IMP/001/913 - Code of Practice for the Economic Development of the EHV System

1. Purpose

The purpose of this document is to state Northern Powergrid's policy for the economic development of the EHV system. The document states the requirements to achieve a robust, economical and efficient EHV system, taking into account the initial capital investment, system losses and the maintenance and operation costs over the life of the assets forming the system. It also takes into account the continuing commitment to improve the quality and reliability of supply to Customers. The document applies to the distribution systems of both Northern Powergrid Northeast and Northern Powergrid Yorkshire, the licensed distributors of Northern Powergrid.

This Code of Practice also helps to ensure the company achieves its requirements with respect to the Electricity Act 1989 (as amended by the Utilities Act 2000 and the Energy Act 2004), The Electricity Safety, Quality and Continuity (ESQC) Regulations 2002 (as Amended)[1], the Health and Safety at Work Act 1974, the Electricity Distribution Licences, the Distribution Code and the Grid Code.

This document supersedes the following documents, all copies of which should be destroyed:

Document Reference	Document Title	Version	Published Date
IMP/001/913	Code of Practice for the Economic Development of the EHV System	4.0	June 2020

2. Scope

This document applies to:

- The Extra High Voltage (EHV)[2] distribution systems of Northern Powergrid Northeast and Northern Powergrid Yorkshire;
- All EHV distribution system developments including new connections, system reinforcement and asset replacement; and
- All assets with a nominal operating voltage of 33kV or 66kV, including the 33kV or 66kV circuit breaker(s) at a 400 or 275kV/EHV, 132kV/EHV or EHV/HV substation.

It is not intended to apply this Code of Practice retrospectively, but when work is being done on the EHV system, the opportunity shall be taken to improve sections of network to comply with the Code of Practice when it is practicable and economic to do so.

Where distributed generation is embedded within an EHV system, or embedded into a lower or higher voltage system and may have an impact on the EHV distribution systems, this Code of Practice should be read in conjunction with the Code of Practice for the Economic Development of Distribution Systems with Distributed Generation, IMP/001/007.

1 This includes The ESQC (Amendment) Regulations 2006 (No. 1521, 1st October 2006) and The ESQC (Amendment) Regulations 2009 (No. 639, 6th April 2009).

2 EHV refers to voltages equal to or greater than 33kV and less than 132kV. For the purposes of this Code of Practice 25kV traction supplies are also considered to be EHV.

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3. Code of Practice

3.1. Assessment of Relevant Drivers

The key internal business drivers relating to the economic development of the EHV system are:

- Employee commitment - achieved by developing a safe EHV system to ensure that employees are not exposed to risks to their health as far as reasonably practicable;
- Financial strength - achieved by developing an integrated distribution system having minimum overall lifetime cost;
- Customer service - achieved by reducing the potential number of Customer Interruptions and Customer Minutes Lost;
- Regulatory integrity - achieved by designing a robust system that meets mandatory and recommended standards;
- Environmental respect - achieved through due consideration being given to the environmental impact of new developments including the impact on system losses and carbon footprint; and
- Operational excellence - achieved through improving the quality, availability and reliability of supply.

In support of the environmental respect business driver and as the UK transitions towards a low-carbon economy, new technology and digitisation are driving unprecedented change in the way energy is generated and used. As an electricity infrastructure provider, it is important to make sure that the Northern Powergrid distribution system is able to facilitate these changes economically and efficiently whilst maintaining high standards of customer service.

The industry is responding to this change by transitioning from a traditional Distribution Network Operator (DNO) to a Distribution System Operator (DSO) model. The transition to a DSO will require changes to the way in which distribution systems are designed and operated.[3] One of the changes relates to the use of flexibility services contracted with services contracted directly or indirectly with customers as an alternative to traditional reinforcement. Initial guidance on the application of flexibility services is provided in this Code of Practice.

The external business drivers relating to the development of the EHV system are detailed in the following sections.

3.1.1. Requirements of the Electricity Act 1989 (as amended)[4]

Section 9 (1) of the Electricity Act 1989 (as amended) places an obligation on Distribution Network Operators (DNOs) to develop and maintain an efficient, co-ordinated and economical system of electricity distribution and to facilitate competition in the supply and generation of electricity.

Discharge of this obligation is supported by this document in providing guidelines on the efficient development of the EHV system.

3.1.2. The Health and Safety at Work Act 1974

Section 2(1) of The Health and Safety at work Act 1974, states that 'It shall be the duty of every employer to ensure, so far as is reasonably practicable, the health, safety and welfare at work of all his employees.' Section 3(1) also states that 'It shall be the duty of every employer to conduct his undertaking in such a way as to ensure, so far as is reasonably practicable, that persons not in his employment who may be affected thereby are not thereby exposed to risks to their health or safety.'

3 Further details are set out in the Northern Powergrid DSO v1.1 Development Plan and subsequent updates.

4 The Utilities Act 2000 and The Energy Act 2004 and The Energy Act 2004 (Amendment) Regulations 2012 (No. 2723, 2012).

This is addressed in this Code of Practice by:

- Providing guidance on substation location;
- Requiring consideration to be given to the level of risk to which employees and the public are exposed by a proposed overhead line route; and
- Requiring that circuits and plant have appropriate continuous, cyclic and short circuit ratings.

3.1.3. Requirements of The Electricity Safety, Quality and Continuity (ESQC) Regulations

The ESQC Regulations 2002 (No.2665, 31st January 2003) and its amendments[5] impose a number of obligations on the business, mainly relating to safety and quality of supply. All the requirements of the ESQC Regulations that are applicable to the design and development of the EHV system shall be complied with.

5 This includes The ESQC (Amendment) Regulations 2006 (No. 1521, 1st October 2006) and The ESQC (Amendment) Regulations 2009 (No. 639, 6th April 2009).

Reg. No	Text	Application to this Code of Practice
3(1)(a)	…distributors…shall ensure that their equipment is sufficient for the purposes for and the circumstances in which it is used.	This Code of Practice will contribute to compliance with the ESQC Regulations by requiring that analysis is carried out to ensure that the continuous and short circuit duties to which equipment is exposed is within its capability.
3(1)(b)	…distributors…shall ensure that their equipment is so constructed…as to prevent danger…or interruption of supply, so far as is reasonably practicable.	This Code of Practice gives guidance to the routing of overhead lines, in particular the need to avoid the construction of overhead lines in high-risk areas.
6	A…distributor shall be responsible for the application of such protective devices to his network as will, so far as is reasonably practicable, prevent any current, including any leakage to earth, from flowing in any part of his network for such a period that part of his network can no longer carry that current without danger.	This Code of Practice requires that appropriate protection is fitted to EHV circuits and substation equipment in accordance with Northern Powergrid policy.
23(1)	A distributor shall ensure that his network shall be- (a) so arranged… as to restrict, so far as is reasonably practicable, the number of consumers affected by any fault in his network.	The Code of Practice sets the level of system complexity to EREC P18 in order to reduce the impact on customers in the event of the loss of a circuit on the EHV system Guidance is also given on substation arrangement and on the level of interconnection required in order to maintain the security of supply.
27(3)	For the purposes of this regulation, unless otherwise agreed in writing… the permitted variations are- …(c) in the case of a high voltage supply operating at a voltage below 132,000 Volts, a variation not exceeding 6 per cent above or below the declared voltage at the declared frequency.	This Code of Practice states the acceptable limits of voltage variation experienced by Customers connected to an EHV supply.

3.1.4. Requirements of the Electricity at Work Regulations 1989

Regulation 5 of The Electricity at Work Regulations 1989 states: 'No electrical equipment shall be put into use where its strength and capability may be exceeded in such a way as may give rise to danger' and places obligations on the business relating to the safety of plant and equipment used on the distribution system. It requires that plant and equipment is designed and operated within the limits of its capability.

Compliance with this Code of Practice will help to ensure that the relevant requirements of the Electricity at Work Regulations are satisfied.

3.1.5. Requirements of Northern Powergrid's Distribution Licences

Additional external business drivers relating to the development of the EHV system include compliance with the distribution licences applicable to Northern Powergrid Northeast and Northern Powergrid Yorkshire. These Distribution Licence obligations include:

Standard Licence Condition 7A (Whole Electricity System Obligations) requires the licensee to coordinate and cooperate with other electricity distribution and transmission licensees to achieve optimal efficiency across the whole of the electricity distribution and transmission system.

Standard Licence Condition 20 (Compliance with core industry documents) requires the licensee to comply with the core industry documents relevant to the design of distribution systems:

- Standard Licence Condition 20.1 requires the licensee to comply with the Grid Code;
- Standard Licence Condition 20.2 requires the licensee to at all times have in force, implement, and comply with the Distribution Code;
- Standard Licence Condition 20.3 requires the licensee to be a party to and comply with the Connection and Use of System Code (CUSC). The CUSC defines the contractual framework for connection to and use of Great Britain's high voltage transmission system; and
- Standard Licence Condition 20.3 requires the licensee to be a party to and comply with the Distribution Connection and Use of System Agreement (DCUSA). The DCUSA is a multi-party contract between the DNOs, Suppliers and Generators that deals with the use of distribution system to transport electricity.

Standard Licence Condition 24 (Distribution System planning standard and quality of performance reporting) includes requirements relating to system planning:

- Standard Licence Condition 24.1 requires that the distribution system is planned and developed to a standard of security 'not less than that laid down in Engineering Recommendation P2/7 of the Energy Networks Association or set out in any subsequent Engineering Recommendation in the EREC P2 series of the Energy Networks Association, as may be directed by the Authority, so far as that standard is applicable to it'. This Code of Practice requires that the distribution system is designed to at least the standard required by Engineering Recommendation P2.

Standard Licence Condition 31E.1 (Procurement and use of Distribution Flexibility Services) requires the licensee to coordinate and direct the flow of electricity onto and over its Distribution System in an efficient, economic and coordinated manner. This includes:

- Procuring and using Distribution Flexibility Services where it is economic and efficient to do so; and
- Procuring Distribution Flexibility Services in the most economic manner possible.

Standard Licence Condition 49 (Electricity Distribution Losses Management Obligation and Distribution Losses Strategy) requires the licensee to ensure that distribution losses from its distribution system are as low as reasonably practicable, and to maintain and act in accordance with its Distribution Losses Strategy.[6] In particular:

- Standard Licence Condition 49.2 requires the licensee to design, build, and operate its distribution system in a manner that can reasonably be expected to ensure that distribution losses are as low as reasonably practicable; and

6 Strategy for Losses, Oct 2023. https://www.northernpowergrid.com/losses.

- Standard Licence Condition 49.3 requires that in designing, building and operating its distribution system the licensee must act in accordance with its Distribution Losses Strategy, having regard to the following:
  - the distribution losses characteristics of new assets to be introduced to its distribution system;
  - whether and when assets that form part of its distribution system should be replaced or repaired;
  - the way that its distribution system is operated under normal operating conditions; and
  - any relevant legislation that may impact on its investment decisions.

The Distribution Licences also facilitate an incentive scheme for overall network performance known as the Interruption Incentive Scheme (IIS). This scheme is a driver to reduce Customer Minutes Lost (CML) and Customer Interruptions (CI), which may incentivise network investment or the use of flexibility services beyond that needed to meet the requirements of Engineering Recommendation P2. This requirement is addressed in this Code of Practice by requiring a level of interconnection and/or transfer capacity and/or flexibility services above that required by Engineering Recommendation P2 where this can be provided economically.

Compliance with this Code of Practice will help to ensure that the relevant requirements of the Distribution Licence are satisfied.

3.1.6. Requirements of the Distribution Code

As a Distribution Licence holder, Northern Powergrid is required to hold, maintain and comply with the Distribution Code of Licensed Distribution Network Operators of Great Britain.

The Distribution Code covers all material technical aspects relating to connections to and the operation and use of the distribution systems of the Distribution Network Operators. The Distribution Code is prepared by the Distribution Code Review Panel and is specifically designed to:

- permit the development, maintenance and operation of an efficient co-ordinated and economic system for the distribution of electricity;
- facilitate competition in the generation and supply of electricity; and
- efficiently discharge the obligations imposed upon DNOs by their Distribution Licence and comply with the Regulation[7] and any relevant legally binding decision of the European Commission and/or Agency for the Co-operation of Energy Regulators. This objective was particularly relevant in relation to the recent introduction of a suite of European Network Codes which place additional obligations on Generators and DNOs.

The Distribution Planning and Connection Code (DPC) specifies the technical and design criteria and the procedures which shall be complied with in the planning and development of the distribution systems. It also applies to users of the distribution systems in the planning and development of their own systems in so far as they affect Northern Powergrid systems.

The Distribution Planning and Connection Code (DPC) also sets out principles relating to the design of equipment and its operating regime. Equipment on the Northern Powergrid systems and on user's systems[8] connected to them shall comply with relevant statutory obligations, international and national specifications and Energy Networks Association technical specifications and standards.

7 Regulation has the meaning defined in the distribution licence.

8 DPC 4.4 refers specifically to the requirements of Users Systems.

Compliance with this Code of Practice will help to ensure that the relevant requirements of the Distribution Code are satisfied.

3.1.7. Requirements of the Distribution Connection and Use of System Code

As a Distribution Licence holder, Northern Powergrid is required comply with the Distribution Connection and Use of System Code (DCUSA) which is a multi-party contract between licensed electricity distributors, suppliers and generators in Great Britain concerned with the use of the electricity distribution system. DCUSA is generally concerned with the commercial and contractual relationship between suppliers, DNOs and customers, but there are some aspects of DCUSA that have technical implications for the design of connections to distribution systems. For example:

- Schedule 22 (Common Connection Charging Methodology) Clause 1.1 defines the Minimum Scheme associated with a connection request which links to the requirements of Engineering Recommendation P2 and hence to the potential requirement to increase the capacity of the distribution system to accommodate new / additional import from the distribution system.
- Schedule 2D (Curtailable Connections) relates to the provision of a Curtailable Connection offer which may require an import and / or export management scheme to be installed as an interim arrangement until the capacity of the distribution system has been increased where necessary.

Compliance with this Code of Practice will help to ensure that the relevant requirements of the Distribution Connection and Use of System Code are satisfied.

3.2. Key Policy Requirements

The general objective in developing the EHV system is to obtain a simple and robust system having minimum overall cost, taking into account:

- the initial capital investment;
- the annual cost of any flexibility services, expressed in net present value for the duration of the service; and
- system losses; and
- the maintainability and operability over the life of the asset.

Any development of the EHV system should seek to improve the quality and reliability of the supply provided i.e., reduce the number of potential Customer Interruptions (i.e., to improve reliability) and Customer Minutes Lost (i.e., to improve availability).

This Code of Practice is written to help ensure that all EHV system developments are made in such a way as to:

- prevent danger to members of the public and Northern Powergrid staff and our sub-contractors;
- optimise system security, reliability and availability;
- optimise power quality experienced by Customers;
- discharge the obligation under section 9 of the Act, and specifically to have due regard to future requirements and network performance;
- facilitate the use of standardised plant and equipment;
- facilitate the use of flexibility services as an alternative to Northern Powergrid plant and equipment;
- minimise environmental pollution and statutory nuisance; and
- satisfy all other relevant obligations.

3.3. EHV System Development

3.3.1. Background

The EHV system serves as a distribution role between the 132kV and HV systems, since direct 132kV/HV transformation is only economically justified in special cases. There are a number of situations where it is appropriate to connect distributed generation or large industrial customers to the system at EHV voltages. Furthermore, the system generally gives additional security by providing interconnection between the EHV busbars at 132kV/EHV substations that can be utilised under 132kV outage conditions.

Historically, in Northern Powergrid Yorkshire the 33kV system was developed mostly in urban areas, being more economic for situations requiring underground cables and indoor metal-clad substations, with use being made of three-circuit developments in conjunction with Continuous Emergency Rated (CER) transformers to maximise the utilisation of cables and overhead lines. The 66kV system was developed mainly in rural areas between large urban conurbations, and generally comprises overhead lines with outdoor-type substations.

