Network Development Plan

Introduction & Methodology Report

May 2024

Electricity Distribution

nationalgrid

Contents

Document Revision and Review

Date	Comments/Changes
28/03/2024	Draft for consultation period
01/05/2024	Final publication

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, 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 15th April 2024.

Table 2: NDP stakeholders

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.

NDP Publications

Based on stakeholder feedback, the report that most stakeholders found useful are the Development Reports, which are the most descriptive reports we produce as part of the Network Development Plan.

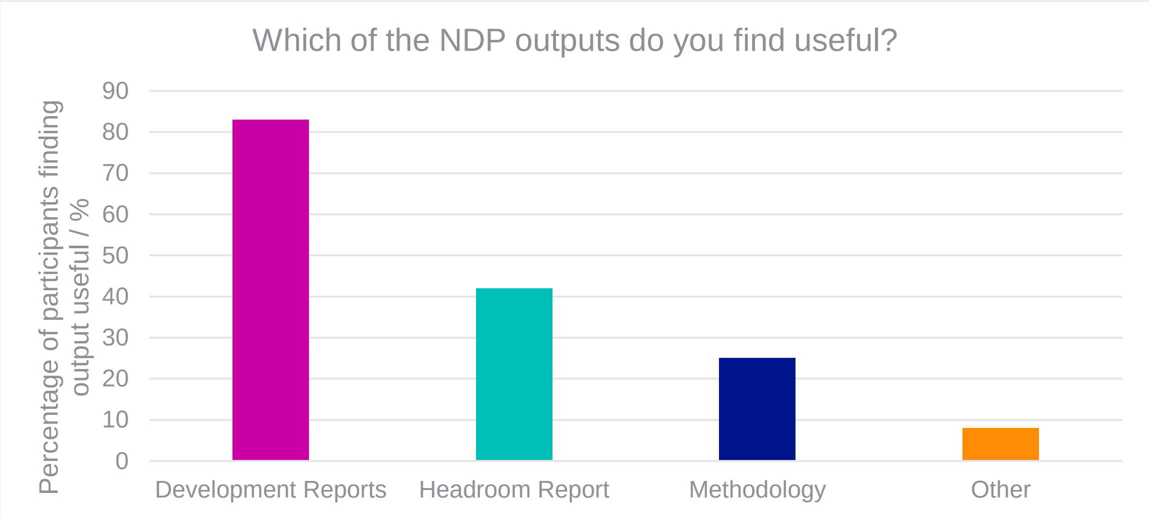

Figure 1: NDP consultation poll results for most useful NDP output

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 published a table in Appendix A detailing the reports that cover areas within each local authority.

Stakeholder Consultation Summary

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. The survey provided on our website and promoted through social media platforms did not have a sufficient number of responses to publish the results.

Table 3: Stakeholder consultation feedback and actions summary table

You said	We did	We will do
You would like to see flexibility summarised	We have identified where flexibility could be used as a solution to a constraint within the network development reports.	Following further flexibility analysis, we will be publishing a consolidated view of the flexibility zones created through this analysis on the flexibility map on our website.
You would like to see the NDP data input summarised	We have developed this methodology report to summarise the inputs and analysis methods used to identify constraints.	-
You would like to see the preferred solution summarised	We have added a section at the bottom of each constraint within the reports where a proposed solution is described.	-

You said	We did	We will do
You would like to see the impacts of the highlighted constraints on connections, and how this is being addressed	We use our forecasts to estimate future connections onto the network, to inform our strategic planning process. It is possible that an unforeseen development will want to connect, or the demand may arise sooner than anticipated, in this case, the project will progress as usual through the connections process, and if required the planned reinforcement can be brought forward.	-
You said you would like to see the methodology summarised	We have developed this methodology report to summarise the inputs and analysis methods used to identify constraints.	-
You would like to see the N-2 (or second circuit outage) analysis summarised	Where an N-2 condition is causing a constraint, we have included this within the network development reports.	-
You would like to see maps included in the NDP	We have improved the maps published in our network development reports to also include existing circuits to help provide additional context to the reports.	-
You would like to see area contacts included in the NDP	If you would like to get in touch with the System Planning team, please email nged.energyplanning@nationalgrid.co.uk	-
You would like to see confidence metrics included in the NDP	In the results of the network development reports we have included a section detailing the uncertainty of when the constraints arise under different scenarios. This aims to provide context around least worst regrets of the investment.	-
You would like to see a breakdown of which reports are relevant to each local authority	As mentioned above, we have provided this in Appendix of this report.	In future, we will look to deliver the results in a way that they can be aggregated and presented by local authority.
You would like to see new upgrades included in the NDP	This is a key part of the NDP, and each constraint listed in the reports has an upgrade or solution associated with it.	-
You would like to see a flow chart included in the NDP	We have included a flow chart of the internal process that the NDP is a part of in the National Grid Strategic Investment Process section of this report.	-

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 2. 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.

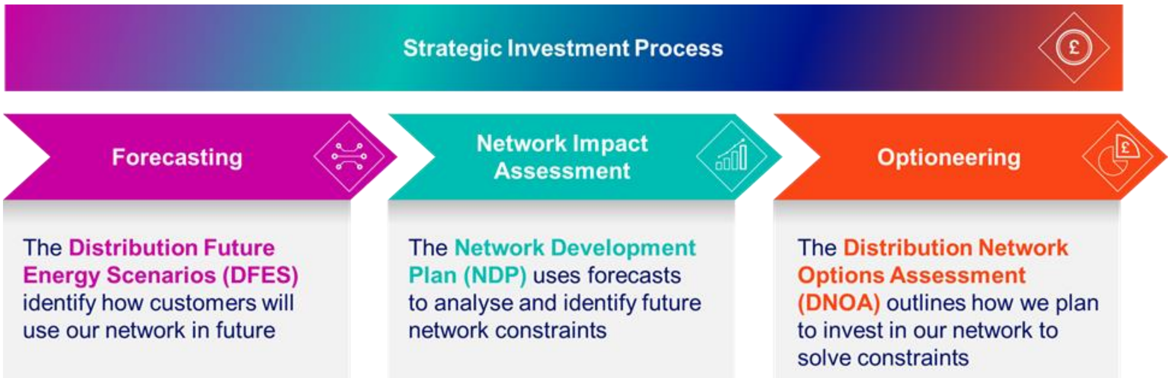

Figure 2: Diagram of end-to-end National Grid strategic investment planning process

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 3.

