IMP/001/914 - Code of Practice for the Economic Development of the 132kV System

1. Purpose

The purpose of this document is to state Northern Powergrid's policy for the economic development of the 132kV system. The document states the requirements to achieve a robust, economical and efficient 132kV 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 licenced 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This document supersedes and replaces all previous versions of this document all copies of which should be withdrawn from circulation.

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2. Scope

This document applies to:

- The 132kV distribution systems of Northern Powergrid Northeast and Northern Powergrid Yorkshire;
- All 132kV distribution system developments including new connections, system reinforcement and asset replacement; and
- All assets with a nominal operating voltage of 132kV, including any 132kV busbar and the 132kV/lower voltage transformer at a 132kV to EHV or HV substation.

It is not intended to apply this Code of Practice retrospectively, but when work is being done on the 132kV 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 a 132kV system, or embedded into lower voltage system and may have an impact on the 132kV 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).

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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 132kV system are:

- Employee commitment - achieved by developing a safe 132kV 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 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.[2] One of the changes relates to the use of flexibility 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 132kV system are detailed in the following sections.

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

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.

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’.

This is addressed in this Code of Practice by:

- Providing guidance on substation location;

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

- 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[3] 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 132kV system shall be complied with.

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 132kV circuits and substation equipment in accordance 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 Engineering Recommendation P18 in order to reduce the impact on customers in the event of the loss of a circuit on the 132kV system. Guidance is 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 a high voltage supply at 132kV.

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

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 132kV 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 some of 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 the 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 licensed electricity distributors, 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 132kV 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.[4] 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
- 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 headline performance derived from the Interruption and Incentive Scheme (IIS). This scheme is a driver to reduce Customer Minutes Lost and Customer Interruptions 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 policy by requiring a level of interconnection and / or transfer capacity 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[5] 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 distribution systems. It also applies to users of distribution systems in the planning and development of their own systems in so far as they affect Northern Powergrid systems.

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

5 Regulation has the meaning defined in the Distribution Licence.

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[6] connected to them shall comply with relevant statutory obligations, international and national specifications and Energy Networks Association technical specifications and standards.

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 132kV system is to obtain a simple and robust system having minimum overall cost from the interface with the transmission system to the customer, 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;
- system losses;
- the maintainability and operability over the life of the assets; and
- the implications for the transmission system.

Any development of the 132kV system should seek to improve the quality and reliability of the supply provided and to reduce potential Customer Interruptions (i.e. to improve the reliability) and Customer Minutes Lost (i.e. to improve availability).

This Code of Practice is written to help ensure that all 132kV system developments are made in such a way as to:

- prevent danger to members of the public and Northern Powergrid staff and sub-contractors;
- optimise system security, reliability and availability;
- optimise power quality experienced by customers;

6 DPC 4.4 refers specifically to the requirements of Users' Systems

- 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. 132kV System Development

3.3.1. Background

The 132kV system serves in a sub-transmission role between the National Grid Electricity Transmission (NGET) transmission system (operating at 400kV and 275kV) and the 33/66kV system, although in some cases, direct 132kV/HV transformation exists.[7] There are also situations where customer connections are provided at 132kV.

The 132kV system was originally built as a transmission system, some parts of which were first commissioned as early as the 1920s (forming the original national grid). It continued in this role until the building of the 275kV and 400kV systems effectively formed a replacement grid at the higher voltage, relegating the 132kV system to more of a distribution role. Consequently, the responsibility for it was transferred from the Central Electricity Generating Board (CEGB) to the Area Boards on 1 April 1969. Initially only financial responsibility was transferred, but full responsibility for planning, operation and maintenance was eventually assumed by the Area Boards in the early 1980s. As a result of this history, most of the design policies and standards in use today are based on those originally developed by the CEGB.

3.3.2. Application

The policy requirements outlined in this document shall apply to the majority of situations where the 132kV system is developed, including new demand and generation connections, system reinforcement, application of flexibility services and asset replacement and asset 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 shall be agreed with the relevant Design Manager[8] at an early stage of the design process. Any such deviations relating to strategic network development shall be agreed with the relevant Planning Manager[9] 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; and

7 Traction supplies are typically provided via 132/25kV transformers.

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

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

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

The design of the 132kV system shall ensure that the following 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 132kV system shall be designed to operate at the nominal voltage set out in Code of Practice for Distribution System Parameters, IMP/001/909. This requires that the voltage at the source substation 132kV busbars will normally be held constant by means of Automatic Voltage Regulator (AVR) relays controlling the tap changers of the transformers feeding that busbar. These tap changers are NGET assets and the target operating voltage shall be agreed between Northern Powergrid and NGESO.[10] Similarly lower voltage busbar of a Northern Powergrid 132kV/EHV or 132kV/HV substation will normally be held constant by means of Automatic Voltage Regulator (AVR) relays controlling the tap changers of the transformers feeding that busbar.

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 low and 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 from 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.

The Electricity Safety, Quality and Continuity Regulations require the voltage to be declared to customers connected to the 132kV system and limit the voltage variation at these customers' supply terminals to ±10% of the declared voltage. The 132kV system shall therefore normally be designed to limit the maximum voltage variation to ±10% of the nominal voltage in order to accommodate any future customer connections at this voltage. However, in situations where customers are supplied with a high voltage supply below 132kV via transformers that do not have on-load automatic tap changers, for example Network Rail traction supplies where the standard 132/25kV transformers are equipped with off-load tap changers, the variation must not exceed 6% above or below the declared voltage unless otherwise agreed with the customers affected.

The 132kV system shall also be designed to enable the limiting voltage conditions at lower voltage levels to be maintained in accordance with Engineering Recommendation P10, Voltage Control at Bulk Supply Points, for the specified operating scenarios.

