under the present market driven regulatory regime. It was clear that the results of previous work had been presented in a general manner without reference to specific cases. Therefore, a key outcome of this assignment was the identification of the quantifiable risks and benefits of islanding leading to proposals which can be implemented.

The results of the literature review are contained in Appendices A and B.

3.2 Consultation

Several DNOs and Ofgem were consulted, to obtain their views on the benefits and risks of islanding. Discussions were prompted through the presentation of information on the October 2002 storms (and the impact of other severe weather related events) with the Distribution Price Control Review (DPCR) due to take effect from April 2005, together with relevant aspects from the previous July 2003 DPCR. This included the Information and Incentives Project (IIP) and the interaction of distributed generation and Registered Power Zones (RPZs).

3.2.1 Consultation with DNOs

Discussions were held with 5 DNOs during the first phase of this project. These 5 DNOs were:

- Scottish & Southern Electricity Ltd (SSE)
- Yorkshire Electricity Distribution Ltd (YEDL)
- Western Power Distribution (WPD)
- United Utilities (UU)
- Electricite de France (EDF)

The objectives of these discussions were to review any experience they had with islanded parts of their networks, and to identify the potential benefits and risks to DNOs, customers and generators in operating sections of network in islanded mode during fault or bad weather conditions.

3.2.1.1 Experience of islanding geographical islands

SSE and WPD have relevant experience of islanding. SSE has network responsibility for several (geographical) islands, and WPD has network responsibility for the Scilly Isles. These islands were originally powered by stand-alone diesel generator (DEG) systems. However, to improve the reliability and quality of power supply to customers, sub-sea feeders were installed from the respective mainland distribution grids to the islands. At present, these networks normally operate as part of the grid power system. However, if faults occur on these sub-sea feeders, they can be switched to islanded mode powered solely by the DEGs. Manual switching is usually required to interrupt the sub-sea supply on the island network, and there is normally a break in supply to customers before the DEG is started and the load re-applied to the network. Seamless transfer can be employed for the transfer back to the grid provided that synchronising control facilities are present. As the islands were originally established for DEG operation, the protection schemes were designed accordingly to give satisfactory operation at low fault levels, and these protection systems are operational during islanded operation. Note that the Scilly Isles generation is under 3rd party ownership.

In addition to the above examples of geographical islands, there have historically been parts of DNO networks with privately owned local generation schemes that could be suitable for supporting an islanded network. These DNO owned generation facilities had typically been replaced following network reinforcements. DNOs are specifically excluded from operating generation (for sale) under their current licence conditions. The only other examples, apart from cases of on-site generation providing critical standby support (e.g. for hospitals, water treatment plant etc), were for sections of SSE's network situated in Southwest Scotland, and one example within WPD's Welsh area.

3.2.1.2 Islanding on Kintyre

In southwest Scotland, SSE has, on the Kintyre peninsular, several hydroelectric power stations connected by 132kV double circuit into the Scottish transmission network through Sloy grid supply point. Several of these hydro sets (but not all) can be, and are, used from time to time to maintain supplies in their local areas during periods of maintenance and following some fault conditions. The SSE network in that area has several unusual possible network configurations to allow local generation to give this necessary support. When SSE are able to use islanding to minimise CIs and CMLs during planned maintenance, it is customary to stage an initial proving run to confirm satisfactory separation and subsequent independent operation of the islanded section of network, whilst having the capability to reconnect to the grid in the event of problems.

When using local generation to facilitate the restoration of supplies due to faults (e.g. storms etc), SSE adopt an informed trial and error approach to establish operational islands, on the basis of having little to lose if they cannot achieve stable operation with one islanding arrangement or another.

Crucial to the success of these islanding operations is the extensive knowledge and experience base of all the engineers involved in the islanding operation, whether at System Control, in the hydro stations or on network operations. Any islanding arrangement requires good working relationships and communications as exist within that part of the SSE organisation. It should be noted that these activities have been practised over many years, previously in a nationalised utility environment, and more recently after privatisation and conversion to a vertically integrated utility. Discussions indicated there was some uncertainty within the SSE staff over the long-term impact of splitting the SSE DNO and generation businesses.

3.2.1.3 Islanding under fault conditions in Wales

One part of WPD's Welsh network operates as an island under fault conditions. In this instance, the network connects to a DG owned and operated by UU Generation, near to the 11kV busbars of a single primary transformer substation.

Under normal network operating conditions, this generation contributes to UU's generation portfolio, and is sold to UU's energy supply operation. This UU generation facility also has a contract with WPD for network support, including support for the network voltage, and to provide P2/5 type support on failure of the single 33kV feeder to the primary. This case is of great interest to this present investigation, as the contract for network support is with a 3rd party generator, which may prove useful as a model (provided there are no major confidentiality issues).

3.2.1.4 Technical issues of islanding for DNOs

With regard to the possibilities for the DNOs to incorporate islanding capability into other parts of their distribution networks, they naturally and generally require to be convinced that there would be adequate commercial and technical benefits from the islanded operation for themselves, customers and distributed generators. In the commercial DNO environment this attitude is expected because, under current low penetration of DG, the cost incurred to incorporate islanding capability into particular networks may not be justified. In addition, DNOs, among others, may face several technical issues during islanded operation. These technical issues are summarised as follows.

1) Meeting statutory limits for system frequency and voltage throughout the disconnection, islanded operation and reconnection of DG, and achieving satisfactory power quality
2) Difficulties in ensuring that all relevant members of staff can react effectively and in a co-ordinated manner with each other throughout the above process
3) Achieving satisfactory earthing arrangements, including provision for the earthing of the neutral of the islanded network. Note that it is becoming more difficult to establish adequate earth electrode systems due to the high earth leakage currents on long single-phase 11kV cable feeders supplying many mobile phone masts
4) Difficulties in achieving seamless transfer, especially on disconnection from the grid and transfer into the islanded mode, with regards to protection issues
5) Establishing synchronising or blocking schemes to prevent any out-of-phase re-closure onto an islanded network
6) Managing large step increases in loads (e.g. the scheduled switching of electric storage heating, especially in rural areas where large numbers of these are installed)
7) An anticipated significant level of ancillary equipment to permit islanding, especially where intermittent use of local generation is involved. This situation could lead to a requirement for standby diesel generation as part of a DG facility

Although there are significant technical and financial barriers to the islanded operation of DG, all DNOs contacted as part of this study agreed that the potential benefits to themselves and other parties would increase as the penetration of DG increased. Significant increases in DG within the UK are anticipated over the next 10 years, especially due to the government's continuing commitments to reduce CO_2 emissions.

The consulted DNOs generally considered their entire networks to be P2/5 [1] compliant in respect of security of supply. None of the DNOs contacted could identify any particular part of their network, which was unusually susceptible to outages. The consistent theme was that the vulnerable portions of network had been identified previously, and the performance of these parts of the network had been improved by a combination of auto-reclosers, automation, reconstruction, and provision of increased ring circuit configurations to provide alternative feeds.

It was confirmed during consultation that primary substations may become disconnected on occasions, most frequently by common-mode failure of the two incoming 33kV circuits. It is well known that networks can be particularly prone to this problem if the circuits are run on separate poles in close proximity, or are carried on the same set of poles. The costs of removing this type of vulnerability can be very high (due to difficulties in obtaining planning permissions). This matter was considered to warrant further investigation in Phase 2 of this study. However, the general view of canvassed DNOs was that they could generally restore supplies to the majority of customers within 1 – 4 hours following the loss of a primary substation, and it may be too costly to reduce this restoration time by any significant amount.

Islanding which incorporates DG connected at 11kV or 33kV was considered to hold more promise of benefits to all stakeholders than islanding with widespread LV DG (such as domestic combined heat and power (DCHP)). This was due to the probable size of DG facility compared with the number of customers benefiting. Control of the generation and loads within a DCHP island was perceived as very difficult to achieve without significant penetration of intelligent load switching devices and high levels of co-operation between householders. There is also an issue of the need for generation licences (or exemptions) for individual participants.

Many DNOs operate a fleet of mobile generators (common rating approx 500kVA), complete with dedicated protective devices, to provide islanded supplies to remote customers under outages (either planned for maintenance, or unplanned due to faults). These generators are generally installed where there is no alternative feed and the majority generate into the LV network, although a small number of mobile 11kV generators are used. At the 11kV voltage level the occurrence of high earth leakage currents (due to increasing numbers of long single phase 11kV feeders supplying mobile phone masts) is seen as a major obstacle to the practice of using mobile generators, with instances of overheated earth electrodes catching fire. The use of Peterson Coil earthing is a possible mitigation measure, and it is also technically possible for a LV generator to back-feed unearthed 11kV overhead line circuits for short-term operation. However, this practice does need a formal derogation under the Electricity Safety, Quality & Continuity Regulations (ESQCR) [2]. It was generally considered difficult under post fault operation of mobile generators to maintain voltages within statutory limits for all customers in these temporary islands, although this requirement is mandatory for planned outages.

On the issue of mitigation measures for outages caused by extreme weather, the DNO experience was that fragmentation of the LV circuits was the primary reason for long restoration times. Therefore, DG islanding with these fragmented LV circuits would have a very limited application.

3.2.2 Discussions with Ofgem

A meeting was held with John Scott, Ofgem's Technical Director and Gareth Evans, Technical Advisor.

Ofgem has a primary aim of increasing the delivered benefits to customers in terms of lower costs, higher quality of supply and better service, from various regulatory measures including the better utilisation of DNO assets. Ofgem is keen for DNOs to embrace DG installation and is currently detailing concepts to incentivise developments as part of the DPCR to take effect from April 2005. One of these developments concerns Registered Power Zones (RPZ), which aim for electrical sections of networks to be registered as "nursery sites" where the host DNO can develop and demonstrate cost-effective ways of connecting DG. In addition, the Innovation Funding Initiative (IFI) aims to encourage DNOs to invest in developments focussing on technical aspects of network design, operation and maintenance (i.e. a wider remit than just DG). These initiatives are intended to encourage DNOs to invest in research and development, up to 0.5% of turnover (compared with a current industry average of 0.1%). The requirements for both of these initiatives will be released by Ofgem in the near future.

Ofgem recognise that there are significant technical challenges to overcome in order that islanding concepts can be developed and accept that each DG technology has its own issues which will need to be addressed.

3.2.3 Looking forward

In discussions with all the above parties, it was considered useful to take a long-term view on the potential achievability and benefits for DG powered islands. The extent to which these islands might be achieved will depend in part on the parallel development of other technologies. For example, if demand side management (DSM) techniques were well developed, even to the extent of white goods routinely being fitted with intelligent, communicating controls at manufacture, then achieving a load match with available generation may become a reality. This could then ensure that priority loads (lights, TV, heating controls, street lighting, communications etc) could be supplied from limited generation resources, providing maximum benefit to customers and society at large under difficult network operating conditions.

4 Identified technical criteria for operating sections of network in islanded mode

In this section, the present (2004) position of DNOs in relation to islanded operation is described. Some general islanding scenarios are discussed, along with the characteristics of different distributed generation. Section 5 then considers the technical solutions to these issues.

4.1 What is islanding?

Please refer to report "Assessment of Islanded Operation of Distribution Networks and Measures for Protection" issued as DTI/Pub URN 01/1119 [3] for an introduction to islanding.

There are many possible zones of islanding involving one or more distribution feeders, substations and voltage levels. An extract from [3] discussing possible islanded zones is contained in Appendix C.

4.2 Present position on islanding

Under present design practice and culture of distribution network operation, the DG would be shut down by either the "G59/1" [4] protection located on the DG interface protection [3] [5], or by an intertripping signal originating at the circuit breaker (CB) tripping on fault. With G59/1 protection, the DNO may include additional backup protection in its CB. The means of preventing continued supply to customers in an islanded section of network, and responsibilities for maintaining the protection scheme, would be included in the Connection Agreement.

The G59/1 protection typically included:

- Under / over voltage
- Under / over frequency
- Loss of mains. The types of loss-of-mains protection in common usage were
    - Rate of change of frequency (also known as rocof or df/dt) – preferred [3]
    - Vector shift (detecting the step change in generator power angle on the change in load impedance at the instant of islanding) – non-preferred

There were several active lines of research and development into alternative, more reliable means of detecting the loss of mains at the time of this study, and these included application of Artificial Neural Network (ANN) architectures.

It is worth noting that there was a divergence between DNOs in their policies on tripping methods to prevent islanding. Some DNOs would only accept the loss of mains relays under certain limits of generator size and/or minimum feeder loading. Under all other circumstances, they specified that inter-tripping be installed, requiring the establishment of reliable high-speed communications between critical network CBs and the generation interface protection.

DG was required to be shut down during islanded operation due to the risks associated with the following issues.

1) DNOs may not be able to maintain the frequency, voltage balance and magnitude in the islanded network within the required statutory limits or industry standards. In addition, there may be voltage fluctuations to an extent where they cause annoyance (flicker)
2) The neutral of the islanded network may not be earthed, thus allowing uncleared earth faults to persist. Phase to phase voltages can therefore arise between phase and earth conductors, causing insulation to be overstressed, resulting in breakdown or flashover

3) The fault level contribution from the DG may be insufficient to allow protection to operate satisfactorily, resulting in sustained fault currents

4) Synchronising equipment may not be installed in the islanded network, so that it cannot be resynchronised with the main network following clearance of the fault which led to islanding. Unless measures are in place to prevent out of phase reclosures, there remains the risk of an out of phase closure causing high current flows and large voltage transients, with potential consequential damage to rotating equipment (especially the DG) through excessive mechanical torque transients

Unless mitigating measures are implemented, the risks arising from these conditions will almost certainly result in complaints, and present unacceptable risks of danger to personnel and/ or damage to equipment (from e.g. over-speed, overload, stalling, overheating, mal-operation).

As a result, all of the above conditions represent a breach of one or more statutes such as the Electricity Safety, Quality and Continuity Regulations [2], and the Electricity at Work Regulations [6], as well as various national and international standards for network plant operation.

4.3 Future options for network response to islanding

Although the general risk issues relating to the operation of islands identified above appear daunting, they can be resolved by applying appropriate network designs, which include additional facilities and/or equipment. Because the number of DG installations has risen dramatically over the past 10 years, and looks set to continue for the foreseeable future, it was relevant for this study to identify how these risks can be mitigated. As will become clear in later sections of the report, for DG to operate safely and satisfactorily within an islanded section, certain measures will need to be invoked. In the main, these measures are not appropriate for use when the network is intact, and therefore they will need to be installed and made ready to be activated upon islanding. The loss of mains protections described above may still be applicable for initiating these measures.

4.4 Network topology and voltage levels considered in study

This study considered distribution networks. In most cases, the amount of DG connected to a circuit will be less than the load on that circuit. Therefore, it was appropriate to place priority on the consideration of islands formed where there is no step-up in voltage from that at which the generation is connected. In very few situations where, through coincidence, the relative generation and load size may allow loads to be supplied via a step up transformer, there will be significant additional complications in respect of earthing and protection that must be addressed. These situations should be addressed once experience has been gained with the "simpler", more probable scenarios that do not involve stepping up a voltage level.

If generation was connected to the distribution network at say 11kV, only the local 11kV and associated LV circuits were considered for the island, and it was assumed that the appropriate 11kV CB disconnected the 33/11kV primary transformer.

Figures 1 to 4 show generic potential islanding scenarios considered in this study. These cases include common mode failure of two 33kV feeders, single 33kV feeder fault, 11kV feeder fault and islanding of 11kV spur, and 11kV feeder fault with LV islanding and DCHP. Whilst there are very few of these DCHP schemes at this time, and numbers will be insignificant in the short term due to the slow future growth of such installations (due to capital cost and market inertia), it is conceivable that there will be a major growth over the next 10 – 20 years if claimed efficiency benefits are confirmed, and that entire housing estates or commercial developments may be so equipped from new build. Symbols used in the diagrams are defined in Table 1.

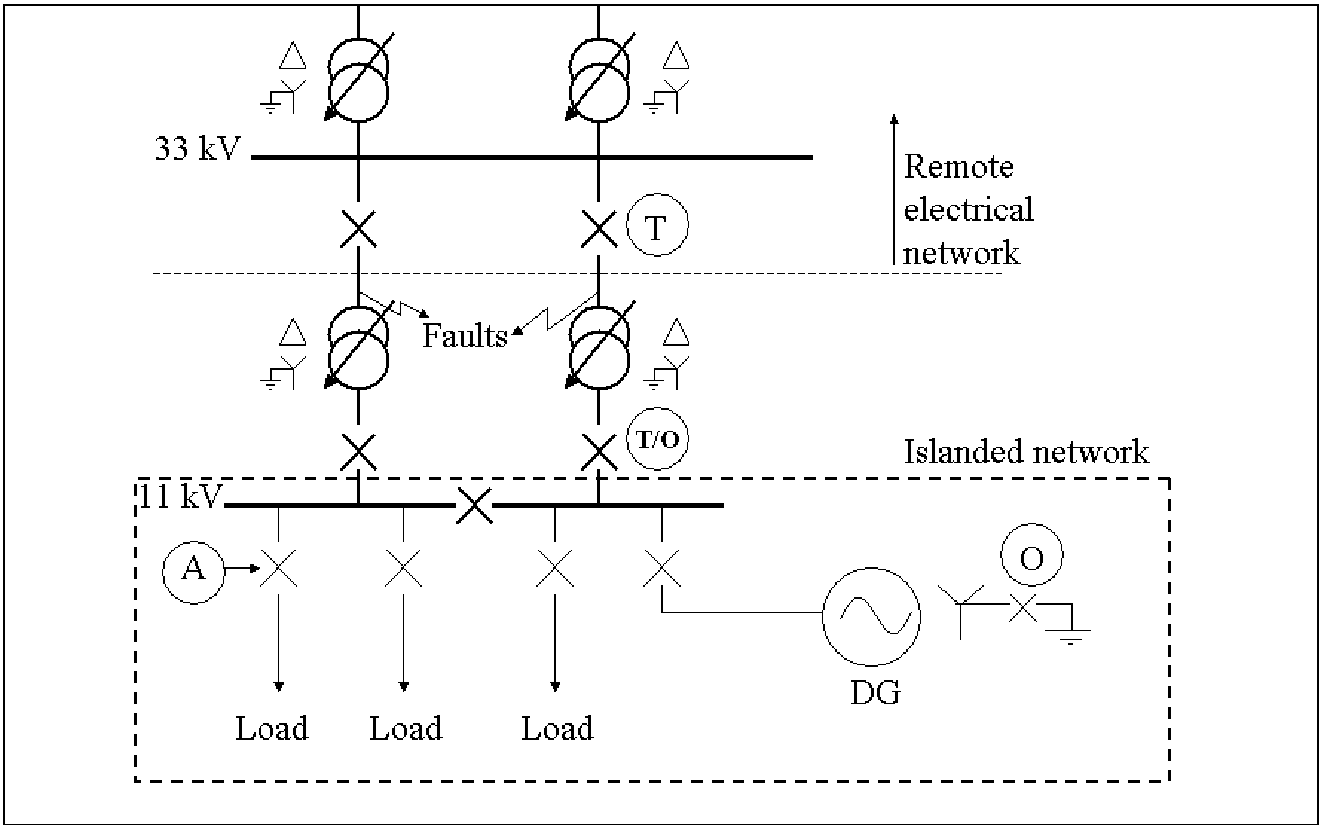


Figure 1. Common mode failure of 2 x 33kV feeders causing islanding of primary substation 11kV Busbars

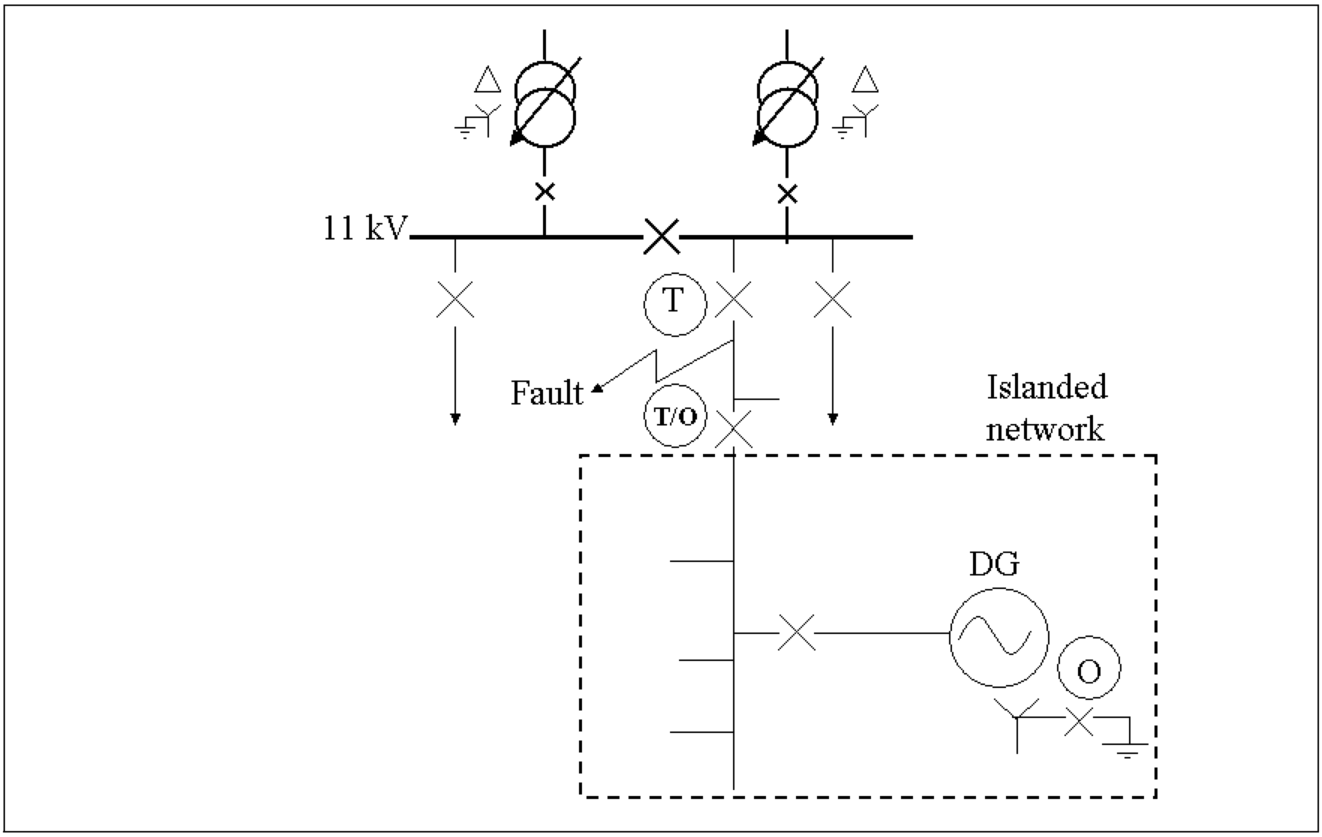


Figure 2. 11kV feeder fault causing islanding of 11kV spur

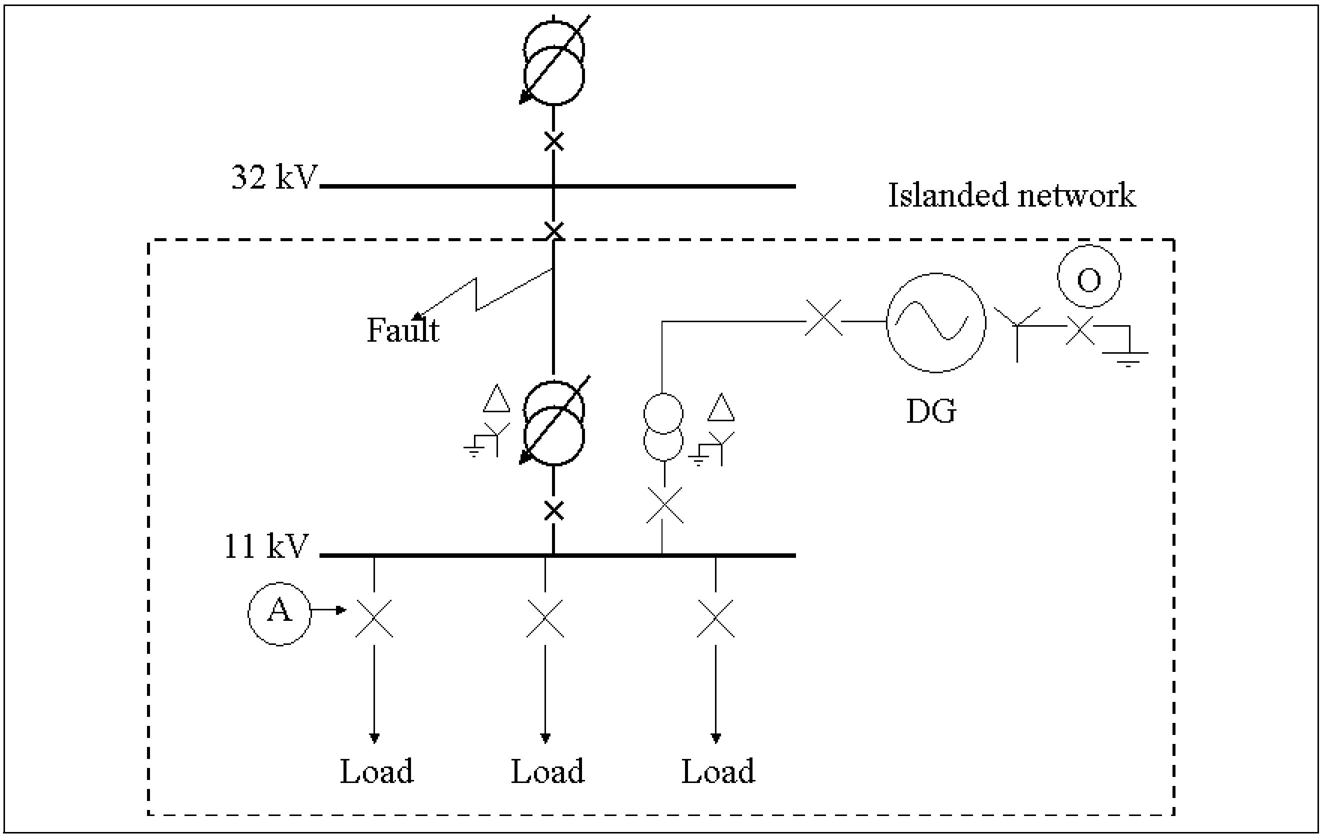


Figure 3. 33kV fault islanding at 11kV network

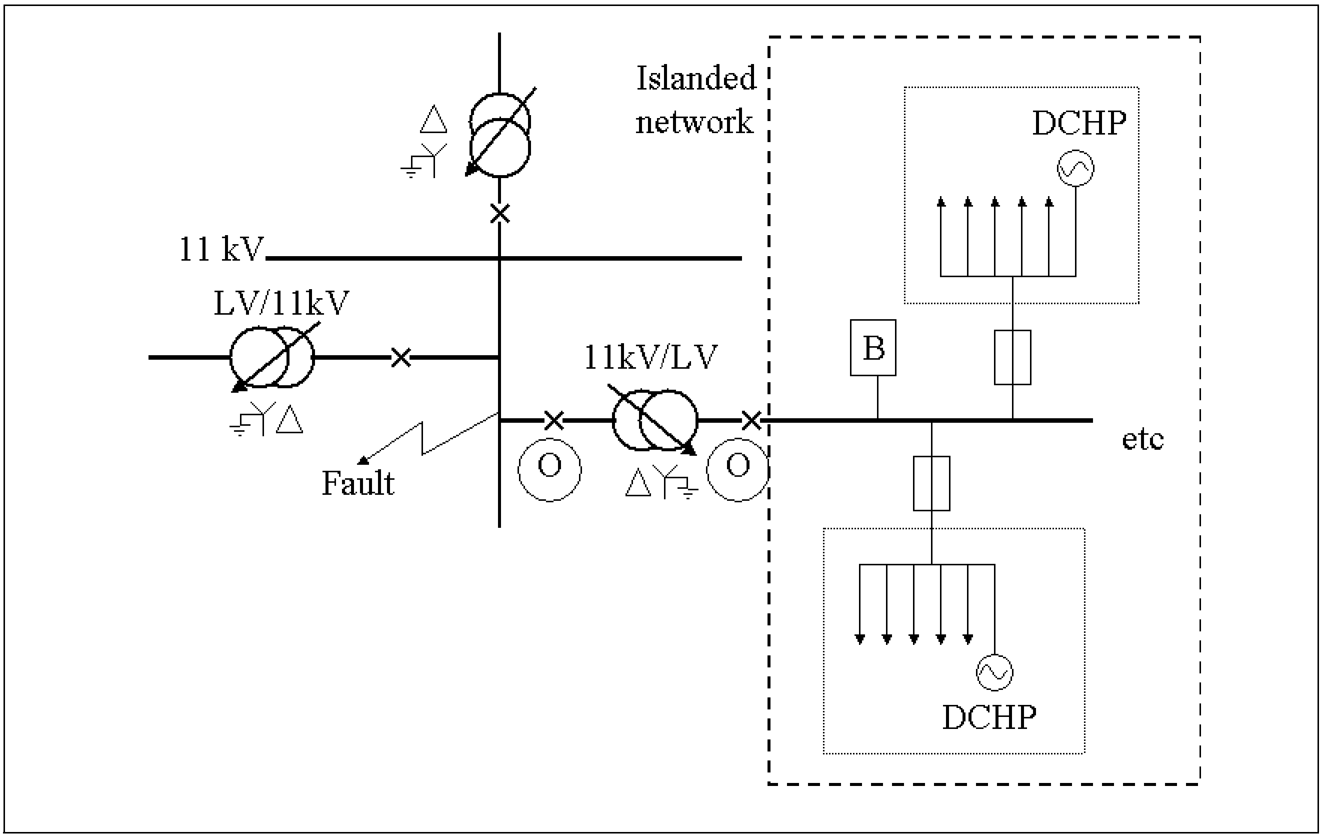


Figure 4. 11kV fault islanding at LV network with DCHP

Where

T = Trip to clear fault

T/O = Trip or operated by a control system

O = Operated by a control system

A = CBs may be selectively opened to keep load $\leq$ generation

B = Earthing and protection unit

= Fuse

DG = Distributed Generation

DCHP = Distributed Combined Heat And Power

Table 1. Key to diagrams

4.5 Characteristics of different types of generation

It is useful to recognise that not all DG is alike. Each generation scheme is installed for specific purposes (e.g. support to critical loads, generating electricity for sale) and islanding operation will be affected by typical sizes and functions of the various generation types described in Table 2. Table D1 of Appendix D is also a useful guide to the main technical issues for different generator types and prime movers.

DG category	Typical Location	Typical Function	Typical Installed Capacity
Biomass – Gasification	Rural/ urban perimeter	Sale of Energy	300kW – 50MW
Biomass – Landfill Gas	Rural/ urban perimeter	Sale of Energy	300kW – 10MW
Diesel – Private Standby	Rural/ Urban	Support to Critical Loads/ Contracted to NGT for rapid response	500kW – 2MW
Diesel – Island Standby	Island normally supplied via sub-sea cable	Standby Support (faults and outages)	50kW – 2MW
Energy from Waste	Rural/ Urban	Waste Disposal/ Sale of Electricity	1MW – 100MW
Hydro	Rural	Sale of Energy	100kW – 140MW

Mine Gas	Rural/ Urban perimeter	Sale of Energy	1MW – 10MW
Natural Gas CCGT	Rural/ Urban Perimeter	Sale of Energy	50MW – 400MW
Natural Gas CHP reciprocating engines	Industrial/ heavy commercial	Economical Provision of Heat & Electricity/ Sale of surplus electricity	500kW – 5MW
Natural Gas CHP Gas Turbines	Industrial	Economical Provision of Heat & Electricity/ Sale of surplus electricity	10MW – 50MW
Wind	Rural	Sale of Energy	1MW – 50MW

Table 2. Characteristics of different types of generation

4.6 Location of distributed generation

In the discussions on generic islanding scenarios it was noted that communications for control and for transmitting information between the DNO and the DG are essential. There are therefore obvious benefits if the DG is physically close to the DNO islanding CB, as this should facilitate cheaper communications systems than if the DG is several kilometres away. In the main, however, the geographical positioning of DG will be determined by factors other than the ideal network configuration. Table 2 provides typical location, size and purpose for the building of DG facilities.

The location and relative abundance of fuel resource dominates considerations for the siting of DG, (e.g. wind, hydro, landfill gas, mine gas, small natural gas wells), with distribution network characteristics being considered secondly, in conjunction with land availability and planning constraints. The nature of the wind and hydro resource means generation schemes are frequently located towards the remote ends of distribution feeders.

The location of generation using fuels requiring road/rail transport (e.g. energy from waste, coppice-wood, diesel) is much less dependent on the location of the energy source. Diesel powered standby DG is installed on many islands off the Scottish coast, and also on the Scilly Isles. These networks evolved from isolated island grids initially supplied by diesel generation, being subsequently supplied via sub sea cables, but with the diesel sets retained for standby use.

There are many privately owned diesel generators which were discounted from the scope of this study as they are typically set to run in emergency mode only and are not running regularly (e.g. standby support to dedicated critical loads or on rapid response contract from National Grid Transco (NGT)) due to high fuel costs. For economic reasons it is improbable that these sets have been sized to provide any significant levels of power to support an island outside their owner's facility (e.g. hospital).

Energy from waste and coppice wood powered DG have flexibility of siting subject to road access and planning issues only. The sizes of these generating facilities are frequently such that connection is required either onto the 11kV busbars at a primary substation or directly to the 33kV network. Both of these types of generation have a high requirement to maintain operation even during network outages to prevent damage to plant. This applies particularly to gasification plant.

CHP plant is installed primarily to satisfy a heating load and is therefore located on a site where the heat is to be utilised.

Gas driven plant has some flexibility on location, as the cost of installing buried connecting pipelines to deliver the fuel can be of the same order (or cheaper) than the cost of installing underground HV cables to export the generated power.

5 Technical issues associated with operating sections of network in islanded mode

The key technical issues to be solved within an islanded section of distribution network to allow the safe and satisfactory operation of DG, without breach of statute, are as follows.

1) Maintain stable, acceptable levels of frequency and voltage
2) Provide an earth reference/neutral earthing for the duration of islanding
3) Achieve acceptable clearance of faults
4) Prevent reclosure of the islanded section of network with main grid network unless the two supplies are in synchronism
5) Maintain a power balance so that load is less than or equal to generation

This section discusses the proposed ways to comply with these issues.

5.1 Required quality of frequency and voltage at islanded networks

As required by the Electricity Safety Quality and Continuity Regulations (ESQCR) [2], there is a statutory responsibility for the distributor to notify the Supplier (who in turn notifies the consumer) of the supply characteristics at a point of connection. The supply characteristics cover information such as the number of phases, the frequency and the voltage. Unless otherwise agreed between these parties in writing (or alternatively by variation authorised by the Secretary of State for Trade & Industry) the following nominal values and allowed variations apply.

Parameter	Nominal	Minimum	Maximum
Frequency	50Hz (±1%)	49.5Hz	50.5Hz
Voltage (LV)	230V (+10%/-6%)	216V	253V
Voltage (11kV)	11kV (± 6%)	10.34kV	11.66kV
Voltage (33kV)	33kV (±6%)	31.02kV	34.98kV

Table 3. Nominal values and permitted variations for frequency and voltage

In order to consistently maintain these values following the formation of an island, the following conditions must apply.

1) Total Load ≤ Total Generation (applies equally to real power and reactive power)
2) Stable speed (frequency) control must be provided either by a mechanical governor or electronically through fast switching control of ballast loads. Generating schemes designed principally for grid-connected operation can have shortcomings in maintaining stable frequency in islanded mode
3) The generator automatic voltage regulator (AVR) can achieve a suitable voltage to ensure that supplies at all connected customers remain within limits after allowing for circuit voltage drops within the island. The AVR is also required to provide a suitable response to step load changes to avoid excessive voltage excursions
4) Limits must be placed on the maximum size of discrete loads, particularly motors that are used during the period of islanding to prevent undue voltage fluctuations. These are

aggravated with large motors due to the very large demands made for real and reactive power whilst starting up

5) When in island mode, stricter limits may need to be imposed on equipment with high harmonic emissions than when connected to the main network, as the lower fault level under islanding conditions will be less tolerant

It is worthy of note that the ESQCR [2] regulations do not recognise, nor make provision for, variations from the above table for systems operating in islanded mode.

Attention is drawn, however to BS EN 50160 [7]. This standard suggests limits on the variations for voltage and frequency but, unlike the ESQCR, takes a probabilistic approach under normal conditions. It also recognises that when a power island exists, then wider limits for voltage and frequency levels are appropriate to accommodate the effects of a weak distribution network. It states "Under normal operating conditions, the mean value of the fundamental frequency measured for systems with no synchronous connection to the grid (e.g. islanded power systems) over a period of 10 s shall be within a range of

- 50 Hz ± 2 % (i.e. 49 – 51 Hz) during 95 % of a week
- 50 Hz ± 15 % (i.e. 42.5 – 57.5 Hz) during 100 % of the time

Also under normal operating conditions, excluding situations arising from faults or voltage interruptions, the 10 min mean rms values of the supply voltage shall be within the range of U_n + 10 % / -15 % during 95 % of a week."

This probabilistic approach has much merit as it reflects the probable reality of a non-standard configuration. A review of the quoted permitted variations under BS EN 50160 was therefore recommended, with a view to allow reasonable power quality to be experienced under islanding conditions.

5.1.1 Suitability of various types of DG to provide acceptable voltage and frequency under islanded conditions

Manufacturers of DG plants may select different generator types, namely synchronous, induction (i.e. asynchronous) and doubly fed induction machines. The general characteristics of all these machine types are described in Table D1, Appendix D and detailed below.

Under normal "grid connected" conditions, the grid network determines the frequency. Fossil fuelled generators operate their governors in isochronous mode, according to the target power output required. Other generator types, (e.g. wind and hydro) will tend to initiate control of input energy capture only when rated output levels are reached. More modern wind turbines may include the ability to govern to intermediate levels, as well as full output under the control of the SCADA systems. The above scenarios are satisfactory as the grid is kept in synchronism by large central generators and will be relatively unaffected by individual DG plant. However in island mode, the DG must be set to control frequency, either by means of its inherent characteristics or by the use of ancillary equipment.

Of equal importance to the quality of power generation are the prime mover characteristics, especially those that might limit their application in islanded mode (e.g. hydro turbines and gas engines that will not operate stably at loadings of less than say 50% of rated capacity). Wind turbines present specific challenges due to the variable nature of the energy generation. Excess energy can be utilised using appropriate ballast loads with fast electronic switching to maintain the system energy balance. Wind turbines employing pitch regulation as a power control measure can "spill" surplus energy and reduce the amount of energy being dumped in the ballast load, although the ballast load capability will need to be retained to achieve the required speed of response. Standby plant (e.g. batteries & inverters, or a diesel generator) will need to be available to provide energy when wind speeds are low.

In general, synchronous generators coupled to suitable prime movers equipped with governors are the most likely generator type to cater for the real and reactive power demands of an islanded section of network, and be capable of maintaining the system frequency and voltage within the statutory limits during islanded operation.

Doubly fed induction machines are the next most likely generator type to be able to supply the real and reactive power requirements of the islanded network. These generator types are normally used in conjunction with wind turbines as they can allow short-term gust energy to be stored on the rotor as kinetic energy, by allowing the rotor to accelerate. The power electronics contained within the generator control can maintain stable output frequency during rotor speed changes. It is expected that, provided the balance for the islanded network is maintained, i.e.

power capture – internal losses = electrical load (including any ballast load)

then voltage and frequency stability should be achievable. Some form of demand side management can improve the utilisation of the available wind energy.

In order for plain induction generators to supply the real and reactive power requirements and achieve adequate voltage control, ancillary equipment such as SVCs (static VAr compensators) or a synchronous compensator will be required. As for the doubly fed induction machines, a dynamic ballast load and standby generator will typically be needed to maintain the power balance unless demand side management techniques can be used.

5.2 Unearthed neutral of the islanded network

As required by the UK ESQCR 2002 [2], a generator or distributor has an obligation in respect of any high voltage network which he owns and operates to ensure that:

"the network is connected with earth at, or as near as is reasonably practicable to, the source of voltage but where there is more than one source of voltage in that network, the connection with earth need only be made at one such point"

The control of voltage reduces any overstressing of insulation, which may fail and present a shock hazard to personnel. In addition, the earthed neutral provides a path for earth fault current to flow so that the protection systems can detect and reduce the prospective fault current.