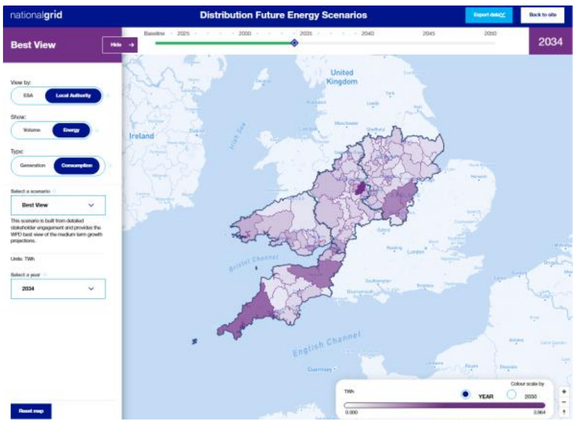

Figure 3: DFES map interface, to allow stakeholders to explore forecast projections

Optioneering: Distribution Network Options Assessment

The Distribution Network Options Assessment (DNOA) is a document published 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 4: 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 4: 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.

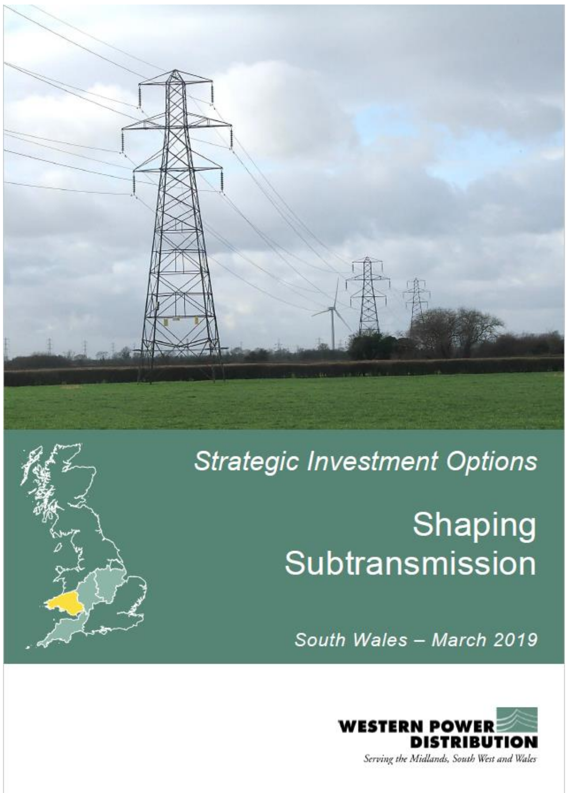

Figure 5: WPD Shaping Subtransmission South Wales document, published in 2019

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.

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

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 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

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.

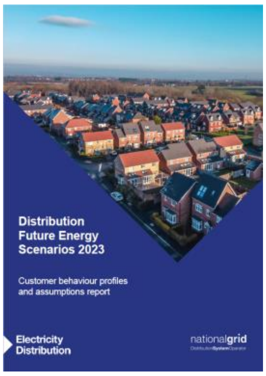

Figure 6: DFES Customer Behaviour Assumptions report for the 2023 edition of the DFES projections

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 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 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. 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 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, 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.

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 carried out 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 2034 as part of the NDP process (as assets installed in the near future 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 at a later date 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 at a later date if load growth materialises).

For network integrity 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 February 2024 Distribution Network Options Assessment (DNOA) Appendix A (which is specifically aimed at outlining why flexibility is unsuitable for deferring asset condition driven reinforcement expenditure).

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 are summarised below.

Table 7: 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 generation	✓	✓	✓	*
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 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 carried out. In order 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 integrity 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 only by N-2 or arranged outages. 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 as a whole 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; 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 8: 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.

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 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.

6.6 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, the vast majority of 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 roughly 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 high voltage) increasing the nominal voltage allows for a greater scale of voltage change throughout the network. Paired with the aforementioned 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.

In order 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, utilised by NGED in 6.6 kV networks, are rated for operation at 11 kV (Um = 12 kV), to ensure that they are capable of carrying 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 utilised by NGED on the network are given in the table below. There are a number of reasons why larger units are not utilised. 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 utilise 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 of the ancillary equipment, circuits at the higher and lower voltage levels and the aforementioned switchgear would need to be uprated to match (driving up overall costs drastically).

Table 9: 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 MVA 132 kV winding: 60 MVA, 11 kV windings each 15/30 MVA
33/11 kV	20/40 MVA
33/6.6 kV	12/24 MVA

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 highlighted in the Network Development Reports 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 7. 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

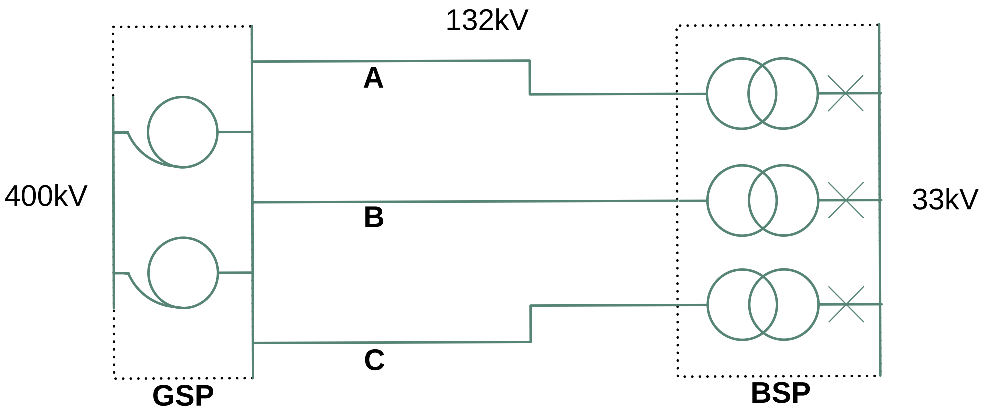

Figure 7: Three-circuit group example network

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 intertripping 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, 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 (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 consider 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.

