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Methodology

Network Development Plan

April 2023 – an update of 2022 methodology for the Network Scenario Headroom Report only

Contents

1. Introduction and Form of Statement

Publication of a Network Development Plan has been a regulatory requirement for the DNOs since 2022, in accordance with Standard Licence Condition 25B. Working via the Energy Networks Association, the detailed scope of the publication has been agreed collectively for the industry with stakeholder engagement in a form of statement. Following experience with the first publication of the Network Development Plan in 2022, the form of statement was updated at the end of 2022, with minor clarifications to the guidance highlighted.

The Network Development Plan (NDP) consists of three components:

1. Network Development Report (plans for infrastructure and flexibility services, updated every two years)
2. Network Scenario Headroom Report (NSHR) (data tables for demand and generation, updated annually – these show unused substation capacity, noting this capacity may be committed or contracted to customers)
3. Methodology (**this document**, updated as needed).

For 2023, we are only publishing the Network Scenario Headroom Report and updates to the Methodology. The Network Development Report will be updated in 2024.

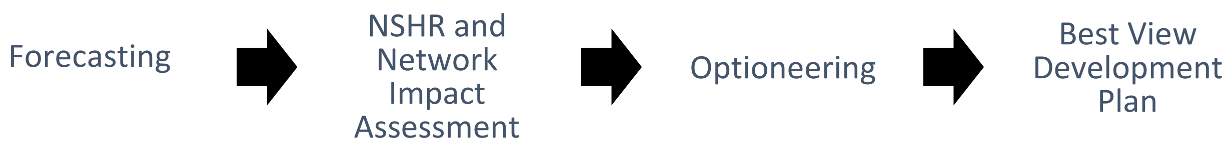
This is the standalone methodology document for the NDP for all UK Power Networks' licence areas – Eastern Power Networks (EPN), South Eastern Power Networks (SPN) and London Power Networks (LPN).

The NDP Methodology explains how the unused capacity (headroom) in the Network Scenario Headroom Report was calculated and how network requirements in the Network Development Report are decided. It describes the business-as-usual end-to-end processes underlying the NDP as an integral part of DNO network planning and truly reflective of best view developments. Sufficient detail is provided to allow stakeholders to understand sensitivities and extrapolate the NDP results. This includes details of the assumptions made by the licensee in preparing the NDP.

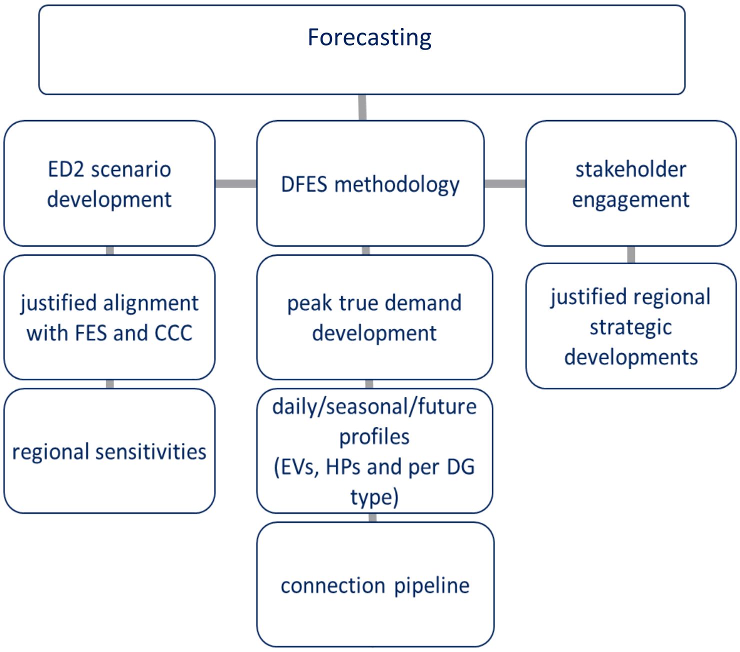
At a high level, the scope of the NDP Methodology includes:

- Relevance of the reported parameters;
- Description of the end to end process shown below;
- References to published data and network parameters; and
- Assumptions, for example those on the export from existing and accepted generation connections.

The methodology document covers the network planning end-to-end process over sections 2-5:



2. Methodology – Forecasting



This section of the methodology explains how regional forecasts for each UK Power Networks area have been developed and describes the building blocks that underlie the forecasting approach covering the high-level aspects of how forecasts are created as shown above. Specifically this includes: what parameters are forecast; the steps taken to create the forecasts; and how they are informed, alongside descriptions of the adopted scenarios. It details what differentiates a best view forecast from those which define the range of an uncertain future, in particular how policy, stakeholder engagement and local characteristics are considered.

We have worked together with our stakeholders and Element Energy to develop our Strategic Forecasting System and to publish annually a set of Distribution Future Energy Scenarios (DFES) describing the evolution of demand and generation across our licence areas out to 2050. The scenarios modelled show that the greatest uncertainties relate to the extent and pace of decarbonisation of heating, transport and of the electricity generation mix (uptake of distributed renewables/storage). This matters because electrification of transport and heat results in significant load growth and it is key to ensuring there is sufficient network capacity, so the electricity network is not a barrier for the uptake of LCTs, or for connection of distributed generation, under any scenario.

Our published DFES documents provide further information on the methodologies used to produce DFES. The Strategic Forecasting System contains daily and seasonal profiles for assumed electrical consumption and generation – these are not simple profiles per kW installed, but in the case of demand technologies are also related to the underlying demands for heat and transport energy (kWh) which are then converted to kW and assigned to the appropriate substation. These profiles are combined with the predicted volumes of new Low Carbon Technologies (LCTs) into additional electrical power flows.

In relation the 2023 NDP, a 2022 baseline is used. This uses different DFES versions for demand and generation.

- DFES 2022 – the assumptions in this DFES are combined with the substation 2022 demand data (for the period 1 April 2021 to 31 March 2022)
- DFES 2023 – this DFES starts from a 2022 installed generation baseline.

DFES considers four scenarios to capture the broad range of different possible futures for demand and generation across our region. Two of these scenarios, System Transformation and Consumer Transformation, are consistent with a Net Zero energy system by 2050, reflecting the significant uncertainty in key areas such as the decarbonisation of heating.

The Leading the Way scenario sees an acceleration in the uptake of LCTs, resulting in achieving Net Zero before 2050. The Steady Progression scenario however forecasts a slower uptake and therefore fails to meet the 2050 Net Zero target. The four scenario worlds are structured as follows:

- **Steady Progression:** General progress towards decarbonisation continues; however, the rate of change is not sufficient to meet Net Zero carbon emissions by 2050. (In our DFES 2023, this scenario has been renamed to Falling Short based on National Grid ESO's Future Energy Scenarios (FES) 2022 publication. We continue to refer to Steady Progression throughout this document, since DFES 2022 was used to produce our 2022 planning outputs which are presented in the 2023 Network Scenario Headroom Report
- **Consumer Transformation:** Meets Net Zero emission by 2050 with significant engagement and behavioural change at an individual level and a high degree of electrification
- **System Transformation:** Meets Net Zero driven primarily by centralised initiatives and transformation of existing infrastructure, including the production of low-carbon hydrogen, requiring less change for individuals; and
- **Leading the Way:** Achieves Net Zero before the 2050 target, thanks to use of both electric and hydrogen decarbonisation technologies, as well as high level on consumer engagement.

