Network Development Plan

Introduction & Methodology Report

March 2024

Electricity Distribution

nationalgrid

Contents

Document Revision and Review

Date	Comments/Changes
28/03/2024	Draft for consultation period

Introduction

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 Clean Energy Package 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 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 section in this report where we provide further details about additional publications.

Network Development Plan Structure

The Network Development Plan comprises of three different parts, following the Form of Statement jointly developed by Distribution Network Operators through the Open Networks project.

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

Component part of Network Development Plan	Purpose	Publication format
Introduction & Methodology	Outlines the methodology for preparing the plan and any assumptions made. This report also summarised the approach to stakeholder engagement.	PDF report published in March 2024 to begin consultation period, updated in April 2024 with stakeholder feedback
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.	Suite of PDF reports for each area of network.
Network Headroom Report	Indicate 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).

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

The National Grid approach to this consultation period is as follows:

- Publish a copy of our Introduction & Methodology Report and an example Network Development Report and associated example Network Headroom Report on the website
- Provide a survey on the 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. As part of the final publication of the Network Development Plan in April 2024, the feedback collected will be summarised including how National Grid have acted on any feedback.

Table 2: NDP stakeholders

Stakeholder group	Details
Interconnected electrical network operators	• Other DNOs, IDNOs, TO, ESO
Community Energy	
Local Authorities (LA) / Government organisations	
Flexibility Service providers	
Other network operators	• Transport • Gas network • Water network
Developers	• Property/ Building, Generation, Industrial customers, Generation customers
Universities	

Please contact nged.primarysystemplan@nationalgrid.co.uk to provide any additional feedback on the content of the NDP.

Developments since 2022 publication

As outlined in the 2022 publication of the Network Development Plan, a number of developments were identified as National Grid strives to improve capability in analysing distribution networks. Over the past two years the following developments have been implemented in National Grid's approach to investment planning

Forecasting

- Updated our approach to deriving the Best View scenario, to accurately reflect how the uptake of low carbon technologies and renewable generation (which are more heavily impacted by national level policy decisions or affected by external factors)

- 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 Network Development Plan.
- Expanded the reach of the strategic studies to cover all areas of primary network using automated analysis. This results in a ten-year plan for all areas of primary networks, which provides much greater insight to future investment proposals.
- Updated the Network Development Report template to provide additional information on the options considered to alleviate constraints across primary networks. This increases transparency of decision making and indicative information on capacity released through different solutions.
- Improved on the methodology used to generate the Network Headroom Report, to more accurately reflect the principles outlined in the System Assessment and Constraint Identification section of this report.
- Engaged with other Distribution Network Operators, Transmission Networks and Electricity System Operator to analyse detailed constraints where multiple parties are required in decision making.

Optioneering

- Evolved the Distribution Network Options Assessment process by increasing visibility of reinforcement schemes not viable for flexibility deferral and utilising dynamic flexibility prices to increase market participation and unlock the full value of reinforcement deferral through flexibility.

Institutional and process

- Formalised the interactions between the Distribution System Operator and Distribution Network Operator within National Grid for load related expenditure, published as a policy document and Guide to DSO DNO Governance.

National Grid Strategic Investment Process

Since 2016, National Grid Electricity Distribution 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 1. The network impact assessment process aims to identify where and when network constraints could materialise as a result 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.