Until the 1960's the 66kV system formed the main distribution infrastructure in Northern Powergrid Northeast with the 33kV system generally confined to areas around York and Darlington. From the mid 1960's the 33kV system was introduced more extensively into urban areas.

The 66kV system in both regions has some parts arranged in a radial configuration, but others are configured and operated as closed rings with mesh substations.

3.3.2. Application

The policy requirements outlined in this document shall apply to the majority of situations where the EHV system is developed, including new demand and generation connections, system reinforcement, application of flexibility services and asset replacement and recovery. There may be a small number of cases where special arrangements, which are not strictly in accordance with the documented policy, may be more appropriate and can be considered where there are benefits to both Northern Powergrid and its Customers. Any such deviations relating to tactical implementation at an individual site shall be agreed with the relevant Design Manager[9] at an early stage of the design process. Any such deviations relating to strategic network development shall be agreed with the relevant Planning Manager[10] at an early stage of the design process.

This Code of Practice shall be read in conjunction with relevant Engineering Recommendations and other Northern Powergrid documents including the following:

- Code of Practice for the Economic Development of Distribution Systems with Distributed Generation, IMP/001/007;
- Code of Practice for Standard Arrangements for Customer Connections, IMP/001/010;
- Code of Practice for the Methodology of Assessing Losses, IMP/001/103;
- Code of Practice Guidance for assessing Security of Supply in accordance with Engineering Recommendation P2/7, IMP/001/206;
- Code of Practice for Distribution System Parameters, IMP/001/909;
- Code of Practice for the Economic Development of the HV System, IMP/001/912; and
- Code of Practice for the Economic Development of the 132kV System, IMP/001/914.

9 The Design Manager is a defined term - see section 5.

10 The Planning Manager is a defined term - see section 5.

The design of the EHV system shall ensure that the technical characteristics associated with:

- voltage levels,
- voltage and waveform quality,
- neutral earthing,
- system phasing, rotation and vector groups, and
- short circuit levels,

comply with the requirements of the following sub-sections.

3.3.3. Voltage Levels

The EHV system shall be designed to operate at the nominal voltage set out in the Code of Practice for Distribution System Parameters, IMP/001/909. To achieve this, the lower voltage busbars will be controlled by means of Automatic Voltage Regulator (AVR) relays and the transformer tap position automatically adjusted as appropriate to maintain the target voltage.

Historically, the target voltage has been based on the need to maintain the voltage at customers' points of supply within statutory limits at times of high system demand. However, as the penetration of generation connected to distribution systems increases there is a need to consider voltage rise at times of high net export. This has resulted in a reduction of the standard HV target voltage at 132kV/HV and EHV/HV substations from 11.3kV to 11.1kV, and 20.3kV to 20.1kV for the systems operating at a nominal 11kV and 20kV, respectively. Similarly, a programme to reduce the standard target voltages at substations with a secondary voltage at EHV is in the process of being implemented. Further guidance is provided in in the Code of Practice for Managing Voltages on the Distribution System, IMP/001/915.

Where non-standard target voltages are deployed, they shall be agreed between Engineering and Control Operations. Where tap changers controlling the voltage on the lower voltage busbar are NGET assets e.g., at 400kV or 275kV/EHV grid supply points, the target operating voltage shall be agreed between Northern Powergrid and NGESO.[11]

The Electricity Safety, Quality and Continuity Regulations require that the voltage be declared to Customers connected to the distribution system. In the case of Customers connected to a high voltage supply operating at a voltage below 132kV, the variation must not exceed 6% above or below the declared voltage at the declared frequency. The EHV system shall therefore normally be designed to limit the maximum voltage variation to ±6% of the nominal voltage in order to accommodate any future customer connections at this voltage.

There may be some parts of the system comprising long EHV overhead line circuits without any directly connected Customers, where there is very little likelihood of new customers requesting a direct connection to them. In such situations consideration should be given to relaxing the voltage variation to ±10% of nominal if there are significant cost savings. Any such an arrangement should be agreed with the relevant Design Manager.

Northern Powergrid policy for voltage management is set out in the Code of Practice for Managing Voltages on the Distribution System, IMP/001/915.

3.3.4. Voltage and Waveform Quality

New connections provided at EHV voltages shall meet the requirements of:

11 The target voltage shall be agreed on a site-by-site basis between NGESO, Northern Powergrid Control Operations and Northern Powergrid Engineering.

- Engineering Recommendations P28, Voltage fluctuations and the connection of disturbing equipment to transmission systems and distribution networks in the United Kingdom;
- Engineering Recommendation P29, Planning Limits for Voltage Unbalance in the UK for 132kV and Below;
- Engineering Recommendation G5, Harmonic voltage distortion and the connection of harmonic sources and/or resonant plant to transmission systems and distribution networks in the United Kingdom, and
- Engineering Recommendation G99, Requirements for the connection of generation equipment in parallel with public Distribution Networks on or after 27 April 2019.[12]

In respect of fluctuations, voltage unbalance and harmonic voltage distortion, whilst there is no requirement for the EHV system itself to operate within the parameters set out in these Engineering Recommendations it should generally be designed to do so.

Detailed design studies to assess the impact of potentially disturbing loads and generation such as large motors, welders, inverters and other harmonic producing equipment shall be carried out as part of the application process for connecting such loads or generation and when modifications to the systems are being considered. In some cases, a proposed HV connection of a large abnormal load or generation can only be accepted if its point of common coupling is on the EHV system.

3.3.5. Neutral Earthing

The earthing arrangements at the EHV source shall be such that the earth fault current does not exceed the full load current of the transformer. In consequence, the short circuit rating of equipment on the 33kV and 66kV system need only take account of the maximum short circuit phase to phase fault current.

The arrangements for earthing each Super Grid Transformer (SGT) at a NGET interface substation shall be agreed with NGESO on a site-by-site basis.

In Northern Powergrid Northeast, NGET SGTs with a secondary voltage of 33kV shall normally have a delta secondary winding and be earthed via an earthing transformer. SGTs with a secondary voltage of 66kV shall normally be earthed at the star point of the 66kV winding except where it is necessary to constrain fault-current or reduce the rise of earth potential. In this case a neutral earthing resistor may be connected between the star point and earth in such instances due regard must be given to the insulation grading of transformers and associated switchgear and protection issues.

In Northern Powergrid Yorkshire, NGET SGTs with a secondary voltage of 66kV or 33kV shall normally have a delta secondary winding and be earthed via an earthing transformer.

There is a requirement to ensure that following a fault on the HV system supplied from an EHV/HV substation, sufficient fault current flows to enable the fault to be detected without overloading any plant. This is achieved by limiting the earth fault current at EHV/HV substations by Neutral Earthing Resistors (NERs) connected to the neutral connection of the lower voltage transformer terminals. Typically, the HV fault current is limited by the NER to 600A at urban EHV/HV substations (i.e., those with HV circuits comprising <10% OHL) and 1500A at EHV/HV substations (i.e., those with HV circuits comprising >10% OHL).[13]

Transformers supplying HV switchboards that feed long lengths of overhead line should be fitted with an Arc Suppression Coil (ASC) in accordance with the section level document, An Application Guide for Arc Suppression Coils, IMP/001/912/001. ASC earthing works in conjunction with the existing overhead

12 Engineering Recommendation G99 permits some relaxations of voltage step changes in defined operational scenarios associated with generation connections.

13 Further guidance can be found in An Application Guide for Arc Suppression Coils, IMP/001/912/001.

line protection, typically comprising auto-reclose schemes. The inductive reactance of the coil is adjusted to match the capacitive reactance to earth of two phases with the third phase connected solidly to earth. In the event of a transient single-phase-to-earth fault, the resulting lagging current negates the capacitive current due to the overhead lines. Hence, there will be negligible fault current, and customers will consequently experience fewer interruptions and an improved quality of supply. In the event of the detection of a permanent single-phase-to-earth fault, a bypass circuit breaker operates to short-out the ASC and allow the circuit protection to detect the fault and disconnect the circuit. The time applied to the scheme will be dependent on the original method of system earthing to limit the duration of overvoltage on the healthy phases. Typically, ASCs are fitted at an EHV/HV substation where the feeders comprise predominantly overhead lines and where the aggregate length is greater than 35km in Northern Powergrid Northeast or 50km in Northern Powergrid Yorkshire.

3.3.6. System Phasing, Rotation and Vector Groups

The phase vector relationship and phase connections on the EHV system shall be in accordance with the Code of Practice for Distribution System Parameters, IMP/001/909.

Standard Northern Powergrid Northeast 33kV/11kV and 33kV/6kV transformers shall be of vector group Yy6 (connected Yy10).

Standard Northern Powergrid Northeast 66kV/11kV and 66kV/6kV transformers will be of the vector group Dy11, both resulting in the red phase vector on the 11kV or 6kV busbar leading to the reference 132kV vector by 30°.

Standard Northern Powergrid Northeast 66kV/20kV transformers shall be of the vector group Yy0, resulting in the red phase vector on the 20kV busbar being the same as the reference 132kV vector, 0°.

Standard Northern Powergrid Yorkshire 33/11kV and 66/11kV transformers shall be of vector group Yy0, resulting in the red phase vector on the 11kV busbar leading the reference 132kV vector by 90°.

Note that there are existing non-standard vector groups in service particularly on the Northern Powergrid Northeast system referenced in the Code of Practice for Distribution System Parameters, IMP/001/909.

3.3.7. Short Circuit Levels

The Code of Practice for Distribution System Parameters, IMP/001/909 states the present design maximum prospective short circuit current and the minimum break rating for new switchgear.

Because of earthing arrangements on the source EHV transformer, the prospective short circuit currents on the EHV system will generally be higher for phase-to-phase faults than for phase-to-earth faults, thus the short circuit ratings of circuits and switchgear shall be chosen with particular care to avoid overstressing under phase-to-phase fault conditions. When assessing the capability of EHV switchgear, consideration should be given to the X/R ratios on the system; where the X/R ratio is higher than 14.1, the capability of circuit breakers may be less than its nameplate rating.

When assessing the short circuit duty on EHV assets, consideration shall be given to all the credible operational scenarios, e.g., where four SGTs are installed at a NGET interface substation and the site is normally configured with two pairs of SGTs operating in parallel, a credible running arrangement during an outage of an SGT could be with three SGTs operating in parallel.

In order to facilitate future uprating of the short circuit capability of the distribution system, for example to permit the connection of generation, all new switchgear installed on the 33kV and 66kV distribution system will normally be specified with dual three-phase symmetrical short-circuit ratings i.e. a rating for two X/R values: 14.1 and 37.7.[14,15] The rating at different X/R values can be deduced using the standard IEC preferred R10 rating series; further information can be found in the ENA Engineering Report 89, Specification of d.c. Time Constants for Switchgear

In circumstances on the 33kV system where the existing short circuit duty does not exceed 20kA, and is not expected to exceed 20kA in the future and the whole life-cycle cost of installing 25kA rated switchgear is less than that of 31.5kA switchgear, then the use of switchgear rated at 25kA (at an X/R ratio of 14.1) may be permitted. In circumstances on the 66kV system where the existing short circuit duty does not exceed 25kA and is not expected to exceed 25kA in the future and the whole life-cycle cost of installing 31.5kA rated switchgear is less than that of 40kA switchgear, then the use of switchgear rated at 31.5kA (at an X/R ratio of 14.1) may be permitted. Section 3.5.3, Switchgear, adds further clarity on the circumstances in which 25kA or 31.5kA rated switchgear may be used. As higher rated plant becomes available on the market, then this shall be specified where economic.

3.4. System Design Criteria

When designing new or modifying existing EHV systems, care shall be given to ensure that any development is consistent with known proposals for new connections, authorised asset replacement or system reinforcement schemes and that consideration is given to the longer-term future system requirements. Consideration should be given to the impact of different credible upstream running arrangements, which for instance increase fault-levels, and their impact on the design. Reference should be made to the Northern Powergrid Investment Plan, Network Development Strategies, Distribution Load Estimates and Northern Powergrid Distribution Future Energy Scenarios[16] to ensure that EHV system designs take account of demand growth and generation plant connections that can reasonably be expected within the ten-year planning period[17] and facilitates the transition towards the Government's 2050 net greenhouse gas emissions target.

The sub-sections below set out key design criteria for the EHV system.

3.4.1. System Configuration

The EHV system shall have limits of complexity set out in Engineering Recommendation P18, Complexity of Distribution Circuits Operated at or above 22kV. All EHV circuits shall be protected in accordance with the Policy for Protection of Distribution Networks, IMP/001/014. When designing new EHV circuits and / or alterations to existing EHV circuits consideration shall be given the physical circuit construction i.e., the mixture of underground cable and overhead line, the number of customers connected or likely to be connected and the potential time to locate and isolate faults.

The preferred arrangement in areas of high and medium load density is for a matched pair of 33kV/HV or 66kV/HV transformers at an EHV/HV substation to be operated in parallel to provide a continuous supply to the HV busbar in the event of an outage of one of the EHV/HV transformers. Wherever possible, symmetrical feeding arrangements shall be used for the two transformers, as this will generally minimise losses and circulating currents, and help to avoid voltage control problems when generation is connected. New 33kV/HV or 66kV/HV substations should be located, as far as practicable, so as to minimise the extent of the distribution infrastructure (particularly lines and cables) required to service the demand and generation connected to it, having due regard to the economics of laying new incoming and outgoing feeders, the environmental impact of the development and likely future land development.

The use of two 15/30MVA CER transformers is the preferred arrangement, although the selection of the appropriate capacity transformer should be based on a cost benefit analysis that considers the likely expected demand that the transformer will be subjected to during its lifetime. The minimum CER

14 See section 3.5.3.

15 In ENA Technical Specifications for EHV switchgear, short circuit ratings are specified at two time constants, 45ms and 120ms which relate to X/R ratios of 14.137 and 37.699 respectively. $X/R = 2 \times \pi \times f \times t(ms)$

16 https://www.northernpowergrid.com/downloads/4211.f.

17 The current Distribution Load Estimates cover an eight-year period, and the plan is to extend this period to ten years.

transformer size for all new installations is 12/24MVA. 20/40MVA CER transformers may be appropriate in areas with a high load density e.g., city centre areas, where additional substation sites are unlikely to be available. The use of 20/40MVA CER transformers may present protection issues and therefore consultation must take place with Technical Services at an early stage in the development of a scheme.

In areas that require an injection point to the HV system to provide adequate voltage support, an EHV/HV substation equipped with a single transformer may be installed to supply demands of less than 12MW provided that there is sufficient automatic HV interconnection or automatic transfer capacity e.g. via an Automatic Power Restoration System (APRS) or a hard wired auto close scheme, with other EHV/HV substations to supply all the demand under first circuit outage conditions to ensure compliance with Engineering Recommendation P2. Automation of existing HV interconnection or transfer capacity shall also be considered for existing single transformer EHV/HV substations when practical and economic to do so. Such a substation would normally be equipped with a 12/24MVA CER transformer. Single-transformer EHV/HV substations may also be used to provide generation connections and where abnormal loads e.g., arc furnaces, associated with a specific customer require a segregated 'dirty' HV busbar and to establish a point of common coupling on the EHV system, this includes the use of a single SGT infeed from the transmission system.

In general, radial transformer feeder circuits from the nearest EHV source shall be the preferred circuit arrangement for 33kV systems. Extensions to the 66kV system shall normally maintain the same system configuration as the system being extended i.e., radial or closed ring.