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 132kV shall meet the requirements of:

10 This 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 Recommendations P29, Planning Limits for Voltage Unbalance in the UK for 132kV and Below;
- Engineering Recommendations 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. [11]

In respect of voltage fluctuations, voltage unbalance and harmonic voltage distortion, whilst there is no requirement for the 132kV 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 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, relatively small loads or generation may need to be connected to the 132kV system to reduce their impact on other customers.

3.3.5. Neutral Earthing

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.

Each NGET 400/132kV and 275/132kV auto-transformer at a Grid Supply Point (GSP) substation shall normally be solidly earthed at the star point of its 132kV winding except where it is necessary to constrain fault current or reduce the rise of earth potential. In this case a Neutral Earthing Resistor (NER) may be connected between the star point and earth. In such instances due regard must be given to the insulation grading of transformers and the associated switchgear and protection issues.

For 132kV/66kV transformation, Northern Powergrid Northeast normally utilise star-star transformers with the star point of the 132kV winding solidly earthed and an earthing resistor connected to the star point of the 66kV winding. For 132kV/33kV transformation, star-delta transformers are normally used in Northern Powergrid Northeast. The star point of the 132kV winding should be solidly earthed and the 33kV winding equipped with an earthing transformer and in some cases an additional NER. The earthing transformer and NER shall be selected to limit the maximum substation earth fault current to 3000A.[12]

The Northern Powergrid Yorkshire distribution system employs star-delta transformers for both 132kV/66kV and 132kV/33kV transformation. The star point of the 132kV winding shall be solidly earthed and the lower voltage delta winding shall be earthed via an earthing transformer and in some circumstances an additional NER. The earthing transformer and NER shall be selected to limit the maximum substation earth fault current to 3000A.[13]

3.3.6. System Phasing, Rotation and Vector Groups

The red phase vector on the 132kV system is the reference vector for phasing on the distribution system and is in phase with the red phase vector on the 400kV and 275kV systems, all of which are taken to be at 0°. Standard phasing and transformer connections are detailed in Code of Practice for Distribution System Parameters, IMP/001/909.

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

12 Typically the earth fault current is limited to 1000A per transformer which allows for three transformers to be installed in a given substation.

13 Typically the earth fault current is limited to 1000A per transformer which allows for three transformers to be installed in a given substation.

The Northern Powergrid Northeast distribution system typically employs Yy0 transformers for 132kV/66kV transformation; therefore, the red phase vector on the 66kV system is in phase with the reference vector. For 132kV/33kV transformation, Yd1 (or Yd11 connected Yd1) transformers result in the 33kV red phase vector lagging the reference vector by 30°.

The Northern Powergrid Yorkshire distribution system typically employs Yd1 or Yd11 transformers (both connected Yd9) resulting in the 33kV or 66kV red phase leading the reference vector by 90°.

3.3.7. Short Circuit Levels

The Code of Practice for Distribution System Parameters, IMP/001/909, states that the maximum design short circuit levels to which the 132kV system should be designed and below which it should be operated.

Because of the multiple earth paths for earth fault current on the 132kV system, the prospective short circuit currents on the 132kV system are often higher for phase-to-earth faults than for phase-to-phase faults. The short circuit ratings of circuits and switchgear shall be chosen with particular care to avoid overstressing under both phase-to-earth and phase-to-phase fault conditions. When assessing the capability of 132kV switchgear consideration should be given to the X/R ratios on the 132kV system as 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 132kV 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 132kV 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.

Consideration should be given to the short circuit rating of the earth screen of 132kV cables. As a minimum the short circuit rating of the sheath (typically a lead sheath) forming part of a 132kV system shall have a capability in excess of the system I^2t duty, which is a factor of the phase to earth current and the maximum (backup) protection operating time.[16] Where a new 132kV cable is being installed consideration should be given to the potential future earth fault current and the new cable should be specified to cater for such additional short circuit current. Consideration should be given to the:

- potential future requirement for additional NGET SGTs;
- potential to implement a different operational arrangement such that a greater number of SGTs are operated in parallel;
- potential to connect additional 132kV/EHV transformers (as they will have a solidly earthed neutral);
- potential to connect additional embedded generation plant; and
- physical limitations of the site.

Care shall be taken to ensure that short circuit level compatibility is maintained in situations where a third party has equipment at a 132kV interface point.

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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 x π x f x t(ms))

16 Typically assumed to be 1 second.

3.4. System Design Criteria

When designing new or modifying existing 132kV systems, care shall be taken 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 also be given to the impact of different credible transmission system 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 and Distribution Load Estimates and Northern Powergrid Distribution Future Energy Scenarios[17] to ensure that 132kV system designs take account of demand growth and generation plant connections which can reasonably be expected within the ten year planning period[18] and which facilitate the transition towards the Government's 2050 a net greenhouse gas emissions target.

The sub-sections below set out key design criteria for the 132kV system.

3.4.1. System Configuration

The 132kV system serves in a sub-transmission role between the NGET transmission system and the 33kV and 66kV systems, generally comprising single or double 132kV busbar substations and simple 132kV transformer feeders to 132/33kV or 132/66kV substations. In some cases, however, direct 132/11kV or 132/20kV transformation may be economically justified.

New 132kV/EHV and 132kV/HV substations should be located as far as practicable to minimise the extent of the distribution infrastructure (particularly overhead lines and underground cables) required to service the demand and generation plant 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.

132kV system developments are usually subject to bespoke design because they are generally built as developments of existing 132kV infrastructure. The topology normally expected is of the form of radial transformer feeders comprising either cables or overhead lines usually operated in pairs. However, more complex interconnected circuit arrangements may be adopted, subject to the approval of the relevant Planning Manager.

