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HEAT AND POWER FOR BIRMINGHAM

SUCCESSFUL DELIVERY REWARD CRITERIA REPORT
SIMULATING AND APPLYING ENHANCED FAULT LEVEL ASSESSMENT PROCESSES

LCN Fund Low Carbon Networks

THE UNIVERSITY OF WARWICK

PARSONS BRINCKERHOFF

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Contents

Glossary

Abbreviation	Description
CHP	Combined heat and power
DFIG	Doubly-fed induction generation
DNO	Distribution network operator
EFLA	Enhanced fault level assessment
EHV	Extra high voltage
ENA	Energy Networks Association
ER	Engineering Recommendation
ESQCR	Electricity safety, quality and continuity
ETR	Engineering Technical Report
FCL	Fault current limiter
FLM	Fault level monitor
FLMT	Fault level mitigation technology
GSP	Grid supply point
GT	Grid transformer
HV	High voltage
LCNF	Low Carbon Networks Fund
LV	Low voltage
NOP	Normally open point
Ofgem	The Office of Gas and Electricity Markets
OHL	Overhead line
PF	Power factor
PSS/E	Power System Simulator for Engineering
pu	Per unit
rms	Root mean square
SDRC	Successful Delivery Reward Criteria
SGT	Supergrid transformer
SI	Short interruption
WPD	Western Power Distribution

1 Introduction

1.1 FlexDGrid Project Overview

FlexDGrid offers an improved solution to the problem of the timely and cost-effective integration of customers' generation and demand within urban high voltage (HV) electricity networks. The project seeks to explore the potential benefits arising from the demonstration of three complementary methods: (Alpha) Enhanced Fault Level Assessment; (Beta) Real-time Management of Fault Level; and (Gamma) Fault Level Mitigation Technologies. The project location is Birmingham. This project aims to deliver a highly transferrable system-level solution, using real-time knowledge of the fault level status of the electricity network and application of fault level mitigation technologies (FLMTs), to manage multiple generation and demand connections. The learning will be transferrable to all Great Britain (GB) networks. The FlexDGrid solution has the potential to deliver £1Bn savings across GB through the avoidance of network reinforcement and safeguarding of electricity network assets. This could facilitate 6 GW of generation connections and offset 5.05 $MtCO_2$ / year.

FlexDGrid is being delivered by Western Power Distribution, in collaboration with Parsons Brinckerhoff and the University of Warwick, and supported by Cofely District Energy and Birmingham City Council.

1.2 Objectives and scope

This document fulfils the fourth Successful Delivery Reward Criterion (SDRC) of FlexDGrid “Simulation and application of an enhanced fault level assessment process” (SDRC-4). The purpose of this document is to demonstrate what can be achieved with customers’ connections (increased capacity released and quicker connection times at reduced connection costs) by implementing a number of enhancements to WPD’s present fault level assessment process. A full list of the SDRCs is given in the FlexDGrid Project Direction from Ofgem[1].

The scope of the enhanced fault level assessment process is defined in SDRC-1, aiming to provide customers with a variety of connection options depending on how quickly they require connection to the network and the cost of the connection. This SDRC presents the results from the initial demonstrations of Method Alpha. Further results of the demonstration process will be reported in two other SDRCs, as listed below:

1. SDRC-10: Analysis of test results, evaluating and quantifying benefits of the FlexDGrid solution and applicability to GB HV electricity networks (31 December 2016); and
2. SDRC-11: Development of novel commercial frameworks with generation and demand customers (31 March 2017).

FlexDGrid is focused on calculation, modelling and simulation methods that are used by DNOs to assess HV (11kV and 6.6kV) distribution network fault levels. FlexDGrid is particularly focused on fault levels within urban environments where synchronous generation is currently connected or expected to be connected in the future as electricity and heating systems are decarbonised.

[1] Project Direction ref: WPD/ FLEXDGRID – Advanced Fault Level Management in Birmingham, 21 December 2012.

1.3 Identification of EFLA Processes

The processes, which have been developed in the initial phase (Phase 1) of FlexDGrid and which were identified in the SDRC-1 report[2], are outlined below:

1. Baseline the consistency of application of present fault level assessment methods;
2. Explore assumptions and carry out a parametric sensitivity analysis of present fault level standard calculation methods;
3. Increasing the frequency of fault level assessments and granularity of fault levels within HV electricity networks;
4. Network design and deployment of fault level monitoring technologies;
5. Network design and deployment of fault level mitigation technologies; and
6. Connection offers based on novel commercial frameworks.

These processes will be evaluated throughout the project and the comparison of results from models and results from practical deployments will be reported as outputs of SDRC-10 (Analysis of results) and SDRC-11 (Development of novel commercial frameworks). This SDRC relates to the modelling aspects of Methods Alpha, Beta and Gamma, which have been simulated and applied to Birmingham's HV network as part of FlexDGrid.

1.4 Background

1.4.1 Fault level definition

Various definitions of fault level have been produced by industrial, academic and regulatory stakeholders. For the purpose of the FlexDGrid project, fault level has been defined in the following way:

Fault level is a measure of electrical stress when an unintentional conducting path (fault) causes a short circuit. This causes high "fault currents" to flow in the electricity lines, cables and substation equipment. The amount of fault current varies from location to location, depending on how close it is to the energy source (for example a transformer or generator).

A fault (short circuit) occurs when one electrical component contacts another, intended to be at a different voltage level. This allows an electrical current to flow along an undesired, often negligible, impedance path.

The short circuit currents can be orders of magnitude larger than the normal operating current. For example HV fault currents can typically be 10kA – 15kA, whilst load current may be 0.1kA – 0.6kA. Examples of unintentional conducting paths (faults) in a 3-phase system are given in Figure 1-1. Common sources of faults include lightning strikes, manufacturing defects, a tree branch falling on to an overhead line or a digger cutting through a cable.

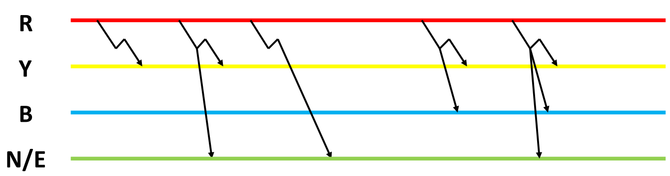

Figure 1-1 - Examples of unintentional conducting paths (faults) in a 3-phase system

[2] Successful Delivery Reward Criteria Report "Development of Enhanced Fault Level Assessment Processes (SDRC-1)", FlexDGrid, Western Power Distribution and Parsons Brinckerhoff, submitted to Ofgem on 28 May 2013.

1.4.2 Substation identification

FlexDGrid's second Successful Delivery Reward Criteria Report (Confirmation of the Project Detailed Design)[3], detailed the methodology which was applied to determine the ten substations for implementation of Method Beta and five substations for implementation of Method Gamma. Table 1-1 summarises the substations that were selected and the technologies that will be demonstrated in each particular substation. Figure 1-2 shows the geographical location of the substations in Birmingham which have been selected for technology demonstrations. System studies have been based on models of the HV network connected to these substations.

SDRC-2	Substation Name	Technology
Substation A	Kitts Green 132/11kV	Fault level mitigation and fault level
Substation B	Castle Bromwich	Fault level mitigation and fault level
Substation C	Chester Street	Fault level mitigation and fault level
Substation D	Bournville 132/11kV	Fault level mitigation and fault level
Substation E	Sparkbrook 132/11kV	Fault level mitigation and fault level
Substation F	Hall Green 132/11kV	Fault level monitoring
Substation G	Elmdon 132/11kV	Fault level monitoring
Substation H	Chad Valley 132/11kV	Fault level monitoring
Substation I	Perry Barr 132/11kV	Fault level monitoring
Substation J	Winson Green	Fault level monitoring

Table 1-1 Substation identification key

Figure 1-2 Substation locations in Birmingham

The substations listed above were selected based on a scoring system that identified the suitability of each particular site to accommodate fault level monitoring and mitigation technologies. Details of the selection process for each substation are provided in SDRC-2 (Confirmation of project detailed design) and SDRC-6 (Evidencing the Methodology of Method Gamma).

[3] Successful Delivery Reward Criteria Report "Confirmation of the Project Detailed Design (SDRC-2)", FlexDGrid, Western Power Distribution and Parsons Brinckerhoff, submitted to Ofgem on 28 May 2013.

2 Successful delivery reward criteria evidence

The measureable criteria, agreed with Ofgem for the delivery of this SDRC, were:

(i) A developed and tested enhanced fault level assessment (EFLA) process with endorsement from WPD planning and design engineers;
(ii) Quicker response to customers' connections applications;
(iii) Characterisation of the substations to determine the suitability of potential fault level mitigation technologies;
(iv) Open source fault level mitigation technology models; and
(v) Quantification of additional capacity that will be unlocked to accommodate future customers' connections.

The evidence to fulfil these criteria is given in Sections 2.1 – 2.5.

2.1 A developed and tested EFLA process with endorsement from WPD engineers

As part of SDRC-1 (Development of Enhanced Fault Level Assessment Processes) six potential enhancements to the present fault level assessment process were defined:

1. Baseline the consistency of application of present fault level assessment methods;
2. Explore assumptions and parametric sensitivity analysis of present fault level standard calculation methods;
3. Increasing the frequency of fault level assessments and granularity of fault levels within HV electricity networks;
4. Network design and integration of fault level monitoring technologies;
5. Network design and integration of fault level mitigation technologies; and
6. Novel connection offers based on the network integration of monitoring and mitigation technologies.

Process 1 (Base-lining) was tested by analysing the questionnaire responses which were provided by all GB DNOs to assess the consistency of application of present fault level assessment processes (defined in Engineering Recommendation G74 and DNO-specific policy documents). Questionnaire responses were received by licence areas representing all of the GB DNOs. Previous work carried out by others in this area has only represented a selection of licence areas whereas the results reported as outputs of FlexDGrid (in this SDRC) represent a formal response from all of the GB DNOs. The analysis of the responses is given in Section 4 and the collated responses are given in Appendix A.

Process 2 (Sensitivity analysis) was tested by applying the sensitivity analysis methodology to representative 11kV feeders of the Primary Substations which have been selected for technology demonstrations. The results of this modelling analysis are summarised in Section 2.5 and the application process is detailed in Section 5.

Process 3 (Fault level decrement along feeders) was tested by application to 12 substation sites (Primary Substations and the associated 11kV network) in the demonstration area. The results of this analysis are summarised in Section 2.5, the methodology (which enabled this modelling enhancement to be evaluated) is described in Section 3 and the detailed results of this modelling process are described in Section 6.

Process 4 (Real-time fault level management) was tested by the application of the modelling process to ten Primary Substations, representing those sites which have been selected for fault level monitoring demonstrations in SDRC-2 (Confirmation of the project detailed design). The results of this analysis are summarised in Section 2.5 and the detailed modelling process and results are described in Section 7.
Process 4 has identified the potential headroom for accommodating generation connections and the implementation of Method Beta will put the systems in place to exploit the headroom if a flexible 'connect and manage' approach is adopted by customers.

Process 5 (Fault level mitigation) was tested by the application of the modelling process to five Primary Substations, representing those sites which have been selected for fault level mitigation technology deployments in SDRC-2 (Confirmation of the project detailed design). The results of this analysis are summarised in Section 2.4, 2.5 and the detailed modelling process and results are described in Section 8. This process has identified the potential headroom for accommodating generation connections and the implementation of Method Gamma will put the systems in place to exploit the headroom by deploying fault level mitigation technologies such as fault current limiters.

Process 6 (Novel commercial frameworks) will be developed and tested throughout FlexDGrid and reported as the output of SDRC-11 (Development of novel commercial frameworks). However, as part of SDRC-4 and based on the emerging learning from the testing of Processes 2 – 5 together with learning transferred from WPD's LNCF Tier-2 Project "Lincolnshire Low Carbon Hub", connection options have been initially scoped out for Methods Alpha, Beta and Gamma. These connection options are discussed in Section 9.

A series of consultations have taken place with WPD 11kV Planners and Primary System Design Engineers, providing endorsement for the EFLA processes and engaging the wider WPD business in FlexDGrid. In addition, two DNO workshops have taken place to discuss the development and implementation of the EFLA processes. This has given other DNOs the opportunity to provide feedback on the processes and endorse the planned approach.

2.2 Quicker response to customers' connection applications

Table 2-1 summarises the indicative response times to customers' connection applications based on the demonstration of modelling processes in Methods Alpha, Beta and Gamma, and using WPD's present (Business as Usual) connection application assessment process as a reference. The technical study times do not include timescales for the production of the commercial offer. Furthermore, it should be noted that the connection application assessment and offer acceptance is an interactive and iterative process.

From the customer's perspective the access to heat maps created by WPD engineers could provide a visual indication of the those areas of the network that are more favourable for generation applications due to lower relative fault levels and therefore potential avoidance in triggering network reinforcement.

2.3 Characterisation of substations for fault level mitigation technology deployment

During the bid stage of FlexDGrid, Birmingham's Primary Substations were characterised according to their modelled fault level values for split and parallel operation. On this basis, 18 sites were identified for consideration as demonstration locations for Method Beta (Real-time Management) and Method Gamma (Fault level mitigation technologies). The characterisation process also considered the proximity of the Primary Substations to Birmingham's Central Business District and planned future generation developments.

In the initial project delivery phase of FlexDGrid, a series of site surveys were conducted for the 18 Primary Substations identified in the Full Submission Pro-forma to understand the physical limitations of the sites. The selection criteria for the ten Primary Substation sites for the installation of real-time fault level monitoring devices and five Primary Substation sites for the installation of fault level mitigation technologies is given in Table 2-2 and described in detail in SRDC-2 (Confirmation of the Project Detailed Design). The results of the selection process are given in Table 2-3 and shown on the map in Figure 1-2.

Method	Indicative technical study time to identify point of connection	Indicative time to connect customer (from offer acceptance)	Comments
Business as Usual	3 days	24 - 36 months	Based on customer connection triggering fault level related network reinforcement
Method Alpha	2.5 days	6 – 12 months	½ day saving on study time (assuming 11kV model is already built) and up to 30 month reduction in customer connection time (assuming enhanced fault level assessment is within policy limits)
Method Beta	3 – 4 days	12 – 18 months	Up to 1 day increase in study time (depending on whether previous study has been conducted for substation site) but up to 24 month saving in customer connection time
Method Gamma	3 – 5 days	24 – 30 months	Up to 2 day increase in study time (depending on whether FLMT is already deployed at site and not accounting for site surveys) but up to 12 month saving in customer connection time
Combined Methods	2.5 – 5.5 days	12 – 30 months	Up to 2 ½ day increase in study time, based on ½ day saving from Method Alpha, 1 day increase from Method Beta and 2 day increase from Method Gamma but up to 24 month reduction in customer connection time

Table 2-1 Customer connection application study times and indicative connection times

Criteria	Weighting
Availability of Space	37.5%
Network connection	27.5%
Substation access	20.0%
Investment Plans	10.0%
Auxiliary supply capacity	5.0%
Overall score	**100.0%**

Table 2-2: Site selection criteria

Location	Score	Technology
Substation A	92.5%	Fault level mitigation and fault level monitoring
Substation B	85.6%	Fault level mitigation and fault level monitoring
Substation C	83.3%	Fault level mitigation and fault level monitoring
Substation D	79.2%	Fault level mitigation and fault level monitoring
Substation E	78.8%	Fault level mitigation and fault level monitoring
Substation F	78.3%	Fault level monitoring
Substation G	77.5%	Fault level monitoring
Substation H	75.8%	Fault level monitoring
Substation I	68.8%	Fault level monitoring
Substation J	65.0%	Fault level monitoring

Table 2-3: Site selection results

2.4 Open source fault level mitigation technology models

As part of SDRC-4, Method Alpha built on the initial work in SDRC-2 to determine the fault level reduction requirements at each of the five Primary Substation sites for the installation of fault level mitigation technologies in order to accommodate generation up to 10% of the firm load capacity of each site without exceeding equipment ratings. This aligns with various low-carbon scenarios for the integration of combined heat and power (CHP) in the DECC 2050 Pathways analysis.

A functional specification has been developed together with an excel tool for the planning of fault current limiter (FCL) installations (see Section 8 and Appendix B) in order to mitigate fault level issues. This tool supports the Primary System Design team (who are responsible for the assessment and design of the distribution network system throughout WPD) with the planning and integration of future customers' connections by allowing the team to establish which technologies are suitable for deployment in particular substations. The tool also allows the design parameters of fault level mitigation technologies to be determined (for example, the target fault level reduction and the required impedance characteristic of a fault current limiter).

Building on the output of SDRC-4, the excel model will be further refined to provide a cost-benefit analysis tool for DNOs to evaluate the merits of fault level mitigation technology deployments when compared to network reinforcement. Moreover, through collaboration with FLMT suppliers, technology-specific fault current limiter models will be developed and integrated into WPD's power system analysis package (PSS/E). The results of the technology-specific demonstrations will be reported in SDRC-10 (Analysis of test results).

2.5 Quantification of additional capacity to accommodate future customers' connections

Table 2-4 summarises the additional capacity that could be unlocked by the various Methods that are being demonstrated in FlexDGrid.

Method	Description	Indicative generation capacity released per Primary Substation site (MW)	Indicative duration of capacity release	Comments
Method Alpha	Enhanced network model accuracy and power factor control	1.1 – 1.15 per MW of 'Business as Usual' capacity[4]	Up to 100%	Based on the results in Section 5
Method Beta	Connect and manage	4.6 – 19.7	Up to 96.2% - 99.9% per annum	Based on the results in Section 7
Method Gamma	Fault level mitigation technologies such as fault current limiters	7.8 – 15.6	Up to 100%	Based on the results in Section 8

Table 2-4 – Additional capacity unlocked by various methods

Although network reinforcement (switchgear up-rating from 250 MVA to 500 MVA) could unlock the greatest capacity for customers connections (31.1 MW – 51.0 MW per site for the Primary Substations considered in FlexDGrid), the health and safety implications[5], significant costs, and long deployment lead times associated with this solution make Methods Alpha, Beta and/or Gamma (or a combination of all three) more attractive options, based on the modelling work to date.

Considering Method Alpha, up to 5% improvement in the accuracy of downstream fault contributions could be achieved by the detailed modelling of distribution feeders and using a distributed load model. The downstream fault level contribution is approximately 5 - 20% of the combined (upstream and downstream) fault contribution (see Figure 2-1 and 2-2), representing a 0.25% to 1% improvement in accuracy of the fault levels at the 11kV bars of Primary Substations. However, the Method provides fault level values for distribution substations and allows fault level heat maps to be generated, giving a visual indication of those areas in the network that are more favourable for the accommodation of customers' connections reducing the need for interventions such as network reinforcement, deployment of novel fault level mitigation technologies or fault level management.

Furthermore, the sensitivity of calculated fault level to input parameters has shown that up to a 9% reduction in customers' fault contribution could be achieved by controlling the power factor operation of the generation plant to import VArs at maximum power output (operating the generation at a leading power factor). Since customers tend to enter into connection agreements to export power at unity power factor, there is scope to explore the commercial frameworks that would provide customers with the incentive to control the power factor of their generation (and hence fault contribution) in order to access quicker and cheaper connections to the network (see Section 5.2.1).

[4] Through network model accuracy enhancements and generation power factor control a 10% – 15% reduction in fault in-feed can release capacity on a per-MW basis when compared to the capacity assessments from the Business as Usual approach

[5] Customers' legacy switchgear is potentially not rated for operation above 250 MVA (Break rms).

In situations where parallel fault levels already exceed equipment ratings, Method Alpha would not unlock capacity for customers' connections by itself. However, the detailed modelling of the network in Method Alpha allows accurate fault level assessments to take place more quickly and is an enabler for detailed modelling of real-time fault level profiles for fault level management in Method Beta and the behaviour of fault level mitigation technologies in Method Gamma.

The modelling of Method Beta (Real time fault level management) demonstrates that between 4.6 MW and 19.7 MW of capacity per Primary Substation site could be released for customers' connections for between 96.2% and 99.9% of the year (see Section 7 and Table 7-2). This includes a 5% safety margin and represents the potential capacity that could be unlocked through the deployment of real-time fault level measurement and monitoring infrastructure in Method Beta, managing fault levels in real-time through the connection and disconnection of customers' generation and demand.

The modelling of Method Gamma (Fault level mitigation technologies) demonstrates that generation could be accommodated up to 10% of the firm capacity of the Primary Substations (between 7.8 MW and 15.6 MW of capacity released per Primary Substation site) through the deployment of fault level mitigation technologies. This analysis aligns with DECC's 2050 Pathways for CHP integration.

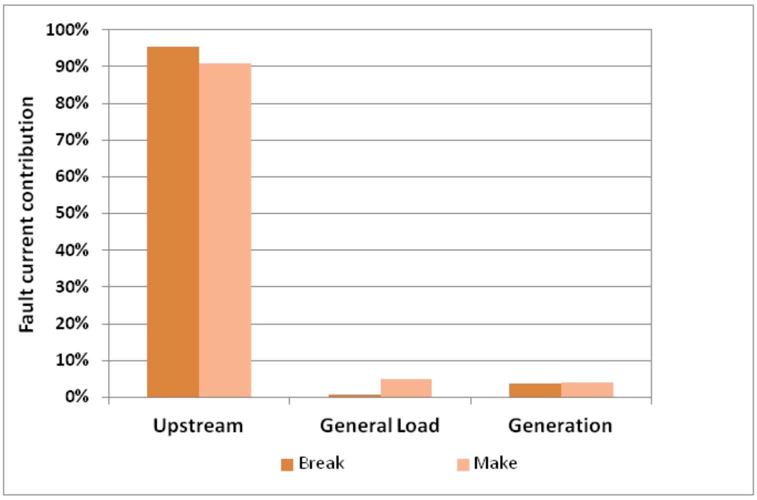

Figure 2-1 – Fault level decomposition into its constituent components with existing generation levels at an illustrative 132kV/11kV Primary Substation

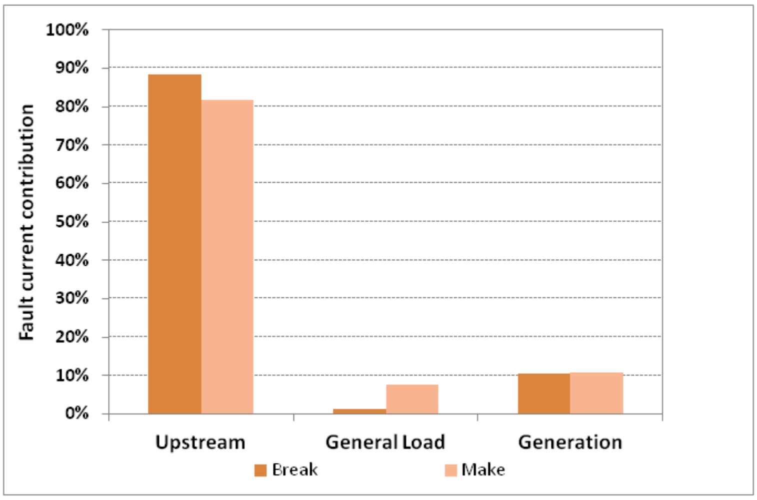

Figure 2-2 – Fault level decomposition into its constituent components with generation penetration levels up to 10% of the firm load capacity of an illustrative 132kV/11kV Primary Substation

3 HV network modelling and benefits

As part of Method Alpha, the Birmingham HV electricity network model was developed in order to create the test bed for demonstrating and evaluating the enhanced fault level assessment processes. The existing model for the Birmingham HV network is updated on a periodic basis and is not directly integrated with the EHV model at present. There are a number of different data sources that are used by design and planning engineers to conduct fault level assessments. The 11kV network model is currently fit-for-purpose, however, a more detailed electricity network model, such as the model developed in FlexDGrid, allows the future complexities associated with the integration of low carbon technologies to be more fully understood.

A methodology for modelling HV networks in PSS/E (power system analysis software) was developed and demonstrated during the first six months of FlexDGrid. The process and data sources used in the modelling methodology are shown in Figure 3-1. EMU, a geographical asset management system, was identified as the most up-to-date data source within WPD representing the geographical connection of the network assets. EMU was used to identify the network connectivity and the type of conductors installed in different parts of the 11kV network. A detailed description of the methodology used for integrating the EHV and HV network models was published in SDRC-1 (Development of Enhanced Fault Level Assessment Processes).

The modelling methodology also delivers additional potential benefits to the WPD business by bringing together the information from multiple data sources into a single power system analysis model. These benefits could be passed on to distribution customers through greater efficiencies in the 11kV connection assessment processes.

Based on the knowledge gained and methodology developed during the first six months, a user-friendly Excel-based tool was developed to automate the modelling process by converting EMU data to a PSS/E model. Figure 3-2 shows the user interface for developing the PSS/E models.

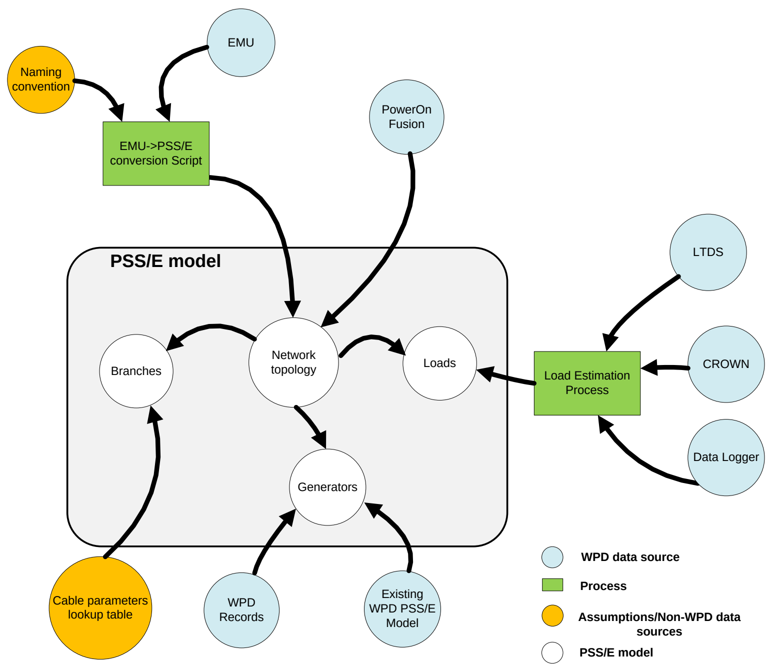

Figure 3-1 Methodology for modelling the HV network in PSS/E

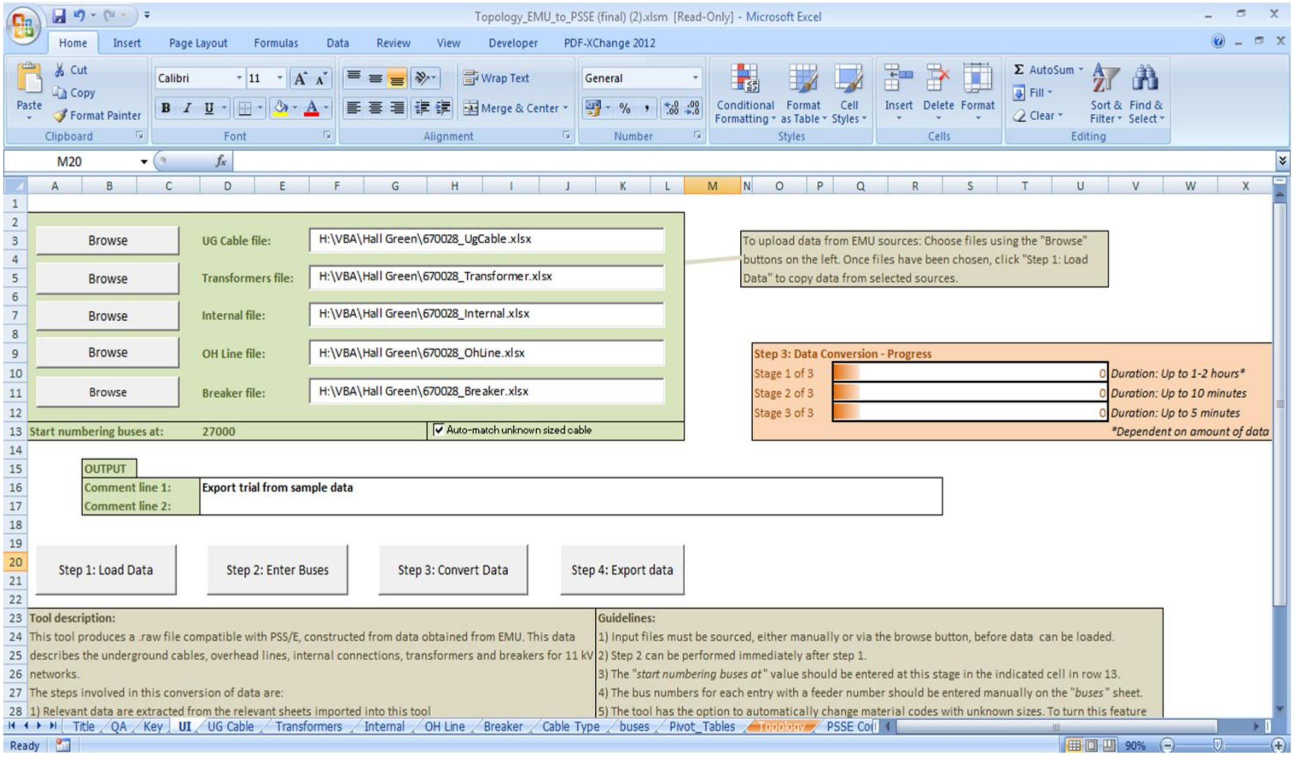

Figure 3-2 – Excel-based tool for converting EMU data to the PSS/E model

This tool was used to create the PSS/E models of HV networks associated with 12 Primary Substations in the demonstration area of Birmingham. These substations are as follows:

1. Kitts Green;
2. Castle Bromwich;
3. Chester Street;
4. Bournville;
5. Sparkbrook;
6. Hall Green;
7. Elmdon;
8. Chad Valley;
9. Perry Barr;
10. Winson Green;
11. Ladywood; and
12. Summer Lane.

Each of these substations, with the exception of Ladywood and Summer Lane, have been selected as demonstration sites in FlexDGrid for fault level mitigation technologies (Method Gamma) and/or fault level management methodologies (Method Beta). Ladywood Primary Substation has been selected to test the fault level monitoring device developed through WPD's Tier 1 LCNF project "Implementation of an active fault level management scheme". Summer Lane Primary Substation supplies a large HV network with many connections to the Primary Substations selected for demonstrations within FlexDGrid. Figure 3-3 shows examples of the developed HV network models.