Provided that the system can be protected in accordance with the Policy for Protection of Distribution Networks, IMP/001/014, a single teed connection from an EHV circuit can be used to provide supplies to an individual demand and/or generation customer who only requires single circuit security. When assessing such an arrangement consideration should be given to:

- The possibility of receiving requests for new demand or generation connections in the foreseeable future which may be better serviced via a looped substation rather than a teed substation;
- The number and duration of outages that would result in the customer being off-supply. These may be for prolonged periods, potentially several weeks for asset replacement and new construction work. If a customer has agreed to a single circuit security, it would be unreasonable for Northern Powergrid to incur significant additional costs to minimise outage frequency and duration;
- Whether it may be possible to install pole mounted EHV switchgear, to isolate equipment. This may enable isolation of a new teed circuit to maintain supplies to existing customers or to maintain supplies to customers supplied via a new teed connection for an outage of the EHV system downstream of the tee-off point;
- Ensuring compliance with the principles of Engineering Recommendation P18. The presence of multiple tee-offs on a circuit increases the number of sites that need to be visited to isolate the circuit. Distances between sites, particularly in relation to 66kV circuits, can be significant and creating new tees may impact on travelling times / resources required to isolate and restore circuits back to service; and
- The costs of complying with the Policy for Protection of Distribution Networks, IMP/001/014. This may require the normal distance protection to be replaced by a three ended unit protection scheme. The communications required to implement the three ended protection must be sufficiently stable, reliable and available so that there is not excessive reliance on backup protection, which would be less discriminatory than the main protection. Experience has shown that UHF digital radio systems are not sufficiently stable to be used as the communications link for a unit protection scheme, and a fibre wrap or microwave communications link, together with the associated towers (which may require planning permission) is typically required.

New EHV/HV substations connected into a closed ring system should be of a single switch design[18] comprising an EHV bus section circuit breaker. Such substations typically have lower capital and operating costs and provide an acceptable level of security of supplies to customers. The guiding principle is that is that transformer faults and circuit faults are sufficiently rare that the risk to customer supplies, until the faulty plant can be isolated, is not unacceptable. The use of remotely controllable isolators would reduce the time to isolate faulty plant allowing healthy transformer or circuit to be returned to service.

Where switchgear is being replaced at an existing EHV/HV substation in a closed ring, in order to minimise the changes to the existing protection scheme and the associated costs, the preferred arrangement is to retain the existing arrangement e.g., an existing three or five switch arrangement.

Situations that require further consideration of the number and location of the EHV circuit breakers include where:

- at an existing substation, the existing arrangements cannot comply with Policy for the Protection of Distribution Networks, IMP/001/014;
- at an existing substation, the asset replacement work is sufficiently extensive that it is reasonable to review the EHV configuration;
- the EHV/HV substation load or export generation capacity is greater than the capacity of one of the transformers where the loss of an EHV circuit would result in a healthy transformer being tripped, as this could impose excessive demand on the remaining transformer;
- there is an Active Network Management (ANM) scheme, and the tripping of healthy transformers or circuits would have an adverse impact on the capacity available for generation export until the healthy plant is returned to service;
- an EHV circuit forms part of a critical interconnector between two 132/EHV substations; and
- the EHV/HV substation contains only a single transformer.

Appendix 1 illustrates a typical radial feeder arrangement and also illustrates the preferred method of adding a single switch 66kV substation to a closed ring system. Other arrangements requiring additional circuit breakers may be required, for example where there are more than two 66kV circuits supplying the substation.

In some circumstances, for example where larger size conductors are already installed, extending an existing EHV feeder to supply a new primary substation using a '3-panel arrangement'[19] may provide the most economical solution.

A 3-panel arrangement located in urban substations should normally comprise indoor ground-mounted metal-clad circuit breakers controlling the transformer and outgoing circuit, with the incoming cable connected to the busbar via a non-automatic circuit breaker. A typical system architecture utilising 3-panel arrangement is illustrated in Appendix 1. The resulting system can provide the flexibility to transfer capacity between the two source substations by moving the position of the open point.

Using a 3-panel arrangement to extend EHV cable circuits has the following advantages over supplying a new primary substation by radial feeders from the supply point:

18 The protection arrangements need to comply with the requirements set out in the Policy for the Protection of Distribution Networks, IMP/001/014, including clearance times for busbar and transformer faults. The availability of communications circuits may influence the type of protection that can be used and hence whether a single switch substation can be protected in accordance with IMP/001/014. Where a single switch substation cannot comply with IMP/001/014 a three or five switch substation should be established.

19 '3-panel arrangements' are used to implement 3-circuit development network architecture. Historically this has comprised a 33kV circuit breaker, a 33kV switch and a cable end box. More recently 33kV circuit breakers have been used in place of a switch. Currently this functionality is provided via a 33kV switchboard comprising three circuit breakers; a circuit breaker being used in place of a cable end box.

- Provided that the cable supplying the existing substation has a sufficient rating, savings can be made on the length of cable and the amount of excavation required to commission a new primary substation; and

- The EHV switchboard at the source substation will not require extending thus avoiding potential availability issues of compatible plant and avoiding potential civil works.

The use of a 3-panel arrangement is preferable to the use of simple tees for the following reasons:

- A 3-panel arrangement can reduce the impact of a fault occurring on the second leg of the feeder by enabling protection to disconnect only the faulted section; and

- A 3-panel arrangement enables the transformers at either substation to be isolated for maintenance or when undertaking fault location. Feeders connected by a simple tee may, depending upon the presence of suitably rated Air Break Switch Disconnectors (ABSDs),[20] require both transformers to be removed from service, thus placing both EHV/HV substations under single circuit security.

At a 400kV/EHV, 275kV/EHV or 132/EHV substation where the EHV switchboard cannot be extended, a new EHV switchboard can be installed close to the existing EHV switchboard to effectively create additional connection points for EHV circuits. The installation of such a EHV switchboard should not sterilise the land within a 400kV/EHV, 275kV/EHV or 132/EHV substation making the eventual replacement of the substation plant more expensive. The choice of switchgear and housing for the switchboard shall take into consideration:

- The number of additional EHV circuits required;

- Whether the EHV substation may be extended in the future;

- The protection requirements of the EHV circuits;

- Whether the EHV switchboard could be used as the basis for a new EHV switchboard at a replacement 400kV/EHV, 275kV/EHV or 132/EHV substation.

In the case of EHV overhead circuits, it will often be economic and practicable to connect two transformers to a single overhead line. This shall usually be achieved with a simple tee with isolators controlling the transformer at each substation. It may be necessary to up-rate the existing circuit with 200mm² AAAC conductors to ensure that the capacity of the refurbished line matches its potential future duty. A simple overhead line tee with transformer isolators is illustrated in Appendix 1. There is a requirement to install a delayed auto reclose scheme in order to return circuits to service after transient line faults.

Where there are two EHV/HV transformers either located at the same or different substations supplied by an EHV circuit, the rating of the circuit needs to be considered when assessing the capacity of the substation(s) under first circuit outage conditions, in accordance with the document, Guidance on the assessment of major substation firm capacity, IMP/001/920.

For reasons of economy and operational convenience, in rural areas circuits shall comprise overhead lines where feasible, however the difficulties and timescales obtaining planning permission, wayleaves / easements mean that the use of cable is often a pragmatic and economic solution.

The environmental impact of proposed overhead and underground circuit routes shall be taken into account.

20 Category 1 ABSDs can be used to isolate up to 40MVA (at 66kV) of transformer capacity.

3.4.2. System Security and Interconnection

The distribution system shall be planned and developed to provide at least the standard of security required by Engineering Recommendation P2, Security of Supply. This is a requirement of the distribution licences of Northern Powergrid and the Distribution Code. Further guidance on the application of Engineering Recommendation P2 can be found in the Guidance for Assessing Security of Supply in Accordance with Engineering Recommendation P2/7, IMP/001/206.

In most cases, connections to single customers can be to a lower standard than Engineering Recommendation P2 provided that written confirmation of the acceptability of this is obtained from the customer. The level of security, and hence investment, will be chosen to meet an acceptable level of business risk to the customer. The level of security provided shall be stated in their connection agreement.

At NGET interface substations i.e., 400kV/EHV or 275kV/EHV substations there is a requirement for the substation to comply with the requirements of the National Electricity Transmission System Security and Quality of Supply Standards (NETS SQSS), which is a requirement of NGESO's Transmission Licence.

NGET interface substations shall generally be arranged to enable two or more[21] SGTs to be operated in parallel with protection designed to provide a continuous supply to the EHV busbar in the event of an outage of one of the SGTs or the circuit supplying the SGT. The number of SGTs required will depend upon the maximum system demand,[22] the availability of EHV interconnection and / or lower voltage transfer capacity, the presence of distributed generation plant and the presence of flexibility service contracts. For larger demand groups, in order to comply with the recommended level of security it will normally be necessary for some EHV interconnection and / or lower voltage transfer capacity to be provided. The compliance of NGET interface substations with NETS SQSS shall be agreed with NGESO annually in order to identify any existing or forecast non-compliance where reinforcement or flexibility service contracts may be required. Such liaison is required to comply with the whole system requirements set out in Standard Licence Condition 7A.

At NGET interface substations with more than two SGTs installed, short circuit currents, especially if there is significant generation plant connected to the system, may be too high to permit all the SGTs to be in service at the same time. In such situations consideration can be given to operating one of the SGTs on hot standby or to operating with a bus section circuit breaker open, provided that an assessment of NETS SQSS security compliance, step voltage change, short term SGT overload, generation stability etc. has been carried out, in conjunction with NGESO, and the agreement from the relevant Planning Manager has been obtained.

132kV/EHV substations shall generally be arranged to enable two 132/EHV transformers to be operated in parallel with protection designed to provide a continuous supply to the EHV busbar in the event of an outage of one of the transformers or the circuit supplying the transformer.

In response to the Interruption Incentive Scheme (IIS) and to mitigate the risks associated with extended customer disconnection, the system shall, where economically justified, be designed to provide a level of security above that required by Engineering Recommendation P2. This shall be achieved by using either flexibility services as detailed in section 3.4.11 or by providing EHV interconnection and / or transfer capacity where economical such that one third of the 400kV/EHV, 275kV/EHV or 132/EHV substation's firm capacity can be secured in the event of a second circuit outage. The EHV circuits linking such substations should be configured such that the interconnection / transfer capacity can be utilised by remote switching of normally open points.

21 There may be situations where it economical to commission a new NGET interface substation equipped with a single transformer. Such a substation could operate in parallel with other NGET interface substations either as an interim development pending the connection of further demand or generation plant, or as an enduring solution.

22 Generally, the required capacity of a NGET interface substation is driven by the demand, however if there is a significant amount of generation connected to a NGET interface substation the required capacity may be driven by generation export.

In circumstances where the group demand is significantly less than the substation capacity under first circuit outage conditions, the level of security implied in this section may not be justified. Where appropriate, risk analysis should be carried out to provide justification for interconnection by considering the Interruption Incentive Scheme (IIS) implications.

When assessing system security, consideration should be given to reducing common modes of failure where this is economically viable. When designing a new substation or an asset replacement scheme the opportunity should be taken to:

- Un-bank EHV circuits at switchboards such that each circuit is controlled by its own circuit breaker;
- configure the connections to the busbars so that incoming transformer circuits are not installed adjacent to a bus section circuit breaker;[23] and
- configure the connections to the busbars so that mutually dependant outgoing circuits are not installed as adjacent circuits[24] or connected to one side of a bus section or bus coupler circuit breaker.[25]

EHV/HV substations shall generally be arranged to enable two EHV/HV transformers to be operated in parallel, with appropriate protection to provide a continuous supply to the EHV busbar in the event of an outage of one of the transformers or the circuit supplying the transformer. EHV/HV substations equipped with a single transformer can be used to supply demands of less than 12MW provided that the criteria set out in section 3.4.1 can be met.

At EHV/HV substations, the duplicate transformer arrangement secures supplies under first circuit outage conditions and there is no requirement in Engineering Recommendation P2 to maintain supplies under second circuit outage conditions. However, in response to the Interruption Incentive Scheme (IIS) and to mitigate the risks associated with extended customer disconnection, the system shall, where economically justified, be designed to provide a level of security above that required by Engineering Recommendation P2. This shall be achieved by either using flexibility services as detailed in section 3.4.11 or designing the HV system so that it is configured as open interconnectors between EHV/HV substations, where economically viable. The open points in each interconnector shall be capable of remote operation. This will enable the transfer of load in the event of an unplanned outage occurring during a planned outage or a double unplanned outage. Where it is uneconomic to secure all the EHV/HV substation demand under second circuit outage conditions, consideration should be given to provision of one suitably rated HV interconnector onto each section of HV busbar. This will ensure that rota disconnection of customers can be easily achieved.

HV interconnection may also enable load to be transferred in the event of an outage at the source EHV substation. This may help ensure Engineering Recommendation P2 compliance of that substation; however, it should be noted that the provision of HV demand transfer to ensure compliance is likely to only be appropriate where the there is a relatively small deficit.

Except in special situations, such as where requested by a customer as part of a development funded by that customer, it is unlikely to be economic to install two parallel EHV cables in separate trenches.

3.4.3. Design Feasibility

System studies shall be carried out whenever it is necessary to ensure that the EHV system will operate correctly following a change (for example a modification or replacement, or a new or increased capacity Customer connection) or as part of a regular system compliance review. In particular, the aspects of system performance identified in section 3.4.3.1 below shall be modelled to ensure that acceptable

23 This will reduce the possibility of a failure of a bus section circuit breaker affecting both incoming transformer circuits.

24 This will reduce the possibility of a failure of one circuit affecting the other dependent circuit, and manage issues associated with proximity outages.

25 This will reduce the possibility of a failure of a single circuit breaker affecting two dependent circuits.

performance is ensured following any proposed change. The model used shall be up to date i.e., populated with demands from the latest published version of the Distribution Load Estimates, NGESO Grid Code Week 42 data submission and contain the technical parameters associated with all authorised internally driven and customer driven developments that may have a material impact.[26]

System studies, including load flow, short circuit, voltage transient stability and voltage step change analysis shall be carried out at the design stage for all credible system running conditions, including outage conditions, to ensure compliance with the security requirements of Engineering Recommendation P2, the stability requirements of Engineering Recommendation G99[27], the voltage fluctuation requirements of Engineering Recommendation P28 and Northern Powergrid design criteria set out in the Code of Practice for the Economic Development of Distribution Systems with Distributed Generation, IMP/001/007. Where the design of the EHV system can affect the transmission system e.g., the provision of transfer capacity to ensure compliance with NETS SQSS and the connection of material generation plant, [28] there should be liaison with NGESO.

Any design that will result in a material change in system capability, e.g., relating to:

- the capacity of a substation in system intact, first circuit outage and second circuit outage conditions;
- plant and circuit rating; or
- short-circuit duty / capability,

shall have that change in system capability recorded in the Investment Appraisal Document and notification provided to the System Forecasting team for incorporation into the Distribution Load Estimates and Fault-Level Survey as appropriate.

3.4.3.1. Transient and Steady State Stability

Prior to the connection of new generation plant, the connection of large rotating plant or following the proposed change to any part of the system to which there is generation plant or large rotating plant currently connected, the transient stability of the planned system shall be assessed by carrying out dynamic stability studies.[29] Such studies will identify critical clearance times for the operation of protection. Unless protection systems can be designed to achieve the required clearance times, an alternative network configuration that is stable under transient conditions shall be established.

Generation connected to the EHV system shall also be 'steady state stable' i.e., following a small disturbance on the system it shall return to a stable steady state operation. In the case of synchronous generating plant, if electro-magnetic oscillations caused by disturbances are not damped by the inertia of the generating units, then power system stabilisers should be fitted as described in Engineering Recommendation G99. Further guidance is provided in the Code of Practice for the Economic Development of Distribution Systems with Distributed Generation, IMP/001/007.

3.4.4. Traction Supplies

Balanced three-phase traction supplies can be provided from the EHV system subject to meeting normal design requirements. Particular attention should be given to voltage fluctuations associated with the transient nature of the load and harmonic distortion associated with the customer's power conversion equipment.

26 This would, for example, ensure that a new generation connection study would take into account the fault-level contribution from all authorised, but not yet connected generation and connected generation.