In the present UK distribution network practice, the neutral of an islanded section may not always be earthed because the neutral earth connection was provided by the main grid, and on separation from the main grid, the metallic contact with the earthed neutral is lost. Therefore, the DG connected to the islanded part of the network will have to be shut down unless or until a satisfactory alternative earthing method is effected, or a derogation on neutral earthing can be secured from the Secretary of State for Industry.

An option to achieving an earth may be the use of Neutral Voltage Displacement (NVD) protection, which is normally installed as part of the protection overseeing the interface between the DG and the grid. NVD protection relies on the creation of a virtual neutral in a 3-wire circuit by the natural balance caused by capacitive coupling of each of the 3 phases. An earth fault on any phase causes a voltage shift in this virtual neutral, which then causes protection to operate. However, this technique may not be suitable on networks having a significant long single-phase HV cable circuit spur.

5.2.1 Neutral earthing of an islanded network

There are several alternative techniques, which can be employed to achieve acceptable earthing, including but not necessarily limited to:

- Connect generator star point to earth (via interlocked contactor) (Figure 5)
- Connect standby earthing transformer (Figure 6)

Under normal running conditions, these devices would need to be disconnected.

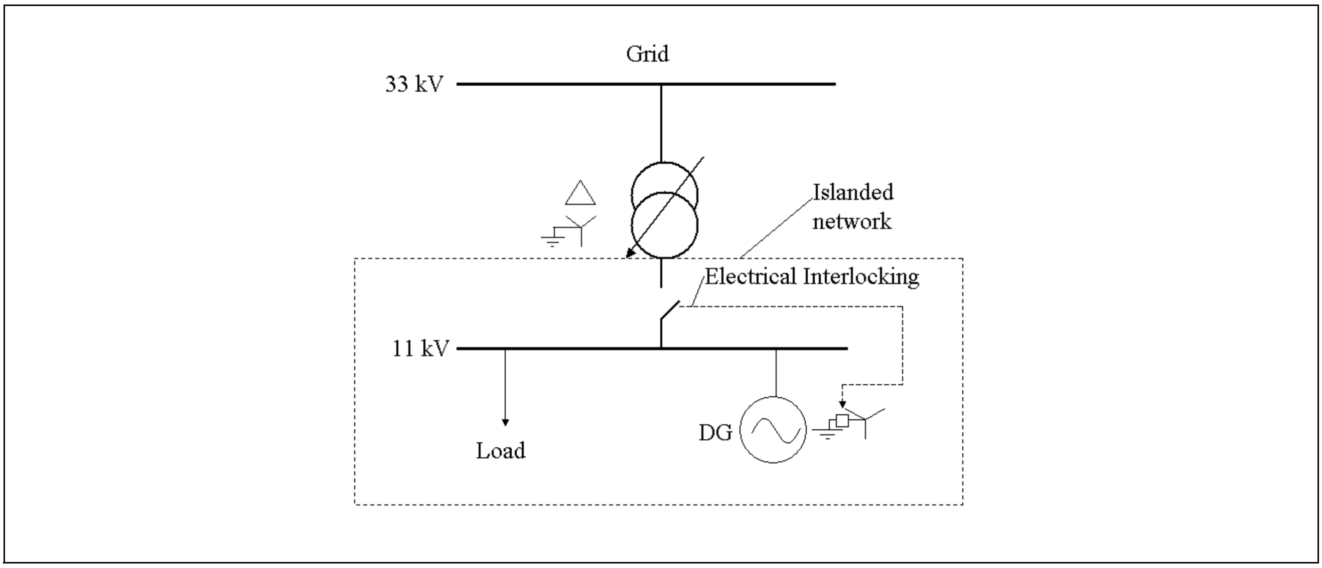


Figure 5. Neutral of DG being earthed (via interlocked contactor)

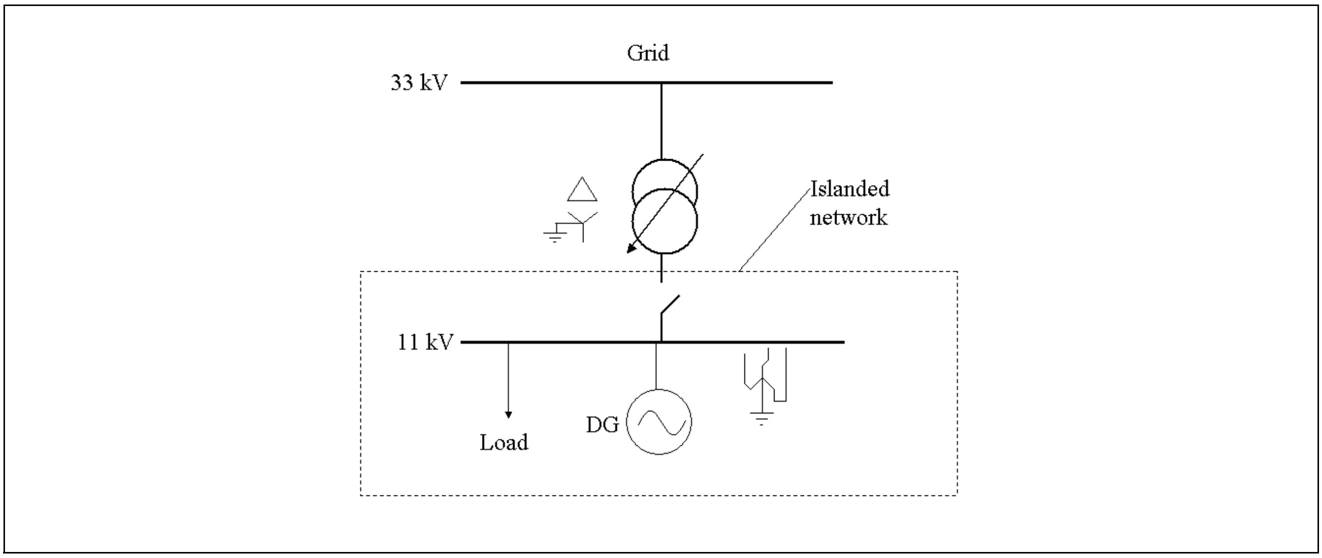


Figure 6. A zigzag transformer being used to provide an earth to the islanded network

5.3 Protection systems in islanded networks

As detailed previously, under normal interconnected operation, the network will have a co-ordinated scheme of protection. This scheme will be arranged to clear faults in a manner that the minimum number of customers are disconnected. Such a scheme will almost certainly be making full use of the range of fault levels on the network to optimise the discrimination between protective devices on a circuit.

When a DG island is created, it is required that any faults occurring will be cleared quickly to minimise damage or danger to personnel. However, the fault contribution of the DG will almost certainly be significantly lower than that of the interconnected network.

It may be possible in some cases to apply protection settings within an intended island, which will be acceptable when operating as an island and also co-ordinate with other protection when in interconnected mode. However, it is more likely that protection settings will need to be changed between the alternative modes of operation. Modern relays accept control signals to select alternative pre-set groups of settings.

If additional protective devices are required, they may be similarly enabled or disabled by the appropriate signal. These signals can be invoked automatically on the establishment of the island.

As the operation of a DG island is likely to be only an occasional event, and the likelihood of occurrence of a subsequent fault within the island is very remote, it is considered appropriate that the entire island can be tripped on fault, without need for normal discrimination. This may need to be reviewed if islanding was to become a more common procedure, for example to cover planned outages.

5.4 Synchronising islanded networks with the main electrical grid

Synchronising two separate pieces of electrical network is a well-established practice of fulfilling the three conditions under which two energised electrical systems can be connected. These three conditions are that the phase angle, frequency and voltage magnitude differences between the two separate pieces of networks must be within acceptable tolerances. These conditions must be satisfied to limit excessive current flow when the two networks are connected, hence avoiding severe voltage and frequency fluctuations, and limiting mechanical shock to the DG.

There are several proprietary devices and complete systems available for achieving these conditions. A complete scheme will contain a synchroscope, phase angle voltmeter, synchronising check relay and synchronising relay [8]. These devices check the differences of phase angle, frequency and voltage between two systems before allowing the circuit breaker to be closed or closing the circuit breaker automatically at the point of interconnection. The synchroscope and phase angle voltmeter are used when adjusting network conditions prior to manually closing the interconnecting circuit breaker. A synchronising check relay is used to provide an electrical interlock which prevents closing of the circuit breaker when the frequency, voltage and phase angle differences between the two systems are not within the acceptable limits.

5.5 Match of load and generation by demand side management

As stated previously, it is essential that the load and generation be matched. It is almost certain that there will be fluctuations in both these quantities, depending on customer needs and the type of generation.

Demand side management (DSM) is a well-established technique to control the levels of electricity consumption, both in island and grid-connected networks [9] [10]. The primary role of demand side management in islanded networks is to maintain power system frequency, voltage and stability in the light of unpredictable load and generation profiles and avoid otherwise unnecessary expansion of the capacity of generation. The key function of using demand side management technologies on grid-connected networks is to reduce power demand on the networks during times of peak demand, allowing network operators to prevent their power systems from overloading and hence maintaining the safety and effective operation of their electrical networks.

The DSM control may either be arranged as a direct response to frequency, or it may be under central supervisory control. Depending on the required levels of sophistication, DSM control can be arranged to control large sections of an islanded network, or smaller loads down to individual consumer electrical equipments including white goods. Other market drivers will affect the uptake of DSM technology, and DSM infrastructure may, in the future, be installed for reasons other than islanding.

6 Impacts of islanding on trading and settlement

6.1 Introduction

The impact of islanding on trading and settlement is complex.

Firstly, the appropriate comparison for islanded operation is not vis-à-vis normal operation but vis-à-vis an outage, as without network islanding it is assumed that the customers will not be supplied and affected DGs will not generate.

Secondly, there are different impacts between customers who are half-hourly (HH) metered and those who are not (i.e. non-half-hourly metered, NHH). All UK customers over 100kW maximum demand are half hourly metered.

Thirdly, if the DG is contracted under SVA (supplier volume allocation) i.e. as negative demand, there will be different impacts compared to generation contracted under CVA (central volume allocation) i.e. generation which directly participates in the balancing and settlement code. As virtually all DG below 50MW and between 50MW and100MW is contracted in SVA one can simplify an investigation by considering the majority of cases where DG is contracted under SVA.

Fourthly, at the instant of islanding, it is unlikely that the generation output will exactly meet the islanded load demand and therefore on separation from the grid the generation output will have to increase or decrease to meet the islanded load (unless dynamic DSM is used to achieve this). Most DG plant on the system (e.g. renewables and CHP), if running and connected, will only be capable of reducing output, as these units are normally run at maximum load. It follows that standby generation plant must be brought into service onto the islanded network if it is necessary to increase generation output.

Fifthly, Demand Side Management could be used as an alternative, or as an added control feature to reduce or to increase demand to match generation to the islanded load.

6.2 Background

Under NETA (New Electricity Trading Arrangements) and the BSC (British Settlement Code) (and in Scotland under BETTA (British Electricity Transmission and Trading Arrangements) post April 2005), electricity suppliers provide forecasts for their half hourly demand on an hour-ahead basis. Any error in outturn compared to forecast is penalised through the balancing mechanism.

Suppliers typically forecast “long” (i.e. overestimate their expected demand) so that they are spilling power in the balancing mechanism and receive the spill price (System Sell Price) for their excess energy. Any loss of supply to customers, which is recorded by the metering and settlement system, will make their forecast longer and they will be subject to increased sell price error payments. However, for the supplier this circumstance is preferable to a situation where the supplier’s demand outturn is less than forecast, when they become liable to purchase the shortfall at the System Buy Price (SBP), which is generally much higher that System Sell Price (SSP) and more volatile.

6.3 Impact on supplier of affected customers

6.3.1 Impact of an outage on supplier of HH-metered customers

For any outage there will be a reduced amount of energy metered at the customer and at upstream meters in the system for that period. However, the meter data variation for a short interruption of a few seconds or minutes over the half hourly (HH) settlement period is very small compared to the demand forecast error. If only a small proportion of customers are disconnected within a grid supply point (GSP) Group then the overall impact on the supplier's forecast position will be insignificant.

If the outage is of longer duration, say for the whole HH settlement period, the error may be more significant depending on the proportion of HH- metered customers of that supplier who are affected by the outage.

If the outage was for considerably longer duration, and was likely to persist, the supplier would be able to adjust the forecast to take account of the customer(s) being off supply. However given the likelihood of this occurrence and the small proportion of customers involved it is unlikely that any supplier would find it economic to have systems in place to achieve this forecast adjustment unless their existing customer demand notifications for large customers already catered for this possibility.

6.3.2 Impact of islanding on supplier of HH-metered customers

If HH customers were supplied by an islanded system instead of being disconnected, there would be a marginal benefit to the supplier as the supplier's forecasts would continue to have the same accuracy as existed before the islanding operation occurred. The value of islanding to the supplier would depend on the energy supply loss avoided by islanding, i.e. on the number of customers, the size of the customers and the duration of the avoided outage. As the value of energy lost currently is very small, the value of islanding HH-metered customers to suppliers is also very small.

6.3.3 Impact of an outage on supplier of NHH-metered customers

In order to calculate the settlement position of each supplier in each half-hour period a demand estimate for each customer must be obtained. This is achieved by profiling of the non-half hourly (NHH) metered customers. The same profile is assumed for each customer of the same type. The profiling is used to allocate the measured demand from quarterly meter readings (or estimates) over each half hourly period such that the total demand from NHH- metered customers equals the balance of energy measured at each GSP meter (once losses and all HH-metered customers have been accounted for).

If a NHH-metered customer is disconnected from the system and draws no power for a period, there is an extremely small affect on the customer's supplier, as the profiling will spread the reduction in demand over all customers of all suppliers.

6.3.4 Impact of islanding on supplier of NHH-metered customers

If NHH customers were supplied by an islanded system there would be no adverse impact on the supplier, although the benefits of islanding are insignificant due to the lack of any significant costs resulting from an outage.

If in future there were to be significant disconnections and a supplier were to encourage islanding of its NHH customers, the benefits of islanding would be shared by all other suppliers through the profiling process.

6.4 Impact on supplier purchasing energy or demand side management services

6.4.1 Impact of outages on supplier purchasing DG

In this section and the next section it is assumed that

- As previously explained, the supplier is purchasing output from the DG under SVA i.e. as negative demand
- The generation is half hourly metered
- The generator normally operates (e.g. is CHP or renewables and not a standby generator)

The supplier will assume a generation profile for the generator, which will probably be a constant output equal to the average output, unless there is some other predictable operational pattern. The supplier will deduct this generation from his total demand estimate to produce the demand forecast.

Under an outage the generator will cease to generate and the supplier's demand will increase. This will tend to push the outturn toward a shortfall, leading to possible exposure of the supplier to System Buy Price as explained in section 6.2.

6.4.2 Impact of islanding on supplier purchasing DG

If the generator is able to operate islanded, this capability will benefit the supplier who has contracted the generator output, as it will reduce the supplier's exposure to System Buy Price. However, as explained above, it is unlikely that the generator can island and maintain full output. To balance the load in the island, the generator will either have to increase output or reduce output. It is unlikely that a renewable or CHP generator will be able to increase output, as there is no financial incentive to carry any reserve capacity and there are large financial incentives to maximise the exploitation of the renewable energy resource in particular.

Therefore it is likely that most operating DG (CHP and renewables) would have to reduce output to sustain the island. The greater the reduction in output to achieve islanding the lower the benefit will be to the supplier.

6.5 Impact on a supplier purchasing standby DG

In this section and the next section it is assumed that

- The supplier is purchasing output from the DG under SVA i.e. as negative demand
- The generation is half hourly metered
- The generator does not normally run (e.g. a standby diesel)

To sustain network islands it may be necessary to "constrain on" standby generation plant (as an alternative or in addition to continuing to operate DG that would normally be running).

The supplier contracting such plant would normally assume that it is not operating and therefore would not include its output in the supplier's demand forecast.

Under outage conditions there would be no impact on the supplier in relation to the generation if it did not run, as that is the normal mode of operation.

If the generator did run during an outage the supplier would reduce his outturn demand and, given that the forecast was long, would further increase his exposure to SSP. It is extremely unlikely that the costs of running a standby generator (e.g. a diesel generator) would be lower than the SSP in any half hourly period. Therefore there would have to be other incentives for which the generator or supplier would contract to make this islanded operation viable.

6.5.1 Impact on a supplier utilising DSM

Demand Side Management (DSM) could have a role in facilitating islanding operation of DG. Where demand is greater than generation, DSM may be used to reduce demand and allow the generation to match the islanded load. Where the generation output is fluctuating, e.g. for a wind generator, dynamic DSM may match load to generation to control frequency. Where islanded demand would be too low to sustain the islanded DG at above minimum output, DSM could add load to the island network in these periods.

Where the DSM is located on the premises of a HH-metered customer, the change in demand will affect the supplier's outturn in that half hour period. Where the DSM is at a NHH-metered customer the change in demand will be smoothed over the period by the profiling process.

In the first case (HH) the impact on the supplier will be small unless large amounts of energy are involved for long periods, which is not considered likely at present. In the second case the impact will be even smaller, spread over a longer period due to the profiling of NHH metered data. The impact on the supplier will be negative if the DSM results in increased exposure to SBP compared to the non-islanded case without DSM.

6.6 Summary

For suppliers of NHH-metered customers there is currently no significant trading impact of outages as these effects are lost in the averaging process of profiling meters to provide pseudo half hour data sets. Therefore there is absolutely no incentive on the supplier to support islanded operation, although there is also no incentive to resist islanded operation.

For suppliers of HH-metered customers there is an impact of outages on their settlement position. However this impact is insignificantly small considering the overall forecast error. Therefore there is not sufficient incentive on suppliers to encourage islanding, although it would be in their interests if islanding took place.

For suppliers contracting with normally operating DG (e.g. most renewables and CHP), islanding would reduce their exposure to SBP compared to the non-islanding alternative where the generator must shut down.

For suppliers contracting with standby generation (e.g. standby diesel generators) commencing operation in islanded mode could reduce their exposure to SBP or increase their exposure to SSP. However this action can also be taken during normal network operation. If this activity is beneficial suppliers will put arrangements in place during normal operation first. It should then be possible, and in supplier's interests, to extend this operation to islanded situations.

For suppliers operating DSM in islanded operation the picture is even more complex depending on the scenarios and assumptions made.

None of these benefits would appear to be sufficient to drive suppliers to promote islanded operation of DG.

7 Benefits of islanded operation

7.1 General

This section examines the commercial and regulatory drivers and benefits for operation in islanded mode. The impacts on the different players will be examined, i.e.

- Various categories of customers
- Society in general
- Electricity Suppliers
- Transmission System Operator (NGT)
- Distribution Network Operators (DNOs)
- Generators
- Developers of DG
- Equipment /Generator Manufacturers

Where there are or may be contractual relationships between the above parties the benefits may be difficult to ascribe to one party or the other, as both parties may share the benefits in the associated contract.

This section does not attempt to examine or consider the costs, technical problems, practicality or probability of islanding operations, but focuses on the benefits to different players if islanding were achieved.

Finally this section considers how different future scenarios may significantly change and enhance the current drivers for islanded operation.

7.2 Customers

Customers are defined as all persons or organisations taking a supply of electricity from a network. In order to understand the picture across a very wide range of customers they must be divided into appropriate categories.

1) Permanently islanded customers
2) Customers on geographical islands connected to the grid
3) Customers with standby generation / uninterrupted power supplies (UPS)
4) Best served customers
5) Worst served customers
6) Storm affected customers
7) Power starved customers
8) Customers during planned works

When the impacts on suppliers are considered the different impacts of HH and NHH-metered customers will become apparent.

7.2.1 Permanently islanded customers

There are customers in the UK who obtain power on a permanent basis from islanded operation. The largest such system is Shetland, which is the only permanent island system operated by a licensed DNO. There are a number of smaller island systems operated privately by landlords and/or community schemes e.g. Fair Isle, Foula, Rum, Muck, and Lundy. There are also a number of individual customers based on the mainland and on islands who operate “off-grid” in a “household island”. Many of these customers are located in the remoter areas in the North of England, where it was considered uneconomic to make connections to the distribution network. In Scotland the social policy of subsidising connections ensured that fewer remote users (especially on the mainland) were left unsupplied from the grid.

Of all customers, these permanently islanded customers receive the greatest benefit from islanded operation, as without it they would not have the benefits of electricity, even though in many cases the costs per kWh are much higher than for other UK customers.

7.2.2 Customers on geographical islands connected to the grid

Electricity supplies on several remote islands were initially obtained solely from within the island (e.g. Islay, Orkney, Outer Hebrides). However, over time these islands have been connected to the mainland network by undersea cables. Nevertheless, if there were a cable fault, the island would be unsupplied for a single cable connection (or where there is a dual circuit supply the second circuit may be overloaded at peak demand times). In this case the island based generation, which has been retained, would operate to support the system. This requirement for generation is driven by the restoration time for the customers' supplies. As the connection is by undersea cable, the repair time for a fault could be many weeks or months given the weather conditions and the need to mobilise appropriate vessels and equipment to undertake the work.

By definition these remote connected island customers also receive a substantial benefit from network-islanded operation when required.

7.2.3 Customers with standby generation / UPS

Many customers have chosen to employ their own "islanded operation" through the provision of standby generation or UPS. Typically these larger customers include banks (to maintain central computer systems), hospitals (to maintain life support systems) and supermarkets (to maintain freezers and refrigeration). Many customers also maintain UPS for key items such as personal computers and servers.

Experience indicates that most customers will only provide standby generation or UPS plant for a few mission critical activities and will not aim to supply all their normal electrical demands under "islanded operation".

These customers have made a deliberate decision that the cost of installing and maintaining this equipment is outweighed by the benefits. In selecting a case study one may wish to consider if this service could be bought in from the islanded network with the same reliability but at lower cost.

7.2.4 Best served customers

Typically the "best served" customers are those in urban areas with a high reliability of supply due to the network configuration. Urban networks are usually based on underground cable connections, which are not subject to weather (storm and tree) damage and allow a high degree of interconnection, which permits alternate feeds during repair of damaged or failed underground cable.

These customers would not in general benefit from islanded operation, as underground mains cable failure is a relatively rare event. Those who place a very high value on continuity of supply are expected in any case to have purchased standby generators or UPS systems.

7.2.5 Worst served customers

Typically the "worst served" customers are in remote rural areas with a lower reliability of supply due to the network configuration. The network mainly consists of overhead conductors mounted on poles, which are vulnerable to damage or intermittent faults due to trees, weather, bird collisions, wind blown debris, etc. By definition, there is also a lesser degree of interconnection for alternative supplies to remoter customers and longer lengths of line associated with any given customer and automatic protection or switching scheme.

Encouraged by Ofgem responding to customer complaints, the service to these worst served customers has undoubtedly improved considerably over recent years. The view amongst DNOs is that customers who have always been in this position are quite content with their electricity supply (and therefore would not see a benefit in islanded operation). Customers who have moved to remoter rural areas form urban areas (and therefore from best to poorer served status) are likely to complain about the service and these customers would benefit from network islanding, especially if it could be done without interruption of supplies. However ascribing a value to the benefit, which is psychological in nature, is a challenge that still remains. Ofgem are currently undertaking a customer survey to attempt to estimate the value, as it is acknowledged that a previous survey of this type was inadequate in this respect.

7.2.6 Storm affected customers

These customers are not a discrete or easily identifiable group but will generally be supplied by overhead lines, which are more vulnerable to damage in severe weather. As severe weather (sufficient to cause widespread damage) is an irregular event, storm affected customers may be in any part of the country and would be off supply as a result of severe weather for that part of the country.

Severe weather interruptions are typically the longest duration interruptions experienced by customers.

These customers would benefit from islanded operation if it could be achieved for selected areas of network following these severe weather circumstances.

7.2.7 Power starved customers

There has been considerable discussion recently about security of supply in relation to the UK's increasing dependence on imported fuels, particularly gas. The Energy White Paper [11] sets out a policy for maintaining diverse and secure energy supplies as one of its four key goals.

If there were power cuts as a result of a shortage of generation (either planned rotational power cuts or unplanned via low frequency load shedding) there would be a benefit to those customers who could operate islanded during these periods, provided of course, that energy supplies for the islanded generation were not affected. This may particularly benefit vulnerable customers such as the elderly and infirm.

7.2.8 Customers during planned works

Many DNOs use portable standby generation to maintain "islanded" supplies to customers while undertaking works on their network. Using switching and sectionalising to allow works and minimise disruption to customers, this method has the following advantages over a more traditional approach of taking outages to undertake necessary works.

- Faster work rates due to ability to provide greater simultaneous access
- Reduced risks to staff and contractors
- Reduced customer interface and communications required
- Reduced penalties or compensation payments due to delays or for longer outages for complex work

7.3 Society in general

Our society is increasingly reliant on electrical power for many purposes, and many are safety related. There is a risk of civil disobedience, assault and looting if there were a loss of power in city centres as the normal security systems (lighting and street lighting, CCTV, burglar alarms) may not function.

Lifts in multi-storey buildings and some public transport systems are powered by electricity and these are vulnerable to disruption, putting passengers at risk.

If islanded operation prevented or reduced these risks, there would be a general public benefit.

7.4 Electricity suppliers

The costs and benefits for electricity suppliers have been covered in Section 6 above in relation to many different scenarios.

The benefits to suppliers arising from islanding would be

- Reduced risk of exposure to System Buy Price through maintaining output of DG under SVA contracts
- Reduced exposure to System Sell Price through keeping demand from HH-metered customers during faults/ outages
- Potential of improved customer satisfaction if supplier can offer this service

7.5 System operator & system security

There is some concern at present that most DG could trip off the system during a major system disturbance due to the protection settings specified by the DNOs. Such an occurrence could lead to a large loss of generation to the GB system with the potential for load shedding or even system shutdown.

If DG were set up for islanding operation then there would be a reduced likelihood of tripping for a total system disturbance and therefore a lower risk to the system.

7.6 DNOs

There are a number of potential areas for DNO benefit to consider.

- P2/5 [1] (or P2/6) compliance
- Investment Incentives Project (IIP) incentives
- Capital expenditure savings
- Active network management
- Reduced risk of severe weather payments
- Generation connection incentives
- Reduced compensation payments to generators
- Ancillary services

7.6.1 P2/5 or P2/6 compliance

DNO networks are obliged to comply with the security standard P2/5 [1] (which is currently under review and being updated to standard P2/6). P2/6 will allow DNOs to use modern generation technologies to achieve security of supply standards in conjunction with the traditional methods of network reinforcement. However, the major focus of P2/6 will be the operation of generation in parallel with the network (i.e. not islanded) to avoid the overloading of interconnection circuits, especially during a circuit outage.

At present most DNO networks readily comply with P2/5. The drivers for reinforcement are primarily the customer minutes lost (CML) and customer interruptions (CI) data under the IIP project which results in networks that are much more robust than the requirements of P2/5.

It is therefore unlikely that islanding would be a benefit to DNOs unless P2/6 or future security standards were to be much more stringent in their requirements.

It should be noted that in the former Scottish Hydro Electric Area (in the North of Scotland) Scottish and Southern (SSE) have exemptions from P2/5 due to the geography of area, remoteness of customers and the costs of providing interconnection and alternative supplies.

SSE can operate a number of “islanded” systems with a variety of sizes under fault conditions with diesel or hydro generation.

7.6.2 IIP incentives

The islanded operation of embedded generation will result in improved security of supply to the DNOs’ customers in terms of reduced CML, and reduced number of CI provided the transfer to islanded operation takes place in less than three minutes. The DNO’s revenue in consequence can be enhanced by improvements in the quality of supply indices recognised under the IIP.

However, in discussions with DNOs only one instance was found where the DNO had used DG to provide islanded operation to improve IIP performance. Although SSE may derive an IIP benefit from the islanded operation described in 7.6.1 above, these islanding capabilities were in place prior to the IIP scheme and therefore have not been specifically developed under an IIP driver. SSE have considered islanding operation in one situation (Achiltilbuie, north west of Ullapool) in recent years but eventually other more cost effective measures were been used to improve quality of supply. Therefore there would need to be other incentives to release this IIP value.

7.6.3 Capital expenditure savings

Where DNOs are considering making a major capital investment (capex) they could be interested in contracting for generation support instead. The drivers for this expenditure are due to demand growth, P2/5 [1] or IIP or some combination of these factors.

All other things being equal, if islanded operation can defer or reduce capital expenditure this would be a benefit to the DNO.

However, from discussions with DNOs there does not seem to be a DNO business case at present to achieve islanding. The most likely stepping stone to this situation would be operating generation in parallel with a partially intact network to support the system and make capital expenditure savings. For example, the generation on Orkney is designed to be operated at peak demand periods if one of the undersea cables fails. This method avoids the costs of investing in a third 33kV sub sea cable.

The most immediate capex savings for DNOs will be in situations where the generation can run in parallel with a partially intact system. Once these installations are in place there could then be a move to the next stage, which is islanded operation.

7.6.4 Active network management, IFIs and RPZs

DNOs are being encouraged to embrace active network management by Ofgem under the Distribution Price Control Review. Ofgem is proposing that DNOs should increase R&D expenditure and is also encouraging this under the Distribution Price Control Review. The Innovation Funding Incentive (IFI) is to encourage research, and Registered Power Zones (RPZs) are to encourage demonstration.

Therefore DNOs can allocate cash, which is earmarked for innovation. Islanded operation of DG offers a means of achieving this innovation.

7.6.5 Reduced risk of severe weather payments

In the current price control period, loss of supply to customers under severe weather conditions does not automatically trigger compensation payments to customers. However under the current price control review it is proposed that additional guaranteed standards should be introduced in severe weather circumstances and that a semi automatic payment standard should be made under the supply restoration standard.

Whilst these proposals are not yet in place, assuming islanding DG can reduce the number of outages, this would be a benefit to DNOs if these changes go through.

7.6.6 Generation connection incentives

Under the Distribution Price Control Review there are plans to reward and incentivise DNOs for connecting generation to the network. DNOs may be able to connect more generation to the system, particularly standby generation, which would normally only operate in off grid stand-alone mode, if it can run this generation in islanded mode on the network.

7.6.7 Reduced compensation payments to generators

Under the distribution price control review DNOs are expected to move to a shallower connection charging policy for generation from April 2005. Associated with this change it is expected that generators will start to pay distribution use of system charges for exported energy. If generators are paying for this access to the network there is expected to be either a compensation payment or a reduced charge from the DNO if the network is unavailable. In either case this is a loss of revenue to the DNO.

Enabling generation to operate in islanded mode would protect DNOs from exposure to this compensation payment or income reduction.

7.6.8 Ancillary services

Currently the Transmission Owner or System Operator does not charge DNOs for services such as reactive power, voltage control or frequency control. If greater differentiation of service provision is brought in, DNOs may be obliged to contract for or play in the market for some of these services in the future. In addition, DGs may seek to gain increased access to markets for ancillary services.

Therefore if DNOs are seeking to obtain these ancillary services, in some cases they may be able to contract these at lower cost from DGs rather than from the TSO. If DGs are able to contract in the market for these services they will be in a better position to

- Provide islanded operation – as the costs of providing the equipment to operate islanded will be covered by ancillary service provisions
- Operate in islanded mode – as there would be a means of rewarding the ancillary service provision under islanded operation (the reward might also be tailored to the increased importance under islanded operation)

To summarise, an ancillary services market in the Distribution Networks would encourage more generators (and load/demand customers) to offer services, which could be used to provide islanded operation.

7.6.9 Summary

From discussions with DNOs the most likely instance of interest for islanding would be where a primary substation, or bulk supply point, with a large number of customers was potentially vulnerable to a common mode failure of the two incoming 33kV or 132kV circuits. This would be the case where the supply was by cables, which shared the same duct, or trench or where a double circuit structure carried twin overhead line feeds.

When there is general use of DG to support the existing network, under the new rules of P2/6, it is possible that islanded operation will offer an alternative to reinforcement. Without the network support role of DG, it is unlikely that islanding will take place.

7.7 Generators

There are two sets of financial drivers for generators to operate islanded.

- Increased revenue through operation in islanded mode when they would otherwise be unable to generate
- Reduced wear and tear on plant which can operate islanded and which therefore is not required to shut down during short interruptions

Currently most distributed generators accept that there will be periods when they are unable to generate due to network faults. For most renewable generators this downtime represents lost revenue, as there are no associated fuel savings during the shutdown (as there would be for fossil fuelled plant). Most DG is currently not compensated if it is unable to generate during a network outage or fault. However, the total duration of such outages is usually very small and therefore generators would not consider the additional revenues to be gained during islanded operation to be worth the costs of achieving it.

Some generating plant can be sensitive to supply interruptions as this can cause over-speed, shutdown and wear and tear or even damage to the plant. Ability to operate islanded would have capital cost advantages in allowing lower cost plant and/or reduced operational wear and tear, provided a seamless switch to islanded operation is achieved.

7.7.1 DG ancillary services revenue

To provide for islanded operation of DG requires investment in voltage and frequency control. These capabilities would then remain during normal network operation. It is anticipated that active management and control of distribution networks will develop greatly in the near future to allow for the likely increase in distributed generation capacity. If DG had access to ancillary services markets this would provide an additional income stream to fund the control systems required for islanded operation.

7.8 Developers of DG

Developers of DG may be able to design and provide their plant with islanded operation capability at installation. If this provided the local population with islanded operation capability it could be a “planning gain” and a reason for the local population to support the planning application. Capability for islanding at initial plant procurement may also be more cost-effective than retrofit of technologies to enable islanding capability.

7.9 Equipment & generator manufacturers

Equipment and generator manufacturers, contractors and suppliers would benefit from the islanded operation of DG in that the demand for their equipment and services would rise to fulfil the technical demands and requirements of islanding.

7.10 Future scenarios

For islanding benefits to increase significantly there would have to be a significant increase in the value of continuity of supply and/or an increase in the duration and frequency of incidents when islanding could come into play.

If the "business as usual scenario" is followed, there is increasing sophistication and investment in networks, which focus on increasing network reliability and reduce the opportunities for islanding to take place. With the increased incidence of DG it may be that this investment could be better directed at islanded operation, which would require appropriate incentives.

However, we should also consider divergent scenarios where these trends would reverse and where islanding could play a more major role. These scenarios could include

- Severe weather changes where severe weather conditions cause increasing breakdown of the distribution (or transmission) networks. These incidents could include extreme high temperatures, storms, icing / snow
- Power cuts due to fuel supply shortages
- Power cuts due to demand changes – e.g. high summer urban demand in the south-east from air conditioning loads driven by climate change
- Terrorist attacks on grid infrastructure
- Planned islanding for system outages

8 Methodology for selecting case studies for islanded operation

The case studies were to be selected to give maximum value for the industry. It would be tempting to say that the obvious case studies are those existing pieces of networks that can already operate in islanded mode, e.g. Islay. However the drivers for this particular island are sub sea cable repair times and therefore this island is not representative of more than a handful of cases in GB.

On the other hand there are currently only trial installations of domestic CHP (DCHP) and these may not be currently considered for island operation, let alone designed to achieve that. However, if the benefits to the players are appropriate it may be that islanding new housing estates on DCHP is viable and can be rolled out to thousands of installations across the coming decade.

A methodology was therefore which scored each potential islanding network configuration / situation for a variety of factors to achieve a comparative score for each configuration. This score should provide an indication of the most effective network configuration to be selected for the islanding case studies.

The methodology assessed each of the following factors in turn.

- Number of customers affected by interruption
- Number of instances of this type of Network Configuration in GB
- Frequency of incidents leading to possible islanding
- Probability of DG being available in this island
- Probability of DG being configured for islanding operation from net cost/benefit assessment

This methodology is explained in greater detail below with two examples of islanding used to illustrate the methodology.

8.1 Example of case selection methodology

Section 4 presented several potential island network configurations. Two of these have been used as examples to demonstrate the case selection methodology, below. The data shown below is based on several assumptions, whilst actual case study selection required data to be verified and populated for the other potential island network configurations.

The two island scenarios shown here as examples are

- An island such as Islay in Scottish and Southern's network where there is a diesel generator to provide supply in the event of a loss of supply due to sub sea cable failure / damage
- An island created on a LV system in a new housing estate, which is all equipped with domestic CHP

8.1.1 Number of customers affected by interruption

For the fault considered and the islanded configuration, estimate the typical number of customers who will be supplied from the operating island.

- Assume there are 1000 customers on a typical Islay island
- Assume there are 100 customers in a typical housing estate

8.1.2 Number of instances of this type of network configuration

For the whole of GB, estimate the number of instances of this type of network configuration. For example for Islay this will be very small, and will increase for primary substations, 11kV feeders, and LV housing estates.

- Assume there are 5 Islay type islands in the UK
- Assume there are 100,000 housing estates in the UK

8.1.3 Frequency of incidents leading to possible islanding

This figure will provide a measure of the average number of incidents (e.g. faults per year) for this kind of interruption leading to an island. The kind of incident will have to be defined. It may be any interruption of supply, an interruption of over 3 minutes (which affects CML and CI data) or over 18 hours (which affects compensation payments to customers). In this case outages over 18 hours were considered.

- Assume there is one outage >18 hours per year per Islay type island
- Assume there is one outage >18 hours in 10 years per housing estate

Note this data is to be confirmed in the next stage of the project.

8.1.4 Probability of DG being available

For a given scenario (e.g. at this point in time or by 2010 or 2020) estimate the probability that there will be sufficient DG already installed in this network configuration to support islanded operation (although the DG may not be set up to achieve islanding). For example it maybe considered that by 2010 2% of all housing estates in GB would have 95% of homes with DCHP that may be considered sufficient to operate in islanded mode (subject to the installation of the necessary ancillary plant).

- Assume there is 100% probability in 2010 for Islay type island
- Assume there is 2% probability in 2010 per housing estate

8.1.5 Probability of DG being configured for islanding operation from net cost/benefit assessment

This factor will assess the probability that an islanded system would be implemented considering the cost benefit drivers. This factor will change for different scenarios e.g. business as usual, increased IIP incentives.

- Assume there is a 100% probability per Islay-type island due to drivers on DNO for security of supply
- Assume there is a 5% probability of all estates housing estates with 95% DCHP due to the additional security of supply and increased value of the houses to the developer

8.1.6 Result (customer benefits per year)

From these figures the results are

- 1000*5*1*100%*100% = 5000 customer incident benefits in GB per year for Islay type island

- 100*100,000*0.1*2%*5%= 1000 customer incident benefits per year in GB for typical housing estate island

These figures suggest that the former would be a more appropriate case study than the latter.

However if all housing estates, which were fitted with 95% DCHP, were set up for islanding because there were sufficient drivers the figures would be

- 5,000 for Islay type
- 20,000 for housing estates

8.2 Evaluation

All islanded network scenarios / network configurations were assessed using this methodology to provide a decision support tool for selecting the appropriate case studies. Much of the data needed to use this tool was not available to a high degree of accuracy and therefore Econnect's judgement was used, complimented by the experience of the TSG work stream, to obtain suitable data estimates.

9 Identification of Case Studies

Five possible systems for islanding were considered at the WS5 peer review meeting on the 9th June 2004 and put through the case selection methodology which considered the following factors:

- Number of customers affected by interruption
- Number of instances of this type of network configuration in Great Britain
- Frequency of incidents leading to possible islanding
- Probability of DG being available in the island
- Probability of DG being configured for islanding operation from an assessment of net cost/benefit

Based on this methodology, which is described in more detail in Section 8, the two systems chosen for modelling were

a) The common mode failure of sole twin 33kV feeders, which would cause islanding of a primary substation 11kV busbars that had no 11kV interconnection

b) The loss of a single transformer feeder primary resulting in the islanding of an 11kV network

9.1 Data Acquisition

Once the scenarios were chosen, two actual case studies had to be found which would conform to the scenario requirements and allow a suitable model to be constructed.

For System A, an area of the Eastern Power Networks (EPN) distribution network was chosen where two 33/11kV transformers supply a primary substation, from which there are six outgoing 11kV feeders, three to each busbar section. Three of the feeders connected to one busbar section have Distributed Generation connected, namely a diesel generator and two landfill gas generators (see Figure 7 in Section 10). These generators can support the summer load on this single busbar section, and hence modelling only incorporated the operation of this busbar section for the purposes of analysing the islanding project. The arrangement of a twin fed 33kV primary with no 11kV interconnection is unusual.