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.

NGED's 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.

Establishing new GSPs becomes necessary as demand and generation grows across the network to deload 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 identified 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 of 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 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 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 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, 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 National Grid Policy Document: SD7F/2. This is added onto the existing maximum fault level and compared to the switchgear make and break ratings, with the headroom incorporated into the final MW headroom figure.

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 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 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.
6. 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.

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, 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. This analysis has already begun and we will work with stakeholders to present the analysis results in a way most valuable for data users.

Appendix A

Table 11 – Local authority breakdown of key NDP reports

Local authority	NDP report title
Amber Valley	Alfreton 33 kV
Amber Valley	Chesterfield 132 kV
Amber Valley	Derby and Derby South 33 kV
Amber Valley	Spondon and Heanor 33 kV
Amber Valley	Stanton 33 kV
Amber Valley	Willington 132 kV
Amber Valley	Winster 33 kV
Ashfield	Alfreton 33 kV
Ashfield	Annesley, Clipstone and Mansfield 33 kV
Ashfield	Chesterfield 132 kV
Ashfield	Spondon and Heanor 33 kV
Ashfield	Stoke Bardolph 132 kV
Ashfield	The Nottingham Group
Ashfield	Willington 132 kV
Bassetlaw	Annesley, Clipstone and Mansfield 33 kV
Bassetlaw	Checkerhouse 33 kV
Bassetlaw	Chesterfield 132 kV
Bassetlaw	Hawton 33 kV
Bassetlaw	Staythorpe 132 kV
Bassetlaw	West Burton 132 kV
Bassetlaw	Whitwell and Staveley 33 kV
Bassetlaw	Worksop 33 kV
Bath and North East Somerset	Bath BSP
Bath and North East Somerset	Bridgwater BSP and 132 kV network
Bath and North East Somerset	Churchill BSP
Bath and North East Somerset	Feeder Road BSP
Bath and North East Somerset	Iron Acton (West Midlands)
Bath and North East Somerset	Iron Acton (South West)
Bath and North East Somerset	Radstock BSP
Bath and North East Somerset	Seabank and Sandford 132 kV
Bedford	Grendon 132 kV
Bedford	The Northampton Group
Bedford	Wellingborough and Irthlingborough 33 kV
Birmingham	Bustleholm
Birmingham	Kitwell

Local authority	NDP report title
Birmingham	Lea Marston
Birmingham	Nechells East
Birmingham	Rugeley
Birmingham	Tamworth Grid and Tamworth Town 33 kV
Birmingham	West Midlands Licence Area Report
Blaby	Coalville 33 kV
Blaby	Coventry 132 kV
Blaby	Enderby 132 kV
Blaby	Grendon 132 kV
Blaby	Hinckley and Nuneaton 33 kV
Blaby	Kettering and Kibworth 33 kV
Blaby	Pailton 33 kV
Blaby	The Leicester Group
Blaby	Wigston 33 kV
Blaenau Gwent	Abergavenny and Panteg BSPs
Blaenau Gwent	Crumlin BSP
Blaenau Gwent	Dowlais 33 kV
Blaenau Gwent	Ebbw Vale BSP
Blaenau Gwent	Rassau GSP
Blaenau Gwent	Upper Boat 132 kV and 33 kV
Blaenau Gwent	Uskmouth GSP
Bolsover	Alfreton 33 kV
Bolsover	Annesley, Clipstone and Mansfield 33 kV
Bolsover	Chesterfield 132 kV
Bolsover	Chesterfield, Goitside and Buxton 33 kV
Bolsover	Spondon and Heanor 33 kV
Bolsover	West Burton 132 kV
Bolsover	Whitwell and Staveley 33 kV
Bolsover	Willington 132 kV
Bolsover	Worksop 33 kV
Boston	Bicker Fen 132 kV
Boston	Boston 33 kV
Boston	Bourne and Stamford 33 kV
Boston	Grantham and Sleaford 33 kV
Boston	Spalding and South Holland 33 kV
Boston	Walpole 132 kV
Bridgend	Bridgend 33 kV
Bridgend	Briton Ferry and Tir John BSPs
Bridgend	Brynhill & East Aberthaw
Bridgend	Hirwaun & Travellers Rest 33 kV
Bridgend	Pyle 132 kV and 33 kV