27 Further information on the stability requirements can be found in IMP/001/007 – Code of Practice for the Economic Development of Distribution Systems with Distributed Generations.

28 Materiality threshold levels, where appropriate, are set out in the Bilateral Connection Agreements for each Grid Supply Point substation.

29 Where only non-synchronous generation is connected to part of a network, stability studies are not required.

Single-phase traction supplies shall be provided at 25kV with direct transformation from the 132kV system via a single-phase transformer. Northern Powergrid shall own the 132/25kV transformer and associated 25kV metering circuit breaker. The connection shall comply with Engineering Recommendation P24. Voltage fluctuations and phase balance should comply with Engineering Recommendations P28 and P29, respectively. Harmonic emissions should comply with Engineering Recommendation G5.

3.4.5. Supply Performance

The distribution system shall be developed such that no customer experiences an unacceptable level of Quality of Supply in terms of supply availability, security and reliability.

The condition and performance of the system and system assets, along with the assessment of any resultant risks are identified through the Asset Serviceability Review (ASR) process in accordance with the Code of Practice for the Asset and Network Planning Processes, INV/001/005. The ASR process informs the Northern Powergrid Investment Plan. Reinforcement or the procurement of flexibility services will then be undertaken as part of a planned programme of improvements. When undertaking work to improve supply performance, the opportunity shall be taken to future-proof the system where practical and economic.

3.4.6. Interfaces with Connected Parties

Arrangements with NGESO, Independent Distribution Network Operators (IDNOs) and with Customers shall comply with the relevant obligations of the Grid Code, Engineering Recommendation G88 and Distribution Code, respectively.

The interfaces with the transmission system shall be managed to ensure that modifications[30] by NGESO to the transmission system and modifications of the Northern Powergrid distribution system are carried out so as to comply with both organisations' obligations to develop economical, efficient and co-ordinated systems and for Northern Powergrid to comply with the whole system requirements set out in Standard Licence Condition 7A. This requires liaison between Northern Powergrid and NGESO, which initially shall be via the regular Joint Technical Planning Meeting.

Similarly, the interfaces with IDNOs shall be managed to ensure that developments of IDNO systems and the Northern Powergrid distribution system are carried out so as to comply with obligations to develop economical, efficient and co-ordinated systems and for Northern Powergrid to comply with the whole system requirements set out in Standard Licence Condition 7A. The interfaces with IDNOs generally relate to the provision of new connections and the necessary liaison is provided via the Northern Powergrid connections process. Where an IDNO connection is provided at EHV, consideration shall be given to the compliance with Grid Code obligations such as those related to demand control[31] and low frequency demand disconnection[32] schemes.

Customer connections at EHV shall be provided in accordance with the principles of the Code of Practice for Standard Arrangements for Customer Connections, IMP/001/010. Guidance on the connection of distributed generation is given in the Code of Practice for the Economic Development of Distribution Systems with Distributed Generation, IMP/001/007, and in Engineering Recommendation G99. The interfaces with Customers generally relate to the provision of new connections and the necessary liaison is provided via the Northern Powergrid connections process. Care shall be taken to ensure compatibility of plant ratings at interfaces with other parties (see section 3.5.7 below).

Where there is a need to reinforce the system, to accommodate new a customer connection or a connection to an IDNO system and the customer reasonably requires that the connection is provided before the reinforcement can be completed, consideration shall be given to providing with customer with

30 The word 'modification' is specifically used here to link to the formal Modification Process defined in the Connection and Use of System Code (CUSC).

31 Grid Code OC.6.5.

32 Grid Code OC.6.6.

a Curtailable Connection offer that complies with the requirements of DCUSA Schedule 2D. Where a Curtailable Connection offer is being developed the connection design may need to include temporary arrangements to facilitate the customer being able to import or export some of their new or additional required capacity before the reinforcement work is complete. Further details are provided in the Code of Practice for Standard Arrangements for Customer Connections, IMP/001/010, and the Procedure for Offering a Curtailable Connection, CNN/021/001.[33]

The design of customer connections or connections to IDNO systems shall be such that the capacity available, i.e., electrical capacity and space to install additional equipment, to meet future customer requirements is not unduly restricted. This is a particular concern at 132kV/EHV or 132kV/HV substations where there is limited space to install additional circuit breakers. In such situations dedicated circuit breakers should not be used to provide a new connection if their use would limit the capability of Northern Powergrid to discharge its legal obligation to develop an efficient and coordinated system by preventing the use of any unutilised electrical capacity to supply future customers due to the lack of space to install further circuit breakers or other equipment.

Such sterilisation of system capacity, which would prevent the efficient connection of future customers, is not permitted by this Code of Practice and all system development shall avoid this situation arising by properly considering this issue at the design stage.

3.4.7. Losses

Values for site-specific losses are needed to produce Use of System charges for those customers connected at EHV or at the HV busbar of an EHV/HV substation. These losses shall therefore be re-calculated as necessary whenever any part of the EHV system used to supply such customers is rearranged or replaced.

The cost of electrical losses in the system is significant and shall be taken into account when procuring assets in accordance with the Code of Practice for the Methodology of Assessing Losses, IMP/001/103. This assessment should be carried out as part of the bulk procurement of equipment and on a bespoke basis where the specification of equipment required is outside that of the bulk procurement arrangements.

Investment Appraisal Documents shall contain an assessment of the electrical losses arising from the different system enhancement options, including system reinforcement and procurement of flexibility services, established by a system study in accordance with the Code of Practice for the Methodology of Assessing Losses, IMP/001/103. The selection of the preferred system enhancement option shall take system losses in to account to comply with Standard Licence Condition 49 of the Electricity Distribution Licence, which requires Northern Powergrid to design, build, and operate its distribution system in a manner that can reasonably be expected to ensure that losses are as low as reasonably practicable.

3.4.8. Electromagnetic Fields

Electric and Magnetic Fields (EMFs) are produced wherever electricity is generated, transmitted or used. Electric fields are produced by voltage; magnetic fields are produced by current. Their magnitudes are dependent upon the source producing them. However, both fields reduce with distance from the source.

The potential health effects associated with EMFs surrounding overhead lines are still not fully understood and is the subject of ongoing research and debate. It is the opinion of the industry that precautionary measures should be taken to reduce EMFs.

On Northern Powergrid distribution systems it is the overhead lines which are the greatest producer of EMFs. These fields are highest close to the line. Magnetic fields vary depending on the load on the overhead line, but the electric fields are almost constant.

33 As of December 2023 this document is in the process of being drafted.

Options for reducing EMFs should be implemented at the design stage where practicable. Reduction techniques can include the following measures:

- Undergrounding of overhead lines;
- Increasing overhead line clearances;
- Optimum overhead line phasing;
- Routing of overhead lines away from residential areas, schools etc.; and
- Improving the balance between loads on double circuit overhead lines.

Decisions about implementing any of the above measures will often involve balancing a number of factors and applying a cost-benefit methodology. The preferred option would be to implement EMF reduction techniques at the design stage which can be introduced at a 'no cost' option such as overhead line routing, line transposition etc. and which would future proof the network rather than address EMF reduction retrospectively.[34]

3.4.9. Operational Liaison

When designing a new EHV system, the views of Control Operations shall be sought in order to ensure that the proposed design enables reasonable contingency plans to be put in place to cater for the occurrence of high impact, low probability, (HILP) events on the EHV system and to identify whether additional risk mitigation could be economically provided. Consideration should be given to the guidance contained in Engineering Recommendation P30, Good Practice Guide for the Risk Management of Planned Long Duration Outages, as it may be economic to manage construction risks in such a way that enduring risk management is provided. Any potential means of managing construction risk should be considered alongside construction risk management that can be provided by flexibility services.

3.4.10. Increasing System Capability

Where the design feasibility study carried out as part of a new demand connection, a new generation connection or an internally driven assessment (e.g., initiated following an Asset Serviceability Review) indicates that the EHV system capacity is insufficient, consideration shall be given to establishing:

- the bespoke rating[35] for the system asset that has been identified as having insufficient capacity, as this may establish that the system capability is sufficient;
- whether existing customers are exceeding their contracted connection capacity, as addressing this may establish that the system capability is sufficient; and
- whether existing customers are operating at an acceptable power factor, as addressing this may establish that the system capability is sufficient.

Where the design feasibility study is caried our as part of an internally driven assessment[36] and it is confirmed that the EHV system capacity issue cannot be accommodated within the capability of existing system consideration shall be given to whether it may be economical and efficient to deploy flexibility service to avoid or defer the need for conventional system reinforcement, as required by the Northern

34 Further information can be found in the two reports produced by the Stakeholder Advisory Group on ELF EMFs (SAGE) Precautionary approaches to ELF EMFs: first interim assessment dated 2007 and second interim assessment dated 2010.

35 Guidance is provided in IMP/001/011 – Code of Practice for Overhead Line Ratings and Parameters, IMP/001/013 - Code of Practice for Underground Cable Ratings and Parameters and IMP/001.918 Code of Practice for Transformer Ratings.

36 As at November 2023 the application of the Flexibility First Policy, INV/007 is focussed on the use of flexibility services as an alternative to discretionary reinforcement related investment. The assessment process is set out in the CoP Flexibility First Decision Making - Use of sustain and secure flexibility service products to address primary network constraints, INV/007/001. Details of the process for deployment of flexibility services in other situations will be developed in due course.

Powergrid Flexibility First Policy INV/007. To facilitate this assessment the characteristics of the insufficiency should be established in terms of the following:

- The electrical location and nominal operating voltage of the relevant system asset(s);
- The type of asset(s), e.g., cable, overhead line or transformer. This will help to inform the required activation speed of a flexibility service;
- Magnitude, expressed in MVA;
- The expected duration of each occurrence, expressed in hours, or the number of contiguous half hour periods;
- The expected frequency of occurrence, expressed in the number of half hour periods per annum;
- A view of whether there should be restrictions on the energy recovery associated with a flexibility service. Where the system load curve reduces relatively slowly after the period of insufficiency there may be a need to place limits on the energy recovery associated with a flexibility service to avoid creating a further system insufficiency following the delivery of a flexibility service;
- A description of the operational scenario in which the system insufficiency occurs, such as under first circuit outage or second circuit outage conditions at times of high demand. This will help to provide context for a flexibility service specification;
- Time to materialise. For a new connection, this could be soon after the new connection is provided, whereas for generic load growth, this could be in several years' time towards the end of the planning period; and
- The extent to which the insufficiency may change through the planning period. This could relate to an increase in the magnitude, frequency of each occurrence, or the duration of each occurrence.

Based on knowledge of the characteristics of the capacity insufficiency, consideration should be given to the use of system reinforcement and flexibility services through the investment appraisal process and the process set out in the Code of Practice for Flexibility First Decision Making - Use of sustain and secure flexibility service products to address constraints on the 132kV and EHV distribution system, INV/007/001. Options that should be considered include:

- Enhancing the capability of the existing asset creating the insufficiency (i.e., a minimum intervention). For example, increasing the clearance of clearance of overhead line spans, spans, applying additional cooling equipment to transformers, changing a substation target voltage or application of Load Drop Compensation;
- Enhancing the capability of distribution system assets to create additional capacity i.e., system reinforcement;
- Use of flexible services as part of a market-based solution. Further details on the use of flexibility services are found in section 3.4.11;
- Application of Active Network Management, where the insufficiency arises from a new connection request – this would be considered to be a Flexible Connection; and
- A combination of the above.

The Code of Practice for the Economic Development of Distribution Systems with Distributed Generation, IMP/001/007 and the Code of Practice for the Application of Active Network Management, IMP/001/915 provide guidance on alternative means of increasing system capability where the insufficiency is associated with generation plant connections. The Code of Practice for Standard Arrangements for Customer Connections, IMP/001/010 provides guidance on alternative means of increasing system capability where the insufficiency is associated with a demand connection. Where the driver for increasing system capability is internally driven the principles of all these Codes of Practice shall be applied where applicable.

3.4.11. Flexibility Services

Through the ENA's Open Networks Project the long-term roles and responsibilities of DNO's are being redefined as markets for flexibility services open up and expand, offering an alternative to increasing the capability of the distribution system using traditional assets. An outcome of the Open Networks project is Northern Powergrid's commitment to openly test the market to compare reinforcement and flexibility services as a means of increasing system capacity for all new projects of any significance. Northern Powergrid has also committed to the developing the ENA's six key steps for delivering flexibility services to ensure the transition is successful.[37]

A flexible service is a commercial service where a customer modifies their generation and/or consumption of electricity in response to an external signal (e.g., change in electricity price or Use of System price or on receipt of a specific communication signal) to provide a service to a distribution system operator, a transmission system operator or electricity supplier.

As part of a commitment to transition towards a DSO and as an output of the Open Networks project, Northern Powergrid has published a DSO development plan[38] and has committed to:

- use flexibility services as an alternative to system reinforcement where it is practical and economic to do so. Demand Side Response is an example of a flexibility service; [39] and
- providing flexible connection offers for new demand or generation customers where appropriate.

These options provide customers with more control and choice over how they use their electricity and provides them with new competitive opportunities to participate in the energy market.

The three use cases for contracted customer flexibility services are:

- As an alternative to system reinforcement (Sustain, Secure and Dynamic Flexibility Service Products) – to avoid or defer spending on traditional system reinforcement;
- As a means of managing system risk during construction or maintenance work (Sustain, Secure and Dynamic Flexibility Service Products) – to manage the risk of supply interruption associated with construction work; and
- Emergency Support (Restore Flexibility Service Product) – to provide emergency support during unplanned supply interruption.

Where a system study has identified a system insufficiency which has been characterised as described in section 3.4.10, this information should be provided to Northern Powergrid's Policy and Market Flexibility Services team as a functional specification for a potential flexibility service so that they can obtain bids for flexibility service, from one or more flexibility service providers. The response from the Policy and Market Flexibility Services team can then be used as part of the decision-making process for addressing the system insufficiency.

Flexibility services should be considered transparently and openly on a level playing field basis alongside other means of addressing the system insufficiency, considering both capital and operational

37 Available from: https://www.energynetworks.org/industry-hub/resource-library/open-networks-flexibility-commitment-2019.pdf

38 Available from: https://www.northernpowergrid.com/asset/0/document/5139.pdf

39 As at December 2023 the application of the Flexibility First Policy, INV/007 is focussed on the use of flexibility services as an alternative to discretionary reinforcement related investment. The assessment process is set out in the CoP Flexibility First Decision Making - Use of sustain and secure flexibility service products to address constraints on the 132kV and EHV distribution system , INV/007/001. Details of the process for deployment of flexibility services in other situations will be developed in due course. As at December 2023 INV/007 and INV/007/001 are in the process of being published.

expenditure. Further guidance is provided in the Northern Powergrid Distribution Flexibility Services Procurement Statement 2023/24.[40]

3.5. Selection, Application and Configuration of Plant

Items of plant that constitute the Northern Powergrid distribution system shall comply with Northern Powergrid's Network Product Specifications.

3.5.1. Standard Plant

Standard Licence Condition 20 requires DNOs to comply with the Distribution Code, which is designed to 'permit the development, maintenance, and operation of an efficient, coordinated and economical system for the distribution of electricity'. The adoption of a standard range of plant and equipment for use on the EHV system helps to achieve this requirement by bringing economies of scale and helps to manage network risks by facilitating the interchangeability of plant under emergency situations. A standard range of plant also offers benefits in terms of reducing the range of spares and tools that need to be carried and limits the number of products for which specialist training is required. The range of standard plant defined in the sections below, provides a co-ordinated suite of switchgear, transformers and circuit ratings.