For System B, the network on the Isles of Scilly, which forms part of the Western Power Distribution (South West) network, was chosen. The connection to the Isles of Scilly is a single 33kV undersea cable that feeds a 33/11kV transformer and a single 11kV primary busbar. Three 11kV feeders are connected to the primary busbar and supply the islands' loads. In addition six diesel generators are connected to the 11kV primary busbar (see Figure 19 in Section 10). These generators are usually called upon to offset demand on the island during outages on the mainland 33kV ring in order to reduce loadings on the mainland 33kV system. However, they are also used to operate in 'islanded' mode, when required for a planned outage of the 33kV undersea cable.

10 Technical modelling

10.1 Scope

The purpose of the technical modelling was to inform the debate on islanding by modelling how two real systems would react to an islanding event. As such the priorities of the modelling project were to

- Make each model a realistic equivalent of the systems under consideration, allowing for time and data constraints
- Apply an islanding scenario based on the normal operation of the systems, but extrapolated to show the Study the effect of any modifications to the systems that could facilitate seamless islanding

Whilst it is likely that many more scenarios would be required to build up a complete picture of the behaviour of the two systems following islanding, such in-depth analyses were deemed to be outside the scope of this report.

10.2 Common mode failure of sole twin 33KV feeders causing islanding of a primary substation 11kV Busbars (System A)

10.2.1 Pre-event base model

10.2.1.1 System design

The system studied in Section 10.2 is referred to as System A. The system diagram is shown in Figure 7. In addition to the twin 33kV incoming feeders, the system includes three 11kV feeders along which loads and local generators are connected.

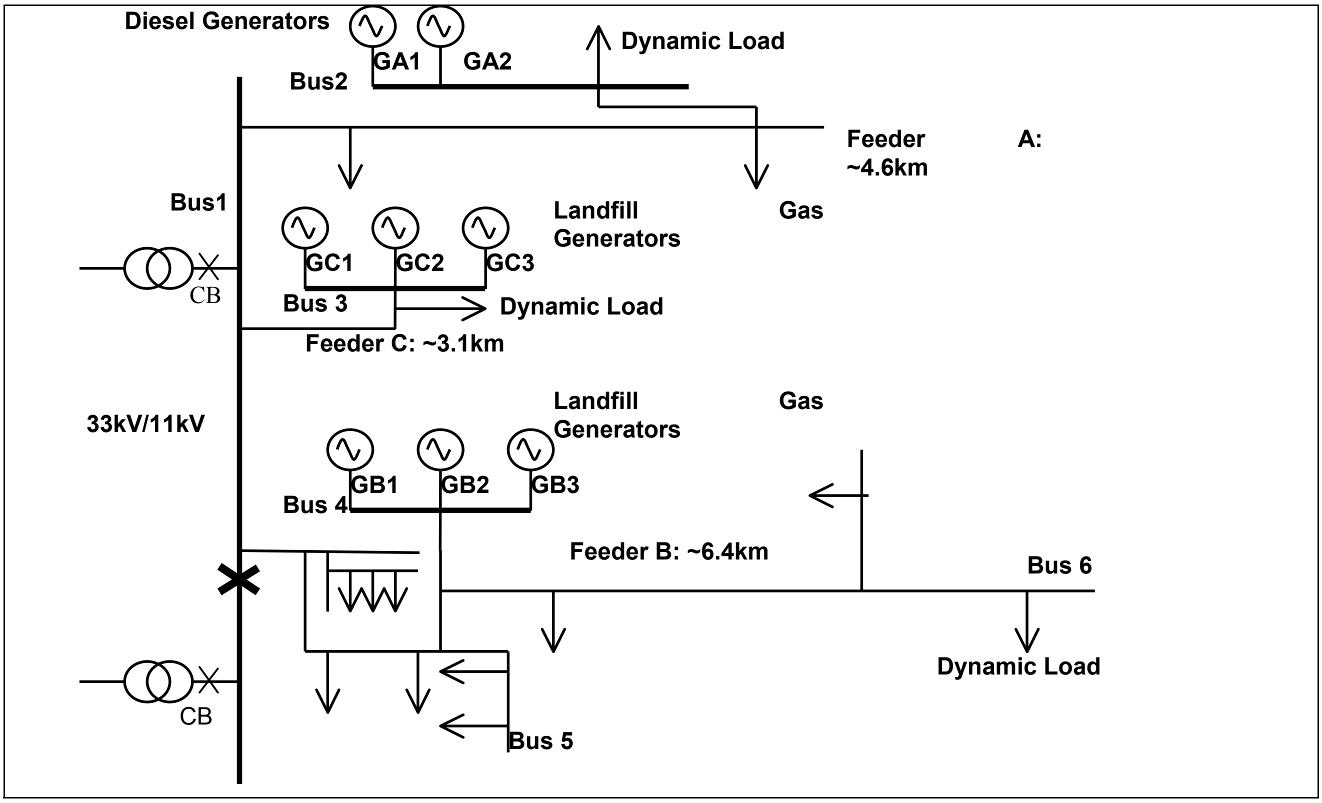


Figure 7. Configuration of System A

More details of the system are shown in Appendix E. The total local generating capacity from the two diesel generators and the six landfill gas generators is 9MW while the local load varies from 8.2MW peak to a minimum of around 3 MW. The scenario studied corresponds to a situation where the local load is low, the landfill gas generators are operating at maximum real power output with a power factor of around 0.9 lagging (i.e. exporting reactive power), and this section of the 11kV system is exporting real and reactive power to the grid. The two diesel generators are assumed to be shut down. This situation corresponds to a typical evening operating mode. The pre-event condition of the system is summarized in Table 4.

The first stage of the modelling process, which is detailed here, was to create the model itself whilst making sure that the outputs from the model were realistic prior to the islanding event taking place, to ensure that confidence could be placed in the results of the simulation once islanding had taken place.

System Condition		State
Generators GC1-GC3	real power output (MW)	1.255 MW (each)
	reactive power output (MVAr)	0.376 MVAr (each)
Generators GB1-GB3	real power output (MW)	1 MW (each)
	reactive power output (MVAr)	0.302 MVAr (each)
Generators GA1-GA2		Disconnected
Total local load		3.06 MW @ ~0.9 pf
Real power exported to grid		3.7 MW
Reactive power exported to grid		0.6 MVAr, lagging

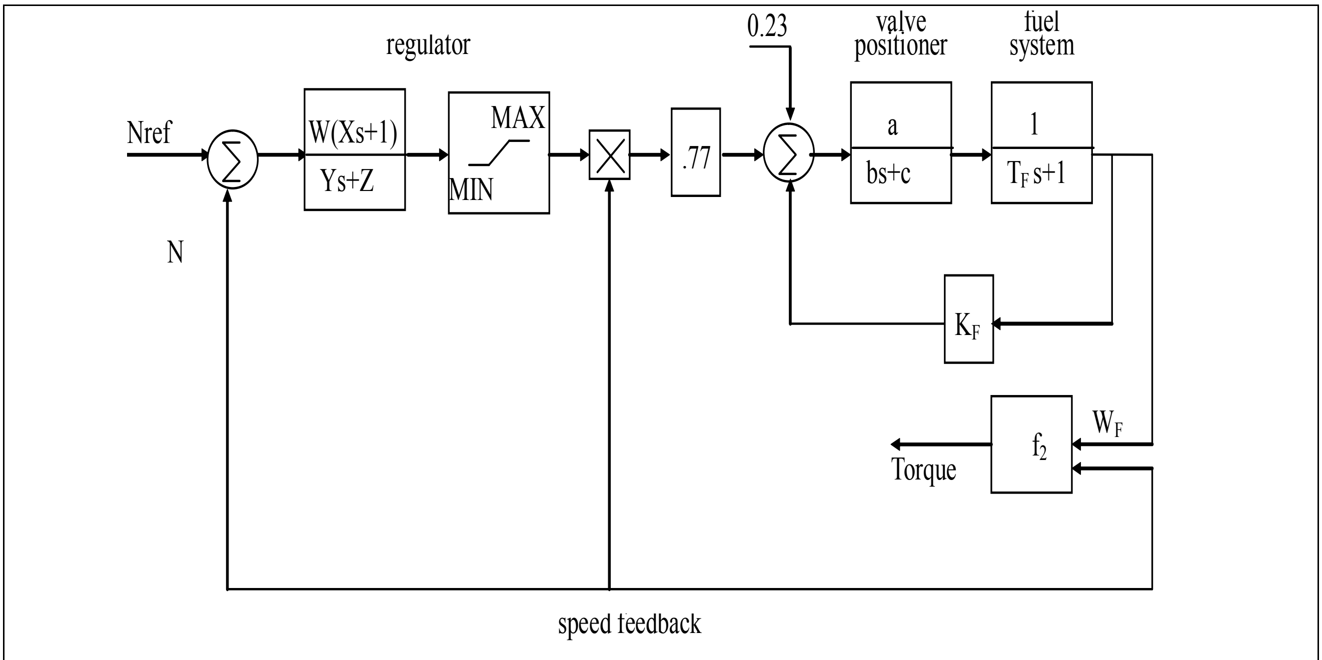
Table 4. Pre-event conditions

Although in reality this particular network is unlikely to export such quantities of power to the wider Grid System, the available data was extrapolated to create an export scenario (as opposed to the maximum import modelled in the second case study), designed to illustrate the dynamic response of the system at a time of high stress (i.e. greatest mismatch between generation and demand) when grid connection on the 33kV side is lost.

10.2.1.2 Method

Simulation runs to predict the dynamic performance of the system were carried out using the time domain simulation software tool SIMULINK. Simulink is a block-orientated program that allows one to simulate dynamic systems in a block diagram format whether they are linear or non-linear, in continuous or discrete forms. The synchronous generator with salient rotor was modelled using the 6th-order transient model in the 'SimPowerSystems' blockset. In such a model, the machine is represented using three stator windings, two damper windings on the rotor quadrature axis, a field and one damper winding on the rotor direct axis. All windings are magnetically coupled except that there is no coupling between the direct and quadrature axis windings. The parameters of the generators are also given in Appendix E.

A speed governor determines the mechanical torque applied to the generator to achieve the speed setting through the frequency control loop. The model for the governor of the gas generator is based on a GE study published in a paper by ASME [12]. The block diagram and the major parameters are shown in Figure 8. In brief, included in the model are a 200ms first-order delay to recognize the change in frequency and a response time around 500ms. A droop characteristic of 5% is represented so that power sharing between parallel generators can be achieved in islanded operation. The generator output at the pre-event frequency (50Hz) can be arbitrarily set, and for this case study, it is set as the nominal real power of the generator for the reasons described in section 10.2.1.1.



KEY

Speed governor transfer function coefficients:

W=1/0.05; X=0; Y=0.05; Z=1;

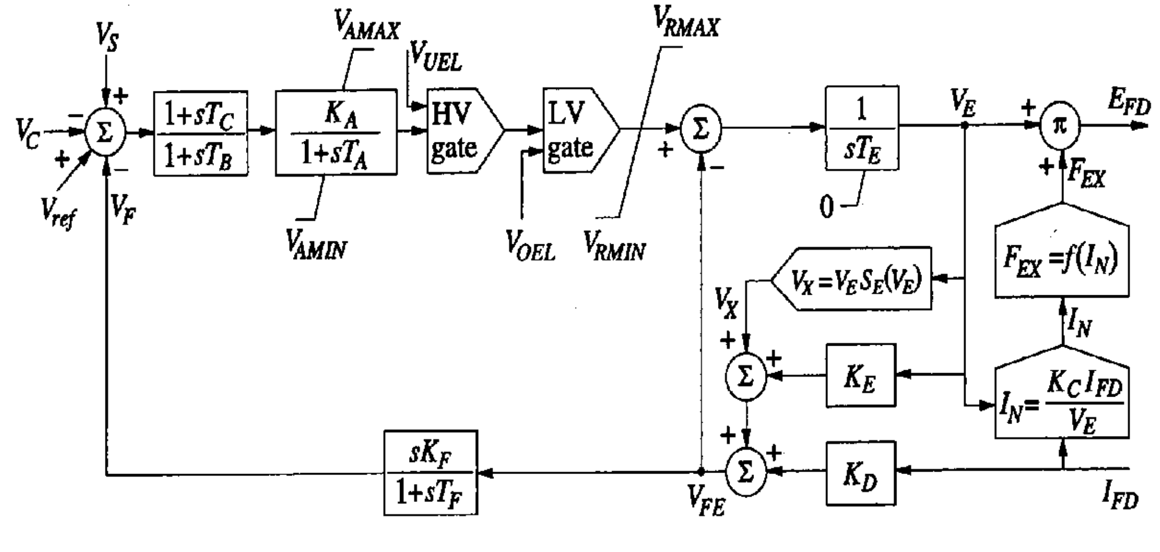
VCE limits: MAX=1.5 pu; MIN=-0.1 pu;

Fuel system characteristics: a=1; b=0.05; c=1; T_F=0.40; K_F=0;

f_2=Turbine Torque=1.3 (WF-0.23)+0.5(1-N)

Figure 8. Block diagram of gas generator governor model

The automatic voltage regulator (AVR) characteristic, which determines the excitation voltage applied to the generator, is mainly derived from the generator terminal voltage, and is represented using the IEEE type AC1A excitation system model as shown in Figure 9; typical parameters as given in the figure are used in the simulation [13]. V_{ref} is the reference terminal voltage of the generator and feedback V_c includes the contribution produced by a load current compensator as shown in Figure 10. Like the droop characteristic in the speed governors, this load current characteristic is important when determining the reactive power sharing between parallel generators during islanding operation. In the model, the load compensator parameters used are R_c+jX_c=0.0005+j0.005 (pu). The signal V_s for power system stabilization is disabled.



KEY

K_A=400	T_A=0.02	T_B=0	T_c=0	K_F=0.03
T_F=1.0	K_E=1.0	T_E=0.8	K_D=0.38	K_C=0.2
V_{RMAX}=7.3	V_{RMIN}=-6.6	V_{AMAX}=15	V_{AMIN}=-15	

Figure 9. Generator excitation system model – IEEE AC1A

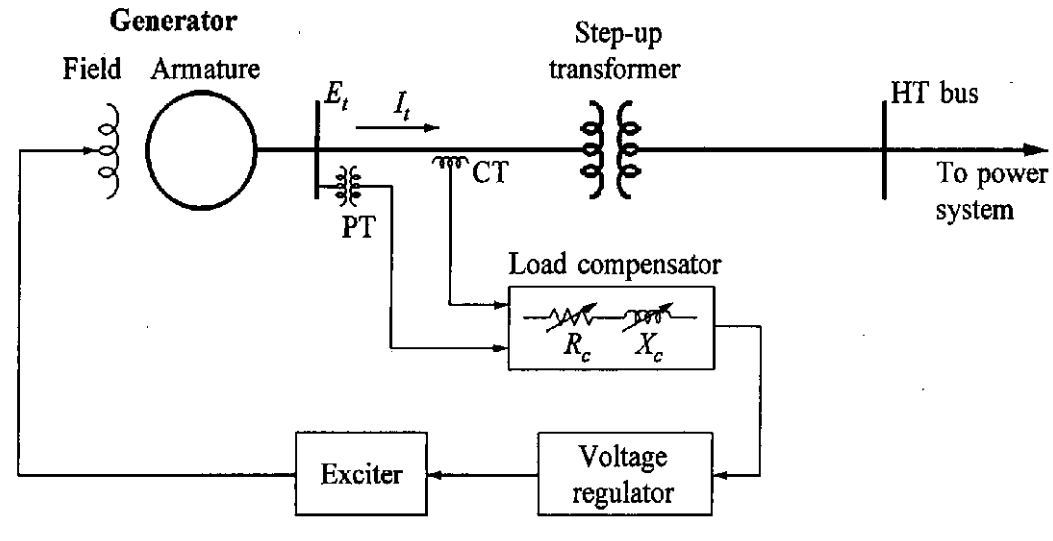


Figure 10. Load compensator (IEEE model)

The 11kV cable or line sections are modelled using a series of three-phase p type equivalent circuits, one π for each section. Static loads are modelled using series RL elements directly attached to the 11kV busbars. The real and reactive power values are specified for the nominal voltage (11kV) and frequency (50Hz). In order to evaluate the impact of islanding on different types of load, some loads were modelled as dynamic loads. These are large, direct-on-line induction motors, which are marked accordingly in Figure 8. Such loads represent about 40% of the total load power in the system. The dynamic loads are located at different places to the generators, as indicated in Figure 8. The values of the dynamic loads are also given in Appendix E.

The moment of inertia constant (H) of both gas generators and dynamic loads is an important parameter that affects the simulation results significantly. A survey of inertia constants used for previous simulation work benchmarked against engineering judgement, led to a typical H constant of 0.5 pu-second being used, according to the generator unit size and type involved in this study. The H constant of the dynamic load was set at a typical value of 0.2 second.

It is assumed that islanding is instigated by a simultaneous fault on both the twin 33kV feeders. To reduce the complexities of this initial analysis the generators and loads are modelled in steady state operation before entering the islanded mode, i.e. Terminal Voltage was set at 1pu rather than 0.8pu post fault clearance for example. Econnect would expect these aspects of the models to be refined should further detailed analysis of the case studies be required.

10.2.1.3 Pre-event model outputs

Figure 11 shows the waveforms of the phase to neutral voltage and the total current flowing through the 33kV feeders measured at the main 11kV busbar. The amplitudes of the voltage and current, and the phase angle between them correspond to the real and reactive exchanges of power between the grid and local system, as shown in Table 4. The current appears out of phase by 180 in the diagram below, but this is due to the way the current has been referenced (analogous to swapping the connections over on a CT) and is actually 80 out of phase, which corresponds to the 0.99 power factor between the real and reactive power export given in Table 4.

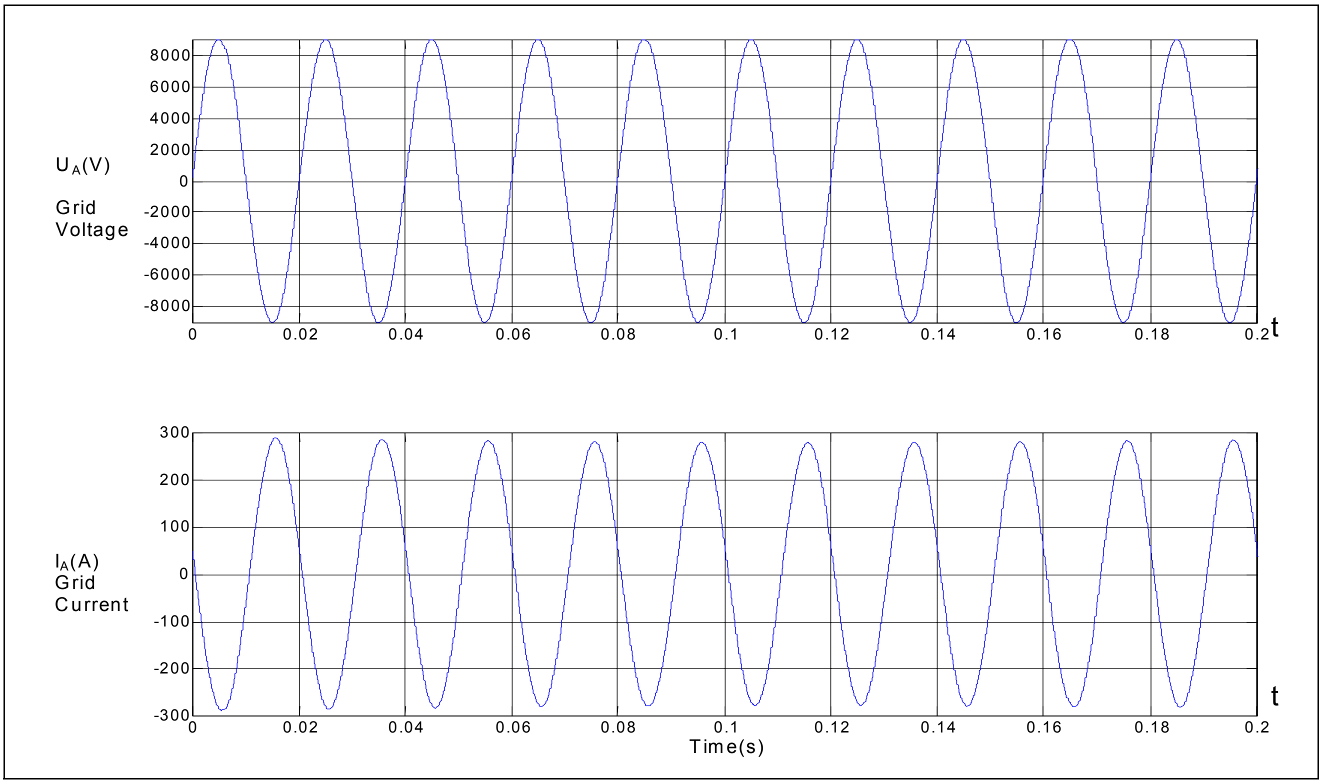


Figure 11. Pre-event grid voltage (phase) and current (from grid)

Table 5 shows the steady state voltages (amplitudes) at busbars 1 to 6. These will be compared with the values at the same busbars in the islanded mode.

Busbar number	1	2	3	4	5	6
Voltage (kV)	11	10.98	11.42	11.25	11.08	10.51

Table 5. Pre-event voltages in System A

The governor and AVR models for the generator were tested using a single machine-single load system. The response to load and input changes was analysed to make sure that the governor and AVR responded in the anticipated way. The results are shown in Appendix F.

10.2.1.4 Pre-event model analysis

From these outputs it was established that the model for System A, which included typical governor and AVR models of the landfill gas generators, was running as expected in steady state mode prior to the islanding event, and therefore could be used with some confidence for simulation of the islanding scenario.

10.2.2 Post-event base model

The second stage of the modelling process was to take the steady state unmodified model created in Section 10.2.1 and subject it to an islanding event.

10.2.2.1 Method

The time domain simulation of the model starts from the steady state at t=0. At t=1 second, islanding is caused by opening the grid side circuit breakers 'CB' as shown in Figure 8. For the purposes of this model the feeders from busbar 7 (Figure 8) are ignored.

10.2.2.2 Post-event model outputs

The simulation results are presented in per unit values. For a generator or induction motor, the base capacity is the nominal VA rating of the machine. The base speed is the synchronous speed, while the base voltage is 11kV.

Figure 12 shows the transient simulation results, from the point of view of a generator on bus 4, following the occurrence of islanded operation with the initial condition shown previously in Table 4. The grid connection is lost at t=1 second. The generator speed initially increases because the mechanical power input exceeds the electrical real power output. Under the control action of the governor, the speed and hence the system frequency oscillates towards a new steady state value. Because of the governor droop characteristic, the final post islanding steady state speed is higher than the nominal value.

10.2.2.3 Post-event model analysis

In this situation, the increase in the frequency of the islanded system is about 2% corresponding to 51Hz from a 50Hz base, which would not be compliant with either the ESQCR [2] (see Appendix G) or Engineering Recommendation G59 [4] (see Appendix H), but would still be within the more probabilistic limits for frequency (see Appendix I) laid down in the BS EN 50160 [7] 'Voltage Characteristics of Electricity supplied by public distribution systems' standard.

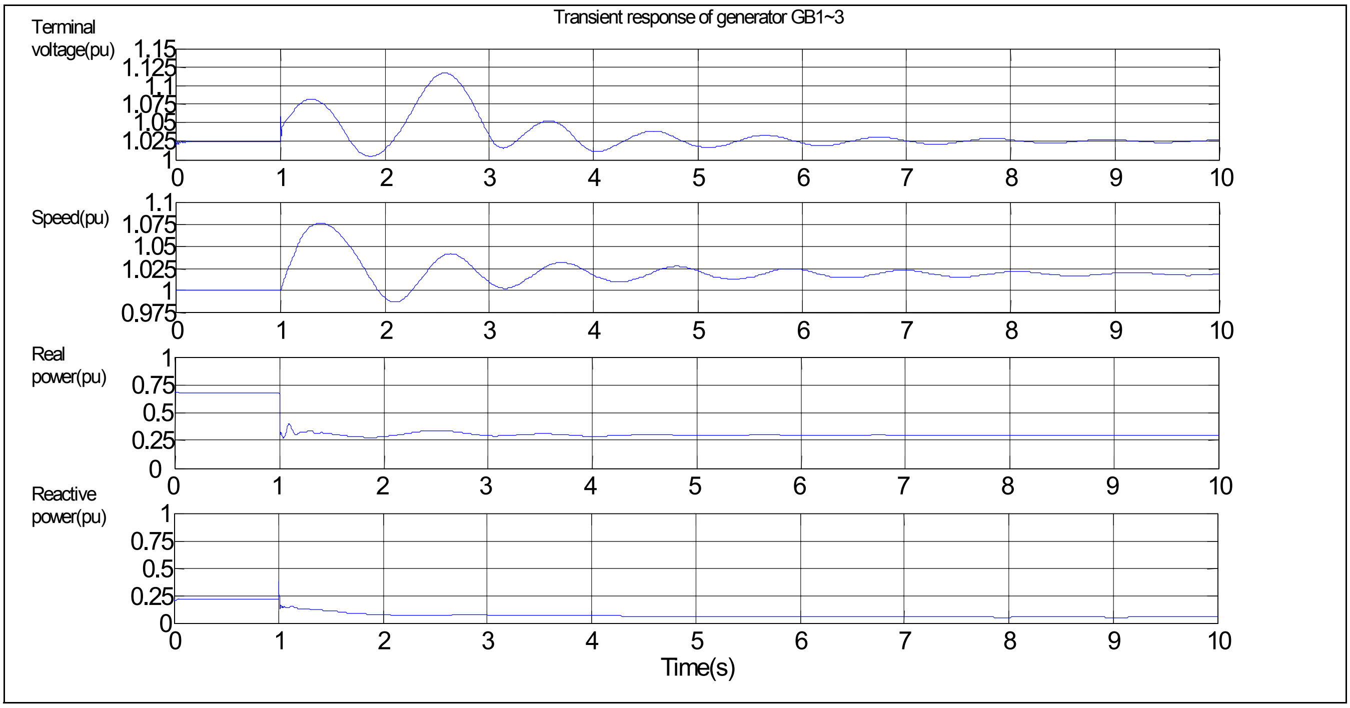


Figure 12. Response of a generator – Droop 5%

The increase of frequency achieved in the post event steady state condition depends on the percentage droop set for the governors. If the droop for all local generators is changed from 5% to 3%, the islanded network responds as shown in Figure 13. The new steady state frequency would now be acceptable for ESQCR [2], G59 [4] and EN 50160 [7] requirements. However the transient excursion of frequency will still exceed the range specified in the ESQCR (+/-1% deviation) and G59 (-6% to +1% deviation). With a reduced droop, the transient oscillation takes a longer time to become damped.

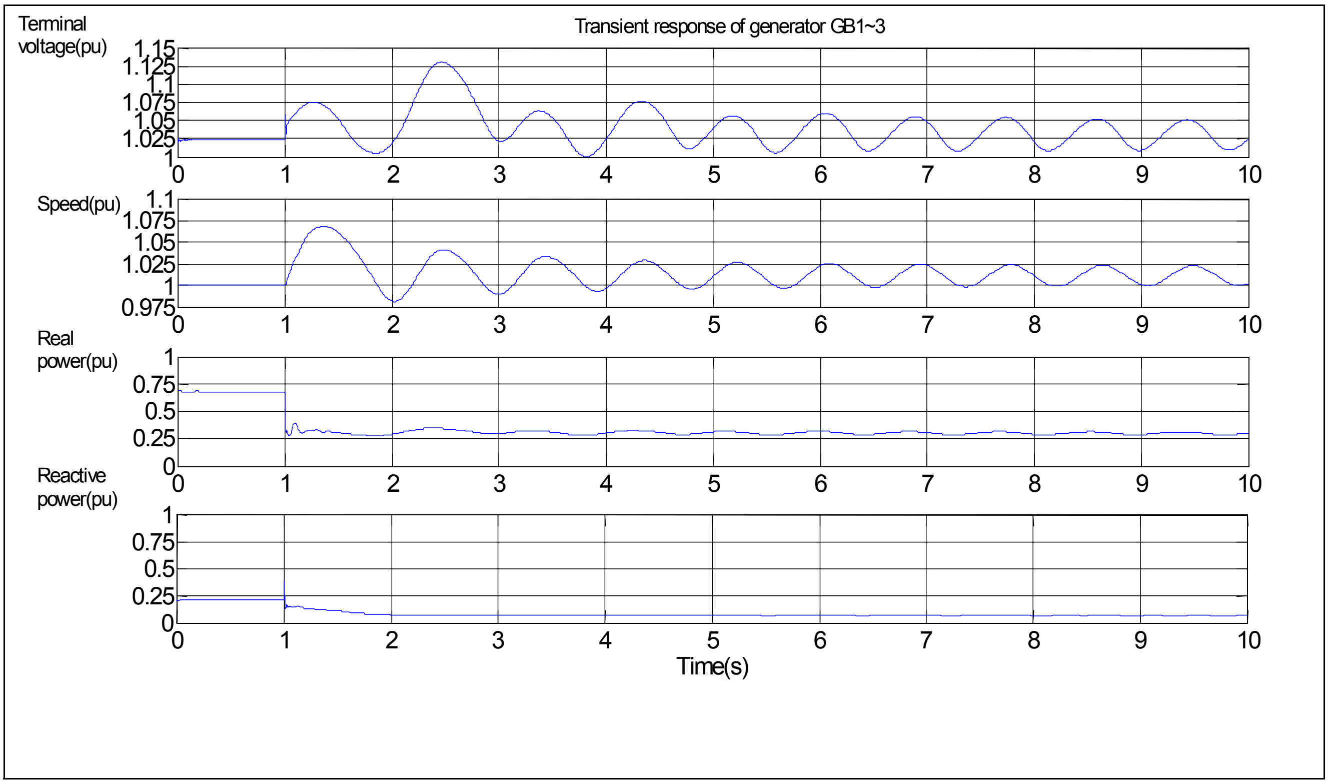


Figure 13. Response of a generator with reduced droop of 3%

In both Figure 12 and Figure 13, the generator terminal voltage also oscillates beyond +10% of the nominal value before settling down to the new steady state value. This oscillation again has implications regarding the over voltage relay settings in the system and compliance with ESQCR standards, although the more lenient EN 50160 standard which allows for temporary over voltages of less than 1.5kV and transient over voltages of less than 6kV can still be met.

10.2.2.4 System (A) induction motor load response

It is revealing to observe the response of dynamic loads in the system. The results are shown in Figure 14. There was concern about whether the induction motor would 'stall' as illustrated in Figure 15. As the system frequency increases, the slip of the motor would increase if the rotor speed remained the same. The motor would eventually stall and stop if the slip became excessive. However, Figure 14 shows that this didn't happen. The total moment of inertia of the motors is much smaller than that of the generators. As the generator speed, and hence the system frequency, increases following islanding, there is adequate chance for the motor speed to catch up with the system frequency and the motor will then remain in the stable operating region of its torque-speed characteristic. However the situation would be more onerous for voltage drop after islanding were there a shortage of reactive power in the system, i.e. the generators were importing rather than exporting reactive power at the moment of islanding.

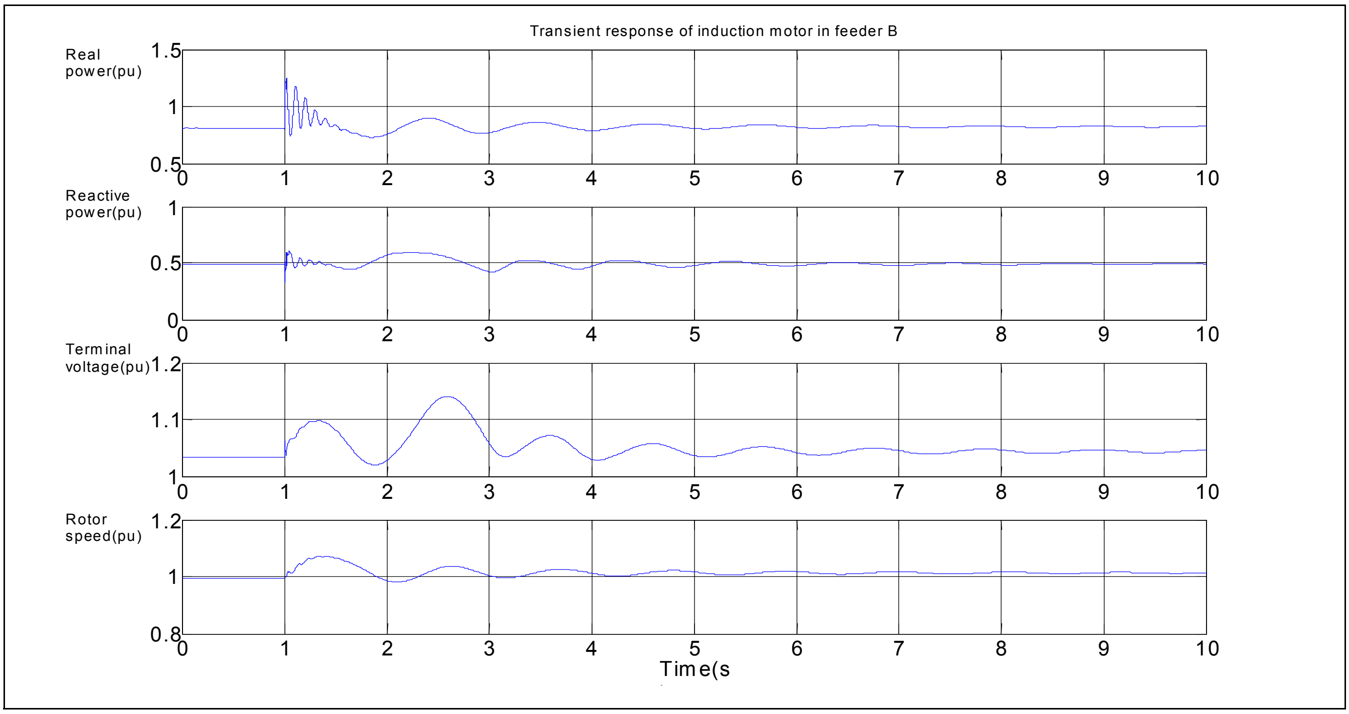


Figure 14. Response of an induction motor in Feeder B

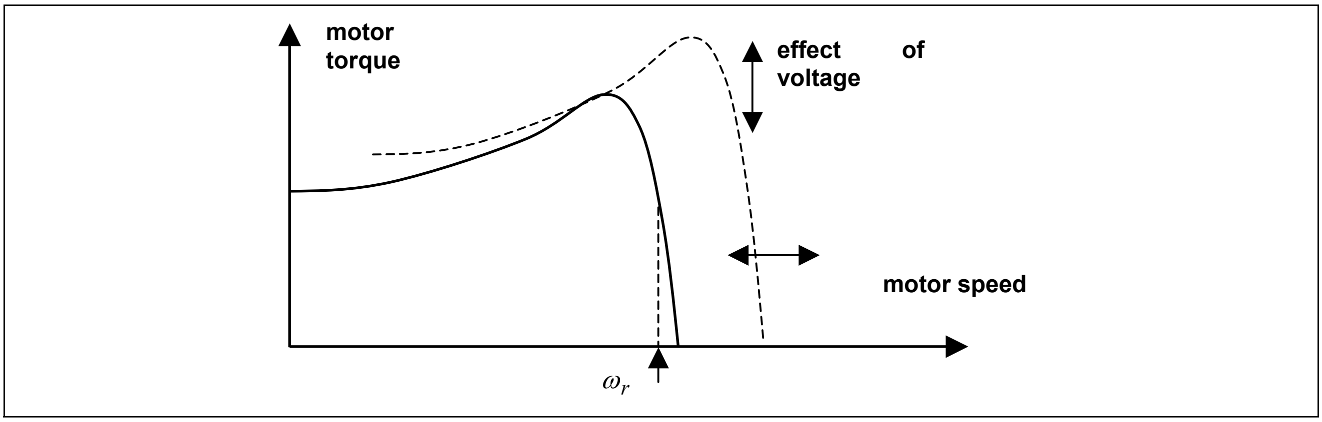


Figure 15. Shift of torque-speed characteristic during transient

The dynamic load in Feeder B is the most remote from the voltage source during islanded operation. The response of other induction motors in Feeder A and Feeder C is shown in Appendix J. It is observed that the voltage excursion profile is similar over the whole system during the transient following islanding

10.2.2.5 Post-event model conclusions

Both the generators and the induction motor loads remain stable following islanding. The frequency and voltage response may deviate from nominal value beyond the acceptable limits specified by ESQCR [2] and G59 [4] although they may well remain within the more probabilistic criteria of EN 50160 [7]. The steady state deviation of frequency depends on the selection of the generator governor droop characteristics and the initial power unbalance immediately following the islanding event.

10.2.3 Post-event modified model

The third stage of the modelling process, involves taking the post-event model created in Section 10.2.2 and modifying it to more easily facilitate the transition into seamless islanding. This scenario required a means of accommodating the excess energy in the islanded system following separation from the grid. The use of dynamic load controllers set in frequency sensitive mode, to effectively 'load match' the island's generation and demand, was deemed to be the most appropriate and cost effective solution, and hence this was the method that was applied to the simulation. Other scenarios may justify the expense of more costly technologies such as Flywheels and Static Compensators, and hence further modelling will be required to identify the optimum technical solution for all credible scenarios.

10.2.3.1 Method

In the case studied, there is surplus generation trapped inside the islanded section of the network following islanding. A suitably sized switched resistive load can be applied at the main 11kV busbar (Bus 1) to control system frequency. The resistance is switched in upon detecting a system frequency rise beyond 50.5Hz (1.01pu) and is switched out when the system frequency returns below 50.4Hz (1.008 pu). Simulation is performed to show the effect of the dump load value on the response of system frequency and voltage measured at the terminal of one of the gas generators.

10.2.3.2 Post-event modified model outputs

Figure 16 shows the generator response with the resistive load set to 20% of system local load and applied when the frequency exceeds 50.5Hz. Compared with Figure 12, the maximum frequency reduces from 1.08pu to 1.06pu. The resistive load remains switched in, since the frequency does not fall below the setting of 50.4Hz in the response time shown in Figure 16.

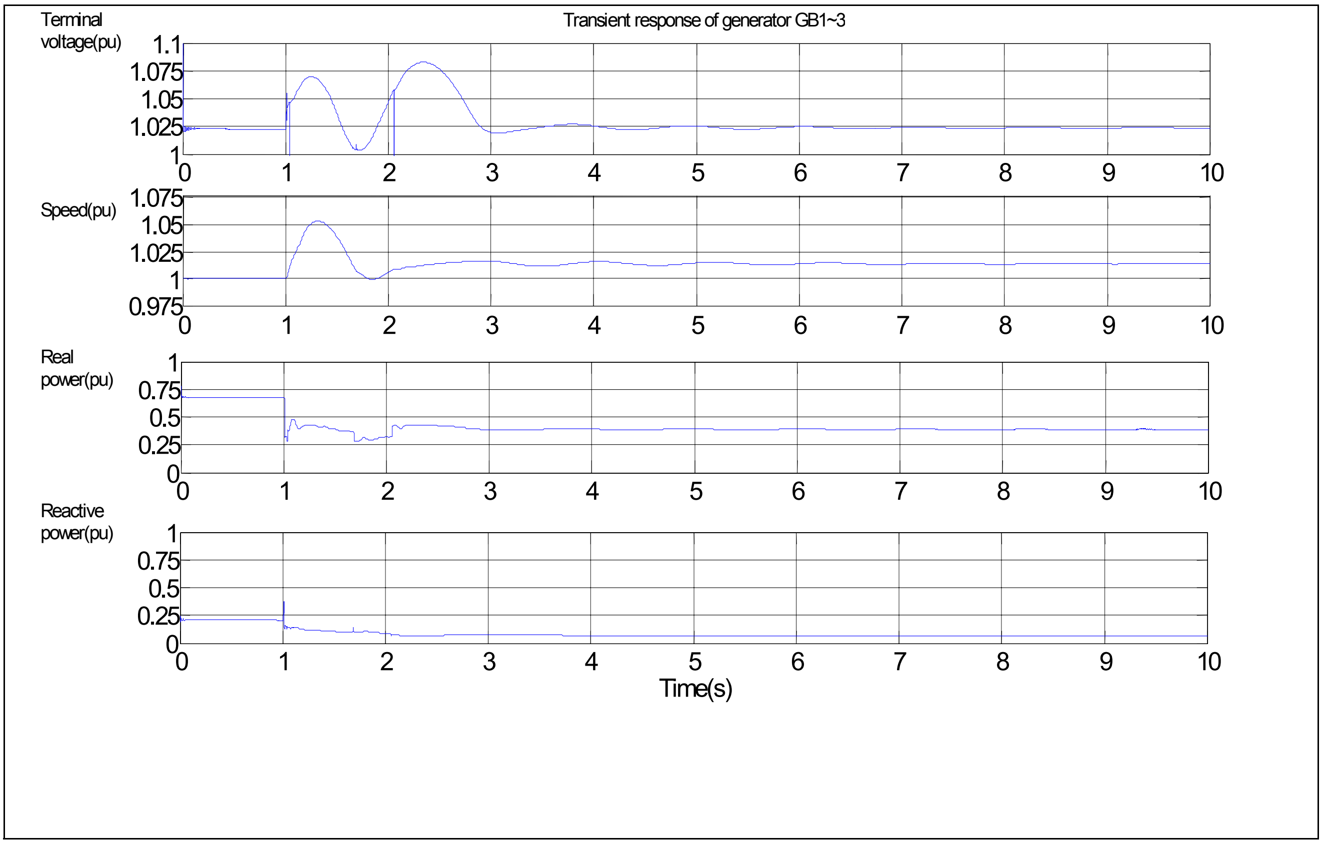


Figure 16. Response of a generator with 20% dump load

The maximum frequency during the speed and power excursion is plotted against various values of resistive load value in Figure 17. It is clear that the resistive load has significant effect on the frequency response of the islanded network. It is now possible to keep the system voltage within the G59 [4] voltage limits (+/-10% around the nominal value) and the more stringent ESQCR [2] limits (+/-6% at 11kV), although at 20% dump load the transient frequency limits for ESQCR (+/-1%), G59 (-6% to +1%) and EN 50160 [7] (+4%) are still exceeded. Figure 17 shows the effect of the resistive load on peak transient frequency.