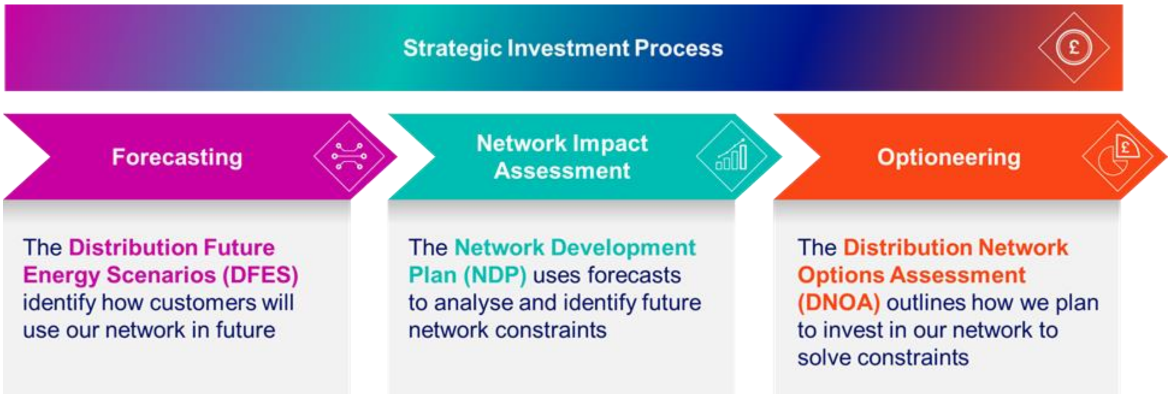

Figure 1: Diagram of end-to-end National Grid strategic investment planning process

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.

In addition to the four scenarios used as part of the DFES, a Best View scenario is also created. This outlines the expected growth pathway over a 0-10 year period, and is built on detailed stakeholder engagement.

In January 2024 the 8th iteration of the DFES was published on the National Grid website, as a suite of documents with supporting data viewable on the DFES map, as shown in Figure 2.

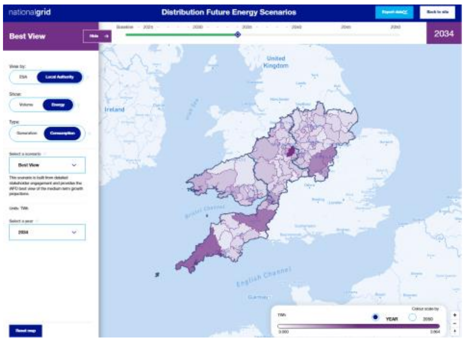

Figure 2: Screenshot from DFES map interface, to allow stakeholders to explore forecast projections

Optioneering: Distribution Network Options Assessment

The Distribution Network Options Assessment (DNOA) is a document published twice a year providing transparency in the investment decision making process. The DNOA uses the Common Evaluation Methodology (CEM) developed under the Open Networks project 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 February 2024 the 7th iteration of the DNOA was published on the National Grid website.

Figure 3: Distribution Network Options Assessment, published in February 2024

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

Table 3: Summary of NDP relationship with other National Grid activities

Publication	Description	How does this differ to NDP?
Shaping Subtransmission Reports	Series of reports published in 2016-2020 outlining how forecast projections will affect 132 and 66 kV networks.	Reports superseded by NDP but following expanded analysis methodology.
Long Term Development Statement (LTDS)	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 2022.
Network Capacity Map and Clearview Connect	Provides customers an up to date indication of existing available capacity to connect at substations across the primary distribution networks. In addition, the Clearview Connect information provides a comprehensive view of capacity headroom at all our license area Grid Supply Points (GSPs). This information may be useful for prospective developers to identify the GSPs at which they could have the earliest chance and lowest cost of accessing a generation connection.	Capacity Map and Clearview Connect both represent an update of the 'committed' position of capacity reserved, not necessarily covered in NDP analysis.
RIIO-ED2 Business Plan	Business plan submission to Ofgem for period from 2023-2028 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 2021.

Shaping Subtransmission Reports

In previous years, National Grid Electricity Distribution published a series of Shaping Subtransmission reports. These overlaid the DFES projections onto a network model of the 132 kV and 66 kV networks and identified potential network constraints over the medium term outlook. As part of these studies, analysis tools and techniques were developed to enable automated analysis of distribution networks. The NDP has formalised this network impact assessment for all DNOs to undertake on a periodic basis. The NDP therefore supersedes the Shaping Subtransmission series of reports from 2022.

Figure 4: WPD Shaping Subtransmission South Wales document, published in 2019

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 assessment. Table 3 also includes a forecast of peak demand for future years, which is based on the Best View scenario. Due to the timing of the publication of the LTDS in November and the DFES in December, the forecast load information is based on the previous year's DFES forecasts and Best View. In order 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 2023, DFES 2022 has been used as the basis for the Network Development Plan. The Network Headroom Report will be published using both DFES 2022 and DFES 2023 scenario projections, to outline how the indicative headroom changes with annual updates to the scenario projections.