3.5.2. Transformers

EHV/HV substations may be equipped with Continuous Emergency Rated (CER) transformers in accordance with the Technical Specification for Continuous Emergency Rated (CER) Transformers, NPS/003/012 or with Continuous Maximum Rated (CMR) transformers in accordance with the Technical Specification for Continuous Maximum Rated (CMR) Transformers, NPS/003/021. Double transformer EHV/HV substations will normally be equipped with CER transformers except in the case where the transformer load profile would not align with the generic transformer ratings,[41] when CMR transformers may be more appropriate. CER and CMR transformers shall have windings configured to achieve the appropriate phasing stated in the Code of Practice for Distribution System Parameters, IMP/001/909. CER transformers shall have a continuous emergency rating selected from the table below:

Nameplate Rating (ONAN) (MVA)	Nameplate Rating (OFAF[42]) (MVA)	Rated Secondary Winding Voltage (kV)	Typical Impedance (100MVA Base)
12	24	11.5	70% or 100%
15	30	11.5 or 20	80% or 100%
20	40	11.5 or 20	70%

15/30MVA CER transformers shall be the normal specification at EHV/HV substations. The lowest rated transformer to be connected as part of a new project is a 12/24MVA CER; consideration of any transformer with a lower rating shall be at the relevant Design Manager's discretion. When assessing the bespoke capability of a CER transformer, it's important to note that CER transformers to NPS/003/012 may have been specified with an OFAF rating at ambient temperatures of either 5°C or 30°C. In order to ensure interchangeability of plant and cater for the expected increase in summer demands, all new CER transformers shall be specified with a forced cooling rating (OFAF or ONAF depending on the

40 https://www.northernpowergrid.com/sites/default/files/assets/Distribution%20Flexibility%20Services%20Procurement%20Statement%202023-24%20v1.0.pdf

41 Refer to the Code of Practice for Transformer Ratings, IMP/001/918.

42 EHV to HV transformers currently being purchased have no oil pumps i.e. ONAF.

manufacturer's design) at 30°C. When establishing the transformer rating to be used consideration should be given to the prospective future demand and / or generation that may be supplied via the transformer.

45MVA CMR transformers may be used to provide system interconnection. Typically, they are used in Northern Powergrid Northeast to provide 66/33kV interconnection.

Under normal operating conditions, the demand on a substation where a single transformer is installed should be within the stated ONAN transformer rating, as transformers are not generally designed for cooling fans or oil circulating pumps to operate on a continuous basis.

The selection of transformer impedance is a balance between the conflicting requirements to keep voltage regulation low, to maximise the fault level to minimise the impact from disturbing demand and to create headroom for embedded generation. Consideration should also be given to the level of distributed generation that is likely to be connected to the HV system in the future, which may cause high volts at times of low load. However, to maintain the interchangeability of transformers, impedances should be selected from values in the table above.

When two or more EHV/HV transformers that would normally operate in parallel with each other have different nominal ratings, when selecting the impedance consideration should be given to whether to select the impedance such that the transformers share demand in proportion to their rating or to maintain the short circuit duty to within the rating of switchgear. The short-term requirements may be different from the long-term requirements e.g., the requirement for an older low-capacity transformer not to become overloaded in the short-term may need to be balanced against the longer-term requirement to balance demand across all transformers when they are replaced in the future. Where transformers of different impedances are being considered for installation at the same substation this shall be agreed with the relevant Design Manager.

Tap changers on EHV/HV transformers are specified in the Code of Practice for Managing Voltages on the Distribution System, IMP/001/915, and shall generally have the tapping ranges indicated in the following table:

Transformer Voltage (kV)	Tap Range
66 or 33/11.5	+10%/-10% in 16 steps (+8×1.25/-8×1.25) or +5.72%/-17.16% in 16 steps (+4x1.43/-12x1.43)
66 or 33/20	+10.5%/-10.5% in 14 steps (+7×1.5/-7×1.5)

Where an EHV/HV substation is to be supplied from long circuits such that maintaining an acceptable HV busbar voltage under outage conditions is not possible with transformers equipped with standard tapping range tap changers, consideration should be given to the use of transformers equipped with tap changers with an extended or displaced tapping range.

3.5.2.1. Auxiliary Transformers

Every power transformer shall be equipped with an auxiliary transformer designed, constructed and tested in accordance with ENATS 35-1 Part 1 – Distribution Transformers, and shall normally have a rating of 50kVA. It is not necessary to provide an alternative LV supply from the surrounding network infrastructure at a dual transformer substation as, for the loss of one transformer supplies will be maintained by the remaining transformer. For single transformer substations an alternative LV supply shall be provided from the surrounding network so that it is possible to support substation auxiliary demand for loss of the main power transformer.

3.5.3. Switchgear

Switchgear shall be to the standard specified in the Technical Specification for Indoor 33kV Switchgear NPS/003/004, the Technical Specification for Outdoor 33kV Switchgear NPS/003/043, or the Technical

Specification for 66kV and 132kV Circuit Breakers NPS/003/008. Single busbar non-oil type metal clad switchgear shall be the normal standard at 33kV. 66kV substations typically comprise outdoor single busbar non-oil type switchgear; however, outdoor substations should only be constructed where an indoor substation would be economically impracticable. Where non-SF_6 switchgear compliant with the relevant Northern Powergrid specification is available and suitable for use at a particular substation, non-SF_6 switchgear should be used.

The selection between Air Insulated Switchgear (AIS) and Gas Insulated Switchgear (GIS) shall take into account the following factors:

- Total cost over the lifecycle of the asset, including switchgear maintenance;
- Flexibility to allow repair and maintenance;
- Risk of catastrophic failure;
- Substation security;
- Available space;
- Environmental impact of equipment containing greenhouse gasses; and
- Future availability of additional units.

Switchgear will normally be selected from the tables below:

33kV Switchgear and Associated Busbars

		Rating				
Application	**33kV Switchgear**[43]	**Device**	**Bus Bar**	**Break Rating (3ph RMS) at X/R of 14.1**	**Break Rating (3ph RMS) at X/R of 37.7**	**Make Rating (pk-pk)**
275/33kV substation 132/33kV substations[44]	Transformer CB (NGET asset at GSPs)	2500A (143MVA)	2500A (143MVA)	31.5kA	20.0kA	78.75kA
	Feeder CB	1250A (71MVA)	2500A (143MVA)	31.5kA	20.0kA	78.75kA
	Bus Section CB	2500A (143MVA)	2500A (143MVA)	31.5kA	20.0kA	78.75kA
3-panel arrangement and switchgear at Customer Point of Supply	Transformer CB	1250A (71MVA)	1250A (71MVA)	31.5kA	20.0kA	78.75kA
	Feeder CB	1250A (71MVA)	1250A (71MVA)	31.5kA	20.0kA	78.75kA
	Bus Section Panel CB	1250A (71MVA)	1250A (71MVA)	31.5kA	20.0kA	78.75kA
33kV overhead line	ABSD	400A	N/A	Category 1,[45] load breaking capability of 400A		7.87kA

43 Panel includes the circuit breaker, disconnector and earth switch.

44 NGET are considering the use of 180MVA SGTs at some Grid Supply Point Substations, which would require the use of 33kV busbars rated at more than 2500A. The highest rated 33kV switchgear currently assessed by Northern Powergrid is 2500A. Discussions should take place with the Policy and Standards Manager before the use of 180MVA transformers is agreed.

45 The category of ABSD shall be stated on-site to indicate its capability to the operative.

The preferred short circuit rating of 33kV circuit breakers is a dual rating of 20kA at an X/R ratio of 37.7 (dc time constant of 45ms) and 31.5kA at an X/R ratio of 14.1 (dc time constant of 120ms), However, the use of circuit breakers with a dual rating of 25kA at an X/R ratio of 14.1 and 20kA at an X/R ratio of 37.7 is acceptable provided that the installation is sufficiently remote from the source 132kV/EHV substation and areas of existing or increasing load / generation activity and consequently, under all credible operational scenarios, short circuit-levels are expected[46] to remain:

- less than 20kA (i.e., one decrement down from 25kA on the R10 series) and the system X/R ratio is expected to remain less than 14.1, or
- less than 16kA (i.e., two decrements down from 25kA on the R10 series) and the system X/R ratio is expected to remain less than 23.57.

2500A is the preferred standard current rating for 33kV transformer and bus-coupler circuit breakers in order that the switchgear can carry current excess of the generic static rating of a 90MVA transformer (1576A) or a 120MVA transformer (2100A). For ex ample:

- The winter long time emergency cyclic rating of a 45/90MVA CMR transformer is 121.5MVA or 2120A; and
- The winter typical normal cyclic rating of a 60/120MVA CMR transformer is 141.6MVA or 2480A.

Such capability becomes increasingly important as bespoke transformer ratings[47] are applied, particularly as switchgear has a limited capability in excess of its nameplate rating.

Due consideration shall also be given to the likelihood of new technologies such as active network management that will result in a higher utilisation of capacity especially in the short-term and under first circuit outage conditions. However, if the initial cost of 2500A switchgear is significantly greater than 2000A devices, and a specific substation has other limiting plant or conductors (which are not likely to be up-rated) which reduces the firm capacity of the substation to less than 114MVA, then circuit breakers with a 2000A normal current may be used, with agreement of the relevant Planning Manager.

46 When assessing expected short-circuit levels and X/R ratios, consideration shall be given to Investment Plan schemes and known new connections activity.

47 In accordance with Code of Practice for Transformer Ratings, IMP/001/918.

66kV Switchgear and Associated Busbars

Application	66kV Switchgear	Rating				
		Device	Bus Bar	Break Rating (3ph RMS) at X/R of 14.1	Break Rating (3ph RMS) at X/R of 37.7	Make Rating (pk-pk)
400/66kV substations, 275/66kV substations, 132/66kV substation	Feeder Panel	1250A (143MVA)	2000A (228MVA)	40.0kA	31.5kA	100kA
	Transformer Panel	2000A (228MVA)	2000A (228MVA)	40.0kA	31.5kA	100kA
	Bus section Panel	2000A (228MVA)	2000A (228MVA)	40.0kA	31.5kA	100kA
	Bus section isolator	2000A (228MVA)	2000A (228MVA)	-	-	-
	Feeder isolator	1250A (143MVA)	1250A (143MVA)	-	-	-
66kV/HV substations or 66kV switching sites	Feeder Panel	1250A (143MVA)	1250A (143MVA)	40.0kA	31.5 kA	100kA
	Transformer Panel	1250A (143MVA)	1250A (143MVA)	40.0kA	31.5kA	100kA
	Bus section Panel	1250A (143MVA)	1250A (143MVA)	40.0kA	31.5kA	100kA
66kV overhead line	ABSD	1250A (143MVA)	N/A	Category 3, no load breaking or fault making capability[48]		

The preferred short circuit rating of 66kV circuit breakers is a dual rating of 40.0kA at an X/R ratio of 14.1 (dc time constant of 45ms) and 31.5kA at an X/R ratio of 37.7 (dc time constant of 120ms). However, the use of circuit breakers with a dual rating of 31.5kA at an X/R ratio of 14.1 and 25kA at an X/R ratio of 37.7 is acceptable provided that the installation is sufficiently remote from the source 132kV/EHV substation and areas of existing or increasing load / generation activity and consequently, under all credible operational scenarios, short circuit-levels are expected[49] to remain:

- less than 25kA (i.e., one decrement down from 31.5kA on the R10 series) and the system X/R ratio is expected to remain less than 14.1, or
- less than 20kA (i.e., two decrements down from 31.5kA on the R10 series) and the system X/R ratio is expected to remain less than 23.57.

Category 1 ABSDs are preferred at both 33kV and 66kV; however, category 1 devices are not currently available at 66kV. If Control Operations indicates that the operational implications associated with using a Category 3 device at 66kV are unacceptable, consideration should be given to the installation of a circuit breaker.

Consideration shall be given to the use of motorised disconnectors where there are benefits to restoration of supplies under fault conditions.

48 ABSDs controlling transformers may only be operated live after the load has been removed from the transformers by opening the low voltage isolating device. The length of cable between the isolators and the transformers must not exceed 41 metres.

49 When assessing expected short-circuit levels and X/R ratios, consideration shall be given to Investment Plan schemes and known new connections activity.

3.5.4. Overhead Lines

EHV overhead lines shall be constructed to one of the following specifications:

- Technical Specification for EHV Wood Pole Lines Operating up to 132kV with Span Lengths Between 140m and 220m, NSP/004/045 (OHL9/10 design) - shall be used for all 66kV overhead lines and 33kV overhead lines operating in onerous conditions;
- Technical Specification for HV Wood Pole Lines up to and Including 33kV, NSP/004/042 (43-40 design) - shall be used for all 33kV overhead lines operating in non-onerous conditions; or
- Technical Specification for HV Wood Pole Lines of Compact Covered Construction up to and including 33kV, NSP/004/044 – shall be used for 33kV overhead lines in high tree density areas or adjacent to known recreational areas.

Overhead line conductors shall be to the standard specified in the Technical Specification for overhead line conductors, NPS/001/007. AAAC conductors shall be the normal standard for EHV circuits as the homogenous construction enables jointing to be carried out more reliably than for composite conductors and the material is not prone to corrosion.

A conductor size of 200mm^2 (AL3) AAAC (Poplar) shall be the normal standard at 33kV and 66kV. Where an overhead line has or is expected to have a high utilisation factor, for example due to the connection of distributed generation, AL5 alloy conductors shall be used due to its improvement in losses performance. Guidance on the ratings of new and existing overhead lines is given in the Code of Practice for Overhead Line Ratings and Parameters, IMP/001/011. The standard design temperature for new overhead lines shall be 75^{o}C, although many existing overhead lines have a design temperature of 50^{o}C.

Overhead lines on EHV system shall be selected from those in the following table; capacities stated are for multi-circuit and primary supply systems and a 75^{o}C design temperature:

Conductor size and type	Voltage	Generic Static Rating (Summer)	Generic Static Rating (Spring / Autumn)	Generic Static Rating (Winter)
200mm^2 AAAC Poplar	33kV	624A, (35.7MVA)	678A, (38.8MVA)	709A, (40.5MVA)
	66kV	638A, (72.9MVA)	692A, (79.1MVA)	708A, (82.8MVA)

Refer to section 3.5.6, Earthing and bonding, for details on earth wire retention for short length alterations, associated remote substation earthing and protection setting assessments.

3.5.5. Underground Cables

33kV and 66kV cables shall be to the standard specified in the Technical Specification for 33kV power cables, NPS/002/021 and the Technical Specification for 66kV power cables, NPS/002/022, respectively.

When selecting the size of cable to be used on the EHV system, consideration shall be given to minimising system losses and maintaining sufficient capacity for the future. This implies that a cable with the largest cross-sectional area that can be reasonably justified shall be used. In most cases this will enable a standard circuit comprising three single core XLPE insulated cable with a 300mm^2 Cu conductor to be used for new dedicated EHV underground transformer circuit feeders. Larger sizes may be used where, for example, required by the network configuration, where the proximity to other cables materially derates the cable and where there is greater requirement for interconnection capacity. When using other than the standard cable, consideration shall be given to the implications and the costs associated with carrying non-standard strategic spares and approval shall be sought from the Policy and Standards Manager.

For 33kV transformer feeder circuits, cable ratings shall normally be chosen to match the rating of the associated transformers, taking into account the interconnection to other substations. 66kV cable ratings shall be chosen to match the rating of the associated transformer in the case of radial circuits, or to match the winter rating of the overhead line in the case of ring circuits.

The standard installation configuration is to use a trefoil formation for single core cables with touching ducts.

Consideration should be given to using the EATL CRATER software package in order to determine a bespoke rating and consequently identify any de-rating of cables associated with the anticipated site installation conditions, for example due to proximity to other cables, installation in tunnels or exposure to solar heating.

On long EHV cable circuits, intermediate isolation / switching points shall be installed every 10km; refer to section 3.7.3 for further details.