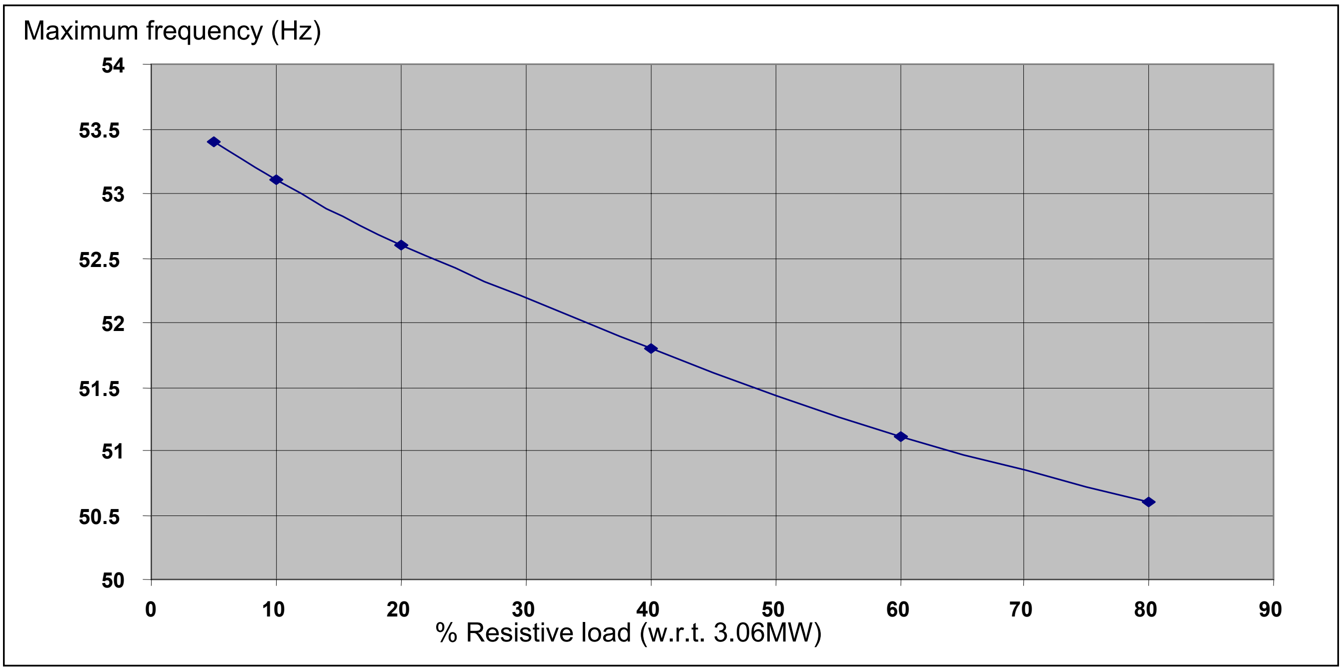


Figure 17. Effect of busbar resistive load on maximum frequency excursion

Using appropriately set droop characteristics for the generator governors, the resistive load is only activated during the frequency excursion transient to quickly add braking effect to the generators, preventing excessive over-frequency and indirect over-voltage conditions. Over the longer term the governors will respond to assist in reducing the output of the generators and thus the thermal rating of the busbar resistive load may be reduced from the value set when the governor operation is ignored. Table 6 gives the steady state voltages at busbars 1 to 6, which may be compared with the values shown in Table 5.

Busbar number	1	2	3	4	5	6
Pre-event Voltage (kV)	11	10.98	11.42	11.25	11.08	10.51
Post-event Voltage (kV)	11.27	11.17	11.37	11.23	11.19	10.97

Table 6. Pre and Post-event steady state voltages in the system

10.2.3.3 Post-event modified model analysis

Increasing values of busbar resistive load can reduce transient peak frequencies significantly following islanding.

For the network configuration studied, a value of approximately 40% of system local load will bring the transient frequency peak within the EN 50160 limits while 80% resistive load will bring the transient frequency peak within the ESQCR and G59 limits. 40% system local load is technically feasible but unlikely to economically practical, however this is an extreme case.

10.2.4 Effect on System (A) fault levels

A solid three-phase fault was applied to the most distant load point in the system, i.e. the remote end of Feeder B in Figure 7. This point was chosen to achieve the lowest fault current in the islanded situation. Figure 18 shows the simulated fault current in the grid-connected condition and in the islanded condition. Before islanding, the generator terminal voltage is held fairly high by the grid during the fault. Our simulation showed 0.8pu for generators GB1-GB3. In this case, the fault current is predominantly provided by the grid. The current quickly reaches steady state owing to the high R/X ratio in the local 11kV network. The peak-to-peak fault current in the steady state is about 4000A.

When the local network is operated in the islanded mode, the same fault causes the generator terminal voltage to drop to a lower level, e.g. 0.5pu for GB1-GB3.

The DG AVRs respond more aggressively than before, providing a short-term voltage and current boost. With the reduced R/X characteristic, the fault current now clearly shows the typical fault decrement characteristic of a synchronous machine with a high sub-transient fault current reducing to a steady state within 500ms. In this steady state the peak-to-peak fault current is about 2000A, although it will reduce further when the short-term AVR boost is automatically concluded (after approximately 10 seconds).

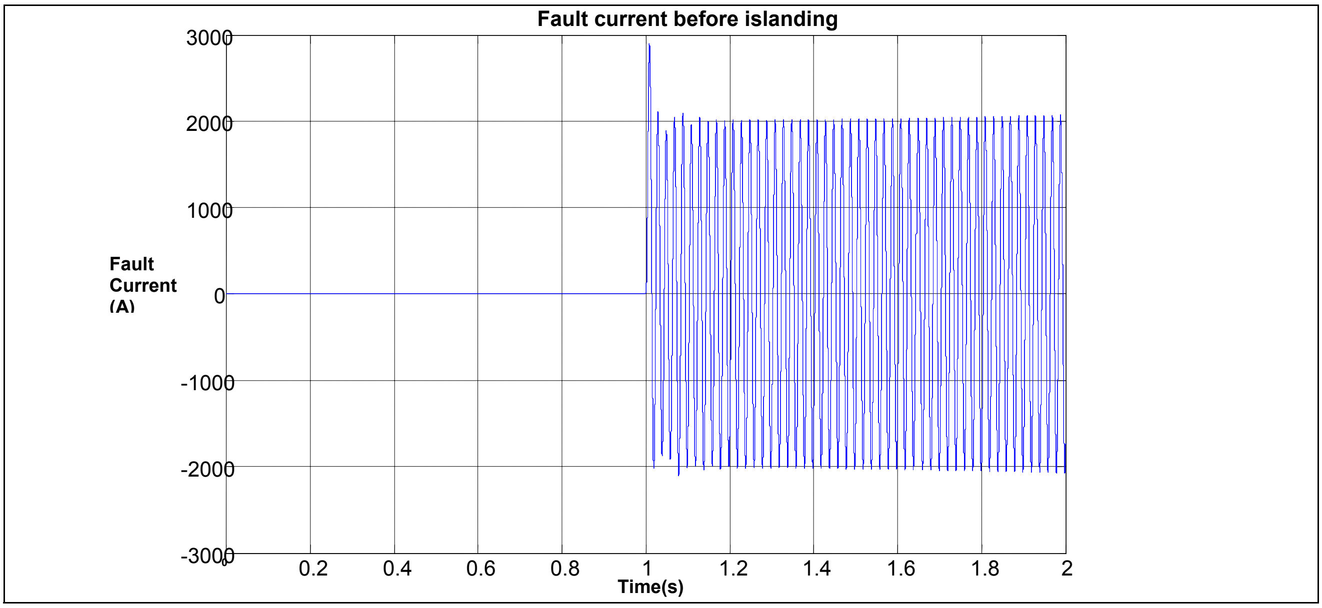


Figure 18a. Simulation of a fault in System A prior to islanding

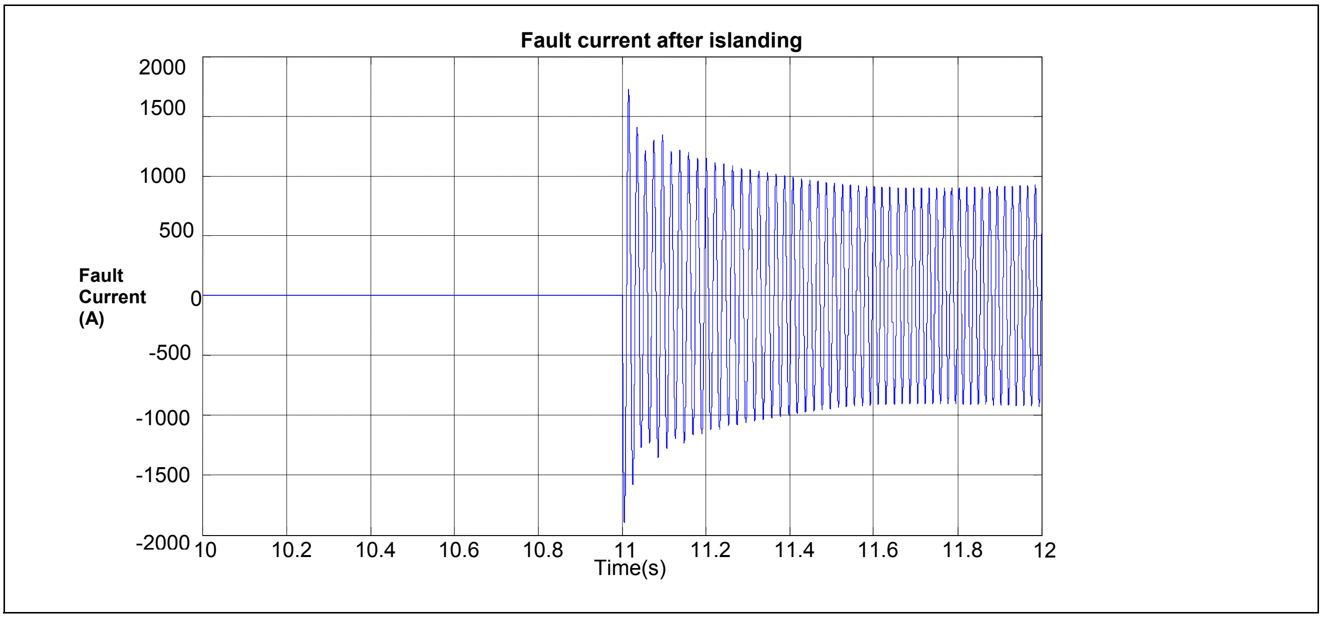


Figure 18b. Simulation of a fault in System A after islanding

Despite the short term boost provided by the generator AVRs, the fault levels in the islanded network are still approximately half those of the grid connected network, and these reduced values would require an adjustment to protection settings to ensure satisfactory protection operation once islanding has occurred.

10.3 The loss of a single transformer primary resulting in the islanding of an 11kV network (System B).

10.3.1 Pre-event base model

10.3.1.1 System description

The system under study in this section is referred to as System B. The network is shown in Figure 19. The main 11kV busbar is supplied through a single 33kV/11kV transformer primary. All the local generators are connected to the main 11kV busbar, some through step-up transformers, (which are not shown in the figure). There are four out-going feeders supplying the local loads. All the generators are powered by diesel engines. Details of the system are given in Appendix K.

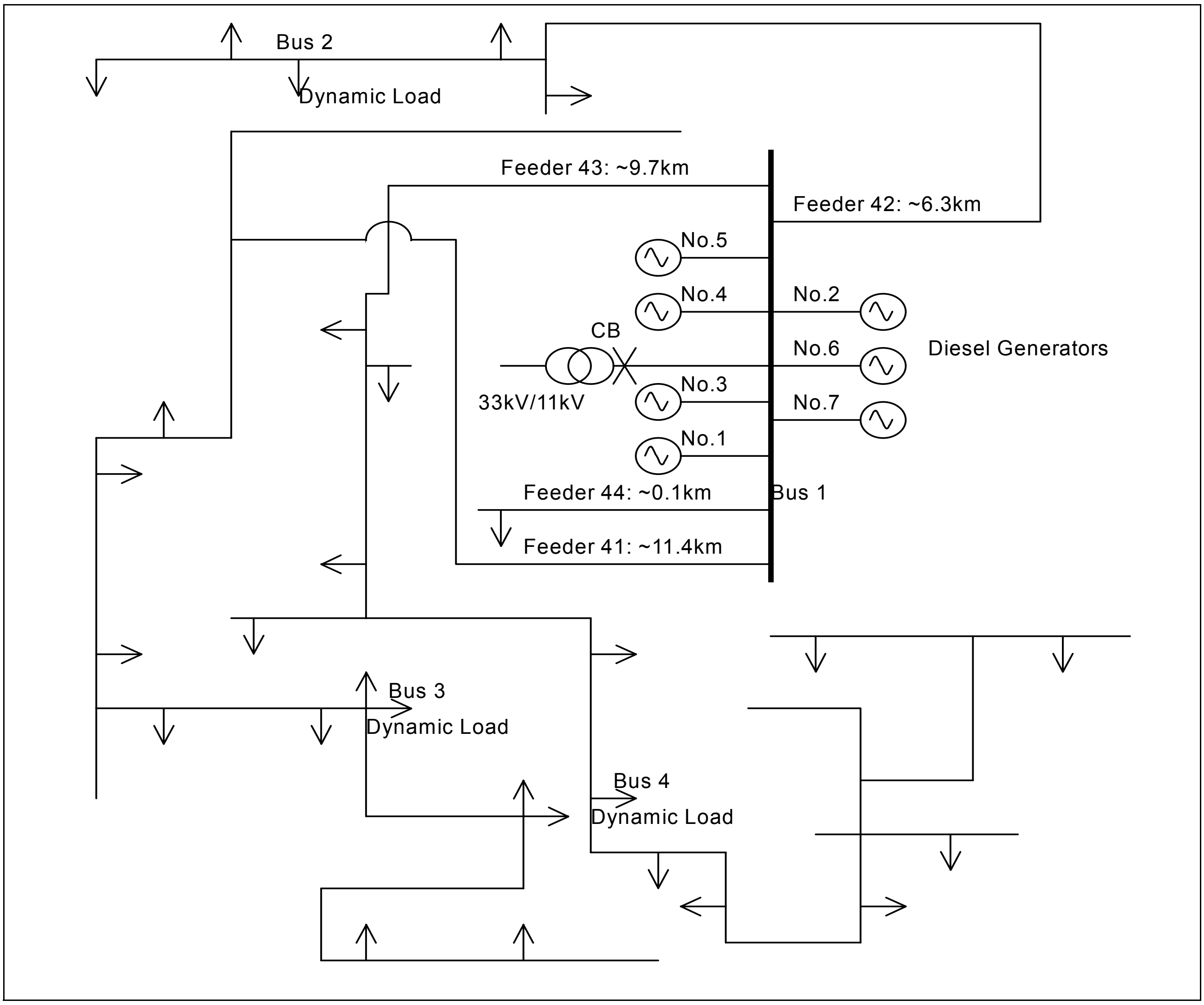


Figure 19. Configuration of System B

The total local generator capacity is 5.81MW and the maximum load is around 3.6MW. The diesel generators are designed to be used for backup purposes and normally the local system imports power from the grid. Therefore, these generators are not seamless at present for loss of mains.

Two scenarios have been selected for detailed simulation. The first scenario (noted in this scenario as Case 1) is for maximum local load with a relatively large number of local generators running on line but only lightly loaded. The second scenario (noted in this report as Case 2) is for lighter local load with fewer local generators on line. Case 1 and Case 2 are different in terms of the total moment of inertia in the system. The two scenarios thus created were designed to illustrate the dynamic response of the system at a time of maximum stress (i.e. greatest mismatch between generation and demand) when grid connection on the 33kV side is lost due to common mode failure of the single 33/11kV transformer feeder causing islanding of the primary substation 11kV busbar. In each case, some feeders include induction motors, marked as 'dynamic load' in Figure 19. The dynamic loads again represent about 40% of the total load in the local system.

The first stage of the modelling process, which is detailed here, was to create the model itself whilst making sure that the outputs from the model were realistic prior to the islanding event taking place, to give confidence in the results of the simulation once islanding had taken place.

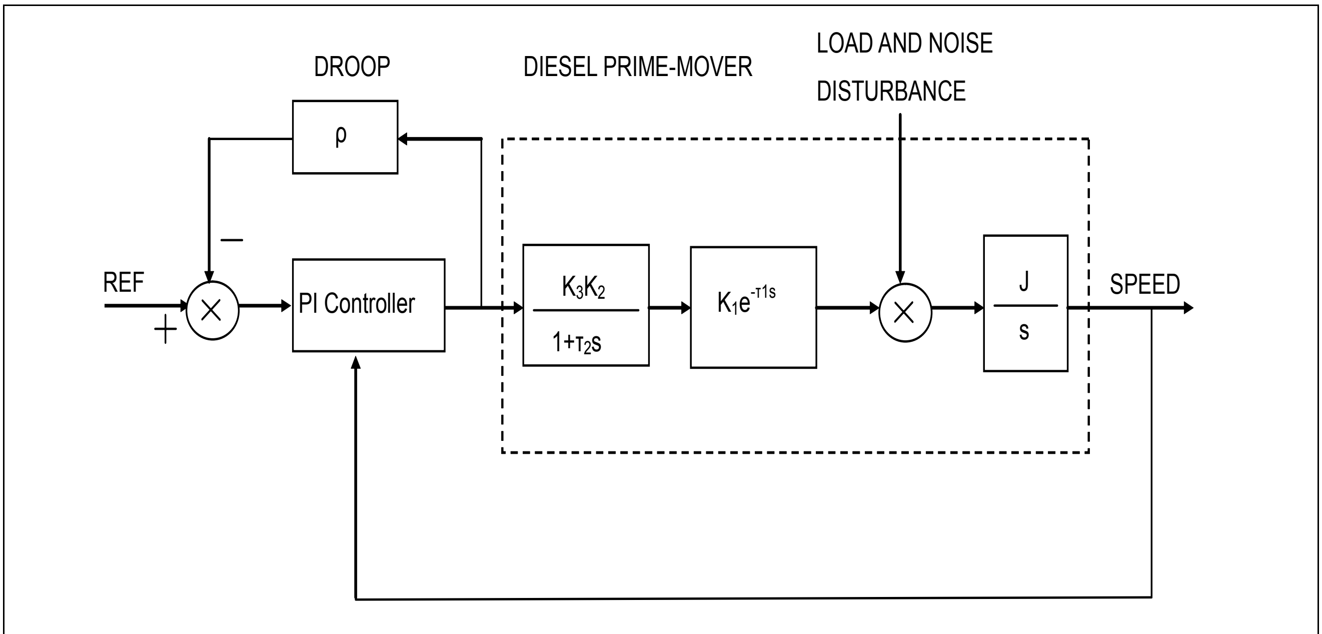
The pre-event conditions of the two selected scenarios are shown in Table 7. The generator reactive power is set to zero in each scenario.

	Case 1	Case 2
Generator 1 (450kW)	off line	off line
Generator 2 (1MW)	20%	off line
Generator 3 (500kW)	off line	20%
Generator 4 (450kW)	off line	off line
Generator 5 (500kW)	off line	off line
Generator 6 (924kW)	20%	off line
Generator 7 (1.98Mw)	20%	20%
Local load	3.6MW, ~0.9p.f.	2.45MW,~0.9p.f.
Power imported from grid	3.1MW, 0.7MVAr	2.1MW,0.48MVAr

Table 7. Pre-event condition for System B

10.3.1.2 Method

The system is modelled in the same way as for System A. However since all generators are diesel units, the governor model was different. The simulation model for the diesel engine governor was adopted from a paper for the IEEE on speed control of diesel driven generators [14] and is shown in Figure 20. Again, a droop of 5% is represented and the model includes frequency/speed detection delay and the response delay of the engine. The parameters as recommended in the IEEE paper [14] are also shown in Figure 20.



KEY

PI controller gains: K_p=7 pu; K_i=4.8 pu;	
Diesel prime-mover parameters:	
K_1=0.8~1.5 pu	engine torque constant
K_2=1.0 pu	actuator constant
K_3=0.5 pu	plant and flywheel acceleration constant
T_1=0.2 s	engine dead-time (limits)
T_2=0.5 s	actuator time constant

Figure 20. Model of diesel engine governor

10.3.1.3 Pre-event model outputs

Time domain simulation was performed for both cases to check that the voltage and grid current measured at the main 11kV busbar agreed with the imported power as shown in Table 7.

The steady state values of voltage amplitude at the main 11kV busbar and Bus 1-Bus 3 where the dynamic loads are connected are shown in Table 8.

Busbar	1	2	3	4
Voltage (kV), case 1	11.11	10.64	10.48	10.47
Voltage (kV), case 2	11.18	11.01	10.73	10.63

Table 8. Pre-event voltages in the system

The governor and AVR models for the diesel generator were tested using a single machine-single load system. The response to load and input changes was analysed to make sure that the governor and AVR responded in the anticipated way. The results are shown in Appendix L.

10.3.1.4 Pre-event model analysis

From these outputs it was established that the system model for System B, which included typical governor and AVR models for the diesel generators, was running as expected in steady state mode prior to the islanding event, and therefore could be reliably used for simulation of the islanding scenario.

Prior to the islanding event the local system is importing power from the grid. Two scenarios are selected to investigate the response following islanding.

10.3.2 Post-event base model

The second stage of the modelling process is to take the steady state unmodified model created in Section 10.2.1 and subject it to an islanding event.

10.3.2.1 Method

Islanding was simulated by opening the only 33kV circuit breaker shown in Figure 19.

10.3.2.2 Post-event model outputs

Figure 21 shows the generator response for Case 1 with islanding occurring at t=1 second. The nominal VA rating of the generator is used as the base capacity in the per unit system. The base voltage is 11kV and the speed response is based on the synchronous speed at 50Hz. In contrast to the results for System A, the islanded system frequency now reduces and the generators start to pick up power after islanding. Because of the droop characteristics of the generators, the new steady state speed or frequency is lower than the pre-event value (50Hz for frequency). The generator terminal voltage is also reduced due to the load compensation characteristic in the excitation system as illustrated previously in Figure 10.

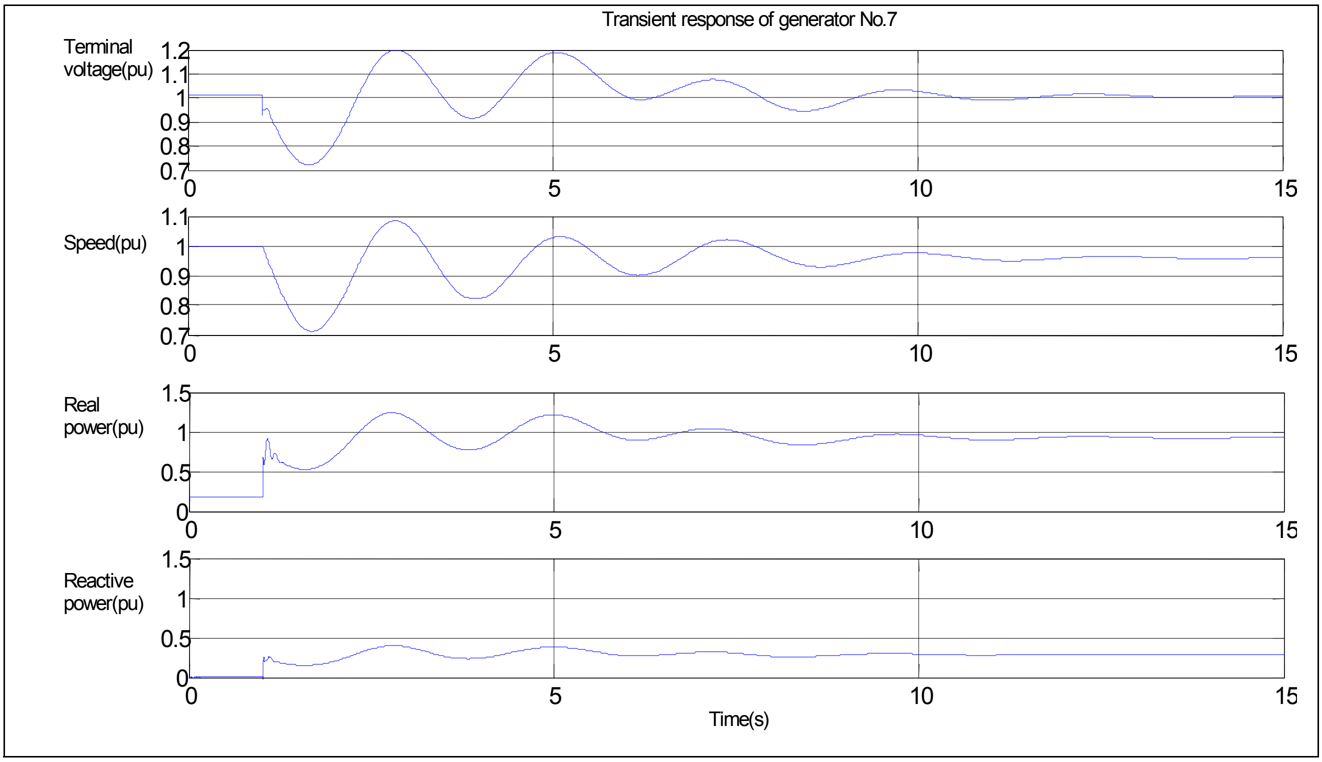


Figure 21. Response of a generator in Case 1

Figure 22 shows the generator response for Case 2. Similar features are observed. In both cases, the transient excursions of the frequency and voltage are too large to be acceptable to the limits set in ESQCR [2], G59 [4] and EN 50160 [7]. The effect of dynamic load control will be considered later.

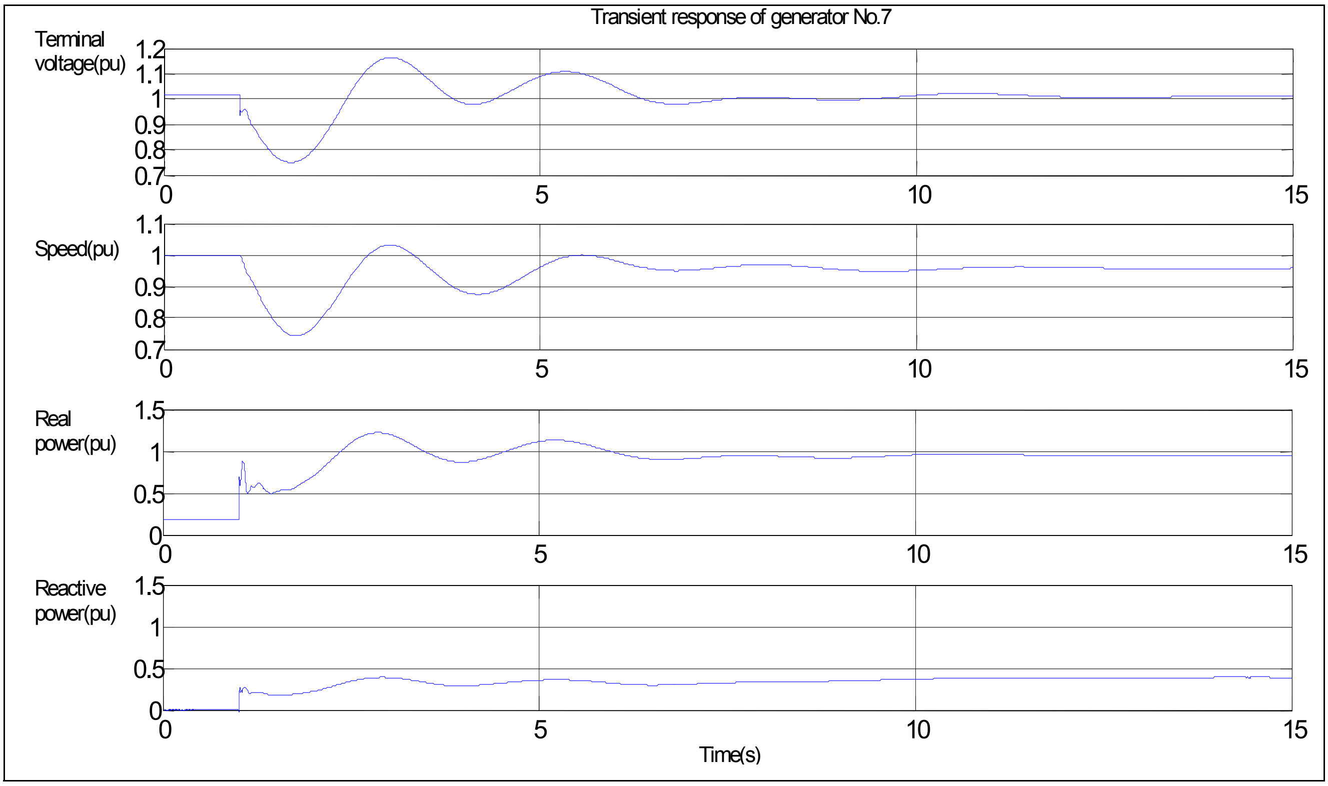


Figure 22. Response of a generator in Case 2

Table 9 compares the maximum frequency and voltage dips in Case 1 and Case 2. The frequency deviation is with respect to 50Hz while the voltage deviation is with respect to the pre-event values. These deviations are related to the total kinetic energy (E_k) stored in the generators which are operating on line (E_k = H * MVA rating (MJ)) and the initial power unbalance (ΔP (MW)) following islanding. Since the $\Delta P/E_k$ ratio is similar in both Case 1 and Case 2, the maximum excursions of frequency and voltage (at the generator bus) are also similar.

	E_k	Initial ΔP	$\Delta P/E_k$	Δf_{max}	ΔV_{max}
Case 1	2171	3.25	0.0015	14.41Hz	3.177kV
Case 2	1380	2.1	0.00152	12.92Hz	2.926kV

Table 9. Comparison between Case 1 and Case 2

10.3.2.3 System (B) induction motor load response

The response of a representative induction motor load in Case 1 and Case 2 is shown in Figure 23 and Figure 24 respectively. As in System A, the transient voltage profile is similar across the whole system. Therefore it is adequate to show the response of only one induction motor. Again the total inertia of the induction motors is less than that of the generators. The induction motors remain stable during the transient without entering the re-generative mode. However, the motor speed changes in line with the system frequency excursions. Without any dynamic load control (to be described later) the initial change of voltage, frequency and motor speed is of the order of 30%.

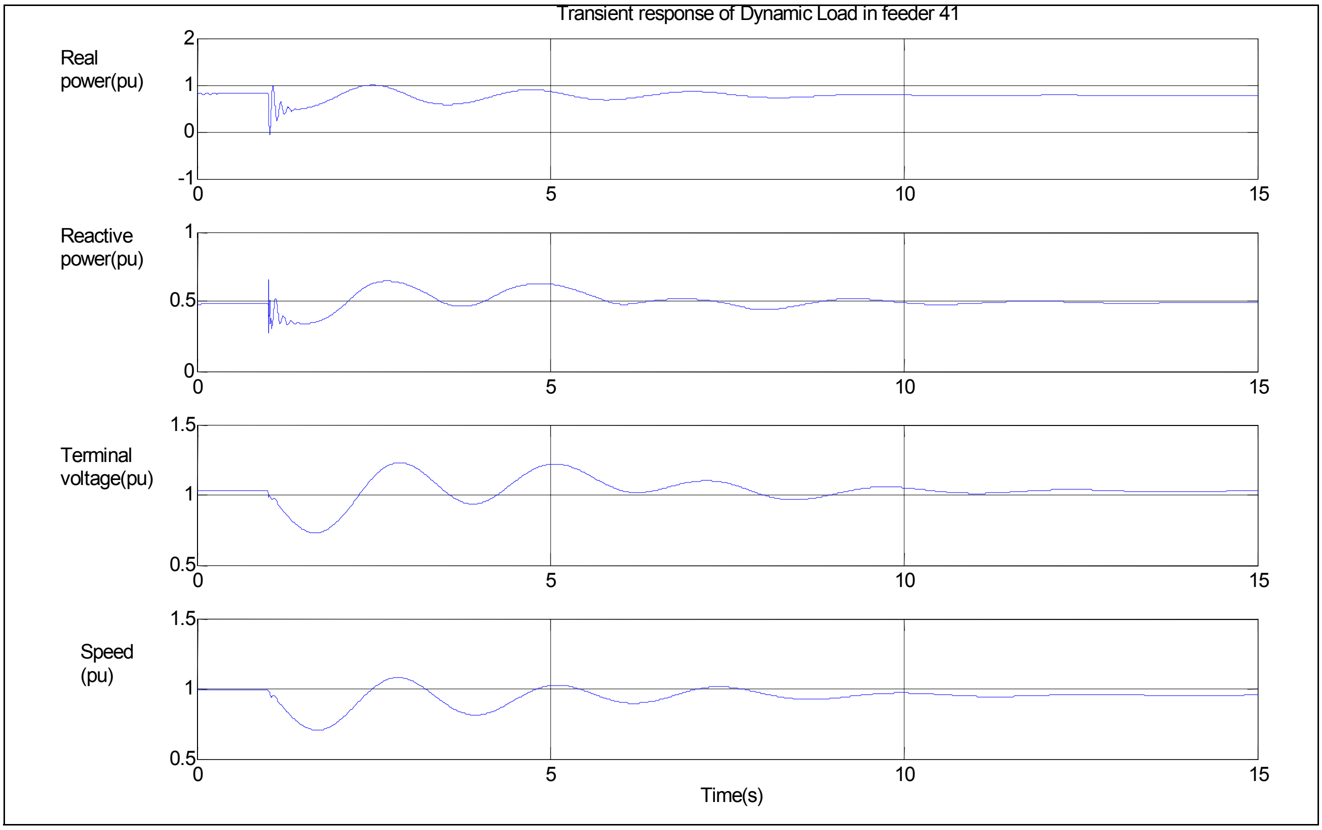


Figure 23. Response of a dynamic load in Case 1

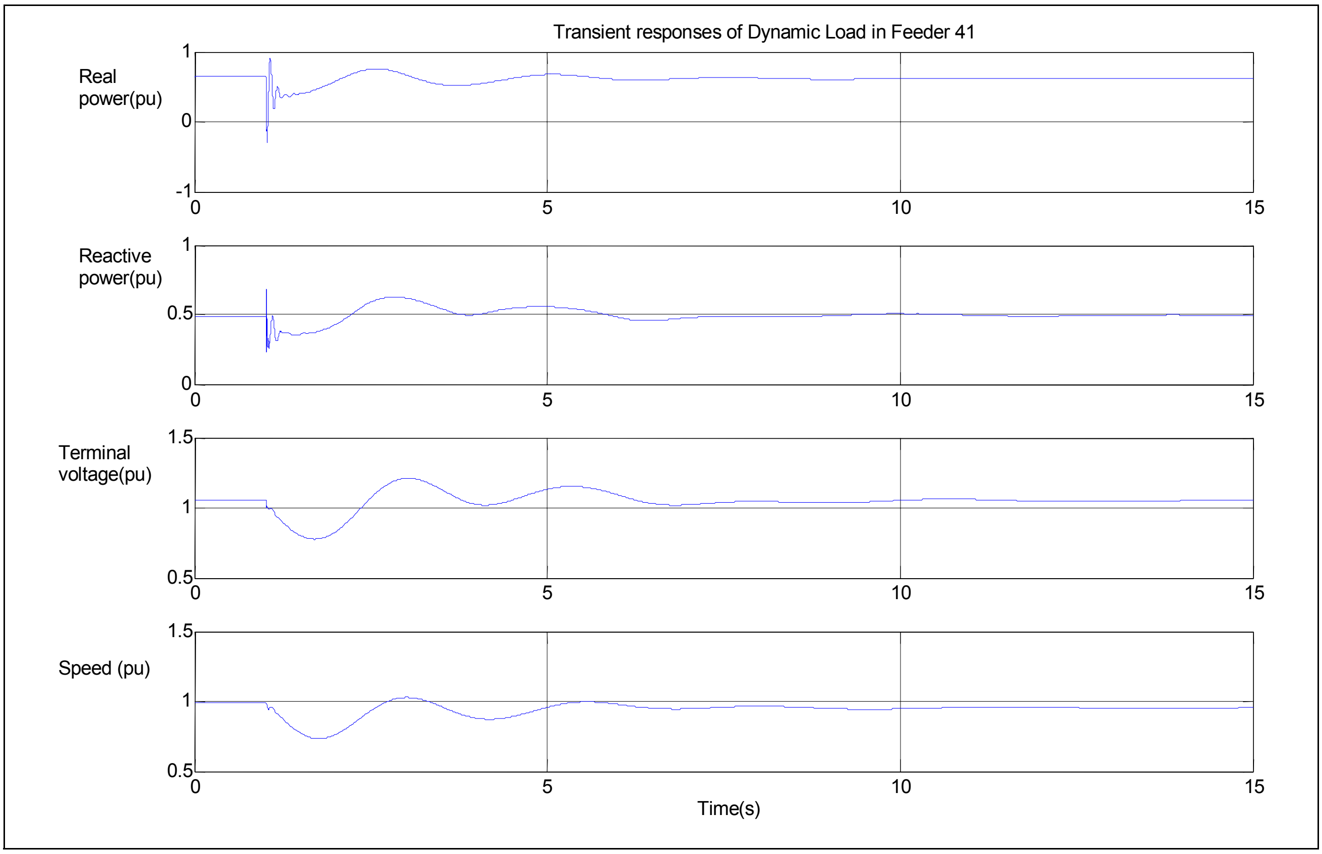


Figure 24. Response of a dynamic load in Case 2

10.3.2.4 Post-event model analysis

Large excursions in system voltage and frequency, which are well outside ESQCR [2], EN 50160 [7] and G59 [4] standards, can be observed following the occurrence of islanded operation. This affects the speed of induction motors in the system. The initial change of voltage and frequency is about 30% of their nominal values, clearly unacceptable in practice.

10.3.3 Post-event modified model

The third stage of the modelling process involves taking the post-event model created in Section 10.2.2 and modifying it to more easily facilitate the transition into seamless islanding. Again the use of dynamic load controllers set in frequency sensitive mode, to effectively 'load match' the island's generation and demand was deemed to be the most cost effective and practical solution, and hence this was the method that was applied to the simulation.

10.3.3.1 Method

The models were modified to investigate the effects of dynamic load control and the performance of diesel engine governors.

For both Case 1 and Case 2 of System B, there is a deficit of power supply following islanding. Therefore the dynamic load control mainly involves load shedding. A simplistic strategy with hysteresis is modelled (i.e. group 5 is shed at 47.5Hz and recovered at 48Hz). The load to be shed is organized in five groups approximately evenly distributed in the 4 feeders. The nominal load power is assumed to be equal in the five groups. Figure 25 shows the logic to switch out the load as the frequency decreases, and to reconnect the load as the frequency recovers. The total load under control can be varied as illustrated later.