The 132kV system shall have limits of complexity set out in Engineering Recommendation P18, Complexity of Distribution Circuits Operated at or above 22kV.

Overhead lines should preferably be used to form 132kV circuits, with cable being used where it is necessary to terminate overhead circuits or to remove the need for a small number of overhead line spans to meet electrical requirements (e.g. to achieve clearances or crossing of lines). However, the difficulties and timescales obtaining planning permission and wayleaves / easements mean that the use of cable is often a pragmatic and economic solution.

In addition, cable circuits may be needed in urban or environmentally sensitive areas. Where cable is used, short lengths (500m) of overhead line should be avoided to reduce the risk of lightning damage and in such cases consideration should be given to undergrounding the complete circuit.

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

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, which is a requisite of Northern Powergrid's Distribution Licences and the Distribution Code. In addition, at NGET interface substations[19] there is a requirement for the substation to comply with the requirements of the National Electricity Transmission

17 https://www.northernpowergrid.com/downloads/4211.

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

19 Also knows as a Grid Supply Point (GSP).

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[20] NGET Super Grid Transformers (SGTs) to be operated in parallel with protection designed to provide a continuous supply to the 132kV 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,[21] the availability of 132kV 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 required level of security, it will normally be necessary for some 132kV interconnection and / or lower voltage transfer capacity to be provided. The compliance of NGET interface substations with the 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 and connected in parallel 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 and the agreement of the relevant Planning Manager has been obtained.

132kV/EHV and 132kV/HV substations shall be arranged to enable two 132kV transformers to be operated in parallel with protection designed to provide a continuous supply to the EHV or HV busbar in the event of an outage of one of the transformers or the circuit supplying the transformer. For larger demand groups in order to comply with the required level of security it may be necessary to provide a third 132kV/EHV (or 132kV/HV) transformer or some EHV (or HV) interconnection and / or transfer capacity in order to provide system security under second circuit outage conditions.

In response to the Interruption and Incentive Scheme (IIS) and to mitigate significant risks of widespread 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 designing systems such that there is no requirement to automatically disconnect demand under first circuit outage conditions (as is permitted for Engineering Recommendation P2 Class of Supply group D), by providing interconnection and / or transfer capacity in excess of the minimum requirements of Engineering Recommendation P2 and, where appropriate, by providing second circuit outage security for demand groups less than 100MW.

In order to manage the risk to customer supplies and the associated IIS risk, additional infrastructure comprising interconnection and / or transfer capacity such that 1/3 of the substation capacity under first circuit outage conditions can be secured in the event of a second circuit outage should be provided where economical. For example, where second circuit security is provided by lower voltage transfer capacity, it shall normally be provided by at least one 33kV circuit for a 2 x 90MVA 132/33kV substation, or two 11kV circuits for a 2 x 30MVA 132/11kV substation.

When assessing options to meet the requirements of Engineering Recommendation P2 and developments to provide enhanced security, options that provide additional transformer and interconnection capability shall be considered alongside those that provide transfer capability, since these options often give a higher level of security or reduce the time to restore customer supplies. For example, if a NGET interface substation has an additional SGT, even if it is maintained on hot standby, increased security will be provided compared to options involving 33kV demand transfer. As second circuit outages on the 132kV system will

20 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.

21 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.

often result in extensive loss of supply, reliability studies shall be used where appropriate to evaluate alternative schemes.

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

- Un-bank 132kV 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;[22] and
- configure the connections to the busbars so that mutually dependant outgoing circuits are not installed as adjacent circuits[23] or connected to one side of a bus section or bus coupler circuit breaker.[24]

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 132kV cables in separate trenches.

In circumstances where the group demand is significantly less than the capacity of the substation supplying that demand 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.

3.4.3. Design Feasibility

System studies shall be carried out whenever it is necessary to ensure that the 132kV 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 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.[25]

System studies, including load flow, short circuit, voltage transient stability analysis and voltage step change studies 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[26] , 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 132kV system can affect the transmission system e.g. the provision of transfer capacity to ensure compliance with the NETS SQSS and the connection of material generation plant,[27] 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;

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

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

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

25 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.

26 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.

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

- 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.[28] 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 132kV 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

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.[29] 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 the Distribution Code, respectively.

The interfaces with the transmission system shall be managed to ensure that modifications[30] managed 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

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

29 See section 3.4.10.

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).

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 132kV 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 132kV shall be provided in accordance with the principles set out in 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 a new 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 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 Code of Practice for the Provision and Management of 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 132kV, 66kV or 33kV, or at the HV busbar of an EHV/HV substation. These losses shall therefore be re-calculated as necessary whenever any part of the 132kV 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 in 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

31 Grid Code OC.6.5.

32 Grid Code OC.6.6.

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

where the specification of equipment required is outside that of the equipment included in the bulk procurement arrangements.

Investment Appraisal Documents shall contain an assessment the electrical losses arising from the different system enhancement options, including system reinforcement and procurement of flexibility services, established by a system study carried out 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 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 power 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.

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

- Undergrounding of overhead lines;
- Increasing overhead line clearances;
- Optimum overhead line phasing;[34]
- 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.[35]

3.4.9. Operational Liaison

When designing a new 132kV system, Control Operations shall be involved in the design enables reasonable contingency plans to be put in place to cater for the occurrence of high impact, low probability, (HILP) events on the 132kV 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

34 Further information can be found in the DECC Voluntary Code of Practice, Optimum Phasing of high voltage double-circuit Power Lines, which sets out key principles for the electricity industry to undertake optimum phasing of all new high voltage (132 kV and above) double-circuit power lines, and to convert existing power lines where practicable.