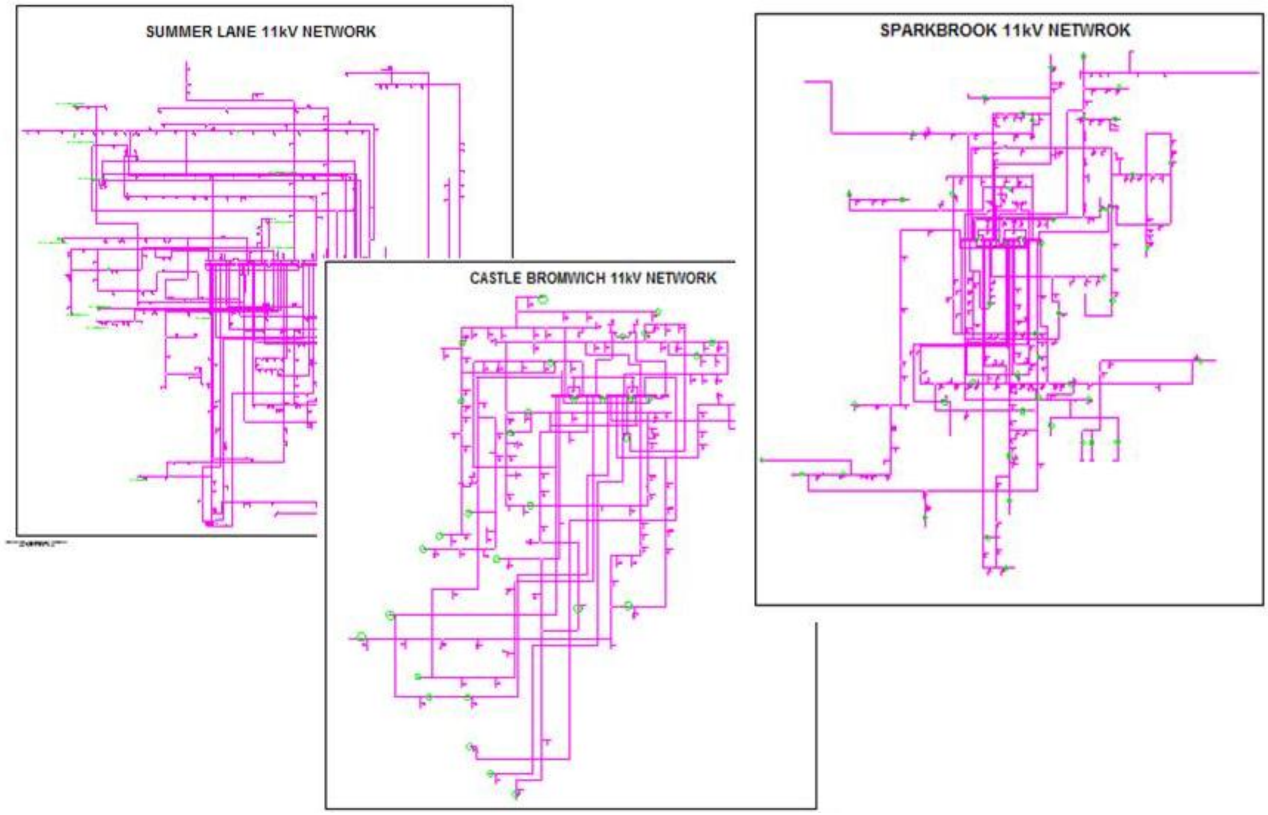

Figure 3-3 – Example of the networks developed

The developed HV networks models can be integrated with the existing WPD EHV PSS/E model. Therefore, a detailed model of the electricity network representing the network from Grid Supply Points (GSPs) to LV substations is now available for more complex analysis.

Some of the benefits of the developed models are as follows:

1. The network topology, cable types and overhead line (OHL) conductors are validated against the PowerOn Fusion schematic diagram. PowerOn Fusion is a network management system used for controlling and managing the distribution network;
2. All normally open points (NOPs) and interconnections between HV networks supplied by different Primary Substations are modelled. This allows detailed power system studies in which different HV network configurations can be considered;
3. The distributed generators are modelled as connected to the actual connection point on the 11 kV network. This allows a more accurate fault level calculation compared to the existing EHV PSS/E model in which HV generator connections are modelled with an equivalent circuit;
4. The developed HV network models create a full representation of the HV busbars at Primary Substations (the front and rear busbar sections as well as circuit breakers and busbar couplers). This enables power system studies to be carried out for different substation configurations; and
5. The load demands are modelled at HV/LV substations. This creates a more accurate representation of loading of each HV feeder, compared to the existing HV model (in which an aggregated load model for the whole HV network is assumed and connected at the HV busbar at the Primary Substation).

The developed HV models are test beds for various studies required in the delivery of Method Alpha, Beta and Gamma within FlexDGrid. Some of deliverables in which the developed HV networks have been (and will continue to be) used are as follows:

1. HV/LV substation fault level calculations: These calculations have enhanced the HV planners' knowledge about the fault levels along the HV feeders. The results of these calculations have been represented in heat map formats (see Section 6);
2. Primary Substation interconnection modelling: This analysis is beneficial during outage planning to further understand the fault contribution from interconnected Primary Substations when back-feeds take place;
3. Sensitivity analysis: This analysis is part of Method Alpha (Enhanced fault level assessment process) and enhances understanding about the sensitivity of calculated fault levels to different model input parameters (see Section 5);
4. Equivalent model versus detailed network model: This study is part of Method Alpha (Enhanced fault level assessment process) and enhances knowledge about fault calculation process. The results of this analysis are given in Section 6;
5. Analysis of operational configurations: This study is part of Method Beta (Real-time fault level management) and demonstrates how fault levels vary with time, based on different configurations at the Primary Substations, creating capacity for customers' connections (see Section 7);
6. Fault level mitigation technology integration: As part of Method Gamma, different fault mitigation technologies have been modelled and the effect of these technologies on HV network fault level reductions will be studied (see Section 8); and
7. Quantification of losses and other metrics for commercial frameworks: A complete HV network model provides the basis for detailed technical and economic analyses which provide the information required for developing novel commercial frameworks within FlexDGrid (see Section 9).

4 Process 1: Base-lining fault level assessment processes

4.1 Questionnaire on current fault level assessment processes

A questionnaire was submitted to all GB DNOs, as given in Appendix A. The objective of the questionnaire was to gain an understanding of:

1. Consistency of application of fault level calculation standards at 11kV or 6.6kV and associated upstream / downstream voltages: IEC 60909[(6)], Engineering Recommendation (ER) G74[(7)] and Engineering Technical Report (ETR) 120[(8)];
2. The assumptions used by DNOs in applying fault level calculation standards;
3. The validity of applying these assumptions, both now and in the future (for example with the anticipated increase in levels of synchronous generation and LV-connected heat pumps); and
4. The merit in proposing an industry-wide review of fault level calculation standards.

Since the publication of SDRC-1 (which contained an initial analysis of the questionnaire responses) five additional questionnaire responses were received. Previous work carried out by others in this area has only represented a selection of licence areas whereas the results reported in FlexDGrid (SDRC-4) represent a formal response from all of the GB DNOs. Furthermore, two additional DNO workshops have taken place to discuss the development and implementation of enhanced fault level assessment processes, giving other DNOs the opportunity to provide feedback on the processes and endorse the planned demonstration approach. The following points emerged from the analysis of the questionnaire responses:

1. Clarifications on the application of Engineering Recommendation (ER) G74 to HV electricity networks would be beneficial to the DNO community;
2. A comprehensive sensitivity analysis of HV electricity network fault levels to input parameters would provide further useful learning for DNOs;
3. A generic database of generator and motor plant types could introduce time savings for planning engineers particularly when dealing with missing or inconsistent data from customers;
4. The development of open source fault level mitigation technology models would be of benefit for planning engineers and allow the capacity to accommodate future customers' connections to be readily assessed;
5. The increase in frequency of fault level assessments would be useful for assessing the potential gains from real-time fault level management. However, the gains would need to outweigh the increased modelling effort for this option to be attractive to other DNOs;
6. A move to probabilistic fault level assessments was not deemed to be feasible at this point in time due to the health and safety aspects contained within the Electricity Safety, Quality and Continuity Regulations (ESQCR); and
7. The need was identified for the training processes within DNOs to be more robustly documented so that planning engineers make consistent decisions regarding the assessment of fault levels.

The application of ER G74 to HV networks varies significantly between DNOs and even between different licence areas of the same DNO. For example, the safety margin applied by different DNOs to fault level assessments can vary from 0 – 10%.

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[6] International Electrotechnical Commission (IEC), 2001, *IEC 60909: Short-circuit currents in three-phase a.c. systems*.
[7] Energy Networks Association, 1992, *Engineering Recommendation G74: Procedure to meet the requirements on IEC 909 for the calculation of short circuit currents*, ENA, London, UK.
[8] Energy Networks Association, 1995, *Engineering Technical Report 120: Calculation of fault currents in three-phase AC power systems (Application Guide to Engineering Recommendation G74)*, ENA, London, UK.

4.2 Analysis of questionnaire responses

All respondents agreed that there is merit in an industry-wide review of fault level standards, in particular ER G74 and its application guide ETR 120. This is because ER G74 is over 20 years old and generator technologies have changed since the standard was developed (DFIGs, generators with fully-rated converters). Therefore, a common methodology for modelling new generation types would be extremely useful and modifications should be introduced to ETR 120 to ensure that G74 is consistently interpreted and applied to HV networks.

Fault level is a growing concern with in-house approaches now being developed to incorporate distributed generation assessments within ER G74 and IEC 60909 calculations. Thus a consistent approach in applying the standards could help to connect generation and demand customers more quickly and cost-effectively to the distribution network. It was also highlighted that it would be beneficial to assess results and present connection assessment processes from other DNOs.

Work has already been done in this area by the ENA[9] to produce a test network. This work was carried out a number of years ago and some of the findings may have been implemented. However, the output of this work may not have been widely disseminated within the various DNO organisations.

The following potential limitations have been encountered with ER G74:

1. The different methods available for calculating fault level can give very different results, for example depending on the X/R ratio selected[10];
2. ER G74 provides a general consistent approach for voltage levels at 33kV and above. However, difficulties are encountered when applying ER G74 at HV levels; and
3. Elements of ER G74 and ETR 120 may need updating and expanding to add further clarifications.

Computer simulations, based on ER G74, are predominantly used amongst DNOs to calculate HV fault levels. However, IEC 60909 hand calculations are used to support and supplement the computer simulation results.

A variety of software packages are used by DNOs to conduct fault level studies, including PSS/E, IPSA, DIgSILENT PowerFactory and DINIS. The extent of the EHV (132kV, 66kV, 33kV) and HV (11kV and 6.6kV) network models varies significantly between DNOs:

1. In some licence areas, 33kV, 11kV and 6.6kV networks are modelled in detail with 132kV interconnections representing the upstream fault in-feed from National Grid;
2. Separate models are used by some DNOs for the EHV network to HV Primary busbars and from HV Primary Substation busbars to corresponding HV distribution networks; and
3. Some DNOs model the electricity network from the National Grid supergrid transformers (SGTs) to the 11kV / 6.6kV Primary Substation busbars.

[9] Based on questionnaire responses received, the ENA previously set up the ASG / OSG X/R sub-group to create a test network and its findings from this work may have been implemented.

[10] The ratio of the system reactance to the system resistance looking back towards the power source from any point in the network. When a fault occurs the fault current that flows comprises of two contributing elements, ac and dc. The ac symmetrical component is determined by the total system impedance between power source and fault. The dc component represents the asymmetry in the fault and decays over a short period of time. The X/R ratio is effectively a time constant that determines the speed of this decay. The actual fault current that is required to be interrupted by a circuit breaker is a combination of the dc and ac symmetrical currents and hence the slower the decay, the higher the prospective current that requires interrupting.

Where there are interfaces between the different software packages used to model the electricity network, a mismatch in fault level values has been reported and represents a source of uncertainty in terms of 'actual' fault level values.

The following software limitations have been reported:

1. Some software packages do not allow the user to vary the time constants for the sub-transient and transient components of the fault level response;
2. Limited guidance is available for the modelling of power electronic devices: doubly-fed induction generators (DFIGs), photovoltaic generation (PV), static compensators (STATCOMs); and
3. The A.C. decrement of fault level can lead to challenges with modelling plant with very short A.C. time constants.

In some DNO licence areas, two separate models are now being used to simulate the Peak Make fault levels and rms Break fault levels respectively. This can lead to issues with switching between different models and ensuring that the correct generator / load models are selected.

The following assumptions are used for modelling distributed generation:

1. In general, devices with power electronic interfaces are currently modelled with a synchronous generator equivalent;
2. At 33kV, distributed generation is modelled within the 33kV network;
3. At 11kV / 6.6kV, some DNOs model the distributed generation within the 11kV network model, whilst some DNOs model the generation as an equivalent source in the EHV model; and
4. At 0.4kV, some DNOs model distributed generation as an equivalent in the EHV model, some DNOs model the generation at a mixture of voltage levels and some DNOs do not model LV-connected generation.

Some DNOs expressed concern with the data for generation connection studies since it can be difficult to obtain detailed technical data from customers. Also, concern was expressed regarding the need to model some generation sources with an equivalent synchronous generator, rather than with a model of the generator type itself.

A variety of approaches are used by DNOs to model the fault level contribution of network general load. The views expressed by different DNOs, regarding the accuracy of the general load contribution to fault level, vary significantly: Some DNOs feel the values provided in ER G74(11) are still fit-for-purpose, some DNOs are unsure and some DNOs feel it is unclear whether the values are still representative of today's loads. There is an overall discrepancy in opinion amongst DNOs regarding this area of fault level modelling. In addition, the view was expressed that it is unclear at which point DNOs should move from HV to LV load modelling.

The safety margins between calculated fault levels and switchgear ratings vary significantly between DNO licence areas. From the questionnaire responses received, the safety margin range is 0% - 10%. Short-term paralleling, which potentially allows fault levels to exceed switchgear ratings, is tolerated by some DNOs under strictly controlled conditions.

[11] ER G74: "Where measured values are not available, the following indicative allowances can be used for calculating the initial three-phase symmetrical RMS short-circuit current contribution at 33kV busbar from the asynchronous motors in the general load supplied from that busbar: For load connected to the supply network at (i) low voltage, allow 1.0 MVA per MVA of aggregate low voltage network substation winter demand; (ii) high voltage allow 2.6 MVA per MVA of aggregate winter demand. These contributions relate to a complete loss of supply voltage to the motors."

The number of uneconomic connections due to fault level is sometimes unknown because DNOs do not find out why customers choose not to proceed with developing projects. However, some DNOs have reported a significant number of uneconomic connections due to extant fault level issues.

5 Process 2: Sensitivity analysis

A sensitivity analysis has been carried out to enhance DNOs' understanding of the fault level calculation process, based on the recommendation in SDRC-1 and responding to a perceived need by the DNO community. This analysis aims to demonstrate the sensitivity of calculated fault level values (Peak Make and rms Break) based on different parameter inputs to the Engineering Recommendation (ER) G74 fault level calculation process.

When implementing ER G74, the pre-fault voltage conditions on the network should be first calculated to determine the pre-fault internal voltage of motors and power plants. The pre-fault voltages are used to determine a Thevenin model, voltage source and series impedance, for each branch connecting to the network node where a fault occurs. Fault levels are more sensitive to those parameters which have a larger impact on the calculated pre-fault internal voltage source of rotating machines and the circuit impedance to the fault point.

The main applications for fault level sensitivity analysis are:

1. Identifying the parameters of the network model which need to be measured and estimated with a high level of accuracy;
2. Developing recommendations on network operation schemes and commercial frameworks which result in reducing the fault levels on HV networks and facilitate the integration of distributed generators; and
3. Validation between measured fault levels and desktop analysis through adjustments of model parameters which have a high impact on fault level. This application is important for validation of measured fault levels in Method Beta within FlexDGrid.

In the sections that follow, the methodology and the results of sensitivity analysis are presented.

5.1 Methodology

An electricity network computer model represents a snapshot of the network operational condition. If the network model parameters are changed from their original values, the model representation will deviate from the original operational condition. For the purpose of the sensitivity analysis, a PSS/E model of a sample network, representing part of Birmingham's 11kV network, has been considered. The parameters of the sample model have been varied within an assumed range to create different operation condition scenarios. For each scenario the corresponding fault levels are calculated. The results are then compared with calculated fault levels from the original model to understand the impact of the each network parameter on the fault level.

All fault level analysis is based on ER G74 using a PSS/E-compatible Python script[12], developed by WPD, for fault level calculations.

The model parameters and the variation ranges assumed for this study are given in Table 5-1. The PSS/E models for different scenarios representing model parameters changes were created. In order to understand the sensitivity of fault level calculations to input parameters, for each scenario only one parameter was adjusted whilst the others remained fixed. Making and breaking fault currents were calculated for each scenario and compared with the values calculated from the original model.

[12] Python is a programming language which allows complex calculations to be implemented and automated: www.python.org

In Table 5-1, the ‘demand’ parameter represents the electrical current supplied to customers whereas the ‘general load fault in-feed’ parameter represents the fault in-feed contribution of the general load element of the electrical current supplied to customers.

Parameter	Variation range
Generation power factor (PF)	Unity, 0.95 leading, 0.95 lagging, Voltage control mode (Vset = 1 pu)
Tap position at Primary Substation	Voltage at 11 kV busbar changes between 0.95 per unit to 1.03 per unit
Demand	- 10% to + 10%
General load fault in-feed	0 to 2 MVA per MVA of load
Cable length	- 5% to + 5%

Table 5-1: Model parameters and range of variations used for sensitivity analysis

In addition, as part of the sensitivity analysis, a comparison has been made between the resultant fault levels from two different approaches for modelling the connection of the embedded generators. In the first approach, “BaU equivalent model approach”, generators are modelled with an equivalent circuit connection to the Primary Substation. The second approach, “detailed model approach”, a detailed model of HV network is considered. The calculated fault level contributions from embedded generators for these two approaches are compared to understand how a detailed modelling of generation connection can affect the calculated fault level.

5.2 Sample network

The sample network consists of two 11kV feeders as given in Figure 5-1. This sample network is part of the Birmingham HV network model which has been developed within FlexDGrid. Feeder A and Feeder B represent a long feeder and a short feeder respectively. These feeders are connected to a 132/11kV primary transformer which is connected to WPD’s EHV network model on the upstream side. WPD’s EHV model embodies a full representation of WPD 132kV, 66kV and 33 kV networks from Grid Supply Points (GSPs) to 11 kV busbars.

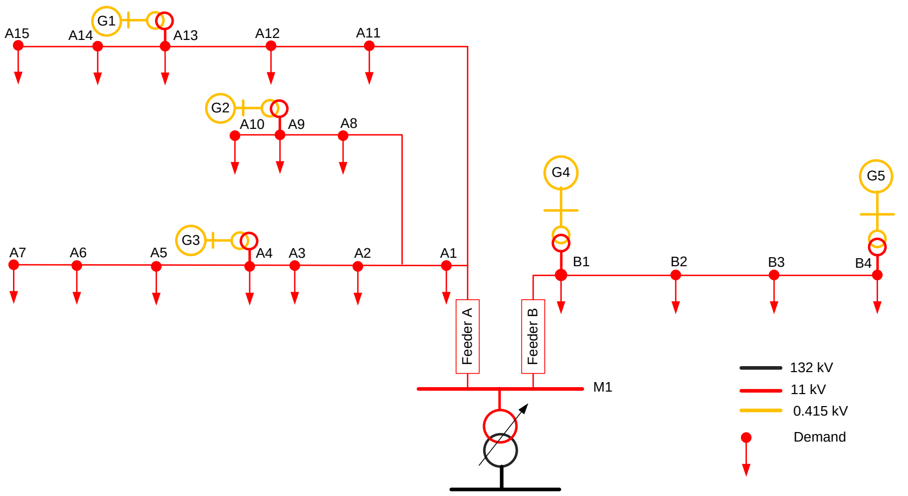


Figure 5-1: The sample model representing a short and a long feeder.

Five generators with total capacity of 8.8 MVA and stochastic connection points are assumed in the sample model. All generators are operating at 0.415kV and unity power factor and connected to the 11kV network with 11kV / 0.415kV transformers. The total demand supplied through feeder A and feeder B is 4.74 MVA

and 1.56 MVA respectively. Table 5-2 shows an outline of the sample model parameters. The detailed data of the sample model and the results of load flow are given in Appendix C.
The results of the power flow analysis and fault level calculation for the sample model are given in Table 5-3. The making fault current and breaking fault current is calculated at 10 ms and 90 ms, respectively.

Distance from Primary Substation [km]	A7	A10	A15	B4	
	5.56	4.62	5.52	2.80	
Generation [MVA]	G1	G2	G3	G4	G5
	2.5	1.6	2.5	1.6	0.6
Power factor of generation	Unity				
Demand supplied by Feeder A [MW] [MVAr]	P	Q			
	4.45	1.62			
Demand supplied by Feeder B [MW] [MVAr]	P	Q			
	1.47	0.53			
Power factor of demand	0.94 lag				
Transformer tap position	8		Maximum tap position 19		

Table 5-2: The outline of sample model parameters

Voltage [pu]	A7	A10	A15	B4	M1
	1.020	1.022	1.024	1.020	1.020
Power flowing from Feeder A to M1 [MW] [MVAr]	P	Q			
	2.12	-1.65			
Power flowing from Feeder B to M1 [MW] [MVAr]	P	Q			
	0.68	-0.55			
Fault contribution from Feeder A to M1 [kA]	Make	Break			
	4.85	1.84			
Fault contribution from Feeder A to M1 [kA]	Make	Break			
	1.91	0.66			

Table 5-3: Outline of power flow analysis and fault level calculation

A series of load flow studies were carried out and it was verified that all busbar voltages were within acceptable ESQCR limits for maximum and minimum generation conditions coincident with maximum and minimum demand conditions.

5.2.1 Generation Power factor

The power factor at which a generator operates has impact on the fault current contribution of that generator. The internal voltage and the impedance (sub-transient/transient) of a generator determine the fault current contribution from the generator. The generator internal voltage, however, has a vector relationship with the pre-fault voltage at the connection point and the pre-fault generator output current. The angle between pre-fault voltage and pre-fault current is determined by the generator's power factor. Therefore, the generator's power factor affects the magnitude of the generator's internal voltage and consequently generator's fault current contribution.

In the following the sensitivity of generator fault current to the operating power factor is first demonstrated using a single machine system. Further analysis is then reported, based on analysis of the sample network.

Single machine system

Figure 5-2 shows a Thevenin model of a single generator connected to the network. In Figure 5-2, V_s is the internal voltage, X_s is the synchronous impedance, V_T is voltage at connection point and I_G is the output current of the generator. The vector relationships between these variables when the generator operates in different power factors are shown in Figure 5-3. The magnitude of the generator internal voltage is larger than the voltage at the connection point when a generator operates in lagging (exporting VARs) and unity power factor whereas in leading power factor (importing VARs) the internal voltage is smaller than the network's voltage.

It is assumed that the generator model shown in Figure 5-2 is operating at 1 pu power output and the sub-transient reactance and synchronous reactance are 0.25 pu and 2.0 pu respectively. The fault current contributions (V_T/ X_s) from the generator against different network voltage (V_T) and for different power factors are calculated and shown in Figure 5-4. This figure shows that when a generator operates in a leading power factor, for a given network voltage, the fault current contribution is lower than when the generator operates in unity or lagging power factor. This is due to a smaller generator internal voltage in leading power factor operating condition.

It should be noted that the generator operation power factor can affect the network voltage (V_T), however, network voltage depends on the operation conditions of all network components. Therefore, in a real system different operating power factor versus different network voltage can be envisaged. Figure 5-4 shows the initial rms fault current contribution for a 1 pu rated output generator for different network voltage level and power factor operation. The sub-transient reactance of the generator is assumed to be 0.25 pu.

For the 1 pu single machine sample case connecting to a point of network with 1.0 pu voltage, the change of power factor from 0.95 leading to 0.95 lagging changes the initial rms fault current contribution by around 1.8 pu. This variation can be larger if the sub-transient reactance is smaller than 0.25 pu as assumed in this study.

The other observation from Figure 5-4 is the effect of network voltage. For a higher network voltage a higher generator internal voltage and therefore a higher fault contribution is expected. For the single machine study case, the fault contribution increases by around 0.4 pu when the voltage at the connection point changes from 0.95 pu to 1.03 pu.

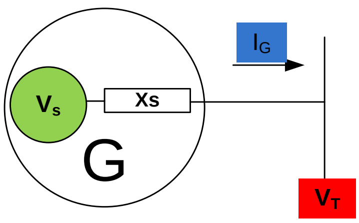


Figure 5-2: Thevenin model of a generator connected to the network

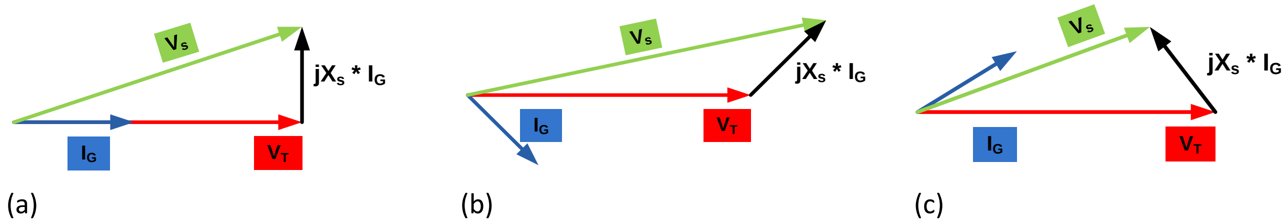


Figure 5-3: The vector calculation for generator internal voltage when it operates at (a) Unity power factor, (b) Lagging power factor, (c) Leading power factor

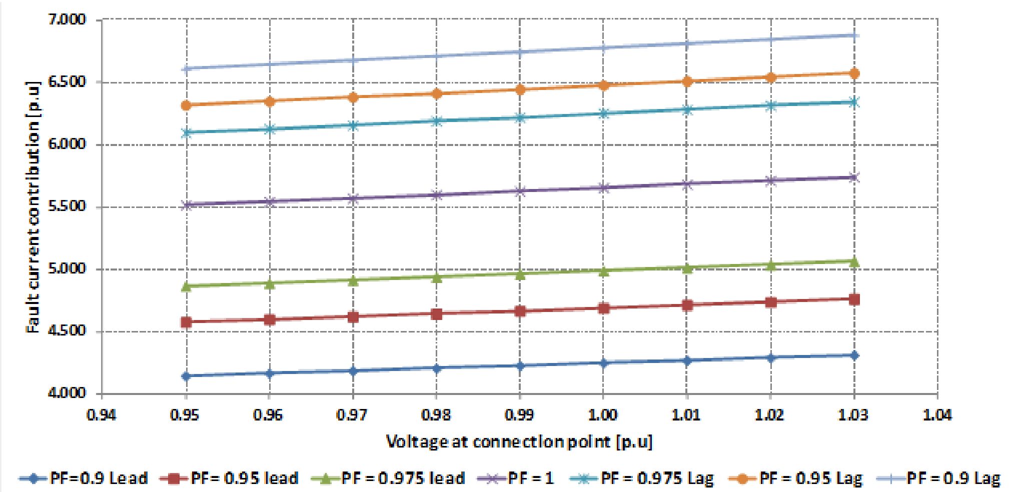


Figure 5-4: The effect of power factor on generator initial rms fault in-feed

Sample network

The effect of the generator's power factor on fault level is also studied on the sample network. Four scenarios, representing a range of generation operating conditions, have been studied and for each scenario the Peak Make and rms Break fault current contributions are calculated.

Table 5-4 shows the making and breaking fault current contribution from feeder A and B. The results show that by distributed generators changing the operation power factor from unity to leading power factor the Peak Make and rms Break fault contribution current reduce by around 7.5% and 8.1%, respectively. Changing the power factor from 0.95 lag to 0.95 lead results in variation of Break fault level in a range between +7.5% to -8.1% (more than 15% variation range) around the fault contribution at unity power factor.

In addition, the fault current contributions when generators are operating in voltage control mode (Vset =1) are calculated. In the sample case, the voltage levels on feeders A and B are above 1 pu therefore generators operate in leading power factor to reduce the voltage to around 1 pu. Operating in leading power factor and reducing the voltage levels both result in smaller fault contributions.

	Unity PF		0.95 lagging PF		0.95 leading PF		Vset =1	
	Make	Break	Make	Break	Make	Break	Make	Break
Feeder A [kA]	4.85	1.84	5.201	1.981	4.487	1.69	4.57	1.725
Feeder B [kA]	1.91	0.66	2.041	0.708	1.773	0.608	1.78	0.611
Change in Feeder A contribution			7.2%	7.7%	-7.5%	-8.2%	-5.8%	-6.3%
Change in Feeder B contribution			6.9%	7.3%	-7.5%	-7.9%	-6.8%	-7.4%
Average change			7.1%	7.5%	-7.5%	-8.1%	-6.3%	-6.9%

Table 5-4 Sensitivity of fault current to the generation power factor – study on a sample network

The calculated fault levels, given in Table 5-4, are based on the assumption that the generators are operating at rated output. It should be noted that for levels of export which are lower than the rated output, the fault contribution of the generators will reduce when they operate at unity or a lagging power factor. In some network operating conditions, if a generator operates in leading power factor, the fault contribution could increase when the level of power exported decreases relative to the fault contribution at maximum export. However, the fault contribution would still be lower, relative to the operation of the generator at unity or lagging power factors.

5.2.2 Tap position of the primary transformer

Transformer tapping is automated in the primary system to maintain the voltage profile on the network within the acceptable limits. Fault levels depend on the pre-fault voltage conditions. The position of the tap at the Primary Substations can alter the voltage profile of the network and consequently the fault current contributions. In order to demonstrate this, the tap position of the 132/11 kV transformer in the sample model is changed to reach different target voltages. For each given voltage target the fault current contribution is calculated, the results are given in Table 5-5.

For lower tap positions, compared to original tap position (8), both making and breaking fault current decreases. For the sample case the target at 11kV busbar can be as low as 0.95 pu while the voltage levels on feeder A and B are still within 6% voltage drop limit. In this case, the fault current contributions reduce by around 6%.

The application of transformer tapping to reduce fault levels should be used with care as changing the voltage at the 11 kV busbar can affect the voltage profile of all 11 kV feeders connected to that 11kV busbar. In this case, there may be some long feeders with no generation connected to them which experience unacceptable voltage drops.

Primary HV Busbar Voltage [pu]	1.02		1.03		1.0		0.98		0.95	
Tap position	Nominal (8)		9		7		6		4	
	Make	Break	Make	Break	Make	Break	Make	Break	Make	Break
Feeder A [kA]	4.85	1.84	4.897	1.856	4.761	1.805	4.689	1.777	4.552	1.726
Feeder B [kA]	1.91	0.66	1.927	0.665	1.847	0.647	1.846	0.637	1.793	0.619
Change in Feeder A contribution			1.0%	0.9%	-1.8%	-1.9%	-3.3%	-3.4%	-6.1%	-6.2%
Change in Feeder B contribution			0.9%	0.8%	-3.3%	-2.0%	-3.4%	-3.5%	-6.1%	-6.2%
Average change			0.95%	0.85%	-2.55%	-1.95%	-3.35%	-3.45%	-6.10%	-6.20%

Table 5-5 Sensitivity of fault current to the tap position of primary transformer – study on a sample network

5.2.3 Demand

Demand variation affects the network voltage profile and general load fault in-feed. These two have opposite effects on fault levels. Increasing demand may result in lower voltage profile along the network and consequently a lower fault current. However, the general load fault in-feed (1 MVA fault contribution for every 1 MVA load) increases if demand increases. The effect of general fault in-feed is higher during Peak Make conditions because the rotating machines as part of general load contributes to the fault current during the sub-transient period of the fault.

The demand in the sample model is altered from -10% to +10% of the original values and the corresponding fault levels are calculated and the results are shown in Table 5-6. The results show, for the sample case, that demand increment mainly affects the Peak Make fault current and the rms Break fault current remains unchanged. In this sample case, the effect of general fault in-feed and network voltage profile on fault current cancels out each other at the breaking time. However, the effect of general fault in-feed is higher on making current so the resultant Peak Make fault contribution is higher.

	Original demand		+10% change		-10% change	
	Make	Break	Make	Break	Make	Break
Feeder A [kA]	4.85	1.84	4.88	1.84	4.83	1.84
Feeder B [kA]	1.91	0.66	1.92	0.66	1.90	0.66
Change in Feeder A contribution			0.62%	0.00%	-0.41%	0.00%
Change in Feeder B contribution			0.52%	0.00%	-0.52%	0.00%
Average change			0.57%	0.00%	-0.47%	0.00%

Table 5-6 Sensitivity of fault current to demand – study on a sample network

5.2.4 General load fault in-feed

Part of the general load consists of asynchronous machines which contribute to the fault level (both Peak Make and, potentially, rms Break). According to ER G74, the initial rms fault contribution from the general load connected to the low voltage network is around 1 MVA per 1 MVA of load when aggregated at 33kV. In a computer model, the fault contribution from general load is usually modelled with an equivalent generator at the 33kV or 11kV points where the aggregate load is connected. For the purposes of this study, 1 MVA per MVA of load has been applied at 11kV (in accordance with the WPD ER G74 script) using an X/R ratio of 2.76. This is because ER G74 does not provide clear guidance on how to deal with situations where there is a direct transformation from 132kV to 11kV with no intermediate 33kV network. It should be noted that ER G74 was developed in 1992 and since then the load mix and appliances used in commercial and industrial environments may have changed.

The sensitivity of fault level to general load contribution is studied for different fault contribution values of MVA per 1 MVA load. The results are shown in Table 5-7. The effect of general load is mainly on the Peak Make as after 90 ms (Breaking time) the fault current from induction generators decays. As shown in Table 5-7, neglecting general load fault in-feed can result in around 7% lower Peak Make fault level whereas the breaking fault current reduces only around 1.5%.