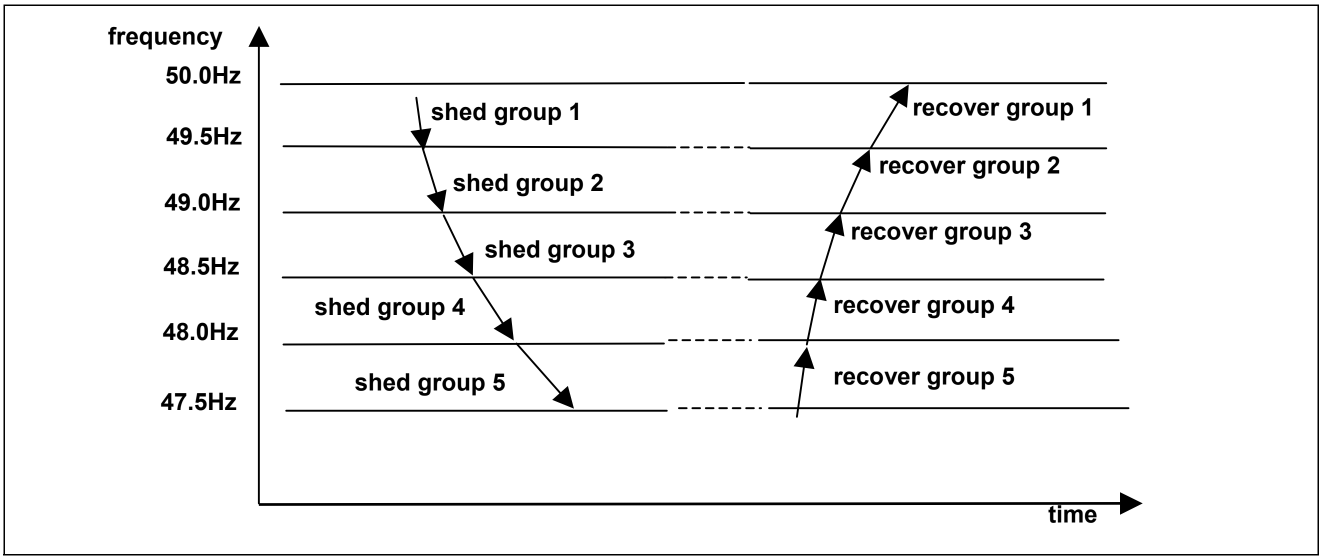


Figure 25. Logic of dynamic load control

In addition to dynamic load control, the performance of the diesel engine governor in simulation could also be adjusted by changing the time constants T1 and T2 as shown previously in Figure 20.

10.3.3.2 Post-event modified model outputs

Figure 26 shows the simulation results for Case 1 from a generator point of view. It is assumed that the total load that can be disconnected by the dynamic load control is 20% of the original load in the local system. Compared with the response shown in Figure 21, the maximum initial frequency dip has been reduced from 13.85Hz to 10.3Hz, although the latter value still far exceeds the acceptable range specified by ESQCR, EN 50160 and G59. Correspondingly the maximum voltage dip is also reduced from 0.287pu (3.157kV, rms, line-line) to 0.21pu (2.4kV, rms, line-line). Dynamic load control is also seen to damp out the oscillations in the frequency and voltage response.

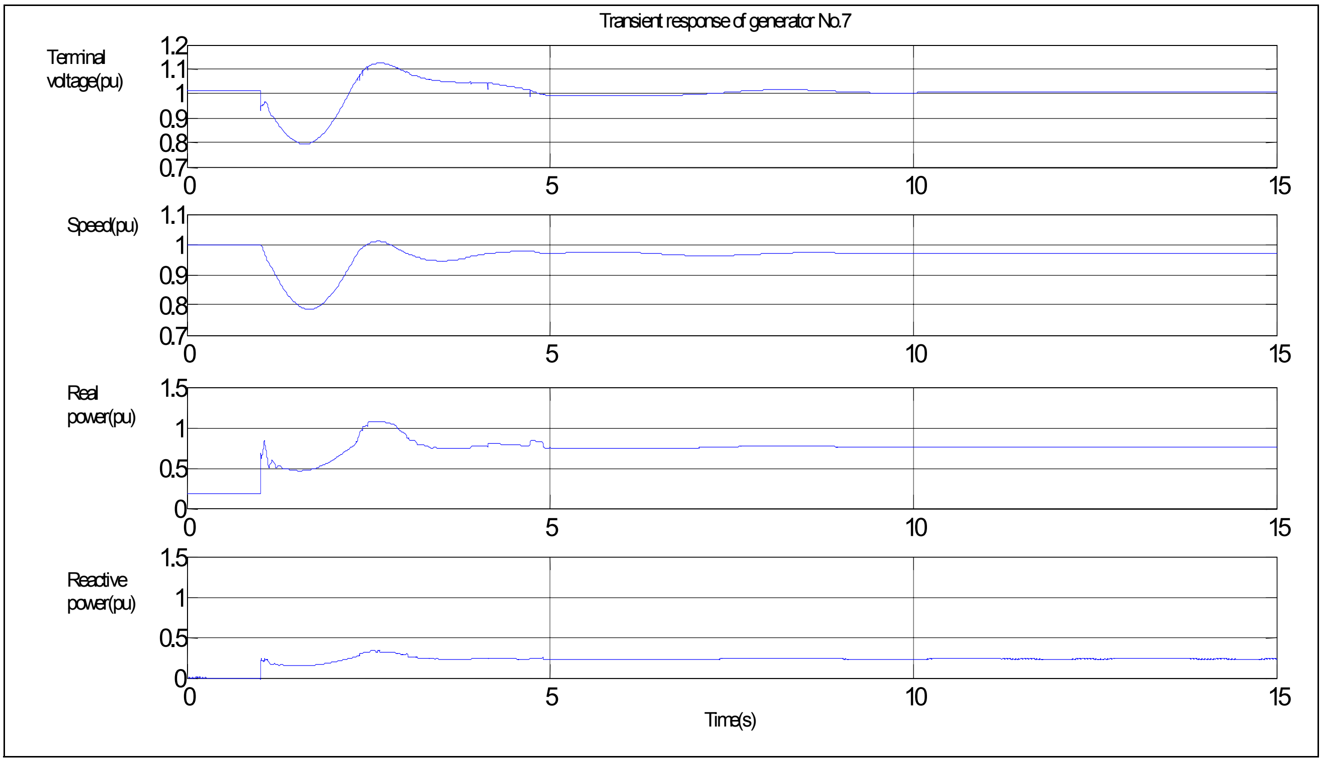


Figure 26. Generator response in Case 1, with dynamic load control

Figure 27 shows the results of the simulation for Case 2 with 20% of the pre-event load subject to dynamic load control. The results should be compared with Figure 22. As in Case 1, improvement is achieved in voltage and frequency response.

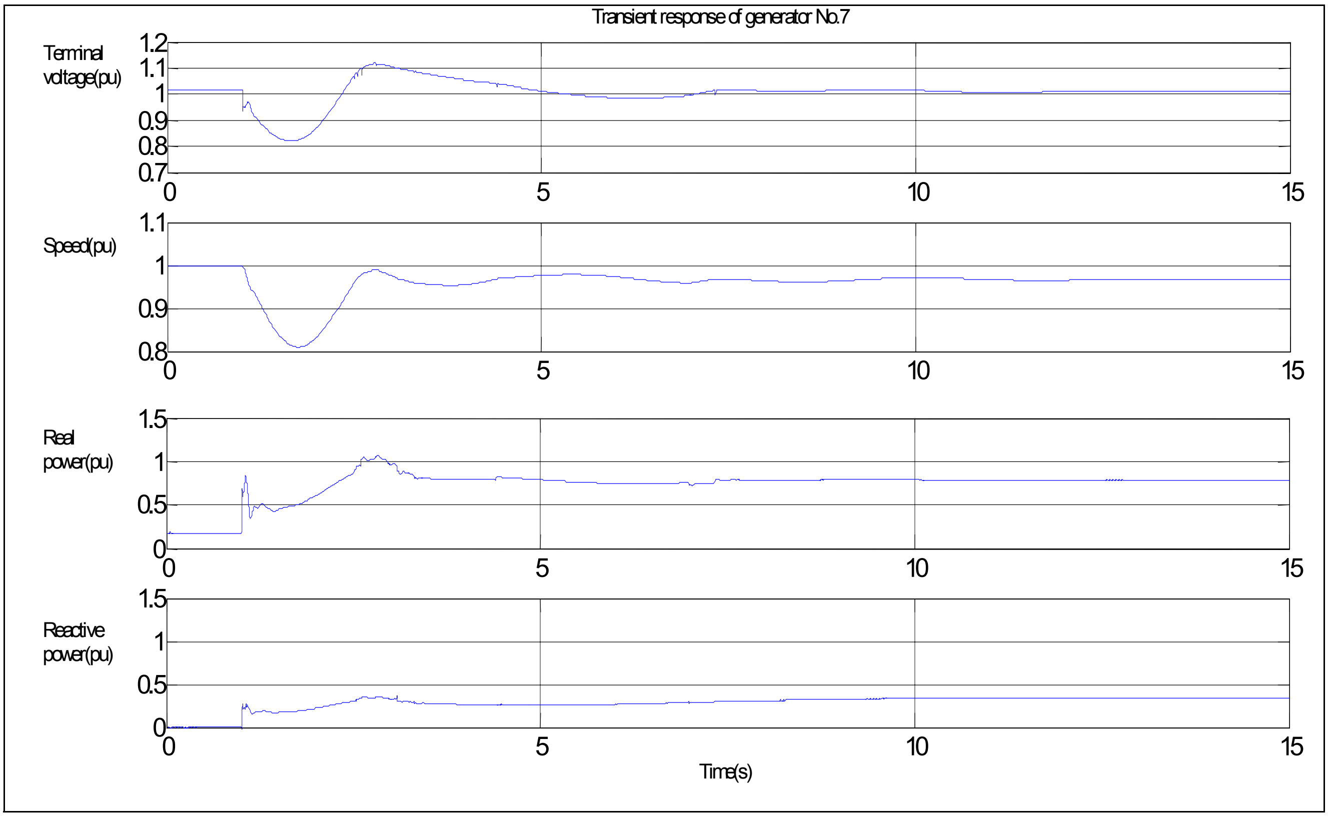


Figure 27. Generator response in Case 2, with dynamic load control

All five groups of the load subject to dynamic control have been switched, because the transient frequency excursion went below 47.5Hz. It is anticipated that if the amount of load available for dynamic control is increased, the transient response will be improved further.

The effect of increasing amounts of switched load on the minimum frequency and voltage values are shown in Figure 28 and Figure 29 for Case 1 and Case 2 respectively. It is clear that dynamic load control has a significant effect on the voltage and frequency excursions immediately following islanding. Given the typical governor performance of the diesel engines as shown in Figure 20, it would be necessary to shed around 60% of the total load temporarily in order to keep the transient frequency and voltage within the acceptable region as specified in both EN50160 [7] and G59 [4]. Normally the region of acceptable under-frequency (-6% in G59 & EN50160) is wider than the over-frequency (+1% in G59 and +4% in EN50160). It is expected that the wider under frequency limits would permit reduced amounts of load to be shed compared with the amount of resistive load required to comply with the over frequency limits. However a much higher percentage of load shedding would be required to keep the frequency within the rigorous limits (+/-1%) imposed by the ESQCR [2].

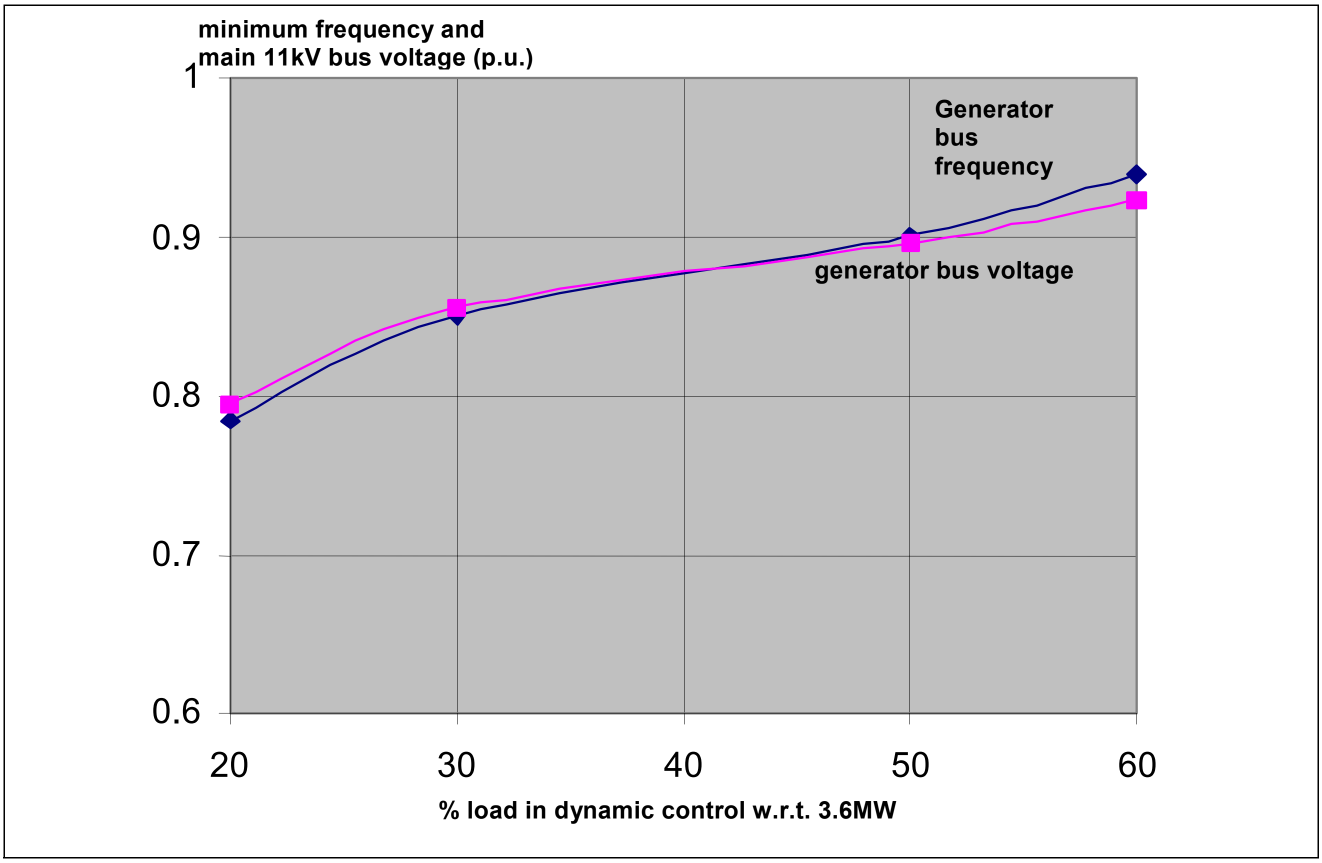


Figure 28. Effect of dynamic load control – Case 1

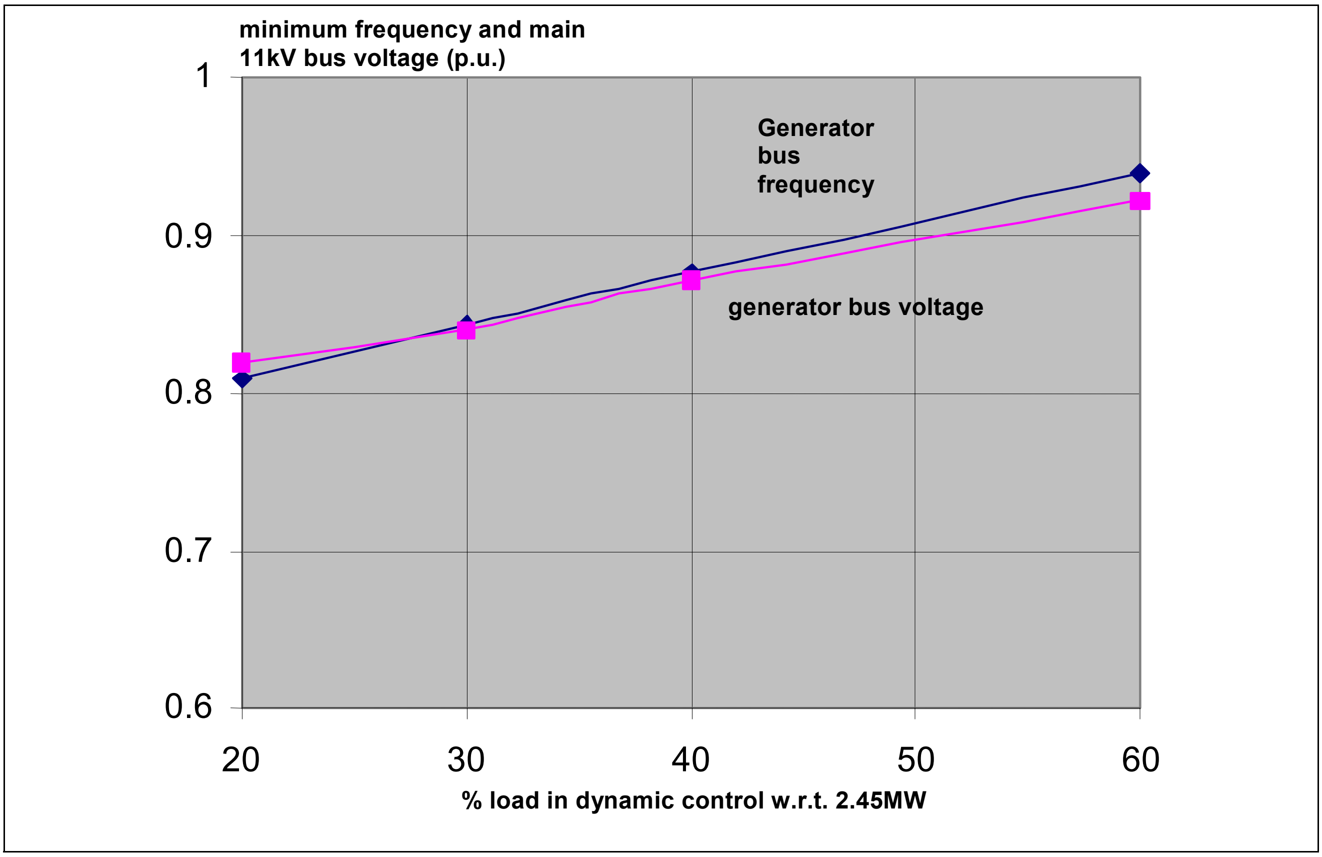


Figure 29. Effect of dynamic load control – Case 2

The amount of load to be shed is also affected by the performance of the diesel engine governor. Figure 30 shows the generator response in Case 1 with the governor time constants T1 and T2 halved, with the total switched load set at 20% of the pre-event value. In comparison with Figure 26, the dips of frequency and generator bus voltage are reduced by 32% and 25% respectively. The resultant frequency and voltage excursions are about 14% and 16% of the pre-event values, which implies that with faster governors, the load required to be shed during the transient period to maintain the voltage and frequency within the acceptable regions would be reduced, compared with the initial settings of the governor time constants. However this benefit must be justified against the additional cost of providing the more sophisticated diesel engine governing system. It is interesting that, according to Figure 28, halving the governor response times would have the equivalent effect of increasing the total load subject to dynamic control (shedding) by another 20%.

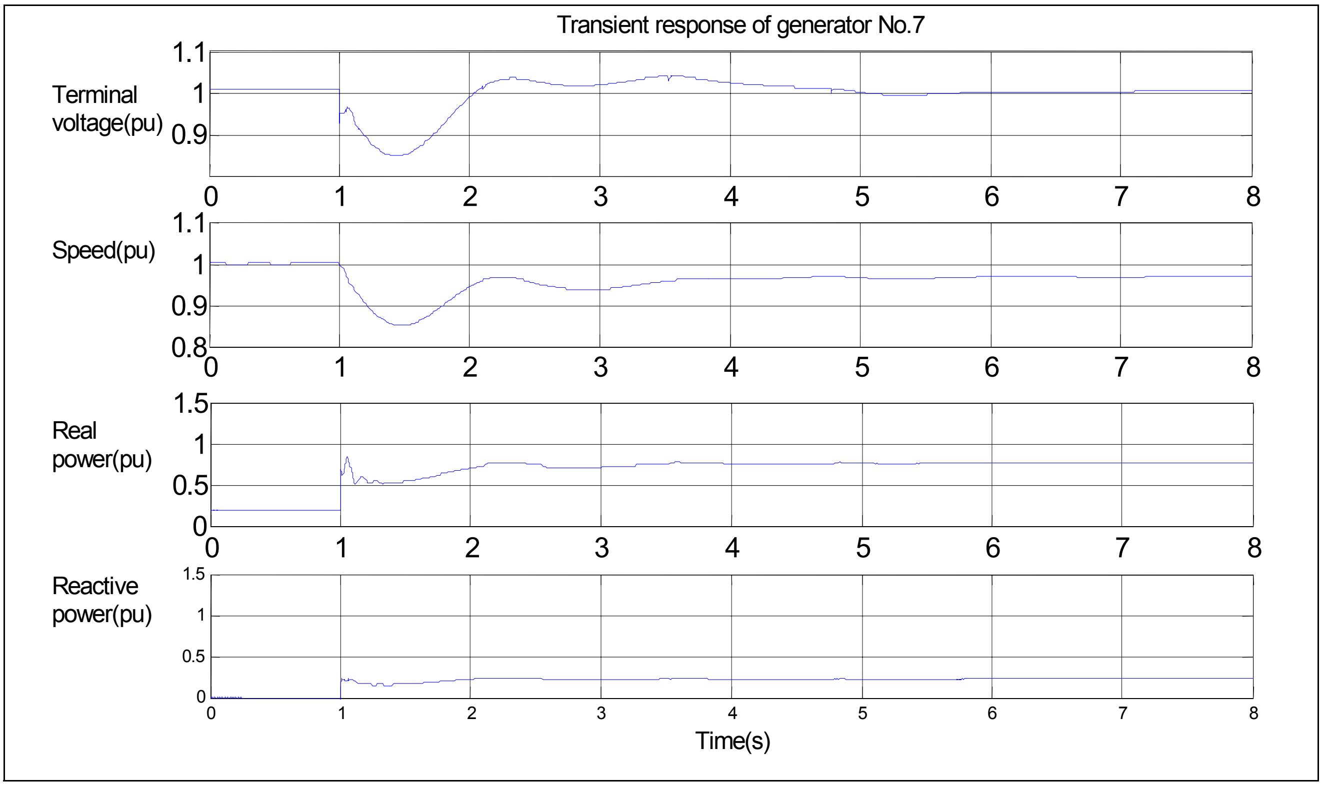


Figure 30. Generator response with faster governor

10.3.3.3 Post-event modified model analysis

Shedding some local loads has significant effects on the response following islanding. A load shedding setting of 20% reduces the negative frequency excursion by 30% and 60% load shedding will bring the frequency and voltage responses within the EN50160 and G59 limits, but not the stringent frequency limits of the ESQCR.

It is interesting that (according to Figure 28) halving the governor response times would have the equivalent effect of increasing the total load subject to dynamic control (shedding) by another 20%.

10.3.4 Effect on System (B) fault levels

A three-phase fault is applied to the remote end of the longest feeder, Feeder 41 shown in Figure 19. This point was chosen to achieve the lowest fault current in the islanded situation. Simulation runs were performed for the same fault mode before and after islanding. The fault current is shown in Figure 31. Again it is observed that the fault current is reduced by approximately 50% in the islanded mode, compared with the 'before' islanding mode. The fault current trace also shows more complicated features than the fault current trace 'before' islanding, including the generator transient and AVR boost response. Again this lower fault current would require an adjustment to protection settings to ensure correct protection operation once islanded.

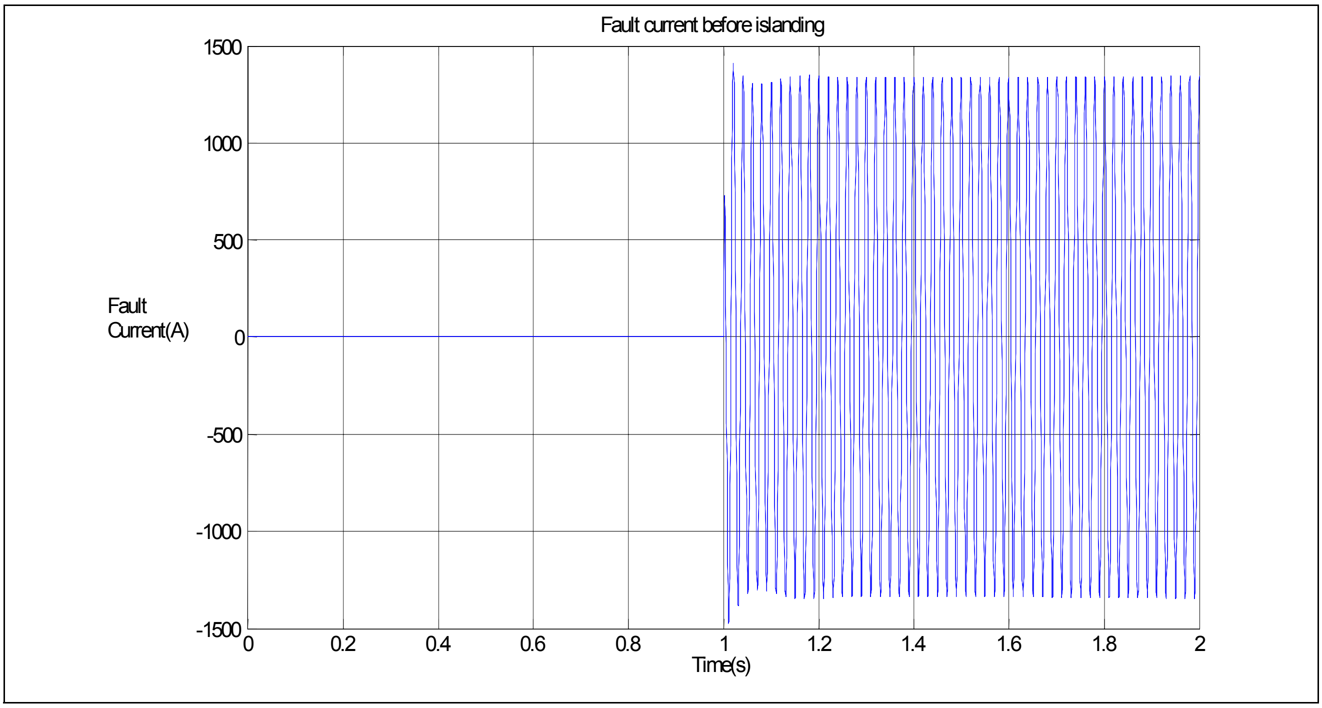


Figure 31a. Simulation of a fault in System B prior to islanding

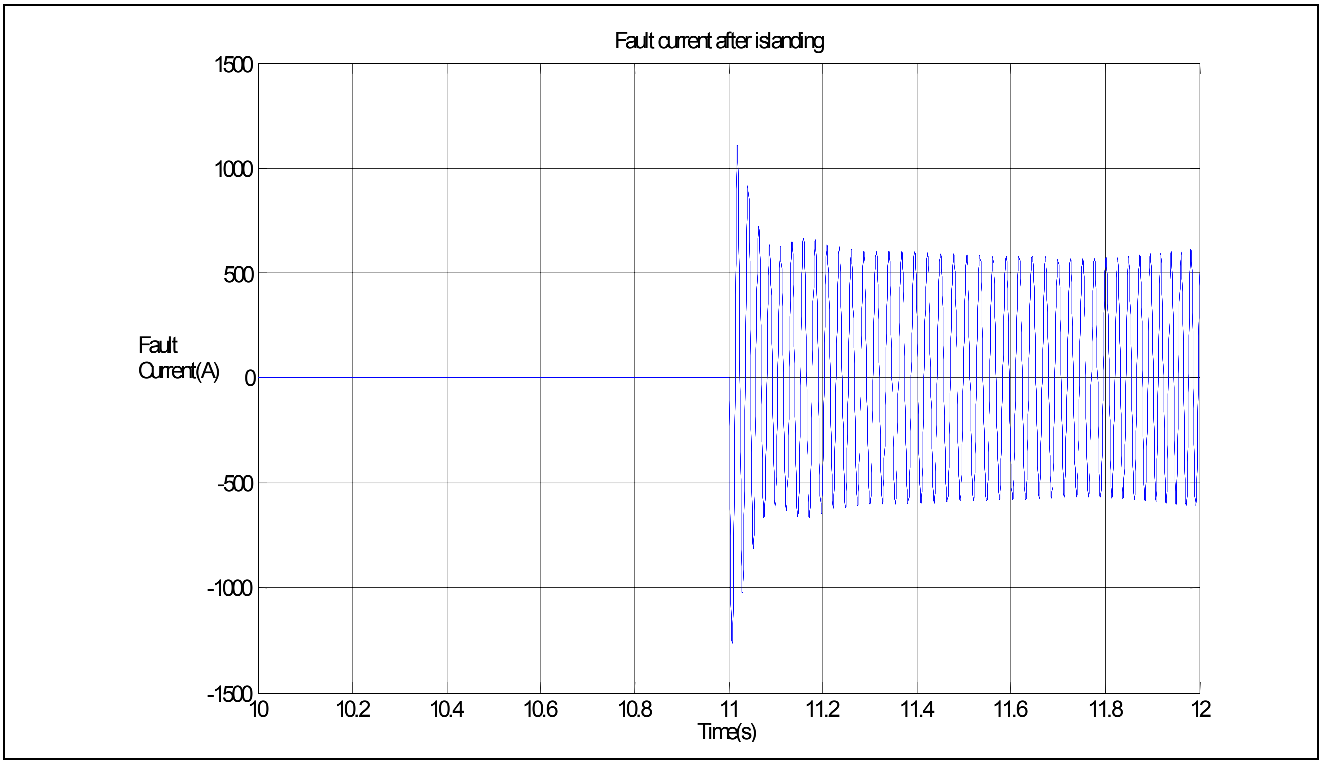


Figure 31b. Simulation of a fault in System B after islanding

11 Commercial modelling

11.1 Scope

The purpose of the commercial modelling work was to establish the commercial risks for the two DNOs whose networks contain the two case studies. These risks would include the probability of islanding, the likely number of occurrences and the level set for possible penalties and rewards as well as a costing of any alternative power supply solutions open to the DNOs. The results from this modelling can then be used with the estimates for potential alternatives and the cost of modifications (derived from the implementation plans) to provide a cost-benefit analysis.

In order to illustrate the worst-case penalties that the DNOs may incur, extreme credible outages were chosen for the commercial modeling process. As such the derived figures should be taken as a cost ceiling rather than the expected norm.

11.2 Probability of islanding

To enable islanding to take place, the DG can either remain connected to the section of network separated from the main system or alternatively restart the network once islanded. A fault occurring at the voltage level on the network to which the DG is connected could initially prevent the DG from operating, which means that the 'fault' must occur at a voltage level greater than that at which most DG are connected, i.e. the fault needs to occur on the 33kV (or above) network. The probability of a 33kV (or above) fault causing an extended loss of supply to customers is reasonably low. Indeed the statistics for the average number of Customer Interruptions (CI) in Great Britain in 2002/03 (shown in Figure 32) show that only 14% of total interruptions resulted from faults on the 33kV, 66kV and 132kV networks as opposed to 73% for faults on the 6.6kV, 11kV and 20kV networks, whilst the percentage of average Customer Minutes Lost (CML) which could be attributed to faults on the 33kV, 66kV and 132kV networks in Great Britain is only 5% as opposed to 72% for the 6.6kV, 11kV and 20kV networks (see Figure 33).

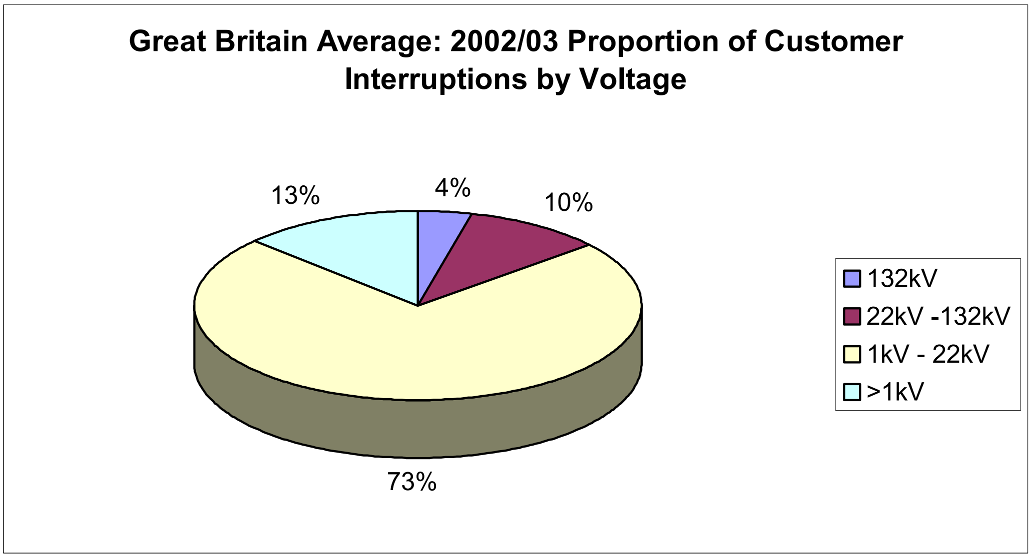


Figure 32. Proportion of Customer Interruptions by voltage (2002/03) [15]

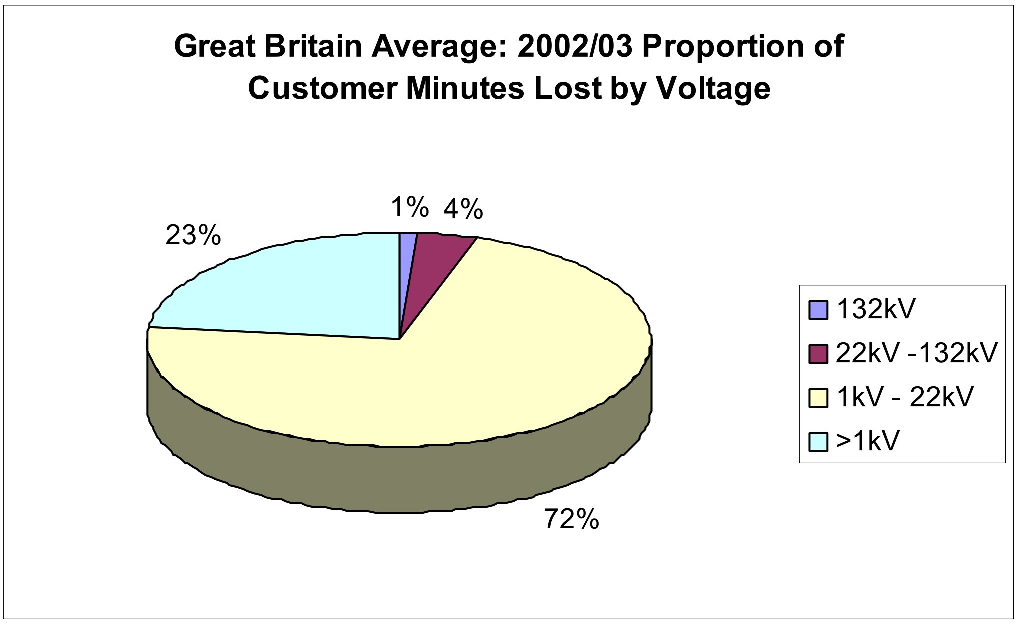


Figure 33. Proportion of Customer Minutes Lost by voltage (2002/03) [15]

An interrogation of the National Fault and Interruption Reporting System (NaFIRS) by the Energy Networks Association revealed that over the last ten years only four faults at voltages above 22kV resulted in long term customer disconnection (i.e. providing an opportunity for islanded operation) (see Table 10).

Customer Interruption Duration for 66kV & 33kV Losses (1994-2004)		
Duration	Unplanned	Planned
>18hrs	3	1
<4hrs	27	26

Table 10. Customer Interruption duration for 66kV and 33kV losses over past ten years

Source: Energy Networks Association

Therefore the commercial modelling was focused on a credible fault that could result in each of the two case studies under consideration becoming islanded for a significant period of time.

11.3 (System A) common mode failure of sole twin 33kV feeders

11.3.1 Credible fault

The credible fault for this scenario is the double circuit loss of several poles and spans of the 33kV feeder due to an extreme weather event. The event is assumed to have caused widespread damage to other areas of the distribution network, resulting in a longer than average restoration time of two days (2,880 minutes). Note this is an extreme event, with most such outages having a restoration time of 24 hours or less. An equally credible fault scenario would be the loss of the 11kV lines connecting the generation to the busbars. However, the 33kV double circuit loss scenario was deliberately chosen as a worst-case scenario.

11.3.2 Financial impact

The predicted financial impacts of this fault on the DNO are listed in Table 11.

Parameter	Lower Limit	Upper Limit	Actual
Number of Customers Affected	5000	15000	3454
Duration (mins)	2880	2880	2880
(Incident) Customer Interruptions (CI)	5000	15000	3454
(Incident) Customer Minutes Lost (CML)	14400000	43200000	9947520
CI Reduced Total (From 2002/03 performance of 91.98)	91.83	91.53	91.88
CI Difference (From 2002/03 performance of 91.98)	0.15	0.45	0.1
CI Incentive Impact	£21000	£63000	£14000
CML Reduced Total (From 2002/03 performance of 101.62)	97.37	88.86	98.68
CML Difference (From 2002/03 performance of 101.62)	4.25	12.76	2.94
CML Incentive Impact	£892500	£2679600	£617400
Interruption Payment (per customer)	£25	£25	£25
Total Interruption Payments	£125000	£375000	£86350
Distributed Generation Capacity (MW)	9	9	9
Distributed Generation Availability	60%	60%	60%
Network Unavailability Payment	£518	£518	£518
Total Financial Impact	£1,039,018	£3,118,118	£718,268

Table 11. Financial impacts of credible fault on case study

The origin of the data and derived formulae used to determine these financial impacts are given in Sections 11.3.2.1 to 11.3.2.9. Actual numbers provided by EdF Energy are for the particular case study (covering three feeders), and that the lower and upper figures are more representative of primary substations. Whilst the CML incentive impact dominates the financial impact estimate, the actual CML penalty incurred following a credible fault would be affected by the overall DNO performance against CML targets.

11.3.2.1 Number of customers affected

The lower and upper limiting values for the number of customers affected by such a common mode failure were estimated at the WS5 peer review meeting of 9th June 2004. The actual figure is the number of customers who would be islanded in the event of the fault on the actual network under consideration in the case study [16], part of Eastern Power Networks (EPN).

11.3.2.2 Customer Minutes Lost

CML = Number of Customers affected x Duration of outage

11.3.2.3 Customer Interruptions reduced total/difference

The reduction in CI has been benchmarked against the performance of EPN over the 2002/03 period and the number of customers as given in the 2002/03 Electricity Distribution Quality of Service Report [15]. The difference is the impact that this particular fault would have on EPNs overall figures. The CI Reduced Total is given by the formula: -

CI Reduced Total = Total 2002/03 EPN CI - Incident CI x100 /3386938 total EPN customers

11.3.2.4 Customer Interruptions incentive impact

These values are derived as a straight calculation of the CI difference derived in 11.3.2.3 multiplied by the 2005/06 CI incentive rate for EPN given in The Losses Incentive and Quality of Service appendix to the Electricity Distribution Price Control Review [17].

CI Incentive Impact = CI Difference x £140,000 (EPN 05/06 incentive)

11.3.2.5 Customer Minutes Lost reduced total/difference

The reduction in CML has been benchmarked against the performance of EPN over the 2002/03 period and the number of customers as given in [15]. The difference is the impact that this particular fault would have on EPN’s overall figures. The CML Reduced Total is given by the formula: -

CML Reduced Total = Total 2002/03 EPN CML - Incident CML /3386938 total EPN customers

11.3.2.6 Customer Minutes Lost incentive impact

This is derived as a straight calculation of the CML difference derived in 11.3.2.5 multiplied by the 2005/06 CML incentive rate for EPN given in The Losses Incentive and Quality of Service appendix to [17].

CML Incentive Impact = CML Difference x £210,000 (EPN 05/06 incentive)

11.3.2.7 Interruption payments

These interruption payments are based on the new arrangements announced in the Ofgem Press Release of 13th November 2003 [18]. These arrangements entitle customers whose power supplies are disrupted for more than 48 hours due to severe weather to a payment of £25, with further payments of £25 for each additional 12 hours of disruption up to a cap of £200.

