May 2026

Network Development Plan

Introduction & Methodology Report

Primary System Planning

nationalgrid DSO

Contents

Document Revision and Review

Date	Comment / Changes
01/05/2026	Final publication

Introduction

The UK electricity system is rapidly changing as decarbonisation targets are driving the electrification of transport, heat, coupled with continued growth in distributed generation and storage. Proactive regulatory steering and the operational environment is evolving to support a smarter, more flexible, and transparent electricity system, to ensure network investment is delivered at pace.

National policy and regulatory drivers are increasing the pace and scale of change on distribution networks, including the growth and diversification of connection requests and the need to deliver timely, efficient connection outcomes. Connections Reform has introduced a new gated process for generation and storage projects, with the intention of speeding up energisation and ensuring only viable and strategically needed projects progress in the queue, supporting delivery of Clean Power 2030 (CP 2030) aligned projects.

The Clean Energy Package (CEP) (EU Directive 2019/944) comprises European legislation for a unified energy strategy for delivering the Paris agreement. As part of the CEP introduction into UK law, Standard Licence Condition SLC 25B outlines the requirement for electricity Distribution Network Operators (DNOs) to publish a Network Development Plan (NDP).

The NDP has three distinct purposes:

- To assess the future suitability of the distribution network for continuing to deliver for customers under credible future energy scenarios across the next 5 to 10 years.
- To identify sites that require intervention due to network constraints, assessing the options available to remedy the constraint to ensure the network complies with relevant design standards and technical limits of assets. Solutions could be provided through flexibility services, conventional reinforcement, or operational mitigation; and
- To provide Ofgem and wider stakeholders with transparent plans to develop the distribution network and continue to enable the transition to net zero.

National Grid Electricity Distribution (NGED) has a variety of publications detailed that provide similar information to the NDP but are tailored for different audiences or published at a different frequency. If your requirements are not covered by the three points above, please see the Interaction with other National Grid documents section in this report where we provide further details about additional publications.

Network Development Plan Structure

The NDP comprises of three different parts, following the Form of Statement jointly developed by DNOs.

Table 1: Summary of the purpose and publication format of the elements of the NDP

Component part of NDP	Purpose	Publication format
Introduction and Methodology	Outlines the methodology for preparing the plan and any assumptions made. This report also summarises the approach to stakeholder engagement.	PDF report is published in May 2026 with stakeholder feedback on the National Grid DSO website.
Network Development Reports	Detailed technical report outlining the parts of the network where constraints are expected in the 0–10-year time horizon. This also covers potential options to solve the identified constraints.	A new interactive map with network constraints and solutions is published on the Network Opportunity and Development Map and can be accessed by choosing NDP filter. Detailed description of each constraint and solution is mapped to the corresponding substation.
Network Headroom Report	Indicates headroom available for additional demand and generation at each substation across primary distribution networks, across the scenarios and years covered by the DNOs forecasting process.	Excel workbook (one per licence area) is published on the National Grid DSO website.

Stakeholder Consultation

Standard Licence Condition **SLC 25B.8** states as part of the NDP, the licensee must:

a) Consult interested parties on the proposed NDP for a period of at least 28 days before publishing as required by **25B.1**; and

b) publish the non-confidential consultation responses.

National Grid Distribution System Operator's (DSO) approach to this consultation period is as follows:

- Provide information from the previous NDP publication on the DSO website.
- Provide a survey on the DSO website for stakeholders to answer consultation questions on the methodology and format of the outputs.
- Run a webinar during the consultation period to present on the outputs and gather feedback from interested parties.

The consultation period encompasses a variety of stakeholder groups as outlined in Table 2, all of which were given the opportunity to provide feedback on the NDP through both an online feedback form and through attending our NDP consultation webinar on 5th March 2026.

Table 2: NDP stakeholders

Interconnected electrical network operators

- Other DNOs, IDNOs, TO, NESO

Community Energy Organisations

Local Authorities / Public Sector

Flexibility Service Providers

Other network operators

- Transport
- Gas network
- Water network

Developers

- Property / building, generation, demand, storage customers

Academic / Research

Please contact us to provide any additional feedback on the content of the NDP.

Stakeholder Feedback

NDP Publications

Based on stakeholder feedback, the report that most stakeholders found useful are the area summary reports which represent the network overview, network topology, table of constraints per GSP within the licence area, and additional information on transmission-distribution interface.

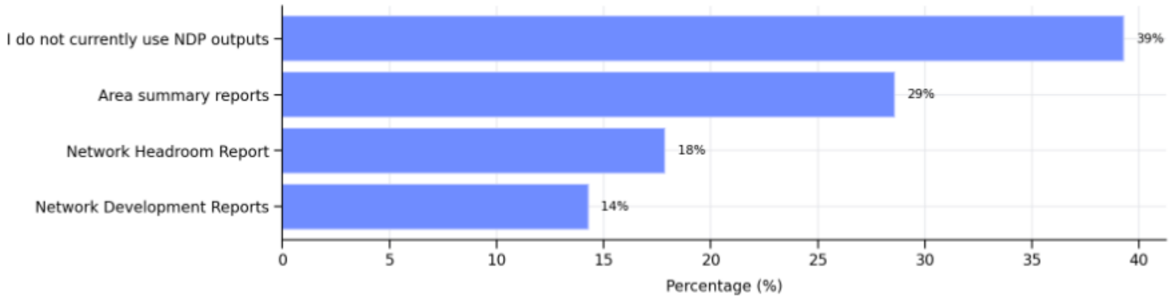

Figure 1: NDP consultation poll results for most useful NDP output

In addition to the categories shown in Figure 1, stakeholders stated that they would also find it useful if there was a way that they could easily find the relevant development reports for their local authority area, as at present the reports are published based on network topology rather than local authority boundaries.

In response to this, we have developed an additional NDP layer on the Network Opportunity Map which provides the interactive map with the NDP outputs, which has been renamed the Network Opportunity and Development Map (NODM). It would be possible for stakeholders to navigate to the interested part of the network on the map and get details on the constraints identified for the next 0-10 years and their proposed solutions.

Table 3 summarises the stakeholder consultation webinar responses and the actions we have carried out to ensure that the NDP best serves the needs of the stakeholders.

Table 3. Stakeholder consultation feedback and actions summary table

Stakeholder feedback	Actions we've taken	Actions we are planning
You would like to see the NDP outputs as an interactive map on the DSO website which holds all the constraints and solutions per substation / local authority	We have implemented an interactive map (NODM) which currently has constraints and solutions mapped to a specific substation	We plan to introduce an additional filter per local authority later in 2026
Despite the highly technical details of the NDP report you would still prefer to have the additional details on the network topology available as an extra resource	Currently all the details can be accessed via NODM which has information on network topology and progressing reinforcement schemes	We are considering the option to create PDF version of the newly developed interactive map which holds all the necessary NDP information in terms of constraint briefs

You would like to understand the different types of solutions we consider for managing network constraints in terms of reinforcing the network, using flexibility services, applying operational mitigation measures	We have included a list of constraints, trigger years, and their corresponding solution linked to a specific substation illustrated on the NDP layer of the NODM	-
You would like to have a simplified summary of the NDP for non-technical audience, potentially using the AI-enabled tools	-	We are exploring summarising the NDP outputs based on the technical background of the audience in terms of AI-enabled tools
You would like to understand the acronyms and definitions while using NDP information	We have included a glossary within the NDP Introduction & Methodology Report	-

Developments since 2024 publication

As outlined in the 2024 publication of the NDP, several developments were identified as National Grid DSO strives to improve capability in analysing distribution networks. Over the past two years the following developments have been implemented in National Grid DSO's approach to investment planning.

Forecasting

- Adoption of Regional Energy Strategic Plan (RESP) pathways, which has changed the planning approach to shift away from Best View to 'Holistic Transition'. RESP provides consistent energy planning pathways to support electricity and gas distribution networks in the development of DNO business plans. RESP is not yet fully implemented, so an interim transitional RESP (tRESP) has been developed for DNOs to feed into business planning processes. The tRESP is reduced in scope compared to RESP, and the tRESP Short-Term Pathway is informed by DNOs' Holistic Transition Pathways, with adjustments carried out by the National Energy System Operator (NESO) to improve consistency and alignment between DNOs. This short-term pathway has a ten-year horizon to 2036 before branching out to the three other pathways to 2050. NGED has taken the technologies in scope of tRESP and created a set of pathways that prioritises the use of tRESP data where available and supplements the outstanding technologies with DFES data. In line with that, the 2026 NDP anchors its primary scenario study directive as Holistic Transition, aligning with NESO – DSO engagement.
- Use of local, near-term evidence alongside tRESP. To maintain near term credibility before the full RESP, tRESP is also supplemented with high confidence local inputs (e.g.: connections pipelines and targeted stakeholder intelligence), consistent with ED3 planning evidence base. Where National Grid DSO has directly reached out to stakeholders to include inputs such as Local Development Plans in our DFES, this has been retained in the inputs to ED3 planning.
- Emerging demand sectors are captured beyond the scope of NDP 2024. Sector-specific evidence for port electrification (maritime technology), aviation, and agriculture has been included in the DFES, where these sectors were previously out of scope.
- Influence from near term external process drivers. CP 2030 and Connections Reform has increased the emphasis of capacity visibility and earlier constraint identification, which will shape the expenditure planning outputs in ED3.
- Incorporated short to medium term plans of major energy users to understand how planned usage of currently unutilised but reserved capacity should be accounted for. This is part of an increased role in engaging with local stakeholders to inform forecasting processes.

Network Impact Assessment

- Established Secondary System Planning (DSO) and Secondary Network Design (DNO) teams to undertake strategic planning and direct investment across secondary networks following the same principles as used for the NDP. External publication of secondary NDPs is not a regulatory requirement, but the capability improves end to end planning and visibility across the entire network and improves customer visibility.
- Database developed and deployed for constraint logging and report automation - Primary System Constraints and Network Solutions (SCaNS). The network impact assessment is increasingly structured to support consistent recording of network constraints in a central register. The output of

the register is multiple Constraint Briefs which inform the structure of the new NDP reports which will also have an element of automation from the SCaNS database.

- Improved the methodology used to generate the Network Headroom Report (NHR), to more accurately reflect the projected network position into future years.
- Engaged with other Distribution Network Operators, Transmission Networks and Electricity System Operator to analyse detailed constraints where multiple parties are required in decision making.
- Network analysis tooling was improved to identify voltage constraints where voltage at a controlling node for a given transformer is outside of the automatic voltage control (AVC) bandwidth for that transformer. An AVC violation at a primary transformer could indicate a voltage constraint on the downstream network. With tooling improved to identify AVC violations, solutions have been developed to resolve these constraints.

Optioneering

- Published the Distribution Network Options Assessment (DNOA) Roadmap outlining how National Grid DSO's Optioneering and Cost Benefit Analysis (CBA) processes will be developed to fully quantify the impacts of investment decisions. This reflects changes which will be introduced to the ED3 Price Control Period regarding how the role of flexibility is expected to evolve in managing constraints and facilitating the net zero transition.
- Refocused the DNOA so that flexibility is not treated as an alternative to reinforcement. Under the Holistic Transition planning anchor, we now aim to distinguish enduring capacity needs (progressed as timely reinforcement) from operational or near-term constraints (where flexibility can add value), maintaining DNOA as the transparent mechanism for options comparison.

Institutional and process

- Formalised the interactions between the DSO and DNO within National Grid for load related expenditure, published as a policy document and Guide to DSO-DNO Governance.
- Formalised interactions across Transmission/Distribution boundaries by establishing a DSO Transmission Distribution Interface (TDI) business unit.
- Developed a suite of internal policies to formalise DSO activities ensuring more consistency and transparency in planning and network development activities and set requirements and roles for coordination with NESO and other parties when managing the transmission impact of distribution connections.
- Implemented a new, interactive map with network constraints and solutions published on the NODM.

National Grid Strategic Investment Process

Since 2016, NGED has developed strategic planning capability and processes to investigate how growth projections will affect the design and operation of the distribution network. Providing transparency in each step of the investment planning process, provides stakeholders with confidence as to how DNOs plan to develop distribution networks to enable the UK transition to net zero.