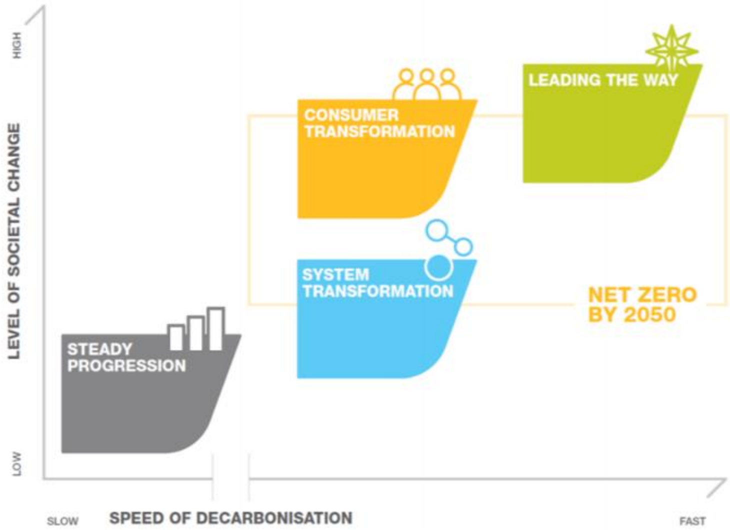


Figure 1 The four DFES scenario worlds

Table 1 Key Assumptions under each scenario in DFES 2022

	Steady Progression	System Transformation	Consumer Transformation	Leading the Way
2050 Net zero compliant	**No**	**Yes**	**Yes**	**Yes**
Electricity demand	Consumers buy similar appliances to today. UK targets for energy efficiency missed.	Reasonable progress in electrical efficiency but insufficient to meet a 30% target. Consumer move towards smaller appliances.	Good progress in electrical efficiency, which leads to a 30% reduction in consumption. Heat and transport mostly electrified.	UK residential electrical efficiency targets enhanced. Consumers rapidly move towards smaller appliances.
Transport incl. EVs	Slow EV uptake Low growth in public transport. EV charging at home is limited.	Internal combustion engines are phased out (petrol, diesel and hybrid cars removed from the market in 2030, and plug-in hybrids in 2035). The perceived access to charging improves.		Same electrification and mileage assumption as ST/CT. However in addition, high demand for autonomous shared mobility and public transport, means smaller increase in car stock growth and therefore EV demand.
Heat	Heat networks not decarbonised. Pilot on clean heat solutions don't scale.	Heat networks switch to mainly hydrogen. Electricity based solutions adopted in mainly new builds and off gas grid.	Heating largely electrified using a combination of building level technologies and district heating.	Solutions are mix of electrification and hydrogen for heating.
Generation	Slow transition to decarbonisation. Non-renewable generation not phased out by 2050.	High development of Renewable Energy (RE) and low-carbon technologies. Geared towards larger, more centralised projects.	High development of RE and low-carbon technologies. Geared towards smaller more decentralised projects.	Highest level to support hydrogen from electrolysis. Develop new projects include CCUS.

Approach to convert from DFES assumptions to substation loading

The translation of the information from our Distribution Future Energy Scenarios (DFES) into peak and minimum load on a specific substation is carried out in the following steps:

The load growth model within the Strategic Forecasting System follows the general logic of first **establishing the number of units** (this would refer to customer connection counts, but also to LCTs). These are often resolved across **different archetypes,** and have a bespoke forecast for each unit for future years (considering growth/uptake scenarios from the DFES).

The scenarios describe the technology deployment at high geographical resolution, making use of the boundaries defined by the Office for National Statistics (ONS). These are called:

- Middle Layer Super Output Areas (MSOAs); and
- Lower Layer Super Output Areas (LSOAs)

Our region is made up of about 2,200 MSOAs which in turn are made up of around **11,000 LSOAs**. The average dimensions of MSOAs and LSOAs across England are given in Table 2 below.

Table 2 Average dimensions of MSOA and LSOA across England

Geography	Minimum population	Maximum population	Minimum number of households	Maximum number of households
LSOA	1,000	3,000	400	1,200
MSOA	5,000	15,000	2,000	6,000

The best available data is used to allocate units geospatially. The model is informed with LCT uptake at LSOA resolution, and the underlying distribution network topology resolves customer counts at LV Feeder level.

The annual consumption (or generation) is modelled for each unit, which is typically archetype specific and subject to additional scenario assumptions, such as changes in energy efficiency.

Once the annual consumption of a specific electricity consumer/generator is established, a profile shape is applied, which is characteristic for the diurnal load (customer behaviour throughout the day). Once the daily load is defined (for specific loading conditions and seasons), the peak load can be obtained. **This peak load is corrected to reflect diversity**, taking into account the phenomenon that a smaller number of customers will cause a higher per customer unit peak on the network than a larger number of customers (see below for additional information).

Low carbon technologies

The load growth model within the Strategic Forecasting System (SFS) considers the uptake of heat pumps, district heating, air conditioning, EVs and solar PV as the most important growing technology segments. Heat pump uptake is modelled in a separate module and considers the various building archetypes separately. This module applies the uptake for each archetype as produced by the Element Energy Renewable Heat model in the DFES, which considers the business case and willingness-to-pay assumptions and evaluates the most suitable heating types for specific building archetypes. heat pumps (and traditional electric heating) are then allocated to specific customer connections, depending on their LSOA location and building archetype.

EVs are modelled in line with the Recharge the Future project conducted by us in partnership with Element Energy. This module has been enhanced since the project; it now considers a variety of additional transport segments, such as vans, taxis and motorcycles. A great number of vehicle types and charging behaviours are considered within each segment.

Generation

The model considers a table of known large generator sites (including near term forecast of the accepted connections pipeline). For these locations, the installation size (capacity), location and fuel type is defined and modelled accordingly. Small scale installations (typically solar PV) that connect behind the meter at LV level are distributed to LV customers. This is informed by uptake assumptions at LSOA level. The model also considers a range of storage installations, which mostly play a role in the constraints modelling.

There are a number of uncertainties which have been modelled based on the best available information, for instance discussions with water and wastewater companies have identified the potential for the reduction of generation output from some sites in order to divert fuels to power the utilities fleet of vehicles, as green electricity can be purchased on a commercial basis, in so reducing CO_2 impact further.

EV charging

This sub section describes the key assumptions and process by which we have modelled EV related demand.

EV uptake forecasts at GB level are disaggregated geospatially using the best available deployment data. Over the shorter term we have forecast PHEV and BEV registrations (modelled at GB level) and allocated to area units according to the historic uptake proportion using DfT and DVLA data. In the longer-term analysis, we then blend towards the distribution of car ownership. In the near term, hotspots form in areas that have a high proportion of early adopters in the baseline year and, as a result, we see high variation in the electrification between MSOAs in 2025, where anywhere from 12% to 42% of cars are electric. In 2030, EVs have reached the majority of the car stock in some MSOAs, but the hotspots are still visible. As the number of EVs grows, the difference in electrification between regions decreases and by 2050, the variation in electrification across MSOAs within our region is less than 3%.

Figure 2 shows an example of how we forecast how EVs will be dispersed across our networks.

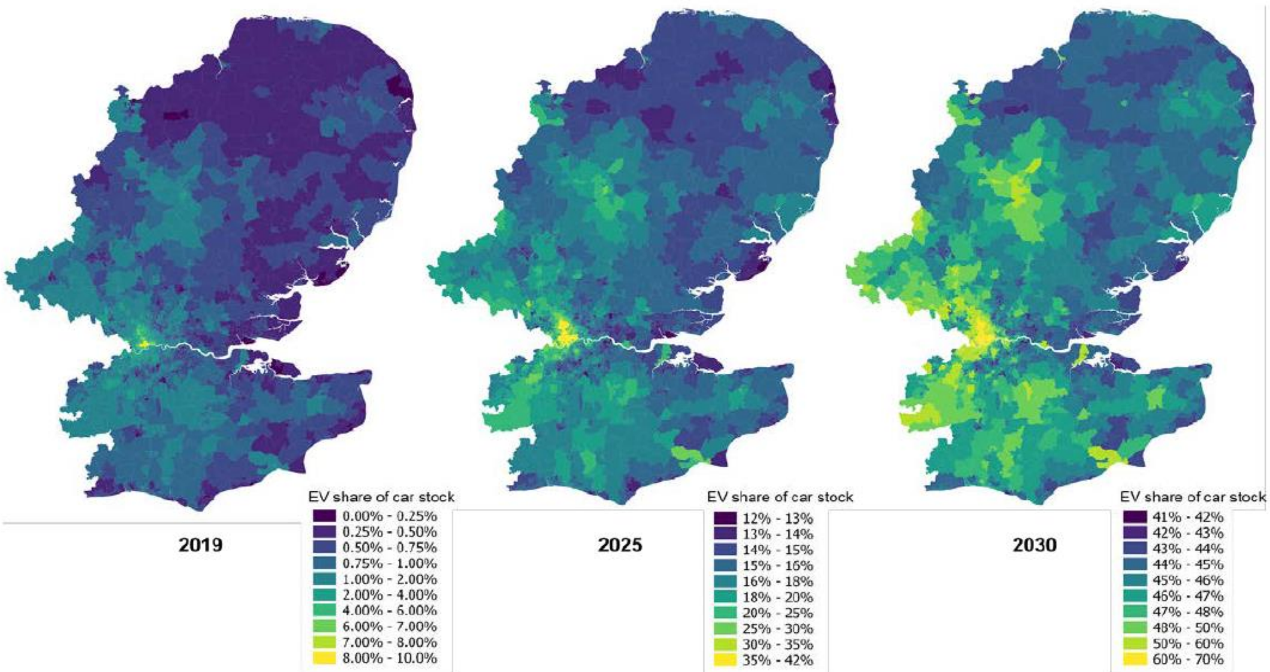


Figure 2: Heat maps showing the electrification of cars in Consumer Transformation and System Transformation at MSOA resolution in 2019, 2025 and 2030.Data from 2020 DFES publication.