35 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.

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 132kV system capacity is insufficient, consideration shall be given to establishing:

- the bespoke rating[36] 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[37] and it is confirmed that the 132kV 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 services to avoid or defer the need for conventional system reinforcement, as required by the Northern 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.

36 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.

37 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 primary network constraints, 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.

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 overhead line spans, applying additional cooling equipment to transformers, changing a substation target voltage or the 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, provides guidance on alternatives means of increasing system capability where the insufficiency is associated with a generation plant connection. The Code of Practice for Standard Arrangements for Customer Connections, IMP/001/010, provides guidance on alternatives 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 these Codes of Practice shall be applied.

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 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 system 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.38

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 plan39 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; [40] and
- providing flexible connection offers for new demand or generation customers where appropriate;

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

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

40 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 primary network constraints, 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.

These options provide customers with more control and choice over how they use their electricity and provide 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 expenditure. Further guidance is provided in the Northern Powergrid Distribution Flexibility Services Procurement Statement 2023/24.[41]

3.5. Selection, Application and Configuration of Plant

Items of plant connected to 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 132kV 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 more detail in the sections below, provides a co-ordinated suite of switchgear, transformer and circuit ratings.

The following table illustrates the co-ordination of equipment for typical new 132kV transformer feeders or interconnectors where the duty of the assets is dominated by demand (rather than generation export);[42]

Equipment	Normal Capacity (feeder with single transformer)	High Capacity (feeder with single transformer)	High Capacity (feeder with banked transformers)
132kV Feeder Switchgear	800A (183MVA)	800A (183MVA)	1250A (285MVA)
Transformers	45/90MVA, cyclic rating 117MVA	60/120MVA, cyclic rating 156MVA	45/90MVA, cyclic rating 117MVA

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

42 Where the duty is dominated by generation export, cyclic rating of assets may be different and the duty may not peak in the winter; the overhead line ratings shown in the table are winter ratings.

Overhead lines	175 ACSR Lynx 651A (149MVA)[43]	300 AAAC Upas 935A (214MVA)[44]	500 AAAC Rubus 1286A (294MVA)
Cables	400Cu XLPE 600A (137MVA)	630Cu XLPE 730A (167MVA)	1000Cu XLPE 840A (192MVA)[45]

3.5.2. Transformers

Transformers with nominal ratings in the table below shall be to the standard specified in the Technical Specification for Continuous Maximum Rated (CMR) Transformers, NPS/003/021.

Nameplate Rating (ONAN) (MVA)	Nameplate Rating (OFAF) (MVA)	Rated Secondary Voltage (kV)	Typical Impedance (100MVA Base)[46]
30	60	66	TBC[47]
45	90	66	27%
75	150	66	20.2%
30	60	33	TBC[48]
45	90	33	27%
60	120	33	20.2%
15	30	11.5	105%

The selection of transformer impedance is a balance between the conflicting requirements to keep voltage regulation low and to maximise the fault level for disturbing demand. Consideration should also be given to the level of distributed generation that is likely to be connected to the system in the future, which may cause high volts at times of low load. Transformer impedance and tap changer range should be selected to comply with the principles of Engineering Recommendation P1 and P10. To maintain the interchangeability of transformers, impedances should be selected from values in the table above. Where transformers of different impedances are being considered this shall be agreed with the relevant Design Manager.

Tap changers on 132kV transformers shall generally have the tapping range of +10%/-20% in 18 steps of 1.67%. In situations where two or more 132kV 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.

In situations where a 132kV substation is being constructed solely to provide a connection to an individual customer, Northern Powergrid should normally own the 132kV transformer so that the customer takes a supply at EHV or HV. This arrangement facilitates the provision of further supplies to other customers from the new EHV or HV busbar. The transformer should be selected from those in the table above.

Every 132/EHV or 132/HV transformer shall have an associated auxiliary transformer to provide auxiliary supplies to the substation. Where a substation is equipped with two transformers, it is not necessary to provide an alternative LV supply from the surrounding network infrastructure as, for the loss of one transformer supplies will be maintained by the remaining transformer.[49]

43 Partially facilitates the replacement of 132/EHV substation with high capacity equipment.

44 In most cases it is possible to upgrade a line originally designed for 175mm ACSR to 300mm AAAC without the need for major tower refurbishment.

45 Consideration should be given to using two smaller cables per phase circuit if a higher rating is required.

46 This is the impedance on the nominal tap. The impedance envelope throughout the tapping range should be established at the design stage for inclusion in the procurement specification.

47 The impedance should be established at the design stage.

48 The impedance should be established at the design stage.

49 Whilst historically NGET have provided auxiliary supplies at NGET interface substations from Unit Auxiliary Transformers (UAT) supplied from their SGT's, NGET do not currently install UATs on at new Super Grid Transformers. Both NGET and Northern Powergrid auxiliary supplies therefore need to

3.5.3. Switchgear

Switchgear shall be to the standard specified in the Technical Specification for Open Bushing, Air Insulated 66 and 132kV Circuit Breakers, NPS/003/008 or the Technical Specification for 66kV & 132kV Gas Insulated Switchgear NPS/003/024. Disconnectors and earth switches shall be to the standard specified in the Technical Specification of 66kV and 132kV Disconnectors and Earth Switches NPS/003/007. Switchgear shall be selected to meet the minimum requirement stated in the table below.[50]