For this credible fault, supply is restored after 48 hours and the Interruption Payment Total assumes that each customer affected is paid the single Interruption Payment of £25 to which they would be entitled. These interruption payments take a relatively extreme worst-case scenario.

11.3.2.8 Distributed Generation capacity/availability

The DG capacity is the rounded capacity of the generation present in the islanded case study, with a realistic level of availability applied.

11.3.2.9 Network unavailability payment

As well as looking at prospective penalties from the point of view of supply customer disconnection, the current Distribution Price Control Review [19] also proposes a penalty payment from DNOs to Distributed Generation for 'network unavailability'. The actual rebate rate will be agreed between the DNO and the DG, so the calculations here are based on the default value of £0.002/kWh. The Network Unavailability formula is given below.

Network Unavailability Payment =

Rebate x DG x (Network Interruption Duration – Baseline Network Interruption Duration)

Rate Capacity

Baseline Network Interruption will have a default value of zero, although this can also be agreed between the DNO and the DG.

11.3.3 Alternative solutions

The obvious alternative to using islanded operation to secure this section of network against the common mode failure is to reinforce the network through interconnection at 11kV. The 'islanded' demand is approximately 8.5MW and the nearest primary substation is 7km away [16]. Two solutions have been costed in Table 12. The first costing would allow the island load to be secured independently of the DG operating, through reinforcement to 10MW. The second costing is dependent on the DG to secure the total island load, through reinforcement to 3.5MW.

11kV Interconnection (7km) 8.5MW load							
10MW Capacity (reinforcement independent of DG)				3.5MW Capacity (reinforcement dependent on DG)			
Item	Quantity	Unit Cost (£)	Total Cost (£)	Item	Quantity	Unit Cost (£)	Total Cost (£)
Circuit Breaker	2	30000	60000	Circuit Breaker	2	30000	60000
Disconnector	4	15000	60000	Disconnector	4	15000	60000
Protection	2	2000	4000	Protection	2	2000	4000
Cable (including soft dig installation)	7	55000	385000	Cable (including soft dig installation)	7	45000	315000
Overhead Line	7	(35000)		Overhead Line	7	(25000)	
Sub Total			£509,000	Sub Total			£439,000
Civil Works			50000	Civil Works			50000
Engineering			52000	Engineering			44000
Capitalised Operation & Maintenance			104000	Capitalised Operation & Maintenance			88000
Total			£715,000	Total			£621,000

Table 12. 11kV Interconnection costing [24]

11.3.4 Summary

Although the generic risk of this type of credible fault occurring is relatively low (judging by the number of previous incidents), it is clear that should such a fault occur then the penalties could be significant for the DNO in question, even assuming negligible compensation for the DG. The costs of reinforcement are also high and approximately equal to the possible penalty total. There could be a case for islanded operation here, if it can be provided at a cost that appreciably undercuts the cost of reinforcement, and hence can be more reasonably offset against the perceived level of risk.

11.4 (System B) single transformer primary failure

11.4.1 Credible fault

The credible fault for this scenario is the loss of the single 33kV undersea cable due to either a ships anchor being dragged across it, or damage caused by fishing gear, particularly the heavy steel doors of ‘otter trawling’ nets [20]. It is estimated that to find and then repair such a fault could take a month or longer depending on the weather and sea conditions, and hence for the purposes of this model a network restoration time of 30 days (43,200 mins) was chosen.

11.4.2 Financial impact

The predicted financial impacts of this fault on the DNO are listed in Table 13. The origin of the data and derived formulas used to determine these financial impacts are given in Sections 11.4.2.1 to 11.4.2.9.

Parameter	Lower	Upper	Actual
Number of Customers Affected	1000	2000	1473
Duration (mins)	43200	43200	43200
(Incident) Customer Interruptions (CI)	1000	2000	1473
(Incident) Customer Minutes Lost (CML)	43200000	86400000	63633600
CI Reduced Total (From 2002/03 performance of 85.47)	85.4	85.33	85.37
CI Difference (From 2002/03 performance of 85.47)	0.07	0.14	0.1
CI Incentive Impact	£6300	£12600	£9000
CML Reduced Total (From 2002/03 performance of 64.57)	34.7	4.83	20.57
CML Difference (From 2002/03 performance of 64.57)	29.9	59.74	44
CML Incentive Impact	£4784000	£9558400	£7040000
18 hr Interruption Payment (per customer)	£50	£50	£50
+12 hr Interruption Payment (per customer)	£25	£25	£25
Total Interruption Payments	£1512500	£3025000	£2227912
Distributed Generation Capacity (MW)	5.8	5.8	5.8
Distributed Generation Availability	60%	60%	60%
Network Unavailability Payment	£5011	£5011	£5011
Total Financial Impact	£6,307,811	£12,601,011	£9,281,923

Table 13. Financial impacts of credible fault on case study

11.4.2.1 Number of customers affected

The lower and upper figures for the number of customers affected by such a generic common mode failure were decided upon at the WS5 peer review meeting of 9th June 2004. The actual figure is the number of customers who would be islanded in the event of the fault on the actual network under consideration in the case study [21], Western Power Distribution (WPD).

11.4.2.2 Customer Minutes Lost

CML = Number of Customers affected x Duration of outage

11.4.2.3 Customer Interruptions reduced total/difference

The reduction in CI has been benchmarked against the performance of WPD (Southwest) over the 2002/03 period and the number of customers as given in [15]. The difference is the impact that this particular fault would have on WPD (S west) overall figures. The CI Reduced Total is given by the formula: -

CI Reduced Total =

Total 2002/03 WPD (S west) CI - Incident CI x100 / 1446280 total WPD (S west) customers

11.4.2.4 Customer Interruptions incentive impact

This is derived as a straight calculation of the CI difference derived in 11.4.2.3 multiplied by the 2005/06 CI incentive rate for WPD (S west) given in The Losses Incentive and Quality of Service appendix to [17].

CI Incentive Impact = CI Difference x £90,000 (WPD (S West) 05/06 incentive)

11.4.2.5 Customer Minutes Lost reduced total/difference

The reduction in CML has been benchmarked against the performance of WPD (S west) over the 2002/03 period and the number of customers as given in [15]. The difference is the impact that this particular fault would have on WPD (S West)'s overall figures. The CML Reduced Total is given by the formula: -

CML Reduced Total =

Total 2002/03 WPD (S West) CML - Incident CML /1446280 Total WPD (S West) customers

11.4.2.6 Customer Minutes Lost incentive impact

This is derived as a straight calculation of the CML difference derived in 11.4.2.5 multiplied by the 2005/06 CML incentive rate for WPD (S west) given in The Losses Incentive and Quality of Service appendix to [17].

CML Incentive Impact = CML Difference x £160,000 (WPD (S West) 05/06 incentive)

11.4.2.7 Interruption payments

These interruption payments are based on Western Power Division's own guaranteed standards of service [22]. These guarantee domestic customers whose power supplies are disrupted for more than 18 hours to an initial payment of £50, with further payments of £25 for each additional 12 hours of disruption.

For this credible fault, supply is restored after 30 days and the Interruption Payment Total assumes that each customer affected applies for both the initial £50 Interruption Payment and the subsequent £25 interruption payments to which they would be entitled. The formula for the total interruption payments is then given by

Total Interruption Payments =

(((duration mins / 60 hrs) - 18hrs (1st incentive)) / (12hours (2nd Incentive))) x (£25 x No of customers) + (£50 x No of Customers)

11.4.2.8 Distributed Generation capacity/availability

The DG capacity is the rounded capacity of the generation present in the islanded case study, with a realistic level of availability applied.

11.4.2.9 Network unavailability payment

As well as looking at prospective penalties from the point of view of supply customer disconnection, the current Distribution Price Control Review [19] also proposes a penalty payment from DNOs to Distributed Generation for 'network non-availability'. The actual rebate rate will be agreed between the DNO and the DG, so the calculations here are based on the default value of £0.002/kWh. The Network Unavailability formula is given below.

Network Unavailability Payment =

Rebate x DG x (Network Interruption Duration – Baseline Network Interruption Duration)

Rate Capacity

Baseline Network Interruption will have a default value of zero, although this can also be agreed between the DNO and the DG.

11.4.3 Alternative solutions

Due to the nature of the section of network that would become disconnected in the event of this fault (i.e. a geographical island some distance from the mainland) and the duration of the disconnection under consideration, two alternatives to using embedded DG to run the network in islanded mode have been considered. The first (see Table 14) again involves reinforcement, although in this scenario this would require a parallel sub sea cable from the mainland to the island, (a distance of 58km). The second (see Table 15) involves the import of temporary generators post fault to support the island's load, and hence minimize the duration of the disconnection.

Parallel Sub sea Cable Costing			
Item	Quantity	Unit Cost (£)	Total Cost (£)
33kV			
Circuit Breaker	2	40000	80000
Disconnector	4	15000	60000
Voltage Transformer	1	4000	4000
Current Transformer	3	5000	15000
Earthing	1	20000	20000
Civil Works	1	110000	110000
Transformer	1	100000	100000
SCADA System	1	10000	10000
Buried Sub sea Cable	58000m	200	11600000
11kV			
Circuit Breaker	1	30000	30000
Disconnector	2	15000	30000
Metering	1	6000	6000
Protection	1	2000	2000
Total			£12,067,000

Table 14. Parallel sub sea cable costing [16]

Standby Generators Costing			
Item	Quantity	Unit Cost (£) (per week)	Total Cost (£) (four weeks)
1250kVA Generator	4	2100	33600
25m Cable Sets	2	110	880
50m Cable Sets	2	250	2000
3000 Gallon Fuel Tanks	2	150	1200
6.3MVA 415V/11kV Transformer	1	4500	18000
40ft Trailer	7	160	4480
50m HV Cable Sets	1	550	2200
Environmental Fee	1	156	624
Sub-total			62984
Fuel Costs (estimated)			234662
Transport Costs (estimated)			15000
Total			£312,646

Table 15. Standby Generator Costing [24]

11.4.4 Summary

Although extreme, such a scenario is credible, and the penalties imposed on the DNO are potentially massive. Obviously no DNO would allow their customers to be disconnected for a period of thirty days or more and the high cost of another sub sea cable link means the only realistic alternative to in-situ DG based islanding, is the importation of standby generators to supply the islanded load. Although the costs involved are reasonable compared to the potential penalties, the figures do not allow for the penalties incurred whilst standby generation is arranged and transported to the island, which could be significant. There is therefore possibly a case for in-situ DG supplying the load, once this section of the network becomes islanded.

12 Implementation plans

12.1 General

In order for a safe and stable electrical island to be established, there are several conditions that must be met. The implementation plan must ensure that these conditions are invoked at the time the island is created and make the required modifications such that the islanded portion of the network has adequate stability to meet the pragmatic requirements of the customers connected therein. It is considered that, in general, customers would rather tolerate a lower quality of supply than that defined in the ESQCR [2], as opposed to a total loss of supply, although the degree of acceptable excursion is expected to vary between customer groups and will be influenced by the needs of their activities. Some activities, particularly commercial and industrial processes (e.g. fabric weaving) can be very sensitive to voltage and frequency disturbances.

The results of the modelling work performed and described earlier in this report highlights the extent of disturbances that will be experienced at the case study locations under certain conditions. It can be concluded from this that, in the majority of cases, the change from an interconnected network to an electrical island will cause fluctuations which exceed these limits, before the governors and AVRs of the distributed generators settle into their revised role within the network. As it could be argued that any designed mode of operation likely to cause excessive excursions is a breach of statute, it would be prudent to seek either derogation or a change in the wording of the legislation. As it should also be possible to identify that the customers within the islanded section would then be receiving an improved service, then the acquisition of derogation or a change in the wording of the legislation is not considered an undue obstacle.

The conditions that are required have been discussed in some detail and are summarised as

a) Power balance – Total available generation of real and reactive power must be greater than or equal to the requirements of the load, and the various DG must have suitable control responses of AVRs and governors to maintain adequate power quality

b) Synchronising – If an islanded section of network is to transfer back to interconnected operation without being firstly shut down, then synchronising facilities are needed on the circuit breakers that are intended to be used to reconnect the island to the grid

c) Earthing – There is a statutory requirement for all distribution circuits to have a reference to earth. The usual earthing method for 11kV circuits is to connect the neutral of the 11kV windings of each primary 33/11kV transformer to earth either directly, by arc-suppression coils, or more commonly through a resistance or impedance to limit the magnitude of earth fault currents. In both of the case studies for islanded operation, the primary transformer becomes disconnected to create the island and therefore a means of establishing a new earth on the 11kV circuits when operating in islanded mode must be in place

d) Network protection – When operating in islanded mode, the main source of power, and fault contribution, is unlikely to be located on the 11kV busbar of the primary 33/11kV substation. In general, the generators of the various DG involved will only be able to provide a fraction of the fault current available when operating with the primary transformers in normal service. The system impedances between the DG and remote faults will further aggravate this reduced fault contribution. Additional protective devices may be needed to ensure that all faults are cleared within an acceptable time. Detailed studies will be required to determine the extent of additional protection for practical configurations of DG and the islanded network

e) "G59" protection – Protection to meet the terms of the ENA document "G59/1 – Recommendations for the connection of embedded generation plant to the Public Electricity Suppliers distribution systems" [4] (up to 5MW and 20kV) is usually installed on DG installations. In addition to overcurrent and earth fault protection (required for any connection irrespective of whether a load or a generator) the main protective devices are for over/under voltage, over/under frequency and loss of mains. The purpose of these is to trip the DG under conditions when an unintentional island may have been created. Therefore, the "standard" settings and time delays need to be reviewed so as to prevent unwanted tripping when a deliberate islanding operation is being invoked. However, protection to avoid unintended island operation is required to maintain an adequately safe system under all circumstances

f) Generator protection – Each DG will incorporate protective devices, which are intended to prevent damage to the generating plant itself, and its ancillary equipment. As the provision and settings of these protective devices may have a background of conventional network requirements (e.g. "G59") then it is probable that negotiations with manufacturers will be required to achieve satisfactory "ride-through" when deliberately transferring seamlessly from the interconnected condition into islanded operation

g) Network operation – The resultant system of protection and control of the network must be easily signalled to the appropriate control point, such that the Control Engineers and the field staff can clearly understand the various network configurations that result when electrical islands are created

12.2 Case Study A – Common mode failure of two 33kV feeders to a Primary Substation

The Single Line Diagram (SLD) as shown in Appendix M illustrates the main protective features assumed to already be present on the network considered for Case Study A. This network is operated by EPN. The generation shown is available for service, and it can be seen that it is all connected to one section of the 11kV busbars. In the modelling exercise described in Section 10, it is assumed that both of the Landfill Gas Generation (LFG) facilities (GB1, GB2, GB3 and GC1, GC2 and GC3) are fully operational and the Diesel Engine Generation (DEG) facility (GA1, GA2) is not operational.

Some additional factors worthy of note are:

a) LFG output is dependant on the amount of methane generated (which in turn is dependant on the nature of the refuse within the landfill) and the stage of decay. It is usual that the owner will estimate a profile of output, typically covering a period of 15 years after the landfill is capped. It is not uncommon for actual output to vary significantly from the estimations (e.g. on one site, estimations provided for adequate methane to evolve to allow generation of 5MW for a period of 12 years, subsequently tapering down to 1MW over the next 5 years. The actuality was that 5MW output was achieved for 4 years, reducing to 3MW)

b) LFG plants generally operate on a continuous basis. Availability of 97% can reasonably be assumed which allows for maintenance, although maintenance will normally be arranged so that only one set in a facility is out of service at any one time

c) The DEG generation appears to be used for peak lopping duties for site loads only, to reduce demand when ½ hourly prices are at a peak. From the data available, it appears to operate in the winter period only on weekdays between the hours of 17:00 and 20:00. As a consequence it is assumed that it would only be available to support an electrical island once islanding had occurred, and it was not assumed to be on line for the transition into islanding

The SLD shown in Appendix N overlays the additional control and protection devices considered necessary to allow safe and stable transition of feeders A, B and C into islanded mode and subsequent continued operation. The key purpose and attributes of these functions are discussed in the following sections, which address the issues for the required conditions for islanding to occur.

12.2.1 Power balance

The load/generation balance used in the model assumes that there is a surplus of generation on the busbar section connecting feeders A, B and C. The loads on the other busbar section (averaging approx 3MW in summer and14MW in winter) cannot be supported. It is also probable that there will be occasions when the DG cannot support the loads on feeders A, B and C together and some loads may need to be shed from these feeders at the time of transfer into island mode.

It is assumed that the initiation of the islanded operation occurs as a result of a common mode failure on the 33kV circuits to the primary substation. In order that a seamless transfer into islanded mode can occur, the disconnection from the fault and from parts of the local network that would cause an overload must be arranged to occur simultaneously. Therefore, monitoring of key power flows must be in place and set to arm the circuit breakers that require to be tripped. Drawing 1150/ 001 (Appendix M) illustrates a PLC being used to receive power flow information from the feeder circuits, and possibly also the generation. The PLC will also be fed with data relating to circuit breaker status and protection.

The PLC is arranged, for the purpose of this case study, to trip the 11kV transformer CB feeding the left-hand side bus section, and also the bus section CB.

12.2.2 Synchronising

A check-synchronising facility is incorporated on each CB that trips when the island is created. For this case study, check synchronising is installed on the transformer 11kV CB and the 11kV bus section CB. Provided that the voltage and frequency of the islanded section can be maintained close to that of the main network, then the two sections will drift in and out of synchronism at an adequately slow rate that additional control over and above check synchronising relays will not be required.

Check-synchronising relays are also considered for the 11kV CBs on the individual feeders A, B and C to avoid any inadvertent out-of-synchronism closure. (This case study is not considering the scenario of any single feeder operating as an island, although this may be a possible refinement.)

12.2.3 Earthing

In this case study, provision of an earth for islanding the left-hand section of busbar, and associated feeders A, B and C, is made using an earthing transformer located on the same section of busbars. During normal interconnected operation, the 11kV earthing transformer CB will be closed (to minimise system disturbance at the time of transit into islanded mode), and the switch in the neutral earth connection left open. Upon islanding, the neutral of the earthing transformer star winding will be earthed via neutral earthing resistor (NER). A CT will monitor current flow in the neutral/earth link and provide standby earth/fault protection to operate on all 11kV feeder CBs, as backup protection.

All DG facilities will incorporate Neutral Voltage Displacement (NVD) protection for normal interconnected operation and for operation in islanded mode.

The NVD protection is regarded as backup protection, for use only in the event of loss of the N/E link on the primary transformer, or on the earthing transformer.

12.2.4 Network protection

It can be seen on the SLD drawings in Appendices N and O, that the DG on feeders A and B are some way along the feeder.

It was earlier determined that the fault level on the 11kV system at busbar 6, represents the worst case whilst the islanded section was operating with the 6 LFG gensets (approx 6.7MW). The fault current contribution at varying times post fault is noted below, together with the comparative contribution when the network is interconnected.

	Full Load Current		RMS Current at various times post fault inception (AVR boost assumed for Islanded condition)			
	At 11kV (A)	1st Asymmetric Peak (kA)	50ms (A)	100ms (A)	250ms (A)	500ms (A)
Islanded Operation (LFG generators total 6.7MW)	200	1.8	920	920	740	670
Interconnected network	200	3.0	1400	1400	1400	1400

Table 16. Comparison of fault current contributions under islanded and interconnected operation

The two most important qualifying conditions are

- The DG contribution will be less than shown in Table 16 if any of the LFG generators is out of service
- The DG AVR boost will operate for a limited duration only (typically 10s) in order to prevent the generator from sustaining damage

From data received from EPN, the maximum normal operating current on each feeder is 200A. If the LFG generation in either of feeders B and C is out of service, then loads on these feeders of up to 350A will result. Therefore it would be reasonable to assume an Inverse Definite Minimum Time (IDMT) relay current setting of 400A on the 11kV feeder CBs. With values of 1.5 times setting on a Standard Inverse IDMT curve then trip times of 10 – 20 seconds would be likely under phase-to-phase fault conditions. As the DG AVR boost action will have ceased by 10s, the fault current will have decayed to approximately full load current by then, reducing the fault current contribution at Bus 6 to approximately 200A, which will not allow the main feeder IDMT protection to operate at all.

In order to provide effective overcurrent protection, it is proposed that voltage-controlled overcurrent be included. This type of protection provides for two levels of current setting sensitivity with the selection being determined by the busbar voltage. When system voltage is normal, then the higher setting applies. However, if the voltage collapses as would be experienced in the transition to islanding, then a second, lower setting is invoked. It is proposed that this voltage controlled overcurrent protection be included on the CBs for each generator and at the feeder CBs for feeders A, B and C. To avoid any spurious trips under the more sensitive current setting under normal interconnected conditions (i.e. in the event of a close-up fault), the sensitive setting would be enabled by the control PLC during islanded operations only.

Lower fault contributions will severely limit the ability to achieve discrimination between protective devices at different points along the network. It is therefore more likely that a fault within the network will result in a loss of a larger section of network when operating in islanded mode.

12.2.5 G59 protection

For DG of the size ranges and connected voltages in this case study, G59 [4] protection incorporating over/under voltage, over/under frequency and loss of mains is assumed to be provided. If no changes are made to the normal setting ranges applied to standard DG schemes then, as identified in the modelling studies, the DG will be tripped on the voltage and frequency excursions (and probably also on the loss of mains protection) which is clearly undesirable. Options include for the G59 protection to have settings and time delays modified and/or for the G59 protection to be replaced by an inter-tripping scheme tied to the 11kV feeder CB and the PLC control scheme described in section 12.2.1 above. The design of G59 protection for islanded operation will need to ensure that there is no likelihood of unintentional islands being created, with consequential dangerous operating conditions. The communications links between primary substation and generation facilities may be used to invoke alternative G59 setting that can prevent such an occurance.

It is proposed to monitor “loss of mains” conditions protection at the 11kV transformer CB. This can be one of the triggers to the PLC to initiate an islanding configuration.

12.2.6 Generator protection

Generator protection arrangements will have to be reviewed against the background of changes in protection and control that may be necessary to achieve stable operation in islanded mode. At this stage it is not envisaged that these changes, nor the costs of implementation, will be significant. The PLC can send a command to the generator to switch from power factor control to voltage control when it recognises a LoM.

12.2.7 Network operation

For Case Study A, it is proposed that a mimic panel be installed at the primary substation to clearly demonstrate the power flows, and the protection status. This mimic panel is to be repeated at the Control Engineer’s desk.

12.2.8 Communications

Good communications between the DNO and the DG operators are essential for the satisfactory operation in islanded mode. There must be a clear understanding of the availability of generating plant, with the necessary agreements on not taking essential generating sets out of service for non-urgent purposes. Therefore a contract for islanding support would require the DG to guarantee a high level of availability. When the island is established, the peak-lopping DEGs could be brought into service to allow service to be maintained to the maximum number of customers whilst accommodating load increases.

12.2.9 Implementation programme

A programme of just under a year has been estimated, covering design through to installation and commissioning. A programme is included in Appendix O.

12.2.10 Budget costs for implementation of islanding capability for Case Study A

Description	Location (& Comment)	£k
Detailed system design		40
PLC Based Control Scheme	Primary S/S	40
Programming of Control		25
Mimic Panels	Primary S/S & Control Desk	35
Power Monitoring Transducers	Primary S/S & Generation Site(s)	50
Addition of Voltage Controller Overcurrent Relays	Generation Sites	30
Addition of Check Sync, incl additional VTs	Primary S/S Transformer CB, Bus Section & Generation Feeders	90
Inter-tripping & Communication links to Generators	Generation Sites -> Primary S/S (incl capitalised revenue charges)	150
Earthling Transformer, NER, CB & NE control	Primary S/S	45
Loss of Mains Relay	Primary S/S	5
G59 Protection Mods	Generation Sites	10
Commissioning	Primary S/S & Generation Sites	30
Ballast stabilising load (short-term)	Primary S/S	15
Case Study A – Budget Total		£565

Table 17. Budget costs for implementation of islanding capability for Case Study A

12.3 Case Study B – Loss of Single Transformer Primary

The SLD as shown on Econnect drawing 1150/ 003 (Appendix P) illustrates the main features of this existing network, which is operated by WPD. All the generators shown are powered by diesel engines and they are owned and operated by a third-party company to provide network support when the main 33kV connection is available. In the event of a failure of the 33kV connection, the DEGs also power the islanded network but only after a manual reconfiguration of earthing arrangements, which requires the control system to interrupt all supplies on fault occurrence, followed by a black start.

The two situations that are modelled in Section 10.3 examine the effect of transition to DEG powered islands with different scenarios for load and operational generators as summarised in Table 7.

It can be seen from the SLD in Appendix P that the total available generation exceeds the maximum demand on this network by approximately 2MW, which allows for the largest generator to be out of service and the maximum demand to be supported from the remaining generators in islanded mode.

Appendix Q contains the Econnect Drawing 1150/ 004, which indicates the additional facilities required to implement the operational islanding capability.

12.3.1 Power balance

The load balance used in the model assumes that the connected generation capacity is controlled to exceed the load demand. In all the scenarios considered, the generators that are running are operating at 20% load at the time the primary transformer is lost. This running condition could be regarded as a pre-emptive condition to provide the spinning reserve for the islanding condition. However, as it cannot be guaranteed that generation will be operational at the time of loss of the 33kV primary transformer, control systems must be in place that can automatically disconnect the excess of load over generation (as in Case Study A). It is considered probable that the PLC could be used to receive signals on circuit loadings and play some role in ensuring that generators are not suddenly overloaded into probable stall conditions. However, the modelling study includes an assessment of the use of frequency-sensing devices controlling non-essential (deferrable) loads, as described in more detail below.

12.3.2 Synchronising

Manual synchronising facilities exist on all generators at present to allow them to be synchronised either together or to the main 33kV incomer. However, these facilities require an operator to be present at the generating station to bring the appropriate sets on line. To provide long term stable operation to cater for changes in network loading then all the generator circuit breakers will need to be equipped with automatic synchronising equipment under central control. Check synchronising already exists across transformer 33kV primary transformer T1 such as to prevent an out of synchronism re closure of its 33kV circuit breaker.

12.3.3 Earthing

In this case study, earthing facilities exist for the generators such that they can operate in an islanded mode. However these facilities require manual intervention and will require automating. No additional NVD protection is considered necessary, as all generation is centrally located connecting in to the 11kV busbars of the primary substation.

12.3.4 Network protection

This case study is very different from Case Study A in that all the generators are connected on to the main 11kV busbar. This arrangement effectively means that the 11kV busbar is the source of all energy for this network. The key issues therefore are that all the 11kV feeder circuits supplying the loads will clear a fault on their own circuits within a reasonable time when the network is operating on DG alone. It is understood that the existing time delayed overcurrent protection on the feeder circuits has time-multiplier settings (TMS) of 0.1 to achieve fast operating times. Also, Sensitive Earth Fault protection, with short time delay, is included. Whilst these protections should allow fast fault clearance whilst on DG, the disadvantage is that there is little room for discrimination with downstream protective devices. It will be necessary to confirm the minimum amount of generation that must be connected to the 11kV busbar to deliver adequate fault current to allow these protections to operate. The lack of fault current is only likely to be a problem under conditions of minimum load. Voltage controlled over current relays could be fitted to increase the sensitivity of protection operating under fault conditions when loads are supplied by the DEGs alone.

12.3.5 G59 protection

As this particular generation is connecting on to main 11kV busbars providing network support and is clearly visible to the control engineer, then G59 [4] type protection is not appropriate. However a Loss of Mains indication relay installed on the 33kV incoming feeder may be a useful input to the overall islanding control scheme to confirm that the 33kV feeder has been lost. Control staff would be aware of the loss of a feeder through other indications following operation of protection.

12.3.6 Generator protection

The existing generator protection may need to be reviewed in the light of changes and the requirements of the control system. However in this particular case study the existing protection scheme design is arranged for operating under network support conditions and it is therefore expected that existing protection schemes and settings applied to the generators will be appropriate. The PLC can send a command to the generator to switch from power factor control to voltage control when it recognises a LoM.

12.3.7 Network operation

For the Case Study B it is proposed that a mimic panel be installed at the primary substation to clearly demonstrate the status of the network and the generation. This mimic panel is to be repeated at the Control Engineers desk.

12.3.8 Communications

Good communications between the DNO and DG operators are essential for the satisfactory operation of the system in islanded mode. There must be a clear understanding of the availability of generating plant, or the necessary agreement on not taking essential generating sets out of service for non-urgent purposes.

12.3.9 Control of deferrable loads

As highlighted in the description of the modelling process, the connected generators are effectively acting as spinning reserve by being pre-loaded to 20% of rated output. Under these conditions there will be significant voltage frequency excursions at the time of transition into islanded mode. The control of certain deferrable loads using frequency as the controlled medium is suggested as a means of reducing these excursions. This control mode will have the effect of reducing the load on the islanded network, thus allowing the generator to respond with fewer excursions during the transition into stable islanded operation. As the DG frequency stabilises, these loads will be brought back into service at intervals over a period of minutes. It is envisaged that these loads will be selected using non-essential loads in customers' premises. Water or space heating loads are ideal candidates for deferrable loads, although other thermal store appliances (e.g. refrigeration) can also be nominated. This concept of short-term load shedding will obviously require the co-operation of the customers. The concept involves the deferring of part of a customer's load, and not a customer's entire load. Frequency responsive control units are commercially available and have been applied for some years to permanently islanded networks supplied by hydro turbines and diesel generators.

12.3.10 Implementation programme

A programme of 47 weeks has been estimated, covering design through to installation and commissioning. A programme is included at Appendix R.

12.3.11 Budget costs for implementation of islanding capability for Case Study B

Description	Location (& Comment)	£k
Detailed system design		40
PLC Based Control Scheme	Primary S/S	40
Programming of Control		25
Mimic Panels	Primary S/S & Control Desk	35
Power Monitoring Transducers	Primary S/S & Generation Site(s)	40
Addition of Voltage Controller Overcurrent Relays	Primary S/S (if required)	30
Inter-tripping & Communication links to Generators	Primary S/S	25
Earthing Control modifications	Primary S/S	20
Loss of Mains Relay	Primary S/S	5
Commissioning	Primary S/S & Generation Sites	30
Frequency responsive load control units	Customer Premises	10
Case Study B – Budget Total		£300

Table 18. Budget costs for implementation of islanding capability for Case Study B

12.4 Summary

Case Study	Cost of islanding capability £k	Financial impact of credible fault		
		Upper	Lower	Actual
Case Study A	565	3,118	1,039	718
Case Study B	300	12,601	6,308	9,282

Table 19. Comparison of budget costs for islanding capability and financial impact of credible fault

Table 19 shows the cost of providing islanding capability for the two case studies, and the financial impact of the case study faults. The case study fault scenarios were taken to be a worst case, and therefore the financial impact of such faults were relatively high. However, the budgeted cost of providing islanding capability was shown to be lower than the lower estimate of the financial impact for both case studies.

13 Commercial & regulatory drivers for islanding

The ideas presented here for commercial and regulatory drivers and incentives that could make islanded operation an attractive proposition for Distributed Generators, Distributed Network Operators, Suppliers, and not least Customers, effectively fall into three broad areas, namely Infrastructure, Services, and Market.

Each of these areas will be discussed in turn.

It should be recognised that the provision of islanding is heavily location dependent, and each of the possible incentives and drivers discussed here would need to be targeted accordingly.

13.1 Infrastructure

13.1.1 Network support

A necessary pre-requisite for islanding on distribution networks is the proliferation of Distributed Generation (DG) in those networks. As the bulk of customer interruptions occur due to faults on the 11kV and below system (73% in 2002/03) [15] then the DG would have to be connected at or below these voltages in order to allow islanded operation. One way to facilitate this is to make the use of DG more attractive for the purposes of network support, i.e. to use the output of the DG to offset the need for reinforcement of the network. Thus the use of DG for network support could provide the ‘stepping stone’ to future ability to island. Incentives to use DG as an alternative to reinforcement, which may increase the penetration of DG, may not result in location-specific drivers for DG in an area that could benefit from DG support to an islanding scenario. However, proliferation of DG in general may increase the likelihood of DG being available in an islanded network.

In the same way, using DG in a more active role to provide ancillary services to both Distribution and Transmission network operators could provide the ‘stepping stone’ to use for network support. (The provision of Ancillary Services from DG is explored in the report ‘Ancillary Service Provision from Distributed Generation (2004) [25].)

At present, reinforcement investment is supported through the Capital Expenditure allowance that each DNO has for reinforcement of its network. A method for incentivising the DNOs to pursue installation of DG to provide network support, instead of reinforcement, may involve some restructuring of this Capital Expenditure allowance.

Such a change has the advantage of shifting the need to drive forward innovation in this area from DG owners and developers to the DNOs with their greater resources.

The disadvantage of this change is in the formulation of such an incentive, i.e. in the decision of how much network reinforcement is necessary and where innovative techniques using DG, such as islanding, could be realistically and cost effectively substituted.

13.1.2 Distribution Code compliance

Another pre-requisite is that the generators themselves have the capability to operate in an islanded system. Making such capabilities a connection condition for DG in the Distribution Code could ensure this (for example under a Fault Ride Through characteristic), in the belief that it is cheaper to design and install such capabilities at the initial build stage rather than try to retrofit them at a later date. However, such a requirement would only be necessary where the ability to run islanded was a commercial or technical requirement.

In addition to the condition to seamlessly island, relevant DG could also be asked to comply with a requirement to black start after disconnection to minimise Customer Minutes Lost. Clause DOC 9.4.1.4. of the Distribution Code already states that local restoration plans may include embedded generators.

The obvious advantage of this is that many DG would then have capabilities to island and black start, which would drive down the unit cost of such capabilities, as they could be designed in as a requirement rather than requested as add on features.

The obvious disadvantage is these conditions would only be required on certain DG with the cost of these particular distributed generation projects rising accordingly, making the projects' economics less attractive and potentially hampering the increased penetration of embedded generation in distribution networks. Hence such a compliance requirement would need to be tied to a commercial incentive which recompensed the financial outlay of the DG involved to ensure equality with those DG not required for islanded operation.

13.1.3 Technical architecture

There are strategic thinkers within the DNOs, regulator, manufacturers and the industry at large who believe that a continuing evolutionary development of the DNO networks will not achieve the necessary flexibility and functionality to accommodate the increasing levels of DG that are projected over the next 20 years or so. In order that the necessary developments can be achieved, a high level view is necessary to identify the route to achieve this future vision. This "think-tank" has been given the title of "Technical Architecture".

The key issues identified at an initial workshop in November 2003 were

- In order to respond to increasing densities of distributed generation, it is likely that networks will need to become increasingly active and intelligent
- This active and intelligent role will be achieved effectively and cost efficiently if consideration is given to the development of a technical architecture for tomorrow's distribution networks
- Technical Architecture provides a high level framework to ensure that compatibility and efficiency is achieved in the design, procurement, construction, and operation of these networks
- The Technical Architecture of today's distribution networks is established by a series of standards, codes and guidance documents
- An understanding of best practice options for future Technical Architecture will directly benefit connecting customers by providing consistency and co-ordination, and will enable manufacturers to respond through their product portfolios, and encourage equipment designs to be made non-proprietary

In many ways the use of DG to deliberately operate islanded sections of the network benefits from this "Technical Architecture" approach. Certain drivers, which need to be in place to allow the commercial benefits to be identified and realised, are unlikely to develop in an evolutionary manner. A high level view must be taken to view the potential benefits in ~20 years (+) time. The incremental costs of incorporating many of the facilities (such as described in the implementation plans in Section 12) in new build DG projects and network reinforcement will be small, whereas retrofitting will be costly. Therefore if a route map can be produced to guide the incorporation of the necessary elements into DG design and DG connection infrastructure, as well as other capital expenditure programmes, then cost saving rewards may be available in the future.

13.2 Services

13.2.1 Provision of islanding service

One way for the generators to recoup their investment in islanding capability would be to receive a payment from the DNO corresponding to their ability to provide this service. The DNO in turn could be incentivised to procure such services through a 'use it or lose it' allowance in their price control review. The incentives must also outweigh the investment required to be effective. The investment required by the generator and DNO will be site specific.

The advantage is that this arrangement would create a market for such services, although by nature they are likely to be location specific.

Again the process of determining an allowance for islanding for each DNO for incorporation into the price control review would be extremely difficult due to the locational requirements and incentives necessary.

13.2.2 Black start capability payments

In a similar way, DNOs could be incentivised to procure black start services, with a system of capability payments to pass on to the generators concerned.

The advantage is that a market for such services would be created, although by nature the services are likely to be location specific.

Determining an allowance for black start for each DNO in the price control review would also be extremely difficult due to the locational requirements and incentives necessary. The justification for establishing small-scale black start capability in distribution networks could also be tenuous, with the local network restoration plans for black start already in place with the transmission system operators.

13.2.3 Customer Interruption (CI) & Customer Minutes Lost (CML) penalties

The obvious incentive currently in place which could be used to encourage (especially seamless) islanding is CI and CML. This could be achieved by making the penalties imposed for the number of CI and CML much more onerous than at present, both by increasing the level of DNO revenue at risk to these key performance indicators as well as by reducing the duration of interruptions before which customers are allowed to obtain compensation. This is the most transparent way of creating a requirement for seamless islanding on Distribution networks. The disadvantage of using CI and CML is that they are applied across the entire DNO area, and would be difficult to target to the areas of DNO network where islanding could be implemented effectively.

13.2.4 Payment for network unavailability

Approaching the issue of islanding from the perspective of a generation customer, it is foreseen that DNOs could avoid having to pay a potentially onerous network unavailability charge by ensuring that the output of the DG can still be distributed under outage conditions.

The advantage of this is that it is another source of penalty payments for disconnection and hence another incentive on the DNO to keep the network available. However, the size of the network unavailability rebate (which is agreed between the DNO and the DG) is likely to be linked to the strength of the DG connection to the distribution network, with higher rebates for stronger connections. Hence in order to negotiate a high rebate payment, the DG may need to invest in increased connection assets, which could prove uneconomic, and this may create a perverse incentive, by actually dissuading new DG connections.

13.3 Market

13.3.1 Uninterruptible Power Supplies (UPS)

There is already a market for seamless islanding, and that market is comprised of all those customers who own and operate their own standby generation or who purchase UPS devices to secure equipment such as computer servers. If a supplier could guarantee an uninterruptible power supply by contracting with the DNO to provide seamless islanding using the local DG rather than the onsite standby arrangements of individual customers, and this could be done at a cost that was competitive with such arrangements, then the market for islanding could operate successfully.

The advantage of such an approach is that it is entirely market driven. However, the demand will be location specific and islanding as a security of supply solution will depend upon the location of the fault.

The disadvantage is that to install the necessary network improvements and generator capabilities would require a number of the customers inside a designated island to sign on to the service in order to make it financially viable.

14 Conclusions

- In the first system studied where the islanded network was exporting power immediately prior to the islanding event, both the generators and the induction motor loads remained stable following islanding. The frequency and voltage response deviated beyond the acceptable limits specified by ESQCR and G59 although they remained within the more probabilistic criteria of EN 50160. The steady state deviation of frequency depended on the selection of the generator governor droop characteristics and the initial power unbalance immediately following the islanding event.
- Increasing values of busbar resistive load reduced the transient peak frequencies significantly following islanding. For the network configuration studied, a value of approximately 40% of system local load brought the transient frequency peak within the EN 50160 limits while 80% resistive load brought the transient frequency peak within the ESQCR and G59 limits.
- Despite the short term boost provided by the generator AVRs, the fault levels in the islanded network were still approximately half those of the grid connected network, and these reduced values would require an adjustment to protection settings to ensure satisfactory protection operation once islanding has occurred.
- Large excursions in system voltage and frequency, which were well outside ESQCR, EN 50160 and G59 standards, were observed following the transition into islanded operation of the second system studied. This islanded network was importing power immediately prior to islanding.
- Shedding some local loads had significant effects on the response following islanding. A load shedding setting of 20% reduced the negative frequency excursion by 30% and 60% load shedding brought the frequency and voltage responses within the EN50160 and G59 limits, but not the more stringent frequency limits of the ESQCR.
- Halving the governor response times would have the equivalent effect of increasing the total load subject to dynamic control (shedding) by another 20%.
- If a significant number of white goods are fitted with frequency responsive load control at the time of manufacture, the need for tripping entire circuits to achieve a generation/ load balance will be reduced.
- Either a relaxation of, or derogations to, the statutory ESQCR limits on voltage and frequency excursions may be required to allow "seamless" transfer into islanded mode.
- In order that islands can be created and operated safely and stably, modifications will be required to (typically) protection and earthing arrangements, and additional control and communications facilities installed between DG facilities, the primary substations and the DNO control engineer. Many of these facilities could be incorporated within the initial connection arrangements of the DG would allow significant savings compared with the budgetary costs indicated in the implementation plans described.
- In both of the case studies used for the basis of the implementation plans, a dedicated control scheme forms an essential role in constantly monitoring load and generation power flows in real time, and running pre-emptive algorithms such that appropriate actions can be implemented immediately on the loss of the primary connection.