The assumptions on LCT profiles that inform peak load estimates

As outlined in the previous section, the model determines an estimated annual consumption (or generation) for a host of customer types and technologies for each future year, scenario and at each network node. This annual consumption is then converted to a diurnal load profile. The load profiles from different technologies/customer types are stacked and the peak load is determined. This logic is repeated for each future year and network node.

The model considers profile shapes for each calendar month, and for min/average/max loading conditions. Furthermore, weekend and weekdays are distinguished where sufficient data is available.

3. Methodology – Network Scenario Headroom Report (NSHR)

NSHR Form of Statement

The NSHR is a component of the Network Development Plan (NDP). At the end of 2021, the Energy Networks Association's Open Networks group defined the scope or form of statement for the NDP and NSHR. The NSHR should be published annually, and has the following scope as defined in the form of statement available on the ENA website (2022 update).

The NSHR indicates where it is anticipated that there will be network capacity to accommodate future connections and where flexibility services may be required. Presented in tabular form, the format of the NSHR is to be consistent with the headings in Table 3 below for each scenario and year covered by the report.

Table 3 – Headings and guidance for the NSHR tables, based on the form of statement

Substation Name	Voltage kV	BSP Group	GSP	Substation location	Demand Headroom MW	Generation Headroom MW

Date range	Every year to be covered individually between 1-10 years.
	After the tenth year, this requirement moves to every five years up to 2050 or aligning with the final year of the Distribution Future Energy Scenario (DFES) forecast.
Scenarios	DFES scenarios, plus a best view scenario. *[UK Power Networks note – based on our current analysis we define the Consumer Transformation DFES scenario as our best view scenario]*
Network capacities and assessment methodology	Demand and generation headroom **(unused capacity rather than contractually available)** in MW **and/or MVA** per reported year per scenario. *[UK Power Networks note – this was updated with the parts in bold as clarifications as part of the 2022 update to the form of statement, but UK Power Networks continues to report in MW]*
	Headroom calculations are considerate of financially approved network developments in delivery or planned for delivery, including asset-based enhancements and the use of flexibility services. This may include updates in network developments in the timeframe 0-5 years which were not included in the latest LTDS (November). If included, this must be stated in the accompanying notes and updated in the next LTDS (end May).
	Headroom calculations are considerate of thermal loading and fault level constraints as a minimum.

Coverage	Capacity information is provided for substations where the greatest voltage is greater than 20kV. This is normally BSP and primary substations down to and including the primary secondary voltage, typically HV (20kV, 11kV or 6.6kV).
Format and publication	The format of the NSHR part of the NDP is tabular in nature, presented in Microsoft Excel or similar spreadsheet format. Interactivity can be added to the workbook to improve visualisation of the data. Guidance shall be included to explain the scope of the data workbook, define each data element and give user instructions. A contents and version control page is included to ensure that users are able to easily access data, accurately reference the report and view approvals. It also states the dates and versions of critical data sources including the LTDS and DFES.
	Licensees shall endeavour to refresh the NSHR with the latest Licensee's data annually, including the years in between publishing the whole NDP (which shall be published by 1 May every two years).
Information sources	Parameters for the existing network underlying the headroom calculations shall be based on the latest LTDS and incorporate a view of financially approved and planned interventions.
	Existing and future network demand and generation shall be based on the licensee's latest LTDS and DFES forecasts for demand and generation at the substation.
	It is expected that the flexibility services incorporated in the NSHR shall be in accordance with DNO Flexibility Procurement Statements and Reports or if not included in those reports, they must be stated in the accompanying notes. Publication of Flexibility Procurement Statements and Reports is a new Standard Licence Condition 31E, and reporting detail is yet to be finalised, but will likely include the location and magnitude of contracted and prospective flexibility services.

Methodology developments since the 2021 consultation

Particularly in the area of unused substation capacity for generation (headroom), our 2022 and 2023 methodology is a significant development from the headroom data published in our August 2021 tables for consultation.

As well as the updates to data baseline, specific methodology improvements have been delivered through our Strategic Forecasting System since the 2022 report:

- Refinement of the peak demand forecast methodology, to better reflect the contribution of different underlying load types per substation
- Including contracted flexibility services as a contribution to capacity for demand
- Improved allocation of generation to specific substations
- Revised assessment of firm capacity for reverse power flow from LTDS transformer ratings, including upstream constraints at Grid Substations and improved forecasts of minimum demand per scenario
- Revised approach to fault-level assessment from LTDS node ratings, including showing the difference between capacity for inverter-based and synchronous generation.

The generation NSHR methodology was further developed in 2023 to:

- Not limit the evaluation of thermal headroom in the generation NSHR to summer. The thermal headroom calculation considers two loading conditions (annual minimum and solar-impacted). We know in which season these occur. The future minimum demand forecast, site rating and generation forecast then reflect the appropriate conditions.

- Again for the generation NSHR, use forecast minimum observed demands from the Strategic Forecasting System for the thermal headroom calculation for the Generation Network Scenario Headroom; the forecast is no longer scaled from the peak demand forecast. The minimum demand in the base year remains based on cleansed measurement data in the previous year.

In 2023, the NSHR tables were also supplemented with information from National Grid Electricity Transmission on 'Earliest in Service Dates' from the perspective of transmission capacity for new applications of demand and generation >1MW (see the end of section 3 of this document for further details).

NSHR – aspects common to Demand and Generation

- For the NSHR published in May of year X, the data baseline is end March of the previous year (X-1). So the 2023 Network Development Plan and NSHR will be based on an end March 2022 baseline e.g. the demand baseline in LTDS November 2022 (with substation forecasts then based on DFES 2022 assumptions) before we update the baseline for the 2023 forecast cycle. DFES 2023 includes generation baseline from the end of March 2022.

- The list of substations included in the NSHR tables are those listed in the latest peak demand LTDS Table 3A/3B for each licence area (e.g. November 2022 for the May 2023 NSHR/NDP publication). This scope of included substations matches the latest LTDS publication by including all operational substations with a higher voltage above 20kV, excluding customer-owned substations and switching-stations at the same voltage level. In practice, this includes all UK Power Networks' Bulk Supply Point (Grid) and Primary substations. Grid Supply Points at the transmission-distribution interface are not in scope.

- The substation names, topology (GSP-Bulk Supply Point-Primary) and voltages are as listed in the latest LTDS Table 3A and 3B. Planned future substations or planned changes in naming or topology of a substation are not shown in the LTDS or the NSHR tables, but new substations will be noted in the Network Development Report.

- Substation locations based on Easting and Northing are as recorded in UK Power Networks' network management system report. Locations are also presented geographically on the data catalogue of our Open Data Portal.

- The report reflects headroom in each DFES scenario at substations. Headroom for specific connection applications will be assessed at their point of connection (PoC), so may reflect constraints between PoC and substation, including voltage. The NSHR tables cannot reflect those considerations.

- The report does not reflect the impact of quoted connection offers on headroom. It reflects an annual snapshot of headroom based on changes in demand and generation of existing connected customers, plus a proportion of accepted connections expected to proceed to connection over time.

- Where network topology is changed and substation is served from a different Bulk Supply Point group or GSP, the substation is shown on its original GSP and Bulk Supply Point.

- Based on our current analysis UK Power Networks considers Consumer Transformation to be its best view scenario.