Typical cable sizes and nominal ratings are given in the tables below.[50] Aluminium conductor single core cables are also acceptable for use at 33kV only. The stated rating is for cables laid in ducts as this tends to be the most common installation method for new cables installed in the highway. If the cable is laid direct there will be a marginal increase in rating, conversely, if cables are laid in close proximity to each other the rating will decrease. Each cable installation will require an individual assessment which may result in the derating of the individual cables in the installation.

33kV Cable

Application	Required capacity (MVA)	Conductor material and size (mm^2)	Insulation and sheath material	Generic static continuous cable rating laid in ducts (MVA)
Transformer feeder only	30	3 × 1 core Cu 300	XLPE PVC (Copper Wire Screen)	30.6
Transformer feeder & Interconnector	45	3 × 1 core Cu 630	XLPE PVC (Copper Wire Screen)	42.9
Capacity to match that of overhead line	40[51]	3 × 1 core Cu 500	XLPE PVC (Copper Wire Screen)	38.3
As above where there are proximity or depth issues	45	3 x 1 core Cu 800[52]	XLPE PVC (Copper Wire Screen)	47.2

66kV Cable

Application	Required capacity (MVA)	Conductor material and size (mm^2)	Insulation and sheath material	Generic static continuous cable rating laid in ducts (MVA)
Transformer feeder	60	3 × 1 core Cu 300	XLPE lead sheath	62.8
Capacity to match that of overhead line	81[53]	3 × 1 core Cu 500	XLPE lead sheath	78.2

50 Depending on the installation conditions, cable sizes other than those in the tables below, but which are included in the relevant NPS specification, may be used to achieve the required rating.

51 Based on the winter rating (3% excursion) of 200mm2 AAAC with a design temperature of 75°C.

52 800mm2 Cu conductors cannot generally be terminated on switchgear.

53 Based on the winter rating (3% excursion) of 200mm2 AAAC with a design temperature of 75°C.

Where insulated sheath cable systems (generally comprising pressure-assisted cables) are being extended or refurbished, the requirements of Engineering Recommendation C55, Insulated sheath power cable systems, shall be observed.

3.5.6. Earthing and Bonding

The rise of earth potential at substation sites shall be assessed in accordance with Engineering Recommendation S34, Guidance on the Assessment of Rise of Earth Potential at Substations. The design of substation earthing shall be in accordance with ENA Technical Specification 41-24, Guidelines for the Design, Installation, Testing and Maintaining of Main Earthing Systems in Substations. Initial substation designs shall consider the rise of earth potential associated with potential future network alterations such as grid infeed changes and shall be designed accordingly.

All EHV cable circuits shall comprise single core cables laid in trefoil formation and shall be earthed and solidly bonded. Cross bonded systems are not permitted on new installations due to the level of maintenance of the ancillary equipment required.

For short diversions or alterations to existing overhead line 4 wire EHV overhead systems the earth wire shall be retained using a CE/C/37 4W construction overhead line. If a 4 wire overhead line is planned to be replaced, e.g., as part of an asset replacement scheme, by a three wire overhead line, consideration needs to be given to the earthing at the remote substation ends and a review of protection settings needs to be undertaken. New overhead lines constructed using a steel support e.g., for long overhead spans, will require the steelwork to be appropriately earthed and bonded.

3.5.7. Co-ordination of Current Ratings

The distribution system has historically been developed using standard components with co-ordinated ratings for the major items of plant. Over time the standard ratings have increased reflecting the difficulties of securing new substation sites and the opportunities that present themselves when time expired assets are replaced. Co-ordination is becoming more complex due to the more frequent use of bespoke equipment ratings. However, such co-ordination is still the preferred approach to system development and aligns with the requirement of section 9 of the Electricity Act ‘to develop and maintain an efficient, co-ordinated and economical system of electricity distribution’.

It is important to check all key technical parameters of a design for consistency. In particular, care shall be taken to ensure that all items of plant are adequate for the duty they are required to perform and can operate within their capability (including seasonal capability for overhead lines) throughout the planning period. The capability of overhead lines, cables and transformers are specified in the Code of Practice for Overhead Line Ratings and Parameters, IMP/001/011, Code of Practice for Transformer Ratings, IMP/001/918, and Code of Practice for Underground Cable Ratings and Parameters, IMP/001/013, respectively. The rating of other plant items also needs to be considered, for example, the rating of busbar clamps or metering CTs must be considered even if the busbar itself is adequate for the proposed duty; similarly, the correct tapping must be selected on multiple-ratio CTs. It is also essential to check the compatibility of plant ratings at an interface with the transmission system[54] or customer connection interface. This is critical to ensure consistent application of seasonal ratings where the customer’s installation has a peak demand in the summer months, or where the rating of the plant has a temperature coefficient dissimilar to that of the connection itself (as for example with gas turbine generation plant).

Checks should be made as to the adequacy of plant ratings within the Northern Powergrid system giving due regard to the circumstances in which the plant is to be used e.g., the replacement of existing EHV/HV 12/24MVA transformers with 15/30MVA transformers may not initially require the replacement of any existing 1200A rated HV switchgear if demands are not forecast to reach such a level during the planning period.

54 The General Conditions of the Grid Code require that Northern Powergrid equipment within the busbar protection zone complies with the NGET Relevant Electrical Standards (RES).

3.5.8. Metering

Tariff metering for 33kV and 66kV Customer connections and 25kV traction supplies shall be provided at the exit point in conjunction with the appointed Meter Operator in accordance with the Code of Practice for Standard Arrangements for Customer Connections, IMP/001/010 and the relevant Metering Codes of Practice specified therein. There are a range of Metering Codes of Practice; it is important to apply the correct Code of Practice which is dependent upon the rating of the circuit forming part of the connection rather than the capacity required by the Customer as defined in the connection agreement; further details are provided in IMP/001/010. Care needs to be taken in the specification of switchgear to select metering CT ratios appropriate to the connection capacity. It should also be noted that the Balancing and Settlement Metering Codes of Practice 2, for connections between 10 and 100MW, requires a dedicated VT winding for metering.

3.5.9. Protection, Control and Monitoring

Protection of the 33kV and 66kV system shall be in accordance with the Policy for the Protection of Distribution Networks, IMP/001/014.

The main protection will be discriminative i.e., disconnect only the faulted system elements for all likely faults on the protected plant.

The thermal rating of CTs used for protection purposes shall be co-ordinated with the capability[55] of the associated primary plant. SCADA facilities shall be provided at substations supplying or supplied from the 33kV and 66kV system.

The protection and control facilities shall be used to provide information to monitor and manage power flow on the EHV system in both real time and planning timescales in accordance with Standard for the Application of System Monitoring, IMP/001/017. This information shall include real and reactive power flows in the forward and reverse direction on all EHV circuits. This information should be made available via SCADA to the Northern Powergrid data historian (PI).

It is important to consider the impact of any system alteration e.g., system reinforcement or new customer connections / alterations, on the effectiveness of any existing Low Frequency Demand Disconnection (LFDD) schemes. The LFDD relays will operate to disconnect demand in the event of falling system frequency. The effectiveness of LFDD relays to disconnect sufficient demand to halt falling system frequency can be hindered, for example, by export from embedded generation reducing the net demand on the system resulting in the LFDD relay disconnecting less demand than anticipated. When making any changes to the EHV networks it is important to assess the implications for the LFDD scheme and for any necessary changes to the LFDD scheme to be included in the functional specification for any system alteration. Appendix 2 provides further information on considerations that may need to be addressed when assessing the continued effectiveness of an LFDD scheme.

The recommendations in Engineering Technical Report 134[56] (Report on lightning protection for networks up to 132kV) have been adopted by Northern Powergrid. Lightning protection shall be achieved by means of surge diverters and spark gaps. The application of surge diverters on the 33kV and 66kV distribution system shall be in accordance with the Code of Practice for the Application of Lightning Protection, IMP/007/011.

3.5.10. Auto-Switching

Where practical and of benefit auto-reclosing facilities shall be provided on all 33kV and 66kV circuit breakers controlling circuits containing 1km or more of overhead line in accordance with the Policy for the Protection of Distribution Networks, IMP/001/014. Auto-reclosing facilities shall also be provided where circuits contain shorter lengths of overhead line supplying a single transformer substation.

55 It is worth noting that the capability of a transformer will be in excess of its nameplate rating.

56 Superseded by Engineering Recommendation G109.

Where practicable and of benefit to customers for quality of supply purposes, auto-isolation of faulty equipment (for example transformers on teed circuits) shall be implemented as part of an integrated scheme to restore supplies to healthy plant by auto-reclosure.

Auto-close schemes shall be considered where there are customer benefits arising from automatically reconfiguring the system following an outage, for example to restore customer supplies or maintain supply security.[57]

3.6. Telecommunications

The telecommunications network forms an integral part of the 33kV and 66kV distribution system and the demands on the telecommunication network is likely to increase as distributed generation penetration increases and Smart Grid technologies evolve. The telecommunications requirements of any development proposal, and the impact of any proposal on the telecommunications network, shall be considered as an integral part of any 33kV and 66kV system development work as specified in more detail below.

3.6.1. Telecommunication Facilities at Substations

The provision of telephone facilities in substations and communication circuits for SCADA purposes at substations shall be in accordance with guidance set by the Technical Services Manager.

3.6.2. Pilot Cables

Historically, the Northern Powergrid Yorkshire system employed dedicated pilot cables for protection and intertripping purposes by means of a 4-core or 7-pair cable installed alongside each 33kV or 66kV circuit, whether forming a complete cable circuit between substations or forming part of a mixed overhead/cable route. Also historically, Northern Powergrid Northeast has not employed dedicated pilot cables and telecommunications cables are generally used for this purpose. For new installations, telecommunications cables with an agreed circuit identification method[58] shall be used to deliver the functionality that has in the past been provided by dedicated pilot cables; see section 3.6.3.

3.6.3. Telecommunication Cables

Development of the 33kV and 66kV system generally provides an opportunity for substantial sections of telecommunications cables to be installed between selected locations. Consequently, when 33kV and 66kV underground cables are to be installed or replaced, the opportunity shall be taken to review the initial and likely future telecommunication cable requirements. Provision of cable ducts and fibre circuits will be considered and implemented as appropriate for future telecommunications requirements.

At least one 19 or 37 pair telecommunications cable and a suitable fibre optic cable (Northern Powergrid's default standard incorporates 24 single mode fibres) as specified in the Technical Specification for Fibre Optic Cables and Fibre Wrap, NPS/002/024, shall be provided between EHV/HV substations and their respective supply points for auxiliary, communications, protection and telecontrol purposes. In some situations, for example when dual 33kV or 66kV cables with the same start and end locations are installed along different routes or it is likely that system rearrangements will be required, one 19 or 37 pair cable or suitable fibre optic cable shall be installed with each 33kV or 66kV cable. The choice between a paired metallic and fibre optic cable is dependent upon the particular protection and intertripping scheme to be used, and the Technical Services Manager shall be consulted at an early stage to select the appropriate cable type.

The opportunity shall also be taken to provide additional telecommunications cables on routes where they can be used to eliminate the need for fault throwing intertripping.

57 For example, where a substation is operated with the bus section open to manage a fault level problem, auto-close facilities should be provided on the bus section circuit breaker to restore supplies in the event of a failure of an incoming circuit.

58 E.g. by the use of red terminal tags.

When specifying new telecommunications infrastructure, consideration shall be given to the future requirements for communications channels, for example, for the implementation of active network management and the additional bandwidth that such systems require. In cases where there are currently no requirements to install telecommunications cables, telecommunications cable ducts shall be installed in accordance with the Technical Specification for Protective Tile, Tile Tape and Cable Ducting, NPS/002/003 and associated access pits in order to facilitate future installation of telecommunications cables.

All schemes requiring the installation of telecommunications cables shall be referred to the Technical Services Manager and Telecommunications Manager for assessment and approval.

3.6.4. Telecommunication Cables Associated with Overhead Line Circuits

Where a unit protection scheme is required on a circuit comprising a 66kV or 33kV overhead line, fibre optic cable shall be wrapped round one of the conductor to provide the associated communications channel. Where a communication channel is required for protection signalling[59] or other purposes a digital radio link with a minimum band width of 200kb/s may be provided as an alternative to a wrapped fibre optic cable.

3.7. Plant Location and Routing of Circuits

General guidance on the location of plant and routing of circuits, and on the associated environmental issues, is given in the Environmental Management System Manual, ENV/001. The following environmental policies are particularly relevant: Network Design and Development, ENV/006/002 and Protection of Plants, Animals and Conservation, ENV/006/001.

In situations where the choice of overhead or underground circuits might be contentious, the Wayleaves Manager shall be consulted. Any easements and wayleaves required shall take into account the likely future land use.

Liaison with local authorities, preparation and submission of Town and Country Planning and Department for Levelling Up, Housing and Communities applications, planning inquiries, easement wayleaves and land acquisition negotiations shall be undertaken in accordance with the requirements of Northern Powergrid Consents and Wayleaves Policy, CNS/001 and Operational Land and Buildings Policy, CNS/003.

3.7.1. Location of Substations

New 33kV or 66kV/HV substations shall be located to minimise the system infrastructure required to service the present demand and generation and the anticipated future demand and generation taking into account future land use and environmental aspects. The Horlock Rules should be taken into account when locating a new substation, which require that consideration be given to local amenity value, existing habitats and landscape features.

New substations should not, where practicable, be sited on land that is exposed to the risk of flooding in line with local planning guidance. To establish whether a proposed substation premises is at risk from flooding and the potential scale of a flood event, a flood risk assessment should be carried out. Where it is necessary to construct a substation on low-lying land, the site will need to be elevated. Guidance on assessing the risk of flooding is provided in the Code of Practice for Flood Mitigation at Operational Premises, IMP/001/012.

Substations shall have 24-hour access and shall occupy the minimum practicable site area to minimise future maintenance costs, subject to the provision of adjacent land, where practicable, that would enable the substation to be rebuilt ‘off-line’ in the future. The substation shall be sited as close as reasonably practicable to the public highway (subject to planning and environmental considerations), with safe direct vehicular access.

59 For example intertripping or signalling associated with distance protection.

New substations should not be constructed close to residential, amenity and environmentally sensitive areas; where this is unavoidable the relevant risks should be assessed, and appropriate mitigation measures implemented. Guidance for the appropriate control of environmental noise sources, dust generated and visual impact on site is provided in The Management of Noise, Dust and Visual Impact, ENV/002/001.

The effects of EMFs on members of the public should be considered when the location of a new substation is being selected. Careful consideration should be taken to minimise the electromagnetic fields within and surrounding the substation compound. EMF reduction techniques such as transposition of overhead cables entering and exiting the substation should be incorporated into the substation design process.

Care shall be taken at the design stage when positioning plant within a substation. For example, if a transformer is located close to the perimeter fence, the fields produced by the cables or busbars supplying the transformer can cause an elevated field outside the fence. Placing equipment near the centre of the substation can minimise the EMFs outside the substation boundary. For safety and environmental reasons all new 33kV plant (with the exception of transformer coolers) should be located indoors. Historically, outdoor equipment was the norm for 66kV substations, but developments in GIS mean that indoor switchgear may be economically viable and offers benefits in term of security and safety which should be taken into consideration. Where transformers are installed in enclosures sufficient ventilation shall be provided to dissipate the heat generated under full load conditions.

Substations shall incorporate fire mitigation measures as required by the Policy for Fire Mitigation at Operational Premises, IMP/011.

Substations on customers' premises shall be free standing and shall preferably have their own access from a public highway. Where access is shared, they shall be situated well away from parking, loading or storage areas to reduce the risk of damage and obstruction of access. Care shall be taken to avoid situations which could lead to potential contact with or damage to lines and cables. Arrangements shall be made with the host company to secure 24-hour access.

3.7.2. Routing of Overhead Circuits

33kV and 66kV overhead line routes shall be selected to minimise the effect on amenity by, for example following contour lines where possible and avoiding skylines. Easements for overhead lines shall be secured in line with guidance contained in Easements for Overhead Lines and Underground Cables, CNS/001/014. Reference should be made to the Holford Rules which primarily seek to avoid routing new circuits through designated areas of international and national interest, whether designated on the basis of nature conservation or landscape.