MVA per 1 MVA load	1		0		0.5		2	
	Make	Break	Make	Break	Make	Break	Make	Break
Feeder A [kA]	4.85	1.84	4.52	1.81	4.69	1.83	5.17	1.86
Feeder B [kA]	1.91	0.66	1.77	0.65	1.84	0.65	2.05	0.67
Change in Feeder A contribution			-6.8%	-1.5%	-3.4%	-0.5%	6.6%	1.2%
Change in Feeder B contribution			-7.4%	-1.5%	-3.7%	-0.6%	7.3%	1.2%
Average change			-7.1%	-1.5%	-3.5%	-0.6%	6.9%	1.2%

Table 5-7: Sensitivity of fault current to the general load in-feed on a sample network

5.2.5 Circuit length

The length of a circuit (cable and overhead lines) are measured based on drawings or two-dimension trajectory of the circuits. The overhead line sag and the terrain slopes in the trajectory of cables may be neglected when the length of a circuit is calculated. In addition, the network asset databases are updated on a periodic basis. All of these may result in underestimation or overestimation of circuit lengths in the model that may have effect on the calculated fault level.

The sensitivity of fault level to circuit length is studied by changing the cable length from -5% to +5% of the lengths in the original model. Table 5-8 shows the results of sensitivity of fault levels to the cable lengths. The effect of cable length variation on the fault contribution from feeder A is larger than feeder B. This is due the fact that feeder A is a longer feeder and therefore a cable length variation has larger effect on voltage profile and impedance within fault current path.

	Original		+5%		-5%	
	Make	Break	Make	Break	Make	Break
Feeder A	4.85	1.84	4.803	1.831	4.903	1.844
Feeder B	1.91	0.66	1.904	0.658	1.915	0.66
Change in Feeder A contribution			-1.0%	-0.5%	1.1%	0.2%
Change in Feeder B contribution			-0.3%	-0.3%	0.3%	0.0%
Average change			-0.65%	-0.40%	0.70%	0.10%

Table 5-8: Sensitivity of fault current to cable length – study on a sample network

5.2.6 Generation connection studies – detailed model versus equivalent model

The network model considered for generation connection studies are sometimes an equivalent model of network rather than a detailed model. This is mainly because an updated network model is not available. For a radial network, the equivalent model consists of the generator connecting to the Primary Substation with an equivalent circuit and an aggregated load of HV network modelled at the Primary Substation. The equivalent circuit representing the network impedance from generation connection point to the Primary Substation.

Figure 5-5 (a) and (b) shows the sample network model and the equivalent network model, respectively. In order to understand the difference in calculated fault level between a detailed model and an equivalent model, the fault level calculation for these two networks are performed.

Two scenarios of power factor operation are assumed:

1. Generators operate at rated output power and 0.95 leading power factor; and
2. Generators operate at rated output power and unity power factor.

Table 5-9 shows the results of fault level calculation for the sample model and the equivalent model. In Table 5-9, the total fault current contribution from the HV network is the summation of generators fault current contribution and the general load fault in-feed.

The results show a difference of 5.5% in Peak Make and 4.0% in rms Break duty between the two network models. The equivalent model is likely to result in a higher calculated fault levels due to two main reasons:

1. The calculated voltage level at the generator connection point in equivalent model is higher than the voltage at the same point in the detailed model. This is because the voltage drop due to load on HV feeder is not considered in the equivalent model. The higher voltage level at the generator connection point would result in a higher fault contribution; and
2. The calculated general load fault contribution in the equivalent model is higher compared to the detailed model. The general load fault in-feed is modelled in the form of equivalent generators at the point where the load is connected. In the equivalent model, this equivalent generator is modelled at the HV busbar of the Primary Substation, therefore, the reducing effect of network impedance on general load fault in-feed is neglected.

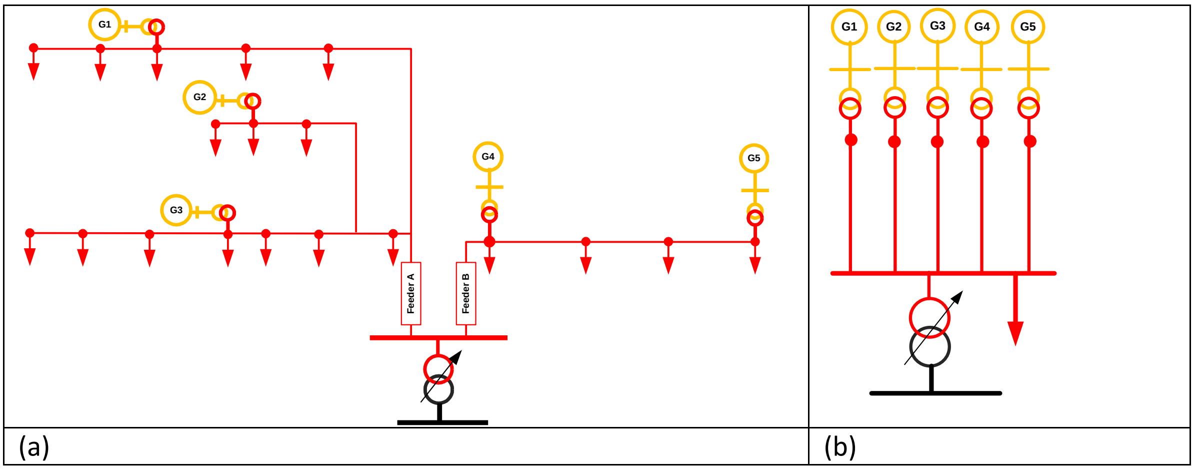


Figure 5-5: Network modelling for connection study (a) a detailed model of 11 kV network (b) an equivalent model of 11 kV network

	Sample model Figure 5-5 (a)				Equivalent model Figure 5-5 (b)			
	Unity PF		0.95 lead PF		Unity PF		0.95 lead PF	
	Make	Break	Make	Break	Make	Break	Make	Break
Total Fault contribution from HV network [kA]	6.76	2.50	6.26	2.23	7.13	2.60	6.71	2.43
Difference					5.5%	4.0%	7.2%	9.0%

Table 5-9: The comparison between fault calculation using a detailed model and an equivalent model

5.3 Discussion

The fault level sensitivity analysis shows that different parameters of the network model have different effects on the making and breaking fault currents. Figure 5-6 summaries the results of sensitivity analysis and shows the average variations in the fault current contributions from HV network against different model parameters of the sample network.

Generation power factor has the largest effect on the fault current, the Peak Make and rms Break fault current change around 7% when the generator's power factor changes between unity to 0.95 lead. In addition the analysis shows that demand can have the lowest impact, less than 1%, on both breaking and making fault current.

Based on the sensitivity analysis results the following recommendations are made for fault level calculations:

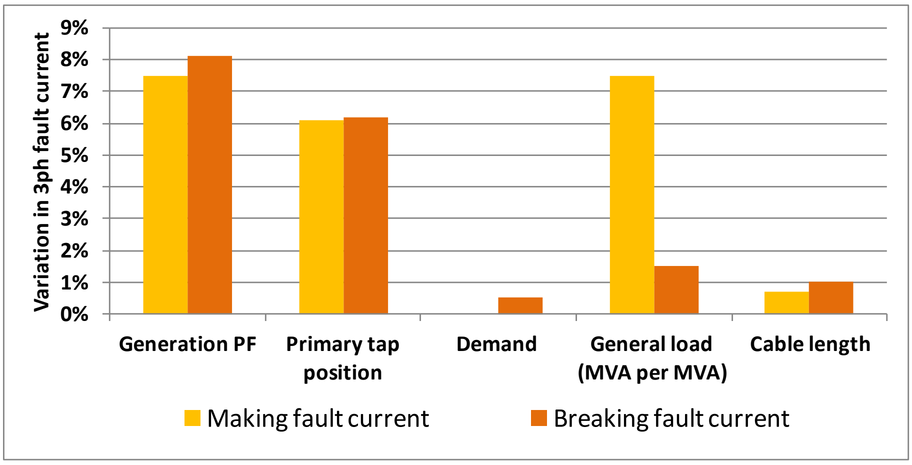


Figure 5-6: Summary of sensitivity analysis results

1. It is recommended that a detailed model of the HV network is used for generation connection studies. This allows pre-fault voltage conditions to be calculated more accurately, resulting in more accurate calculated fault levels. Using equivalent network models is likely to result in higher calculated fault levels;
2. In order to calculate fault currents as accurately as possible, it is recommended that a generator's model represents the actual power factor at which it is set to operate;
3. The tap position at Primary Substations has a high effect on the calculated fault currents. It is recommended that care should be taken to model the tap at the position which results in a network voltage profile representing the system condition in real-life; and
4. General load has a large effect on the making fault current. It is recommended that large synchronous and asynchronous motors are modelled if possible. It is also recommended that work is carried out to understand the load mix and appliances used by low voltage connected customers. The ER G74 recommendation on general load fault in-feed may need to be reviewed.

6 Process 3: Fault level decrement

6.1 Fault level decrement description and application

The model developed for Birmingham HV networks was used to calculate the fault levels at distribution (HV/LV) substations. This information can be used to enhance HV planners' understanding of how fault levels decrease/change on HV/LV substations which are in close proximity to the Primary Substation. The Peak Make and rms Break fault level values at all HV/LV substations in the Birmingham central business district are now available to the Primary System Design team and 11kV planners.

Heat map techniques (colour-coding values to provide a visual representation of fault levels) can be used to demonstrate the fault level decrement along HV feeders and highlight parts of the network where fault levels are close to equipment ratings or, conversely, fault level headroom exists. HV planners could use this information for decision making to expedite the connection of customers to the HV network. In addition, the heat map representation gives the customers looking to develop new generators an indication of where fault level headroom exists and therefore where it might be favourable to locate generation when considering the integration into the electricity network.

Figure 6-1(a) shows the rms Break fault level heat map for the existing arrangement (split operation) of Primary substations and for HV/LV substations within the Birmingham demonstration area. In this operating arrangement, all the HV network fault levels are within the policy limit of the switchgear.

Figure 6-1(b) shows the rms Break fault level for the parallel operation of the five Primary substations which have been selected for fault level mitigation technology demonstrations in FlexDGrid. The comparison between Figure 6-1(a) and 6-1(b) demonstrates that fault levels in large parts of the Birmingham HV network could exceed switchgear policy limits if the Primary Substations were to be operated in a parallel configuration (to improve customers' security of supply) and the fault level mitigation technologies (being demonstrated in Method Gamma) were not deployed.

6.2 Security of supply improvement

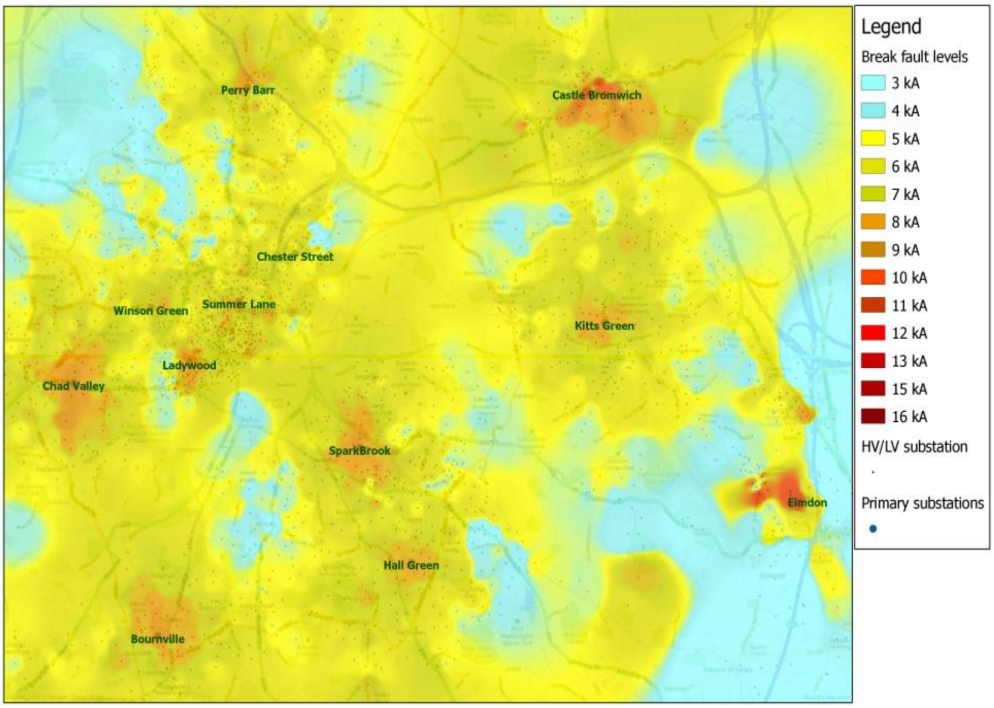
Under the current scheme automatic sequencing of switches can restore the supply within three minutes. This short interruption (SI) time can be mitigated by operating the primary transformers in parallel. However, paralleled operation increases the fault levels on HV networks and in many cases fault level exceeds the equipment policy ratings.

As part of Method Gamma within FlexDGrid the fault level mitigation technologies will be deployed to mitigate the fault level issues in paralleled operation arrangement.

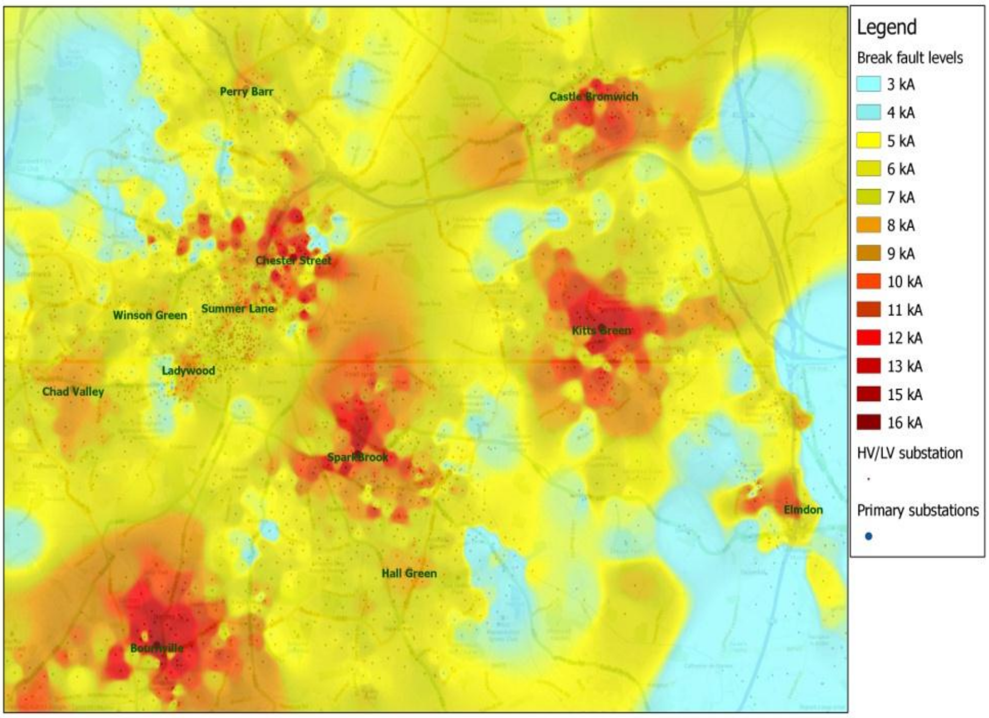
In the following study, the heat map technique is used to demonstrate the effect of fault level mitigation technologies on Kitts Green HV network when primary 132/11kV transformers are operating in parallel.

For the purpose of this demonstration, three network arrangements are considered:

1. **Existing arrangement (split operation):** The interconnectors between the three Kitts Green 132/11/11kV transformers are open;
2. **Parallel operation:** The 11kV interconnector between GT1 and GT3 132/11/11kV transformer is closed and these two transformers are operating in parallel; and
3. **Parallel operation with FLMT:** A FCL is installed within the 11kV GT1-GT3 interconnector. Figure 6-2 shows this arrangement.



(a)



(b)

Figure 6-1: The heat map representing breaking fault level on Birmingham HV networks
(a) Split operation – existing arrangement
(b) Parallel operation - the parallel operation arrangement of five Primary Substations selected for demonstrations

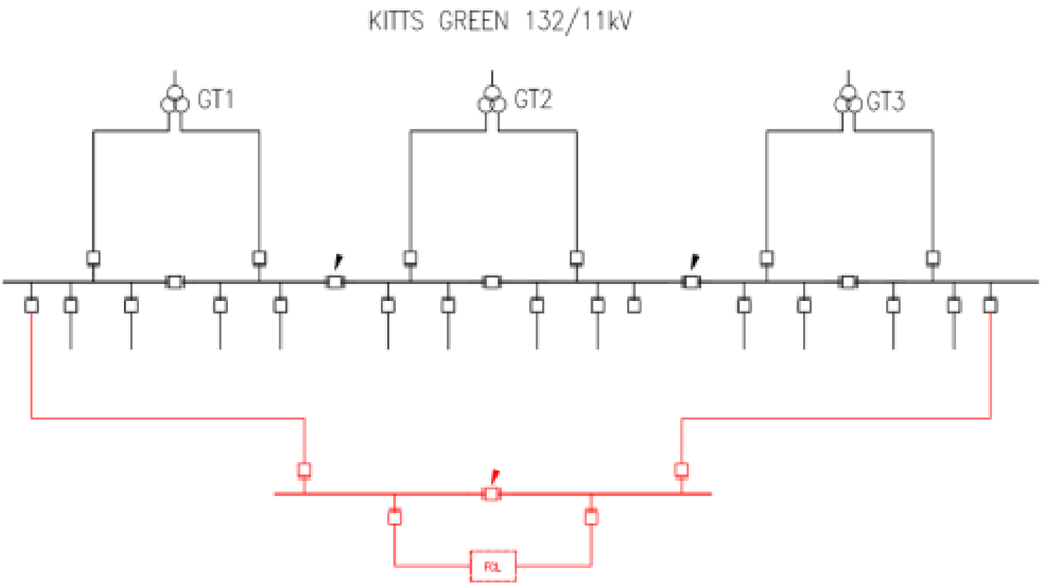


Figure 6-2- Parallel operation with FCL installed within interconnector between GT1 and GT3

6.2.1 Existing arrangement (split operation)

In this network operating arrangement all Kitts Green primary transformers are operating separately and the HV network is operated in a radial arrangement.

Figure 6-3 (a) shows the rms Break fault level heat map for the HV/LV substations which are supplied by Kitts Green Primary Substation. The maximum and minimum calculated Break fault levels on the 11kV network are 8.2kA and 3.5kA, respectively.
With the existing Kitts Green radial network arrangement each HV feeder is only supplied by one primary transformer. Figure 6-3 (b) shows the part of the HV network fed by Kitts Green which is supplied continuously by one or two transformers. All parts of the network are coloured in turquoise, this means all HV/LV substations are supplied by only one source continuously[13].

6.2.2 Parallel operation

In this network operating arrangement GT1 and GT3 are paralleled. Figure 6-4 (a) shows the rms Break fault level heat map for the HV/LV substations supplied by Kitts Green. The maximum and minimum calculated rms Break fault levels on the 11kV network are 15.7kA and 3.5kA, respectively. The fault levels in large part of network have exceeded the fault level policy ratings (13.1 kA).

The benefit of this arrangement is that a larger part of network is now supplied continuously by two sources and therefore the security of supply is improved. As shown in Figure 6-4 (b) a large part of the HV network fed from the Kitts Green Primary Substation is now coloured in green, which means that the HV/LV substations are supplied continuously by two transformers.

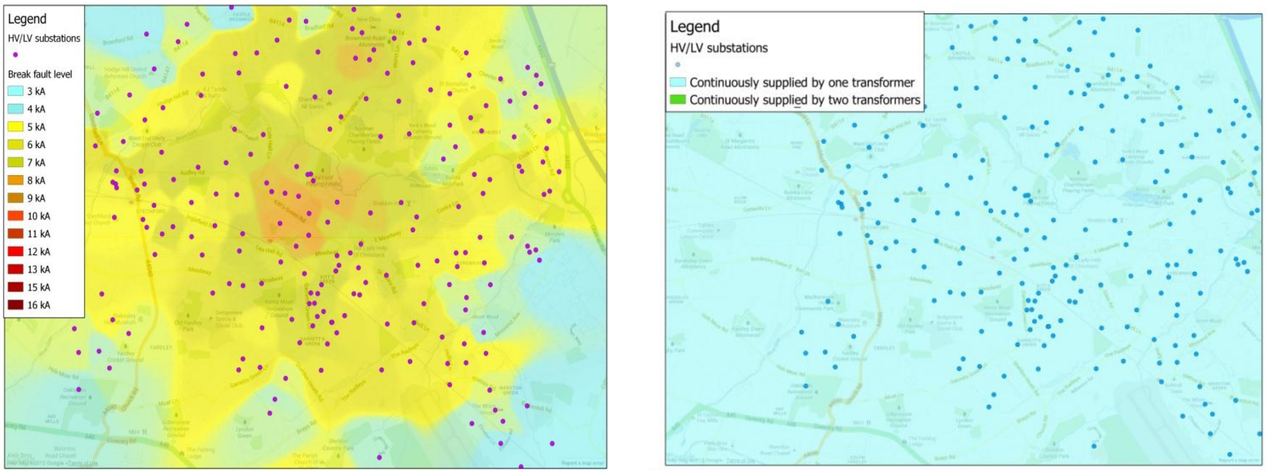
[13] In this study the consideration of automatic network switching is excluded.

6.2.3 Parallel operation with FCL installed at Kitts Green

In order to mitigate the fault level issue when GT1 and GT3 are operating in parallel, a FLMT (FCL) is installed within the interconnector between GT1 and GT3.

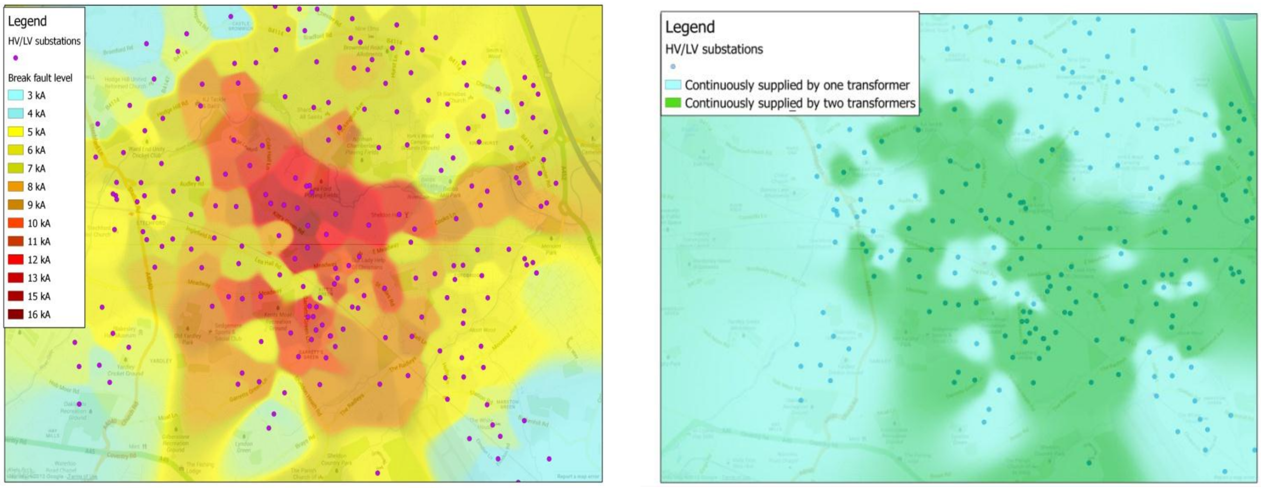
Figure 6-5 (a) shows the rms Break fault level heat map for the HV/LV substations supplied by Kitts Green. The maximum and minimum calculated rms Break fault levels in the 11kV network are 9.0kA and 3.5kA, respectively. All fault levels are now within the policy ratings.

Figure 6-5 (b) shows the Kitts Green network security heat map. A large part of Kitts Green HV network is coloured in green that means HV/LV substations are supplied continuously from two sources.



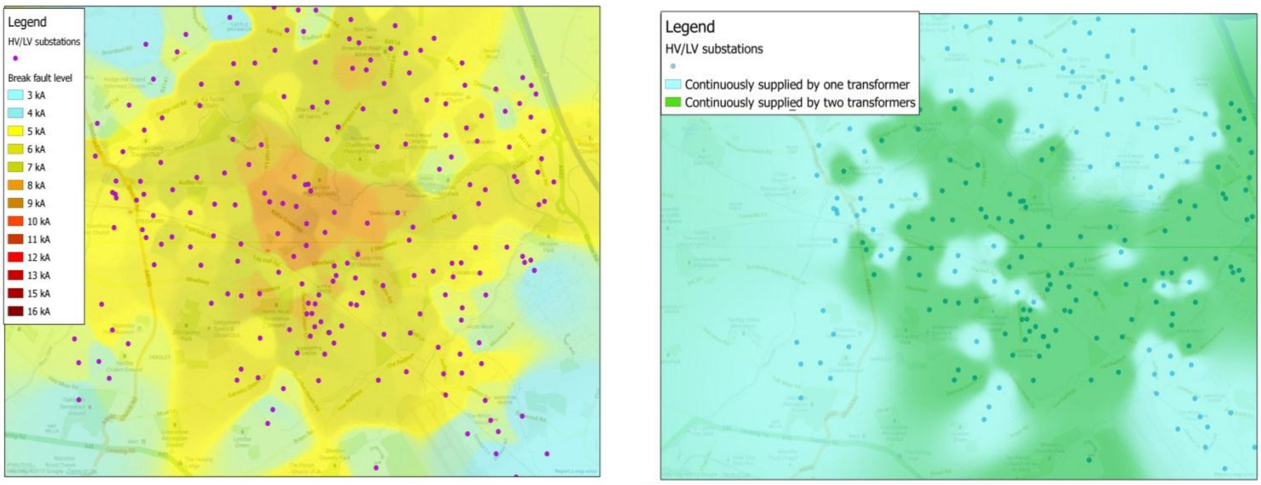
(a) (b)

Figure 6-3 Kitts Green 11 kV network with existing arrangement: (a) – Fault level heat map (b) – Security of supply heat map



(a) (b)

Figure 6-4 Kitts Green 11 kV network when GT1 and GT3 operating in parallel: (a)– Fault level heat map (b) – Security of supply heat map



(a) (b)

Figure 6-5 Kitts Green 11 kV network when GT1 and GT3 operating in parallel and FCL installed at GT1-GT3 interconnector: (a)– Fault level heat map (b) – Security of supply heat map

7 Process 4: Fault level management

The increased fault level granularity, introduced by the 11kV network model, has allowed a detailed analysis of the variation of fault level with time to be conducted for the ten Primary Substation sites selected for the FlexDGrid demonstrations.

This information has been used to quantify the frequency and duration of parallel operations and the headroom for accommodating customers' connections through a "connect and manage" approach. For this Method it is assumed that customers' connections would be integrated into a 'split' network configuration (a typical topology of some city centre electricity networks in the UK) and that infrastructure is in place to disconnect customers' generation and/or demand prior to a switching operation that would parallel transformers. Moreover, commercial frameworks would need to be in place to support the 'connect and manage' approach (as discussed in Section 9).

7.1 Analysis process steps

The technical analysis steps to produce time series fault level graphs (and hence real-time fault level profiles) for each Primary Substation site are given in Figure 7-1. Using these analysis steps, a time-series fault level profile graph was generated for each of the Primary Substations (A – J).

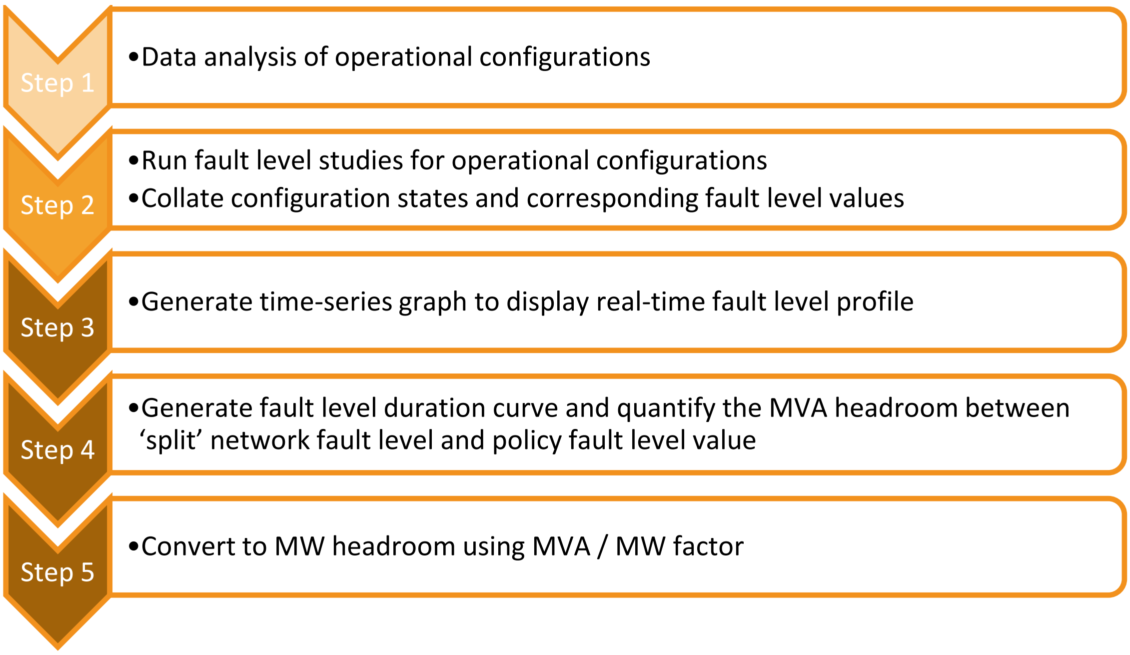


Figure 7-1 Technical analysis of substation fault level profiles

Information was exported from WPD's "Data Logger" (a data historian which records power system parameters at half hourly intervals) and analysed to determine the status of circuit breakers within the Primary Substation (transformer incomer circuit breakers, busbar coupler circuit breakers, busbar section / interconnector circuit breakers). The exported dataset contained the status of circuit breakers with a half-hour time resolution for the operational year from 1st September 2012 to 31st August 2013. Using '1' to represent the 'closed' status, and '0' to represent the 'open' status of each circuit breaker, a binary code was derived for each configuration in which the Primary Substations were operated.

For each operational configuration, at each half-hourly interval, the Peak Make and rms Break fault level values were calculated at each busbar within the Primary Substation and the highest value was used to represent the fault level of the entire substation. Based on this analysis, time-series graphs were generated to display the real-time fault level profile of each Primary Substation. In the limited number of situations where the status of circuit breakers was unknown, the circuit breaker was assumed to be closed as this would result in the worst-case fault level assessment.

In order to create fault level duration curves, the range of operational statuses resulting in the same fault level values were grouped together and ordered from the highest fault level value to the lowest fault level value. Based on the rms Break fault level of the modal (most frequent) 'split' configuration, the difference between the operational fault level and the policy fault level (250 MVA with a 5% safety margin) was calculated and used to quantify the headroom for accommodating customers' connections. Based on the total duration of parallel operations (currently resulting in a temporary and short-term increase in fault level values above the policy value), the percentage of the year was quantified for which capacity could be released.

7.2 Analysis Results

Using Primary Substation F as an example, the substation topology is given in Figure 7-2. During the period from the beginning of September 2012 to the end of August 2013, Substation F was operated in 22 different configurations (11 system normal configurations and 11 outage configurations), which resulted in five discrete fault level values (as given in Table 7-1).

The time-series real-time fault level profile for Primary Substation F is given in Figure 7-3 and the corresponding fault level duration curve for this fault level profile is given in Figure 7-4.

Using the technical analysis process given in Figure 7-1 and an assumed fault in-feed value of 4.5 MVA per MW of installed generation[14], this particular substation could accommodate an additional 18.1 MW of generation for 98.2% of the year if a flexible 'connect and manage' approach is adopted and the fault level in Figure 7-3 is managed appropriately. The results for the other substations selected for demonstrations in FlexDGrid are given in Table 7-2 and Appendix D. Moreover, the corresponding indicative annual energy yield values released by this Method are given in Table 9-1.