Application	132kV Switchgear	Rating			
		Device	Bus Bar[51]	Break Rating at X/R of 14.1	Break Rating at X/R of 37.7
132kV switchgear at 400/132kV & 275/132kV Substation	Transformer CB	N/A (NGET asset)	N/A (NGET asset)	-	-
	Transformer Disconnector	N/A (NGET asset)	N/A (NGET asset)	-	-
	Feeder CB	800A (183MVA) 1250A (274MVA)	2000A (457MVA)	40kA	31.5kA
	Feeder Disconnector	800A (183MVA) 1250A (274MVA)	2000A (457MVA)	-	-
	Bus Section & Bus Coupler CB	2000A (457MVA)	2000A (457MVA)	40kA	31.5kA
	Bus Section & Bus Coupler Disconnector	2000A (457MVA)	2000A (457MVA)	-	-
132kV switchgear at 132/66kV and 132/33kV substations	Feeder CB	800A (183MVA)	800A (183MVA)	40kA	31.5kA
	Feeder Disconnector	800A (183MVA)	800A (183MVA)	-	-
132kV switchgear at customer substation	Metering CB	800A (183MVA) 1250A (274MVA)	800A (183MVA) 1250A (274MVA)	40kA	31.5kA
	Disconnector	800A (183MVA) 1250A (274MVA)	800A (183MVA) 1250A (274MVA)	-	-

Single 132kV busbars shall be the normal arrangement.

Double 132kV busbars (main and reserve busbars each with two sections) shall normally be provided at substations which accommodate, or are likely to be extended to accommodate:

- more than two Super Grid Transformers;
- material generation infeed;
- more than 9 bays of switchgear in total; or
- where the additional cost can be justified by the resulting improved system reliability, security of supply and maintainability.

be derived from the Northern Powergrid LV network. NGET typically install a standby generator and would normally provide a backup supply to Northern Powergrid, via an auto changeover scheme, which can be used to maintain auxiliary supplies to the Northern Powergrid site when the supply from the LV network fails. These arrangements may change depending on the outcome of Grid Code Modification GC0156 (Electricity System Restoration Standard).

50 The rating of 132kV switchgear installed at 132kV switching stations shall be considered on a site by site basis.

51 2000A rated transformer and bus section circuit breakers are required to co-ordinate with the typical maximum short time rating of the NGET 240MVA SGTs of 450MVA.

Double 132kV busbars (main and reserve busbars each with three sections) shall normally be provided at substations which accommodate, or are likely to be extended to accommodate:

- more than four SGT transformers;
- material generation infeed;
- more than 19 bays of switchgear in total; or
- where the additional cost can be justified by the resulting improved system reliability, security of supply and maintainability.

Where double busbars are installed:

- a bus section circuit breaker shall be installed in both the main and reserve busbar; and
- a bus coupler circuit breaker coupling the main and reserve busbars shall be installed in each busbar section.

All the busbar-side 132kV isolators shall be motorised. This will enable the busbars to be configured remotely where necessary.

Mesh busbar arrangements are not preferred. Appendix 1 gives further information on the selection of an appropriate busbar configuration.

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 consideration of all elements of 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.

The minimum break rating for new 132kV switchgear on the distribution system is 40kA at an X/R ratio of 14.1 and 31.5kA at an X/R ratio of 37.7.

3.5.4. Overhead Lines

The legacy CEGB phasing practice for double circuit overhead lines i.e. phasing one circuit R-Y-B (top to bottom) and the other circuit B-Y-R (top to bottom) has been continued in Northern Powergrid. This arrangement, which can only be applied to double circuit lines, tends to reduce the EMFs close to the overhead line, particularly when the load on each circuit is the same, as it provides the greatest degree of cancellation between the magnetic fields produced by the two circuits and hence the lowest resulting field.

In any refurbishment or new build programme associated with overhead lines and / or the associated substations, consideration shall be given to choosing the optimal relative phasing for overhead lines as this can reduce the distance required for the magnetic field to fall to acceptable levels. The incremental cost of the additional work would be comparatively small and can be justified by the potential costs of possible health affects taking into account how many people are affected by the overhead line.

All overhead circuit lines that are currently un-transposed shall be modified where possible and justifiable to ensure that the phasing on each circuit is of the optimal configuration for producing the lowest EMFs.

The largest conductor that can be economically justified should be selected, particularly for the interconnection of Grid Supply Point substations or where the line has multiple tees. The earth fault current rating should also be taken into account in selecting the most appropriate overhead line construction and conductors.

The normal standard for a transformer feeder 132kV double circuit 3-phase overhead lines is ENA Technical Specification 43-7 132kV Steel Tower Transmission Lines: Specification L4 (M) equipped with 175mm^2 ACSR Lynx conductors. In situations where a greater capacity is required, its derivatives L4(M)/1 equipped with 400mm^2 ACSR Zebra conductors or L4(M)/2 with 300mm^2 AAAC Upas conductors may be employed.[52]

Overhead lines on 132kV system shall be selected from those in the following table:[53]

Conductor size and type[54]	Tower Design	Generic Static Rating (Summer)	Generic Static Rating (Spring / Autumn)	Generic Static Rating (Winter)
175mm^2 ACSR Lynx	L4(M)	507A (115.9MVA)	550A 125.7MVA)	575 (131.5MVA)
300mm^2 AAAC Upas	L4(M)/2	728A (166.4MVA)	790A (180.6MA)	825A (188.6MVA)
400mm^2 ACSR Zebra	L4(M)/1	874A (199.8MVA)	946A (216.3MVA)	988A (225.9MVA)
500mm^2 AAAC Rubus	L7/2	1030A (235.5MVA)	1116A (255.2MVA)	1166A (266.6MVA)

The refurbishment of L7 (C) steel tower transmission lines will usually require the replacement of the original 175mm^2 twin Lynx ACSR conductors, which are prone to damage through clashing, with single 500mm^2 AAAC Rubus conductors (L7 (C)/4). The Rubus conductor has a slightly reduced conductor rating and reduced maximum working tension, but with slightly reduced sag compared to the twin Lynx there is increased ground clearance. The earth conductor must be replaced by 160mm^2 twin AACSR Keziah, which has a sag characteristic which resembles that of 500mm^2 AAAC Rubus. The refurbishment of L3 lines (275kV design operating at 132kV) would be treated similarly.