  For planning purposes, UK Power Networks uses the Consumer Transformation scenario as its best view scenario. The choice of best view scenario is based on justification criteria related to:

  - alignment with existing/announced policies;
  - alignment with stakeholder engagement inputs; and
  - alignment with regional and local characteristic inputs.

For each licence area, the best view scenario is shown in the UK Power Networks' LTDS for five years ahead e.g. Table 3A and 3B in the LTDS show Grid and Primary substation peak demand forecasts. The best view scenario is also the key input to the network developments shown in the LTDS for five years ahead.

- Transmission network capacity will affect ability to connect at Primary and Grid substations, but this is outside the scope of the Network Development Plan. Information is not available from National Grid ESO to indicate headroom constraints at Grid Supply Points on the same basis as shown in the NSHR for the Network Development Plan i.e. on a physically unused capacity basis per scenario. On a contractually available basis, generation headroom information is available with a time lag for some substations via the Appendix G process (see bottom of our DER webpage), based on headrooms agreed with National Grid ESO. Similar data is not routinely produced for demand constraints by National Grid ESO.

- For substations which are disconnected, the headroom is shown as zero from the year of disconnection onwards.

Demand – DFES Network Headroom Methodology

1. Demand headroom at a substation in a given year and demand scenario is the minimum of winter firm capacity *minus* winter peak demand and summer firm capacity *minus* summer peak demand as shown in Figure 3. The demand is true demand, consistent with that published in LTDS Table 3B.

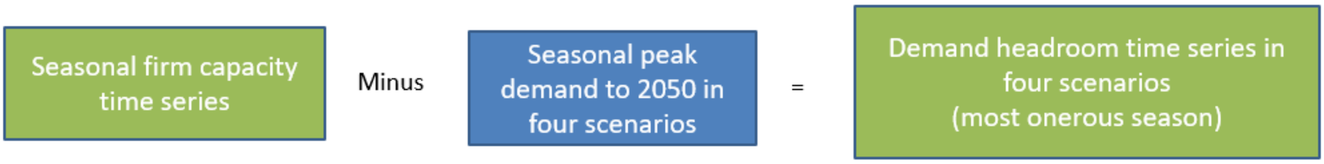


Figure 3 – High-level approach to estimating unused capacity for demand per substation

2. Headroom is calculated annually in each DFES scenario for the first ten years from the baseline year, and then every five years to 2050.

3. The demand headroom tables also include a column indicating 'capacity committed to connected customers but not utilised in 2020, undiversified', per substation, in units of MVA. This value in the baseline year is not used in the demand headroom calculation, but is provided for context and is published to Ofgem in each year's Load Index report. The context this provides for example is that there may be unused capacity on a substation, but the committed capacity indicates that some of that capacity may already be contractually allocated to connected customers who have not yet taken their full load. The DFES demand scenarios and headroom calculations indicate the extent (on a diversified basis) to which our planning then assumes uptake of that load and assumes usage of available capacity by future accepted connections.

Seasonal peak demands to 2050

4. The demand headroom is based on seasonal peak true demand, with peaks in the initial year consistent with the base year value in the last published LTDS Table 3B.
    a. This is consistent with the interpretation of group demand in Engineering Recommendation P2/7 and EREP 130.
    b. For the 2022 publication, the seasonal substation loading baseline is 2020/21, consistent with the latest LTDS Table 3B (November 2021). This would repeat for future years.
    c. Table 3B shows the peak of true demand, calculated as observed demand in normal running arrangements adjusted upwards for latent demand served by generation.

5. The peak demand forecasts are based on the latest DFES which have been converted to substation peak demands for the four DFES scenarios – Consumer Transformation, Leading the Way, Steady Progression[1] and System Transformation.

[1] Our NSHR 2023 reflects the demand assumptions in DFES 2022. Steady Progression in National Grid ESO's Future Energy Scenario (FES) publication in 2022 has been renamed to Falling Short in FES 2023 and DFES 2023.

a. LTDS Table 3B shows a single DFES Scenario for five years ahead e.g. LTDS November 21 showed Consumer Transformation from DFES 2021. This would repeat for future years.
b. The NSHR extends the timescale of the LTDS demand forecast, and provides anticipated headroom in that scenario and other DFES scenarios.
c. For the 2022 NSHR reflecting the 2021 demand scenarios, the baseline for substation demand is 2020/21 and the demand forecasts reflect a snapshot of connections activity mid-2021 and the assumptions in DFES 2021 (published January 2021).
d. For the 2023 NSHR reflecting the 2022 demand scenarios, the baseline for substation demand will be 2021/22 and the demand forecasts reflect the assumptions in DFES 2022 (published January 2022).

New DFES assumptions are published each year; but will not be converted to substation peak demands or reflected in an LTDS forecast until the relevant November LTDS.

6. The baseline winter peak demands are corrected for average cold spell; summer demands are not adjusted for average summer conditions.

Seasonal firm capacities to 2050

7. Seasonal firm capacities for specific substations are stated in MW and are based on
   a. Winter or summer **asset-based firm capacities** including appropriate transfer capacity (calculated by network planning teams)
      i. These are the capacities shown in LTDS, plus planned changes that will be highlighted in the Network Development Report.
   b. Winter or summer **contribution to firm capacity from contracted flexibility services** (sum of dynamic and secure flexibility contracts at the substation). Definitions of flexibility service products and procurement approach are consistent with the LC31 statement submitted to Ofgem at the end of March 2022, indicated on our Flexibility Hub and summarised in Table 4 below.

Table 4 – Summary of flexibility services products procured by UK Power Networks

Product	Constraint voltage	Payment structure	Provider commitment	Dispatch mechanism
Secure	EHV/HV	Availability (£/MW/h) Utilisation (£/MWh)	High (forward commitment of price and volume)	Real-time instruction
Dynamic	EHV/HV	Utilisation (£/MWh)	Low (optional in real-time)	Real-time instruction
	LV			
Sustain	LV	Service fee (£/kW)	Medium (optional month-ahead)	Scheduled month-ahead

      i. Where the same flexibility asset could offer both the dynamic or secure flexibility service, the contribution to capacity is not double-counted.
   c. Where winter is defined as November to March and summer as May to September.

8. Where there is a planned change in capacity (driven by a connectivity change, load-related investment or non-load driver), the capacity and therefore headroom is adjusted accordingly in the year of transfer for the new capacity to reflect the revised capacity on the network. Such changes are listed in the Network Development Report.

9. LTDS Table 3A and 3B are not generally updated between November and the following May LTDS publication, as the update in the loading baseline is reflected annually in the November publication. However if any changes to sites, load or firm capacities are made to these tables, this will be reflected in the NSHR and stated in the accompanying notes.

Generation – DFES Network Headroom Methodology

General approach

The generation headroom is defined as the minimum of the available thermal headroom and fault level headroom, for a given substation and year as shown in Figure 4.

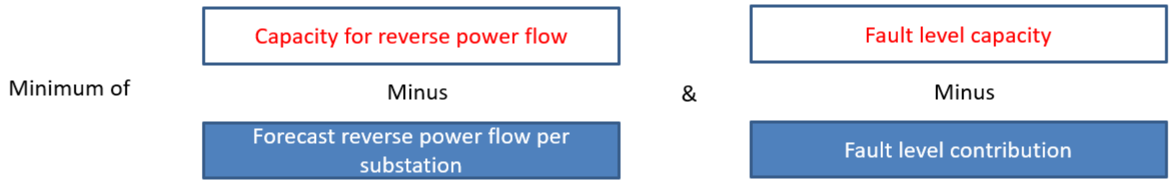


Figure 4 – High-level approach to unused capacity for generation at a substation

Figure 5 below gives a more detailed overview of the various constraints and parameters considered in the methodology applied since the May 2022 submission of the NSHR generation tables. Voltage and harmonics are not considered in this report, but are considered in planning of any new connections.