The NDP forms an important part of the investment planning process, as outlined in Figure 2. The network impact assessment process aims to identify where and when network constraints could materialise because of forecast projections; and identify and model suitable mitigation options to any constraint. To demonstrate that any decision on load related investment is economic, coordinated, and efficient, the network impact assessment must accurately detect network constraints.

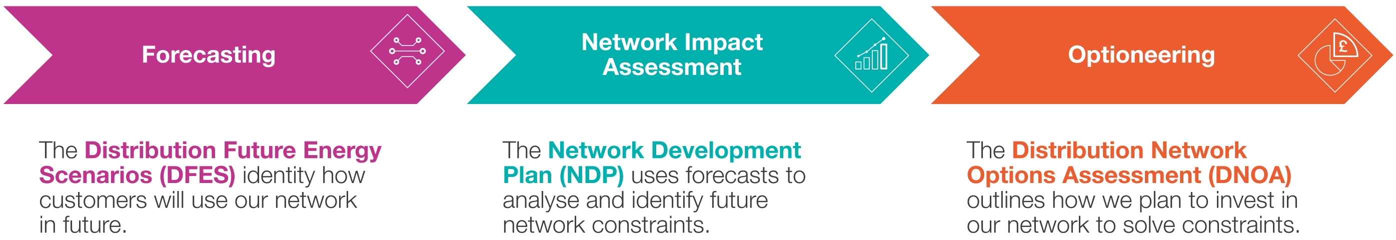

Figure 2. Diagram of end-to-end National Grid DSO strategic investment planning process

A summary of the forecasting and optioneering stages are outlined below.

Forecasting: Distribution Future Energy Scenarios

The first step in the load related planning methodology is establishing a forecast of future network loads across each of our four licence areas. Since 2015, National Grid has been undertaking scenario planning work through Distribution Future Energy Scenarios (DFES) reports, updating these on a two-yearly cycle to provide a forward looking 10-year window of potential low carbon technology uptakes. From 2020, a full suite of DFES documents have been produced annually which consider a horizon out to 2050. The DFES projections are aligned to a common scenario framework, to allow for comparison between DFES publications from different DNOs and the Electricity System Operator Future Energy Scenarios (FES) publication.

Since the DFES 2024 publication, we have adopted 'Holistic Transition' as the pathway to use when planning for the Network Development Plan. This decision was made in alignment with the development of the transitional Regional Energy Strategic Plan (tRESP), which was published in January 2026, and is used as the single decarbonisation pathway that DNOs are required to use for regulatory business plan submissions. Holistic Transition is a pathway which satisfies medium and long-term decarbonisation targets and is more prescriptive than the Best View that has been used in previous iterations of the NDP. Through the Network Headroom Report we demonstrate how the levels of headroom change across the network across the full range of the scenario framework.

In January 2024 the 8th iteration of the DFES was published on the National Grid DSO website, as a suite of documents with supporting data available on the DFES map, as shown in Figure 3.

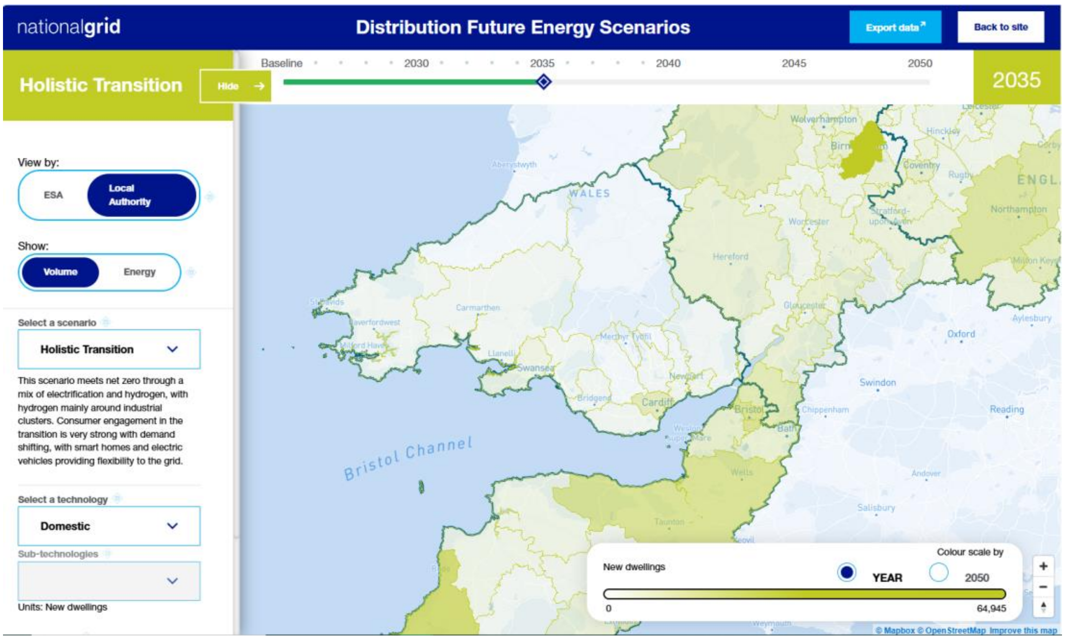

Figure 3. DFES map interface to allow stakeholders to explore forecast projections

Optioneering: Distribution Network Options Assessment

The Distribution Network Options Assessment (DNOA) is a document published once a year providing transparency in the investment decision making process. The DNOA uses the Common Evaluation Methodology (CEM) developed by DNOs to compare options and identify low regret pathways. Conventional reinforcement is always considered as a base case, with flexibility considered alongside. In some cases, alternative conventional solutions are also considered or additionally other innovation solutions that might be available, for example voltage management or compensation. The constraints identified in the NDP will be assessed as part of the DNOA process.

In March 2026 the 8th iteration of the DNOA was published on the National Grid DSO website.

Interaction with other investment drivers

This strategic investment planning process directs the activity within DNOs to increase the capacity of the distribution network to accommodate new demand and generation, based on projections of how customers will use the distribution network in future. It is worth noting that this is not the only method of identifying load related investment on the distribution network. Constraints identified as part of new connections planning and condition-based asset replacement programmes can also affect investment decisions. The responsibilities of system planning within National Grid are outlined in the National Grid Guide to DSO-DNO Governance.

Interaction with other National Grid documents

National Grid regularly publishes information that relates to available capacity and headroom on the distribution network. The interaction between these publications and the NDP is outlined below.

Table 4. Summary of NDP relationship with other National Grid activities

Publication	Description	How does this differ to NDP?
Long Term Development Statement	Long Term Development Statement allows current and future users of National Grid's distribution network to identify and assess opportunities available to them for making new or additional use of the distribution system.	Network model and starting load assumptions data used in NDP analysis. NDP undertakes analysis that is more detailed over a longer time horizon, with updated forecasts based on DFES 2024.
Clearview Connect and CP 2030	Clearview Connect: View BSP headroom across the licence areas. Clearview CP 2030: Regional view of generation or storage connections that have received a response under Connection Reform, customers can check queue position using their enquiry number.	Presents a current or contracted position for customer visibility. This does not correspond to an NDP report which is scenario and year.
Network Opportunity and Development Map	Provides a unified view of potential connection points at bulk supply points, primary substations, and distribution substations. Headroom methodology is enhanced at BSPs and Primaries to show more accurate demand and generation headroom for both the existing connected position and future contracted position (previously called Network Capacity Map)	A regularly updated snapshot of the committed position for customer visibility. Recently an additional NDP layer has been added to the map and renamed to Network Opportunity and Development Map (previously called Network Opportunity Map).
ED3 Business Plan	Business plan submission to Ofgem for period from 2028-2033 outlining how we expect to continue to meet customer needs.	Load related expenditure analysis over the same area of EHV networks, with updated starting load assumptions and forecasts based on DFES 2024.
DSO 4 Policy Directive	A suite of policy directives that formalise the process, roles and governance used to deliver DSO activities. DSO 4/1 Planning and Network Development policy directive sets requirements and roles for forecasting demand/generation,	External DSO policy suites describe 'how we do the work', whereas the NDP is an external publication that presents the output of applying those processes.

	identifying constraints, and selecting solutions.	
DSO 6 Policy Directive	A suite of policy directives that formalise the process, roles and governance used to deliver DSO activities. DSO 6/1 Transmission-Distribution Interface Coordination sets requirements and roles for the processes followed by NGED in coordination with NESO and other parties when managing the transmission impact of distribution connections.	External DSO policy suites describe 'how we do the work', whereas the NDP is an external publication that presents the output of applying those processes.

Long Term Development Statement

The Long Term Development Statement (LTDS) is a publication compiled in accordance with Electricity Distribution Licence Condition 25, to assist existing and future users of National Grid's network in identifying and assessing opportunities available to them for making new or additional use of our Distribution System.

As part of the statement, Table 3 presents forecasts of peak demand on our system in average cold spell conditions. This captures the annual peak demand for each node in the EHV power system model for each licence area, to allow users to apply load assumptions in network assessments. Table 3 also includes a forecast of peak demand for future years, which is based on Holistic Transition outlook.

Due to the timing of the publication of the LTDS in November, and the DFES in March 2026, the forecast load information is based on the previous year's DFES forecasts. To undertake the level of detailed system planning required to produce a full suite of Network Development Reports and ensure consistency with the LTDS published in 2025, DFES 2024 has been used as the basis for the Network Development Plan. The Network Headroom Report will be published using DFES 2024 scenario projections to increase alignment at the time of publication. When available, updates will be made with up-to-date input data to outline how the indicative headroom changes with annual updates to the scenario projections.

Attachment 6 of the LTDS also provides single line diagrams of each area of network, which can be read in conjunction with the Network Development Reports for users to understand the existing network topology.

Network Opportunity Map and Clearview Connect / CP 2030

The Network Opportunity Map, replaced the legacy Network Capacity Map, provides a view of possible connection opportunities across NGED's network. Building on the methodology developed to deliver NDP 2024, we have been able to improve the network analysis undertaken as part of the Network Opportunity Map.

For NDP 2026, the Network Opportunity Map has evolved to become the Network Opportunity and Development Map (NODM) which allows users to access NDP reports via a geographical mapping system.

In addition to the NODM, the Clearview suite provides the following:

- **Clearview Connect**: A detailed view of capacity headroom at Grid Supply points across licence areas. It is intended to help developers identify earliest connection opportunities, lowest cost options for generation connections. It now incorporates Gate 2 to Whole Queue (G2TWQ) process under Connection Reform so customers can see their relative position on the queue within individual GSPs

- **Clearview Clean Power 2030**: Gives a regional view of generation and storage connections that have received a G2TWQ response under Connection Reform. With an Enquiry Reference, a connecting customer will be able to see their specific queue position.

Both the Network Opportunity Map and Clearview are regularly updated with snapshots of connection information incorporating recently connected generation, accepted but not yet connected generation and quoted generation connections. These figures continually change as quotations are issued and expire. As a result, the Network Opportunity Map reflects a ‘committed’ network position, which does not directly correspond to a single scenario or year used as part of the DFES process.

Business Planning for ED3

As National Grid prepares the ED3 Business Plan for the 2028-2033 price control period, the NDP serves as a critical evidence base. The NDP 2026 incorporates comprehensive, forward-looking studies that directly inform our strategic investment requirements and the engineering justifications for the next ten-year period. Across primary distribution networks, this strategic analysis will be captured within a series of Engineering Justification Papers (EJPs) for major schemes. Where appropriate, these are underpinned by detailed Investment Decision Packs (IDPs), which provide the granular technical specifications and cost certainty required to ensure project deliverability from the outset of the ED3 period.

We will undertake a sensitivity analysis of the analysis undertaken for this NDP to test the robustness of our plans against the latest load projections in alignment to the tRESP, and any future changes to our load forecasts.