Overhead line clearances shall be in accordance with the document Guidance on Overhead Line Clearances, NSP/004/011.

Where single circuit lines are required or tower lines cannot be easily be accommodated, designs using wood pole or tubular steel supports should be considered, subject to the agreement of the Policy and Standards Manager.

Further guidance on the rating and corresponding sagging temperature of current and historical overhead line designs is provided in the Code of Practice for Guidance on the Selection of Overhead Line Ratings, IMP/001/011.

3.5.5. Underground Cables

Underground cables will be to the standard specified in the Technical Specification for 132kV Power Cables, NPS/002/023. When selecting the size of cable to be used on the 132kV 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 400mm^{2}Cu conductor to be used for new 132kV underground transformer circuit feeders. Larger sizes may be used where, for example, required by the network configuration, where the proximity to other cables materially de-rates the cable and where there is greater requirement for interconnection capacity. When using a cable other than one in the standard cable range, consideration shall be given to the implications of the costs associated with carrying non-standard strategic spares and approval shall be sought from the Policy and Standards Manager.

52 Where a single circuit is required an overhead line constructed to the Specification for EHV Wood Pole Lines Operating up to 132kV with span lengths between 140m and 220m, NSP/004/045, may be used as an alternative to a tower line.

53 Ratings relate to a Design Temperature of 75°C.

54 It is important to cite the conductor name, especially for ACSR conductors as this describes the number of aluminium and steel cores in the conductor.

Cables on 132kV system shall be selected from those in the following table:

Cross sectional area	Nominal Continuous Rating (Laid Direct)[55]
400mm^2 Cu	650A (148.6MVA)
630mm^2 Cu	815A (186.3MVA)
1000mm^2 Cu	960A (219.5MVA)

Regulation 3(1)a of the ESQC Regulations requires that, network equipment is sufficient for the purpose and circumstances in which it is used. It is therefore necessary that the rating of the cable sheath shall be no less than the source substation single phase to earth fault as a minimum and ideally should equal the single phase to earth short circuit design rating which may be as high as 31.5kA.[56]

3.5.6. Earthing and Bonding

New 132kV underground cable circuits shall comprise single core 132kV cables in trefoil configuration without deploying any special earthing or cross bonding arrangements. This earthing arrangement avoids the maintenance and testing requirements and safety issue associated with link pits, link pillars and sheath voltage limiters required for cross bonded systems, although it does result in a lower thermal rating. Where a circuit rating higher than that typically available from a solidly bonded system is required, consideration can be given to the deployment of a specially earthed / bonded cable system with the agreement of the relevant Design Manager.

Where it is agreed that a specially earthed / bonded cable system is justifiable, it shall be in accordance with Engineering Recommendation C55. Care shall be taken to ensure the correct application of the sheath voltage limiters where necessary.

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 the substation earthing system shall be in accordance with ENA Technical Specification 41-24, Guidelines for the Design, Installation, Testing and Maintaining of Main Earthing Systems in Substations. The design of the substation earthing shall consider increases in short circuit levels in accordance with section 3.3.5.

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 the 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[57] or customer connection interface. This is critical to ensure consistent application of seasonal or cyclic ratings where the customer's

55 The cable rating software package, CRATER, developed by EA Technology can be used to determine a bespoke rating for a cable.

56 IMP/001/909 - Code of Practice for Distribution System Parameters clause 3.6.2.

57 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).

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).

3.5.8. Metering

Tariff metering for 132kV customer connections 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. 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 Metering Codes of Practice 2, for connections between 10MW and 100MW, requires a dedicated VT winding for metering, and that the Balancing and Settlement Metering Code of Practice 1, which applies to connections above 100MW, requires duplicate dedicated CTs and VTs.

Historically, the relatively high cost of providing metering equipment at 132kV meant that metering equipment was normally installed on the low voltage side of the 132kV/EHV or 132kV/HV transformers, with suitable adjustment for the effect of losses. However, 132kV metering equipment is now more readily available, and tariff metering shall normally be provided at 132kV where economic and practicable.

3.5.9. Protection, Control and Monitoring

Protection of the 132kV system shall be in accordance with the Policy for the Protection of Distribution Networks, IMP/001/014. The main protection will be fully discriminative i.e. cover all types of phase and earth faults whilst disconnecting only the faulted protection zone.

The thermal rating of CTs used for protection purposes shall be co-ordinated with the capability[58] of the associated primary plant.

SCADA facilities shall be provided at substations supplying or supplied from the 132kV system.

The protection and control facilities shall be used to provide information to monitor and manage power flow on the 132kV 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 132kV circuit breakers. This information should be made available via SCADA to the Northern Powergrid data historian (PI).

3.5.9.1. Lightning Protection

The recommendations given in ENA Technical Report 134 Lightning Protection for Networks up to 132kV[59] 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 132kV system shall be in accordance with the Code of Practice for the Application of Lightning Protection, IMP/007/011.

3.5.9.2. Auto-Switching

Auto-reclosing facilities shall be provided on all 132kV circuit breakers controlling circuits containing overhead lines in accordance with the Policy for the Protection of Distribution Networks, IMP/001/014.

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.