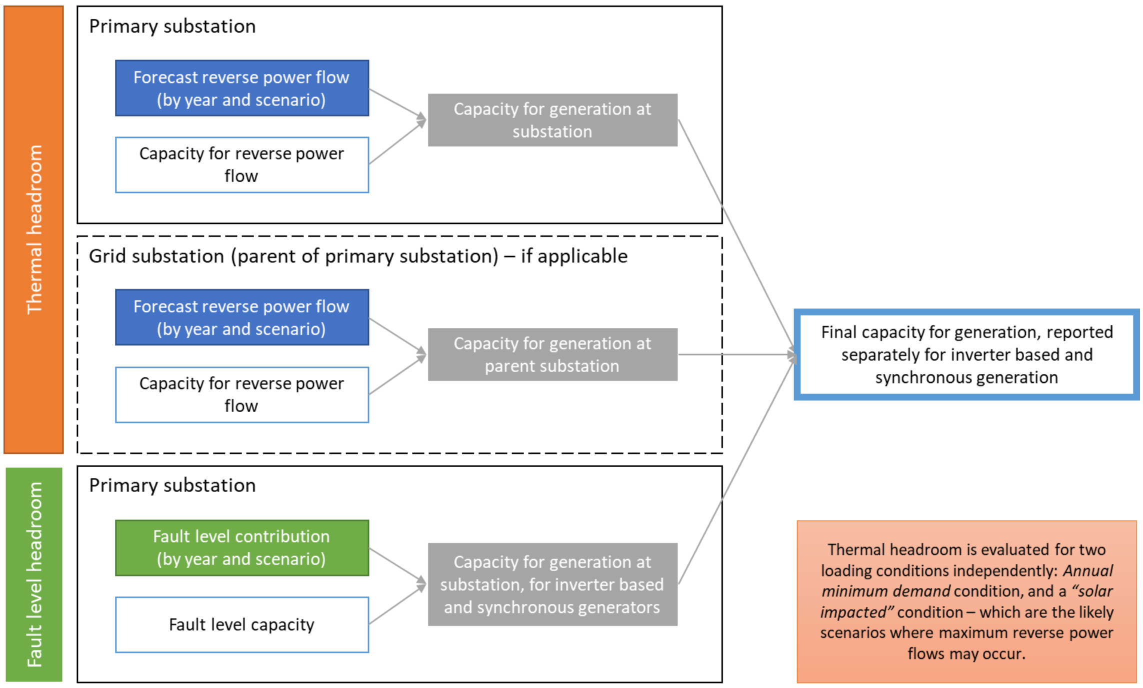


Figure 5 – Detailed overview of the generation headroom methodology

The methodology to establish the DFES generation scenario and their spatial distribution is described in our DFES 2023 report – the notes below relate to allocation of the generation per scenario *at each Primary and Grid substation*. The allocation of generation to Primary and Grid substation is not completed as part of production of the DFES – however generation is fully allocated to substations as part of developing the NSHR.

a. The baseline is connected generation. Embedded Capacity Register (ECR) for generation lists generators >=1MW that are both connected and accepted for connection. Smaller connected generation is based on allocation of metered generators to specific network locations and unmetered generators such as PV based feed-in-tariff and EREC G99 registration data.

b. Accepted generators from the ECR contribute to the DFES scenarios via assumptions on the likelihood and timeframe during which this pipeline of accepted connectors are forecast to connect to the network.

c. Beyond the consideration of accepted generators, the DFES also consider a long term forecast. For this modelled future generation capacity, the exact location, point of network connection and capacity per unit is not known. Forecasted generation is established for each Middle Super Output Layer (MSOA) in the DFES, and this generation is then allocated to the relevant substation region. The DFES consider a range of factors, such as land availability (for PV) to distribute generators geographically. There is then further validation by typical connection voltage to determine the likely connection at/below a Primary, Bulk Supply Point or above. This excludes connections at 132kV from the analysis of Primary and Bulk Supply Points for the NSHR. The typical voltage connection split has also been considered, connecting a fraction of the forecasted capacity directly to bulk supply points or above.

d. Future generation within the DFES scenario is allocated to a specific primary (defined by primary area served GIS data), depending on how the MSOA and primary areas are overlapping, noting that the exact location of all future generation in the scenario is unknown. Best available mapping from MSOAs to postcodes served by primary substations has been applied.

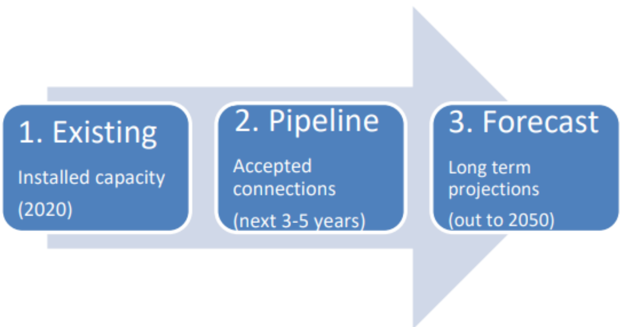
e. Accepted generators (larger than 150 kW) are considered at their registered point of connection.

f. The DFES also defines small scale generation (solar PV with a capacity < 150 kW, and small scale storage), which feeds into the analysis via the LV network topology.

We assume maximum generation output for future generation connections, and the actual output of existing generation in the base year.

Overall this methodology treats the calculated unused capacity for generation as **a potential over-estimate** and **indicative**, since forecasted generation in the DFES is based on allocation of existing generation, a proportion of accepted connections (pipeline) and hypothetical connections projects to a substation. This approach to developing a forecast of generation for DFES is shown in Figure 6.

As future generation in the DFES scenarios is allocated proportionately across the network based on pipeline while actual connections will be at point locations, the generation headroom in this report should be considered **best-case indicative** values of unused capacity (headroom) at the Primary and Bulk Supply Point. In practice an actual project of 5-20MW may connect at a specific primary, rather than being spread across all Primaries that serve a geographic region (MSOA). Similarly, the pipeline percentage scales back the MW of each accepted generator for the appropriate scenario, which means that all accepted generators are modelled at reduced capacity, rather than forecasting the connection of only a few large generators. (Depending on the scenario, only a fraction of the accepted capacity may be deployed, refer to Figure 6).



Technology	Renewable	Pipeline connection rate in scenario (low / medium / high)	Pipeline length	Long-term forecast
Solar PV	✓	20% / 60% / 90%	5 years	Element Energy in-house modelling
Offshore wind	✓	No accepted connections	-	Expected to connect at transmission level in future
Onshore wind	✓	20% / 60% / 90%	5 years	Regional disaggregation of NGESO's FES
Renewable engines (landfill-, sewage- and biogas)	✓	20% / 60% / 90%	3 years	Regional disaggregation of NGESO's FES
Waste incineration (including CHP)	*	20% / 60% / 90%	5 years	Regional disaggregation of NGESO's FES
Biomass and energy crops (including CHP)	✓	20% / 60% / 90%	5 years	Regional disaggregation of NGESO's FES
Hydrogen generation	**	No accepted connections	-	Regional disaggregation of NGESO's FES
Non-renewable CHP	✗	20% / 60% / 90%	3 years	Regional disaggregation of NGESO's FES
Non-renewable engines (non-CHP)	✗	10% / 40% / 90%	3 years	Regional disaggregation of NGESO's FES
OCGTs and CCGTs	✗	20% / 60% / 90%	3 years	Regional disaggregation of NGESO's FES

* Energy from waste is only partially renewable due to the presence of fossil-based carbon in the waste.
** Electricity produced from hydrogen will only be renewable if the hydrogen renewable, i.e. produced via electrolysis using renewable electricity.

Figure 6 DFES approach to model distributed generation (from DFES 2022, Figure 26 and Table 11)

Furthermore, additional constraints may apply at the Grid Supply Point interface or upstream on the transmission network.

Note that due to these factors and the importance of exact generator locations, voltage constraints and seasonal aspects of constraints for generation, these unused capacity headroom figures should still be treated as best-case **indicative** and are likely to over-estimate actual generation headroom. Prospective connection customers should apply to the UK Power Networks connections gateway for an assessment of available capacity which reflects detailed modelling for generation, including seasonally modelled fault-level contribution of existing and accepted generation connections with exact network locations, and the impact of any transmission constraints.

Thermal headroom

Thermal headroom for reverse power flow on a firm capacity basis =

(Substation thermal capacity for reverse power flow + Minimum true demand)
minus
(Actual output of existing generation + Maximum generation output for future installations)

Two conditions are considered: The minimum observed demand of the entire year (informing the annual minimum demand conditions), and a second value observed during times susceptible to high future solar PV output (informing solar-impacted conditions).