Local authority	NDP report title
Bridgend	Pyle GSP
Bridgend	Swansea North GSP
Bridgend	Upper Boat 132 kV and 33 kV
Bristol, City of	Avonmouth BSP
Bristol, City of	Feeder Road BSP
Bristol, City of	Iron Acton (West Midlands)
Bristol, City of	Iron Acton GSP (South West)
Bristol, City of	Lockleaze and Bradley Stoke BSPs
Bristol, City of	Portishead BSP
Bristol, City of	Seabank and Sandford 132 kV
Bromsgrove	Bishops Wood
Bromsgrove	Feckenham
Bromsgrove	Kitwell
Bromsgrove	Lea Marston
Bromsgrove	Penn
Broxtowe	Annesley, Clipstone and Mansfield 33 kV
Broxtowe	Chesterfield 132 kV
Broxtowe	Ratcliffe 132 kV
Broxtowe	Spondon and Heanor 33 kV
Broxtowe	Stanton 33 kV
Broxtowe	Stoke Bardolph 132 kV
Broxtowe	The Nottingham Group
Broxtowe	Toton 33 kV
Broxtowe	Willington 132 kV
Buckinghamshire	Brackley and Stony Stratford 33 kV
Buckinghamshire	Bradwell Abbey and Bletchley 33 kV
Buckinghamshire	East Claydon 132 kV
Caerphilly	Abergavenny and Panteg BSPs
Caerphilly	Cardiff 132 kV
Caerphilly	Cardiff East & North BSPs
Caerphilly	Crumlin BSP
Caerphilly	Dowlais 33 kV
Caerphilly	Ebbw Vale BSP
Caerphilly	Rassau GSP
Caerphilly	Upper Boat 132 kV and 33 kV
Caerphilly	Uskmouth GSP
Cannock Chase	Bushbury
Cannock Chase	Bustleholm
Cannock Chase	Rugeley
Cardiff	Cardiff 132 kV
Cardiff	Cardiff Cental & West 33 kV

Local authority	NDP report title
Cardiff	Cardiff East & North BSPs
Cardiff	Upper Boat 132 kV and 33 kV
Carmarthenshire	Abergavenny and Panteg BSPs
Carmarthenshire	Carmarthen, Ammanford, Rhos, Llanarth and Lampeter BSPs
Carmarthenshire	Hirwaun & Travellers Rest 33 kV
Carmarthenshire	Pembroke Group
Carmarthenshire	Pembroke GSP
Carmarthenshire	Rassau GSP
Carmarthenshire	Swansea North 132 kV
Carmarthenshire	Swansea North BSP
Carmarthenshire	Swansea North GSP
Carmarthenshire	Trostre BSP
Central Bedfordshire	Bradwell Abbey and Bletchley 33 kV
Central Bedfordshire	East Claydon 132 kV
Central Bedfordshire	Grendon 132 kV
Central Bedfordshire	The Northampton Group
Ceredigion	Abergavenny and Panteg BSPs
Ceredigion	Carmarthen, Ammanford, Rhos, Llanarth and Lampeter BSPs
Ceredigion	Rassau GSP
Ceredigion	Swansea North BSP
Ceredigion	Swansea North GSP
Charnwood	Coalville 33 kV
Charnwood	Enderby 132 kV
Charnwood	Grendon 132 kV
Charnwood	Loughborough 33 kV
Charnwood	Melton and Oakham 33 kV
Charnwood	Ratcliffe 132 kV
Charnwood	The Leicester Group
Charnwood	Willoughby 33 kV
Cheltenham	Port Ham
Cherwell	Berkswell 132 kV
Cherwell	Brackley and Stony Stratford 33 kV
Cherwell	East Claydon 132 kV
Cherwell	Feckenham
Cherwell	Warwick and Harbury 33 kV
Cheshire East	Cellarhead
Cheshire East	Chesterfield, Goitside and Buxton 33 kV
Chesterfield	Chesterfield 132 kV
Chesterfield	Chesterfield, Goitside and Buxton 33 kV
Chesterfield	Whitwell and Staveley 33 kV
Cornwall	Camborne BSP

Local authority	NDP report title
Cornwall	Ernesettle BSP
Cornwall	Fraddon BSP
Cornwall	Hayle BSP
Cornwall	Indian Queens and Alverdiscott GSP group
Cornwall	Landulph St Germans BSP group
Cornwall	Pyworthy North Tawton BSP group
Cornwall	Rame BSP
Cornwall	South Devon
Cornwall	St Austell BSP
Cornwall	St Tudy BSP
Cornwall	Truro BSP
Cotswold	Feckenham
Cotswold	Iron Acton (West Midlands)
Cotswold	Port Ham
Coventry	Berkswell 132 kV
Coventry	Coventry 132 kV
Coventry	Hinckley and Nuneaton 33 kV
Coventry	The Coventry Group
Coventry	Whitley 33 kV
Derby	Derby and Derby South 33 kV
Derby	Spondon and Heanor 33 kV
Derby	Willington 132 kV
Derbyshire Dales	Alfreton 33 kV
Derbyshire Dales	Burton, Burton South and Gresley 33 kV
Derbyshire Dales	Cellarhead
Derbyshire Dales	Chesterfield 132 kV
Derbyshire Dales	Chesterfield, Goitside and Buxton 33 kV
Derbyshire Dales	Derby and Derby South 33 kV
Derbyshire Dales	Drakelow 132 kV
Derbyshire Dales	Uttoxeter 33 kV
Derbyshire Dales	Willington 132 kV
Derbyshire Dales	Winster 33 kV
Doncaster	Checkerhouse 33 kV
Doncaster	Staythorpe 132 kV
Dorset	Axminster GSP
Dudley	Bishops Wood
Dudley	Kitwell
Dudley	Penn
Dudley	West Midlands Licence Area Report
East Devon	Axminster GSP
East Devon	Exeter City BSP

Local authority	NDP report title
East Devon	Exeter Main BSP
East Devon	Exmouth BSP
East Devon	South Devon
East Devon	Sowton BSP
East Devon	Taunton BSP and 132 kV
East Devon	Taunton BSP and 132 kV network
East Devon	Tiverton BSP
East Lindsey	Bicker Fen 132 kV
East Lindsey	Boston 33 kV
East Lindsey	Grantham and Sleaford 33 kV
East Lindsey	Lincoln 33 kV
East Lindsey	Skegness 33 kV
East Lindsey	Walpole 132 kV
East Lindsey	West Burton 132 kV
East Staffordshire	Burton, Burton South and Gresley 33 kV
East Staffordshire	Bushbury
East Staffordshire	Cellarhead
East Staffordshire	Drakelow 132 kV
East Staffordshire	Lea Marston
East Staffordshire	Rugeley
East Staffordshire	Uttoxeter 33 kV
East Staffordshire	Willington 132 kV
East Staffordshire	Winster 33 kV
Erewash	Derby and Derby South 33 kV
Erewash	Ratcliffe 132 kV
Erewash	Spondon and Heanor 33 kV
Erewash	Stanton 33 kV
Erewash	Toton 33 kV
Erewash	Willington 132 kV
Exeter	Exeter City BSP
Exeter	Exmouth BSP
Exeter	South Devon
Exeter	Sowton BSP
Fenland	Spalding and South Holland 33 kV
Fenland	Walpole 132 kV
Forest of Dean	Abergavenny and Panteg BSPs
Forest of Dean	Bishops Wood
Forest of Dean	Feckenham
Forest of Dean	Iron Acton (West Midlands)
Forest of Dean	Port Ham
Forest of Dean	Rassau GSP