- Check synchronisation facilities are required at every switching point in the network that may be involved in the creation or maintenance of an island.
- Owners of DG facilities will need to enter into commitments to ensure that an adequate availability of generating plant is maintained to power the islanded sections of network. Fuel availability forms an important aspect of this functionality. It is acknowledged that the nature of the DG (e.g. landfill gas, wind, hydro etc) may introduce uncertainty in the fuel availability and consequential amount of generation available at any time.
- The probability of a 33kV (or above) fault causing an extended loss of supply to customers is reasonably low. An interrogation of the National Fault and Interruption Reporting System (NaFIRS) revealed that over the last ten years only four faults at voltages above 22kV resulted in long term customer disconnection (i.e. provided an opportunity for islanded operation).
- However should such a prolonged fault occur then the penalties could be significant for the DNO in question, even assuming negligible compensation for the DG. The costs of reinforcement are also high and can for geographic islands exceed the likely penalties. Hence a case for islanded operation can be made, if it can be provided at a cost that appreciably undercuts the cost of reinforcement, and hence can be more reasonably offset against the perceived level of risk.
- A necessary pre-requisite for islanding on distribution networks is the proliferation of Distributed Generation (DG) in those networks. As the bulk of customer interruptions occur due to faults on the 11kV and below system then the DG would have to be connected at or below these voltages in order to allow islanded operation. One way to facilitate this is to make the use of DG more attractive for the purposes of network support, i.e. to use the output of the DG to offset the need for reinforcement of the network. Thus the use of DG for network support could provide the 'stepping stone' to future ability to island. In the same way using DG in a more active role to provide ancillary services to both Distribution and Transmission network operators could provide the 'stepping stone' to use for network support.
- Certain drivers, such as the use of DG for network support or designing DG with the ability to provide Uninterruptible Power Supply, which need to be in place to allow the commercial benefits to be identified and realised, are unlikely to develop in an evolutionary manner. A high level view must be taken to view the potential benefits in ~20 years (+) time. The incremental costs of incorporating many of the facilities (such as described in the implementation plans in Section 12) in new build DG projects and network reinforcement will be small, whereas retrofitting will be costly.
- The likely utilisation of DG to operate islanded sections of distribution networks will be enhanced if a long-term view of this functionality is taken (e.g. as part of the Technical Architecture debate).
- Many of the incentives that could encourage DNOs to provide islanding services are already in place, although currently not at a level which would make such services commercially viable.

15 Recommendations

- It is probable that the ESI Engineering Recommendation documents G59/1 and G75, together with Engineering Technical Report 113/1 will be updated soon in the light of the new Grid Codes that are being developed to ensure grid stability during, and following, a major fault on the transmission network. This will ensure a common approach is applied which will benefit overall network stability and resilience. It is recommended that such an update should consider Technical Architecture issues, including the deliberate provision for DG operated islands.
- It is clear that the limits for frequency and voltage excursion laid down in ESQCR are too stringent to allow seamless islanding to occur and that a more probabilistic approach, similar to that used for EN 50160 would need to be developed to accommodate such events, although not necessarily with the same limits.
- That the commercial case for islanding is not pursued until more DG becomes connected and plays a more active role in the operation of both Distribution and Transmission networks, first through the provision of Ancillary Services, and then through network support.
- Although at present there is no commercial reason to take islanding forward, to enable a long term strategy for the technical architecture of future distribution networks to be formulated there is value in gaining further experience of the requirements for successful islanding on actual distribution networks. To enable this it is recommended that a demonstration project should be set up on a section of DNO network under the auspices of the Registered Power Zone arrangements, which incentivise the DNO to designate an area of network in which high quality innovation projects facilitate the added value connection of distributed generation (DG).
- The issue of DG operated islanded operation be included in the brief of the Technical Architecture think-tank so that the route map that may be developed in the near future adequately considers the long-term technical requirements for DNO networks for 2024 and beyond.

16 References

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27) Electricity Association, “EA Engineering Recommendation G75, Recommendations for the connection of embedded generating plant to public electricity suppliers’ distribution systems above 20kV or with outputs over 5MW”, Electricity Association, 1996

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Appendix A. Literature Review

Summary of document “The Costs And Benefits Of Embedded Generation Islanding Operation”

An assessment was undertaken by PB Power [26] to identify the technical, legal and commercial issues of operating distributed generators (DG) in islanded mode as well as to quantify the costs and benefits associated with this mode of operation. This assessment was achieved by undertaking the following tasks:

1) Identifying technical, legal and commercial risks of operating the DG in islanded mode.
2) Identifying ways to mitigate the risks identified in item 1.
3) Quantifying the costs and benefits of islanded operation to Distribution Network Operators (DNOs), generators, and customers.
4) Testing and seeking the consensus of the DNO and small generators on recommendations resulting from the above tasks.

All the tasks undertaken by PB Power are based on the context of existing distribution security standard Engineering Recommendation P2/5 [1]. ER P2/5 which was created in 1978 and has not undergone any modifications since then despite considerable changes in the technology and market structure in the electricity sector in Britain. P2/5 is currently undergoing a review by the Distribution Generation Working Group set up by the DTI and Ofgem in order to recognise the benefits that DG can provide in terms of improved reliability of power supply.

The main benefit that islanded operation can bring to generators is the additional revenues from selling their energy during islanded operation. At the present time without the possibility of islanding generators, the additional revenue that a generator can receive from islanded operation will be small due to the fact that the DNOs are only allowed to keep a section of network separated from the main supply for a specified time, known as the network restoration time. This network restoration time varies depending on the number of electricity users on an islanded network as specified in Electricity Recommendation P2/5. The additional revenue may be so small that it may not be attractive after considering the cost of the additional equipment and facilities required to allow this mode of operation. Islanded operation is expected to be economically feasible in some specific cases that need to be assessed individually, taking into account the characteristics of the network, demand and the size of the distributed generators.

Operating the DG in islanded mode improves the overall reliability of power supply to electricity users. The DNO may gain additional revenue from Ofgem due to the improvement in the quality of power supply. Also the contribution of the DG to the reliability of power supply can reduce or delay the need to reinforce the network to comply with the statutory reliability standards, hence reducing the capital expenditure requirements. However, this contribution does not necessarily have to be associated only with islanded operation. It is generally associated with the overall availability of the distributed generation when needed by the DNO at specific locations.

The main benefit that the islanded operation of the distributed generation can provide to electricity users is the reduction in the frequency and, particularly, the duration of power interruption caused by the disconnection of a section of electrical network from the main supply. An assessment needs to be carried out to quantify this benefit because the customers will be responsible directly or indirectly for any expenditure required to allow the islanded operation of the distribution generation.

Under the existing NETA, the main beneficiaries (the customers and DNOs) of the islanded operation will not have to bear any unbalance penalties caused by the islanding as these penalties are transferred to the generators in the main interconnected system, which would have otherwise been supplying the islanded customers.

Appendix B. Literature Review

Summary of document “Assessment Of Islanded Operation Of Distribution Networks And Measures For Protection”, produced by Econnect Ltd for the DTI, 2001.

This report was prepared by Econnect and was aimed at reviewing existing UK practices and guidelines related to islanded operation of distribution networks and loss of main protection. It begins with an introduction to islanding, followed by the description of a number of hazards as a result of operating distributed generation (DG) in islanded mode. The report states that the DNO has the responsibility to ensure the safety of its distribution network. Therefore, the DNO needs to take appropriate measures to protect its electrical network and customers from all the possible hazards. However, it is identified that operating DG in islanded mode can bring benefits to customers. Therefore, guidelines for deliberate islanded operation are established. It is shown that a seamless transfer of load from the main grid to the islanded DG is the preferred islanding scenario. If the DNO cannot ensure a seamless transfer, then it is required to incorporate a black-start capability to ramp-up DG power output from zero to the rated capability with full voltage and frequency control. This capability will involve substantial modifications of most standard DG, which may result in significant cost implications.

This report also reviews the principles of four loss-of-mains techniques. Each of these loss-of-mains techniques detects the loss of mains if one of the following system quantities undergoes a sudden change.

1) The rate of change of frequency (rocof or df/dt) in distribution networks
2) Voltage vector shift at distribution networks (detecting sudden changes in load angle)
3) Fault level in distribution networks
4) The flow of reactive power from DG to distribution networks

If one of the four quantities undergoes a sudden change, then the corresponding loss-of-mains technique will send a signal to DG such that it will disconnect the DG from the distribution networks. The techniques that measure quantities 1 and 2 are the most commonly used approaches to the detection of the loss of mains.

Intertripping is a technique that detects the opening of the DNO’s circuit breaker contacts at the point of interconnection and transmits a signal to all DG so that the it will be disconnected from the respective island networks. The signal is transmitted through a reliable medium over distances of up to 50km. A leased communication channel scheme such as BT is the most commonly used intertripping communication method.

The principle of the neutral voltage displacement protection (NVD) is described in the report. NVD is used to back up the loss-of-main system such that it can mitigate the risk associated with the unearthed islanded network if the loss-of-main technique fails to trip off the DG. This technique is used to minimise danger to customers since the islanded network is not earthed.

Engineering Recommendation G59/1 [4] specifies that if the size of a distributed generator (DG) is less than 5MW and the DG is connected at below 20kV, then the DG is to be tripped off from the islanded network in order to protect the islanded network and customers. This practice is established based on the assumption that the size of DG is relatively small and is inadequate to contribute to the reliability of the power supply to customers. In addition, G59/1 describes all the scenarios (over-voltage, under voltage, under frequency and over frequency of the islanded network) during which the DG needs to be tripped off. Also, DNOs are allowed to install another loss-of-main systems in their networks in order to enhance the safety of their networks. This approach is to ensure that the DNO networks are always protected even when the loss-of-mains systems implemented by the generators fail to operate. G59/1 states that generators are responsible for all the costs of the loss-of-mains systems including the ones implemented by DNOs. It also specifies that the need to trip off the DG can be exempt if the islanding of DG is for a short period of time and the risk associated with the out of phase re-closure is low. In addition, extended islanded operation of DG is allowed if appropriate measures are taken to protect the islanded networks, providing that the risk of out of phase re-closure is low.

Engineering Recommendation G75 [27] states that if the size of DG is greater than 5MW and the DG is connected at network which is above 20kV, then the DG can be operated in islanded mode to provide electricity to customers. G75 specifies all the guidelines of how the DG should be operated during an islanded operation.

Several problems were identified with regard to the avoidance of the islanded operation. These problems are summarised as follows.

1) Inadequate assessment of network risk: G59/1 and Engineering Technical Recommendations 113/1 [28] do not make any attempt to assess the distribution network and generator risk should the loss-of-mains systems fail to operate. Without such an assessment, it is very difficult to justify whether or not it is worth to improve the loss-of-mains technologies

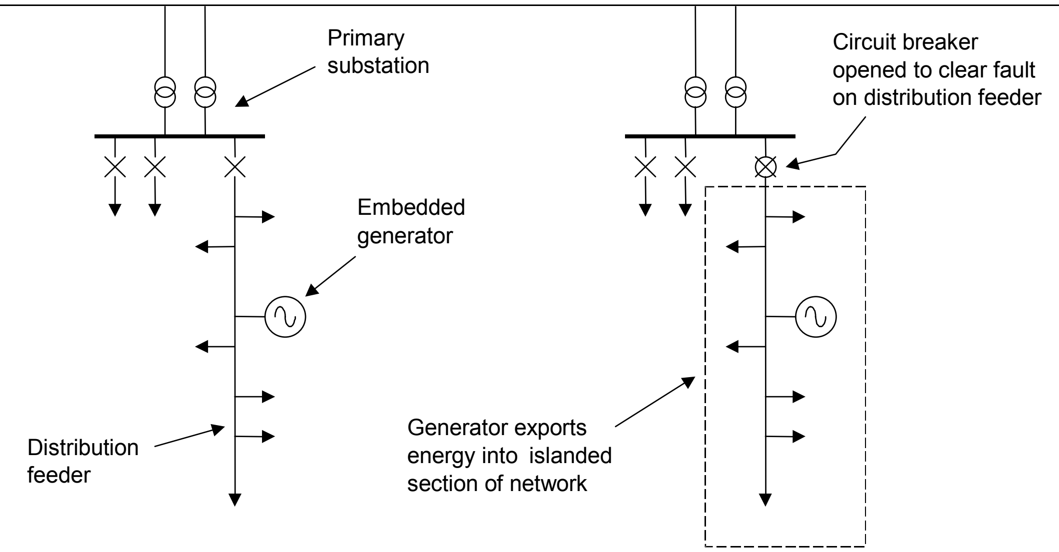
2) Reduction in the availability of power systems due to unnecessary tripping of DG: Existing loss-of-mains systems operate based on the measurement of the network parameters such as rocof and voltage vector shift. The measurement of such parameters often cause the loss-of-mains systems to trip off the DG even though there is no loss of mains. Such unwanted tripping of DG may reduce the quality of supply to the local DNO network if it has a network support role

3) Significant cost to generators due to unnecessary tripping of DG: The unnecessary tripping of DG will lead to the significant loss of generation over a period of time, hence causing the generation owners to suffer a significant reduction in their revenues in addition to an increased maintenance requirement due to 'crash stop'

4) Unclear ownership of loss-of-mains systems: As described previously, generators and DNOs will operate their own sets of loss-of-mains systems in power systems in order to protect their DG and electrical networks. However, under the current UK practices, generators are responsible for the costs of the loss-of-mains systems operated by DNOs, which is a source of dissatisfaction to the generators

Appendix C. Extract from ‘Assessment of Islanded Operation of Distribution Networks and Measures for Protection’

Islanding is the term used to describe a scenario involving a distribution network and one or more embedded generators (Figure C1a).



(a) Distribution network with embedded generator **(b) Islanding of distribution feeder**

Figure C1. Islanding of a distribution network section

In this scenario, a section of the network including the generator is disconnected from the main grid. During the period of disconnection, the embedded generator continues to operate with reasonably normal voltage and frequency and to export energy into the network “zone” to which it remains connected (Figure C1b). The term ‘islanding’ denotes this independent operation of a network zone, in isolation from the main grid and energised by an embedded generator.

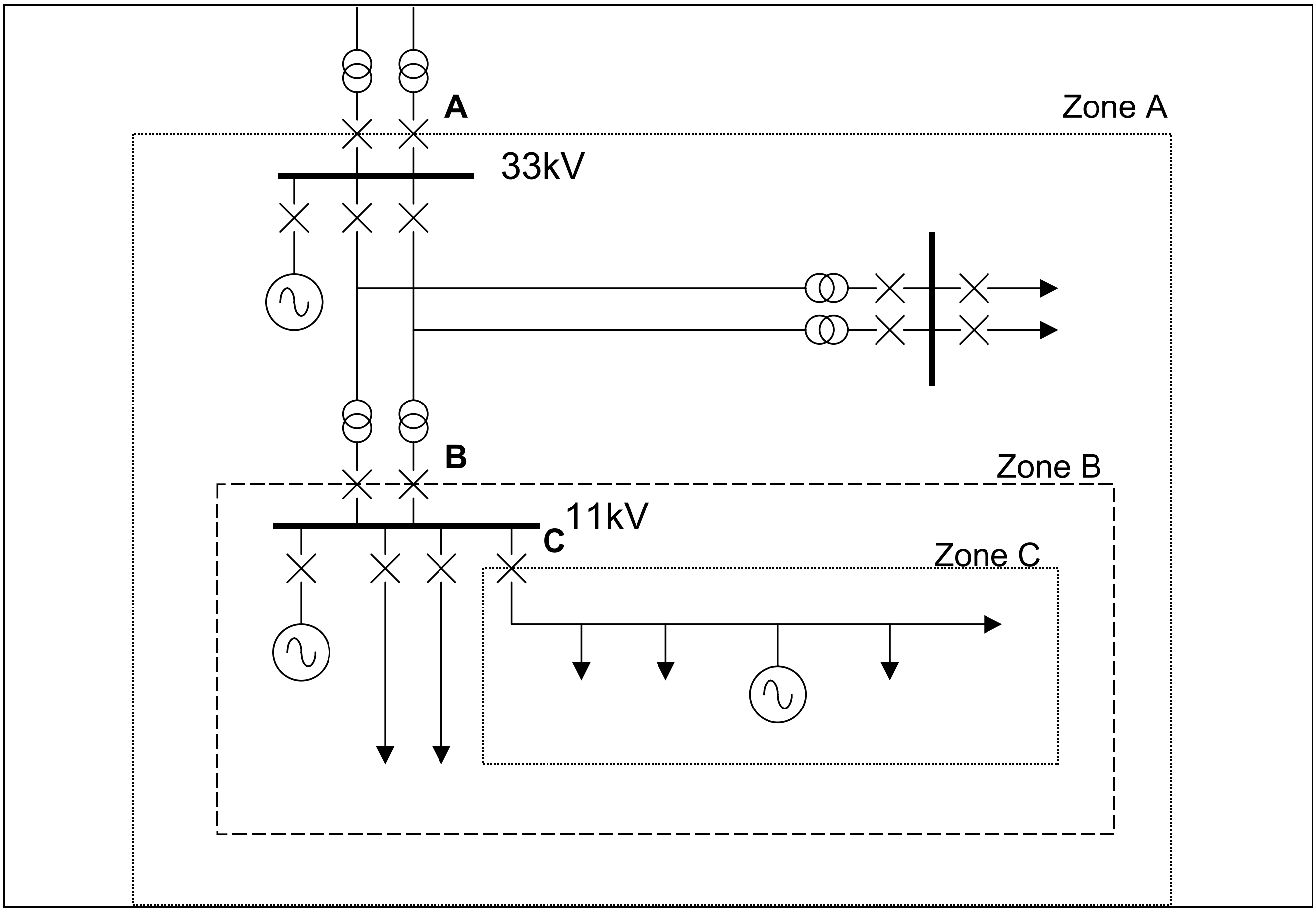


Figure C2. Possible zones of islanding

Each zone is associated with one or more points of disconnection. Figure C2 shows three zones of possible islanding and their corresponding disconnection point(s). This is not, by any means, the full extent of possible zones, which are principally defined by network protection and disconnection facilities. Further zones are created by remote devices such as pole mounted auto reclosers, drop-off fuses and sectionalisers.

The essential property of a sustained island is that the load and generation trapped within it are closely matched at the time of islanding or subsequently by automatic regulation. This means that the actual scope for islanding is limited by the penetration of embedded generation in the distribution network. The traditional grid with little or no embedded generation (Figure C3) did not provide much scope for islanding.

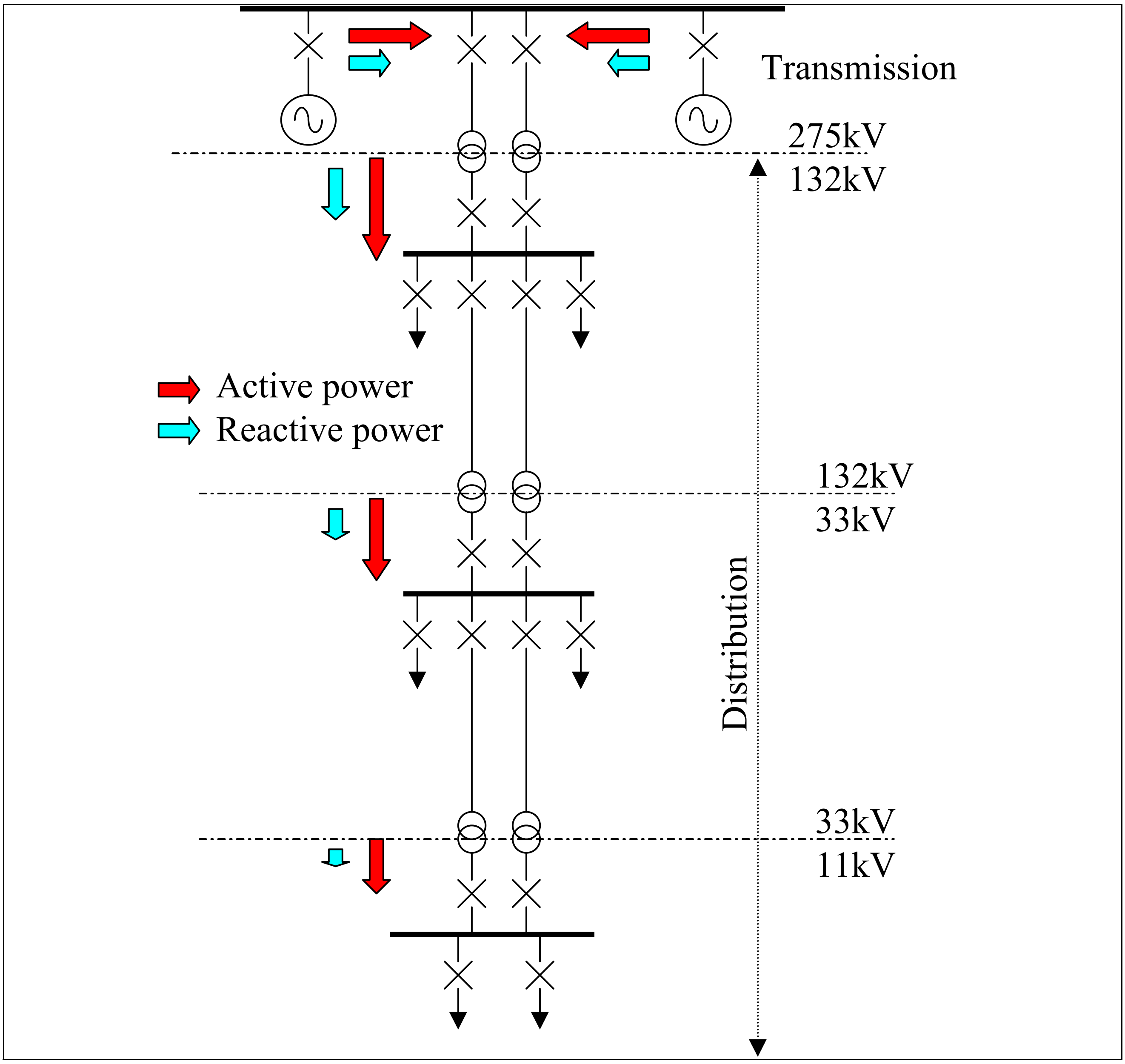


Figure C3. Power flows in a traditional network

However, the growth of embedded generation in recent years (such as that shown in Figure C4) has substantially increased the likelihood of sustained islanding and concerns associated with inadvertent island operation.

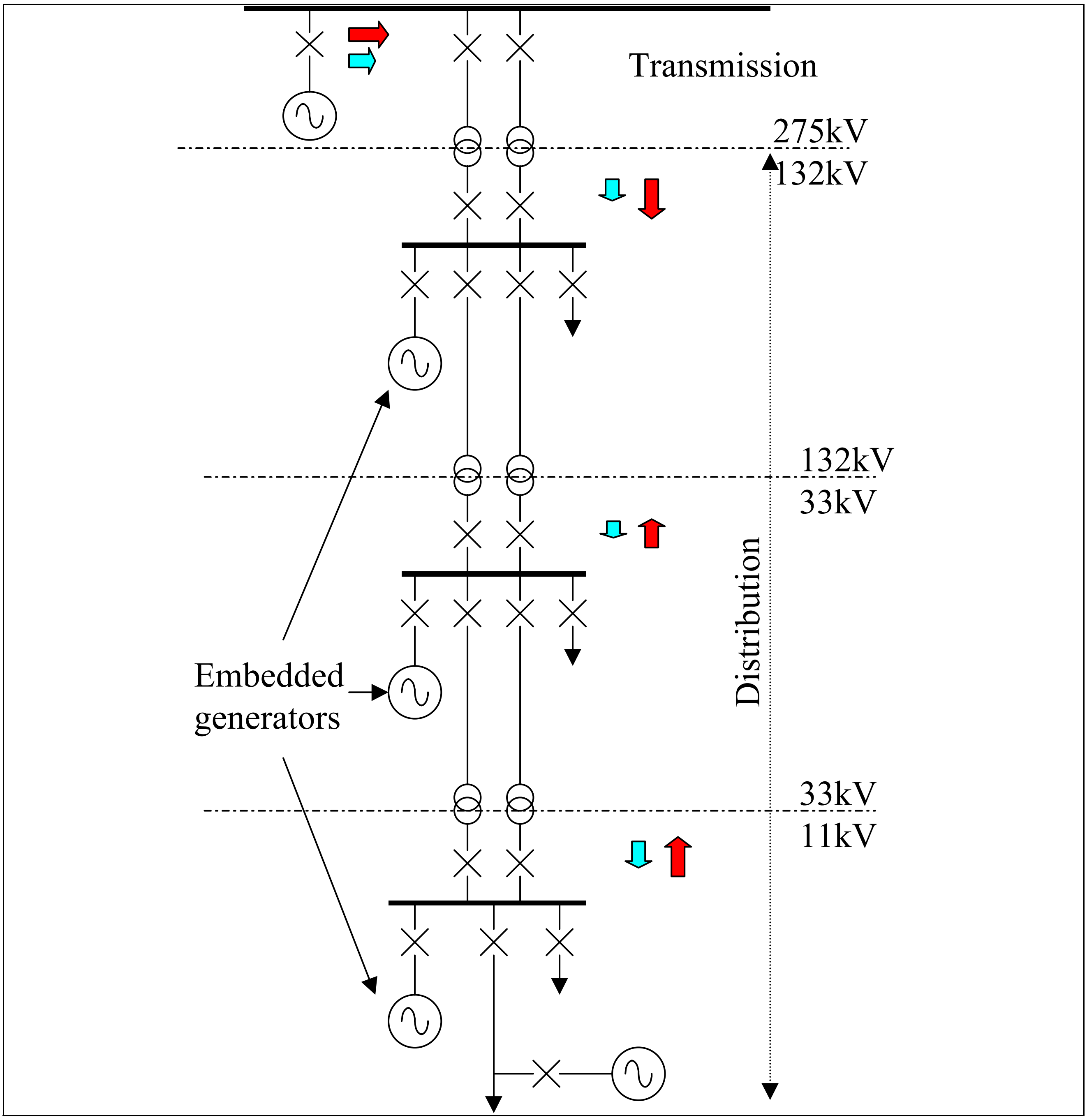


Figure C4. Power flows in a network with embedded generation

Appendix D. Generator characteristics

Table D1. Characteristics of various types of generators and the additional ancillary requirements to enable islanded operation

Generator			General Characteristics						Comments
Main	**Alternator**	**Mechanical**	**Fault Contribution (pu on rating)**			**Additional Ancillary Requirements to allow Islanded Operation**			
			Sub Trans	**Trans**	**Sync**	**Add'l Var'ble Q (kVAr)**	**Add'l Var'ble P (kW)**	**Govn'r (electronic or mech)**	
Diesel Generator	Synchronous	Reciprocating	6 – 8	4	3[D]	N	N	N	Stability @ low loads? Increased maintenance if extended low loading
Natural Gas	Synchronous	Reciprocating	6 – 8	4	3[D]	N	N	N	Stability @ low loads?
Natural Gas	Synchronous	Gas Turbine	6 – 8	4	3[D]	N	N	N	Stability @ low loads?
Landfill Gas	Synchronous	Reciprocating	6 – 8	4	3[D]	N	N	N	Stability @ low loads? Variations in gas quality may vary ability to support loads
Biomass	Synchronous	Reciprocating	6 – 8	4	3[D]	N	N	N	Stability @ low loads?
Steam (EFW)	Synchronous	Turbine	6 – 8	4	3[D]	N	N	N	Stability @ low loads?
Hydro	Induction		6 – 8	1	0	Y	Y[F]	Y	Hydraulic stability issues at certain load levels
Hydro	Synchronous		6 – 8	4	3[D]	N	Y[F]	Y	Hydraulic stability issues at certain load levels
Wind	Induction	Fixed Pitch	6	1	0	Y	Y	Y	Intermittent
Wind	Induction	Variable Pitch	6	1	0	Y	Y	Y	Intermittent
Wind	Induction, wound rotor	Variable Pitch	6[A]	1	0	Y	Y	Y	Intermittent

Wind	DFIG	Fixed Pitch	6^B	1	0	Y^E	Y	Y	Intermittent – Significant variation in ability to operate island according to inverter/ control design
Wind	DFIG	Variable Pitch	6^B	1	0	Y^E	Y	Y	Intermittent – Significant variation in ability to operate island according to inverter/ control design
Wind	100% Inverter Coupled	Variable Pitch	1^C	1^C	1^C	?	Y	N?	Intermittent
Wind	Synchronous	Fixed Pitch	6 – 8	4	3^D	N	Y	Y	Intermittent
Wind	Synchronous	Variable Pitch	6 – 8	4	3^D	N	Y	Y	Intermittent
PV	Direct Inverter Coupled		1^C	1^C	1^C	N	Y	N	Intermittent
Key									
A	Dependant on control to rotor winding								
B	Dependant on control of inverter and size of dc bus capacitor								
C	Dependant on control/ protection of inverter								
D	Assumes AVR boost function incorporated (3 x FLC for 10 s), otherwise <1PU								
E	DFIG can provide high levels of reactive power internally, but required functionality may need to be specified with order								
F	Dependant on flow rate and/ or available storage								

Appendix E. System (A) generator & load parameters

Grid fault level at 11kV bus: 134MVA

Parameters	GA1, GA2	GB1-GB3	GC1-GC3
Xd (p.u.)	1.7	2.26	2.56
Xd’ (p.u.)	0.328	0.19	0.21
Xd’’ (p.u.)	0.188	0.14	0.15
Xq (p.u.)	0.88	1.3	1.9
Xq’’ (p.u.)	0.172	0.12	0.28
Xl (p.u.)	0.05	0.05	0.04
Td’ (short-ckt) (s)	0.29	0.33	0.29
Td’’ (s)	0.03	0.03	0.03
Tq’’ (s)	0.03	0.03	0.03
Rs (p.u.)	0.003	0.003	0.003

Table E1. Generator electrical parameters

Dynamic load (i.e. induction motor) data

Xls: 0.04775 Rs: 0.01379 Xlr: 0.04775

Rr: 0.007728 Xm: 2.416 H: 0.2236 s

Pole pairs: 2

Appendix F. Simulation of single gas turbine generator – single load system

The system consists of a single 1.8MVA, 415V and 50Hz gas turbine unit supplying a constant impedance load of 1.62MW at power factor 0.9 lagging. Initial outputs of the governor and AVR are set so that the terminal voltage and frequency prior to the disturbance are at the nominal values (415V and 50Hz). The generator parameters are the same as those of GC1-GC3 unit in System A. The governor and AVR parameters in per unit are also the same for all gas turbine generators.

Transient simulation results are shown in Figure F1. Suppose 80% of the load is lost at t=5 second. Such a disturbance sends the terminal voltage and system frequency (generator speed) into oscillation. They eventually settle down to new steady state values. The maximum transient surges of the voltage and frequency are 9% and 6% respectively. The voltage and frequency in the new steady state both exceeds their pre-event values. This is attributed to the droop characteristic of the governor and load current compensation in the AVR. Figure F1 also shows the response of the governor and AVR.

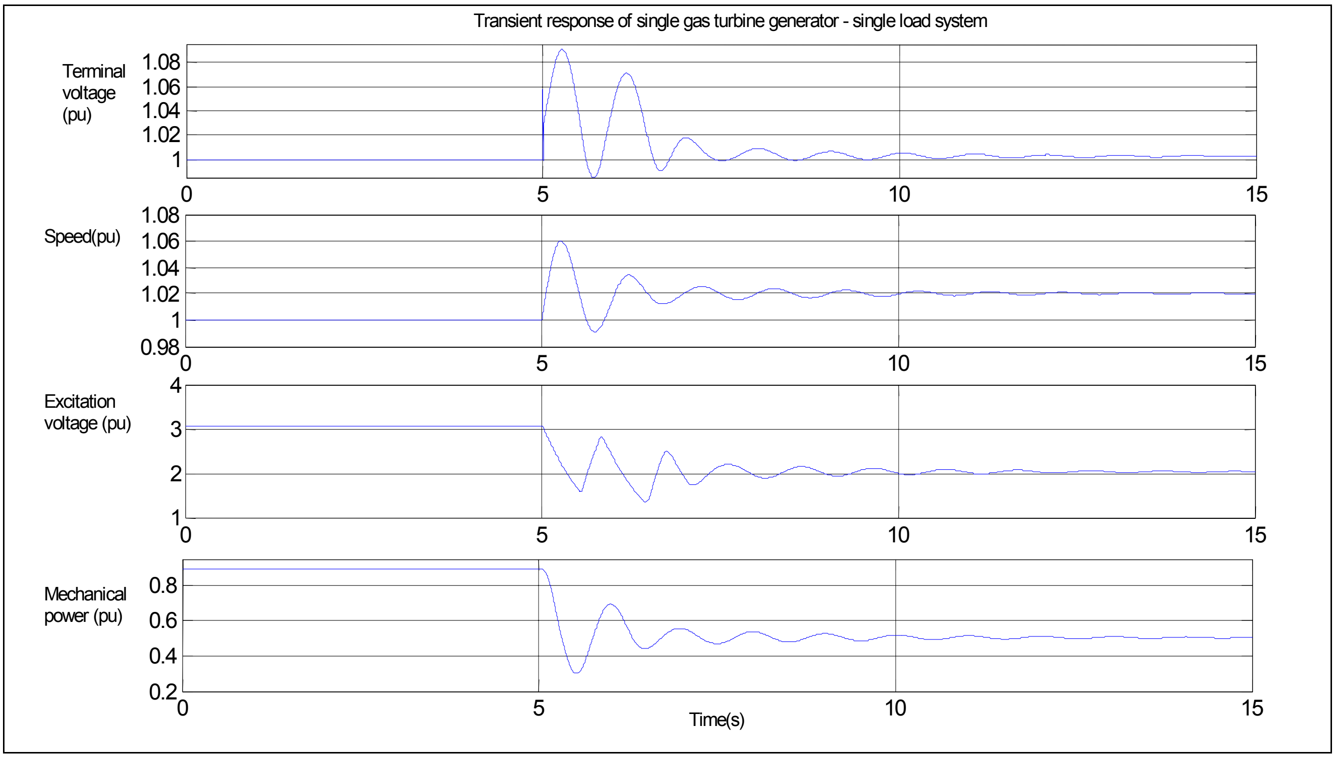


Figure F1. Simulation of single gas turbine generator – single load system

Appendix G. Induction Motor Load Responses

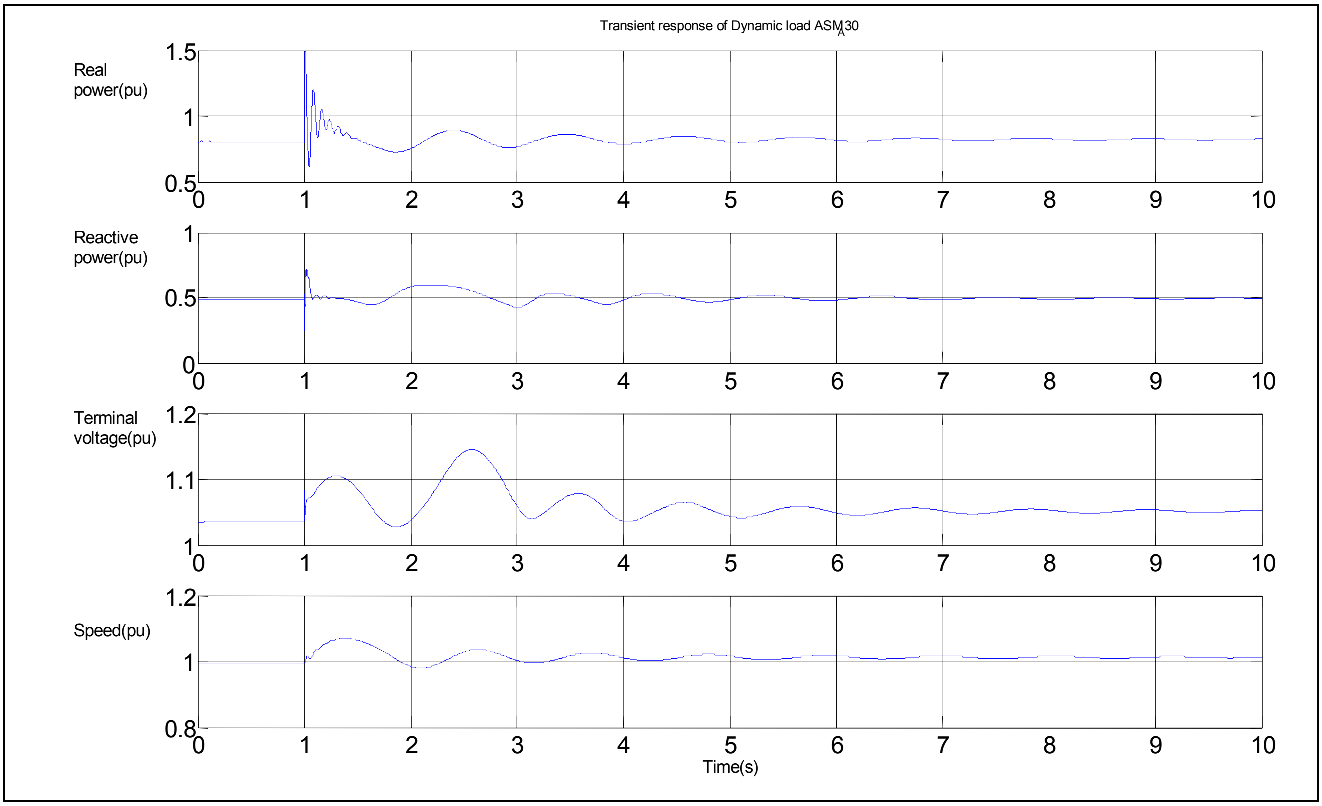


Figure G1. Transient response of induction motor in Feeder A, System A

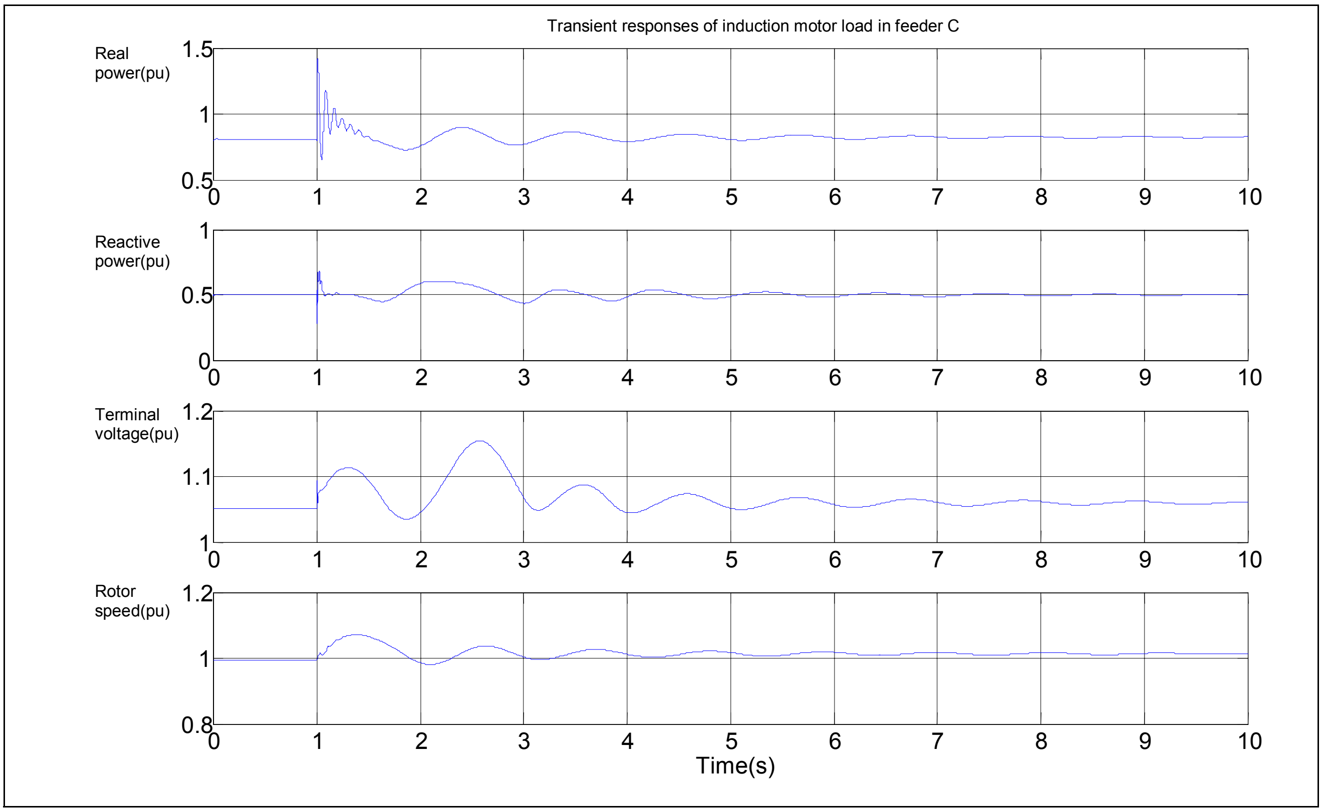


Figure G2. Transient response of induction motor in Feeder C, System A

Appendix H. System (B) generator parameters

Fault level at 11kV bus: 90MVA

Parameters	No. 1, 2, 3, 4, 5, 6, 7
Xd (p.u.)	1.56
Xd’ (p.u.)	0.296
Xd’’ (p.u.)	0.177
Xq (p.u.)	1.06
Xq’’ (p.u.)	0.177
Xl (p.u.)	0.052
Td’ (short-ckt) (s)	3.7
Td’’ (short-ckt) (s)	0.05
Tq’’ (open-ckt) (s)	0.05
Rs (p.u.)	0.0036

Table H1. Generator parameters

Appendix I. Simulation of single diesel generator – single load system

The system consists of a single 2.2MVA, 11kV and 50Hz diesel engine unit initially supplying a constant impedance load of 1MVA at power factor 0.9 lagging. The per unit parameters of the generator are the same as those for the units in System B. The governor model and its per unit parameters are also the same for all diesel units.