National Grid views the NDP as part of a continual process to drive the strategic direction and investment in primary distribution networks. This has three primary functions:

1. Ensure that any investment decisions made for projects during the current price control are efficient, accounting for the uncertainty in the changes in load across our networks,

2. Outline any additional constraints that may result in submissions for a load related reopener, where a project is triggered within the price control that is materially different to what was in the original plan, and

3. Highlight the constraints and strategic investments which will influence the load related expenditure for business plan submissions for future price controls.

Methodology

The NDP aims to identify areas of the distribution network where investment may be required to alleviate a constraint. This section outlines the approach taken to identify network constraints and the input data and tools used.

Input Data

To undertake detailed electrical analysis of any electricity distribution network the four components detailed in the matrix in Table 5 are required. It is important to ensure all four areas of this matrix are included within any analysis to maximise the value and accuracy of the output. Each of these sections are discussed in detail below.

Table 5. Summary of the aspects required for detailed electrical analysis of the distribution system

	Network	Customers
Assets	Network topology and connectivity information, including impedance and 'nuts and bolts' data about the assets connected to the National Grid network. Normally this is captured in a network model in power system analysis software.	Customers connected to the distribution network, including the type of demand or generation connected. This also includes information on the machines or assets that customers have connected to the network (such as Electric Vehicles or Heat Pumps).
Behaviour	Actions taken by the DNO to actively manage the network. This can be in the form of updated running arrangements once an arranged outage is taken, or load management schemes in place to manage network flows. This information is vital if contingency analysis is required.	Expected behaviour of customers connected to the distribution network, with reference to the focus and purpose of the network analysis to be undertaken.

Network Assets: Extra High Voltage Power System Models

National Grid maintains extra high voltage (EHV) network models, which are used to represent network assets. Models are updated regularly as assets are replaced, and new connections made to the distribution network. The network model must also include the appropriate ratings of network components, accounting for seasonal factors and any cyclic capabilities.

Multiple snapshots of the EHV models were taken and used to model the forecast demand sets from the DFES. For each future year, the models were amended to ensure that future connections were incorporated into the model in the correct year and thus the demand be accurately distributed across the assets.

Network Behaviour: Automation and Manual Switching Schemes

To accurately identify the point where an investment decision is required, the effects of network automation and manual switching schemes should be included in analysis. If these actions are not modelled, the results may not be representative of how the network would react to specific outages. This could include the behaviour of network automation and manual switching schemes including:

- Auto-close schemes
- Inter-tripping schemes
- Directional overcurrent schemes
- Overload protection
- Sequential control (SQC)
- Load transfers

Customer Assets: DFES Volume Projections

The Distribution Future Energy Scenarios (DFES) provide granular scenario projections for the growth (or reduction) of generation, demand and storage technologies which are expected to connect to the electricity distribution networks across Great Britain. This also includes projections for new housing growth and increase in commercial and industrial developments. The projections are also informed by stakeholder engagement to understand the needs and plans of local authorities and other stakeholders.

The development of DFES has enabled National Grid to take a more proactive approach to network planning. Stakeholders were consulted via a series of consultation events, as well as ongoing direct engagement with all local authority planners and climate emergency officers.

Large scale generation and storage have been omitted from the current assessments due to the ongoing uncertainty surrounding Connections Reform. Given the absence of a confirmed distributed generation/storage connections queue, the potential scale, timing and location of large connections cannot be accurately forecast at this stage. Once the final position is determined, a reassessment will be undertaken to determine what impact large scale generation, and storage connections might have on network strategies.

Customer Behaviour: DFES Behaviour Assumptions

The next step in the DFES process is to account for the effect of customer behaviour on the projected volumes. This is used to take into consideration the expected demand and generation profiles of new and existing customers connected to the distribution network. This includes assumptions for how consumption of customers connected to the distribution network will change over time due to an increase in energy efficiency and pricing-led Demand Side Response (DSR). When the customer behaviour assumptions in this document are applied to the DFES projections a load set of MW/MVAr values can be generated. The NDP uses the latest published LTDS Table 3 data for the starting load assumptions.

Further information on the customer behaviour assumptions is available as part of the DFES: Customer Behaviour Assumptions Report.

Assessment Periods

Traditionally, distribution networks are assessed using 'edge-case' modelling, where only the network condition that is deemed most onerous is analysed, typically the time of year where the peak demand was observed at a substation. As the installed capacity and behaviour of demand, generation and storage is changing, it has become difficult to predict what network condition will be most onerous. This is due to an increase in low carbon technology uptake, whose operating profiles for large groups are yet to be fully understood over a long period of time, also a higher level of engagement by customers in the energy system and willingness to shift energy consumption across the day.

To cover a range of likely onerous cases, National Grid consider a selection of different potential representative days, which are used to assess network capability, as outlined in Table 6. The definition of seasons is taken from Engineering Recommendation P27/2 (Current rating guide for high voltage overhead lines operating in the GB distribution system):

- **Winter**: January, February, and December
- **Intermediate Cool**: March, April, and November
- **Intermediate Warm**: May, September, and October
- **Summer**: June, July, and August

Table 6. Representative day descriptions used for analysis within the NDP

	Demand Assessment	Generation Assessment
Representative day	• Winter Peak Demand • Summer Peak Demand • Intermediate Cool Peak Demand • Intermediate Warm Peak Demand	• Summer Peak Generation
Justification	The peak demand is assessed with minimum coincident generation. Coverage of all seasons allows for an assessment of the network's capability to meet not only annual peak demand conditions but also the demand conditions during periods of planned maintenance on the network.	The peak generation representative day is assessed with minimum coincident demand. This aims to provide an assessment of the network's capability to manage generation output. Generally, the season where generation constraints occur is during summer, with low demand and high output of renewable generation.

The expected peak network loading under different seasons can be compared against the seasonal rating of assets. The demand profiles for many areas of the network show that although the peak demand may often appear in the cooler months, the reduction of the network's asset ratings in the subsequent warmer seasons can be greater than the corresponding reduction in demand, which could result in the most onerous utilisation of assets occurring in the warmer months.

System Assessment and Constraint Identification

The distribution network is designed to comply with electricity engineering standards and policies, as listed in the sections below. If steady state load flow analysis identifies a deficiency in the network for any one of the assessment criteria below, an investment decision is required.

Contingency analysis

Contingency analysis is the analysis of the network under abnormal conditions to confirm that the network complies with Engineering Recommendation P2/8, which outlines the minimum standards for the demand security of supply that must be provided to customers. Any security assessment should accurately cover the assessment process in Section 4 of Engineering Report 130, which provides guidance on the application of Engineering Recommendation P2/8. The demand and generation capacity of a network is not normally limited by its characteristics under normal running conditions, but by its characteristics under abnormal running conditions. There are two broad classes of network outage:

- **Fault outages:** when a component of the network fails, it is detected by protection relays, which open the circuit breakers enclosing the failed component. This de-energises the network between those circuit breakers, so clearing the fault. By their nature, fault outages cannot be predicted so may be expected to happen at any time.

- **Arranged outages:** each component of the network needs to be accessed for periodic or condition-driven inspection, maintenance, and replacement. Similarly, access may be required for reinforcement or to make new connections. The minimum zone to access any component is usually defined by the isolators enclosing the component. The scheduling of arranged outages is flexible to some extent, so can take advantage of seasonal variation in network loading.

Since any component of the network could fail (fault), and each component of the network needs to be maintained, it is necessary to assess the impact of each credible arranged and fault outage on the network. These are both types of First Circuit Outage (FCO).

It is also possible that a network component could fail (fault) during routine maintenance of another asset on the network. It is therefore also necessary to assess the impact of each credible fault outage during each credible arranged outage. Each combination is a Second Circuit Outage (SCO).

To undertake contingency analysis, a network model that can accurately replicate outage conditions is required. This includes circuit breakers and isolators, to determine protective and isolatable zones, respectively. The following outage types and combinations of outage types should be studied on the distribution networks (and associated transmission networks if necessary):

- The intact (normal running) network
- Each circuit fault
- Each busbar fault
- Each arranged circuit outage
- Each arranged circuit outage followed by each circuit fault
- Each arranged busbar outage
- Each arranged busbar outage followed by each circuit fault

Power systems analysis is necessary to accurately quantify the intrinsic network capacity and transfer capacity available of a network, particularly for networks operating with complex configurations. Some of the EHV networks in National Grid licence areas have complex running arrangements which necessitate multiple contingencies to be studied in different areas to capture the worst-case outage combination.

Network Capability

Network capability is defined as the ability of a network to operate within thermal, voltage and other technical limits, excluding frequency-related limits, under both intact network and outage conditions. The technical limits covered by the NDP analysis are discussed below, more information on the limits with which National Grid operates its network can be found in the following documents:

- Policy Document: SD4/10 (Relating to 11 kV and 6.6 kV Network Design).
- Policy Document: SD3/10 (Relating to 66 kV and 33 kV Network Design).
- Policy Document: SD2/9 (Relating to 132 kV Network Design).
- Policy Document SD11/2 (Requirements for Load Management Schemes)

It is worth noting that for network capability analysis, National Grid covers secured outage conditions more than those identified in Engineering Recommendation P2/8, such as busbar arranged outages, busbar fault outages, and busbar arranged outages followed by circuit fault outages. By increasing the level of detail being analysed and analysing these busbar outage conditions, network capability for thermal and voltage constraints is fully assessed for credible outage combinations.

Thermal assessment

In addition to security assessments, comprehensive network analysis can highlight assets that could operate outside of their technical limitations. Depending on the network running arrangements, a network could comply with the demand security of supply standard requirements but still result in overloaded assets under different outage combinations. At this point, an investment decision must be made, with the solutions selected outlined in the Primary System Planning Solutions section of this report.

Studying multiple seasons is important for the thermal loading assessment to highlight the season where an overload is most likely to occur, as operational mitigating measures or flexibility services could be used to defer conventional reinforcement.

Voltage assessment

The Electricity Safety, Quality and Continuity Regulations (2002) define the voltage limits which distribution network operators can supply to customers. These are dependent on the voltage level and provide a bandwidth for which the voltage at customer terminals must stay within. These limits influence the design of voltage control on all levels of distribution networks and must be accounted for when identifying strategic developments.

Network analysis should identify any voltage exceedances outside of statutory limits for intact network conditions and all secured outage conditions. Solutions to mitigate any voltage exceedances could include reactive power compensation or network reconfiguration, in addition to reactive power services provided by customers.

System Frequency Integrity

System frequency integrity is the ability of the GB system to operate within acceptable frequency-related technical limits under both intact network and outage conditions. System frequency integrity is primarily managed by the Electricity System Operator, but it can be affected by the operation of the National Grid distribution network and customers. No power system stability studies have been conducted for the NDP; however, constraints highlighted that impact the transmission/distribution boundary are an indication that further whole system studies are required.

Fault Level

Calculation of fault levels should be carried out in accordance with Engineering Recommendation G74/2, which was introduced in July 2021 with a year period for networks to implement. Switchgear stressing assessment is required as it can form a large part of strategic investment planning decisions, as the impacts of fault level studies can limit running arrangements on distribution and transmission networks.

Complexity of Circuits

Engineering Recommendation P18/2 relates to the complexity of distribution circuits operated above 22 kV. P18 is aimed at limiting network complexity to ensure that circuits can be effectively protected, maintained, isolated, and operated by DNOs. The restrictions within P18 require that for protection clearance, making dead for operational purposes and isolating on any given circuit between 22 kV and 132 kV no more than seven ends (circuit breakers or switches) located at no more than four sites (also known as addresses) should need to operate under normal running arrangements.

The requirements set out within EREC P18 relate specifically to circuits which are either new or have been significantly modified (i.e., a new end or site has been added).

Other relevant network design standards

In addition to network security, capability and voltage studies on a network, there are additional standards that DNOs must follow when designing networks. These are outlined below, however are currently outside the scope of the NDP. These standards are considered for specific customer connections so are covered by the existing connection planning process:

- Voltage unbalance as defined in Engineering Recommendation ER P29/1.
- Voltage fluctuations as defined in Engineering Recommendation ER P28/2.
- Harmonic limits as defined in Engineering Recommendation G5/5.
- Requirements for the connection of generation equipment in parallel with public distribution networks on or after 27 April 2019 as defined in Engineering Recommendation G99/2.