When constructing new overhead lines or rebuilding / reconductoring existing lines, the crossing of motorways, high-speed dual carriageways and electrified railways shall be achieved with an underground cable route wherever reasonably practicable and economically viable. Where overhead crossings are unavoidable, the crossing of motorways, high-speed dual carriageways, railways, canals and waterways shall be achieved as close to right angles as possible. Overhead line routes in close proximity to, or parallel with, existing overhead lines and electrified railways shall be avoided as far as practicable, as they can give rise to operationally undesirable induced voltages.

Where the crossing of two overhead line circuits is unavoidable consideration shall be given to the undergrounding of the lower voltage line in the following circumstances:

a) Safety clearances between the overhead lines cannot be adequately maintained (the conductor sag of the over sailing line at maximum summer rating shall be used);

b) The cost/complexity associated with the under running overhead line option is uneconomic compared to the cost/complexity of the cable option taking into consideration component reliability;

c) The circuit configuration of the under running line option makes it impractical to make the line dead for the duration of any present/future works; and

d) A safe means of future working cannot be clearly established for carrying out work on both the under slung or over-sailing overhead lines.

New overhead lines (including rebuilds of existing lines) should not be constructed close to residential, amenity and environmentally sensitive areas or in high-risk areas e.g., schools. Where this is unavoidable the relevant risks should be assessed, and appropriate mitigation measures implemented.

Pole-mounted switchgear (such as ABSDs) and terminal poles shall, wherever practicable, be located adjacent to roads that facilitate vehicular access in adverse weather conditions and consideration shall be given for access for test equipment.

Overhead line clearances shall be in accordance with ENATS 43-8 Overhead Line Clearances and the Guidance on Overhead Line Clearances, NSP/004/011.

3.7.3. Routing of Underground Circuits

In routing new 33kV and 66kV cables, consideration shall be given to the potential for future network extension to cater for load development. Easements for underground cables shall be secured in line with guidance contained in Easements for Overhead Lines and Underground Cables, CNS/001/014. Routes shall be simple and direct avoiding crossovers; where practicable the route should avoid sections of exposed cable e.g., bridge crossings. If sections of exposed cables are unavoidable, they should have a level of protection suitable for the security risk at that site. Cables shall be afforded a level of protection in accordance with the Policy for the Installation of Distribution Power Cables, NSP/002.

Cables should, where economical, be laid on routes separate from other 33kV, 66kV and higher voltage cables to avoid the possibility of multiple cable damage from the same third-party incident. Advantage shall be taken of opportunities to use joint excavation with new lower voltage cables. Wherever possible, routes shall be located in the public highway where Northern Powergrid has statutory rights. If for any reason this is not practicable, no site work shall be carried out without first obtaining the relevant consents and security of tenure. Additional consent will be required in some circumstances such as bridge crossings. In the assessment of alternative cable routes, consideration shall be given to the economic benefit and risks associated with each option. Consideration can be given to the use of pipeline type easements for example across agricultural land where this is considered to be more beneficial for fault-finding and repair, although this is usually a higher-cost option requiring appropriate justification.

Where EHV cables are installed, depending on the length of such cables there can be issues associated with the capability of switchgear to cater for the capacitive charging currents when the cable is energised and the ability to carry out fault location and pressure testing using standard test equipment. Current practice is to install intermediate isolation / switching points such that the maximum section length of EHV cable is 10km.[60]

60 Further background information can be found in EATL STP Report S5243_1: AC Cable Connections: Practical and Electrical Limits to Their Length.

4. References

4.1. External Documentation

Reference	Title	Version and Date
BS EN 60076 (IEC 60076)	Power Transformers – 1 General	2011
Distribution Connection and Use of System Code	Distribution Connection and Use of System Code (DCUSA)	Issue 15.3
ENATS 41-24	Guidelines for the Design, Installation, Testing and Maintaining of Main Earthing Systems in Substations	Issue 2, 2018
ENATS 41-37	Switchgear for use on 66kV to 132kV Distribution Systems	Issue 3, 2022
ENATS 43-8	Overhead Line Clearances	Issue 5, 2019
Engineering Recommendation G109	Lightning protection for networks up to 132kV	Issue 1, 2021
Engineering Recommendation P24	AC Traction Supplies to British Rail	Issue 1, 1984
Engineering Technical Report 134	Lightning protection for networks up to 132kV	2013
Engineering Technical Report 89	Specification of d.c. Time Constants for Switchgear	Issue 1, 2016
EREC C55	Insulated Sheath Power Cable Systems	Issue 6, 2022
EREC G5	Harmonic voltage distortion and the connection of harmonic sources and/or resonant plant to transmission systems and distribution networks in the United Kingdom	Issue 5, 2020
EREC G59	Recommendations for the connection of generating plant to the distribution systems of licensed Distribution Network Operators	Issue 3, Amendment 7, 2019
EREC G88	Principles for the Planning, Connection and Operation of Electricity Distribution Networks at the Interface Between Distribution Network Operators (DNOs) and Independent Distribution Network Operators (IDNOs)	Issue 4, 2021
EREC G89	Specification of d.c. time constants for switchgear	Issue 1, February 2016
EREC G99	Requirements for the connection of generation equipment in parallel with public distribution networks on or after 27 April 2019	Issue 1, Amendment 9, 2022
EREC P1	275/33kV, 132/33kV and 132/11kV Supply Point Transformers	Issue 3, 1969
EREC P18	Complexity of Distribution Circuits Operated at or above 22kV	Issue 2, 2022
EREC P2	Security of Supply	Issue 8, 2023
EREC P28	Voltage fluctuations and the connection of disturbing equipment to transmission systems and distribution networks in the United Kingdom	Issue 2, 2019
EREC P29	Planning Limits for Voltage Unbalance in the UK for 132kV and Below	Issue 1, 1990
EREC P30	Good Practice Guide for the Risk Management of Planned Long Duration Outages	Issue1, 2013
EREC S34	A Guide for Assessing the Rise of Earth Potential at Electrical Installations	Issue 2, June 2018
HSAWA	The Health and Safety at Work Act 1974	February 2023
NETS SQSS	National Electricity Transmission System Security and Quality of Supply Standards	Issue 2.5, 2021
SI 2002 No. 2665	The Electricity Safety, Quality and Continuity Regulations	31 January 2003

SI 2006 No. 1521	The ESQC (Amendment) Regulations 2006	1 October 2006
SI 2009 No. 639	The ESQC (Amendment) Regulations 2009	6 April 2009
The Act	The Electricity Act 1989 (as amended by The Utilities Act 2000, The Energy Act 2004 and The Energy Act 2004 (Amendment) Regulations 2012 (No. 2723, 2012)	February 2023
The Distribution Code	The Distribution Code of Licensed Distribution Network Operators of Great Britain	Issue 55, 2023
The Electricity Distribution License	Standard conditions of the Electricity Distribution Licence.	April 2023
The Grid Code	The Grid Code	Issue 6, Revision 20, 2023

4.2. Internal Documentation

Reference	Title
CNN/021/001	Code of Practice for the Provision and Management of a Curtailable Connection (Draft)
CNS/001	Consents and Wayleaves Policy
CNS/001/014	Easements for Overhead Lines and Underground Cables
CNS/003	Operational Land and Buildings
ENV/001	Environmental Management System Manual
ENV/002/001	The Management of Noise, Dust and Visual Impact
ENV/006/001	Protection of Plants, Animals and Conservation Areas
ENV/006/002	Network Design and Development
IMP/001/007	Code of Practice for the Economic Development of Distribution Systems with Distributed Generation
IMP/001/010	Code of Practice for Standard Arrangements for Customer Connections
IMP/001/011	Code of Practice for Overhead Line Ratings and Parameters
IMP/001/012	Code of Practice for Flood Mitigation at Operational Premises
IMP/001/013	Code of Practice for Underground Cable Ratings and Parameters
IMP/001/014	Code of Practice for the Protection of Distribution Networks
IMP/001/017	Standard for the Application of System Monitoring
IMP/001/103	Code of Practice for the Methodology of Assessing Losses
IMP/001/104	Code of Practice for the Management of Short Circuit Currents in Distribution Switchgear
IMP/001/206	Guidance for assessing Security of Supply in accordance with Engineering Recommendation P2/7
IMP/001/909	Code of Practice for Distribution System Parameters
IMP/001/912	Code of Practice for the Economic Development of the HV System
IMP/001/912/001	An Application Guide for Arc Suppression Coils
IMP/001/914	Code of Practice for the Economic Development of the 132kV System
IMP/001/915	Code of Practice for Managing Voltages on the Distribution System
IMP/001/918	Code of Practice for Transformer Ratings
IMP/001/920	Guidance on the Assessment of Major Substation Firm Capacity
IMP/007/011	Code of Practice for the Application of Lightning Protection
IMP/010/011	Code of Practice for Earthing LV Networks and HV Distribution Substations
IMP/011	Policy for Fire Mitigation at Operational Premises
INV/001/005	Code of Practice for the Asset & Network Planning Processes
INV/007	Flexibility First Policy
INV/007/001	Flexibility First Decision Making: Use of Sustain and Secure Flexibility Service Products to Address System Constraints on the 132kV and EHV Distribution System
NPS/001/007	Technical Specification for Overhead Line Conductors
NPS/002/003	Technical Specification for Protection Tile, Protection Tape, Cable Ducting and Route Markers
NPS/002/021	Technical Specification for 33kV Power Cables
NPS/002/022	Technical Specification for 66kV Power Cables

NPS/002/024	Technical Specification for Fibre Optic Cables, Wrap, OPGW and ADSS
NPS/003/004	Technical Specification for Indoor 33kV Switchgear
NPS/003/008	Technical Specification for Open Bushing, Air Insulated (AIS), 66kV and 132kV Circuit Breakers
NPS/003/012	Technical Specification for Continuous Emergency Rated (CER) Transformers
NPS/003/021	The Technical Specification for Continuous Maximum Rated (CMR) Transformers
NPS/003/043	Technical Specification for Outdoor 33kV Switchgear
NSP/002	Policy for the Installation of Distribution Power Cables
NSP/004/011	Guidance on Overhead Line Clearances.
NSP/004/042	Specification for HV Wood Pole Lines up to and Including 33kV
NSP/004/044	Specification for HV Wood Pole Lines of Compact Covered Construction up to and including 33kV
NSP/004/045	Specification for EHV Wood Pole Lines Operating up to 132kV with Span Lengths up to 220m

4.3. Amendments from Previous Version

The following table lists the main material changes that have been made between version 4 and version 5 of this document. It does not include reference to minor changes of negligible impact.

Section	Amendments
3.1.4	New section to refer to the Electricity at Work Regulations added. Subsequent sections renumbered accordingly.
3.1.5	Reference to SLC7A and SLC31E added.
3.1.5	Reference to Engineering Recommendation P2 in SLC 24.1 clarified.
3.1.7	Reference to DCUSA added regarding the minimum scheme and curtailable connections.
3.4.1	Facility to install additional 33kV switchboards at existing substations added.
3.4.10	Reference to the Flexibility First Policy added. Clarification provided that at the moment the Flexibility First Policy, and the associated guidance is focussed on the application to discretionary reinforcement (not customer connection schemes)
3.4.11	Section revised to aid clarity.
3.4.6	Reference to flexibility services and curtailable connections added.
3.5.3	33kV switchgear ratings updated.
All	Minor editorial changes to improve legibility.
Appendix 2	Guidance on the application of LFDD in relation to protected customers added.
Various	Reference to the term firm capacity replaced to aid clarity.

5. Definitions

Term	Definition
AAAC	All Aluminium Alloy Conductor.
Abnormal load	Any new or increased load connection which may cause voltage or waveform distortion.
ABSD	Air Break Switch Disconnector.
ACSR	Aluminium Core Steel Reinforced.
ANM	Active Network Management
Customer	Any person supplied or entitled to be supplied with electricity at any premises within Great Britain but shall not include any Authorised Electricity Operator in its capacity as such.
Customer Interruptions	The number of customers interrupted per year (CI). This is the number of customers whose supplies have been interrupted per 100 customers per year over all incidents, where an interruption of supply lasts for three minutes or longer, excluding re-interruptions to the supply of customers previously interrupted during the same incident.

Term	Definition
Customer Minutes Lost	The duration of interruptions to supply per year (CML). This is the average Customer Minutes Lost per customer per year, where an interruption of supply to customer(s) lasts for three minutes or longer.
Design Manager	The manager responsible for tactical decisions associated with implementing this Code of Practice who can be i) the Policy and Standards Manager for discretionary EHV replacement designs, ii) the System Planning Manager for EHV reinforcement designs and iii) the System Design Manager for other designs.
Distributed generation	A generating plant connected to the distribution network, where a generating plant is an installation comprising one or more generating units.
Distribution Licence	Standard condition of the Electricity Distribution Licence based on Electricity Act 1989 for all electricity distributors.
Distributor	The term distributor is intended to encompass operators transmitting and distributing electricity under the terms of the Electricity Act 1989 (as amended by the Utilities Act 2000).
DNO	Distribution Network Operator. The person or legal entity named in Part 1 of the Distribution Licence and any permitted legal assigns or successors in title of the named party.
EHV	Extra High Voltage. Voltages equal to or greater than 33kV and less than 132kV. For the purposes of this document 25kV traction supplies are also considered to be EHV.
ELF EMFs (SAGE)	Stakeholder Advisory Group
ENA	Energy Network Association
ENATS	Energy Network Association Technical Specification
Flexibility Service	A commercial service where a customer modifies their generation and/or consumption of electricity in response to an external signal (e.g., change in electricity or Use of System price or on receipt of a specific communication signal) to provide a service to a distribution system operator.
Grid Supply Point (GSP)	Any point at which electricity is delivered from a transmission system to the DNO’s Distribution System.
HV	HV refers to voltages greater than 1kV and less than 33kV. For the purposes of this document 25kV traction supplies are considered to be EHV.
HVDC	High Voltage Direct Current
IEC	International Electrotechnical Commission
Independent Distribution Network Operator (IDNO)	Independent Distribution Network Operators (IDNOs) develop, operate and maintain local electricity distribution network. IDNO networks are directly connected to the Distribution Network Operator (DNO) networks or indirectly to the DNO via another IDNO.
LV	Low Voltage. Voltage up to and including 1000V.
MVA	MegaVolt Ampere
Meter Operator	A person, registered with the Registration Authority, appointed by either a Supplier or Customer to provide electricity meter operation services.
NGESO	National Grid Electricity System Operator Limited
NGET	National Grid Electricity Transmission plc.
Northern Powergrid	Northern Powergrid (Northeast) plc and Northern Powergrid (Yorkshire) plc.
OFAF	Oil Forced, Air Forced.
Ofgem	The Office of Gas and Electricity Markets, or its successor.
ONAN	Oil Natural, Air Natural.
Open Networks	An industry initiative that aims to transform the way the energy networks operate, underpinning the delivery of the smart grid.
Planning Manager	The manager responsible for strategic decisions who can be i) the System Planning Manager for issues relating to the strategic planning and development of the system ii) the Smart Grid Development Manager for all other policy related issues.
Planning period	The ten-year period used for forecasting capital requirements, Capital Budgeting and the Network Investment Plan.

Term	Definition
Quality of Supply	The term Quality of Supply is used to describe how well Northern Powergrid satisfy those Customers connected to its distribution system, using minimum targets and standards agreed with Ofgem on their behalf.
R10 Series	R10 Series (Renard 10 series) is a system of preferred numbers that divide a range of values into 10 steps e.g., 10 to 20 into 10 steps.
SCADA	Supervisory Control and Data Acquisition (often referred to as telecontrol)
Supply Point	Substation to transform voltage from 132kV to 33kV or 66kV.