Local authority	NDP report title
Forest of Dean	Sudbrook BSP
Forest of Dean	Uskmouth GSP
Gedling	Annesley, Clipstone and Mansfield 33 kV
Gedling	Chesterfield 132 kV
Gedling	Hawton 33 kV
Gedling	Ratcliffe 132 kV
Gedling	Staythorpe 132 kV
Gedling	Stoke Bardolph 132 kV
Gedling	The Nottingham Group
Gloucester	Port Ham
Harborough	Corby 33 kV
Harborough	Coventry 132 kV
Harborough	Daventry and Rugby 33 kV
Harborough	Enderby 132 kV
Harborough	Grendon 132 kV
Harborough	Kettering and Kibworth 33 kV
Harborough	Melton and Oakham 33 kV
Harborough	Pailton 33 kV
Harborough	Ratcliffe 132 kV
Harborough	The Leicester Group
Harborough	Wigston 33 kV
Harborough	Willoughby 33 kV
Herefordshire, County of	Abergavenny and Panteg BSPs
Herefordshire, County of	Bishops Wood
Herefordshire, County of	Feckenham
Herefordshire, County of	Port Ham
Herefordshire, County of	Rassau GSP
High Peak	Chesterfield 132 kV
High Peak	Chesterfield, Goitside and Buxton 33 kV
Hinckley and Bosworth	Burton, Burton South and Gresley 33 kV
Hinckley and Bosworth	Coalville 33 kV
Hinckley and Bosworth	Coventry 132 kV
Hinckley and Bosworth	Drakelow 132 kV
Hinckley and Bosworth	Enderby 132 kV
Hinckley and Bosworth	Hinckley and Nuneaton 33 kV
Hinckley and Bosworth	Lea Marston
Hinckley and Bosworth	Pailton 33 kV
Hinckley and Bosworth	Tamworth Grid and Tamworth Town 33 kV
Hinckley and Bosworth	The Leicester Group
Huntingdonshire	Bourne and Stamford 33 kV
Huntingdonshire	Corby 33 kV

Local authority	NDP report title
Huntingdonshire	Grendon 132 kV
Huntingdonshire	Walpole 132 kV
Huntingdonshire	Wellingborough and Irthlingborough 33 kV
Isles of Scilly	Hayle BSP
Isles of Scilly	Indian Queens and Alverdiscott GSP group
King's Lynn and West Norfolk	Spalding and South Holland 33 kV
King's Lynn and West Norfolk	Walpole 132 kV
Leicester	Coalville 33 kV
Leicester	Enderby 132 kV
Leicester	Ratcliffe 132 kV
Leicester	The Leicester Group
Leicester	Wigston 33 kV
Leicester	Willoughby 33 kV
Lichfield	Burton, Burton South and Gresley 33 kV
Lichfield	Bustleholm
Lichfield	Drakelow 132 kV
Lichfield	Lea Marston
Lichfield	Rugeley
Lichfield	Tamworth Grid and Tamworth Town 33 kV
Lincoln	Lincoln 33 kV
Lincoln	West Burton 132 kV
Malvern Hills	Bishops Wood
Malvern Hills	Feckenham
Malvern Hills	Port Ham
Mansfield	Annesley, Clipstone and Mansfield 33 kV
Mansfield	Chesterfield 132 kV
Mansfield	Whitwell and Staveley 33 kV
Melton	Bicker Fen 132 kV
Melton	Grantham and Sleaford 33 kV
Melton	Grendon 132 kV
Melton	Hawton 33 kV
Melton	Melton and Oakham 33 kV
Melton	Ratcliffe 132 kV
Melton	Staythorpe 132 kV
Melton	Willoughby 33 kV
Merthyr Tydfil	Dowlais 33 kV
Merthyr Tydfil	Hirwaun & Travellers Rest 33 kV
Merthyr Tydfil	Swansea North GSP
Merthyr Tydfil	Upper Boat 132 kV and 33 kV
Mid Devon	Barnstaple BSP
Mid Devon	Exeter City BSP

Local authority	NDP report title
Mid Devon	Exeter Main BSP
Mid Devon	Indian Queens and Alverdiscott GSP group
Mid Devon	Pyworthy North Tawton BSP group
Mid Devon	South Devon
Mid Devon	Sowton BSP
Mid Devon	Taunton BSP and 132 kV
Mid Devon	Taunton BSP and 132 kV network
Mid Devon	Tiverton BSP
Milton Keynes	Brackley and Stony Stratford 33 kV
Milton Keynes	Bradwell Abbey and Bletchley 33 kV
Milton Keynes	East Claydon 132 kV
Milton Keynes	Grendon 132 kV
Milton Keynes	The Northampton Group
Milton Keynes	Wellingborough and Irthlingborough 33 kV
Monmouthshire	Abergavenny and Panteg BSPs
Monmouthshire	Bishops Wood
Monmouthshire	Ebbw Vale BSP
Monmouthshire	Newport South BSP
Monmouthshire	Port Ham
Monmouthshire	Portishead BSP
Monmouthshire	Rassau GSP
Monmouthshire	Seabank and Sandford 132 kV
Monmouthshire	Sudbrook BSP
Monmouthshire	Uskmouth GSP
Neath Port Talbot	Briton Ferry and Tir John
Neath Port Talbot	Briton Ferry and Tir John BSPs
Neath Port Talbot	Hirwaun & Travellers Rest 33 kV
Neath Port Talbot	Pyle 132 kV and 33 kV
Neath Port Talbot	Pyle GSP
Neath Port Talbot	Swansea North 132 kV
Neath Port Talbot	Swansea North GSP
Newark and Sherwood	Annesley, Clipstone and Mansfield 33 kV
Newark and Sherwood	Bicker Fen 132 kV
Newark and Sherwood	Checkerhouse 33 kV
Newark and Sherwood	Chesterfield 132 kV
Newark and Sherwood	Grantham and Sleaford 33 kV
Newark and Sherwood	Hawton 33 kV
Newark and Sherwood	Lincoln 33 kV
Newark and Sherwood	Staythorpe 132 kV
Newark and Sherwood	Stoke Bardolph 132 kV
Newark and Sherwood	The Nottingham Group