Balance between detailed and simplified analysis

Comprehensive electrical analysis is required to accurately identify network constraints and suggest solutions. Developments in the automation of power system analysis tools means that this analysis is becoming more feasible, quick, and inexpensive. Comprehensive analysis techniques require manual interrogation of results by power system engineers, and modelling of network interventions to enable model convergence in longer-term studies.
However, accounting for the number of outage combinations and representative day inputs that are required for the analysis outlined above results in approximately 3.5 billion individual load flow studies for each scenario and year combination for all National Grid primary networks. With the projected growth in demand and generation connected to distribution networks in years approaching 2050, a large amount of network interventions is required to ensure the steady state load flow analysis can calculate valid results (i.e., the load flow is able to converge).

As a result, DNOs must choose between different approaches to satisfy the licence conditions in the NDP. For the different component reports in the NDP, National Grid runs comprehensive electrical analysis across all primary networks to develop the Network Development Reports. A simplified methodology is used for the Network Headroom Report due to the time horizon required in this publication. The methodology for each part is outlined in subsequent sections of this report.

Other Investment Drivers

Connections driven reinforcement

This strategic investment planning process directs the activity within DNOs to increase the capacity of the distribution network to accommodate new demand and generation, based on projections of how customers will use the distribution network in future. It is worth noting that this is not the only method of identifying load related investment on the distribution network. Constraints identified as part of new connections planning and condition-based asset replacement programmes can also affect investment decisions. The responsibilities of system planning within National Grid are outlined in the National Grid Guide to DSO-DNO Governance.

In many cases synergies can be achieved between strategic load-related reinforcement and connections driven reinforcement. This could include resolving both connections driven and general load growth driven constraints using the same reinforcement proposal. It could also involve enhancing connections driven reinforcement schemes to ensure they create a network which is able to meet the needs of customers in the long term based on load projections for the area. For every constraint identified and solution proposed as part of the NDP process ongoing engagement with the DNO will ensure the most strategic solution is taken forward considering both underlying demand and generation growth for each section of network and any large new connections.

Asset Condition

The replacement of assets based on their condition is conducted across NGED's four licence areas at every voltage level as part of the Asset Replacement Programme.

When assets are replaced on their condition it provides an economic opportunity for uprating to be carried out in anticipation of future load growth, as the additional cost associated with installing higher rated assets while already carrying out works is far lower than the full cost of uprating an asset. Through DSO-DNO engagement it is ensured that the appropriate asset rating is installed to meet the needs of the network on an enduring basis. This may involve uprating assets even if a constraint is not identified before 2036 as part of the NDP process (as assets installed soon are likely to still be in service well beyond this date).

In some cases, as part of the Asset Replacement Programme, it may be prudent to install higher rated assets even if in the short term this will not free up significant capacity. For example, if a transformer were replaced based on its condition and uprated to 20/40 MVA units but the circuits feeding the primary still limited its capacity these circuits could then be uprated later as required to free up the requisite capacity. In summary uprating assets often releases capacity immediately, but even if it does not it can create opportunities to more economically free up capacity in the future. The same logic applies to other examples such as selling reserved substation sites (which, while not reducing network capacity could seriously hinder NGED's ability to create capacity later if load growth materialises).

For network capability and security of supply constraints identified as part of the NDP the condition of existing assets often needs to be considered in solution development and optioneering. For example, resolving a constraint at a primary substation by replacing the transformers with higher rated units could also confer an asset condition benefit (and may make other solutions which do not confer this benefit, such as installing additional transformers, less preferable). In the same way that when undertaking asset condition driven reinforcement future load growth is considered, solutions to load related constraints take the condition of existing assets into account.

As discussed above, whether reinforcement is triggered by asset condition or load growth, significant synergies can be achieved through effective DNO-DSO collaboration. This concept is discussed further in the DNOA Roadmap published in December 2025, which outlines NGED's plans to further develop the optioneering and Cost Benefit Analysis processes used to ensure all factors are accurately accounted for when making investment decisions.

Primary System Planning Solutions

Once a constraint has been identified, the next step is to determine what possible solutions are available to alleviate the constraint. The different types of solutions which are considered are outlined below:

- **Network build:** reinforce existing assets to alleviate the network constraint. This could involve uprating the existing asset for those with a higher rating but could also encompass wider strategic works to establish new circuits, substations and switching devices.

- **Load management schemes:** to manage network loading and voltages by either controlling demand and/or generation connected to the network, operating switchgear to change the topology of the network and/or controlling the settings of tap-change controllers, reactive compensation equipment, and flexible power links.

- **Operational mitigation:** to reduce the risk of overloads occurring, which could include limiting the window where arranged outages can be taken or altering the topology of the existing network. Strategic planning must consider workforce and outage planning when making decisions about potential solution options.

- **Flexibility services:** procure services from customers (where technically appropriate to do so) to reduce network asset loading.

For each of the types of constraint that can be identified through detailed electrical analysis, the suitability of each of the solution types is summarised below.

Table 7. Summary of which solutions considered in Primary System Planning are applicable to different reasons for the constraint occurring

Constraint type	Network build	Load management scheme	Operational mitigation	Flexibility services
Demand security: inability to meet the requirements of EREC P2	✓	✓	✓	✗
Network capability: thermal overload of asset driven by demand	✓	✓	✓	✓
Network capability: thermal overload of asset driven by generation	✓	✓	✓	✓
Network capability: voltages outside of allowable limits	✓	✓	✓	*
Fault level	✓	*	✓	✗
Circuit complexity: Inability to meet the requirements of EREC P18	✓	✗	✓	✗

** Further developments in how both load management schemes and flexibility services fulfil the requirements as outlined in National Grid Policy Document SD11/2 to detect, calculate and actuate for these constraint types could increase the suitability of these solutions in future.*

In the scope of the NDP, when assessing different solutions, the following criteria are used to assess the technical suitability of the solution:

1. Does the solution solve the constraint identified, without introducing additional constraints across the wider network? This is validated by modelling the solution in a power system model and rerunning the analysis, for the time horizon covered by the NDP and where possible to determine beyond.

2. Does the solution provide option value? This involves considering the impacts of the different scenarios on each solution to ensure they are both enduring across a range of future pathways, and strategic when considered in conjunction with other related constraints and solutions. All solutions taken forward are aimed at maximising option value and creating flexibility in the future development of the network to meet the needs of stakeholders and customers.

3. Does the solution provide any challenges for delivery? This covers where any identified solutions require interaction with other Distribution Network Operators, transmission networks, or the NESO, or where barriers to some solutions may necessitate a particular build solution (for example requiring an underground circuit when crossing an Area of Outstanding Natural Beauty).

4. Are wider system benefits created by the proposed solution? This could include replacing older assets, using latent voltage capacity and land availability, improving network operability and transfer capacity between substations or environmental benefits.

The technical competency of each solution is assessed but detailed cost assessment is not within the scope of the NDP. As part of the DNOA process, National Grid undertake cost assessment for the agreed build solution against any alternatives using the Cost Benefit Analysis methodology and make investment decisions aligned to delivery timescales.

Network Operability

There is a continuous schedule of outages taken on the distribution network. Network assets must be maintained at regular intervals, fault-damage must be repaired, and reinforcement must be conducted. To safely access a section of the network, connected circuits must be isolated at suitable boundaries, which may involve a wider part of the network being disconnected. These outages are carefully scheduled to combine coincident work whilst working within the limitations of staff resourcing.

Outages are usually taken at a time of year where demand security and network capability are not adversely affected, which is typically during lower demand conditions in the spring, summer, and autumn months. However, as network loads continue to become more onerous, the outage window in many instances needs to be reduced.

Restricting outage seasons is proposed as a potential mitigation strategy for many of the constraints triggered by an arranged outage or an arranged outage followed by a fault outage. Restricting outages across the network could lead to resources and network access being insufficient to complete the necessary work in the shorter time scales. Strategic planning must consider this aspect when making decisions about potential solution options. This is important to assess not just on a case-by-case basis but looking at the licence area to get a full view of the impact of restricting outage seasons on NGED's ability to effectively operate and maintain the network.

Network Design

Within National Grid, network design is defined as the activities associated with design of the electricity network in response to a System Planning trigger. The scope includes:

- Cost estimates.
- Physical location of assets, including obtaining consents where applicable.
- Ability to deliver a network build solution.
- Power system protection requirements.
- Earthing and power quality requirements.

As part of the National Grid strategic investment planning process network design happens at various stages. High-level network design is needed so that the build solution can be appropriately compared to any non-build solutions as part of the Distribution Network Options Assessment. The Network Development Plan is the trigger for this activity. In addition, further network design is required once the approval to build has been provided in the DNOA. This involves consulting with delivery teams and ordering new assets with long lead times.

Outlined below are some general principles that are used in network design. These are presumed in the Network Development Plan when assessing credible solutions; however, they may be inappropriate to some outlier networks.

Nominal Voltages

Across National Grid Electricity Distribution, most primary distribution networks use the voltages outlined below. These are used as it offers the most efficient distribution system for the load density of most of the areas supplied.

Table 8. Standard voltages used across NGED primary distribution network

Network type	Substation's high voltage side	Substation type
Transmission network	400 kV	Grid Supply Point (GSP) / Super Grid Point (SGP)
	275 kV	
Distribution network	132 kV	Bulk Supply Point (BSP)
	33 kV	Primary substation
	11 kV	Distribution / secondary substation

There are some areas with nominal voltages outside of the above, each of which is discussed below.

Direct 132/11 kV transformation

In areas with a high load density direct 132 kV to 11 kV transformation is used. This is most common across the West Midlands licence area; however, all licence areas include substations with 132/11 kV transformation. It can be a convenient solution to de-load Grid Transformers at an existing Bulk Supply Point (BSP) with a local primary substation, as minimal assets are required to remove the primary substation from the Bulk Supply

Point demand group. Disadvantages of 132/11 kV transformation are that it requires a substation with a larger footprint than an equivalent 33/11 kV primary substation, also when using transformers with two LV windings voltage control and fault level management is more challenging.

In the NDP both establishing 132/11 kV transformers and expansion of neighbouring 33 kV networks to alleviate constraints on 132/11 kV substations are considered as solution options.

66 kV networks

These are used in lieu of 33 kV and 132 kV networks, and often in very rural areas and industrial (or formerly industrial areas). Both the South Wales and West Midlands licence areas use 66 kV networks. There are limited technical advantages over 132 kV networks, as due to the smaller voltage limits on 66 kV network voltage performance is more constrained. However, it can be easier to deliver 66 kV networks due to less stringent consenting and wayleaves requirements compared to 132 kV circuits. Compared to 33 kV networks, 66 kV networks provide improved thermal and voltage performance, especially on long circuits, however cabling and indoor switchgear is more difficult to install.

Across primary distribution networks expansion of existing 66 kV networks is considered as an option in the NDP, but establishing new 66 kV networks in an area is not considered.

6.6 kV networks

In a small number of cities and across some industrial customer networks National Grid operate 6.6 kV as an alternative to 11 kV. Some cities include Bath, Coventry, Leicester, and areas of Chesterfield. These networks do not offer many technical benefits over 11 kV and offer some technical disadvantages, such as using non-standard equipment and limiting the size of assets that can be used.

Irrespective of the voltage at which they are connected to the distribution system, many electricity consumers consume their electrical energy at low voltage. This being the case, the current demand in a high voltage network with nominal voltage of 6.6 kV is estimated to two thirds higher than (i.e., 166.67% of) that in the same network following a conversion to 11 kV.

As thermal capacity is primarily influenced by current, permanently reducing the current magnitude by such a significant degree would unlock substantial thermal capacity across affected high voltage networks. For example, a typical 630 A rated vacuum circuit breaker could cater for an apparent power of 7.2 MVA at 6.6 kV or 12 MVA at 11 kV.