At t=5 second, the load demand is doubled. The generator terminal voltage and frequency (speed) respond to such a disturbance as shown in Figure A5.4. In this case, both voltage and frequency first sag significantly before recovering under the effects of the governor and AVR. The maximum dips for voltage and frequency are 16% and 14% respectively, which of course depend on the response time of the regulators.

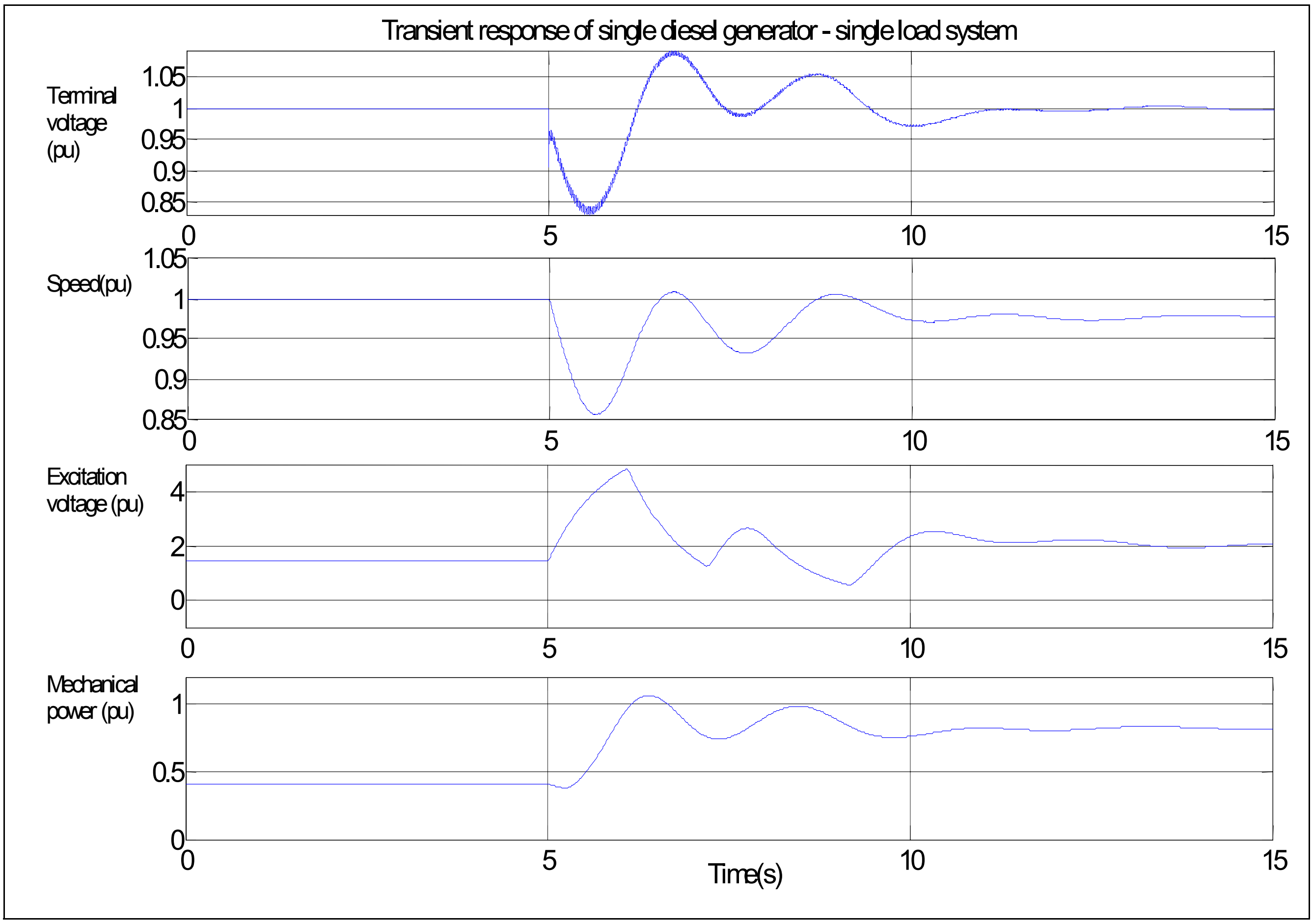


Figure I1. Simulation of single diesel generator - single load system

Appendix J. Summary of Supply Characteristics required by Electricity Safety Quality and Continuity Regulations

Parameter	Nominal	Minimum	Maximum
Frequency	50Hz (+/- 1%)	49.5Hz	50.5Hz
Voltage (LV)	230V (+10%/-6%)	216V	253V
Voltage (11kV)	11kV(+/-6%)	10.34kV	11.66kV
Voltage (33kV)	33kV (+/-6%)	31.02kV	34.98kV

Table J1. ESQCR supply requirements

Appendix K. Summary of BS EN 50160 'Voltage Characteristics of Electricity supplied by Public Distribution Systems' criteria

Supply Voltage Phenomenon	Acceptable Limits	Measurement Interval	Monitoring Period	Acceptance Percentage
Grid Frequency	49.5Hz to 50.5Hz 47Hz to 52Hz	10s	1 Week	95% 100%
Slow Voltage Changes	230V +/- 10%	10min	1 Week	95%
Voltage Sags or Dips (<=1min)	10 to 1000 times per year (under 85% of nominal)	10ms	1 Year	100%
Short Interruptions (<= 3min)	10 to 100 times per year (under 1%of nominal)	10ms	1 Year	100%
Accidental, Long Interruptions (> 3min)	10 to 50 times per year (under 1% of nominal)	10ms	1 Year	100%
Temporary Over-Voltages (Line to Ground)	Mostly < 1.5kV	10ms	N/a	100%
Transient Over – Voltages (Line to Ground)	Mostly < 6kV	N/a	N/a	100%
Voltage Unbalance	Mostly 2% but occasionally 3%	10min	1 Week	95%
Harmonic Voltages	8% Total Harmonic Distortion	10min	1 Week	95%

Table K1. BS EN 50160 voltage requirements

Appendix L. Electricity Supply Industry (ESI) Documents for Distributed Generation

The following documents were prepared by the Electricity Association to assist the DNO planning engineers in devising connection requirements for incorporating DG onto their networks.

Document Reference No	Issued	Title
Engineering Recommendation G59/1	1991 (latest amend '95)	Recommendations for the Connection of Embedded Generating Plant to Public Electricity Suppliers' Distribution Systems (at or below 20kV, or with Outputs of 5MW or less)
Engineering Recommendation G75/1 Iss 2	2002	Recommendations for the Connection of Embedded Generating Plant to Public Electricity Suppliers' Distribution Systems above 20kV or with Outputs over 5MW
Engineering Technical Report No 113 (Rev 1)	1995	Notes of Guidance for the Protection of Embedded Generation Plant up to 5MW for Operation in Parallel with Public Electricity Suppliers' Distribution systems

Table L1. Key electricity industry documents relating to DG

Notes:

1) The Energy Networks Association (ENA) assumed responsibility for issue and future revision of these documents in October 2003, following the dissolution of the Electricity Association

2) References currently remain referring to the Electricity Supply Regulations. These regulations have been replaced by the ESQC Regulations 2002

G59/1 and ETR113/1 were prepared at the early stages of development of DG schemes under private ownership (separate from the electricity supply industry), and were intended to establish a framework under which the impact of introducing sources of energy at distribution levels could be managed, and appropriate interface protection agreed between the DNO and the DG developer. These documents are inter-related and are identified sources of reference within the various Distribution Codes applying within GB.

G59/1 is read in conjunction with ETR113 and is directed at the smaller DG schemes. It specifies the issues that must be considered (e.g. earthing, synchronising, connection and disconnection and communication). It generally requires DG projects to trip the generation in the event of system abnormalities, the main concern being that an (unintentional) island may be created during the clearance of a fault which may either be a direct source of danger or, where reclosing facilities are incorporated in the DNOs network, an out of phase reconnection may occur. The measured parameters used in detecting abnormalities include voltage and frequency thresholds and detection of Loss of Mains (LoM). The following settings are those in G59/1 as typically recommended for LV interface protection.

Protection	Phase	Trip Setting	Total Tripping Time (incl CB operating time)
Under Voltage	All	-10% (phase – neutral)	0.5s
Over Voltage	All	+10% (phase – neutral)	0.5s
Under Frequency	One	-6%	0.5s
Over Frequency	One	+1%	0.5s

Table L2. Protective equipment and settings for LV supply arrangements

These LV figures are typically used as a starting point for negotiating suitable levels for HV connected schemes. Loss of Mains (LoM) protection is frequently added to the above, typically detecting either a rate of change of frequency, or alternatively a transitionary shift in the load angle (e.g. vector shift). Typical values in the UK are 0.5Hz/s and 12 degrees respectively.

One or more of the above conditions are typically experienced when faults are occurring on the section of network. However, spurious trips are also experienced, particularly from LoM relays, which can operate for GB events such as the loss of a major power station or interconnector. This results in cascade tripping of a number of DG schemes, which aggravates the impact of the major power station loss.

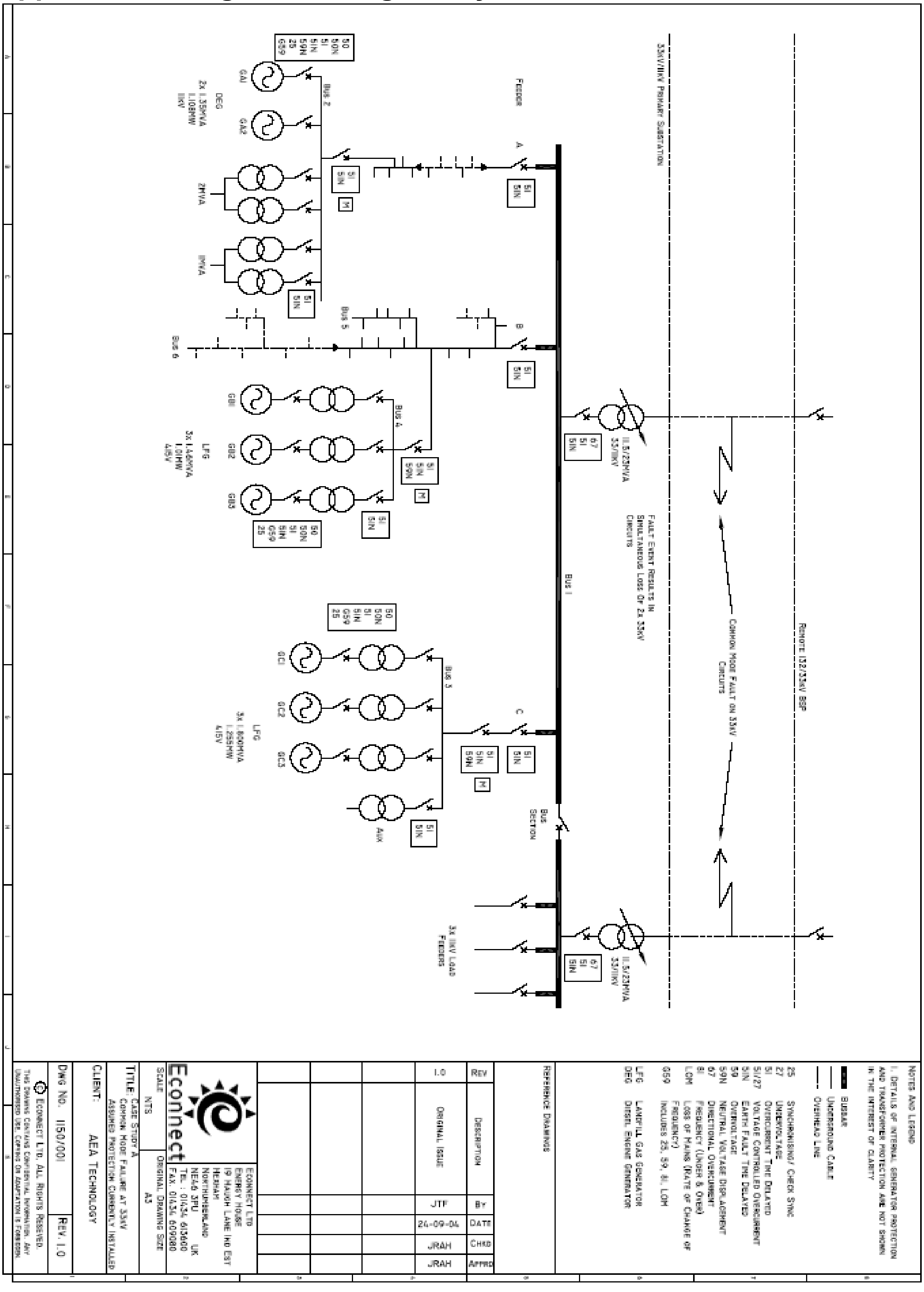
It is stressed that G59/1 and ETR113/1 are recommendations and notes of guidance to aid negotiations with DG developers rather than prescriptive. Indeed clear reference is made within G59/1 that the ETR 113 "...is a guidance document and is not intended to preclude innovation or mutual agreement on alternative means of meeting the [safety and technical] requirements".

The degree of negotiation available between the DG and DNO can be variable, however significant variations in setting and trip times have been agreed on some DG schemes with no serious effects.

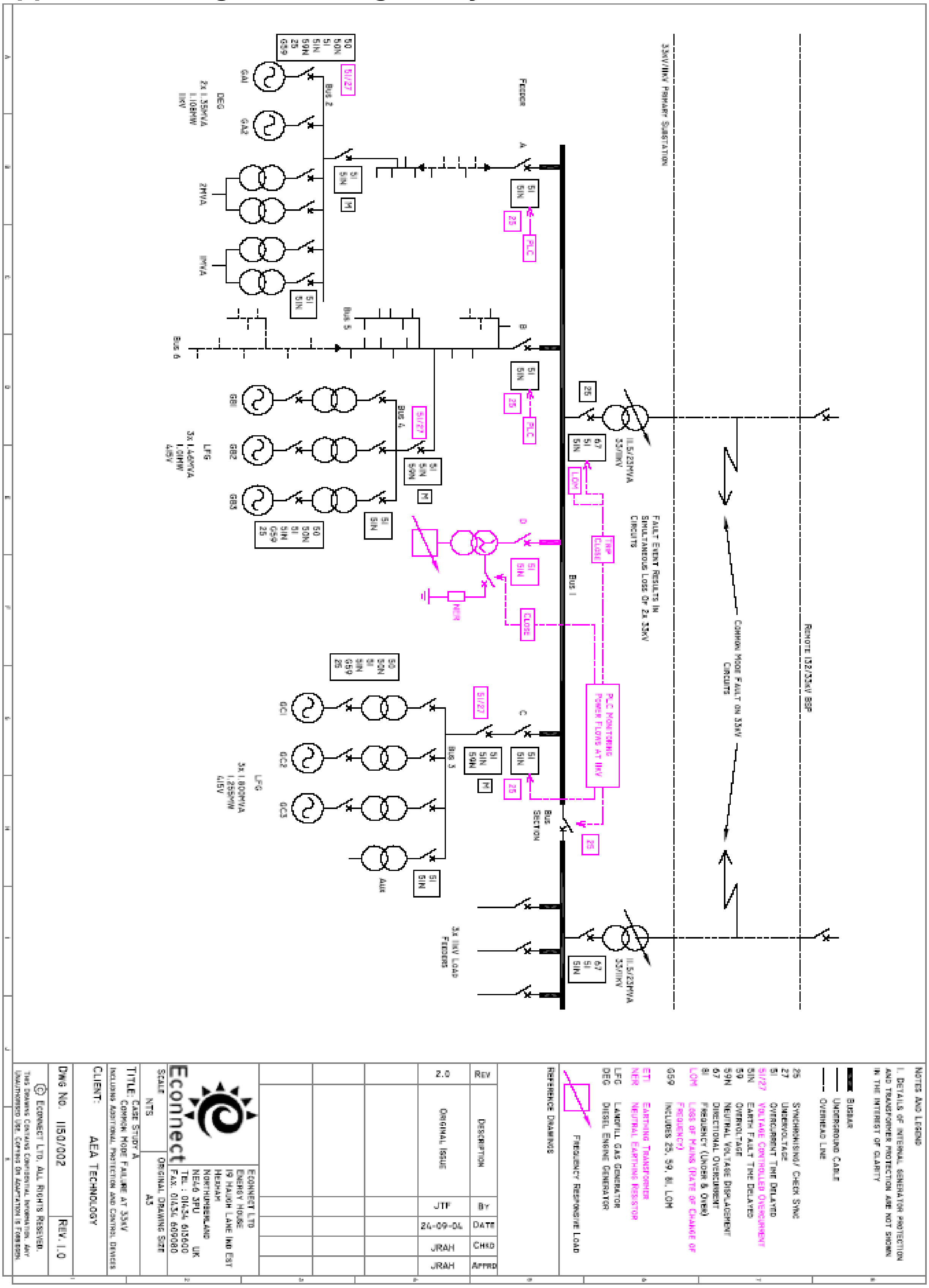
Some DNOs have developed policies, which require that DG be fitted with inter-trip signalling from the primary substation rather than the voltage and frequency relays noted above. This carries a cost of ~£30 – 40k, but reduces the number of spurious trips.

G75/1 recognises the contribution that larger scale DG makes to the GB energy supply, and the negative impact on grid stability if large-scale DG cascade trips on loss of a major power station. It focuses on the need for the DG facility to have a greater resilience to tripping on external fault conditions, although this naturally requires that the local DNO network design can accommodate this without undue danger. Acceptable levels of resilience are also the focus of recently developed Grid Codes, which demand that DG "rides through" onerous short-circuit transmission faults.

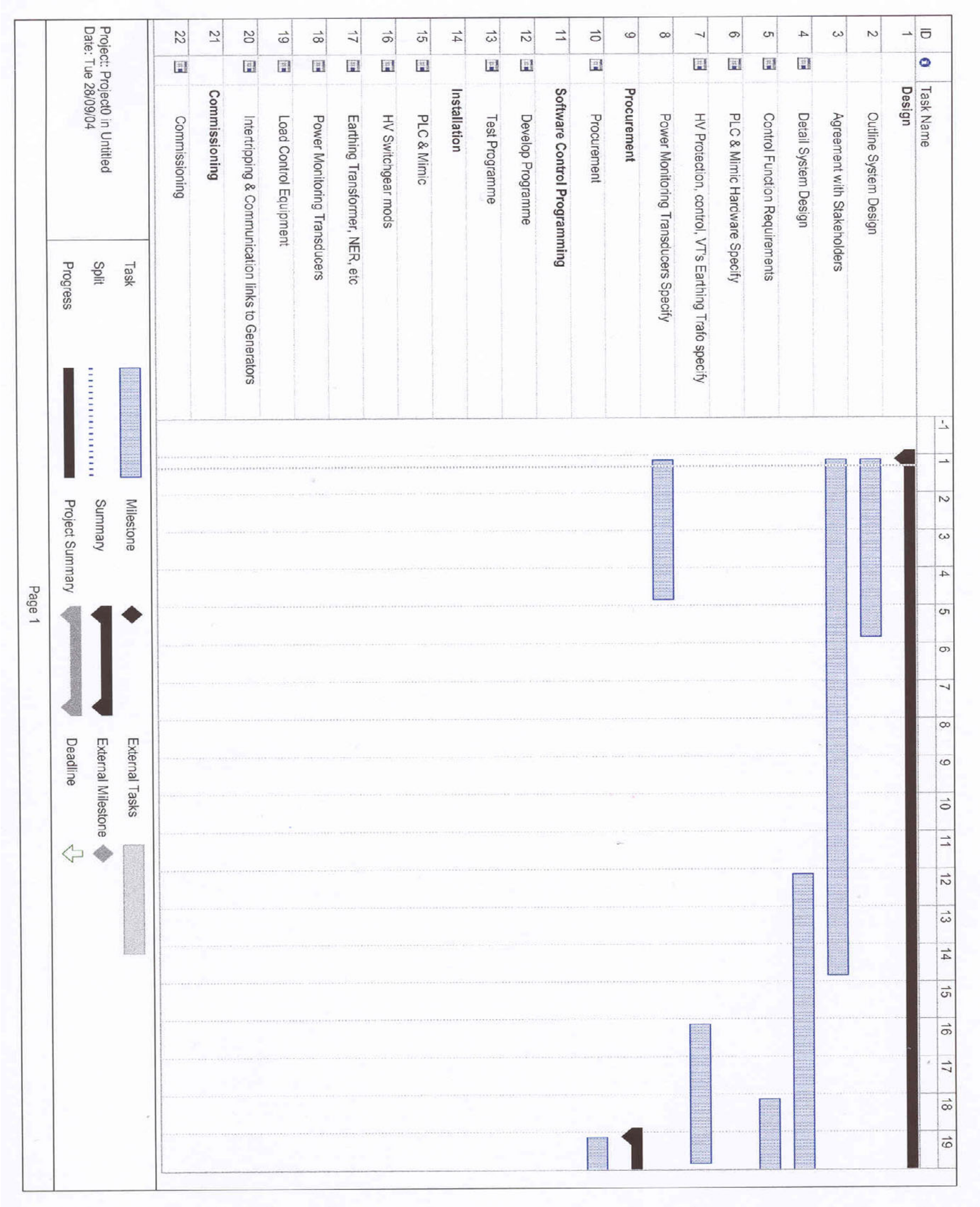
Appendix M. Single Line Diagram System A Pre-modification

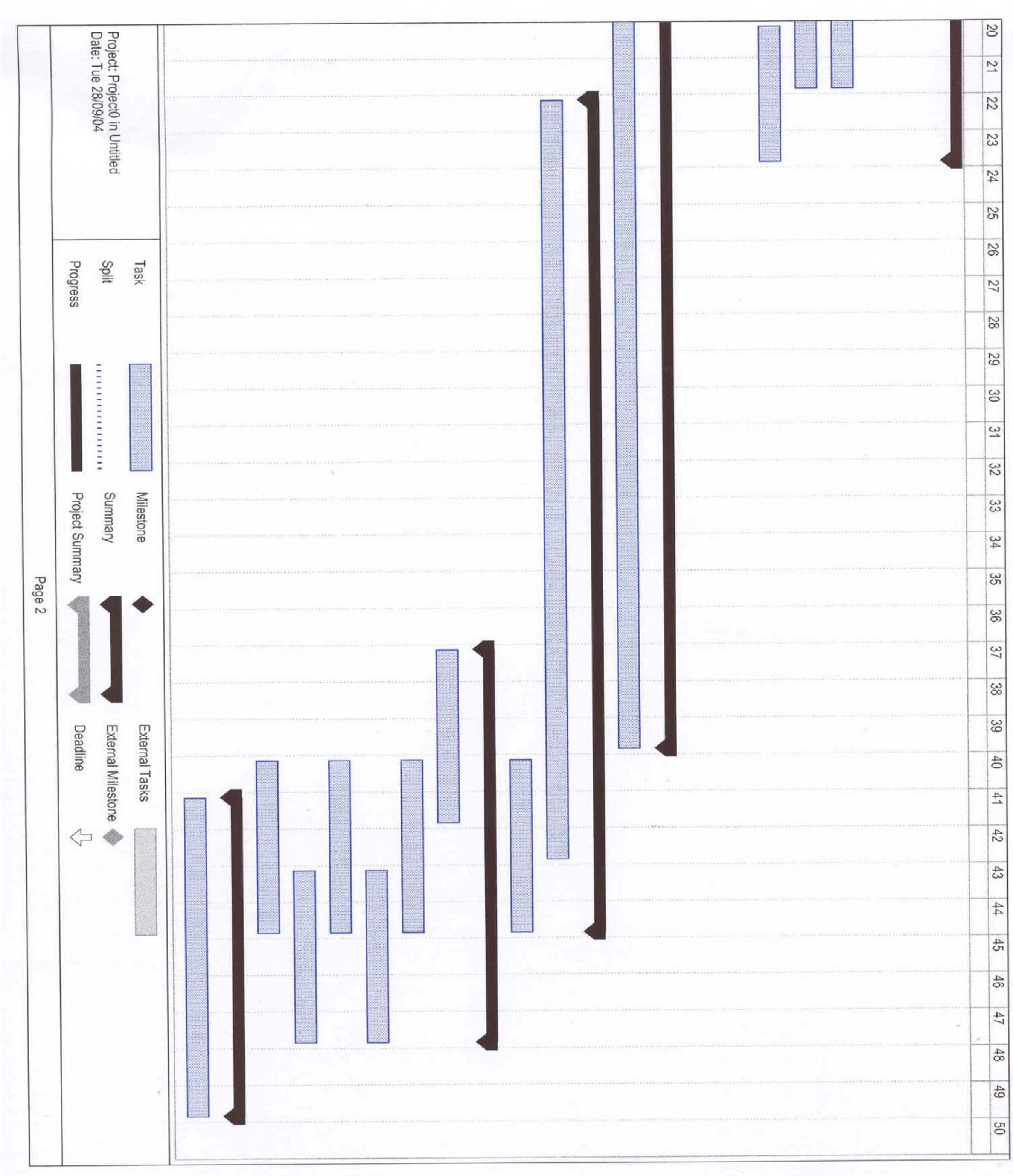


Appendix N. Single Line Diagram System A Post-modification



Appendix O. System A Implementation Project Plan

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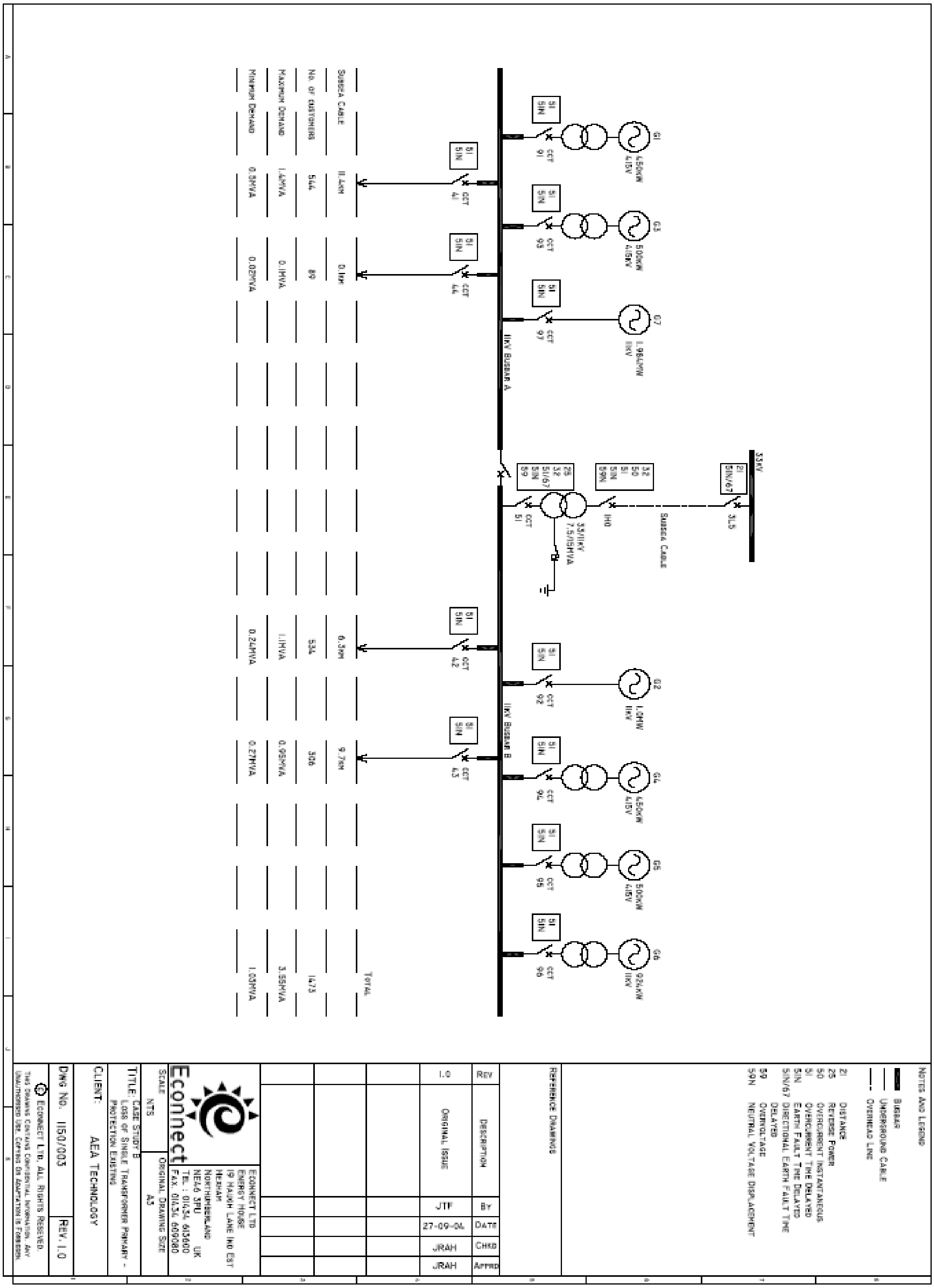
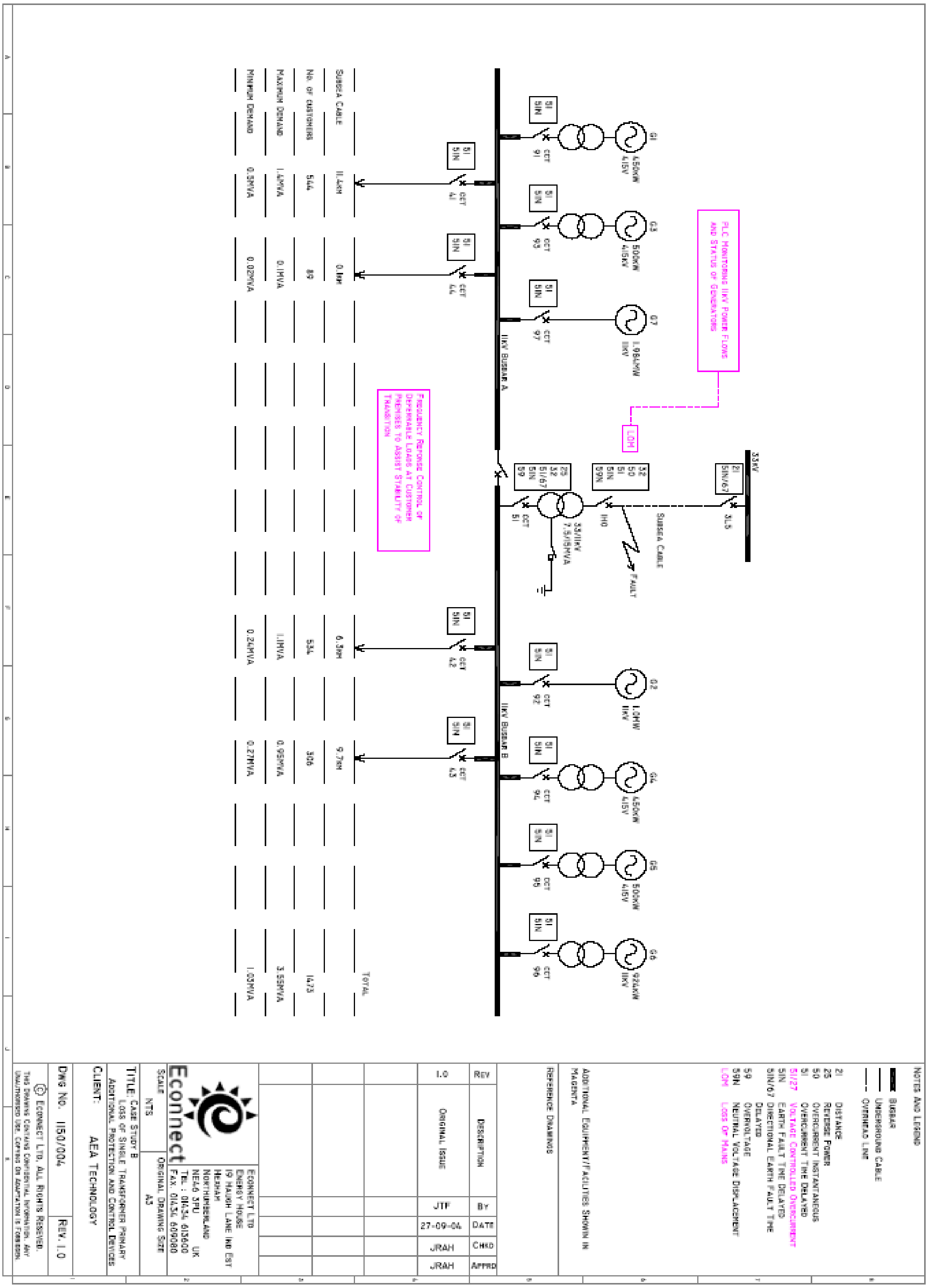
Project: Project0 in Untitled
Date: Tue 28/09/04
Task
Split
Progress
Milestone
Summary
Project Summary
External Tasks
External Milestone
Deadline
Page 2

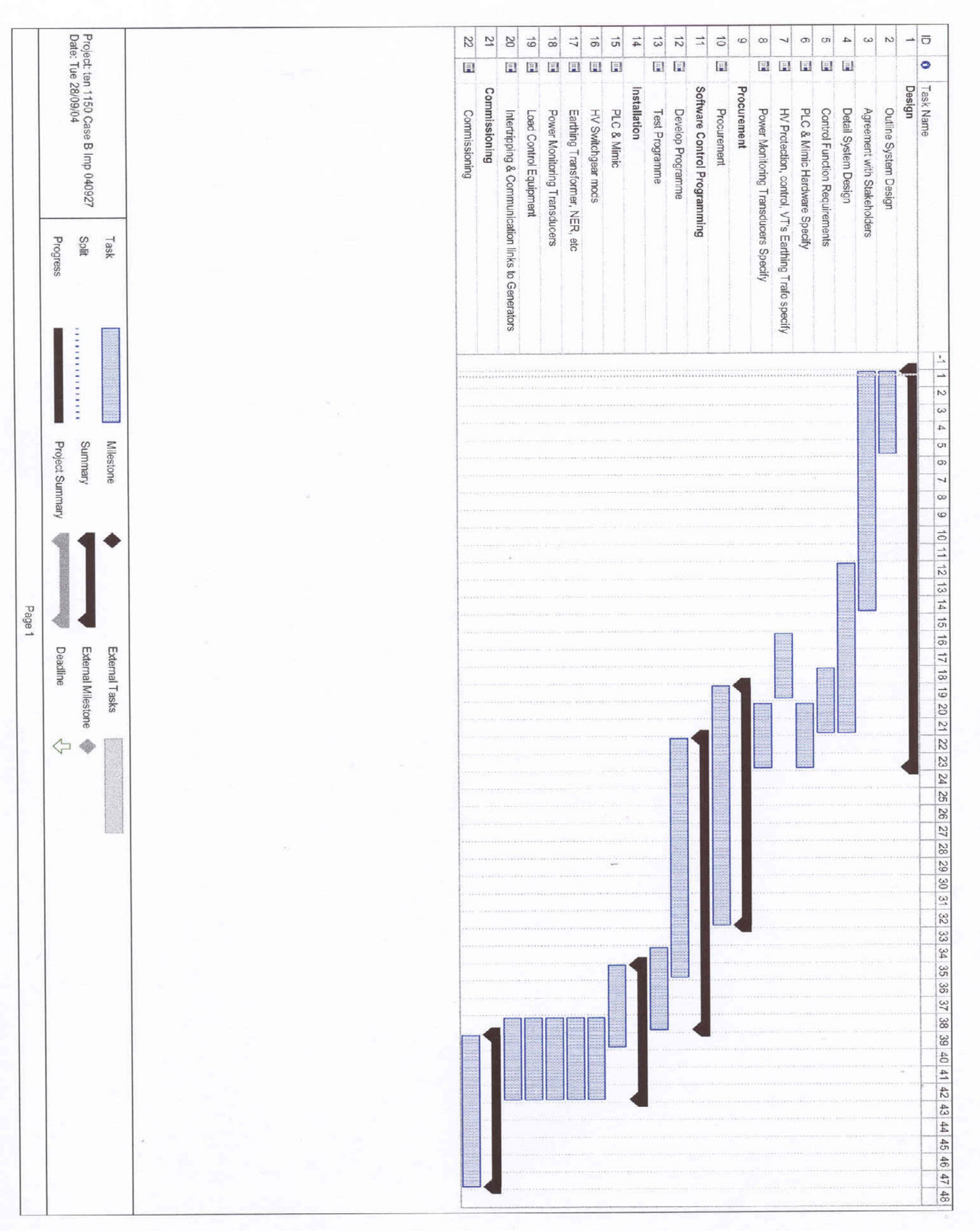
Appendix P. Single Line Diagram System B Pre-modification



Appendix Q. Single Line Diagram System B Post-modification



Appendix R. System B Implementation Project Plan



Appendix S. Definition of acronyms

ANN	Artificial Neural Network
AVR	Automatic Voltage Regulator
BETTA	British Electricity Transmission & Trading Arrangements
BSC	Balancing Settlement Code
CB	Circuit Breaker
CCTV	Closed Circuit Television
CHP	Combined Heat and Power
CI	Customer Interruptions
CML	Customer Minutes Lost
CO_2	Carbon Dioxide
CVA	Central Volume Allocation
DCHP	Domestic Combined Heat and Power
DEG	Diesel Generator
DG	Distributed Generation
DNO	Distribution Network Operator
DPCR	Distribution Price Control Review
DSM	Demand Side Management
DTI	Department of Trade and Industry
EDF	Electricite de France
EPN	Eastern Power Network (subsidiary of EdF Energy)
ESQCR	Electricity Safety, Quality and Continuity Regulations
GSP	Grid Supply Point
HH	Half-Hourly
HV	High Voltage
IDMT	Inverse Definite Minimum Time
IFI	Innovative Finance Initiative
IIP	Information and Incentives Project
LV	Low Voltage
NETA	New Electricity Trading Arrangements
NGT	National Grid Transco
NHH	Non-Half-Hourly
NVD	Neutral Voltage Displacement
PLC	Programmable Logic Control
rocof	Rate of change of frequency

RPZ	Registered Power Zone
SBP	System Buy Price
SCADA	Supervisory Control & Data Acquisition
SLD	Single Line Diagram
SSE	Scottish and Southern Electricity Ltd
SSP	System Sell Price
SVA	Supplier Volume Allocation
SVC	Static VAr Compensator
TMS	Time Multiplier Setting
TSG	Technical Steering Group
TSO	Transmission System Operator
UPS	Uninterrupted Power Supply
UU	United Utilities
WPD	Western Power Distribution
WS5	Work Stream 5
YEDL	Yorkshire Electricity Distribution Ltd