Local authority	NDP report title
Newark and Sherwood	West Burton 132 kV
Newark and Sherwood	Worksop 33 kV
Newcastle-under-Lyme	Cellarhead
Newport	Abergavenny and Panteg BSPs
Newport	Cardiff 132 kV
Newport	Cardiff East & North BSPs
Newport	Newport South BSP
Newport	Sudbrook BSP
Newport	Upper Boat 132 kV and 33 kV
Newport	Uskmouth GSP
North Devon	Barnstaple BSP
North Devon	Bowhays Cross BSP
North Devon	East Yelland BSP
North Devon	Exeter City BSP
North Devon	Indian Queens and Alverdiscott GSP group
North Devon	South Devon
North Devon	Taunton BSP and 132 kV
North Devon	Taunton BSP and 132 kV network
North Devon	Tiverton BSP
North East Derbyshire	Alfreton 33 kV
North East Derbyshire	Chesterfield 132 kV
North East Derbyshire	Chesterfield, Goitside and Buxton 33 kV
North East Derbyshire	Whitwell and Staveley 33 kV
North East Derbyshire	Willington 132 kV
North East Derbyshire	Winster 33 kV
North Kesteven	Bicker Fen 132 kV
North Kesteven	Boston 33 kV
North Kesteven	Bourne and Stamford 33 kV
North Kesteven	Grantham and Sleaford 33 kV
North Kesteven	Hawton 33 kV
North Kesteven	Lincoln 33 kV
North Kesteven	Staythorpe 132 kV
North Kesteven	Walpole 132 kV
North Kesteven	West Burton 132 kV
North Lincolnshire	Checkerhouse 33 kV
North Lincolnshire	Staythorpe 132 kV
North Northamptonshire	Bourne and Stamford 33 kV
North Northamptonshire	Corby 33 kV
North Northamptonshire	Grendon 132 kV
North Northamptonshire	Kettering and Kibworth 33 kV
North Northamptonshire	Melton and Oakham 33 kV

Local authority	NDP report title
North Northamptonshire	The Northampton Group
North Northamptonshire	Walpole 132 kV
North Northamptonshire	Wellingborough and Irthlingborough 33 kV
North Somerset	Avonmouth BSP
North Somerset	Bridgwater BSP and 132 kV network
North Somerset	Churchill BSP
North Somerset	Feeder Road BSP
North Somerset	Iron Acton GSP (South West)
North Somerset	Lockleaze and Bradley Stoke BSPs
North Somerset	Portishead BSP
North Somerset	Seabank and Sandford 132 kV
North Somerset	Weston BSP
North Warwickshire	Berkswell 132 kV
North Warwickshire	Coventry 132 kV
North Warwickshire	Hinckley and Nuneaton 33 kV
North Warwickshire	Lea Marston
North Warwickshire	Nechells East
North Warwickshire	Tamworth Grid and Tamworth Town 33 kV
North Warwickshire	The Coventry Group
North West Leicestershire	Burton, Burton South and Gresley 33 kV
North West Leicestershire	Coalville 33 kV
North West Leicestershire	Drakelow 132 kV
North West Leicestershire	Enderby 132 kV
North West Leicestershire	Lea Marston
North West Leicestershire	Loughborough 33 kV
North West Leicestershire	Ratcliffe 132 kV
North West Leicestershire	Spondon and Heanor 33 kV
North West Leicestershire	Tamworth Grid and Tamworth Town 33 kV
North West Leicestershire	Toton 33 kV
North West Leicestershire	Willington 132 kV
Nottingham	Annesley, Clipstone and Mansfield 33 kV
Nottingham	Chesterfield 132 kV
Nottingham	Ratcliffe 132 kV
Nottingham	Spondon and Heanor 33 kV
Nottingham	Stanton 33 kV
Nottingham	Stoke Bardolph 132 kV
Nottingham	The Nottingham Group
Nottingham	Toton 33 kV
Nottingham	Willington 132 kV
Nuneaton and Bedworth	Berkswell 132 kV
Nuneaton and Bedworth	Coventry 132 kV