58 It's worth noting that the capability of a transformer will be in excess of its nameplate rating.

59 Superseded by Engineering Recommendation G109.

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.[60]

3.6. Telecommunications

The telecommunication network forms an integral part of the 132kV, 66kV and 33kV distribution systems 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 132kV system development work as specified in more detail below.

3.6.1. Telecommunications Facilities at Substations

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

3.6.2. Telecommunication Cables

Since the vast majority of the 132kV system comprises overhead lines, the pilot and telecommunications circuits associated with it have historically been leased from Openreach or provided over microwave circuits. Where system development involves the laying of significant lengths of 132kV underground cable, consideration shall be given to installing telecommunications cables along the same route.

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, consideration shall be given to installing telecommunications cable ducts in accordance with the Technical Specification for Protective Tile, Tile Tape and Cable Ducting, NPS/002/003 and associated access pits in order to provide a more efficient future installation of telecommunications cables. Provision has been made in the Investment Plan for the purpose of providing cable ducts for future telecommunications requirements.

As the telecommunication requirements will be scheme specific, all schemes requiring the installation of telecommunications cables shall be referred to the Technical Services Manager and the Telecommunications Manager for assessment and approval.

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 & Conservation Areas, ENV/006/001.

In situations where the choice of overhead or underground circuits might be contentious, the Wayleaves Manager shall be consulted. Easements and wayleaves 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 wayleave and land acquisition negotiations shall be undertaken in accordance with the requirements of the Northern Powergrid Consents and Wayleaves Policy, CNS/001 and Operational Land and Buildings Policy, CNS/003.

3.7.1. Location of Substations

The general policy for 132kV system design is to establish substations equipped with duplicate 132kV/lower voltage transformers at practicable and convenient locations in the proposed zones of supply, having

60 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 a an incoming circuit.

regard to current loads and possible future demand or generation growth together with 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 be constructed on land which is exposed to the risk of flooding unless appropriate flood defences are installed. 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. Guidance is provided in the Code of Practice for Flood Mitigation at Operational Premises, IMP/001/012.

Substations shall be designed to occupy the minimum practicable site area to minimise future maintenance costs, subject to a reasonable provision for future extension and/or replacement of switchboards and transformers, and any planning requirements. They shall be sited to give safe 24-hour direct vehicular access to the public highway (subject to planning and environmental considerations). Wherever possible substations should be located, and their busbars arranged, to facilitate cable and overhead circuits being routed directly onto the switchgear without circuits crossing each other. This is particularly important for 132kV circuits, where considerable economies can be achieved by landing overhead lines directly onto switchgear terminations. 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.

Substations on a customer’s 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.

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

3.7.2. Routing of Overhead Circuits

132kV 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 (Network Design and Development, Appendix 1, EOC/18) 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. 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. Lower voltage overhead lines shall be undergrounded where these cross a proposed 132kV line route. Consideration should be given to installing a section of underground cable when constructing a new 132kV overhead circuit if it crosses a 400kV, 275kV or 132kV overhead line, rather than install a diamond crossing.

New 132kV overhead 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.

3.7.3. Routing of Underground Circuits

132kV underground cable routes shall be simple and direct avoiding crossovers and allow future network extension. Ideally, cables should be laid on routes separate from 33kV, 66kV and higher voltage cables to avoid the possibility of multiple cable damage from the same third-party incident and to ensure thermal independence between the circuits. Wherever possible, routes shall be located in the public highway where the 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.

Easements for underground cables shall be secured in line with guidance contained in Easements for Overhead Lines and Underground Cables, CNS/001/014.

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.

In the assessment of alternative cable routes, consideration shall be given to the economic benefit and risks associated with each option.

Where 132kV cables are installed, depending on the length of such cables there can be issues associated with 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 132kV is 10km. [61]

It is current practice to replace oil-filled cables with XLPE cables as part of a targeted asset replacement programme, but in the exceptional case where 132kV oil-filled cables are retained, consideration should be given to the recovery of mid-route earthing and bonding facilities and the replacement of street pillars with cable pits. Any auxiliary plant (for example earth links and pressure gauges) shall normally be located within the substation site.

61 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
DECC Voluntary Code of Practice	Optimum Phasing of High Voltage Double-circuit Power Lines. Ref URN 10D/992	Feb 2011
Distribution Connection and Use of System Code	Distribution Connection and Use of System Code (DCUSA)	Issue 15.3
ENA Technical Specification 41-24	Guidelines for the Design, Installation, Testing and Maintaining of Main Earthing Systems in Substations	Issue 2, 2018
ENA Technical Specification 41-37 Part 4	Switchgear for use on 66kV to 132kV Distribution Systems	Issue 3, 2022
ENA Technical Specification 43-7	132kV Steel Tower Transmission Lines: Specification L4(M)	Issue 4, 2012
ENA Technical Specification 43-8	Overhead Line Clearances	Issue 5, 2019
Engineering Recommendation C55	Insulated Sheath Power Cable Systems	Issue 6, 2022
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	Issue 5, 2020
Engineering Recommendation G59	Recommendation for the Connection of Generating Plant to the Distribution Systems of the Licensed Distribution Network Operators	Issue 3, Amendment 7, 2019
Engineering Recommendation 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
Engineering Recommendation 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
Engineering Recommendation G109	Lightning protection for networks up to 132kV	Issue 1, 2021
Engineering Recommendation P1	275/33kV, 132/33kV and 132/11kV Supply Point Transformers	Issue 3, 1969
Engineering Recommendation P10	Voltage Control at Bulk Supply Points	Issue1, 1965
Engineering Recommendation P18	Complexity of Distribution Circuits Operated at or above 22kV	Issue 2, 2022
Engineering Recommendation P2	Security of Supply	Issue 8, 2023
Engineering Recommendation P24	AC Traction Supplies to British Rail	Issue 1, 1984
Engineering Recommendation P28	Voltage fluctuations and the connection of disturbing equipment to transmission systems and distribution networks in the United Kingdom	Issue 2, 2019
Engineering Recommendation P29	Planning Limits for Voltage Unbalance in the UK for 132kV and Below	Issue1, 1990
Engineering Recommendation P30	Good Practice Guide for the Risk Management of Planned Long Duration Outage	Issue 1, 2013
Engineering Recommendation S34	A Guide for Assessing the Rise of Earth Potential at Electrical Installations	Issue 2, 2018
Engineering Technical Report 89	Specification of d.c. Time Constants for Switchgear	Issue 1, 2016