Network Capacity Map and Clearview Connect

The Network Capacity Map provides an indication of the ability of the distribution network to connect large-scale developments to major substations. It can be viewed as a visual representation of some of the data contained in the Long Term Development Statement, with additional information provided for the generation headroom of National Grid substations.

In addition to the Network Capacity Map, Clearview Connect provides additional information on the current contracted position at the boundary interface between transmission and distribution networks. This was introduced as constraints on the transmission network can often be a source of delays for customers connecting to the distribution network, and visibility of the upstream queue is valued by stakeholders.

Both the Network Capacity Map and Clearview Connect are regularly updated with snapshots of connection information incorporating recently connected generation, accepted but not yet connected generation and quoted generation connections. These figures regularly change as quotations are issued and expire. As a result, the Network Capacity Map reflects a 'committed' network position, which does not directly correspond to a single scenario or year used as part of the DFES process. Customers with accepted connection offers do not always progress through to connection, so DFES publications take a view on connection likelihood. In addition, DFES forecasts include the growth of small-scale low carbon technologies, which would not typically be captured by a large-scale connection offer.

RIIO-ED2 Business Plan

As part of the submission of a Business Plan for the RIIO-ED2 price control period, National Grid undertook strategic analysis of the distribution networks to identify areas of investment for the period from 2023-2028. Across primary distribution networks this was captured as a series of Engineering Justification Papers (EJPs) for major projects.

National Grid view the Network Development Plan 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

In order to undertake detailed electrical analysis of any electricity distribution network the four components detailed in the matrix in Table 4 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 4: 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

Network Assets are modelled through the extra high voltage (EHV) network models maintained by National Grid. The same information is published annually as part of the LTDS, to allow third parties to model the distribution network. Models are constantly updated 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.

A snapshot of the EHV models was taken and these were used to model the forecast demand sets from DFES. For each year into the future, 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

In order 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;
- intertripping;
- directional overcurrent schemes;
- overload protection;
- sequential control (SQC); and
- 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.

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 Long Term Development Statement (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.

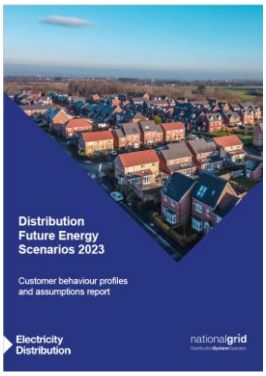

Figure 5: DFES Customer Behaviour Assumptions report for the 2023 edition of the DFES projections.

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 increased 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 5. 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 5: Representative Day descriptions used for analysis within the Network Development Plan.

	Demand Headroom Assessment	Generation Headroom Assessment
Representative Day	• Winter Peak Demand • Summer 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 handle generation output. The season where generation constraints most normally occur is during summer, with relatively 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 profile 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 to occur in the warmer months.

System Assessment and Constraint Identification

The distribution network is designed to comply with a number of 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 particular 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 Integrity

Network integrity 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 integrity analysis, National Grid cover secured outage conditions in excess of those identified in Engineering Recommendation P2/8, such as busbar fault outages and arranged outages followed by busbar fault outages. By increasing the level of detail being analysed and analysing these busbar fault conditions, network integrity 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 System Planning 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 utilised 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 Integrity

System integrity is the ability of the GB system to operate within acceptable frequency-related technical limits under both intact network and outage conditions. System 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 carried out 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.

Other relevant network design standards

In addition to network security, integrity and voltage studies on a network, there are additional standards that DNOs must follow when designing networks. These are outlined below, but 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 G99/1

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 are 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 run 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.

System Planning

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;
- **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 of summarised below.

Table 6: Summary of which solutions considered in 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 Engineering Recommendation P2/8	✓	✓	✓	×
Network integrity: thermal overload of asset driven by demand	✓	✓	✓	✓
Network integrity: thermal overload of asset driven by demand	✓	✓	✓	✓
Network integrity: voltages outside of allowable limits	✓	✓	✓	*
Fault level	✓	*	✓	*
Circuit complexity	✓	×	✓	×

** 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 Electricity System Operator, 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, utilising 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 Network Development Plan. As part of the Distribution Network Options Assessment 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 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; and
- 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 liaising 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 making an assessment of credible solutions; however they may be inappropriate to some outlier networks.