Assumptions

a. The analysis of thermal headroom is performed for two conditions:
   - once for annual minimum demand conditions (which typically occurs during the night, and therefore the impact of future solar PV generation is discounted here),
   - and for minimum summer daytime demand with maximum generation including solar PV (considering demand conditions from May to August between 10am and 3pm).

   This approach enables consideration of the two key time periods for low observed demand – times of low true demand and no solar irradiation, and times of moderate true demand but high (future) generation including output from solar PV.

b. Forecasts of reverse power flow are created. Reverse power flow is a negative observed demand (the largest negative value being the maximum reverse power flow).

   The starting point for the evaluation of thermal headroom is a value extracted from the Data Cleansing Tool (part of our Strategic Forecasting System). For each substation, the minimum observed demand is extracted from 12 month of monitoring data. This minimum observed demand considers the contribution from all existing embedded generators (their actual output at the time of min observed demand, not representing the total generator capacity).

   - Base year values. Cleansed half-hourly data series of observed demand, latent demand (from generation) and true demand were assessed on a half-hourly basis for the baseline year for each substation. For the spring 2022 publication, the baseline is 1 April 2020 to 31 March 2021, and similarly in subsequent years. This baseline data was used in two ways for the analysis.
   - Identifying the substation annual minimum observed demand (combination of true and latent demand), for the year 2020/21. This informs the starting point for the minimum demand forecast for future years, representing minimum demand at a time that usually won't be impacted by solar PV. This was generally a summer minimum.
   - Identifying the substation that summer daytime minimum observed demand between 10am and 3pm during spring/summer, for the year 2020/21. This informs the starting point for the daytime minimum demand forecast for future years, representing a time that is going to be strongly impacted by solar PV.

      i. Forecasts of reverse power flow were then created by combining the base year value (i) with forecasts of minimum true demand and generation (latent demand).

Forecasts of minimum true demand in each DFES scenario were produced from the Strategic Forecasting System (SFS). In addition, we create a forecast of how much generator capacity will connect in future (considering accepted generators and long term DFES forecast).

These minimum true demand forecasts and generator capacity forecasts were applied to the base year starting point, to create scenarios of reverse power flows. This is done for the two conditions annual minimum and summer daytime minimum separately. When considering the annual minimum condition, we discount the impact of solar PV.

We thereby capture the two instances when the generation headroom may be constrained: at times of low demand and times of high (future) solar generation.

c. This assessment of generation output includes full consideration of additional future small scale solar PV (low-voltage domestic and industrial and commercial connections, smaller than 150 kW). This is particularly important for what we are calling our solar impacted minimum demand analysis (the spring/summer daytime minimum demand).

d. The rating for reverse power flow of an individual transformer at the substation (related to its tapchanger) is based on the rating of transformers as shown in LTDS Table 2A and 2B. If it is listed as <100% or 'not available', we assume 50% reverse power flow capability. In practice, while 50% capability is a reasonable starting assumption, further investigation of the rating would occur before reinforcement of a specific site.

   For future developments of the NSHR, the methodology would also reflect the deployment of load blinding relays for directional overcurrent protection. This can address protection-related constraints on reverse power flow so generation can be connected without need for further reinforcement. Some load blinding relays are already installed on the network, and a programme of further developments continues to be rolled out when constraints manifest.

   We are also undertaking a programme of site surveys to confirm reverse power flow ratings as part of our programme of work to release DG capacity.

e. The analysis only considers transformers listed in the previous November's LTDS, and unlike the demand headroom, does not reflect planned changes in substation capacity.

f. Noting there is no generation security planning standard, the total reverse power flow capacity for the substation applies an approach to generation security linked to Table 1 of Engineering Recommendation P2 for demand[2]. This approach determines the number of transformers and their individual rating. It then considers which are in service for reverse power flow in fault conditions at the substation.

   First, the reverse power flow (RPF) rating of all individual transformers at a substation is established based on the ratings in LTDS as described above. The sum total RPF across all transformers shall be called **X** in the below.

   Second, the reverse power flow capability of a substation is evaluated under different fault conditions:
   - Up to 12 MW reverse power flow: Maximum reverse power capacity is set to min(12 MW, **X** - largest transformer RPF capacity + 1 MW)
   - Above 12 MW reverse power flow: N-1 security: Maximum reverse power capacity is set to **X** - largest transformer.

   Finally, the largest reverse power capacity found across the conditions is established as the substation reverse power capability.

   There is no transfer capacity for reverse power flow considered in the methodology – this will be considered in future developments.

2 ENA_EREC_P2 (dcode.org.uk) [dcode.org.uk]

We make use of the power factors provided in LTDS table 3b to convert the transformer ratings (provided in MVA) to MW.

We establish a reverse power flow capability for summer and winter separately. Depending on the season in which the base year value (i) is observed, we apply the corresponding reverse power flow capability value in the thermal headroom analysis.

g. Upstream constraints on the distribution network are considered e.g. restrictions at primary substation due to restriction at Bulk Supply Point. However, upstream constraints at the transmission network (Grid Supply Point) have not been considered, as this is out of scope of the report.

Fault-level headroom (winter only)
Fault level (FL) headroom =

(FL rating at substation from LTDS)
minus
(Existing FL in LTDS + future contribution to FL from new generation connections in DFES scenario)

Assumptions

1. Fault level headroom is based on the fault level at winter peak as presented in the LTDS. In future, LTDS and NSHR may separately consider a summer and winter condition, and determine the worst case.
2. For fault levels in general, only those installations that connect at the voltage level directly below the substation are considered as able to contribute to fault level. So, the primary substation fault level analysis only considers those installations connecting to the HV network not LV; for grid sites it only considers the generation assumed to be installed at 33kV. It is assumed that demand growth (EV, HP) makes no impact on future FL for either three phase and earth faults.
3. Per substation, identify FL ratings per node, obtained from LTDS Table 4a and 4b (both peak make and RMS break for three phase and earth faults), example shown in Table 5 below in which Aberdeen Pl A 11kV has a peak make rating of 32.8kA and 13.1 kA break. The FL rating per substation is the minimum of rating per node at the substation, and has been evaluated in the standard running arrangement, noting that the LTDS tables do not consistently provide information on whether the bars are run solid or open.

Substation	Node Name	Fault Rating	
		Peak Make	Break
		kA	kA
Aberdeen Pl A 11kV	ABPA51	32.8	13.1
Aberdeen Pl A 11kV	ABPA52	32.8	13.1
Aberdeen Pl B 11kV	ABPB51	32.8	13.1
Acton Lane 22kV	ACTL81	49.0	19.6
Amberley Rd 11kV	AMBL51	50.0	20.0
Amberley Rd 11kV	AMBL52	50.0	20.0
Axe St 11kV	AXES51	32.8	13.1
Axe St 11kV	AXES52	32.8	13.1

Table 5 – Excerpt from LTDS Table 4 for LPN showing fault ratings

4. Per substation, identify the FL contribution for existing generation connected, again from LTDS Table 4a and 4b.
5. Table 6 shows the RMS break FL contribution factor per MW assumed for additional generation connecting, beyond that already connected in the baseline year. Typical ratio between peak make and RMS break currents is 2.5. Both make and break constraints are assessed.

Table 6 Assumed RMS break fault level factors for different DFES forecast generation types

Type of generation	Factor
Biomass & energy crops (including CHP)	4
Non-renewable CHP (<=1 MW)	4
Non-renewable CHP (>1 MW)	4
Non-renewable engines (Diesel) (non-CHP)	4
Non-renewable engines (Gas) (non-CHP)	4
Open Cycle and Combined Cycle Gas Turbines (OCGT and CCGT)	4
Onshore wind	1.5
Renewable engines (Landfill gas, Sewage Gas, Biogas)	4
Solar Generation (Large >150 kW)	1.5
Waste incineration (including CHP)	4
Fuel cells	1.5
Co-located storage	1.5
Storage	1.5
Hydrogen	1.5

The factor in Table 7 is defined as the initial symmetrical short-circuit current (I_k", IEC60909-0 Clause 1.3.5) for a three-phase fault at the network terminals of the DG plant, expressed as multiple of the plant's rated current (I_r).