Furthermore, due to statutory voltage limits being based upon a percentage of declared or nominal network voltage (e.g., ± 6% of the declared voltage, at 33 kV) increasing the nominal voltage allows for a greater scale of voltage change throughout the network. Paired with the lower current magnitudes, and assuming power factor remains relatively consistent, the resultant is a greater voltage capacity, throughout converted networks.

Network conversion does, however, come with a notable drawback: It is likely that some of NGED’s legacy assets, along with an unknown volume of customer-owned assets, are not adequately rated for such a network conversion, which could result in expenditure of a presently unknown value, to uprate a minority of plant and switchgear.

To prepare for the eventual conversion of 6.6 kV networks to 11 kV, NGED have, for a number of decades, installed assets that are fit for purpose, when operating at either voltage:

- Dual ratio transformers, with a primary voltage of 11,000/6,600 V, are used in 6.6 kV networks, to allow for conversion to 11 kV without need for the costly replacement of existing assets.

- Similarly, switchgear, such as switches, circuit breakers and ring main units, is specified to have a normal rated voltage of 12 kV; and

- High voltage cables and overhead conductor, used by NGED in 6.6 kV networks, are rated for operation at 11 kV (Um = 12 kV), to ensure that they can carry the higher voltage, following conversion. (Um = Maximum value of the highest system line-to-line voltage)

Throughout the NDP and associated system planning triggers, the suitability of uprating 6.6 kV networks to 11 kV is assessed. Whilst the main driver for this decision will be to alleviate constraints on 6.6 kV circuits, this NDP assesses where primary transformer capacity could also trigger works. As a result, such decisions should be made for the whole geographic area as part of a programme of works, as this may cause disruption to the area and an increased risk of interruptions whilst work is taking place.

Transformer Ratings

For each voltage level the largest standard transformer sizes used by NGED on the network are given in the table below. There are a number of reasons why larger units are not used. Firstly, installing non-standard equipment presents a challenge for finding replacements if serious faults occur. Secondly, without extensive interconnection at the lower voltage level it would have a significant adverse effect on security of supply to use higher rated equipment rather than install new equipment and/or establish new substations. Thirdly, there are a number of technical difficulties with installing and operating switchgear rated above 2000 A. Finally, to unlock the capacity of higher rated transformers all the ancillary equipment, circuits at the higher and lower voltage levels and the switchgear would need to be uprated to match (driving up overall costs drastically).

Table 9. Standard voltages used across NGED primary distribution networks

Voltage transformation	Highest transformer ratings used (nameplate rating)
132/66 kV	60/90 MVA (117 MVA winter cyclic)
132/33 kV	
132/11 kV	15/30 MVA (39 MVA winter cyclic)
132/11/11 kV (double LV winding)	132 kV winding: 30/60 MVA (78 MVA winter cyclic), 11 kV windings each: 15/30 MVA (39 MVA winter cyclic)
33/11 kV	20/40 MVA (38 MVA winter cyclic)
33/6.6 kV	12/24 MVA (23 MVA winter cyclic)

Various constraints identified as part of the NDP involve overloads on assets which are already the highest standard rating (and therefore should not be uprated any further due to the technical and economic factors described above). These constraints can therefore only be mitigated through other strategies (including flexibility, operational mitigation and installing new assets).

Seasonal transformer ratings

Currently policy within National Grid records a rating for transformers in two seasons, summer, and winter. For modelling the representative days for intermediate cool and intermediate warm (for which underground cables and overhead lines have seasonal ratings), the summer rating is used for transformers, based on the assumption that it cannot be guaranteed that the ambient temperature associated with a winter cyclic rating would be available. This analysis methodology does identify some constraints in the intermediate warm and intermediate cool seasons only, which if a full suite of seasonal transformer ratings were available may be alleviated. These are used to improve network capability and network analysis techniques and present an opportunity to improve decision making for load related investment.

Network Topology

Three-circuit groups

Some areas of network are operated with three (or more) circuits in parallel, feeding a group demand of less than 300 MW. Below that threshold, P2/8 has no requirement for demand to be supplied immediately following a second circuit outage. This does not, however, mean that the possibility of a second circuit outage can be ignored.

Consider the network shown in Figure 4. Each of the circuits A, B and C has a rating of 90 MVA. The three circuits share load evenly. The seasonal peak demand at the 33 kV bar of the Bulk Supply Point is:

- Summer peak demand: 85 MW
- Spring/autumn peak demand: 105 MW.
- Winter peak demand: 125 MW

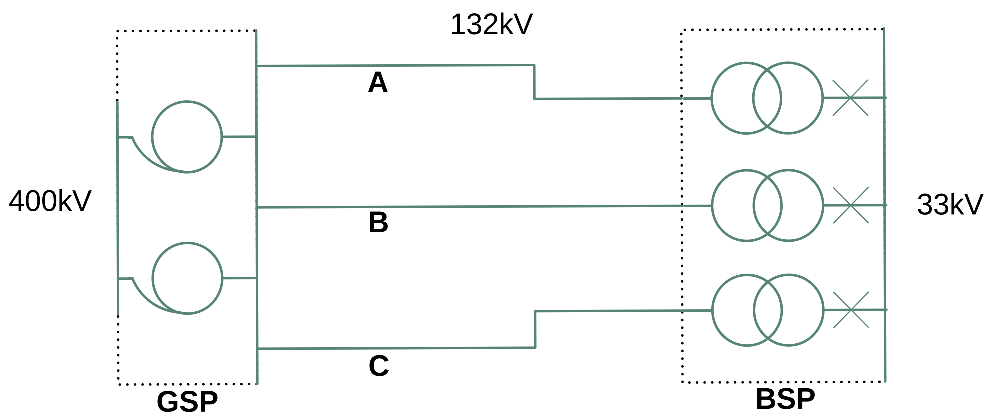

Figure 4. Three-circuit group example network

The group demand is the maximum of the seasonal peak demands, 125 MW, which is Class D of P2/8 with a requirement that:

1. For a circuit fault from an intact network (first circuit outage fault):
    a. Group demand minus up to 20 MW (automatically disconnected), i.e., 105 MW, is met immediately; and

   b. Group demand is met within three hours.

2. For a circuit fault during an arranged outage (second circuit outage):

   a. Group demand minus 100 MW, i.e., 25 MW, is met within three hours; and
   b. Group demand is met within the time taken to restore the arranged outage.

The first circuit outage of one of the three circuits leaves the prevailing demand of the group fed by the remaining two circuits, total rating 180 MVA. Since the group demand of 125 MW is well within the capability of the circuits, this meets the demand security requirements without compromising network integrity. The second circuit outage of any two of the three circuits leaves the prevailing demand of the group fed by the remaining circuit, rating 90 MVA. While the remaining circuit is sufficient to supply the demand required by P2/8 (25 MW), the actual impact on the network depends on the prevailing demand:

- In summer, the demand of 85 MW is within the capability of the remaining circuit.
- In spring or autumn, the demand of 105 MW overloads the remaining circuit.
- In winter, the demand of 125 MW overloads the remaining circuit.

This overload is unacceptable, so steps should be taken to prevent it. Options include:

1. Only taking the arranged outages of the three circuits in summer.
2. Reinforcing all three circuits so that any one circuit can support the group demand of 125 MW.
3. Splitting the 33 kV bar and downstream network into two sections for the duration of the arranged outage, with each section connected to one of the circuits and a 62.5 MW demand group. If a fault occurs during an arranged outage, half of the demand would be disconnected, but the remaining circuit would not be overloaded.
4. Installing inter-tripping or overload schemes to detect and trip any circuit that is overloaded.
5. Contracting with any dispatchable generators within the 33 kV network to operate during arranged outages to reduce the net demand of the group.

Several areas of the National Grid network exhibit similar network access constraints to this case study. Many of these areas were found to have an access window which is limited to summer. This may be acceptable for some areas, but if large parts of the network have narrow, coincident access windows, which may conflict with scheduling requirements for specialist staff and equipment.

Single-transformer primary substations

Across primary distribution networks there are a number of primary substations with a single transformer (many of which also have only a single incoming circuit). These are often in rural areas and have a group demand in Class B of Engineering Recommendation P2/8 (1-12 MW). Whilst secondary networks (6.6 kV or 11 kV circuits downstream of the 6.6 or 11 kV primary switchboard) are out of scope of the Network Development Plan, it is important that they are considered for single transformer primary substations due to their impact on the 33 kV network (both in terms of constraints and the potential solutions to mitigate them).

Many of the networks supplied by single transformer primary sites are constrained by the 11 kV (or 6.6 kV) transfer capacity to neighbouring substations (required to maintain security of supply for the loss of the transformer or infeed). As outlined in Engineering Report 130, the transfer capacity is not only calculated on the circuit capacity of the interconnection between demand groups, but also dependent on the capacity of the adjacent demand group to accept demand transfers.

Through establishing a DSO Secondary System Planning Team, the detailed assessment of 6.6 kV and 11 kV networks to fully understand the transfer capacity of single transformer primary substations ensures more detailed system assessment, and identification if additional 11 kV reinforcement is a viable alternative solution to establishing a second primary transformer and incoming circuit.

Single transformer primaries present a particular challenge due to the fragile nature of being served by a single circuit. This results in connected load becoming reliant upon robust alternative feeding options being available from neighbouring substations, at high voltage, during certain abnormal running conditions.

High voltage network analysis is undertaken for a specific set of outage conditions, to confirm continued compliance with Engineering Recommendation P2/8 and to ensure the available transfer capacity is well understood. These outage conditions comprise:

- An unplanned outage of the incoming EHV circuit or primary transformer, during high load conditions.
- A planned outage of the HV busbar(s), during lower load conditions (i.e., during a time of year in which such an outage would be planned, outside of the high load period); and
- Unplanned outages on all outgoing HV circuits, during high load conditions.

For the first two of the above conditions, the network is assessed considering applicable load points from the preceding 24 months. The remaining available capacity is then established by means of applying a fictitious load(s) at the primary busbar(s) (or to the HV circuits, where they are disconnected from the busbar(s)), before aggregating the existing load and the fictitious load(s) that can be supported during these outages. This aggregated load value is recorded as the site's firm capacity.

Networks running in parallel.

Across the primary distribution networks there are numerous networks normally operated in parallel. This is due to the evolution of the distribution networks over time in each licence area, with different owners and therefore design principles and operational practices. Such practices look to balance the cost of establishing and maintaining a large number of assets, with the complexity of analysing and operating these networks, with the resilience provided to customers.

Automated contingency analysis offers the opportunity to identify constraints across primary networks that could otherwise be difficult to identify through manual inspection. This can identify credible through-flow risks, where a combination of outages could result in a lower voltage network (operated in parallel) being used to supply upstream voltages which are weakly interconnected at the higher voltage.

Within the Network Development Plan consideration is given to rationalising networks currently operating in parallel, where it can provide a benefit in terms of network complexity, operability, and utilisation of existing assets.

Cross-boundary engagement

Part of both system planning and network design can include interactions across boundaries between DNO licence areas and the transmission and distribution interface. At this point, whole system options analysis is required to ascertain whether the solution aligns to the criteria used to assess the technical viability of a solution when considered for the whole energy system.

An example would be for a constraint on the distribution or transmission network at an existing Grid Supply Point, where one possible solution is to establish a new Grid Supply Point. The whole system options analysis should consider both the cost and deliverability of transmission infrastructure to establish a site in different locations, along with a subsequent cost and delivery assessment by distribution networks to understand if new circuits are required to distribute electricity from the new Grid Supply Point location to the load centres across the distribution network.

NGED's approach is the proactively engage with the NESO, National Grid Electricity Transmission and other DNOs where constraints have cross-boundary impact and solutions. This is often in the form of bilateral discussions but can also be connection applications where firm costs are required.

Establishing new GSPs becomes necessary as demand and generation grows across the network to de-load existing GSPs. As an alternative to expanding existing GSPs, these could provide a number of benefits:

- Existing GSPs may be unable to expand due to space constraints, or difficulties in building new circuits out of the site.

- Adding more than four or five SGTs to a single GSP is often an inefficient way to add capacity. This is because a limited number of SGTs can usually be run in parallel due to fault levels, and setting up more SGTs independent from each other (i.e., multiple SGTs would not be lost for a single outage or fault) becomes prohibitively expensive and complex with the amount of switchgear required at 400 kV (or 275 kV) and 132 kV (or 66 kV).