Nominal Voltages

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

Table 7: standard voltages used across National Grid primary distribution networks

Voltage	Substation involved in voltage transformation
Transmission (275 kV or 400 kV)	
	Grid Supply Point
132 kV	
	Bulk Supply Point (132/33 kV)
33 kV	
	Primary Substation (33/11 kV)
11 kV	
	Distribution/secondary substation (11 kV/LV)
Low Voltage	

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.

66kV 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 provides 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.

6.6kV 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.

As a result, 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

Across National Grid standard asset sizes are used. Across primary networks the lower limit of the asset rating used is primarily an economic decision based on the most efficient way to transfer power. The upper limit of asset rating that is used across primary network is impacted to the rating of switchgear suitable for use at unattended substations on distribution networks. National Grid use primary switchgear up to a rating of 2000 A, this dictates the maximum transformer rating that can be used (calculated against lower voltage of transformation), as outlined below:

Table 8: Highest transformer rating used by National Grid at each voltage transformation level

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

In the NDP analysis this is used to determine if proposed solutions may require additional transformers or new substations, if the highest asset rating is already used.

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 300MW. 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 6. Each of the circuits A, B and C has a rating of 90MVA. The three circuits share load evenly. The seasonal peak demand at the 33kV bar of the Bulk Supply Point is:

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

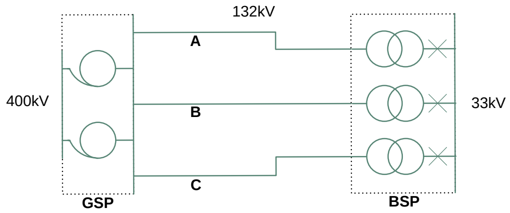

Figure 6: Three-circuit group example network

The group demand is the maximum of the seasonal peak demands, 125MW, 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 20MW (automatically disconnected), i.e. 105MW, 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 100MW, i.e. 25MW, 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 180MVA. Since the group demand of 125MW 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 90MVA. While the remaining circuit is sufficient to supply the demand required by P2/8 (25MW), the actual impact on the network depends on the prevailing demand:

- In summer, the demand of 85MW 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 125MW 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 125MW.
3. Splitting the 33kV 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 62.5MW

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 intertripping or overload schemes to detect and trip any circuit that is overloaded.
5. Contracting with any dispatchable generators within the 33kV 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, that 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 and 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 (11 kV circuits downstream of the 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 the impact on the 33 kV network. This is due to the fact that many of these networks are constrained by the 11 kV transfer capacity to neighbouring substations (required under First Circuit Outage conditions). 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 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.

Networks running in parallel

Across the primary distribution networks there are numerous network 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.

NGEDs approach is the proactively engage with the Electricity System Operator, National Grid transmission and other Distribution Network Operators where constraints that have cross boundary impact and solutions. This is often in the form of bilateral discussions, but can also connection applications were firm costs are required.

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 carried out on areas of the network where developments are required. This analysis was performed using the four DFES scenarios as well as the Best View and each section of network is assessed across the next 10 years.

As outlined in the Please contact nged.primarysystemplan@nationalgrid.co.uk to provide any additional feedback on the content of the NDP.

Developments since 2022 publication section of this report, the scope of the analysis was expanded for the 2024 Network Development Reports to cover all areas of primary distribution networks. Each area of network where an investment decision is required in the 0-10 year window is reported as a series of technical reports. These will provide the justification of the required investment to stakeholders through robust evidence and technical detail.

Since 2016 National Grid has developed a tool for automated analysis of EHV 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 as a whole 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 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 Remedial Action Scheme (RAS) 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. The modelling of schemes is agreed and confirmed with operational and planning colleagues across the DSO and DNO Teams. Details on specific Remedial Action Schemes modelled are included in each of the individual Network Development Reports as part of the NDP publication. 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 System Planning 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 for each area of network (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 9: 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, the topology of the primary distribution network and any operability schemes that have been modelled.
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, constrained asset and uncertainty across multiple scenarios. • Detailed solution options, encompassing those as outlined in the System Planning section of this report. This includes an outline of the solution, capacity released 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 analysis methodology used to obtain the network headroom figures contained in the Network Headroom Report. On the [National Grid website] a workbook for each licence area contains the network headroom for both additional demand and generation connections across the four DFES scenarios as well as the Best View. These are included for all years out to 2050. The methodology for both demand and generation headroom is discussed separately below.