6. For the calculation of the remaining headroom – after the effect on FL of both existing generation and forecast generation within the DFES scenario – this will be shown as the headroom available for converter-based generation (1.5 factor). Headroom for other generation technologies would be reduced typically by a factor of 4/1.5.
7. Assume maximum generation output (not seasonally adjusted for fault level).
8. The method for considering future fault-level uses simple assumptions for contribution by generation type, consistent with UK Power Networks' engineering design standard for fault levels (EDS 08-1110). This notes that a converter-connected generator contributes between 1.2 to 2.5 times of its rated output, and where detailed information is not available, a sub-transient fault current contribution of 1.5 times of rated output shall be assumed.

In future developments of the Strategic Forecasting System to produce NSHR, the methodology would use profiles of generation and demand in a modelled headroom calculation, not a peak and minimum snapshot value. For example, we combine peak generation output with minimum annual demand when considering reverse power flow capability but will combine profiles in the future. We also use a tabular approach for calculating future headroom now but will used a modelled approach in future. The methodology will also consider how we have incorporated learning from our innovation projects on how to address fault-level constraints.

Information from NGET – EISDs for new applications

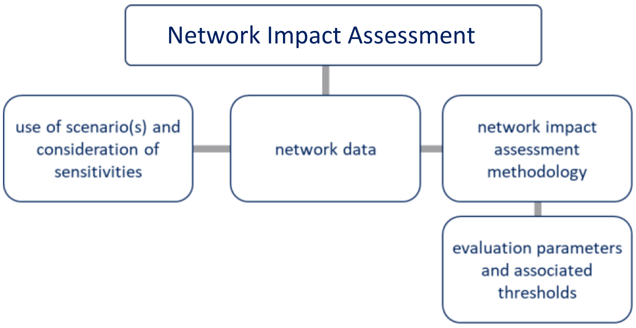
This section of the NSHR is new for 2023, and addresses stakeholder feedback to provide information on transmission constraints which would affect distribution customers' access to capacity on the distribution network in the different DFES scenarios. It is information provided by the transmission owner – National Grid Electricity Transmission (NGET) – and goes beyond the scope of the Network Development Plan in the licence as a description of the distribution network.

- Earliest in service dates (EISDs) represent a snapshot of the Transmission Owner's view at the 'freeze date' of the earliest date for connection for NEW applications for demand and generation of significant size (>1MW).
- For customers which already have accepted connections with a DNO, DNOs may already have agreed with transmission for earlier connection dates for demand and generation customers.
- For storage, both the demand and generation EISDs may be relevant.
- Where an EISD has not been established for a GSP, this is shown as N/A.
- There is likely to be some headroom for connection because there is no constraint yet defined with defined construction works affecting connection, this is shown as no date restriction identified.
- Where the transmission owner is actively reviewing construction works and earliest in service dates for new applications may be revised e.g. due to an application for capacity affecting that GSP, this is shown as under active review.
- The EISDs reflect both works at a Grid Supply Point and in wider transmission network.
- Unlike the rest of the DNO NSHR, this is a snapshot of current status based on connection applications, not a scenario based output.
- The list of GSPs includes at a minimum the GSPs associated with the primary substations and Bulk Supply Points in the DNO's last Long Term Development Statement Table 3. Future new GSPs may not be included.

Potential provision of EISDs per GSP (demand and generation) was highlighted in the December 2022 update of the NDP form of statement (p19/20) for the first time in the 2023 NSHR.

Given the current status of the transmission-distribution queue, it was expected that the 2023 snapshot of the EISDs would show many connection dates for new demand and generation in the late 2020s and 2030s. The next snapshot in early 2024 should show the benefit of the Transmission Reinforcement Works Review being undertaken by NGET between 1 March 2023 and 29 February 2024.

4. Methodology – Network Impact Assessment



The section of the NDP Methodology explains how forecasts are applied to understand whether the forecasted electrical needs of customers can be accommodated within existing distribution networks. The high-level components of network impact assessments shown above are covered in this section.

The parameters evaluated during network analysis and the pertinent network data which have a significant impact on assessment outputs are described at a high level, including reference to data publications where relevant. Use of monitored network parameters and smart meter data is explained alongside key assumptions used in the absence of measurements. Network limitations used to identify the need for interventions are detailed along with the associated thresholds.

Standard network design and operation at all voltage levels – including typical equipment ratings – are detailed in our LTDS 'Network Summary' documents for each licence area, available on our Open Data Portal.

In developing and maintaining an efficient, coordinated and economical distribution system, there are a range of drivers that need consideration when modelling future network needs:

- A range of credible scenarios identified through advanced analysis, modelling and focussed stakeholder engagement and validation (DFES);
- The views and feedback of stakeholders, including regional government, community energy groups, road network operators and utility providers;
- The condition of the electrical network, as measured by the Network Asset Risk Metric (NARM) and informed by automated data and regular inspection of assets;
- Insight into new and upcoming innovative technologies, which may allow either increased benefit to customer or a reduced whole life cost;
- Connections applications which provide indication of trends or changes in the demand for electricity within an area or present an opportunity to deliver a lower cost solution for customers. Insight is also gained through requests for diversions, both customer and network funded in a similar way; and
- Regular network analysis to identify emerging issues, including EREC P2 compliance, fault level issues and voltage compliance.

Figure 7 highlights the range of inputs into the planning process. Key areas feeding into this process are expanded in the sections below.

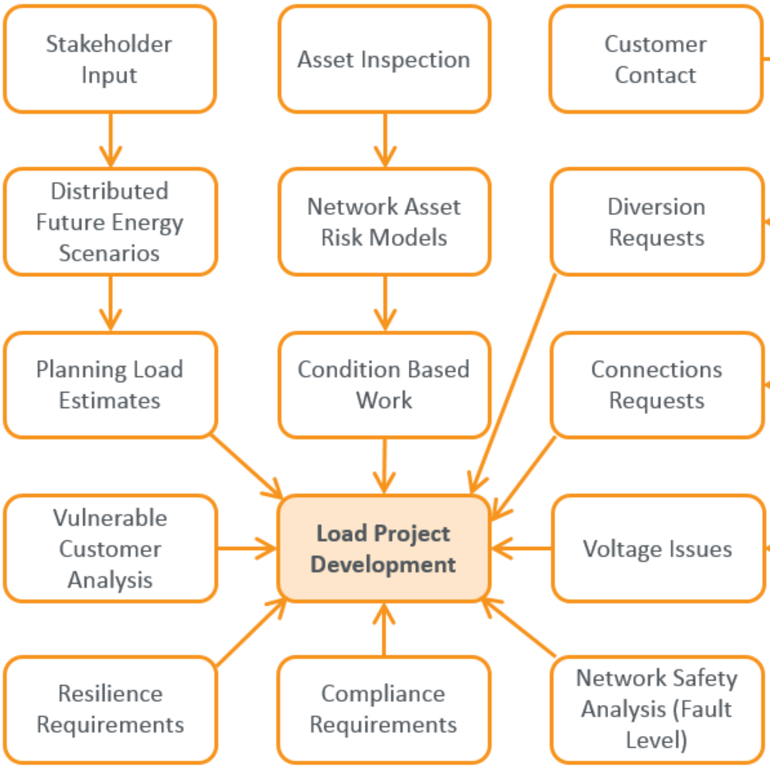


Figure 7 Load project planning process:

Key parameters (thermal, voltage, fault-level and harmonics)

The Strategic Forecasting System includes a load aggregation model and network constraint forecasting module that uses the load and generation forecasts outlined earlier as inputs to generate costs and volume drivers. Once load is forecast for individual customers connected to the LV and HV networks, peak and trough loads are aggregated upstream from secondary substations, to primary substations, grid sites and finally to Grid Supply Points. This aggregation takes into account interconnection, network losses, and the fact that peaks and troughs do not necessarily occur at the same time, or on the same day using the diversity methodology outlined in the previous section.

The Strategic Forecasting System is based upon real network data wherever this is available, including information on customer number, customer type, and network properties including cable types, length, ratings, transformer types and ratings. The approach of using real network data includes the LV network level data, where possible, which facilitates a more accurate assessment of the impact of future load growth across the distribution networks as shown in Figure 8. Modelling assumptions and the use of representative networks are only relied upon to fill gaps in the real network data.