Configuration	Percentage of year	Break (MVA)	Make (MVA)	Break (kA)	Make (kA)
Parallel 1	1.19%	287	841	15.1	44.1
Parallel 2	0.55%	286	832	15.0	43.7
Parallel 3	0.02%	284	816	14.9	42.8
Split 1	91.17%	156	459	8.2	24.1
Split 2	7.07%	154	438	8.1	23.0

Table 7-1: Summary of operational configurations and corresponding fault levels for Substation F for the period 1 September 2012 – 01 August 2013

[14] KEMA Ltd, 2005, *The contribution to distribution network fault levels from the connection of distributed generation*, Crown, London, UK.

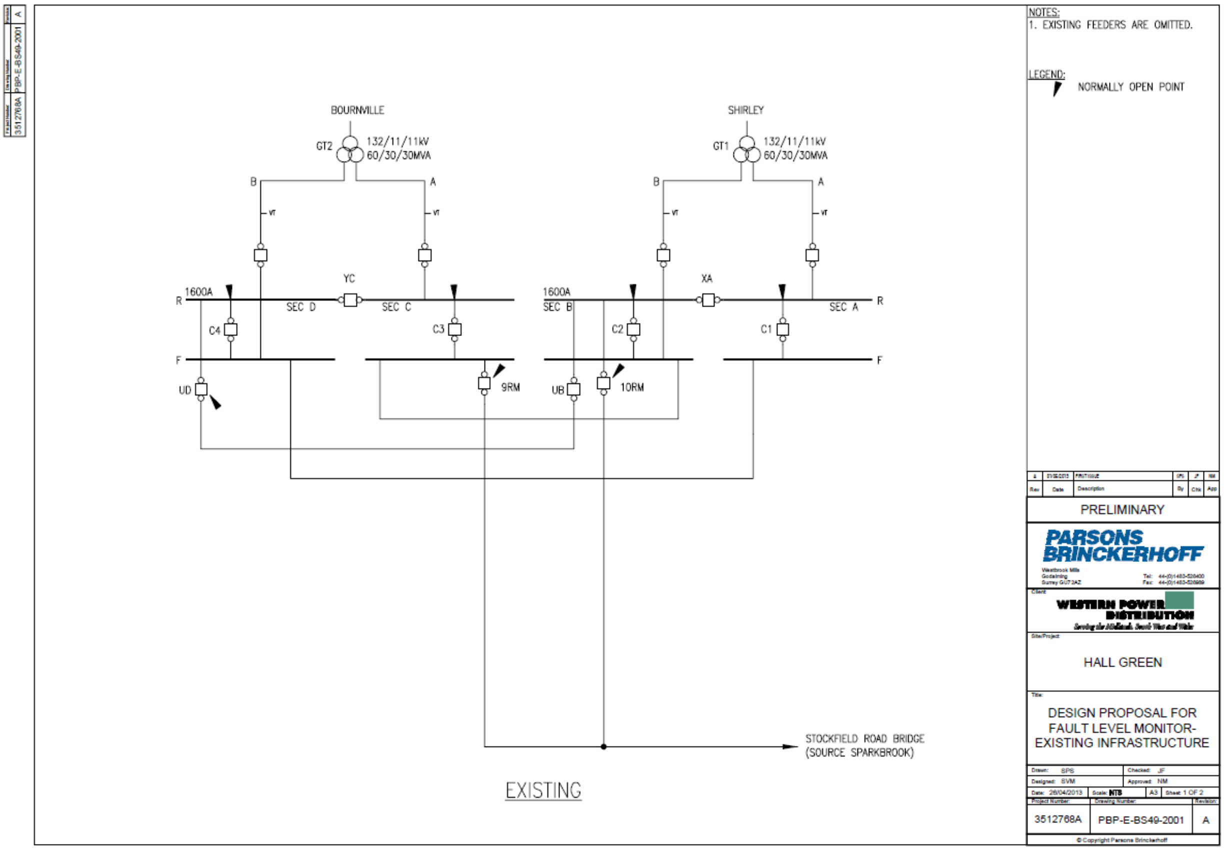


Figure 7-2 Topology of Substation F

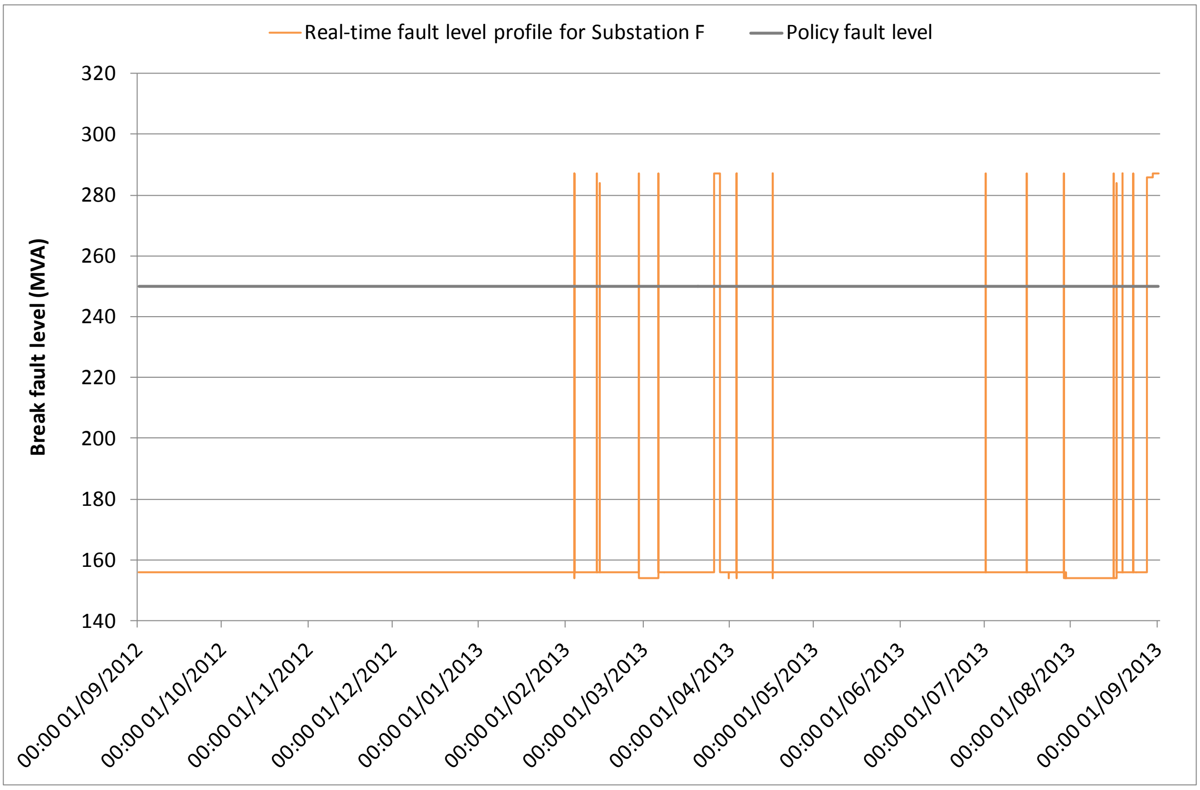


Figure 7-3 – A time series analysis of the real-time fault level profile at Substation F for the period 1 September 2012 – 01 August 2013

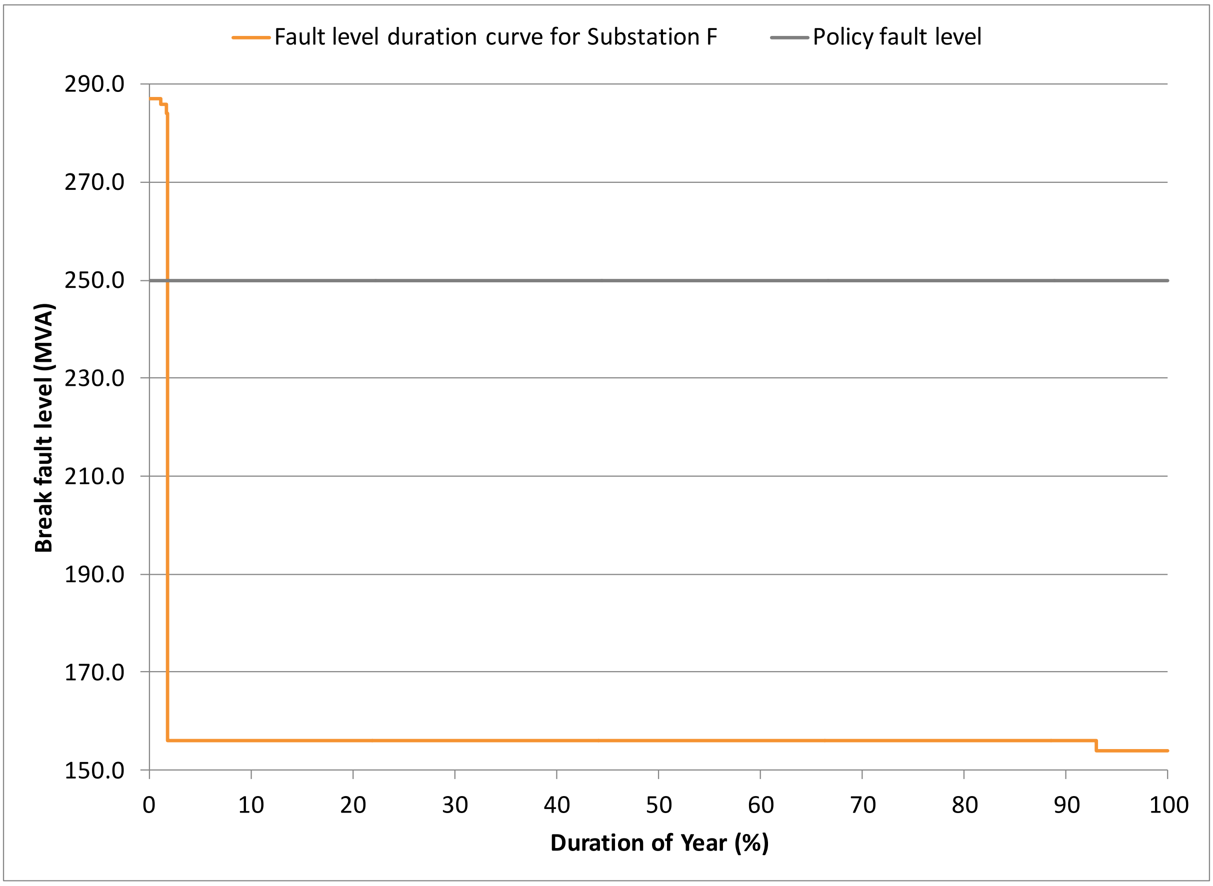


Figure 7-4 – Fault level duration curve for Substation F for the period 01 September 2012 – 31 August 2013

Substation ID	Cumulative duration of parallels	Parallel Fault Levels (MVA)	Split Fault Levels (MVA)	Switchgear rating (MVA)	Fault level headroom	Generation headroom
	(%)	**3ph Break (rms)**	**3ph Break (rms)**	**3ph Break (rms)**	**(MVA)**	**(MW)**
A	0.34%	304	162	250	75.5	16.8
B	3.80%	261	217	250	20.5	4.6
C	2.27%	268	149	250	88.5	19.7
D	0.22%	314	170	250	67.5	15.0
E	0.13%	308	166	250	71.5	15.9
F	1.76%	287	156	250	81.5	18.1
G	0.99%	258	217	250	20.5	4.6
H	0.39%	319	172	250	65.5	14.6
I	2.21%	304	160	250	77.5	17.2
J	1.13%	283	156	250	81.5	18.1

Table 7-2 Summary of Method Beta results

7.2.1 Analysis of Substation A

During the period from the beginning of September 2012 to the end of August 2013, Substation A was operated in 20 different configurations (18 system normal configurations and two outage configurations), which resulted in four discrete fault level values (as given in Appendix D, Table D-1).

Based on the operational configurations of Substation A from the beginning of September 2012 to the end of August 2013, 16.8 MW of capacity could be released for 99.7% of the year. If this capacity was exploited by CHP developers, a net energy yield of up to 139.1 GWh could be achieved.

7.2.2 Analysis of Substation B

During the period from the beginning of September 2012 to the end of August 2013, Substation B was operated in seven different configurations (four system normal configurations and three outage configurations), which resulted in four discrete fault level values (as given in Appendix D, Table D-2).

Based on the operational configurations of Substation B from the beginning of September 2012 to the end of August 2013, 4.6 MW of capacity could be released for 96.2% of the year. If this capacity was exploited by CHP developers, a net energy yield of up to 36.5 GWh could be achieved.

7.2.3 Analysis of Substation C

During the period from the beginning of September 2012 to the end of August 2013, Substation C was operated in 16 different configurations (six system normal configurations and ten outage configurations), which resulted in three discrete fault level values (as given in Appendix D, Table D-3).

Based on the operational configurations of Substation C from the beginning of September 2012 to the end of August 2013, 19.7 MW of capacity could be released for 97.7% of the year. If this capacity was exploited by CHP developers, a net energy yield of up to 160.0 GWh could be achieved.

7.2.4 Analysis of Substation D

During the period from the beginning of September 2012 to the end of August 2013, Substation D was operated in 18 different configurations (eight system normal configurations and ten outage configurations), which resulted in five discrete fault level values (as given in Appendix D, Table D-4).

Based on the operational configurations of Substation D from the beginning of September 2012 to the end of August 2013, 15.0 MW of capacity could be released for 99.8% of the year. If this capacity was exploited by CHP developers, a net energy yield of up to 124.6 GWh could be achieved.

7.2.5 Analysis of Substation E

During the period from the beginning of September 2012 to the end of August 2013, Substation E was operated in 17 different configurations (nine system normal configurations and eight outage configurations), which resulted in five discrete fault level values (as given in Appendix D, Table D-5).

Based on the operational configurations of Substation E from the beginning of September 2012 to the end of August 2013, 15.9 MW of capacity could be released for 99.9% of the year. If this capacity was exploited by CHP developers, a net energy yield of up to 132.1 GWh could be achieved.

7.2.6 Analysis of Substation F

During the period from the beginning of September 2012 to the end of August 2013, Substation F was operated in 22 different configurations (11 system normal configurations and 11 outage configurations), which resulted in five discrete fault level values (as given in Appendix D, Table D-6).

Based on the operational configurations of Substation F from the beginning of September 2012 to the end of August 2013, 18.1 MW of capacity could be released for 98.2% of the year. If this capacity was exploited by CHP developers, a net energy yield of up to 148.1 GWh could be achieved.

7.2.7 Analysis of Substation G

During the period from the beginning of September 2012 to the end of August 2013, Substation G was operated in 20 different configurations (seven system normal configurations and 13 outage configurations), which resulted in five discrete fault level values (as given in Appendix D, Table D-7).

Based on the operational configurations of Substation G from the beginning of September 2012 to the end of August 2013, 4.6 MW of capacity could be released for 99.0% of the year. If this capacity was exploited by CHP developers, a net energy yield of up to 37.5 GWh could be achieved.

7.2.8 Analysis of Substation H

During the period from the beginning of September 2012 to the end of August 2013, Substation H was operated in ten different configurations (seven system normal configurations and three outage configurations), which resulted in six discrete fault level values (as given in Appendix D, Table D-8).

Based on the operational configurations of Substation H from the beginning of September 2012 to the end of August 2013, 14.6 MW of capacity could be released for 99.6% of the year. If this capacity was exploited by CHP developers, a net energy yield of up to 120.7 GWh could be achieved.

7.2.9 Analysis of Substation I

During the period from the beginning of September 2012 to the end of August 2013, Substation I was operated in eight different configurations (five system normal configurations and three outage configurations), which resulted in five discrete fault level values (as given in Appendix D, Table D-9).

Based on the operational configurations of Substation I from the beginning of September 2012 to the end of August 2013, 17.2 MW of capacity could be released for 97.8% of the year. If this capacity was exploited by CHP developers, a net energy yield of up to 140.2 GWh could be achieved.

7.2.10 Analysis of Substation J

During the period from the beginning of September 2012 to the end of August 2013, Substation J was operated in ten different configurations (seven system normal configurations and three outage configurations), which resulted in four discrete fault level values (as given in Appendix D, Table D-10).

Based on the operational configurations of Substation J from the beginning of September 2012 to the end of August 2013, 18.1 MW of capacity could be released for 98.9% of the year. If this capacity was exploited by CHP developers, a net energy yield of up to 149.0 GWh could be achieved.

7.3 Discussion

The modelling of Method Beta (Real time fault level management) demonstrates that between 4.6 MW and 19.7 MW of capacity per Primary Substation site could be released for customers' connections for between 96.2% and 99.9% of the year. This includes a 5% safety margin and represents the potential capacity that could be unlocked through the implementation of real-time fault level measurement and monitoring infrastructure in Method Beta, managing fault levels in real-time through the connection and disconnection of customers' generation and demand.

Each substation has fault level issues that would result in generation constraints for periods of the year. Therefore the suitability of each site for deployment of fault level mitigation technologies was considered. Substation G currently has low fault level headroom and was not selected for a fault level mitigation technology demonstration as there are plans already in progress to build a new substation adjacent to the site with sufficient capacity to accommodate future customers' connections.

Due to space availabilities, it was concluded in SDRC-2 that Substations A – E are more suitable for fault level mitigation technologies and Substations A – J are suitable for fault level monitoring technologies.

7.4 Evaluation

In this process, Method Alpha has identified the potential headroom for accommodating generation connections and Method Beta will put the systems in place to exploit the headroom if a flexible 'connect and manage' approach is adopted. The benefits of modelling Method Beta are:

1. A real-time fault level profile is created which can be directly compared with measured and monitored fault level values;
2. The modelling aspects of this Method can be implemented with Business as Usual fault level assessment processes or enhanced fault level assessment processes;
3. Network reinforcement can be avoided in situations where there is a constraint on capital investment;
4. Generation can be readily integrated with limited requirements for network reconfiguration; and
5. This could lead to quicker and cheaper customer connections.

However, the following should be considered when evaluating the benefits of this Method against Method Alpha, Method Gamma and network reinforcement:

1. There could be an increase in study time (up to 1 day) in order to generate the real-time fault level profile based on historic data and network configuration analysis;
2. Additional communications infrastructure would be required to implement this Method to control generation connections and this bares additional risk; and
3. Method Beta may not yield the same security of supply benefits as Method Gamma (fault level mitigation technologies) and network reinforcement, in terms of reducing customer interruptions and customer minutes lost, as the network is operated in a split configuration to release capacity for future customers' connection.

8 Process 5: Fault level mitigation

8.1 Functional specification

A functional specification has been developed together with an excel tool for the planning of fault level mitigation technology installations (such as fault current limiters). This tool supports WPD's Primary System Design team with planning the integration of future customers' connections by allowing the team to establish which technologies are suitable for deployment in particular substations. The tool also allows the design parameters of fault level mitigation technologies to be determined (for example, the target fault level reduction and the required impedance characteristic of the fault current limiter).

The functional specification for the fault level mitigation technology planning and analysis tool is given in Appendix B.

8.2 Excel model

A generic calculation is given below for rms Break fault levels at an illustrative Primary Substation in Figure 8-1. Similar calculations were carried out for Peak Make fault levels. A typical value of 4.5 MVA per MW was used to represent the fault level contribution from CHP generators.

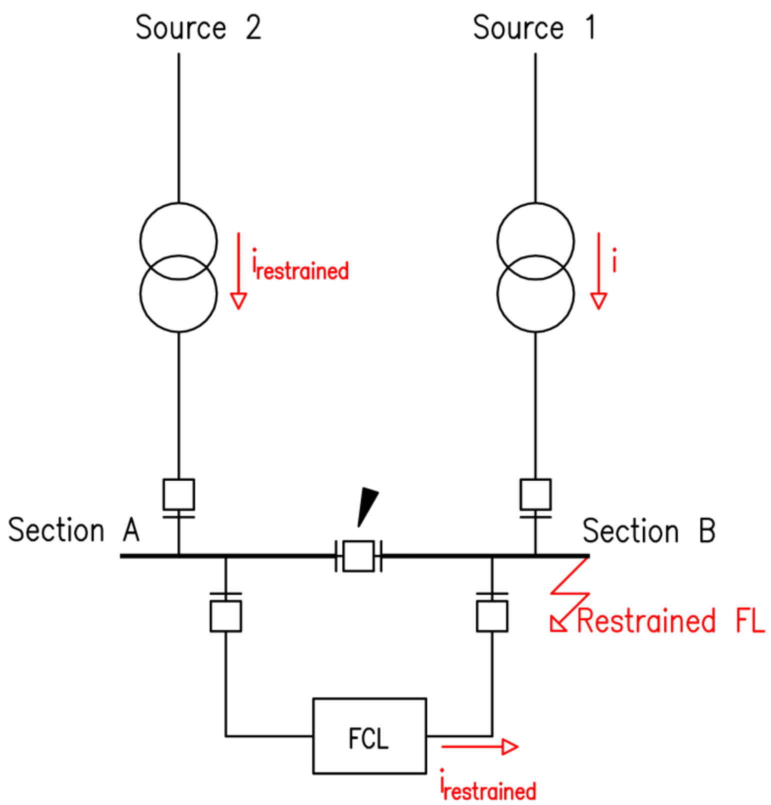


Figure 8-1: An illustrative Primary Substation for fault level reduction calculations

Unrestrained fault level (Source 1 II Source 2) = 300 MVA (Source 1 in parallel with Source 2)

Fault level contribution from generation = *Contribution Factor* $\times$ *(10% of Firm Capacity)*
= 4.5 MVA / MW x 0.1 x 156 MVA
= 70.2 MVA

Restrained fault level = *Policy Break Fault Level – Generation Contribution*
= 250 MVA – 70.2 MVA
= 179.8 MVA

Required fault level reduction through FCL (from Source 2)

$$= \left[1 - \left(\frac{Restrained\ FL - Source\ 1}{Source\ 2}\right)\right] \times 100\%$$

$$= \left[1 - \left(\frac{179.8\ MVA - 150\ MVA}{150\ MVA}\right)\right] \times 100\%$$

= 80.1%

Reduction as a percentage of Unrestrained FL

$$= \left[1 - \left(\frac{Restrained\ fault\ level}{Unrestrained\ fault\ level}\right)\right] \times 100\%$$

$$= \left[1 - \left(\frac{179.8\ MVA}{300\ MVA}\right)\right] \times 100\%$$

= 40.1%

As part of FlexDGrid's detailed design phase, this calculation was applied to Primary Substations (A to E) and for each substation a 5% contingency was included in the target fault level reduction value. The target reduction (restrained fault level) values and the overall percentage fault level reduction values are given in Table 8-1 and Table 8-2. The graphical user interface for the fault level mitigation models is given in Figure 8-2.

Substation	Firm Capacity	Parallel Fault Levels (MVA)		Target FL (MVA)	
Site	(MVA)	3ph Break (rms)	3ph Make (peak)	3ph Break (rms)	3ph Make (peak)
Substation A	156.0	300	901	170.81	531.81
Substation B	78.0	261	770	204.16	565.16
Substation C	78.0	268	753	204.16	565.16
Substation D	78.0	292	837	204.16	565.16
Substation E	78.0	307	908	204.16	565.16

Table 8-1: Substation firm capacities, parallel fault levels and target fault level reductions

	Including 5% Contingency			
	Source 2 FL Reduction		Overall FL Reduction	
Substation	3ph Break (rms)	3ph Make (peak)	3ph Break (rms)	3ph Make (peak)
Substation A	86%	82%	43%	41%
Substation B	44%	53%	22%	27%
Substation C	48%	50%	24%	25%
Substation D	60%	65%	30%	32%
Substation E	67%	76%	34%	38%

Table 8-2: Substation source and overall percentage fault level reductions

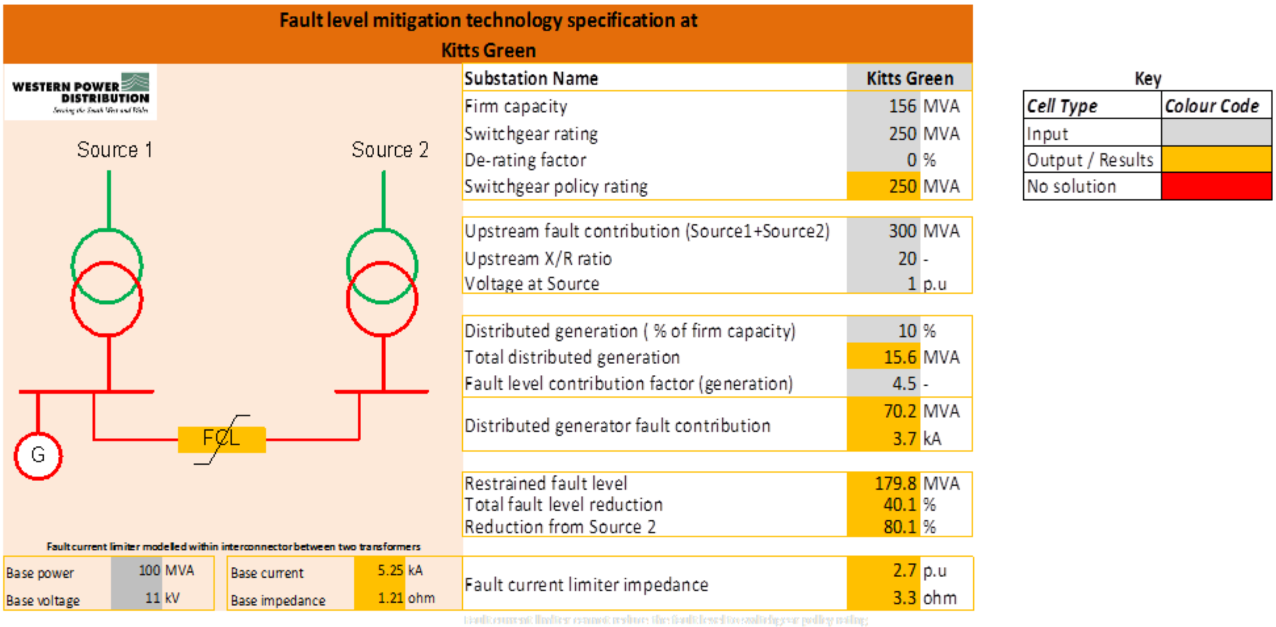


Figure 8-2 Example graphical user interface for excel planning tool

8.3 Learning points and recommendations

A learning point and observation from the development of this tool was related to the definition of the required fault level reduction and the communication of requirements to fault current limiter manufacturers. As a result, it is recommended that fault level reductions are defined in two ways: (i) relative to the total (overall) fault contribution from combined sources; and (ii) relative to the fault contribution from the single source which is to be restrained. This is because the fault contribution from some sources (for example, the Grid Transformer at the faulted busbar) are unaffected by the fault current limiter operation in terms of fault level reduction. Therefore a much more significant fault level reduction is needed from the other source in order to achieve the overall target fault level reduction.

It is recommended that any network operator who is looking to utilise this initial design tool should model both the Peak Make and rms Break fault contributions for three-phase and single-phase-to-earth faults to identify the most onerous condition in which the fault current limiter will be required to operate. Furthermore, this model could be extended to incorporate existing generation, downstream load contributions to fault level and variable X/R ratios in the system resulting from dynamic equipment. In addition, it is recommended that transient analysis studies should be conducted to understand the dynamic behaviour of the fault current limiter and its impact on the power system during fault conditions.

Building on the output of SDRC-4, the excel model will be further refined to provide a cost-benefit analysis tool for DNOs to evaluate the merits of FLMT deployments when compared to network reinforcement. Moreover, through collaboration with FLMT suppliers, technology-specific models (such as fault current limiter models) will be developed and integrated into WPD’s power system analysis package (PSS/E).

A key outcome from the FlexDGrid Workshop discussions with other GB DNOs was that the onus should be on manufacturers to provide DNOs with comprehensive fault current limiter models which can be readily integrated into DNOs’ power system analysis packages (for example, as plug-ins or user defined models).

9 Process 6: Novel commercial frameworks

Data has been gathered to characterise the Primary Substations in terms of historic connection applications (number of applications and prospective installed capacity) and reliability data (customer interruptions and customer minutes lost). This will act as the reference from which the benefits of Method Alpha, Beta and Gamma can be measured (the benefits analysis of the different Methods will be reported in SDRC-10).

Building on learning from WPD's LCNF Tier-2 Project "Lincolnshire Low Carbon Hub", connection options have been initially scoped out for customers who are flexible in terms of their connection to the distribution network. For example, as part of Method Beta, a 'Connect and Manage' commercial framework is being developed (see Figure 9-1), building on the technical analysis in Section 7 to quantify the indicative energy yield constraints and CO_2 savings that are given in Table 9-1. This information will be used in a cost-benefit analysis tool to evaluate the merits of offering 'Connect and Manage' solutions alongside network reinforcement options.

To date, the following learning points have been transferred from "Lincolnshire Low Carbon Hub" to FlexDGrid:

1. Terminology: New terms have been developed and defined through "Lincolnshire Low Carbon Hub" for the active management of customers' connections. Where applicable, FlexDGrid will adopt the same terminology and definitions.
2. Providing certainty for customers: Following a workshop with customers as part of the "Lincolnshire Low Carbon Hub" project, a key outcome was that generation customers require certainty in terms of generation constraints (particularly the total cumulative duration of time that generators could be constrained from exporting their full power output). This allows customers to assess the financial risks associated with developing generation.
3. Streamlining novel commercial frameworks with existing connection offers and connection agreements: The new connection offers and connection agreements need to follow the same format as existing connection offers and connection agreements. If there is too much deviation between new and existing offers and agreements the customers may not secure the finance to develop the generation project.

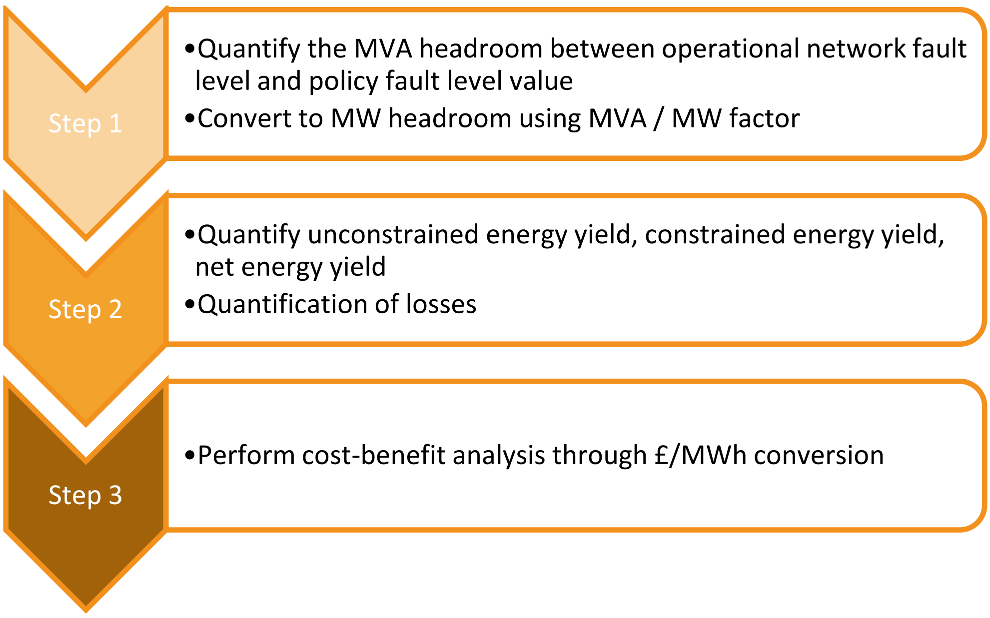


Figure 9-1 Techno-economic analysis of 'connect and manage' solution

Substation ID	Generation headroom (MW)	Indicative cumulative annual connection time (% per year)	Unconstrained Energy Yield (GWh/year)	Constrained Energy Yield (GWh/year)	Net Energy Yield (GWh/year)	CO_2 savings (kt/year)[15]
A	16.8	99.7%	139.6	0.5	139.1	20.6
B	4.6	96.2%	37.9	1.4	36.5	5.4
C	19.7	97.7%	163.7	3.7	160.0	23.6
D	15.0	99.8%	124.8	0.3	124.6	18.4
E	15.9	99.9%	132.2	0.2	132.1	19.5
F	18.1	98.2%	150.7	2.7	148.1	21.8
G	4.6	99.0%	37.9	0.4	37.5	5.6
H	14.6	99.6%	121.1	0.5	120.7	17.9
I	17.2	97.8%	143.3	3.2	140.2	20.7
J	18.1	98.9%	150.7	1.7	149.0	22.0

Table 9-1 Indicative energy yields for potential generation capacities connected to the different substation sites

Novel commercial frameworks are also being developed for Method Alpha (based on generation power factor control) and Method Gamma (based on fault current limiter deployments). The results of the development of these novel commercial frameworks will be reported in SDRC-11 (Development of novel commercial frameworks) at the end of the project in March 2017.