- Continuing to develop large existing GSPs could lead to certain sites becoming too critical, presenting a concern for network security (compared to a greater number of smaller GSPs which would increase network resilience).

- Replacing 240 MVA SGTs with 460 MVA SGTs would add significant thermal capacity but increases fault levels significantly.

Two of the most important considerations in identifying the optimal location for new GSPs are how they can be integrated into the existing network and how far they are from the centre (or centres) of load growth. Establishing new GSPs in the right location can resolve constraints on the distribution network (usually 132 kV circuit constraints) and significantly reduce the cost of developing the network in the future if the new GSP is closer to load centres that would be difficult to supply from existing GSPs.

Determining the optimal location for a new GSP requires extensive optioneering at both distribution and transmission (including a siting strategy and full cost benefit analysis considering all the whole system impacts).

Network Development Report Methodology

This section outlines the analysis methodology used in the Network Development Reports, which contains the results of comprehensive power systems analysis that has been conducted on areas of the network where developments are required. This analysis was performed using the four DFES scenarios and each section of network is assessed across the next 10 years.

Since 2016 National Grid has developed a tool for automated analysis of primary distribution networks, aligning to the comprehensive electrical analysis as outlined in the System Assessment and Constraint Identification section of this report. The Switch-Level Analyser tool is a bespoke power system analysis program written in Python 2.7. It uses PSS/E version 34 as its core analysis engine to perform the actual load-flow calculations and uses some of PSS/E's built-in contingency analysis tools for efficiency.

All input data for studies are stored on a centralised server-side database. The following inputs are combined for each half hour, representative day, year, and scenario studied:

- Network model, including network changes made relative to the year studied.
- Load set mapped to the boundary nodes of the network model (aligned to the definition of an Electricity Supply Area used in the DFES studies). This also includes half-hourly profiles for each type of demand, generation and storage and representative day.
- Appropriate ratings of network components; and
- Existing network automation and manual switching schemes.

These results are processed within the program and exported to a results database, which are summarised in tabular and graphical formats for further evaluation by skilled power systems engineers. Whilst this approach can be seen as computationally expensive, a distributed computing approach is used to improve runtime efficiency.

Constraint Identification

Outage Modelling

To assess the current and future constraints that require intervention during the 0–10-year horizon, all outage combinations are studied using the Switch-Level Analyser tool. Each study is broken into a specific year, scenario, half hour, and representative day for a focused area of network. Where areas of the distribution network run interconnected, the network is studied to account for changes in other parts of the parallel group and fully capture the constraints for the distribution network.

For each half hour, day, year, and scenario studied, the program returns the following for all outage combinations modelled:

- MVA flow on all branches of interest.
- Voltage limit exceedances for all nodes of interest.
- Lost load (i.e., demand disconnected) for all groups.
- Group load (i.e., the demand and generation of each GSP, BSP and primary substation group) for all networks; and
- Any studies where the program was unable to calculate valid results (non-convergences).

Modelling Network Automation and Manual Switching Schemes

The demand and generation capacity of a network is not normally limited by its characteristics under normal running conditions, but by its characteristics under abnormal running conditions. Abnormal running arrangements occur due to faults, maintenance, network construction, and other reasons. The Switch-Level Analyser tool uses the PSS/E Advanced Contingency and Operational Behaviour Scheme (OBS) add-on module. This module takes user-defined conditions and performs an action dependent on the outcome of the condition. National Grid has used this module to model the behaviour of network automation and manual switching schemes as outlined in the Network Behaviour: Automation and Manual Switching Schemes section of this report. Operational Behaviour Schemes were incorporated into analysis to identify constraints on the network and modelled as possible solutions to constraints. The scope of automation and manual switching schemes are outlined below:

- Network reconfiguration - Under outage conditions, the topology of the EHV distribution network can be altered, either by Control Engineers or by network automation. This can be to ensure network compliance is maintained, to reduce the risk of overloading assets for a credible next fault or to limit the Customer Interruptions (CIs) and Customer Minutes Lost (CMLs) for a credible next fault. As each outage combination is simulated on the network model, the Switch-Level Analyser checks the status of isolators and circuit breakers across the monitored contingency area. If the user-defined condition statement returns true, a subsequent switching action is taken as would be by the Control Engineer or network automation scheme.

- Load management schemes - Defined as plant, equipment and software systems that together manage network loading and voltages by either controlling demand and/or generation connected to the network, operating switchgear to change the topology of the network and/or controlling the settings of tap-change controllers, reactive compensation equipment and flexible power links. An example of a load management scheme is an overload protection scheme to open circuit breakers when a current limit is exceeded on a monitored branch.

The following schemes are considered outside of the scope of the existing analysis tooling:

- Active Network Management – A type of Load Management Scheme. The existing analysis tools do not replicate the ANM logic, which requires iterative load flows to control generation or demand according to the Last in First Out (LIFO) stack of connected customers. The behaviour for customers with existing ANM contracts is modelled to validate the behaviour of existing systems.

- DSO procured flexibility services – these can be used to reduce network loading for a given condition through network users in their own consumption by increasing, reducing, or shifting their net import or export during peak loading periods. The existing analysis tools do not replicate the existing flexibility customers to identify constraints, to ensure that no constraints are masked.

Constraint Alleviation

Upon the identification of a constraint, solutions can be modelled and assessed for suitability to alleviate the network constraints. Each of the following remedial solutions are considered and modelled for their impact on the network studied and adjacent/interconnected networks aligned to the criteria as outlined in the Primary System Planning Solutions section of this document.

A key aspect of the comprehensive network analysis is the ability to model the solution options to ensure that any solution is fit for purpose in future years in the 0–10-year horizon as covered by the NDP. For network build solutions, these are also checked against expected growths to reduce asset stranding risks out to 2050.

Report Structure

A Network Development Report is produced in the form of several Constraint Briefs for each area of network where there is a projected network constraint (broadly covering a Bulk Supply Point(s) and associated downstream network, or a Grid Supply Point(s) and associated downstream network. The table below outlines the structure of the reports.

Table 10. Summary of the sections within each of the Network Development Reports

Section	Purpose
Network Overview	A summary of the network within scope of the report. This includes an overview of the area supplied by the network and the topology of the primary distribution network.
Summary of Network Constraints	List of the constraints identified in the 0–10-year horizon covered by the Network Development Report.
Network Constraint Details and Solution Options	A section for each constraint identified, which contains the following information: • Table of conditions that causes the constraint, including the year of occurrence, outage condition and constrained asset. • Detailed solution options, encompassing those as outlined in the Primary System Planning Solutions section of this report. This includes an outline of the solution, capacity added by solution and what becomes the limiting factor for the constraint considered once the solution is implemented. • A solution recommendation, based on a technical analysis of how well it solves the constraint, provides wider benefits (such as improving network operability or facilitating future upgrades) and the potential to be cost effective.

Network Headroom Report Methodology

This section outlines the methodology used to obtain the network headroom figures contained in the Network Headroom Report. On the National Grid DSO website, a workbook for each licence area contains the network headroom for both additional demand and generation connections across the four DFES scenarios, included for all years out to 2050. Holistic Transition was chosen as the best view scenario. The data in the network headroom report is refreshed on an annual basis.

Consideration of headroom calculation approaches

NGED owns a large, complex and interconnected network across multiple voltage levels. Customers seeking to connect to the distribution network will go through a formal connection offer process, including full power system analysis alongside many other factors to assess the impact of the prospective connection on the network.

Similar comprehensive load flow analysis for every substation would provide the most accurate headroom result. However, this would be overly time-consuming and resource intensive to produce for every substation, year and DFES scenario as required for the NDP and strays from the intent of the headroom report to provide a view of the medium-term development of the network against the DFES scenarios rather than a view of the contractually available capacity.

Firm capacity style assessments are simple to complete in bulk and produce accurate results when considering the assets directly connected to a substation such as the primary transformers. However, this may not capture the available headroom at an upstream voltage of the distribution network, which may be the limiting factor to connect new demand and generation, particularly when the network is complex and non-radial. Furthermore, where areas of the distribution network run interconnected, each distinct area cannot be studied in isolation as the network loading is susceptible to changes in other parts of the parallel group.

Sensitivity analysis based headroom calculation

Since 2024, NGED have developed a methodology for calculating headroom intended to bridge the gap between full power system analysis and a firm capacity style analysis.

NGED have extended the Switch-Level Analyser (SLA) tool to optionally perform sensitivity analysis during contingency analysis. With sensitivity analysis enabled, for the intact network position and each contingency case, a 1 MW load is added sequentially at each boundary node in the network model, and the following information is recorded:

- **Branch loadings**: MW and MVar on each monitored branch, where the values have changed by a more than a deadband threshold set by the user for contingency cases.
- **Branch ratings**: season and outage specific MVA rating for each monitored branch.
- **Sensitivity factors**: values recorded against node-branch pairings, quantifying the impact of a MW change in demand at the node on the MW flow on the branch. Only sensitivity factors above a minimum threshold and deadband threshold for contingency cases are recorded.

Assuming linearity between adding load at a node and the subsequent branch flow, this information can be used to calculate headroom at a particular node, defined as the MW that would need to be added at the node until there is a thermal overload on a branch anywhere in the network where the sensitivity factor is above a user-defined threshold. The calculation is impacted by the direction of current flow along the branch, the direction of the sensitivity factor and whether demand or generation is added at the boundary node.

The sensitivity factors and branch loadings can also be used to calculate a new set of branch loadings under a different load set, as a linear proxy to a full AC load flow.

This approach was used to calculate headroom at each primary substation and BSP for every year and DFES scenario. Sensitivity analysis was run using the SLA for each GSP in NGED's licence areas to FCO level (akin to the concept of firm capacity) for two years on the Holistic Transition pathway (Baseline and 2030) for one peak half hour in both a demand and generation representative day. These studies included the comprehensive library of network automation and manual switching schemes that were used in network studies.

The AC load flow results from the SLA studies were used with the recorded sensitivity factors to calculate the demand and generation headroom for both study years for the Holistic Transition scenario. For every other year and scenario, a proxy load flow was first computed using the sensitivity factors and MW change at each node compared to the study year according to the DFES forecasts. The demand and generation headroom for the given year and scenario was calculated.

Two study years were chosen to capture high-certainty, medium-term reinforcement schemes being progressed by NGED in the network model and operational behaviour schemes. This may be observed in the Network Headroom Report as a step change increase in headroom in the year 2030.

Consideration of accuracy

Whilst the mathematical equations used to undertake steady state load flow calculations are inherently non-linear and iterative, this approach assumes a linearity between adding load at a node and the subsequent branch flow. For example, if 1 MW of demand is added at a node increases branch flow by 0.3 MW, adding 5 MW at the same node will increase branch flow by 1.5 MW. Extensive testing of the solution algorithm has indicated that this approach is suitable to indicate materiality headroom at a node within the scope of the Network Headroom Report. When addition of load in the model causes model instability (significantly increased reactive power flows leading to voltage collapse and potentially load flow non-convergence), at this point the headroom available at a node is less than zero so the indicative headroom will indicate that interventions would be required on this network.

Fault level assessment

Consideration of fault level is included as it can be a major constraint on generation connections. For the Network Headroom Report, an assessment of the expected fault level contribution from forecasted connections within each substation has been made. The existing maximum prospective fault levels under normal system running conditions and the make and break switchgear ratings at bussing points can be taken from the LTDS Table 4.

The total contribution from the demand and generation expected to connect at each primary substation for each year, scenario and generator type is calculated using an expected fault infeed contribution consistent with the figures published in the National Grid Policy Document: SD7F/2. This can be assessed against the existing maximum fault level and compared to the switchgear make and break ratings.

This approach has known limitations which can result in the fault level assessment overestimating the fault contribution from individual substations (due to uncertainties around the voltage and topology of future connections). NGED will continue to routinely assess fault level changes from new connections and topology changes and regularly review the duty against switchgear ratings. This includes more comprehensive analysis to inform investment plans for the ED3 price control period and as part of the Connections Reform process.