Local authority	NDP report title
Nuneaton and Bedworth	Hinckley and Nuneaton 33 kV
Nuneaton and Bedworth	Lea Marston
Nuneaton and Bedworth	Tamworth Grid and Tamworth Town 33 kV
Nuneaton and Bedworth	The Coventry Group
Oadby and Wigston	Enderby 132 kV
Oadby and Wigston	Grendon 132 kV
Oadby and Wigston	Kettering and Kibworth 33 kV
Oadby and Wigston	The Leicester Group
Oadby and Wigston	Wigston 33 kV
Pembrokeshire	Carmarthen, Ammanford, Rhos, Llanarth and Lampeter BSPs
Pembrokeshire	Pembroke Group
Pembrokeshire	Pembroke GSP
Pembrokeshire	Swansea North GSP
Peterborough	Bourne and Stamford 33 kV
Peterborough	Spalding and South Holland 33 kV
Peterborough	Walpole 132 kV
Plymouth	Ernesettle BSP
Plymouth	Milehouse BSP
Plymouth	Plymouth BSP
Plymouth	Plympton BSP
Plymouth	South Devon
Powys	Abergavenny and Panteg BSPs
Powys	Bishops Wood
Powys	Carmarthen, Ammanford, Rhos, Llanarth and Lampeter BSPs
Powys	Dowlais 33 kV
Powys	Ebbw Vale BSP
Powys	Hirwaun & Travellers Rest 33 kV
Powys	Ironbridge and Shrewsbury
Powys	Rassau GSP
Powys	Swansea North BSP
Powys	Swansea North GSP
Powys	Upper Boat 132 kV and 33 kV
Redditch	Bishops Wood
Redditch	Feckenham
Rhondda Cynon Taf	Brynhill & East Aberthaw
Rhondda Cynon Taf	Dowlais 33 kV
Rhondda Cynon Taf	Hirwaun & Travellers Rest 33 kV
Rhondda Cynon Taf	Pyle 132 kV and 33 kV
Rhondda Cynon Taf	Pyle GSP
Rhondda Cynon Taf	Swansea North GSP
Rhondda Cynon Taf	Upper Boat 132 kV and 33 kV

Local authority	NDP report title
Rotherham	Chesterfield 132 kV
Rotherham	Whitwell and Staveley 33 kV
Rugby	Berkswell 132 kV
Rugby	Coventry 132 kV
Rugby	Daventry and Rugby 33 kV
Rugby	Hinckley and Nuneaton 33 kV
Rugby	Pailton 33 kV
Rugby	The Coventry Group
Rugby	Warwick and Harbury 33 kV
Rugby	Whitley 33 kV
Rushcliffe	Grendon 132 kV
Rushcliffe	Hawton 33 kV
Rushcliffe	Loughborough 33 kV
Rushcliffe	Melton and Oakham 33 kV
Rushcliffe	Ratcliffe 132 kV
Rushcliffe	Spondon and Heanor 33 kV
Rushcliffe	Staythorpe 132 kV
Rushcliffe	Stoke Bardolph 132 kV
Rushcliffe	The Nottingham Group
Rushcliffe	Toton 33 kV
Rushcliffe	Willington 132 kV
Rushcliffe	Willoughby 33 kV
Rutland	Bourne and Stamford 33 kV
Rutland	Corby 33 kV
Rutland	Grendon 132 kV
Rutland	Kettering and Kibworth 33 kV
Rutland	Melton and Oakham 33 kV
Rutland	Ratcliffe 132 kV
Rutland	Walpole 132 kV
Rutland	Willoughby 33 kV
Sandwell	Bustleholm
Sandwell	Kitwell
Sandwell	Penn
Sandwell	West Midlands Licence Area Report
Sandwell	Willenhall
Sheffield	Chesterfield 132 kV
Sheffield	Chesterfield, Goitside and Buxton 33 kV
Sheffield	Whitwell and Staveley 33 kV
Shropshire	Bishops Wood
Shropshire	Bushbury
Shropshire	Cellarhead

Local authority	NDP report title
Shropshire	Ironbridge and Shrewsbury
Shropshire	Penn
Solihull	Berkswell 132 kV
Solihull	Kitwell
Solihull	Lea Marston
Solihull	Nechells East
Solihull	The Coventry Group
Solihull	Warwick and Harbury 33 kV
Somerset	Axminster GSP
Somerset	Barnstaple BSP
Somerset	Bowhays Cross BSP
Somerset	Bridgwater BSP and 132 kV
Somerset	Bridgwater BSP and 132 kV network
Somerset	Churchill BSP
Somerset	Exeter Main BSP
Somerset	Indian Queens and Alverdiscott GSP group
Somerset	Radstock BSP
Somerset	Seabank and Sandford 132 kV
Somerset	South Devon
Somerset	Street BSP
Somerset	Taunton BSP and 132 kV
Somerset	Taunton BSP and 132 kV network
Somerset	Tiverton BSP
Somerset	Weston BSP
South Derbyshire	Burton, Burton South and Gresley 33 kV
South Derbyshire	Derby and Derby South 33 kV
South Derbyshire	Drakelow 132 kV
South Derbyshire	Lea Marston
South Derbyshire	Ratcliffe 132 kV
South Derbyshire	Spondon and Heanor 33 kV
South Derbyshire	Tamworth Grid and Tamworth Town 33 kV
South Derbyshire	Toton 33 kV
South Derbyshire	Uttoxeter 33 kV
South Derbyshire	Willington 132 kV
South Derbyshire	Winster 33 kV
South Gloucestershire	Avonmouth BSP
South Gloucestershire	Bath BSP
South Gloucestershire	Feeder Road BSP
South Gloucestershire	Iron Acton (West Midlands)
South Gloucestershire	Iron Acton GSP (South West)
South Gloucestershire	Lockleaze and Bradley Stoke BSP