[15] CO_2 emissions have been calculated using the same methodology, as given in Appendix P of the FlexDGrid Full Submission Pro-forma, to compare emissions savings from CHP with the present UK generation mix for electricity and provision of heating from domestic boilers.

10 Conclusion

This report has provided evidence to fulfil the following criteria, as defined in SDRC-4:

(i) A developed and tested enhanced fault level assessment (EFLA) process with endorsement from WPD planning and design engineers;
(ii) Quicker response to customers' connections applications;
(iii) Characterisation of the substations to determine the suitability of potential fault level mitigation technologies;
(iv) Open source fault level mitigation technology models; and
(v) Quantification of additional capacity that will be unlocked to accommodate future customers' connections.

Fulfilling criterion (i), enhanced fault level assessment processes have been developed and tested with endorsement from WPD planning and design engineers. Furthermore, two additional DNO workshops have taken place to discuss the development and implementation of enhanced fault level assessment processes, giving other DNOs the opportunity to provide feedback on the processes and endorse the planned demonstration approach.

Fulfilling criterion (ii), Method Alpha could result in up to a 30-month reduction in connection time, Method Beta could result in up to a 24-month reduction in customer connection time and Method Gamma could result in up to a 12-month reduction in customer connection time when compared to typical fault level-related network reinforcement timescales (36 months).

Fulfilling criterion (iii), substations have been characterised to determine their suitability for integration of fault level mitigation technologies based on analysis and ranking of a number of considerations such as fault level reduction requirements, space availabilities, network connection requirements, substation access, investment plans and auxiliary supply capacities. The detailed results of this analysis have been reported in SDRC-2 (Confirmation of project detailed design) and SDRC-6 (Evidencing the Methodology of Method Gamma).

Fulfilling criterion (iv), open source fault level mitigation technology models have been developed in MS Excel and the functional specification of the models has been published as part of this SDRC for access by other DNOs and interested parties. Based on the technologies selected for demonstrations, FlexDGrid will collaborate with manufacturers to develop technology-specific models. The results of developing and demonstrating these models will be published as part of SDRC-10 (Analysis of test results).

Fulfilling criterion (v), the enhancements resulting from Method Alpha could lead to a 10% - 15% reduction in fault contribution from generation and hence release 10% - 15% additional capacity. In situations where parallel fault levels already exceed equipment ratings, Method Alpha would not unlock capacity for customers' connections by itself. However, the detailed modelling of the network in Method Alpha allows accurate fault level assessments to take place more quickly and is an enabler for detailed modelling of real-time fault level profiles for fault level management in Method Beta and the behaviour of fault level mitigation technologies in Method Gamma.

The modelling of Method Beta (Real time fault level management) demonstrates that between 4.6 MW and 19.7 MW of capacity per Primary Substation site could be released for customers' connections for between 96.2% and 99.9% of the year. This represents the potential capacity that could be unlocked in Method Beta by managing fault levels in real-time through the connection and disconnection of customers' generation and demand.

The modelling of Method Gamma (Fault level mitigation technologies) demonstrates that between 7.8 MW and 15.6 MW of capacity per Primary Substation site could be released for customers' connections, based on accommodating generation up to 10% of the firm load capacity of the Primary Substation through the deployment of fault level mitigation technologies.

11 Appendices

- Appendix A - Questionnaire and collated responses;
- Appendix B - Functional specification of fault level mitigation technology models;
- Appendix C - Network model parameters for sensitivity analysis; and
- Appendix D - Modelling of Method Beta and its application to substation sites.

Appendix A – Questionnaire and collated responses

12 questionnaire responses were received, representing all GB DNOs and 11 licence areas. The collated questionnaire responses are given in Table A-1.

	Question	Response
1.1	Is there merit in an industry-wide review of fault level calculation standards?	Yes (10 respondents). Unsure (2 respondents).
		Additional comments: • A National Working Group was set up (through the ENA) a few years back, but the results were quite different for different DNOs.
1.2	Please explain why / why not.	Consistent approach from DNOs will help demand and generation customers.
		Consistency across DNOs and for regulatory reporting.
		G74 was written some 20 years ago and generator technologies that exist now are quite different to those that existed then e.g. DFIGs, fully inverted generators. Some common methodology of modelling these new technologies could be useful.
		It will be beneficial for an engineer to assess results from other bodies.
		G74 gives different results for DC decrement due to X/R ratio treatment
		To create an industry-wide standardised approach with more accurate and reliable calculations.
		Fault level assessments are carried out on regular basis with the most up-to-date model of the network. Further work can be done in terms of improving the information held in the models and validating the output with measurements at defined locations.
		Consistency of approach.
		G74, ETR120 require clarification.
		There is a need to develop consistent guidelines to deal with the fault contribution from a range of new generation technologies. Similarly, guidance for fault contribution from the load is given in G74 at 33kV only. This guidance should be reviewed in light of changing load technology and small embedded generators. Is it appropriate to extend this guidance to other voltage levels?
1.3	Would the establishment of a simple but comprehensive test network be useful in order to gain confidence in software and /or methods employed?	Yes (10 respondents). No (2 respondents).
		Additional comments: • Current network model is sufficient to test different calculations methods and has been confirmed with other software packages • It's worth noting that it's been done before in the ASG/OSG X/R sub-group (ENA). Any learning points from that exercise may have already been implemented.

	Question	Response
1.4	Would you welcome clarifications to make the interpretation and application of ER G74 more consistent?	Yes (10 respondents).
		No (2 respondents).
1.5	Please explain your answer to (1.4)	General consistent approach for higher voltage networks (>=33kV) but G74 difficult to apply at secondary network level.
		To ensure accurate modelling and consistency between analysis applications.
		We're comfortable with the way that we apply G74, but we recognise that there may be elements that may need updating or expanding.
		The method options to calculate fault level could give very different answers e.g. X/R ratio.
		Wide interpretations can be made at present with the application of G74 to 11kV networks. Different types of loads and different fault in-feed characteristics now exist to those when G74 was written. Suspect that 5-10% is added on – could be too onerous, or not onerous enough!
		No issues with G74.
		To include more information and clarification on generator modelling.
		Believe that there is a certain amount of confusion over the interpretation of G74.
		To include advice on different generation application modelling and load fault contribution.
		Consistent application of a fault calculation standard across the industry makes sense, particularly when dealing with fault level mitigation due to new generation connections.
2.1	Are you assessing 11 kV or 6.6 kV fault levels by applying computer simulations?	Yes (12 respondents)
		Additional comments: • To some extent.
2.2	If so, what software is used?	DINIS (3 respondents).
		IPSA for EHV networks to primary substation busbars. DINIS for HV networks to LV busbars.
		IPSA, PSS/E.
		From Primaries to 11kV / 6.6kV bars, 11kV planners use DINIS. Elements of 11kV model may be built for primary substation upgrades although generally it is assumed that if everything is ok at 11kV bars then everything is ok downstream.

	Question	Response
2.2 cont.	If so, what software is used?	'PSSE' in conjunction with proprietary "bolt on" G74 software, for 132kV & EHV network design, including Primary Substation 11kV & 6.6kV switchgear. 'Dinis' is our HV design tool (11kv & 6.6kV circuits / plant). It has no G74 capability.
		GROND Version 7.
		DigSilent and GROND.
		PSSE to obtain FL at 132/11kV primary substations. DINIS to model HV/LV generation.
		DigSilent & DINIS.
		DigSilent PowerFactory and PSS/E.
2.3	• What is the extent of the model (e.g. 132 kV equivalent infeed to 11 or 6.6 kV primary substation busbars or 132 kV equivalent infeed to 11 or 6.6 kV ring main units etc)	33kV, 11kV and 6.6kV networks modelled in detail. Each BSP connected to 132kV slack bar.
		33kV equivalent generator at the transmission – distribution interface.
		Separate models for EHV networks down to HV primary substation bars (IPSA) and HV primary substation bars and corresponding HV distribution networks (DINIS). For the EHV model: NGET week 42 equivalent infeeds used at a transmission voltage (i.e. GSPs – SGTs are modelled. Remaining networks modelled down to 11kV busbars at primaries. For the HV model: Infinite busbar with an impedance modelled on the primary side of primary substation transformers. Modelled through to LV busbars in distribution substations (excludes LV ways). The HV and EHV models can be merged to create a single model from the GSP to the LV busbars.
		From National Grid SGTs to 11/6.6kV busbars.
		PSS/E model extends from 400kV to 11kV / 6.6kV primary substation bars. There are 4 boundary nodes into NG's network.
		'PSSE': Fully modelled from NGT's 400kV network down to Primary substations. 'Dinis': Primary substation equivalent infeed to 11kV/6.6kV RMUs etc.
		The 11kV network is modelled in GROND Version 7 with all the 11kV Primaries and associated feeders modelled with all the transformers located along the feeder with the cables/conductors in between them.

	Question	Response
2.3 cont.	• What is the extent of the model (e.g. 132 kV equivalent infeed to 11 or 6.6 kV primary substation busbars or 132 kV equivalent infeed to 11 or 6.6 kV ring main units etc)	DigSilent – Equivalent model of 400kV and 275kV, full representation of the 132kV, 33kV and 11kV network down to busbars at Primary substations (feeder data is not represented in DigSilent). Grond – 11kV network modelled with an equivalent infeed at 11kV Primary Substation busbar.
		132 kV equivalent infeed to 11 or 6.6 kV primary substation busbars
		DigSilent: 400/275kV equivalent energises 132kV to 11/6.6kV model DINIS: 132 to 11/6.6kV equivalent energises 11/6.6kV model
		Transmission network down to (mainly 11kV) primary busbars.
2.4	• Does EA ER G74 (1982) [and/or EA ETR 120 (1995)] influence the simulation?	Yes (9 respondents). We don't use the G74 package in DINIS (1 respondent). To some extent (1 respondent). No (1 respondent).
2.5	• Briefly describe the influential factors	G74 equivalent induction motor infeed modelled at each primary substation 11kV or 6.6kV busbars.
		Takes account of estimated motor contribution therefore returns higher FL result.
		Based on full DQ axis machine models including saturation, saliency, sub-transient and transient decay and second harmonic effects (extract from IPSA Power website).
		We calculate sub-transient infeeds at time = 0.
		X/R ratio(DC decay), load fault infeed.
		Basic data is used in the GROND model, e.g. transformer impedances and line impedances. Simple calculations are carried out to give a result which is normally sufficient for our studies. If the result is close to limits, then a more detailed study needs to be carried out.
		Fault level contribution from the downstream network dependent on type and profile of connected load.
		DigSilent: Method C used for X/R, equation 5.2.3 used for peak make current, equation 5.3 used for DC current.
		Considering load infeed has an impact, as does the use of IEC60909 method c) for estimation of equivalent X/R ratios.
2.6	• Please define any specific problems encountered with the application of aspects of ER G74 (and/or ETR 120)	None.
		It is only an estimate of possible motor connected load.
		Not aware of any with IPSA.
		We don't assume any decrement of the a.c. component of fault current. However, this leads to difficulty with plant with a very short a.c. time constant.

	Question	Response
2.6 cont.	• Please define any specific problems encountered with the application of aspects of ER G74 (and/or ETR 120)	Some software does not facilitate variable time constant for subtransient and transient component. It will also be helpful to provide guidance of modelling power electronics e.g. DFIG, PV, STATCOM etc.
		Treatment of fault in-feed from different GSP groups – not necessarily taken into account consistently.
		General lack of detailed information for generators, particularly where inverters feature.
		High X/Rs resulting in high peak making and breaking DC currents not always credible and can be a concern.
		Some software does not properly support some G74 requirements so that scripts and/or post-processing had to be used.
2.7	• Is the fault time a variable set by the software user (e.g. 10 ms make, 100 ms break)?	Yes (9 respondents) No (2 respondents)
		Additional comments: • Make – 10ms, Break – 100ms. • For the IPSA EHV model. • For the EHV DINIS models only sub-transient fault-levels are used as a most onerous case. • 10 ms make, 50ms break – this will be investigated further if close to limits. • 10ms 'Make', 10ms to 250ms 'Break'. • 60ms break time constant is generally used for 33kV switchgear, 60ms to 120ms time constant for new 132kV switchgear types. • 10 and 60msec respectively. • Peak make current is calculated as described in 5.2.3 of G74, i.e. not at a specific time. For 33kV and below, a 90ms break time is normally used for routine studies.

<table>
<tr><th></th><th>Question</th><th colspan="3">Response</th></tr>
<tr><td rowspan="3">2.8</td><td rowspan="3">• Is distributed generation modelled?</td><td>At 33 kV</td><td>At 11 or 6.6 kV</td><td>At 0.4 kV</td></tr>
<tr><td>Yes (9 respondents).</td><td>Yes (9 respondents).</td><td>Yes (7 respondents).
No (4 respondents).
N/A (1 respondent).</td></tr>
<tr><td>Additional Comments:
• Everything is modelled.
• Yes & no (currently in PSSE, but not in Dinis)
• N/A for Distribution Planning - GROND Version 7 models the 11kV system.</td><td>Additional comments:
• As an equivalent in the EHV model.
• Most generation.
• Yes & no (currently in Dinis but not in PSSE).
• GROND Version 7 does not have the ability to model distributed generation. GROND Version 10 has the ability to model distributed generation and it will be used by mid-2014.
• When directly connected to 11kV bars).</td><td>Additional comments:
• As a mix of equivalent & actual models.
• As an equivalent in the EHV model.
• Standby generation.
• GROND Version 7 models the 11kV system.</td></tr>
<tr><td rowspan="8">2.9</td><td rowspan="8">• How is inverter-connected generation modelled?</td><td colspan="3">As equivalent synchronous model</td></tr>
<tr><td colspan="3">Not modelled accurately. Only model generators above 50kW</td></tr>
<tr><td colspan="3">Mixture – some are modelled as synchronous plant with an equivalent infeed resulting in errors to either make or break duty values. Others are modelled independently for make and break duties – manual switching by user required dependent upon study being undertaken i.e. make or break.</td></tr>
<tr><td colspan="3">Modelled as synchronous plant with an equivalent infeed resulting in errors to either make or break duty values.</td></tr>
<tr><td colspan="3">Obtain fault infeed current characteristics and mimic the fault current by a synchronous machine model.</td></tr>
<tr><td colspan="3">Synchronous generator with higher impedance to limit fault in-feed</td></tr>
<tr><td colspan="3">Currently, unless otherwise stated by Developer, as a pure reactance value which will contribute 1.1 times its rated output. This practice is under review.</td></tr>
<tr><td colspan="3">N/A for GROND Version 7.

In GROND Version 10, the generation form will show the generators found on the selected circuits up to a maximum of eight generators.</td></tr>
</table>

	Question	Response
2.9 cont.	• How is inverter-connected generation modelled?	DigSilent - Generic model for inverted connected generation, in particular Solar PV. Ability to model real parameters when they are provided by customers.
		Considered not to contribute to FL
		By DigSilent library model
		Equivalent voltage source behind impedance model.
2.10	• Is load fault contribution modelled?	Yes (10 respondents). No (2 respondents).
		Additional comments: • In IPSA but not in the DINIS HV model. • Not in DINIS itself, this is calculated in spreadsheet and added to the results. • No, not at 11kV but it is modelled at 33kV in DigSILENT Powerfactory.
2.11	If so, • How is section 9.5 of ER G74 applied at busbars other than 33 kV?	Applied at the HV busbar with appropriate allowance is made for transformer impedance.
		DINIS allows the modelling of an equivalent motor representing G74 contribution. Modelled at 11kV bus-bar at each 33/11kV site.
		The contribution is considered at the 33kV bar and inflated based upon an average primary transformer impedance and then added in to the IPSA model at the HV busbar.
		The contribution is applied at the 33kV bar and inflated based upon the actual impedance between it and the lower voltage busbar.
		In IPSA, equivalent motor was attached to load bar in order to mimic fault infeed. In PSS/E, a separate python script was used to produce G74 calculation.
		1.1 MVA / MVA at 33kV, ratio can be changed by user
		A default value of 1.1 MVA contribution / 1 MVA of load (adjustable on a ‘per busbar’ basis).
		N/A at 11kV in GROND.
		Contribution proportional to the load on the 11kV busbars
		General load assumed to contribute 1MVA per MVA of MD (G74 9.5.1)
		1: 1.1MVA/MVA of aggregate winter demand at 11 and 6.6kV
		With no generator contribution, the 11kV load infeed is scaled to give the required G74 infeed at 33kV.

	Question	Response
2.12	• Are significant numbers of HV-connected motors modelled (either individually or as groups)?	Yes (4 respondents). No (8 respondents).
		Additional comments: • Yes – grouped based on peak 33/11kV site load. • Yes as groups. • Yes, and modelled for future years, 0.5 MW and above. • No – some but not many. • Not at Distribution level.
2.13	• Are you satisfied that load fault contribution is of acceptable accuracy?	Yes (1 respondent). Unsure (6 respondents). No (5 respondents).
		Additional comments: • We are going from G74 values but fault levels are largely unknown. • It's unclear whether the values calculated are still representative of the loads calculated today. It's unclear at what point we should move from HV to LV load modelling.
2.14	• What is the extent of modelling of circuit susceptance, e.g.33 kV cables, 33 kV lines, etc.	Included at 132kV, but limited data at lower voltages (2 respondents).
		Unknown
		Modelled for all circuits. Data forms part of the cable database
		Included at 132kV, but limited data at lower voltages.
		132/66/33kV lines
		Standard cable values used
		Fully modelled
		Basic impedances of transformers and lines are used to model the 11kV in GROND.
		Circuit parameters are used which include susceptance (B and B0) per km
		Generic data included in HV network
		Modelled fully at all voltages
		Circuit susceptance is modelled for 33kV and above.
2.15	• What is the extent of modelling of power factor correction, e.g. 33 kV SVC etc.	None (5 respondents).
		Modelled where it exists, but there are limited instances, it's also manually adjusted (2 respondents).
		Do not normally have SVC on system except GSP busbars.
		All NG kit is modelled Not aware of any other kit on network excepted for a few switched capacitor banks

	Question	Response
2.15 cont.	• What is the extent of modelling of power factor correction, e.g. 33 kV SVC etc.	Network has a small number of such connections. A few static Capacitor Banks are modelled.
		Modelled at and above 6.6kV where they occur.
		DNO equipment is represented.
2.16	• For circuit resistances (e.g. transformers, cables and overhead lines) are hot AC values applied or cold DC?	Hot A.C. (8 respondents). Unsure (3 respondents). Cold resistances (1 respondent).
		Additional comments: • Hot values used – although cold are preferred for fault studies.
2.17	• Are transformer off-nominal voltages and the associated effect on impedance modelled?	Yes (8 respondents). No (4 respondents).
		Additional comments: • Off-nominal voltages included but fixed transformer impedance. • Full range of tx taps modelled (and change in voltage, but the impedance is not changed)
2.18	• Are changes in transformer impedance with tap position modelled?	Yes (2 respondents). Unsure (1 respondent). No (9 respondents).
		Additional comments: • Full range of tx taps modelled (and change in voltage, but the impedance is not changed)
2.19	• For generator modelling, is the saturated or the unsaturated impedance used?	Saturated (7 respondents). Saturated, unsure (1 respondent). Unsaturated (3 respondents). N/A (1 respondent).
2.20	• In pre-fault load flow studies, what demand condition is modelled?	Max (9 respondents). Other (2 respondents). N/A (1 respondent).
		Additional comments: • Max and min demand. • Max generation, max demand. • Diversified maximum demand (MD). • Load flow not undertaken pre-fault. • In some cases Min as fault levels can be higher and these are considered as required.

	Question	Response
2.21	• Does the DNO's Long Term Development Statement include the results of the above modelling /computer simulation / studies?	Yes (9 respondents). No (3 respondents). Additional comments: • LTDS should cover assumptions. • Long Term Development Statement uses calculations from DigSILENT Powerfactory. These are then used in GROND and the fault level at the Primary is manually put into GROND. • Yes at EHV.
3.1	Are you assessing fault levels by applying hand / spreadsheet calculations?	Yes (4 respondents). No (8 respondents). Additional comments: • To compare against plant rating. • For make duty component. • For load contribution.
3.2	If so, • What is the extent of the system analysed in the calculation (e.g. 11 or 6.6 kV primary substation busbars to 11 or 6.6 kV ring main units or 11 or 6.6 kV primary substation busbars to 0.4 kV busbars)	N/A (6 respondents). Additional Comments: • 33kV, 11kV & 6.6kV substation switchgear. • Assessment of load (inc latent demand) to calculate load related back-feed for make duty calculation. • Confirmation of fault current rating capability of switchgear against calculated values for 132kV and 33kV. • Load contribution.
3.3	• Does IEC 60909 influence the calculation	Yes (2 respondents). No (2 respondents). N/A (6 respondents).
3.4	• Briefly describe the influential factors	• Unsure • G74 philosophy adopted for d.c. component decrement in make duty calculation.
3.5	• Please describe any specific problems encountered with the application of aspects IEC 60909	No problems reported.
3.6	• Does the DNO's Long Term Development Statement include the results of the above hand / spreadsheet calculations?	Yes (1 respondent). No (5 respondents). N/A (6 respondents).

	Question	Response
4	Do you allow a safety margin between calculated fault levels and switchgear fault rating (make and break)?	Yes (4 respondents). No (8 respondents).
		Additional comments: • 10% margin. • 10% margin (Break only). • 5% margin. • 2% margin. • Engineering judgement made. • A risk-management approach is used to assess high fault level cases.
5	Do you assess fault levels for abnormal operating scenarios e.g. short term paralleling of primary substations etc?	Yes (10 respondents). No (2 respondents).
		Additional comments: • Where required, but not included in LTDS. • For outage/load transfer. • Yes in normal running arrangement. Fault conditions that could result in higher fault levels. If make fault levels are exceeded, autoreclosers may be turned off and operational switching used as an interim measure. • Not generally, but there are instances. • These are part of pre-outage checks. Mitigation may be put in place to reduce fault level. • N-1 outages when 11 or 6.6kV operates with 3 transformers in parallel. • Typically, this is done operationally as required, e.g. for unusual feeding arrangements.
6	Is it a requirement that fault levels must be acceptable under all operating scenarios (including short term paralleling)	Yes (8 respondents). No (4 respondents).
		Additional Comments: • Not necessarily – closed bars during temporary paralleling could result in higher fault levels for a short period – DNO does not have a policy on this. • Special operating conditions or restrictions may be put in place in areas where the fault level is close to the limits and there is a requirement to short term parallel for example. • A risk-management approach is used to assess high fault level cases.

	Question	Response
7.1	Do you have any issues with data for generation connection studies?	Yes (10 respondents). No (2 respondents).
		Additional comments: • Collecting accurate data, including generator transformers. • Generally due to us needing an equivalent synchronous infeed. • In many cases, it is difficult to obtain detailed technical data from customers. Also, different software/standards give different fault level answers for generators. • Data requirements are clearly identified in Distribution Code. DNO carefully controls the application process and is tough on asking for complete data. • Do not do FL studies for most types of generation unless synchronous machines. • GROND Version 7 does not have the ability to model distributed generation. GROND Version 10 has the ability to model distributed generation and GROND Version 10 will be used by mid-2014. Currently, 11kV generation studies are carried out using DigSILENT Powerfactory. • Generators do not always provide sufficient impedance data.
7.2	Do you update models with as-built generator data after connection?	Yes (10 respondents). No (1 respondent). Ongoing (1 respondent).
		Additional comments: • For big generations (>5MW). Generic model sometimes were used if risk is low or data was not available. • For large synchronous machines. • 33kV generators which are connected are currently being updated in DigSILENT Powerfactory. 11kV generators which are connected are not currently being updated in a modelling tool. 11kV generators which are connected will not be updated in DigSILENT Powerfactory because the 11kV feeders are not modelled in DigSILENT Powerfactory (the system is only modelled from the 11kV busbars and above).
8	Is fault level currently or expected to be a constraint on the connection of distributed generation?	Yes (10 respondents). No (2 respondents).
		Additional comments: • Particularly in urban areas of the network. • Run city centre 11kV & 6.6kV with bus-section open to limit fault level. • This is a standard consideration for connecting customers rather than an expected constraint. • Network is largely rural with significant numbers of PV applications. • Could be an issue in dock areas, for example. Depends on substation and substation location. • Not at 11kV.

	Question	Response
9	How many connections do you estimate have been uneconomic due to fault level reinforcement needs in the past 5 years?	Not known (3 respondents). None (2 respondents). Minimal (<10), (2 respondents). 75 (1 respondent). Unquantifiable (1 respondent).
		Additional comments: • We don’t find out why customers do not proceed with developing their projects. • Haven’t needed to reinforce network due to fault level. • None that DNO is aware of due to fault level apportionment rule. • At 11kV it is only usually an issue where the Primary has switchgear rated at 150MVA or at a Primary if it has direct transformation. There are not many Primaries like this so I would not estimate it to be a big problem in our DNO at 11kV. • Connection at several substations is restricted due to fault level. Unquantifiable at the moment due to the high volume of generation applications. • Connections of 5MW or more, mostly at 33kV or 11kV primary substations.

Table A-1: Collated questionnaire responses on the consistency of application of HV fault level modelling standards.

Appendix B – Functional specification of fault level mitigation technology models

1. Introduction

One of FlexDGrid's aims is to achieve the integration of fault current limiters into five sites. The need has been identified to create a planning tool (i) for calculating fault level reduction requirements; and (ii) for calculating the required steady state impedances of the fault current limiters.

These top-level functions will be initially implemented using Microsoft Excel. The ultimate aim will be to create a 'black box' fault current limiter model for use by Primary System Design engineers in PSS/E.

In addition, a cost-benefit analysis tool will be created in Excel for evaluating fault current limiters versus network reinforcement for new customers' connections.

2. Functional specifications

2.1 Calculation of required fault level reduction

2.1.1 Input

1. Allow user to specify different positions for the fault current limiter;
2. Accept fault level inputs (individual sources and parallel sources, both make and break) in kA or MVA with nominal voltage;
3. Accept policy fault level limits in kA or MVA with nominal voltage;
4. Allow user to input the fault in-feed from new generation connections in kA or MVA (or use % of firm capacity of substation with fault in-feed conversion factor);
5. Nominal system voltage (kV);
6. Busbar voltages (pu);
7. Substation firm capacity (MVA).

2.1.2 Calculation

1. Use the information provided in 2.1.1 together with the equations published in SDRC-6 to calculate the required fault level reduction in kA or MVA for both make and break duties.
2. Calculate the change in steady-state voltage.
3. Calculate any effect on the firm capacity of the substation through the installation of a FCL.

2.1.3 Output

1. Source fault level reduction(s) as % of original and absolute values (in kA and MVA);
2. Overall fault level reduction(s) as % of original and absolute values (in kA and MVA);
3. Potential fault current limiter technologies that fulfil (1) and (2) above;
4. An error message if the required fault level reduction exceeds the maximum value which can be achieved by FCL technologies;
5. Change in steady-state voltage at the Primary Substation busbars
6. Indicative costs of fault current limiter technologies.

2.2 Calculation of required impedance

2.2.1 Input

1. Nominal system voltage (kV);
2. Busbar voltages (pu);
3. Maximum loading condition (kA or MVA);
4. Continuous rating of substation equipment, for example, busbars (in kA or MVA);
5. Prospective fault level values (in kA or MVA), for example maximum, minimum and average;
6. Target fault level values, (in kA or MVA), for example maximum and minimum;
7. Maximum % reduction achievable by fault current limiter technology.

2.2.2 Calculation

1. Use information provided by fault current limiter manufacturers to validate that maximum loading conditions and minimum fault level conditions can be discriminated;
2. Use the information provided in 2.2.1 to calculate the steady-state impedance of the fault current limiter;
3. Use the FCL impedance value(s) along with a range of prospective fault level values to calculate the range of limited fault level values.

2.2.3 Output

1. The steady-state impedance of the fault current limiter for equipment specification / procurement purposes;
2. An error message if the required fault level reduction exceeds the maximum value which can be achieved by FCL technologies or cannot be discriminated by the FCL when compared to maximum loading condition;
3. Losses associated with the fault current limiter in normal operation.

3. Exclusions and next steps

At present, the following items are excluded from this functional specification:

1. The cost benefit analysis tool (it is anticipated that a tool will be developed in a similar way to the CBA used in the FlexDGrid bid document). This will include an evaluation of the financial cost of losses and power consumption (kWh/annum) ;
2. The 'black box' PSS/E model;

The timescale for the production of these items will be agreed with WPD, taking into account dependencies such as the impedance data for fault current limiters from manufacturers.

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Appendix C – Network model parameters for sensitivity analysis

This appendix provides the sample network parameters that were used for sensitivity analysis. The sample network is part of the existing Birmingham 11 kV network and consists of two 11kV feeders as given in Figure C-1. Feeder A and Feeder B represent a long feeder and a short feeder respectively.

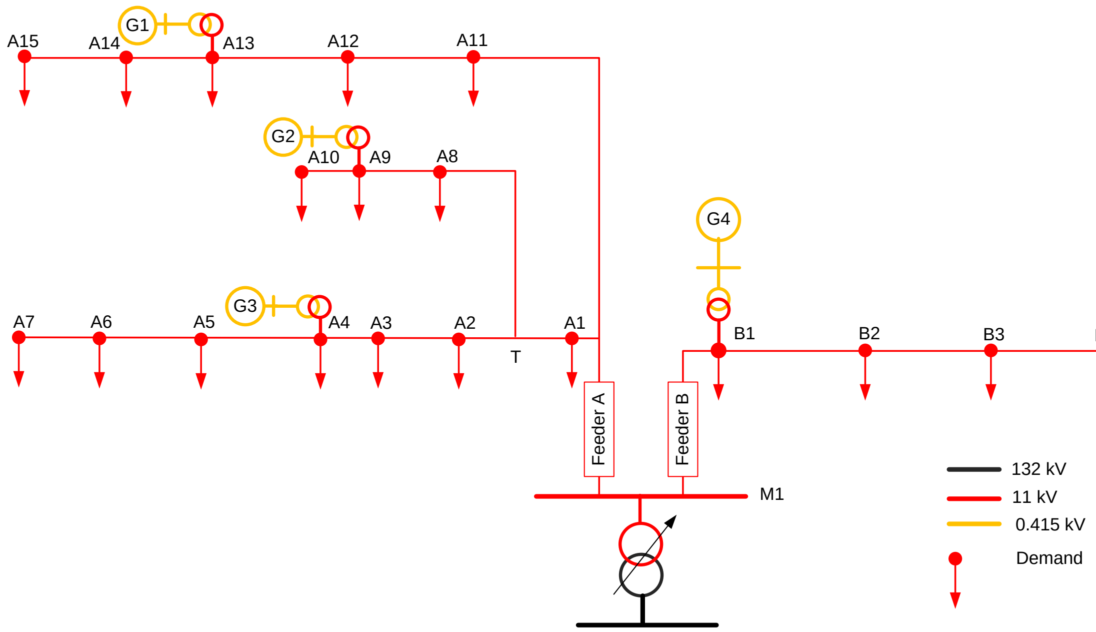

Figure C-1: The sample model representing a short and a long feeder

These feeders are connected to a 132/11kV primary transformer which is connected to WPD's EHV network model on the upstream side. WPD's EHV model embodies a full representation of WPD 132kV, 66kV and 33 kV networks from Grid Supply Points (GSPs) to 11 kV busbars.

The detailed data of the sample network is given in Tables C-1 to C-4.