Report Structure

The structure of the Network Headroom Report is unchanged from the 2024 publication. It provides a headroom for the following:

- Substation (both Primary and Bulk Supply Point),
- Scenario
- Year
- Definition of headroom (demand or generation)

Limitations and future development

There are several substations that are fed from or interconnected with other DNO's networks. Due to limited data being available at these boundaries, LTDS data from the other DNOs is used to estimate the available headroom at the substation, as such this may not capture any upstream constraints which are limiting the available headroom. This is a current limitation in the process.

The following limitations and opportunities for future development of the Network Headroom Report methodology have been identified:

- The available headroom given in the headroom report should not be used as definitive source of headroom for a prospective connection customer. The headroom calculated is based on the DFES forecasts rather than the contracted connections queue. Headroom is calculated on a per substation basis and does not consider the impact of concurrent connections at multiple substations. Therefore, the sum of the headroom reported in the Network Headroom Report for a group of primary substations would not equal the actual headroom for connections at these primaries. Prospective connection customers should submit a formal connection application to be assessed against the current contracted queue. The headroom report is designed to provide transparency on where capacity may be limited and where reinforcement may be required to facilitate connection to the distribution network.

- Generation headroom has been calculated against generation growth at or below 11 kV only, due to the uncertainty during the period of NDP analysis around the EHV connections pipeline assumptions in the DFES forecasts following Connections Reform.

- As NGED supplies a wide range of network topologies, ranging from simple radial networks to complex interconnected groups, it is not a straightforward exercise to choose a sensitivity factor threshold across an entire licence area. Setting this value too low could mean remote constraints are picked up which wouldn't reasonably be considered in a connection application, distorting the headroom figures. Setting this value too high could mean genuine upstream constraints are missed, removing the value of this method over a firm capacity style assessment. For the NDP 2026, the sensitivity threshold was chosen empirically and set on a licence area basis. Further work could be carried out to determine a more localised sensitivity factor threshold.

- The figures reported only account for headroom on the primary network. In some cases, a secondary network asset may be the limiting factor, for example the back-feed capacity of a single transformer primary. Further work could be carried out in collaboration with the Secondary System Planning team to include secondary network constraints into the Network Headroom Report.

- A sensitivity factor deadband threshold is set to avoid storing results where the sensitivity factor between a node and a branch does not materially change between the intact case and a contingency case. This significantly reduces the data intensity and run-time of this process. However, in certain cases an operational behaviour scheme is modelled which does not change the sensitivity factor of a given node to a given branch above the deadband but does change the branch loading significantly, for example due to a demand transfer. These results are not recorded due to the deadband threshold and in cases where this changes the limiting asset, the reported available headroom will be higher than expected. Future work could be carried out to determine a better or more localised sensitivity factor deadband threshold.

- Due to full load flow analysis only being carried out on two study years for one scenario, the network topology and operational behaviour, captured by the sensitivity factors, are assumed to be the same for all other years and scenarios. This means that all high-certainty medium-term reinforcement schemes have been included in the year 2030. This doesn't reflect year-on-year reinforcement completion which could show capacity being released in the Network Headroom Report later than expected. Further work to implement the planned changes as part of the Long-Term Development Statement reform will enable the production of year-based models, which could mean that full load flow analysis of every year to calculate headroom becomes economic.

- The impacts of contracted flexibility and active network management schemes are not included in the Network Headroom Report. In addition, comprehensive power systems analysis requires network interventions to be modelled to enable model convergence in future years – these are modelled for the areas considered in the Network Development Reports.

Future Developments

The approach to investment planning ensures that National Grid has a transparent framework for identifying and selecting the optimal investment plan. The distribution network continues to become more complex and active due to the decentralisation of the generation mix across the UK and more opportunities for customers to alter energy consumption and participate in flexibility markets. As a result, the analysis tools and techniques required for network impact assessment also require development. This is to ensure that the network impact assessment captures the most onerous network loading conditions, essential to the coordinated, economic, and efficient design of the network.

National Grid's strategic vision is to continue to develop our capability to undertake forecasting and network impact assessment. For forecasting activities, this includes incorporating improved techniques to better understand the composition and coincidence of demand and generation customers to more accurately study the credible onerous network loading conditions. For network impact assessment activities, this includes further development in automating analysis tools and techniques to more comprehensively study our networks.

Current limitations

1. To enable accurate analysis of the distribution network, a representative Transmission model is necessary. This Transmission representation is an equivalent of the full Transmission network and, when incorporated into the National Grid power system model, approximates the network behaviour. This data is provided as part of the Week 42 data exchange. The size of the equivalent model varies for each licence area, depending on the level of GSP parallel running and interconnection. Currently Transmission models are not provided for future years, scenarios, and seasons, which could increase the accuracy of future headroom modelling.

2. Only load-flows assessing steady-state voltage and power flows have been undertaken. No power quality, protection or stability studies have been conducted.

3. The Network Headroom Report does not outline the headroom on transmission network assets. Whilst the impact of outages on the transmission networks are modelled, the available headroom at the transmission/distribution boundary is best provided by the National Energy System Operator, or through information sources such as Clearview Connect.

4. Fault level assessment assumes that new demand and generation would connect directly to the 11 kV or 6.6 kV bar of the primary substation. As a result, this is a worst-case assumption as no additional impedance assumptions have been made for the connection of new demand and generation.

5. The reactive behaviour of load, in particular projected load, modelled at the 11 kV bars of primary substations does not take detailed account of the reactive behaviour of individual customers nor the effects of secondary network impedance. Development of load survey and analysis techniques will enable the materiality of these effects to be better understood.

6. At network boundaries, currently LTDS information is the only source of information about capacities of other networks. This may not always be the most accurate and up to date source of information.

The areas for further development in the NDP are listed below:

- An updated model of the transmission network for future years, scenarios and times of year would help to increase the accuracy of power systems analysis results. Additional data exchange requirements between transmission and distribution networks are currently being explored as part of Grid Code modification GC0139 National Grid will continue to look to improve the network model data at the transmission and distribution boundary. will continue to look to improve the network model data at the transmission and distribution boundary.

- Whilst improvements have been made to the technical capabilities of the existing Switch-Level Analyser tool, further developments to cover switchgear stressing, voltage unbalance and voltage fluctuation studies could be introduced. This will align the strategic planning process with the existing connections planning process run by DNOs.

- Continue to increase the scope of the NDP analysis to cover more High Voltage (HV) networks. This requires automated tools as the complexity and size of HV networks is significantly larger than EHV networks. This analysis has already begun, and we will collaborate with stakeholders to present the analysis results in a way most valuable for data users.

- Improve collaboration with other DNOs to more accurately model other networks to give a more reliable indication to customers looking to connect at these network boundaries.

Glossary

Acronym / Initialisation	Term	Definition
AAAC	All Aluminium Alloy Conductor	Conductor type used on the network.
ABI	Air-Break Isolator	Isolator used on the overhead line network. Also known as Air-Break Switch Disconnectors (ABSD's).
ACSR	Aluminium-Conductor Steel Reinforced	Conductor type used on the network.
ANM	Active Network Management	The Energy Networks Association Active Network Management Good Practice Guide summarises ANM as: Using flexible network customers autonomously and in real-time to increase the utilisation of network assets without breaching operational limits, thereby reducing the need for reinforcement, speeding up connections and reducing costs.
BSP	Bulk Supply Point	A substation comprising of one or more Grid Transformers and associated switchgear.
CB	Circuit Breaker	Device capable of making, carrying and breaking currents under normal circuit operation and also making, carrying for a specified time and breaking, fault current. Also includes auto-reclosers. It does not include any circuit breakers that form part of an RMU.
CBA	Cost Benefit Analysis	A process used by NGED to measure the benefits of a business decision compared to the costs associated with taking that action. Used to determine the optimal reinforcement solution, which is then tested against market provided flexibility by the DSO as part of the DNOA process.
CEM	Common Evaluation Methodology	A methodology developed under the Open Networks project to compare options and identify low regret pathways. The CEM tool is used in the DNOA

		process to assess flexibility against conventional reinforcement.
CEP	Clean Energy Package	European legislation for a unified energy strategy for delivering the Paris agreement.
CF	Counterfactual	One of the pathways that forecasts the volumes and regional distribution of low carbon technology uptake NGED's licence areas. This uses stakeholder-informed bottom-up analysis to align with national industry developed future energy scenarios. The only scenario in which net zero is missed, though some progress on decarbonisation is achieved. Significant use of gas remains across a range of sectors, particularly in power and space heating. Electric vehicle uptake is slower than other scenarios and overall lower levels of renewable energy is deployed under this scenario.
CIs	Customer Interruptions	The proportion of total customers whose supplies have been interrupted in a year. 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.
CMLs	Customer Minutes Lost	A measure of the duration of interruptions to supply per year.
CT	Current Transformer	A type of transformer that is used to measure an alternating current.
–	Cable	A conductor used to distribute electrical power, typically buried directly in the ground, installed in ducts or troughs or strung up in the air between poles or pylons. This excludes under eaves or mural wiring.
–	Consac	A type of cable with paper insulation and aluminium sheathing, used for distribution of electricity at low voltage.

–	Constraint	Any limit on the ability of the licensee's Distribution System, or any part of it, to transmit the power supplied onto the licensee's Distribution System to the location where the demand for that power is situated.
-	Constraint Brief	A Constraint Brief is an overarching collective that combines multiple related Constraints. A Constraint Brief can have multiple Constraints linked below it.
–	Curtailment	Any action taken by NGED to restrict the flow of electricity at the Connection Point.
–	Curtailable Connection	A connection whereby the Required Capacity can be reduced by the licensee.
DANM	Distribution Active Network Management	The process of a Distribution operator using flexible network customers autonomously and in real-time to increase the utilisation of network assets without breaching operational limits.
DG	Distributed Generation	Generation connected to a distribution network. Sometimes referred to as Embedded Generation.
DOC	Directional Overcurrent	A type of protection used on the network that operates when subject to power flow above a certain magnitude and in a specified direction.
DNO	Distribution Network Operator	A company, licenced by Ofgem, which distributes electricity in the United Kingdom who has a defined Distribution Services Area.
DNOA	Distribution Network Options Assessment	A document published twice a year by NGED that provides transparency in the investment decision making process.
DSO	Distribution System Operator	A department within NGED that creates an efficient and more flexible electricity network to meet future energy demands as well as co-ordinating transmission and distribution services at a local level with other network and system operators.

DSR	Demand Side Response	Ofgem led tariffs and schemes, which incentivise customers to change their electricity usage habits.
DT	Definite Time	Operating time characteristic of a protection relay.
–	Demand	The consumption of electrical energy.
–	Disconnector	A type of switching device with visible contacts, used to ensure that an electrical circuit is completely de-energised for service or maintenance.
–	Distribution Asset	Any of the electric lines, cables, plant and equipment included within the licensee's distribution system.
EA	Environment Agency	An Executive Non-Departmental Public Body responsible to the Secretary of State for Environment, Food and Rural Affairs and an Assembly Sponsored Public Body responsible to the National Assembly in Wales concerned mainly with rivers, flooding, and pollution.
ECCR	Electricity (Connection Charges) Regulations	The Electricity (Connection Charges) Regulations 2002 (SI 2002/93).
EE	Electric Engagement	One of the pathways that forecasts the volumes and regional distribution of low carbon technology uptake NGED's licence areas. This uses stakeholder-informed bottom-up analysis to align with national industry developed future energy scenarios. Net zero is met through significant levels of electrification of energy demand. Highly engaged consumers adopt heat pumps, a range of smart technologies and electric vehicles. Significant levels of renewable energy generation and electricity storage are seen under this scenario.
EHV	Extra High Voltage	Voltages over 22 kV and up to but not including 132 kV.