6. Authority for Issue

6.1. CDS Assurance

I sign to confirm that I have completed and checked this document and I am satisfied with its content and submit it for approval and authorisation.

		Date
Deb Dovinson	Governance Administrator	25/03/2024

6.2. Author

I sign to confirm that I have completed and checked this document and I am satisfied with its content and submit it for authorisation.

Review Period - This document should be reviewed within the following time period:

Standard CDS review of 3 years?	Non-standard Review Period & Reason	
Yes	**Period:** N/A	**Reason:** N/A
Should this document be displayed on the Northern Powergrid external website?		Yes
		Date
Alan Creighton	Senior Smart Grid Development Engineer	03/04/2024

6.3. Technical Assurance

I sign to confirm that I am satisfied with all aspects of the content and preparation of this document and submit it for authorisation.

		Date
Mark Callum	Smart Grid Development Manager	24/04/2024

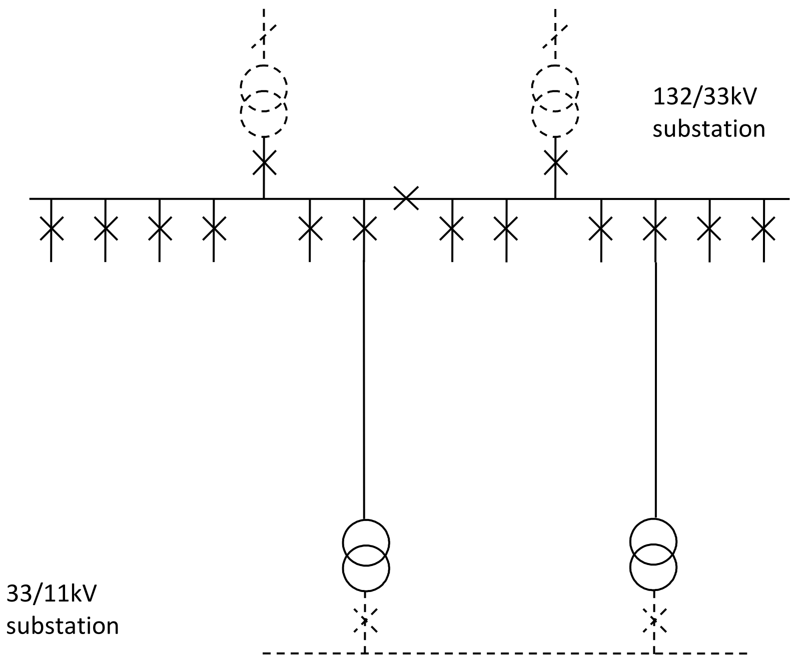
6.4. Authorisation

Approval is granted for publication of this document.

		Date
Mark Nicholson	Director of Engineering	01/05/2024 cx

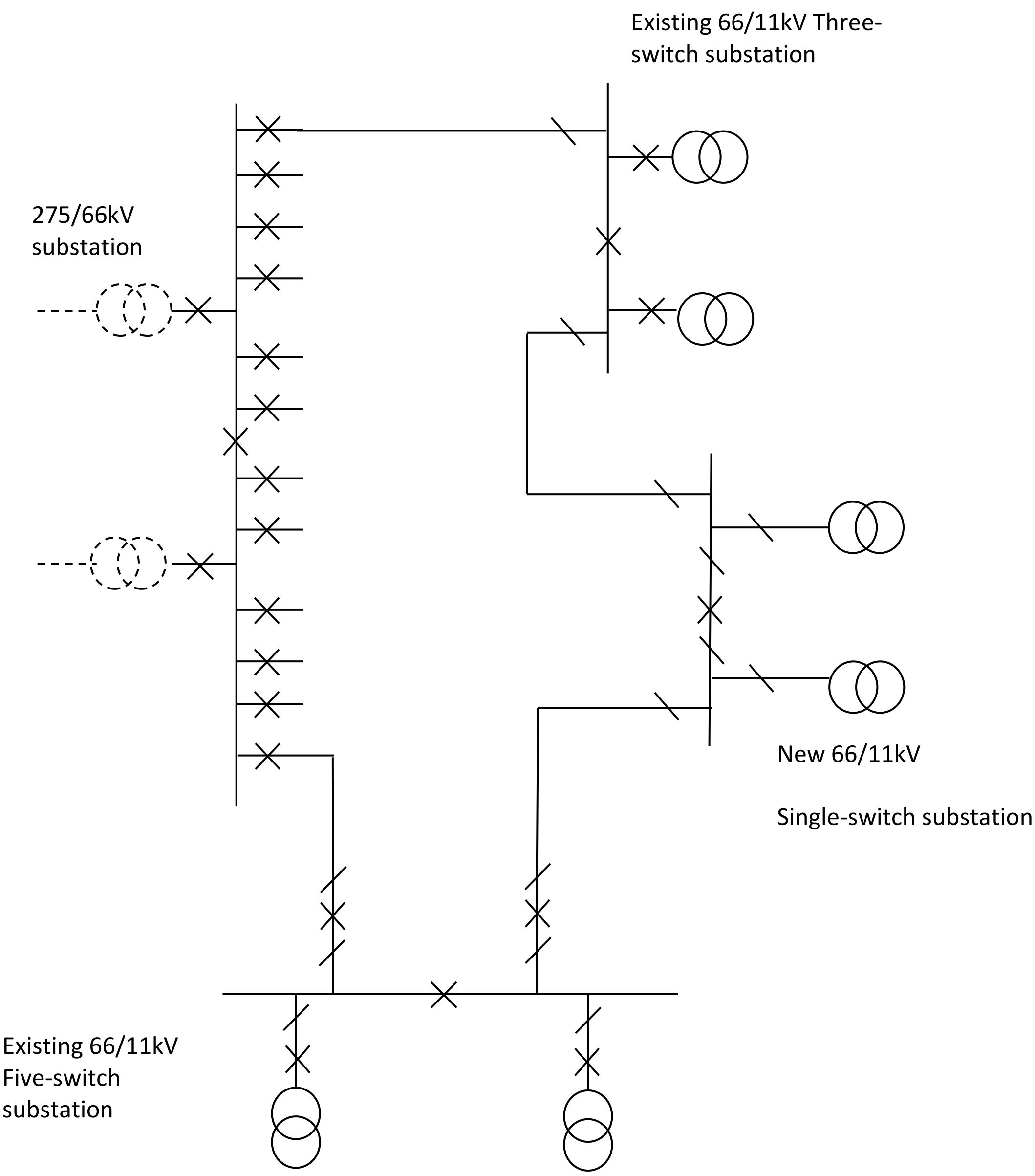
Appendix 1 – General Arrangements

33kV Radial Feeders

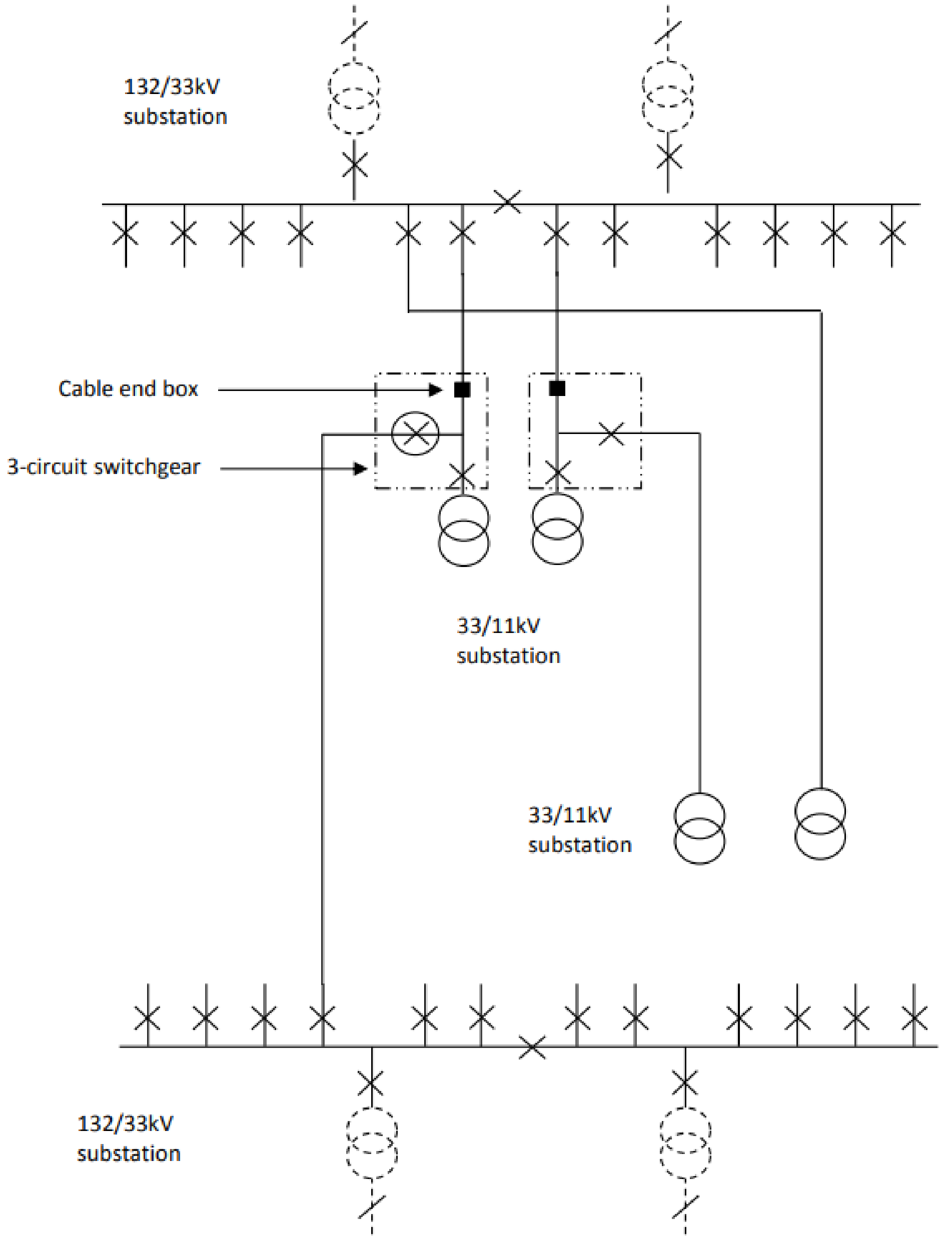


Note: Solid lines indicate equipment that falls within the scope of this Code of Practice

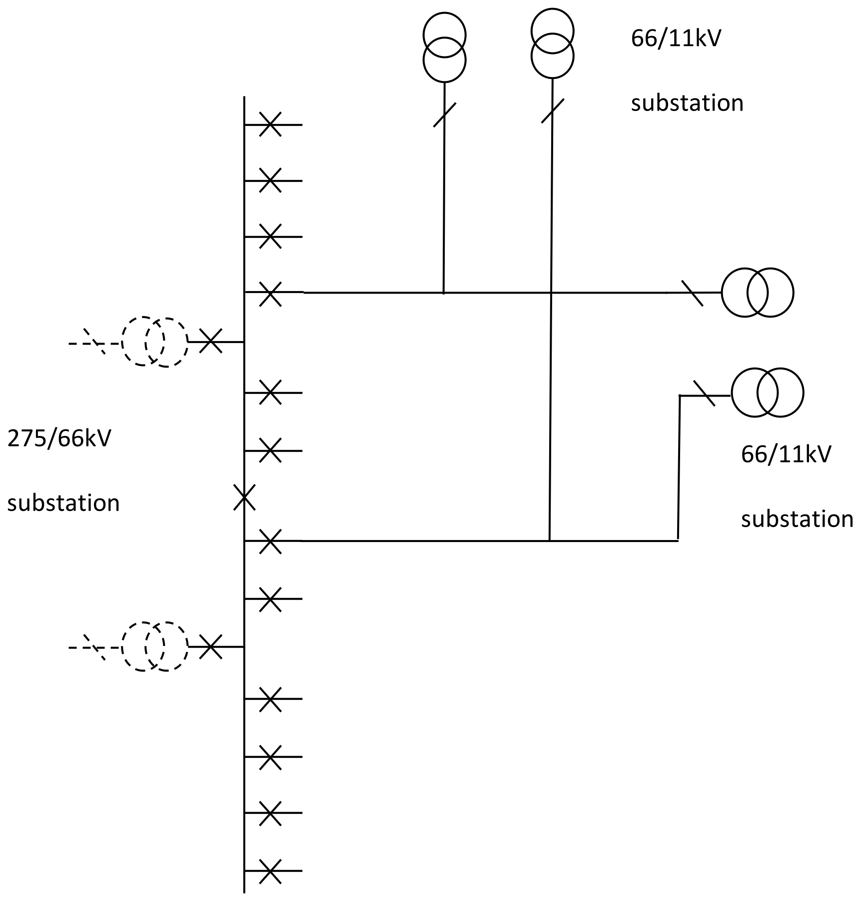
66kV Ring Circuit



33kV 3-Circuit Development (Cable)



66kV Overhead Line Teed Transformer Feeders with Transformer Isolators



Appendix 2 – LFDD Scheme

Background

The Grid Code requires DNOs to make arrangements to disconnect demand on their network if the system frequency falls during a major system disturbance. The LFDD scheme is a multistage scheme that disconnects 5% of demand when the frequency falls to 48.8Hz increasing to a total of 60% of demand as the frequency falls to 47.8Hz. LFDD relays are typically installed on the lower voltage transformer circuit breakers at 275/66kV, 275/33kV, 132/66kV and 132/33kV substations although they are sometimes installed on the 66 or 33kV outgoing feeder circuit breakers, particularly in Northern Powergrid Northeast.

LFDD Considerations for System Alterations

This section describes some of the issues that should be considered when making alterations to the EHV system to assess whether there are implications for the LFDD scheme.

- Where substations equipped with Low Frequency relays are normally operated in parallel (including parallels made via a lower voltage system), such substations should be in the same LFDD group, and the relays should have the same settings. The Low Frequency relays at such substations should preferably be of the same type, and where applicable have the same firmware versions. Intertripping between such substations should be considered where practicable to ensure the LFDD scheme operates in unison.

- Where a Delayed Auto Reclose, Auto Close or other auto switching scheme is installed, low frequency inhibit should be a functional feature of such schemes if the operation of such an auto switching scheme could limit the effectiveness of Low Frequency relay operation.

- As part of the process of allocating substations to LFDD groups, the impact of any auto switching schemes and manual restoration on LFDD operation should be considered.

- As part of the process of allocating substations to LFDD groups, consideration should be given to the presence of any sensitive customers e.g., major transport hubs or hospitals, that would be affected by the operation of a LFDD relay.

- When implementing changes to the transmission or Northern Powergrid distribution system, it is important to consider the impact of permanent demand transfers and the creation of new parallel circuits between different LFDD groups that could compromise the effective operation of the LFDD scheme.

- Following an incident in August 2019 when the LFDD scheme operated, DNOs received a request from the Electricity Task Group to review their LFDD arrangements to ensure, wherever practical, that supplies to customers named on the Protected Sites List should not be disconnected if the first few LFDD stages were to operate. When implementing changes to the Northern Powergrid distribution system, it is important to understand the implications for any customers named on the Protected Sites List. Advice can be sought from Control Operations on the customers on the Protected Sites List, as this information is not in the public domain.

All of these general points apply when reviewing the LFDD groups as part of the annual Week 24 submission and are included within the Section Level Procedure for the Production of the Week 24 Submission.

- In addition, when designing network reinforcement schemes or new customer connection schemes there is a need to consider the impact the network changes might have on the LFDD schemes, and identify any changes required to maintain the LFDD scheme effectiveness in the Functional Specification.

- The LFDD schedules that are used to populate the LFDD table for the Week 24 submissions may provide useful high level information on LFDD schemes in service on the EHV network. This may prove useful when working on EHV designs and is available on request from the Week 24 author in System Forecasting.