Generator	Nominal Voltage (kV)	Output (MW)	Rating (MVA)	Sub-transient reactance (pu)*
G1	0.415	2.5	2.78	0.2
G2	0.415	1.6	1.78	0.2
G3	0.415	2.5	2.78	0.2
G4	0.415	1.6	1.78	0.2
G5	0.415	0.6	0.67	0.2

* The pu values are calculated based on nominal voltage and rating of the machines

Table C-1: Generators data in the sample network

Transformer	Rating (MVA)	R (pu)*	X (pu)*	Number of taps	Minimum ratio	Maximum ratio
All 11/0.415 kV transformers	5	0.0	0.06			
132/11 kV transformer	30	0.008	0.212	19	0.8	1.1

* The pu values are calculated based on nominal voltage and rating of the transformers

Table C-2: Transformers data in the sample network

Bus Name	P [MW]	Q [MVAr]
A1	0.330	0.120
A2	0.330	0.120
A3	0.165	0.060
A4	0.330	0.120
A5	0.330	0.120
A6	0.330	0.120
A7	0.330	0.120
A8	0.330	0.120
A9	0.165	0.060
A10	0.330	0.120
A11	0.330	0.120
A12	0.330	0.120
A13	0.330	0.120
A14	0.330	0.120
A15	0.165	0.060
B1	0.426	0.155
B2	0.373	0.135
B3	0.373	0.135
B4	0.298	0.108

Table C-3: Demand distribution on the sample network.

From Bus	To Bus	R [ohm]	X[ohm]
M1	B1	0.2500	0.1381
B4	B3	0.0641	0.0401
B1	B2	0.0657	0.0306
B2	B3	0.0490	0.0241
M1	A1	0.2160	0.2021
A9	A8	0.1970	0.1036
A9	A10	0.0530	0.0260
A3	A2	0.1449	0.0837
A3	A4	0.0162	0.0094
A5	A4	0.0896	0.0517
A5	A6	0.0232	0.0196
A8	T	0.0415	0.0306
A15	A14	0.0517	0.0234
A1	A11	0.1678	0.0621
A14	A13	0.1757	0.0624
A2	T	0.0441	0.0290
A12	A13	0.1590	0.0562
A12	A11	0.1474	0.0514
A6	A7	0.0979	0.0455
A1	T	0.0037	0.0028

Table C-4: Circuit data in the sample network

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Appendix D: Modelling of Method Beta and application to substation sites

1. Overview

This appendix summarises the results from the modelling of Method Beta and the application of the Method to the ten Primary Substations selected as sites for trials in FlexDGrid. Each substation was analysed for the period 01 September 2012 – 31 August 2013. Based on this analysis, the following information is given:

1. The system normal topology of the substation (the status of circuit breakers in terms of normally open and normally closed);
2. A table of the substation operating configurations with associated cumulative durations of fault levels;
3. A graph of the real-time fault level profile at each site; and
4. The fault level duration curve, providing a graphical representation cumulative durations of fault levels (from which headroom for generation connections and generation connection constraints can be assessed).

Substation A (Kitts Green)

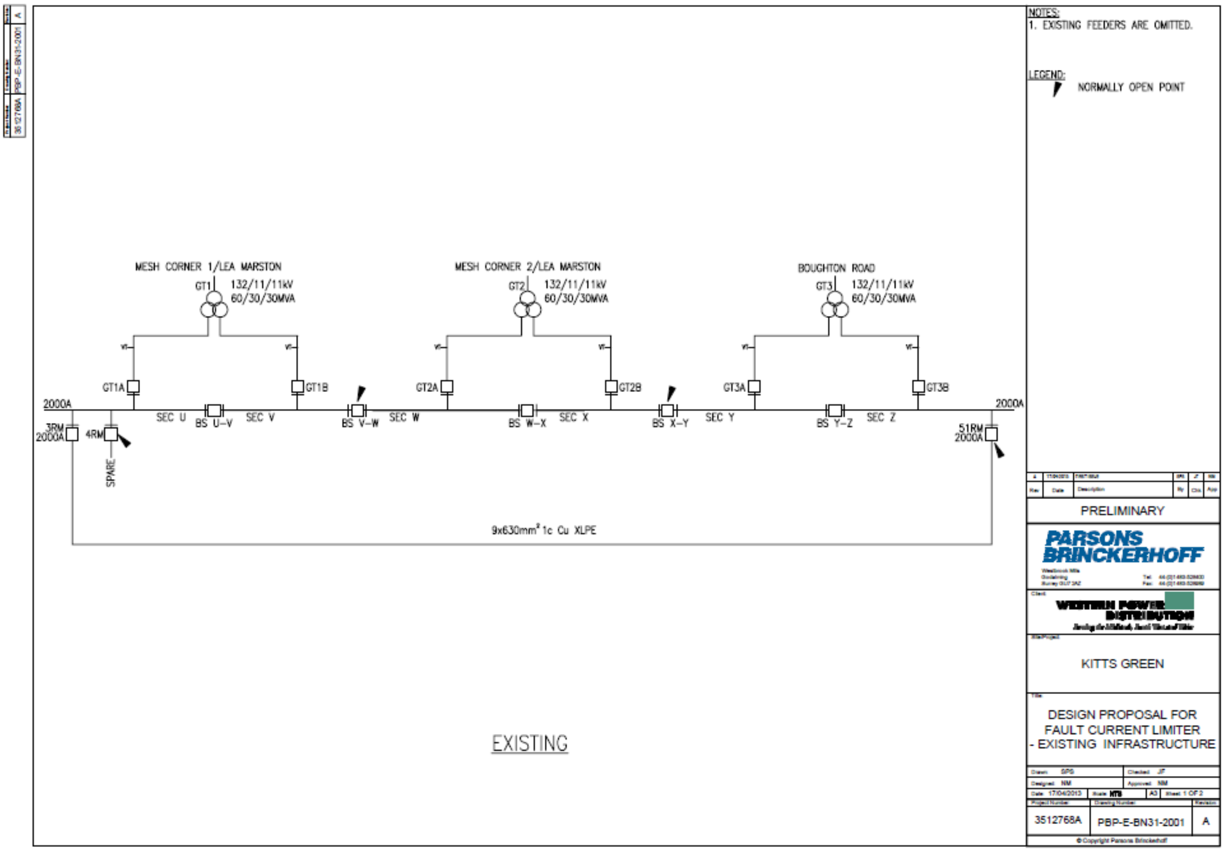

Figure D-1: Topology of Substation A

Combination	% of year	Break (MVA)	Make (MVA)	Break (kA)	Make (kA)
1	0.34%	304	936	16.0	49.1
2	99.12%	162	495	8.5	26.0
3	0.12%	160	478	8.4	25.1
4	0.42%	158	461	8.3	24.2

Table D-1: Operational configurations, durations and corresponding fault level values

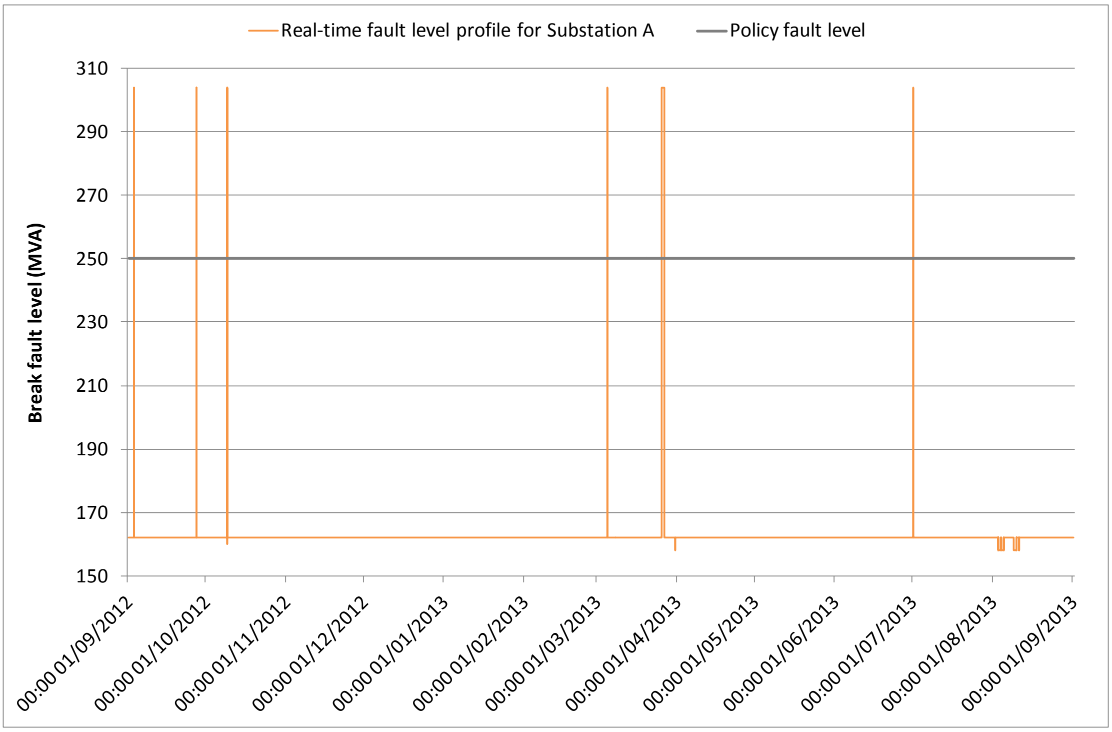

Figure D-2: Real-time fault level profile of Substation A for the period 01 September 2012 to 31 August 2013

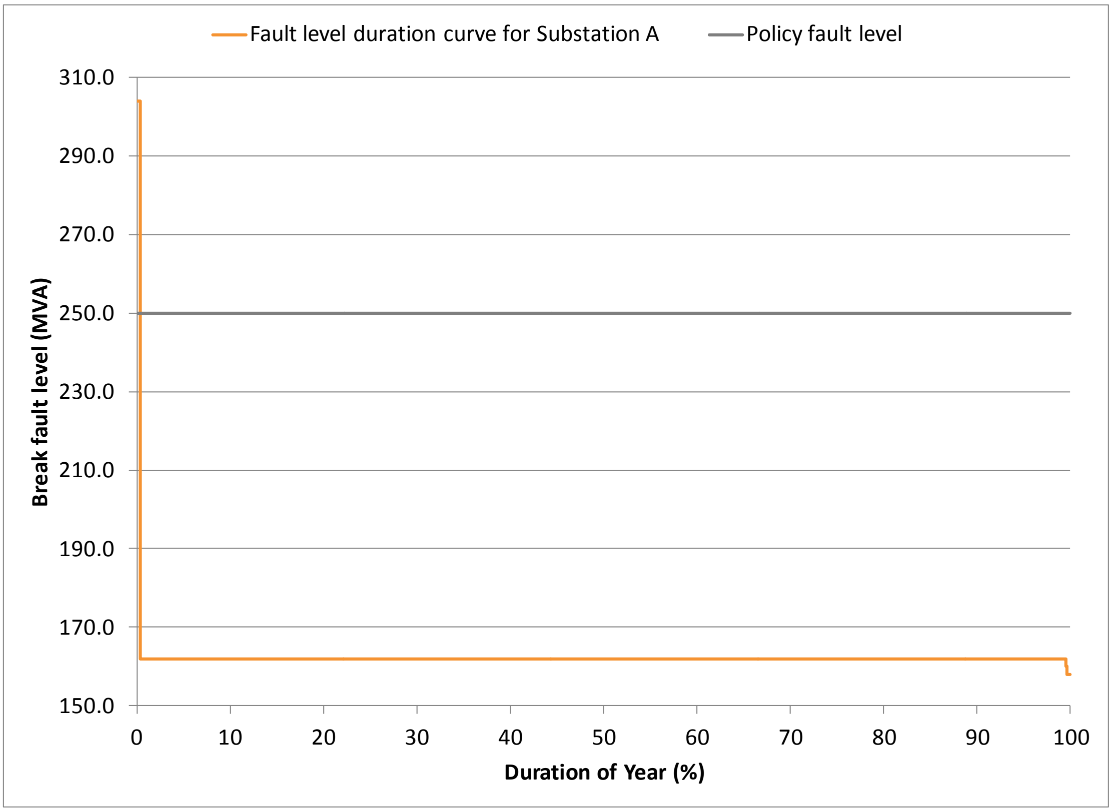

Figure D-3: Fault level duration curve for Substation A for the period 01 September 2012 to 31 August 2013

Substation B (Castle Bromwich)

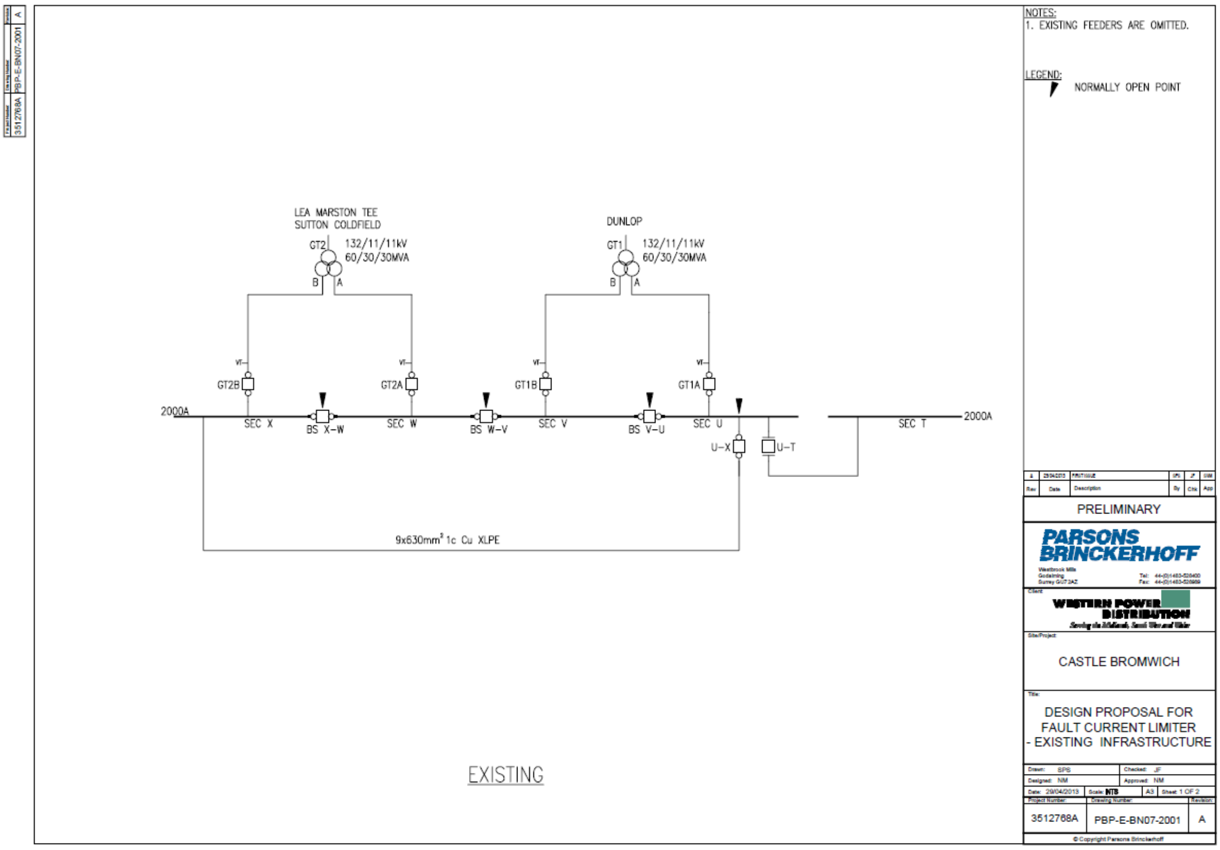

Figure D-4: Topology of Substation B

Combination	% of year	Break (MVA)	Make (MVA)	Break (kA)	Make (kA)
1	3.80%	261.0	770.0	13.7	40.4
2	96.10%	217.0	640.0	11.4	33.6
3	0.03%	190.0	555.0	10.0	29.1
4	0.07%	152.0	427.0	8.0	22.4

Table D-2: Operational configurations, durations and corresponding fault level values

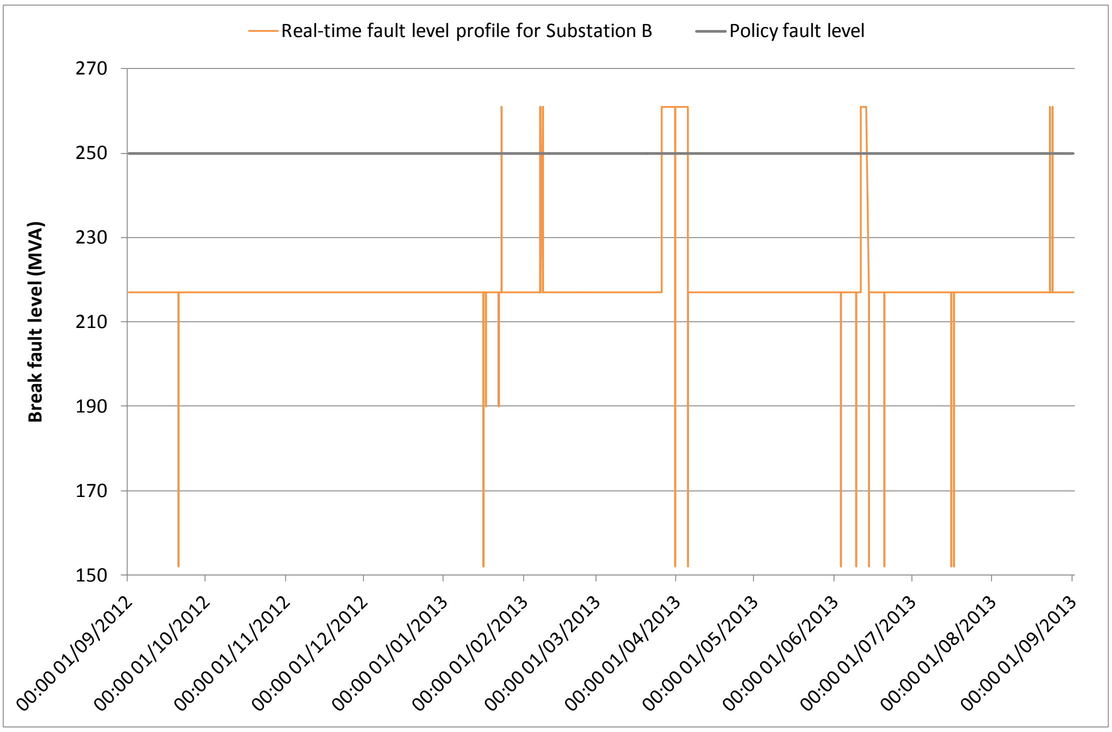

Figure D-5: Real-time fault level profile of Substation B for the period 01 September 2012 to 31 August 2013

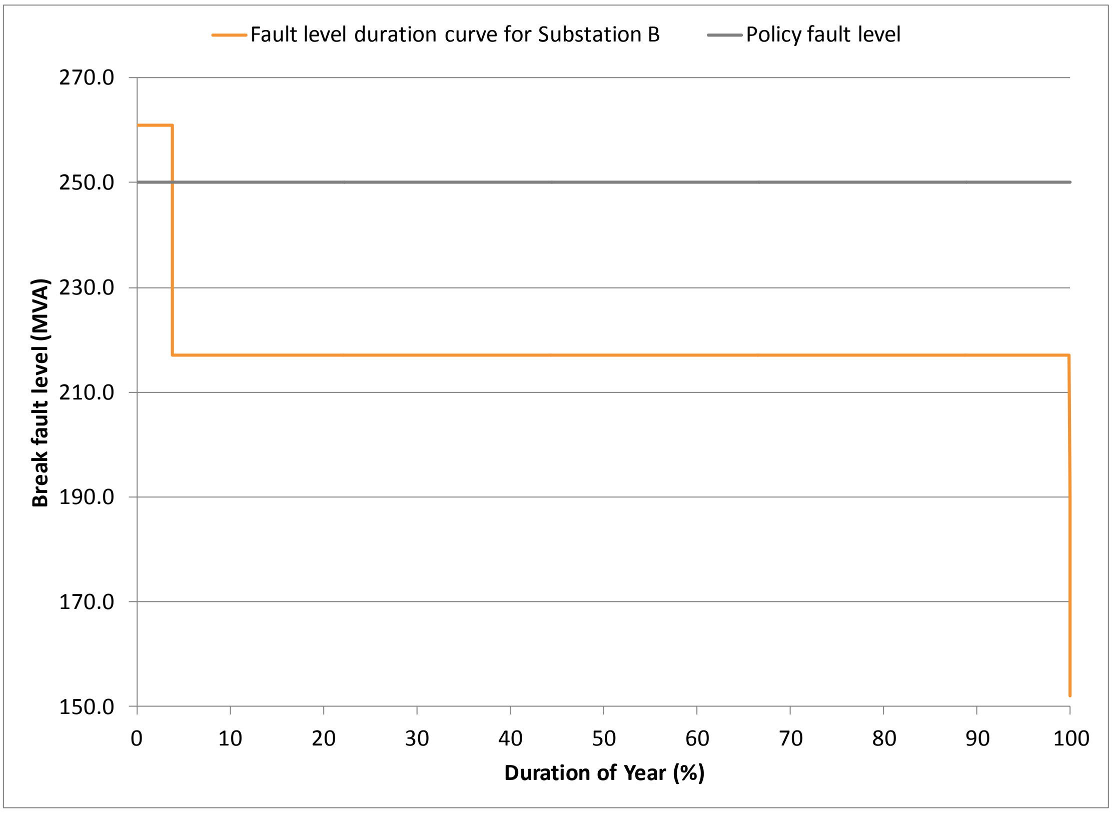

Figure D-6: Fault level duration curve for Substation B for the period 01 September 2012 to 31 August 2013

Substation C (Chester Street)

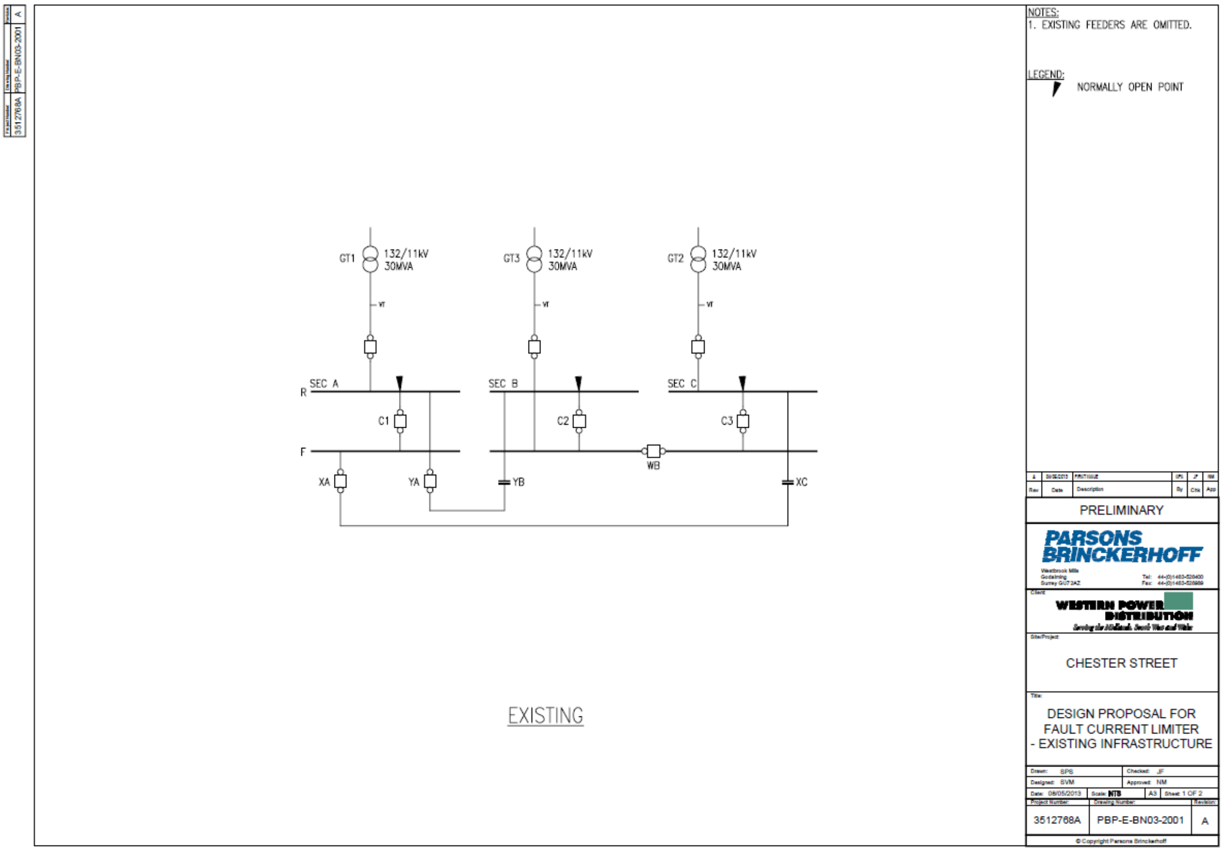

Figure D-7: Topology of Substation C

Combination	% of year	Break (MVA)	Make (MVA)	Break (kA)	Make (kA)
1	2.27%	268	753	14.1	39.5
2	96.26%	149	408	7.8	21.4
3	1.47%	135	385	7.1	20.2

Table D-3: Operational configurations, durations and corresponding fault level values

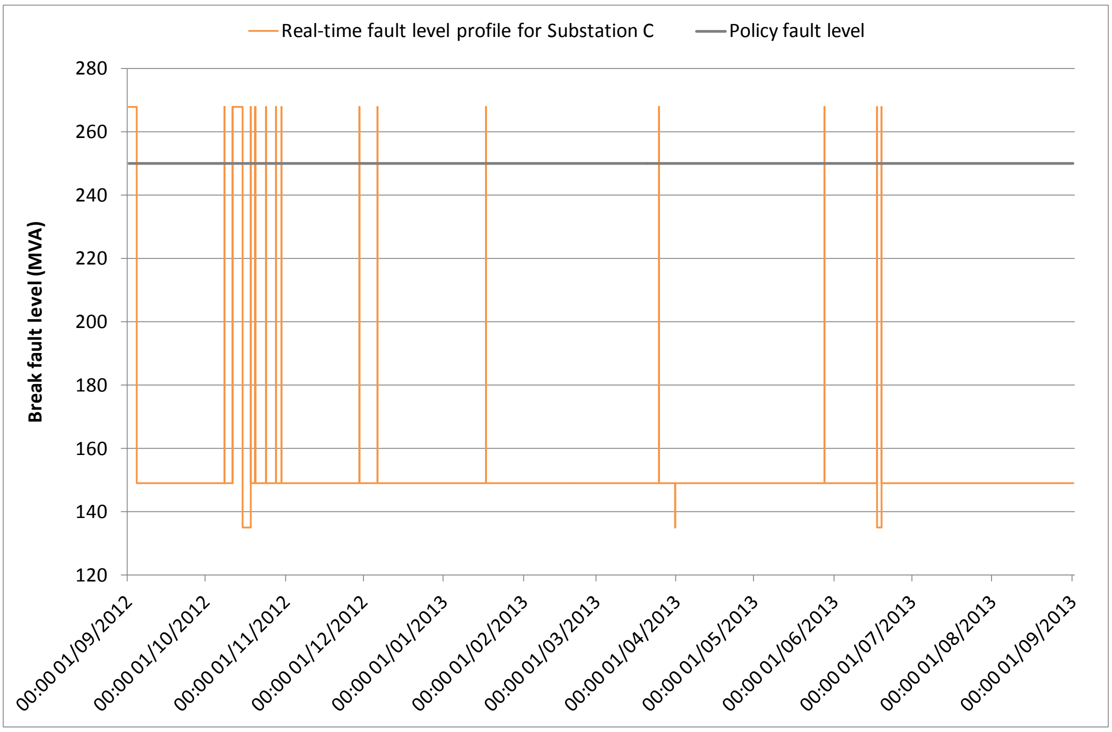

Figure D-8: Real-time fault level profile of Substation C for the period 01 September 2012 to 31 August 2013

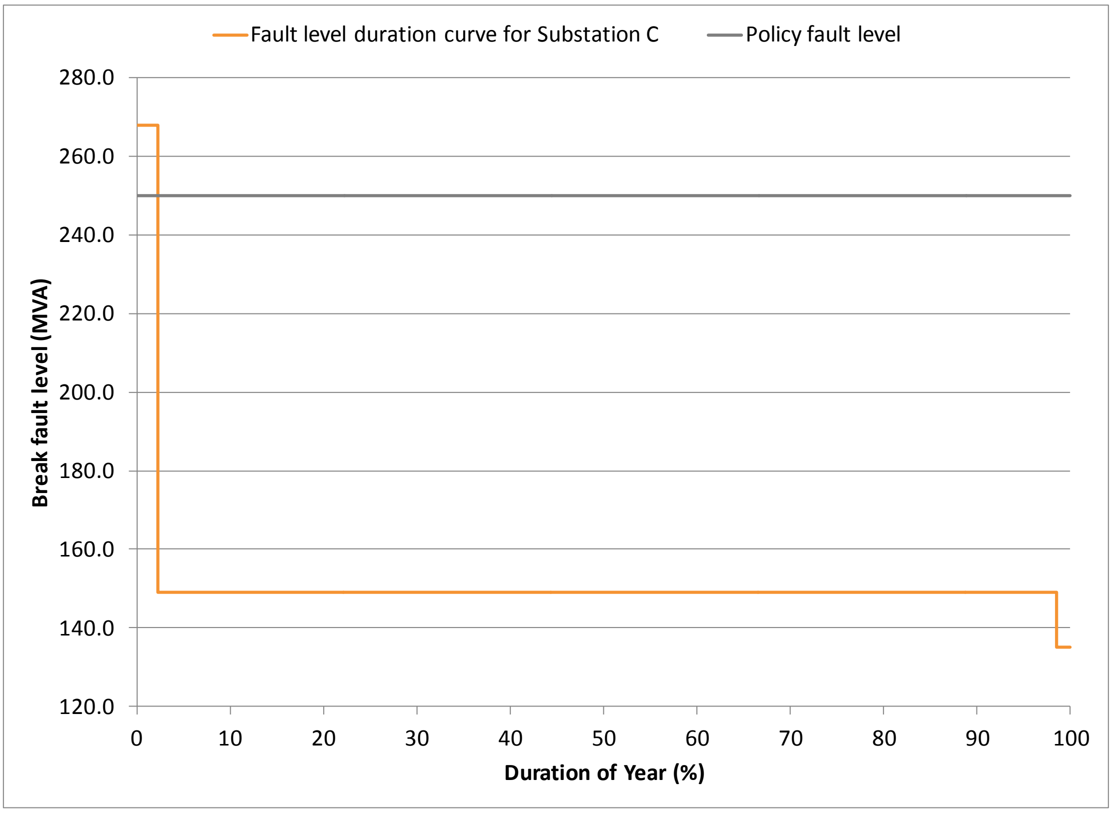

Figure D-9: Fault level duration curve for Substation C for the period 01 September 2012 to 31 August 2013

Substation D (Bournville)