ENW	Electricity North West	Electricity North West is a DNO that is licenced by Ofgem to distribute electricity in the North West of England.
EPR	Ethylene Propylene Rubber	Cable type used on the network.
EREC	Engineering Recommendation	A document published by the Energy Networks Association.
ER G98	Engineering Recommendation G98	G98 is the "Requirements for the connection of Fully Type Tested Micro-generators (up to and including 16 A per phase) in parallel with Low Voltage Distribution Networks" document.
ER G99	Engineering Recommendation G99	G99 is the "Requirements for the connection of generation equipment in parallel with public distribution networks" document.
ER P2	Engineering Recommendation P2	'Engineering Recommendation P2 – Security of Supply' (ER P2) is a distribution network planning standard. It sets the minimum levels of security of supply that Distribution licensees must achieve on GB distribution networks.
ER P18	Engineering Recommendation P18	ER P18 sets out guidance relating to the complexity of 132 kV networks and was published in 1978.
ESA	Electricity Supply Area	Each ESA represents a block of demand and generation as visible from the distribution network, being one of: - The geographic area supplied by a primary substation. - A customer directly supplied at 132 kV, 66 kV, 33 kV or 25 kV.
FCO	First Circuit Outage	EREC P2/8 defines a First Circuit Outage as: …a fault or an arranged Circuit outage…
FES	Future Energy Scenarios	A set of scenarios developed by National Grid to represent credible future paths for the energy development of the United Kingdom.
Fuses (PM)	Pole Mounted Fuses	Low voltage fuses which are pole mounted.

Fuses (GM) (TM)	Ground/Transformer Mounted Fuses	Low voltage fuses which are ground mounted or transformer mounted, including fuse ways in LV pillars.
–	Flexibility	Reducing loads on the network by using customers' ability to change their usage patterns by either switching on generators or reducing consumption.
–	Flexible Connections	Connection arrangements whereby a customer's export or import of electricity is managed (often through real-time control) based upon contracted and agreed principles of available capacity. Flexible Connections typically allow quicker and cheaper connection to the Distribution System but are made on the basis that there is no limit on the extent to which a user's access can be interrupted.
–	Flexibility Payments to service providers	Flexible service contracts to manage network capacity constraints. Expenditure should include payments made for the availability of flexibility services and payments made for service utilisation. The volumes relate to total MVA of flexible services contracted during the reporting year.
–	Forecast	A prediction of future events that, in the balance of probabilities, NGED believes will occur.
–	Fuse	A fuse is a safety device in an electric circuit. It contains a piece of wire which melts when there is a fault, so that the flow of electricity stops.
GB	Great Britain	A geographical, social and economic grouping of countries that contains England, Scotland and Wales.
GIS	Gas-Insulated Switchgear	Switchgear with gas used as the insulating and current breaking medium.
GSP	Grid Supply Point (also referred to as SGP – Super Grid Point)	A substation comprising of one or more Super Grid Transformers and associated switchgear.

GT	Grid Transformer	The transformers used at a Bulk Supply Point. Typically used to step down from 132 kV to 66, 33 or 11 kV.
GWh	Gigawatt hours	Gigawatt hours (1,000,000,000 watt hours). Gigawatt hours is a measure of electrical energy.
–	Generation	The production of electrical energy.
–	Group Demand	The maximum demand of a substation group.
HDC	Hard Drawn Copper	Overhead line type used on the network.
HE	Hydrogen Evolution	One of the pathways that forecasts the volumes and regional distribution of low carbon technology uptake NGED's licence areas. This uses stakeholder-informed bottom-up analysis to align with national industry developed future energy scenarios. Net zero is met through an accelerated adoption of hydrogen, particularly for industry and space heating. Consumer engagement is lower overall than other net zero scenarios, but electric car uptake remains high. Notable levels of renewable energy are still deployed, but hydrogen power generation and hydrogen storage provides the majority of system flexibility under this scenario.
HSL	–	Cable type used on the network.
HT	Holistic Transition	One of the pathways that forecasts the volumes and regional distribution of low carbon technology uptake NGED's licence areas. This uses stakeholder-informed bottom-up analysis to align with national industry developed future energy scenarios. Net zero is met through a mixture of electrification and low carbon hydrogen. Hydrogen is focused on decarbonising heavy industry. Consumer engagement is very high, shifting demand, adopting electric vehicles and heat pumps. The highest level of renewable energy is

		seen under this scenario, alongside significant levels of electricity storage to provide system flexibility.
H-Type	–	Cable type used on the network.
HV	High Voltage	A nominal voltage of more than 1,000 V, but no more than 22,000 V.
–	Insulated Conductor	An overhead conductor covered with insulating material which will prevent danger in the event of accidental contact with other objects and is deemed safe to touch.
–	Interruption	The loss of supply of electricity to one or more customers due to an incident. This excludes voltage quality and frequency abnormalities, such as dips, spikes or harmonics.
–	Isolator	A switch or control that completely stops the flow of electricity to a particular place.
LI	Load Index	Tier 2 Network Output Measure related to network utilisation. The Load Index (LI) is a framework for collating information on the utilisation of the Distribution Assets supplying each Demand Group and for tracking changes in their utilisation over time. The LI will be used to inform an assessment of the efficacy of the DNOs' general reinforcement decisions over the price control period.
LIFO	Last In First Out	ANM logic where most recently connected ANM customers are the first to have their output altered.
LTDS	Long Term Development Statement	An annually published document that sets out the use and likely development of the distribution network and the DNO's plans for modifying the distribution system for the following two years.
–	Loose Couple	Interconnection at a lower voltage level which could cause circulating current at a higher voltage. Typically found at lower

		voltage busbars of Primary substations or BSPs.
MVA	Mega volt amperes	Volt-ampere is a unit of electric power equal to the product of one volt and one ampere, equivalent to one watt at unity power factor (pf) is a unit used for measuring apparent power.
MWh	Megawatt hours	Megawatt hours (1,000,000-Watt hours). Megawatt hours is a measure of electrical energy.
NDP	Network Development Plans	A plan published every two years as required by SLC 25B to provided stakeholders with transparency on network constraints and needs for flexibility.
NDR	Network Development Report	A component of the NDP that provides readers with valuable additional information on potential development projects.
NESO	National Energy System Operator	National Energy System Operator is the electricity system operator for Great Britain.
NGED	National Grid Electricity Distribution	National Grid Electricity Distribution is a DNO that is licenced by Ofgem to distribute electricity in the East Midlands, West Midlands, South West, and South Wales.
NGET	National Grid Electricity Transmission	National Grid Electricity Transmission owns the electricity transmission network in England and Wales.
NHR	Network Headroom Report	Annually published dataset to indicate where it is anticipated that there will be network capacity to accommodate future connections and where flexibility services may be required.
NPg	Northern Powergrid	Northern Powergrid is a DNO that is licenced by Ofgem to distribute electricity in the North East England and Yorkshire regions and the North Lincolnshire area

–	National Grid	An energy company operating in the UK and US.
OBS	Operational Behaviour Scheme	Python code used to represent actions taken on the distribution network (such as intertrips or actions taken by Control Engineers) as part of analysis conducted for the NDP.
Ofgem	Office of Gas and Electricity Markets	Ofgem is responsible for regulating the gas and electricity markets in the United Kingdom to ensure customers' needs are protected and promotes market competition.
OH (or OHL)	Overhead Lines	An overhead line is a bare conductor used distribute electricity, typically via wooden poles or metal towers.
–	Offshore Wind	A category of DG. Electricity generation using a wind turbine situated offshore.
–	Onshore Wind	A category of DG. Electricity generation using a wind turbine situated onshore.
–	On-load Tap Changer	A piece of equipment that regulates the voltage ratio of an electrical transformer without interrupting the load current.
PF (pf)	Power Factor	The ratio of active power to apparent power.
PSS/E	Power System Simulator for Engineering	Software suite used by engineers to display, simulate, analyse and optimise electricity networks.
PV	Photovoltaic	A category of DG. Electricity generation using photovoltaics (solar panels or cells).
–	Pathway	A hypothesis of future events that would or could occur given certain political, economic, social, technological, and environmental conditions.
–	Primary Distribution	The sections of an electrical distribution network which provide the interface between transmission and Secondary Distribution. In NGED's network, the 33 kV circuits and Primary Substations are considered Primary Distribution.

–	Primary Substation	A substation comprising of one or more primary transformers and associated switchgear.
–	Primary Transformer	A transformer that steps voltage down from 66 or 33 kV to 11 or 6.6 kV.
–	Projection	The time-series of future changes to a parameter in each Scenario or Forecast.
RDP	Regional Development Programme	A joint study between NGET and NGED on possible 132 kV reinforcement options in the South West.
RESP	Regional Energy Strategic Plan	An activity established by Ofgem and delivered by NESO. The aim of the RESP is to provide greater clarity and consistency on local decarbonisation pathways. The first full RESP is due to be published in 2027.
ED3	Electricity Distribution 3	The electricity distribution price control period that runs from 1 April 2028 to 31 March 2033.
RMU	Ring Main Unit	Packaged switchgear that is either pre-welded together or shares the same tank. The unit is therefore non-extensible and is replaced as a single unit.
RVC	Rapid Voltage Change	A power quality issue related to voltage disturbance.
–	Reinforcement	Work carried out on the network: • to enable new load growth (both demand and generation) which is not attributable to specific customers; or • Connections Reinforcement on the Primary Network which involves the installation of assets at a voltage level above that of the Minimum Scheme.
–	Renewable Generation	Technologies and definitions listed in Directive 2009/28/EC of the European Parliament and of the Council of 23 April 2009 on the promotion of the use of energy from renewable sources. This Directive lists energy from renewable sources to include: wind, solar, aerothermal, geothermal, hydrothermal

		and ocean energy, hydropower, biomass, landfill gas, sewage treatment plant gas and biogases.
SCaNS	(Primary) System Constraints and Network Solutions	Primary SCaNS is a database where details of existing and future constraints on the distribution network between primary substations and the transmission interface are recorded, along with the potential solutions to these constraints which have been identified.
SCO	Second Circuit Outage	EREC P2/8 defines a Second Circuit Outage as: …a fault following an arranged Circuit outage…
SF6	Sulphur Hexafluoride	The chemical symbol for Sulphur hexafluoride, a gas that is used as both an insulating and arc extinction medium in electrical plant. The reporting requirement is in respect of fugitive BCF emissions attributed to SF6 lost from electrical plant.
SGT	Super Grid Transformer	Transformers used at a Grid Supply Point. Typically used to step down from 400 or 275 kV to 132 kV.
SoW	Statement of Works	The process under which the DNOs request that National Grid assesses the potential impact of the connection of DG upon the National Electricity Transmission System.
SPEN	Scottish Power Energy Networks	Scottish Power Energy Networks is a DNO that is licenced by Ofgem to distribute electricity in Central and Southern Scotland, North Wales, Merseyside, Cheshire and North Shropshire.
SSEN	Scottish and Southern Electricity Networks	Scottish and Southern Electricity Networks is a DNO that is licenced by Ofgem to distribute electricity in central southern England and in the north of Scotland.

SQC	Sequential Control	Method of managing the network without the need for manual intervention from a Control Engineer.
–	Sub-transmission	The sections of an electrical distribution network which provide the interface between transmission and Primary or Secondary Distribution. In NGED's network the GSPs, 132 kV circuits and BSPs are considered Sub-transmission.
–	Switchgear	A device capable of making, carrying and breaking currents under normal circuit operation but not normally capable of breaking fault current.
TANM	Transmission Active Network Management	The process of a Transmission operator using flexible network customers autonomously and in real-time to increase the utilisation of network assets without breaching operational limits.
tRESP	transitional Regional Energy Strategic Plan	An initial RESP produced by NESO with a reduced scope. The tRESP was designed to be used to inform ED3 business plans. The tRESP was published in early 2026.
UGC	Underground Cable	An insulated conductor used distribute electricity, typically buried or ducted underground.
UK	United Kingdom	A geographical, social and economic grouping of countries that contains England, Scotland, Wales and Northern Ireland.
UKPN	UK Power Networks	UK Power Networks is a DNO that is licenced by Ofgem to distribute electricity in the South East England, the East of England and London.
XLPE	Cross-Linked Polyethylene	A common cable type used on the network.