Reference	Title	Version and Date
Engineering Technical Report 134	Lightning protection for networks up to 132kV	2013
HSAWA	The Health and Safety at Work Act 1974	1974
NETS SQSS	National Electricity Transmission System Security and Quality of Supply Standards	Issue 2.5, 2021
SAGE Report	Stakeholder Advisory Group on ELF EMFs First Interim Assessment	April 2007
SAGE Report	Stakeholder Advisory Group on ELF EMFs Second Interim Assessment	June 2010
SI 2002 No. 2665	The Electricity Safety, Quality and Continuity Regulations	31 January 2003 (as amended)
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, and 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 (In Draft)
CNS/001	Consents and Wayleaves Policy
CNS/001/014	Easements for Overhead Lines and Underground Cables
CNS/003	Operational Land and Buildings Policy
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	Policy 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/001/915	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	Standard 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/002/023	Technical Specifications for 132kV Power Cables
NPS/003/007	Technical Specification of 66kV and 132kV Disconnectors and Earth Switches
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	Technical Specification for Continuous Maximum Rated (CMR) Transformers
NSP/002	Policy for the Installation of Distribution Power Cables
NSP/004/011	Guidance on Overhead Line Clearances.
NSP/004/045	Code of Practice 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
All	Minor editorial changes to improve legibility.
Various	Reference to the term firm capacity removed and text amended to aid clarity.
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.
3.4.6	Reference to flexibility services and curtailable connections 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.
3.5.3	Disconnector information added.

5. Definitions

Term	Definition
AAAC	All Aluminium Alloy Conductor
Abnormal Load	Any new or increased load connection which may cause voltage or waveform distortion.
ACSR	Aluminium Core Steel Reinforced.
ANM	Active Network Management
CEGB	Central Electricity Generating Board, the precursor of National Grid Electricity Transmission plc.
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 (CI)	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.
Customer Minutes Lost (CML)	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.
DCUSA	Distribution and Use of System Code
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.
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	Means voltages equal to or greater than 33kV and less than132kV (for the purpose of this Code of Practice 25kV traction supplies are considered to be EHV).
EMF	Electromagnetic Field.
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	Any point at which electricity is delivered from a transmission system to the DNO's Distribution System.
HV	Means voltages greater than 1kV and less than 33kV (for the purpose of this Code of Practice 25kV traction supplies are considered to be EHV).
HVDC	High Voltage Direct Current.
IEC	International Electrotechnical Commission.
Independent Distribution Network Operators (IDNOs)	Independent Distribution Network Operators 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.
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.
Open Networks	An industry initiative that aims to transform the way the energy networks operate, underpinning the delivery of the smart grid.

Term	Definition
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.
Planning Period	The ten-year period used for forecasting capital requirements, Capital Budgeting and the System Development Plan.
Quality of Supply	The term Quality of Supply is used to describe how well Northern Powergrid Northeast and Northern Powergrid Yorkshire satisfy those customers connected to its distribution system, using minimum targets and standards agreed with Ofgem on their behalf. One aspect is Supply Performance, which is measured against the following targets. Availability – Average minutes lost per connected customer. Security – Number of Supply interruptions per 100 connected customers. Reliability – Number of faults per 100km of distribution system mains.
SCADA	Supervisory Control and Data Acquisition (often referred to as telecontrol).
Supply Terminals	As defined in the Electricity Supply Regulations, this normally means the terminals of the meter on the customer's premises furthest from the distribution system.
XLPE	Cross-linked Polyethylene.

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
Liz Beat	Governance Administrator	20/03/2024

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. Approval and Authorisation

Approval and authorisation is granted for publication of this document.

		Date
Mark Nicholson	Director of Engineering	01/05/2024

Appendix 1 – 132kV Busbar Configuration

The principal considerations which influence any decision on busbar configuration are the level of security and degree of flexibility of operation required, and the resulting cost. The benefits of a double busbar over a single busbar arrangement are as follows:-

- improved operational flexibility;
- the ability to maintain all items of plant without significantly reducing system security;
- the ability to carry out commissioning and testing without affecting system security;
- increased resilience to busbar and switchgear faults during circuit outages;
- where there are sufficient infeeds to provide security, it can be operated as two discrete busbars to reduce short circuit levels (although switchgear should normally be rated for “solid” operation);
- bus-couplers (where installed) can maintain busbar flexibility if bus-section out of service; and
- improved symmetry facilitating improved balance of load, generation and grid infeeds on each section (minimising load flows along or between busbars).

Although mesh arrangements demonstrate some of the same advantages, the fact that clearance of a fault on plant connected to a mesh corner relies on tripping of two bus-section breakers means that they can also have significant disadvantages, as follows:-

- tripping of a mesh corner may disconnect healthy plant;
- transformers banked on a mesh corner are unable to provide mutual support;
- complexity of plant and protection is likely to reduce reliability; and
- complexity of plant and protection can give rise to an increased risk of human error.

For these reasons, mesh busbar arrangements shall not be used without the approval of the Planning Manager.