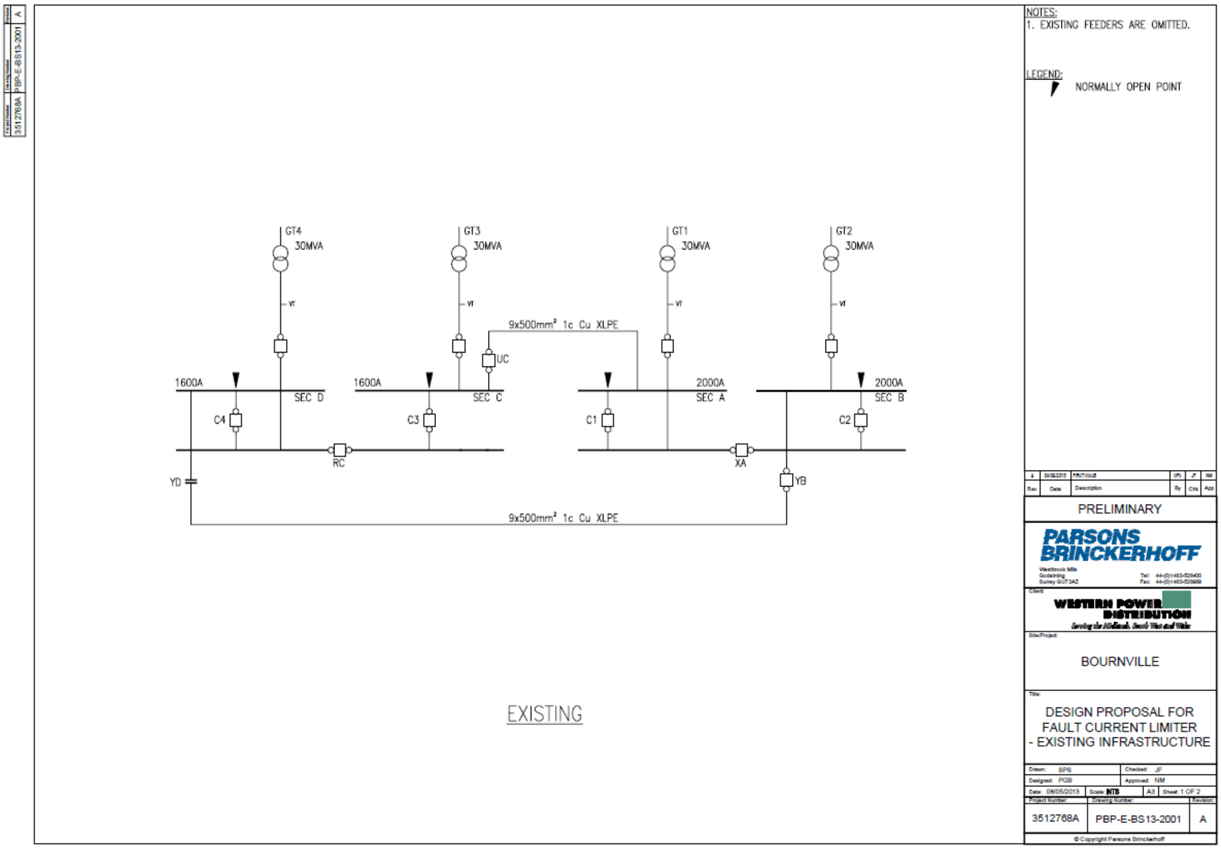

Figure D-10: Topology of Substation D

Combination	% of year	Break (MVA)	Make (MVA)	Break (kA)	Make (kA)
1	0.19%	314	889	16.5	46.7
2	0.03%	310	884	16.3	46.4
3	98.41%	170	478	8.9	25.1
4	1.18%	166	473	8.7	24.8
5	0.19%	141	394	7.4	20.7

Table D-4: Operational configurations, durations and corresponding fault level values

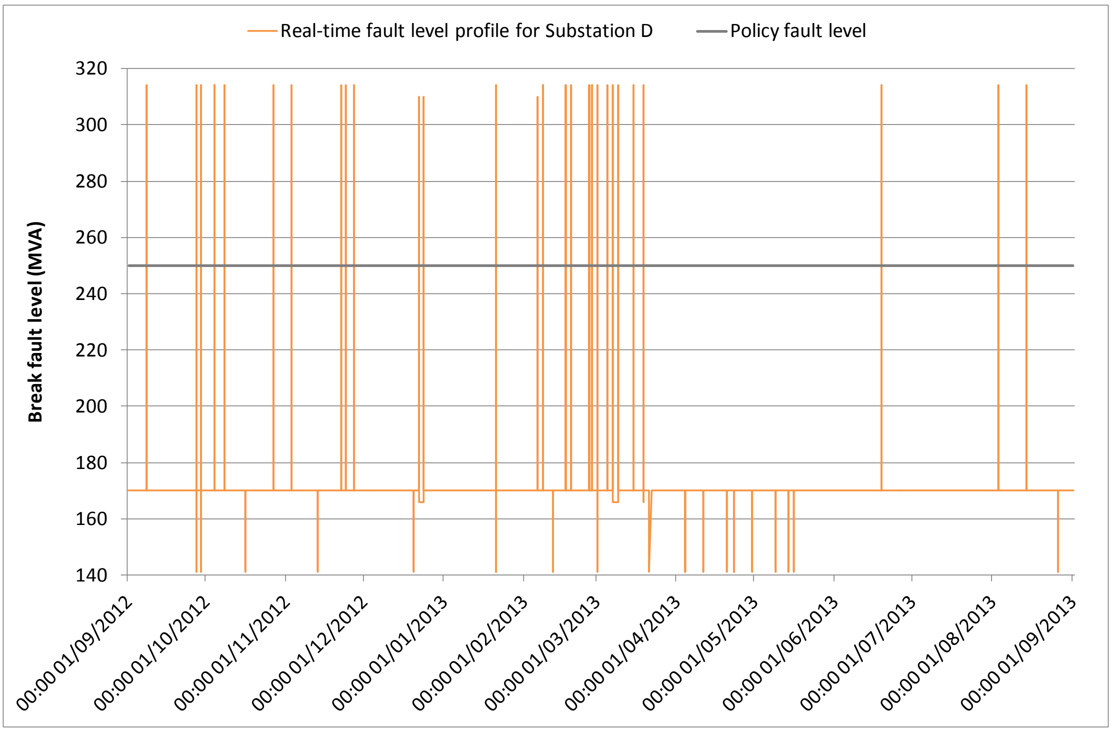

Figure D-11: Real-time fault level profile of Substation D for the period 01 September 2012 to 31 August 2013

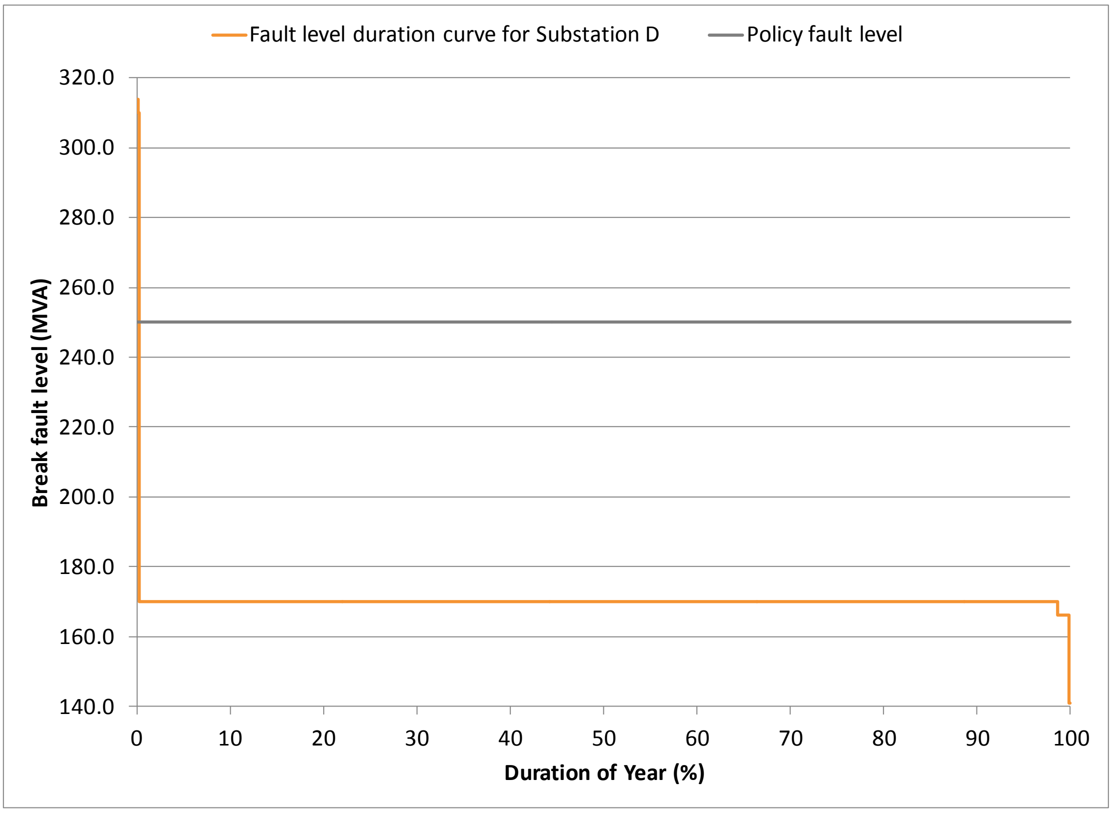

Figure D-12: Fault level duration curve for Substation D for the period 01 September 2012 to 31 August 2013

Substation E (Sparkbrook)

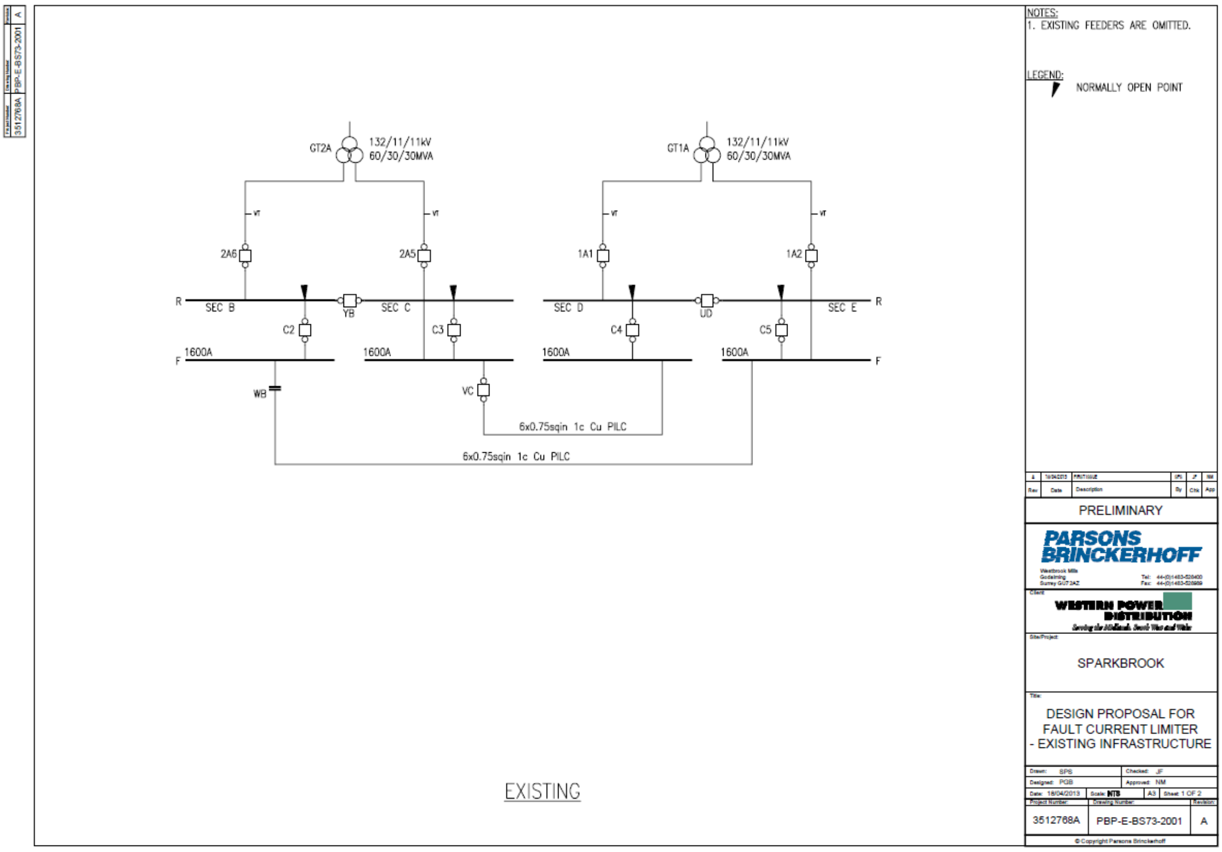

Figure D-13: Topology of Substation E

Combination	% of year	Break (MVA)	Make (MVA)	Break (kA)	Make (kA)
1	0.12%	308	908	16.2	47.7
2	0.01%	201	592	10.5	31.1
3	64.89%	166	486	8.7	25.5
4	34.80%	164	476	8.6	25.0
5	0.18%	162	465	8.5	24.4

Table D-5: Operational configurations, durations and corresponding fault level values

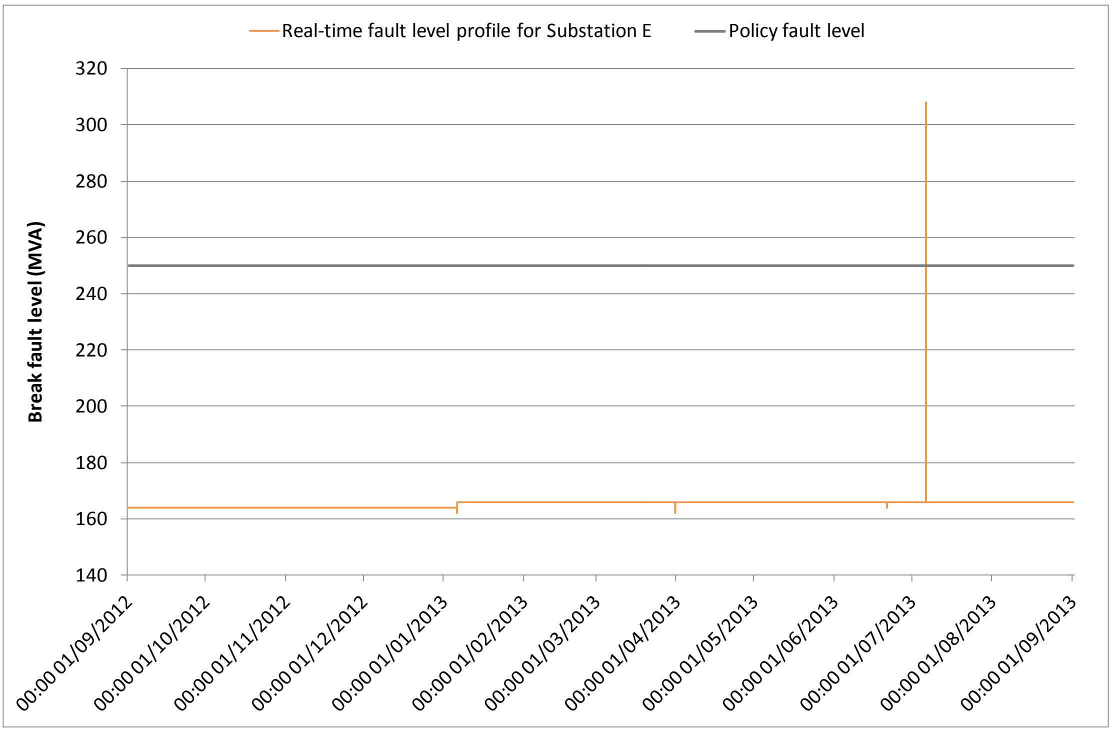

Figure D-14: Real-time fault level profile of Substation E for the period 01 September 2012 to 31 August 2013

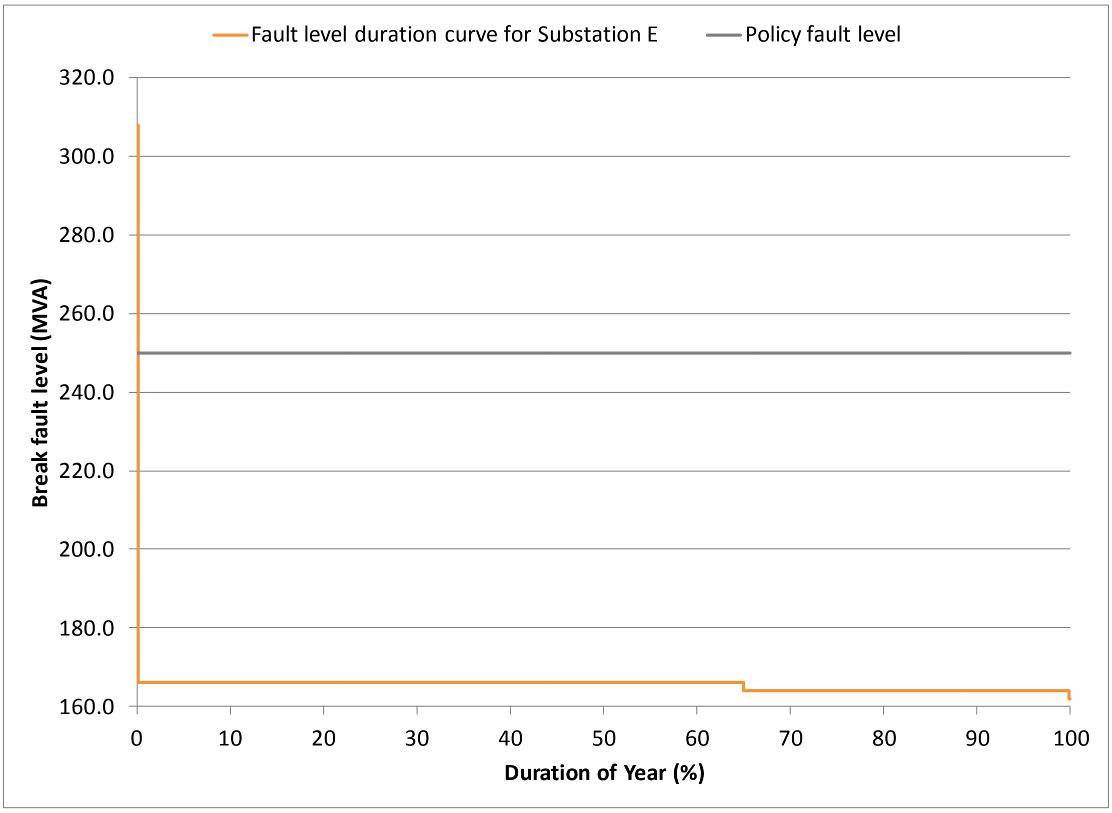

Figure D-15: Fault level duration curve for Substation E for the period 01 September 2012 to 31 August 2013

Substation F (Hall Green)

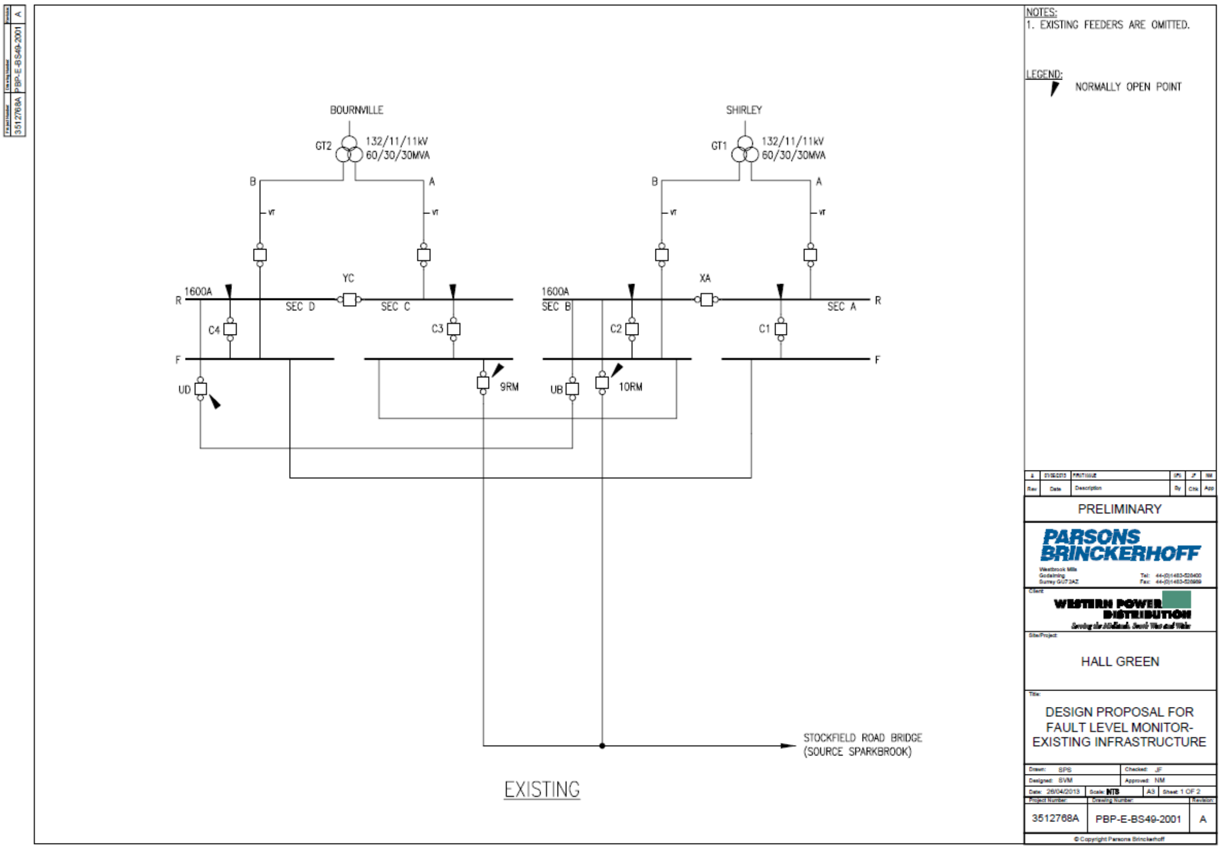

Figure D-16: Topology of Substation F

Combination	% of year	Break (MVA)	Make (MVA)	Break (kA)	Make (kA)
1	1.19%	287	841	15.1	44.1
2	0.55%	286	832	15.0	43.7
3	0.02%	284	816	14.9	42.8
4	91.17%	156	459	8.2	24.1
5	7.07%	154	438	8.1	23.0

Table D-6: Operational configurations, durations and corresponding fault level values

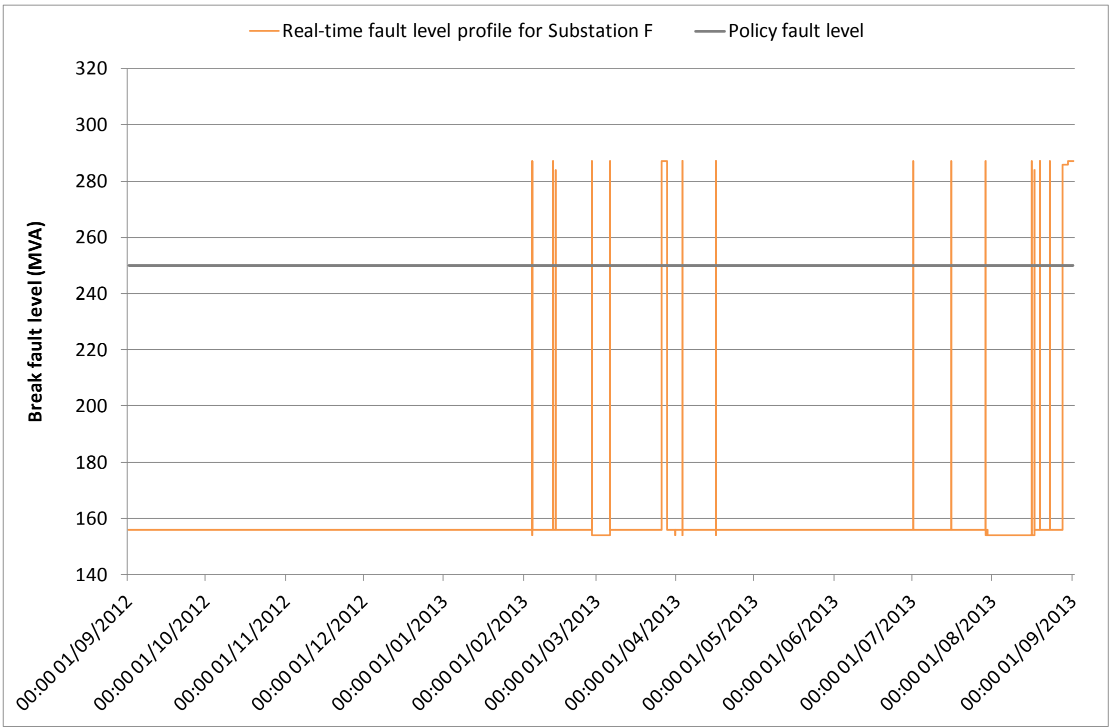

Figure D-17: Real-time fault level profile of Substation F for the period 01 September 2012 to 31 August 2013

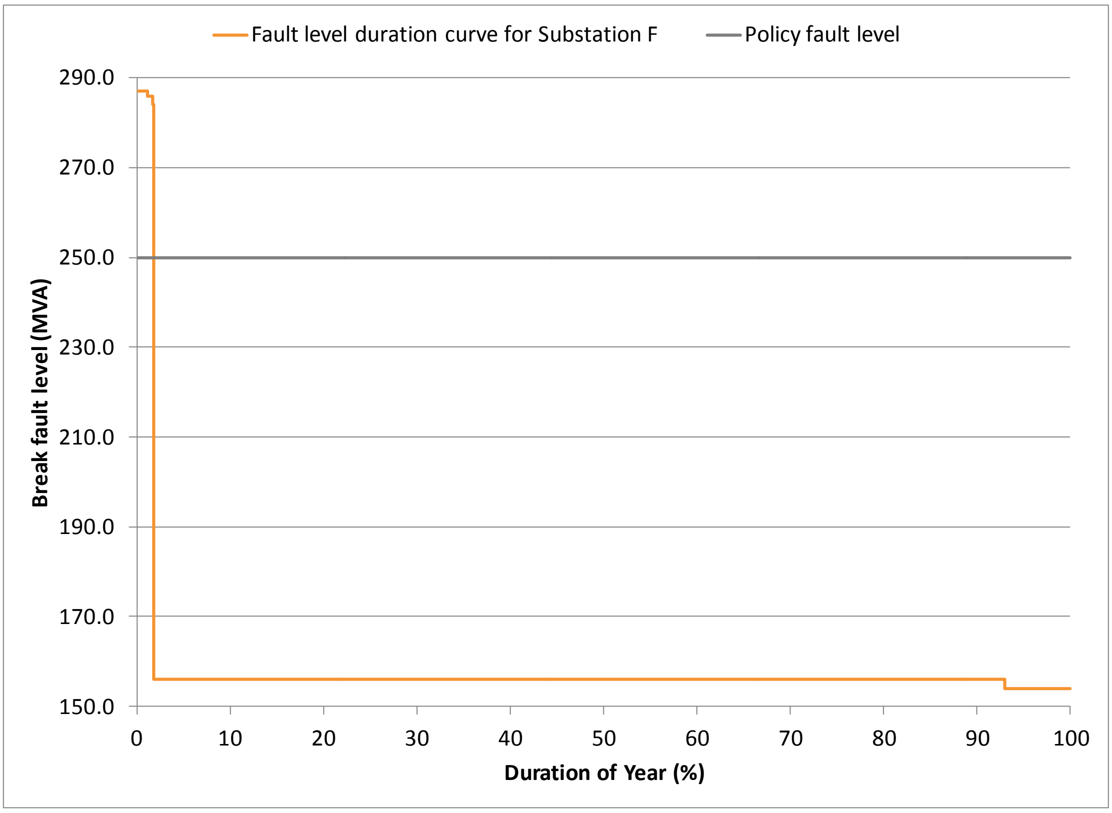

Figure D-18: Fault level duration curve for Substation F for the period 01 September 2012 to 31 August 2013

Substation G (Elmdon)

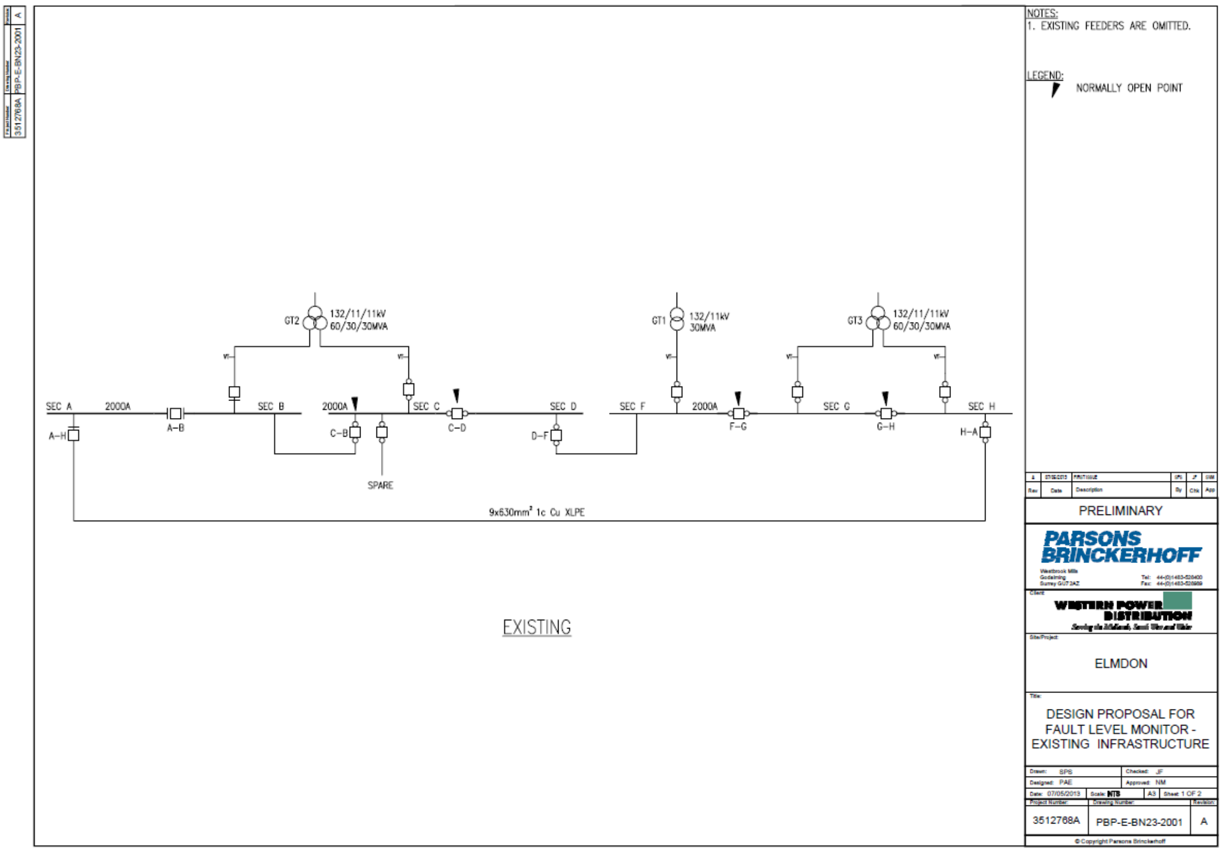

Figure D-19: Topology of Substation G

Combination	% of year	Break (MVA)	Make (MVA)	Break (kA)	Make (kA)
1	1.19%	287	841	15.1	44.1
2	0.55%	286	832	15.0	43.7
3	0.02%	284	816	14.9	42.8
4	91.17%	156	459	8.2	24.1
5	7.07%	154	438	8.1	23.0

Table D-7: Operational configurations, durations and corresponding fault level values

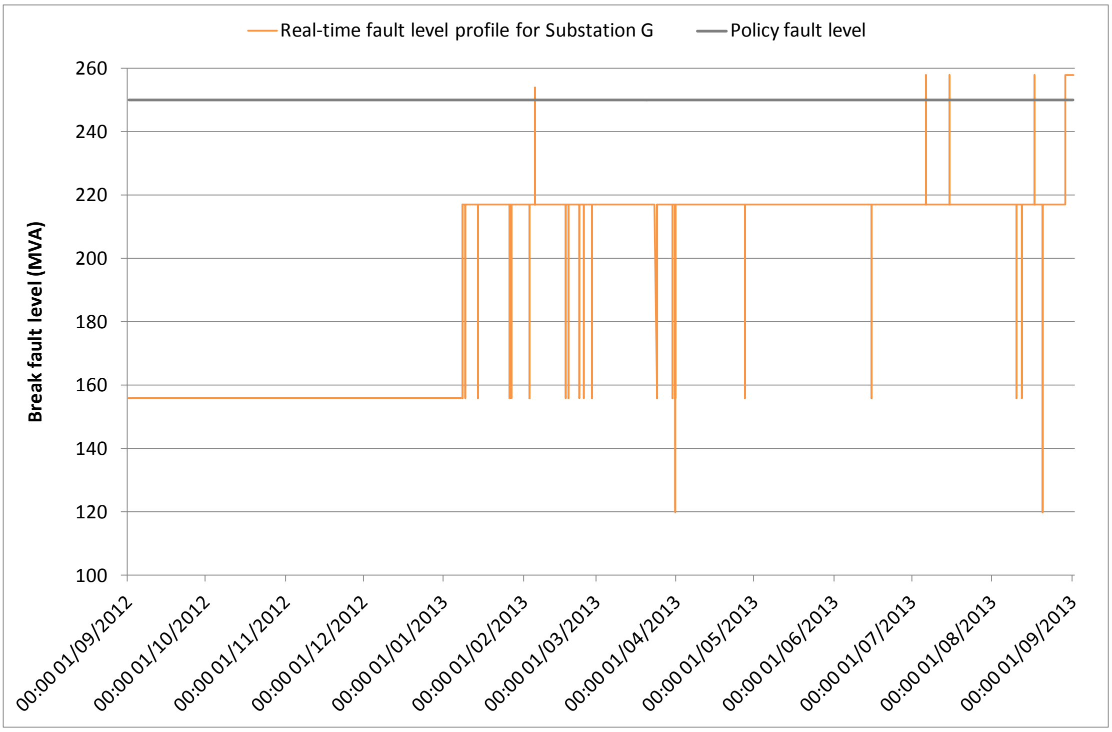

Figure D-20: Real-time fault level profile of Substation G for the period 01 September 2012 to 31 August 2013