The methodology for the Network Headroom Report has been developed for 2024 to overcome some of the major limitations with the approach taken in 2022. In particular, a limitations of many standard approaches to calculating headroom by using firm capacity style analysis is outlined below (taken from the limitations section of the 2022 NDP Methodology Report)

> *"For both demand and generation network headroom assessments, a firm capacity style analysis may not fully capture the complex nature in which distribution networks are run. Where areas of the distribution network run interconnected, each distinct area cannot be studied in isolation the network loading is susceptible to changes in other parts of the parallel group. Comprehensive power systems analysis is required to fully capture the available headroom for the distribution network."*
>
> *"A firm capacity style analysis may define the headroom available to connect demand or generation at a particular voltage level, however this may not capture the available headroom at upstream voltage of the distribution network, which may be the limiting factor to connect new demand and generation. Again, comprehensive power systems analysis is required to fully account for the materiality headroom for different parts of the distribution network."*

The updated analysis methodology is outlined in the sections below.

Constraint identification

Over 2023 National Grid has expanded the Switch-Level analyser tool to undertake sensitivity analysis embedded in the contingency analysis engine. The sensitivity analysis is run for each contingency analysed as part of a network study. Firstly the node voltages and branch flows are recorded after a load flow simulation has been run. Subsequently a 1 MW load is added at each boundary node in the network model for the given contingency. A load-flow is then run on the network, and any change (above a material threshold set by the user) on any branch is recorded along with the ratings of each branch. This includes all of the network automation and manual switching schemes for any first circuit outage.

A unique a sensitivity factor is recorded on each boundary node in the model for the following factors:

- Representative assessment period (year, scenario, season and half hour)
- Outage combination
- Branch in the network model whose current flow is impacted by the change of load at the node.

Once a sensitivity factor is identified for each of the unique combinations above, a calculation can be run to ascertain how many MW of load would need to be added at each node until there is a thermal overload on a branch in the network. 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.

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 because it is a major constraint on generation connections. For the Network Headroom Report, an initial fault level assessment is undertaken using the functionality provided in the Switch-Level analyser tool. The existing maximum prospective fault levels under normal system running conditions and the make and break switchgear ratings at bussing points are taken from the LTDS Table 4.

The additional 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 Western Power Distribution Policy Document: SD7F/2. This is added onto the existing maximum fault level and compared to the switchgear make and break ratings to calculate a fault level headroom in kA.

Report Structure

The methodology adopted for the 2024 Network Headroom Report is considered an improvement on previous pre-defined firm capacities. It not only overcomes some of the limitations identified in 2022, but it encompasses all contingencies studied and the comprehensive library of network automation and manual switching schemes that are used. When used on the current committed network model, the available headroom calculated is more closely aligned to the figure that would be provided as part of a connection offer.

The structure of the Network Headroom Report is unchanged from the 2022 publication. It provides a headroom for the following:

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

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 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 carried out.
3. The impacts of planned reinforcements, contracted flexibility and active network management schemes are not included in the Network Headroom Report. Comprehensive power systems analysis requires network interventions to be modelled in order to enable model convergence in future years – these are modelled for the areas considered in the Network Development Reports.
4. The Network Headroom Report does not outline the headroom on assets on the transmission network. Whilst the impact of outage on the transmission networks are modelled, the available headroom at the transmission/distribution boundary is best provided by the Electricity System Operator, or through information sources such as Clearview Connect.
5. 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.

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 is 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.
- Improve the technical capabilities of the existing Switch-Level Analyser tool to cover switchgear stressing studies, voltage unbalance and voltage fluctuation studies. 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 High Voltage (HV) networks. This requires automated tools as the complexity and size of HV networks is significantly larger than EHV networks.