Local authority	NDP report title
South Gloucestershire	Lockleaze and Bradley Stoke BSPs
South Gloucestershire	Radstock BSP
South Gloucestershire	Seabank and Sandford 132 kV
South Gloucestershire	Seabank BSP
South Hams	Ernesettle BSP
South Hams	Newton Abbot BSP
South Hams	Paignton BSP
South Hams	Plymouth BSP
South Hams	Plympton BSP
South Hams	South Devon
South Hams	Totnes BSP
South Holland	Boston 33 kV
South Holland	Bourne and Stamford 33 kV
South Holland	Spalding and South Holland 33 kV
South Holland	Walpole 132 kV
South Kesteven	Bicker Fen 132 kV
South Kesteven	Bourne and Stamford 33 kV
South Kesteven	Grantham and Sleaford 33 kV
South Kesteven	Grendon 132 kV
South Kesteven	Hawton 33 kV
South Kesteven	Melton and Oakham 33 kV
South Kesteven	Spalding and South Holland 33 kV
South Kesteven	Staythorpe 132 kV
South Kesteven	Walpole 132 kV
South Staffordshire	Bishops Wood
South Staffordshire	Bushbury
South Staffordshire	Bustleholm
South Staffordshire	Cellarhead
South Staffordshire	Ironbridge and Shrewsbury
South Staffordshire	Penn
South Staffordshire	Rugeley
Stafford	Bushbury
Stafford	Cellarhead
Stafford	Ironbridge and Shrewsbury
Stafford	Rugeley
Staffordshire Moorlands	Cellarhead
Staffordshire Moorlands	Chesterfield, Goitside and Buxton 33 kV
Staffordshire Moorlands	Uttoxeter 33 kV
Staffordshire Moorlands	Willington 132 kV
Staffordshire Moorlands	Winster 33 kV
Stoke-on-Trent	Cellarhead

Local authority	NDP report title
Stratford-on-Avon	Berkswell 132 kV
Stratford-on-Avon	Coventry 132 kV
Stratford-on-Avon	Daventry and Rugby 33 kV
Stratford-on-Avon	East Claydon 132 kV
Stratford-on-Avon	Feckenham
Stratford-on-Avon	Kitwell
Stratford-on-Avon	Lea Marston
Stratford-on-Avon	Warwick and Harbury 33 kV
Stroud	Iron Acton (West Midlands)
Stroud	Port Ham
Swansea	Briton Ferry and Tir John
Swansea	Briton Ferry and Tir John BSPs
Swansea	Carmarthen, Ammanford, Rhos, Llanarth and Lampeter BSPs
Swansea	Hirwaun & Travellers Rest 33 kV
Swansea	Swansea North 132 kV
Swansea	Swansea North BSP
Swansea	Swansea North GSP
Swansea	Swansea West
Swansea	Trostre BSP
Tamworth	Lea Marston
Tamworth	Tamworth Grid and Tamworth Town 33 kV
Teignbridge	Exeter City BSP
Teignbridge	Exmouth BSP
Teignbridge	Indian Queens and Alverdiscott GSP group
Teignbridge	Newton Abbot BSP
Teignbridge	Pyworthy North Tawton BSP group
Teignbridge	South Devon
Teignbridge	Sowton BSP
Teignbridge	Torquay BSP
Teignbridge	Totnes BSP
Telford and Wrekin	Cellarhead
Telford and Wrekin	Ironbridge and Shrewsbury
Tewkesbury	Bishops Wood
Tewkesbury	Feckenham
Tewkesbury	Iron Acton (West Midlands)
Tewkesbury	Port Ham
Torbay	Paignton BSP
Torbay	South Devon
Torbay	Torquay BSP
Torbay	Totnes BSP
Torfaen	Abergavenny and Panteg BSPs

Local authority	NDP report title
Torfaen	Crumlin BSP
Torfaen	Ebbw Vale BSP
Torfaen	Rassau GSP
Torfaen	Uskmouth GSP
Torridge	Barnstaple BSP
Torridge	East Yelland BSP
Torridge	Exeter City BSP
Torridge	Indian Queens and Alverdiscott GSP group
Torridge	Pyworthy North Tawton BSP group
Torridge	South Devon
Vale of Glamorgan	Bridgend 33 kV
Vale of Glamorgan	Brynhill & East Aberthaw
Vale of Glamorgan	Cardiff 132 kV
Vale of Glamorgan	Cardiff Cental & West 33 kV
Vale of Glamorgan	Pyle 132 kV and 33 kV
Vale of Glamorgan	Upper Boat 132 kV and 33 kV
Walsall	Bushbury
Walsall	Bustleholm
Walsall	Penn
Walsall	Rugeley
Walsall	West Midlands Licence Area Report
Walsall	Willenhall
Warwick	Berkswell 132 kV
Warwick	Coventry 132 kV
Warwick	Lea Marston
Warwick	The Coventry Group
Warwick	Warwick and Harbury 33 kV
Warwick	Whitley 33 kV
West Devon	Barnstaple BSP
West Devon	Ernesettle BSP
West Devon	Exeter City BSP
West Devon	Indian Queens and Alverdiscott GSP group
West Devon	Landulph St Germans BSP group
West Devon	Plympton BSP
West Devon	Pyworthy North Tawton BSP group
West Devon	South Devon
West Devon	Totnes BSP
West Lindsey	Bicker Fen 132 kV
West Lindsey	Grantham and Sleaford 33 kV
West Lindsey	Lincoln 33 kV
West Lindsey	Skegness 33 kV

Local authority	NDP report title
West Lindsey	West Burton 132 kV
West Northamptonshire	Berkswell 132 kV
West Northamptonshire	Brackley and Stony Stratford 33 kV
West Northamptonshire	Bradwell Abbey and Bletchley 33 kV
West Northamptonshire	Coventry 132 kV
West Northamptonshire	Daventry and Rugby 33 kV
West Northamptonshire	East Claydon 132 kV
West Northamptonshire	Feckenham
West Northamptonshire	Grendon 132 kV
West Northamptonshire	Kettering and Kibworth 33 kV
West Northamptonshire	Pailton 33 kV
West Northamptonshire	The Northampton Group
West Northamptonshire	Warwick and Harbury 33 kV
West Northamptonshire	Wellingborough and Irthlingborough 33 kV
West Oxfordshire	Feckenham
Wiltshire	Bath BSP
Wiltshire	Iron Acton (West Midlands)
Wolverhampton	Bushbury
Wolverhampton	Penn
Wolverhampton	West Midlands Licence Area Report
Wolverhampton	Willenhall
Worcester	Bishops Wood
Wychavon	Bishops Wood
Wychavon	Feckenham
Wychavon	Port Ham
Wyre Forest	Bishops Wood
Wyre Forest	Penn

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