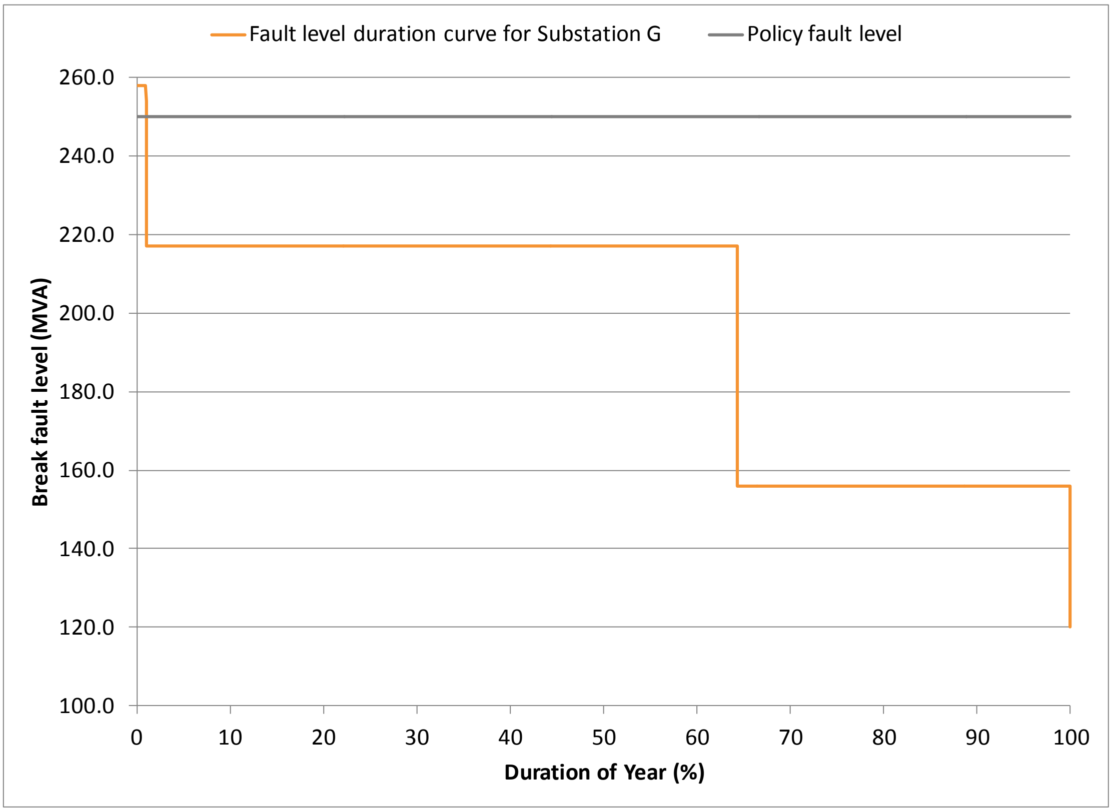

Figure D-21: Fault level duration curve for Substation G for the period 01 September 2012 to 31 August 2013

Substation H (Chad Valley)

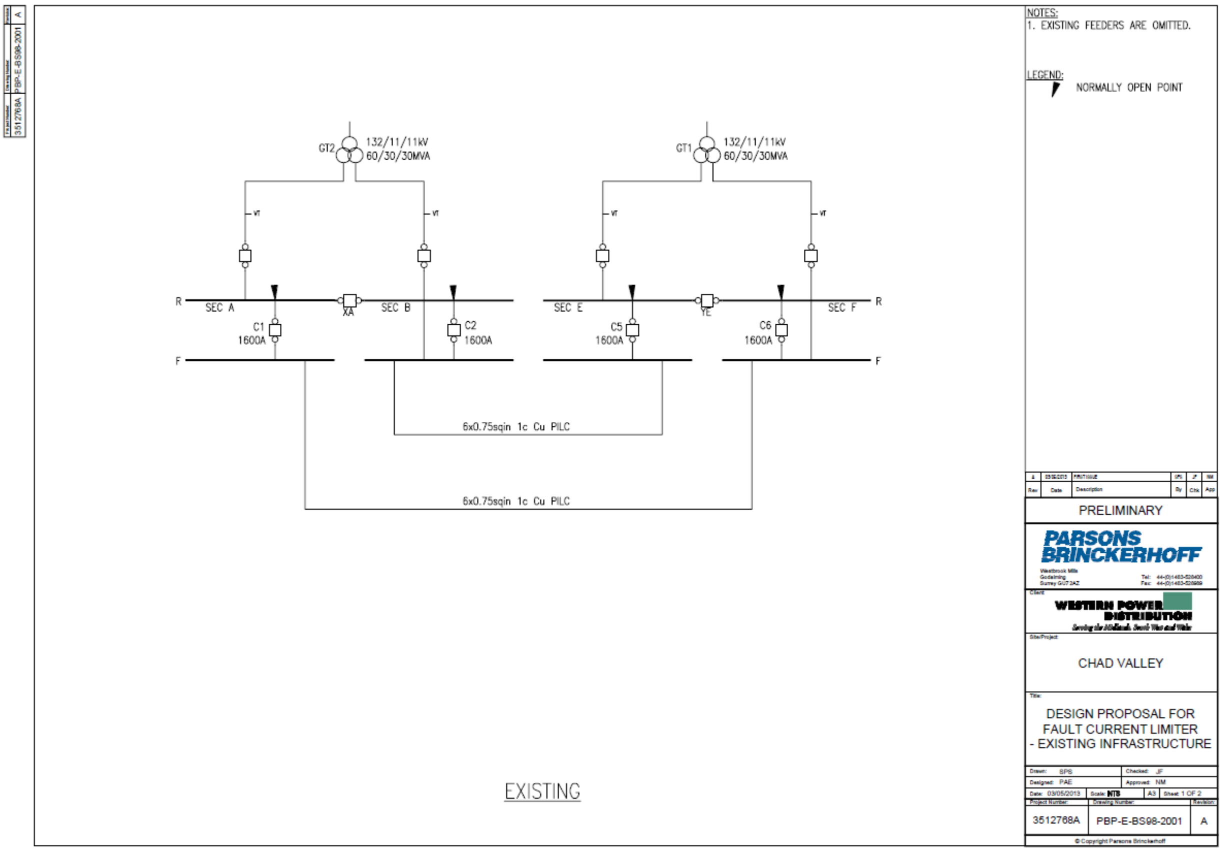

Figure D-22: Topology of Substation H

Combination	% of year	Break (MVA)	Make (MVA)	Break (kA)	Make (kA)
1	0.30%	319	940	16.7	49.3
2	0.01%	318	936	16.7	49.1
3	0.06%	211	619	11.1	32.5
4	0.03%	210	614	11.0	32.2
5	99.59%	172	495	9.0	26.0
6	0.02%	170	486	8.9	25.5

Table D-8: Operational configurations, durations and corresponding fault level values

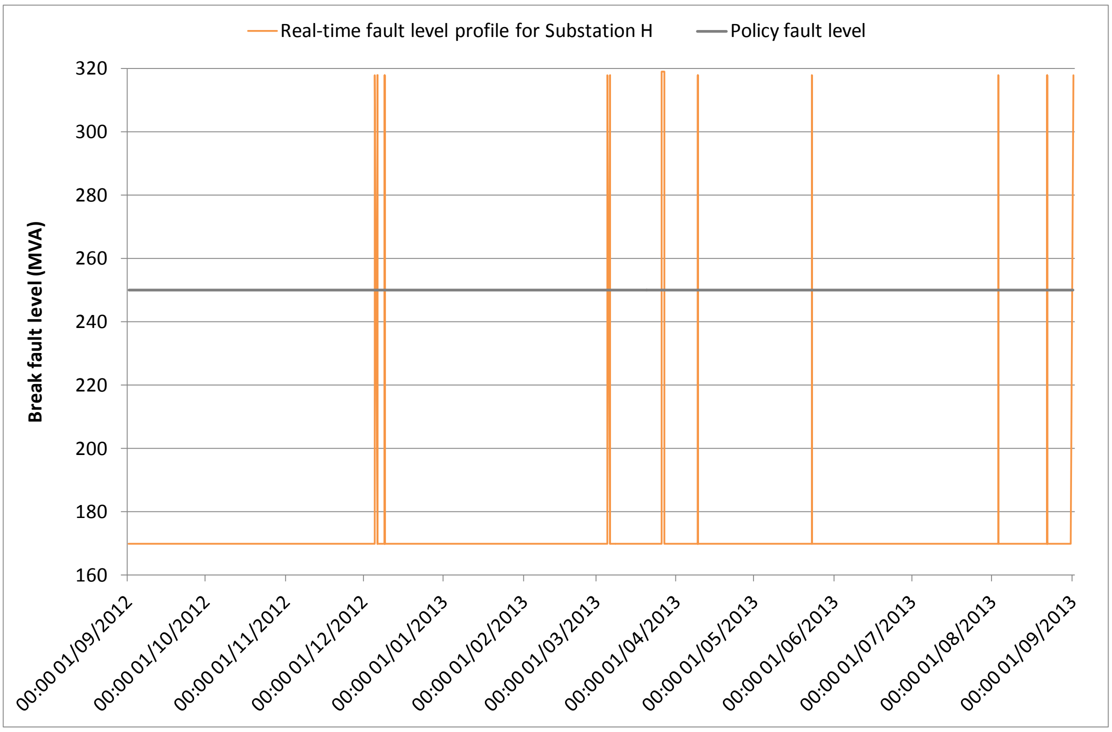

Figure D-23: Real-time fault level profile of Substation H for the period 01 September 2012 to 31 August 2013

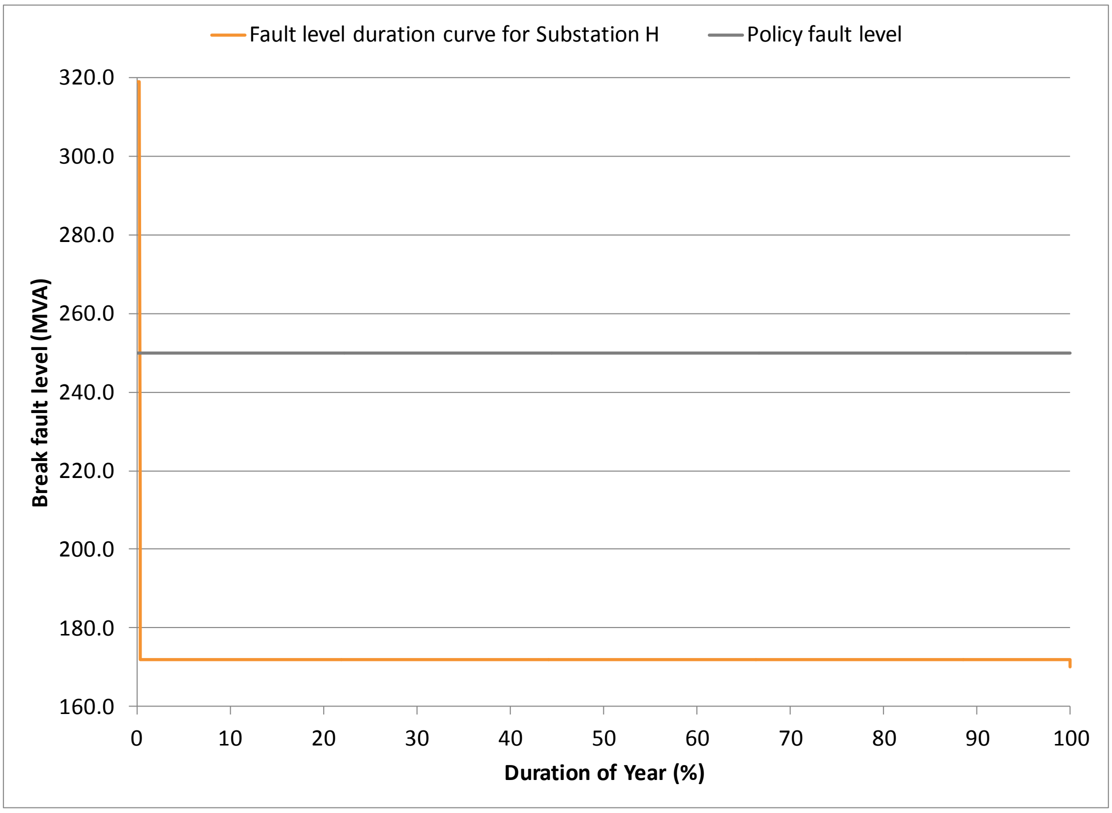

Figure D-24: Fault level duration curve for Substation H for the period 01 September 2012 to 31 August 2013

Substation I (Perry Barr)

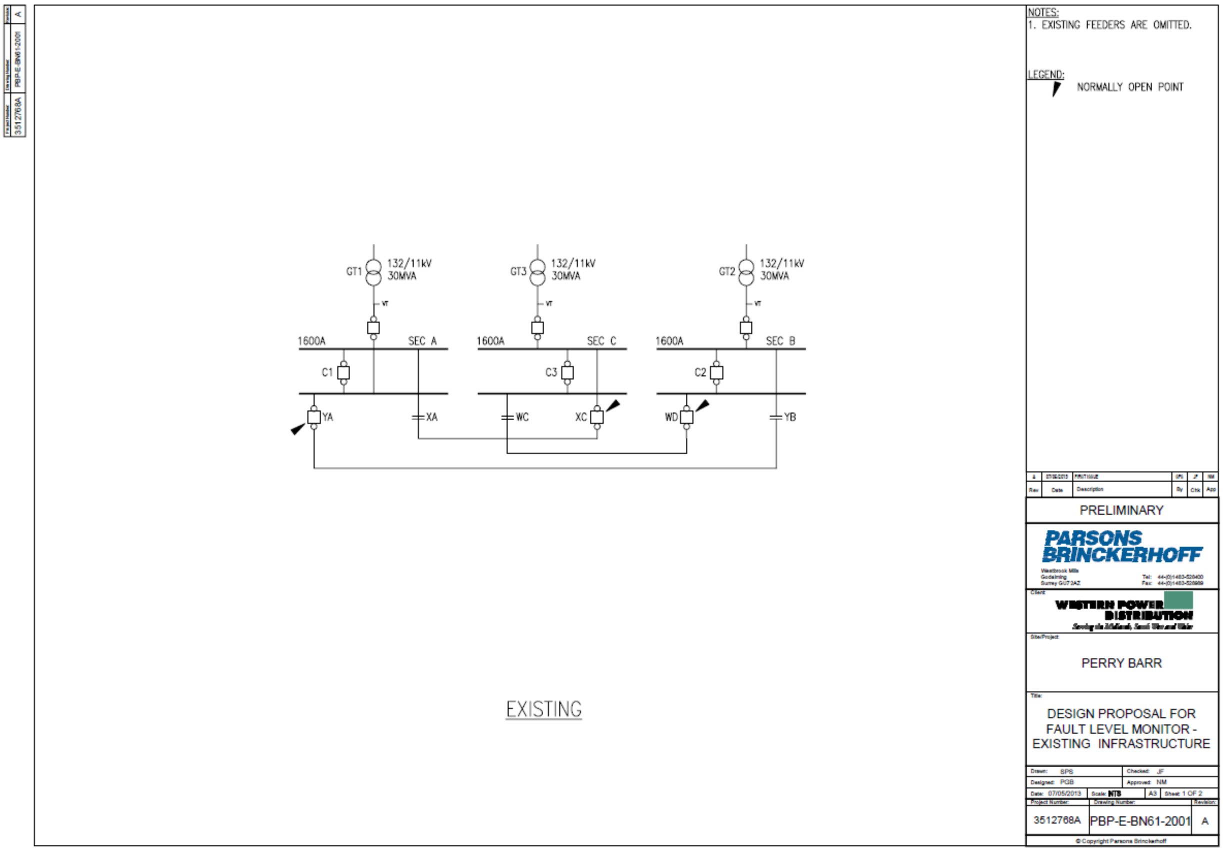

Figure D-25: Topology of Substation I

Combination	% of year	Break (MVA)	Make (MVA)	Break (kA)	Make (kA)
1	2.20%	304	886	16.0	46.5
2	0.01%	282	828	14.8	43.5
3	96.67%	160	459	8.4	24.1
4	1.11%	158	450	8.3	23.6
5	0.01%	135	391	7.1	20.5

Table D-9: Operational configurations, durations and corresponding fault level values

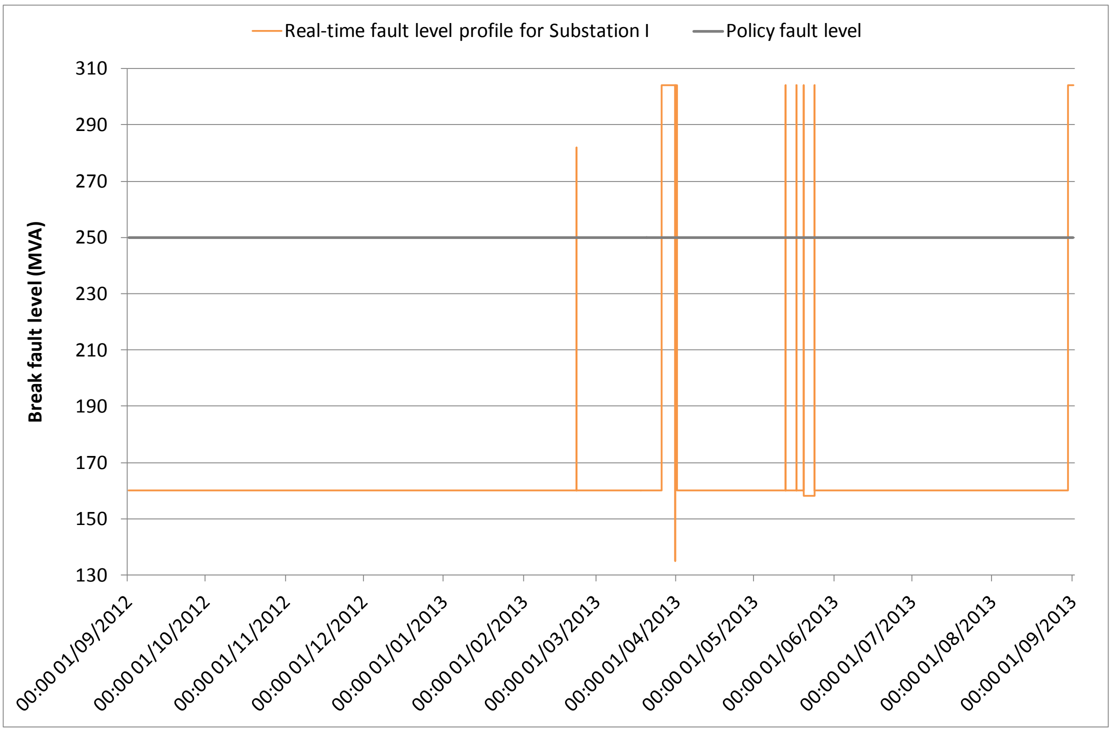

Figure D-26: Real-time fault level profile of Substation I for the period 01 September 2012 to 31 August 2013

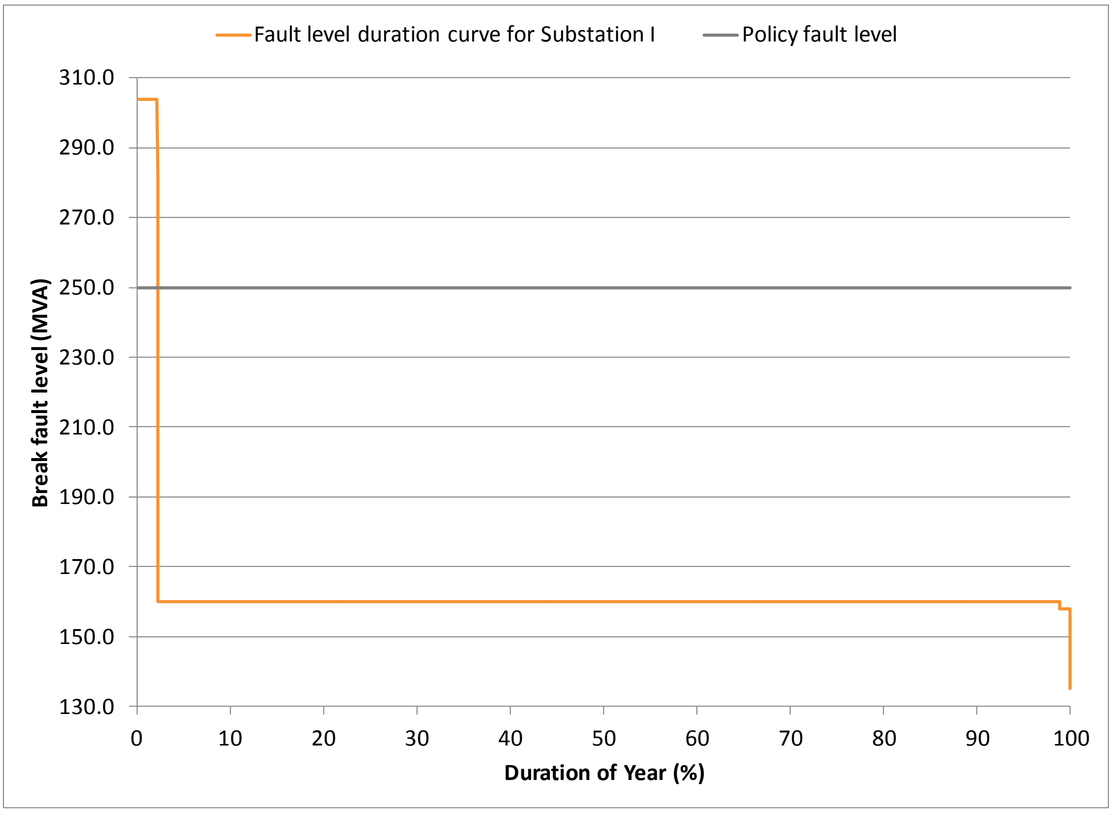

Figure D-27: Fault level duration curve for Substation I for the period 01 September 2012 to 31 August 2013

Substation J (Winson Green)

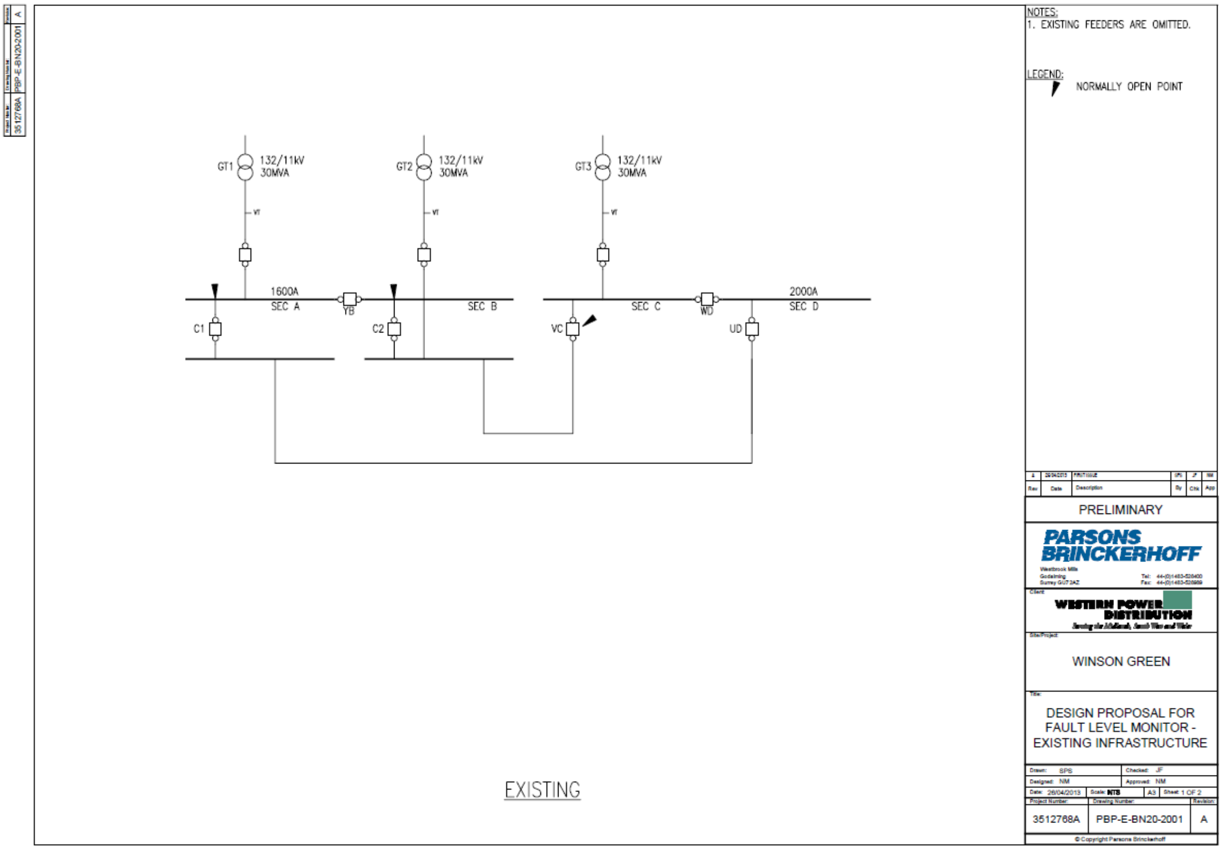

Figure D-28: Topology of Substation J

Combination	% of year	Break (MVA)	Make (MVA)	Break (kA)	Make (kA)
1	1.13%	283	825	14.9	43.3
2	0.02%	271	764	14.2	40.1
3	98.84%	156	448	8.2	23.5
4	0.02%	143	385	7.5	20.2

Table D-10: Operational configurations, durations and corresponding fault level values

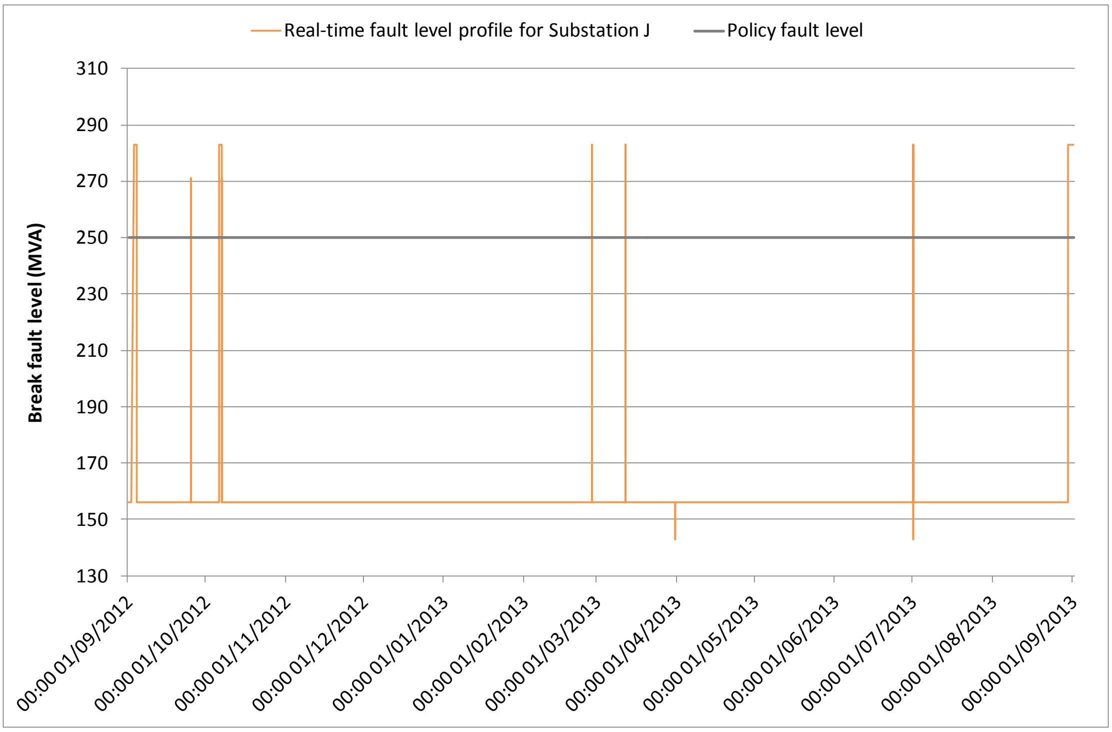

Figure D-29: Real-time fault level profile of Substation J for the period 01 September 2012 to 31 August 2013

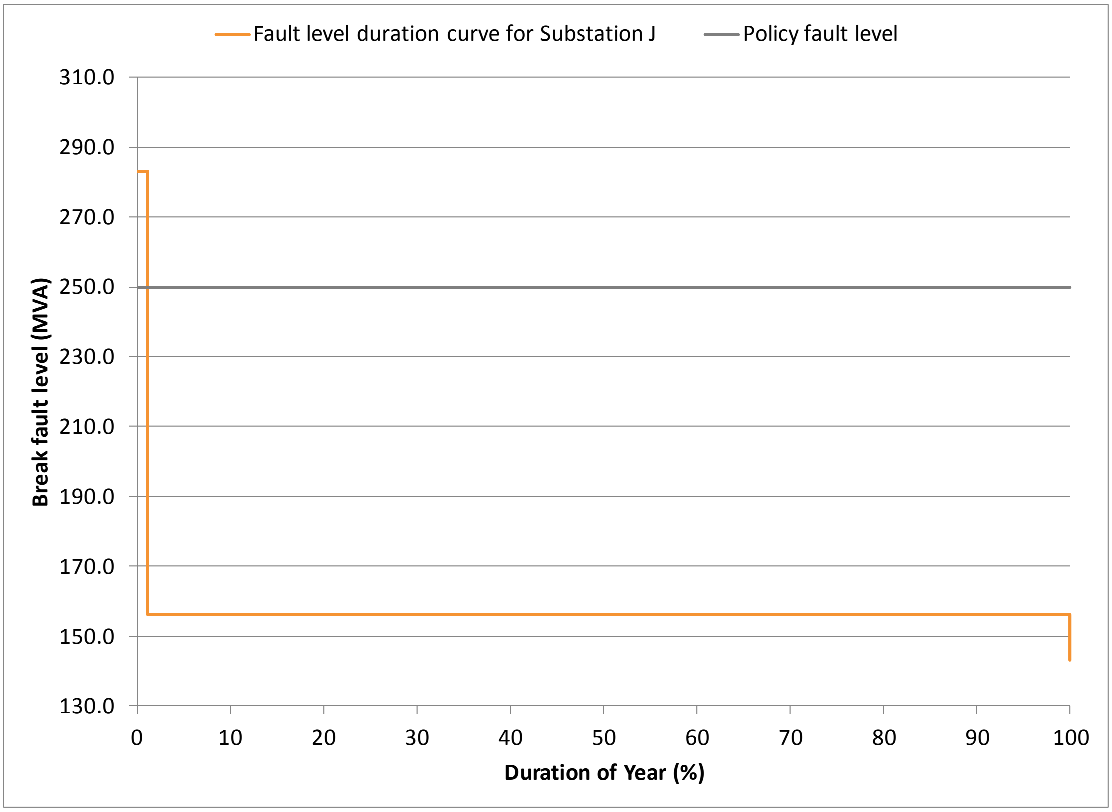

Figure D-30: Fault level duration curve for Substation J for the period 01 September 2012 to 31 August 2013