Using this approach, the load flow and constraints module produces forecasts of the following values at a selected voltage level for each of our distribution licence areas:

- Winter peak flow through each network section including transformers and cables;
- Voltage for winter peak conditions at each busbar;
- Summer peak flow through each network section including transformers and cables;
- Summer minimum flow through each network section including transformers and cables;
- Voltage for summer peak and minimum generation conditions at each busbar; and
- Voltage for summer minimum and maximum generation conditions at each busbar.

From these load flows and voltage assessments the Strategic Forecasting System is able to identify future constraints on the LV, HV and EHV networks. This includes identification of thermal constraints on feeders and transformers, as well as forecasts of voltage constraints.

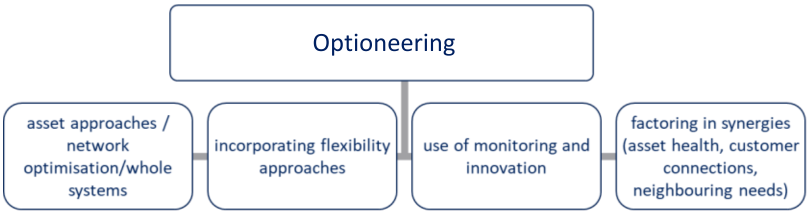
The model then **forecasts when firm capacity is breached** so that we can calculate the load index of a substation.

Fault levels (single-phase and three-phase) are calculated for the present network configuration and loading. Future fault levels are calculated by adding the contribution from network upgrades and from new generation calculated from declared net capacity and corresponding fault level factors per generation type.

Based upon the constraints identified as outlined above, the appropriate network intervention is then derived.

5. Methodology – Optioneering and Best View Development Plan

Optioneering approach



The overarching approach to network investment is described based on the high-level components of the optioneering process as shown above, drawing out how this manages the range of possible future demand scenarios and the associated network impacts.

The process for identifying and assessing credible network interventions to address fault level, voltage, power quality and thermal issues is described. All options are included, for example the use of flexibility services to defer reinforcements, or the application of innovation and monitoring to better inform timely network investments. This section of the methodology discusses the benefits of each solution, timing and risks.

To manage network constraints, we can

1. Release capacity by reinforcing
2. Release capacity through flexibility, or
3. Increase network utilisation alongside smart grid solutions

These options are not mutually exclusive e.g. increasing deployment of flexibility services can increase utilisation, and flexibility services can be in a combination with a reinforcement plan.

Once the site and assets that will be constrained in the future are identified, a process to understand the primary options to deliver the needs is triggered. We have considered a range of solutions, including a comprehensive assessment of traditional network investment options versus the commercial service counterfactual across the majority of sites requiring interventions.

UK Power Networks committed to a 'flexibility first' approach when we launched our Flexibility Roadmap[3] in 2018. Since then, through regular tender rounds, we have been market testing whether flexibility can offer a more economical solution to reinforcing or upgrading assets across our whole network. We will take this approach whenever it is the most cost-effective option for our customers.

[3] Flexibility Roadmap - https://smartgrid.ukpowernetworks.co.uk/flexibility-hub/

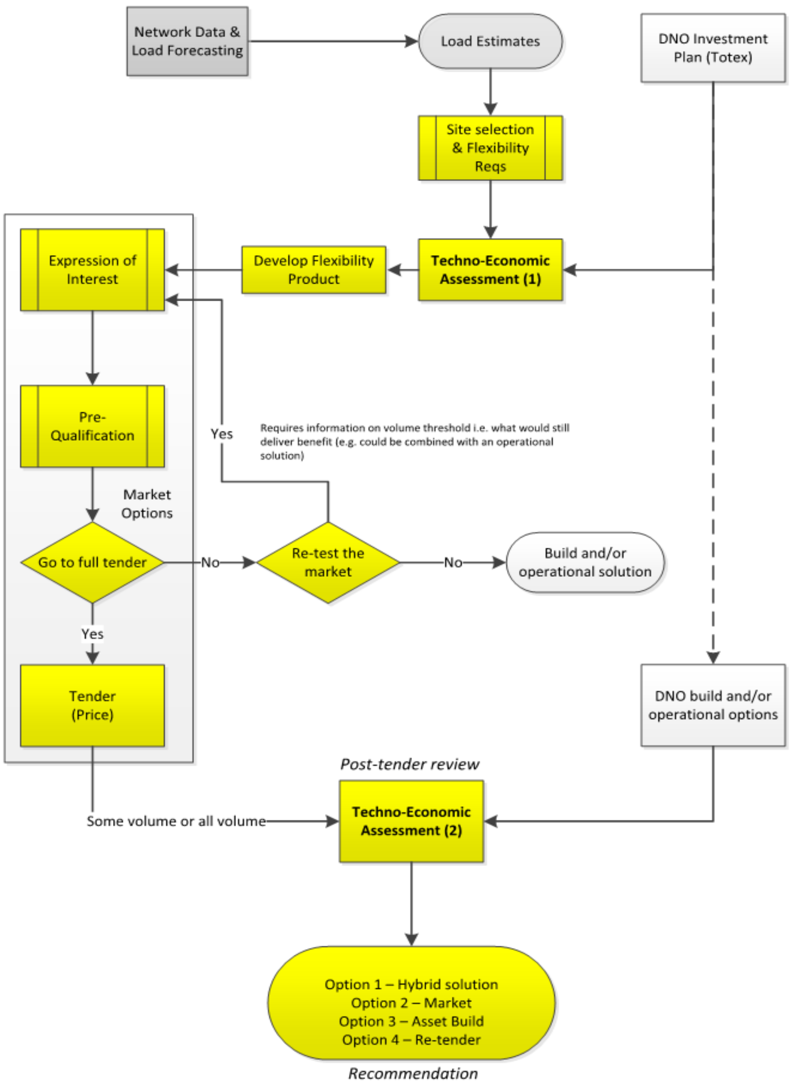


Figure 8 Market Testing Process

Sites are identified by assessing the impact of load growth forecasts on our substations. These sites are forecasted to go over firm network capacity (the capacity guaranteed to be available under all probable operating conditions) considering a range of growth scenarios.

The load forecasts (known internally as our planning load estimates and used for the NSHR) are forward looking, identifying shortfalls in firm capacity in future years in different DFES scenarios.

1. We then decide whether this shortfall can be met by flexibility or requires reinforcement, this involves a market test:
    a. The load forecasts versus capacity (as in the NSHR) to determine the amount of flexibility required, taking account of the historic performance of flexibility services.
    b. If insufficient economical flexibility is available, then reinforcement is instigated
    c. If sufficient economic flex, then flexibility contracts are awarded
3. We will take account of actual flexibility performance and makes adjustments as necessary to the procurement strategy
4. Following the next update of the load forecast, we will undertake the same evaluation, looking at whether there is a shortfall
    a. If there is a shortfall, we will again market test to either procure more flexibility or trigger reinforcement
    b. If market test fails, reinforcement is instigated

For each identified site requiring a capacity intervention, we undertake a techno-economic assessment of the value of flexibility at that site. This involves completing a cost-benefit analysis (CBA) that uses the cost of reinforcement to estimate the net present value of deferring the reinforcement capex. We use the Common Evaluation Methodology (CEM) model developed through the Open Networks project for this analysis, based originally on Ofgem's CBA methodology. The CEM tool provides a common methodology for DNOs to assess flexible versus non-flexible options to meet network needs. The tool can be used to evaluate a range of non-flexible options and will allow us to test different flexibility strategies under different load scenarios.

The net present value (NPV) of the deferral becomes the available funding pot for commercial services. In more detail, the CBA models how the cash flows from reinforcement are received by our business over time. We then look at the same cash flows associated with deferring investment. The difference between the two cash flows represents value of deferring the cash flows for that deferral period. This represents the value of deferring reinforcement, to our customers. The flexibility budgets are converted into prices by dividing by forecasted availability and utilisation volume requirements. These are determined from the site-specific load profile. More detail on this can be found in our DSO Strategy for the RIIO-ED2 period, and the associated CBA that assesses DSO related options against traditional asset-based options.

Under our flexibility first approach, we will ensure that all primary sites are put out to tender before undertaking any reinforcement work. We will:

1) Propose to tender for flexibility at all sites which could require interventions under the highest load scenario

To ensure that we can facilitate all load scenarios, we have assessed all primary sites which could require reinforcement under the highest load scenario. We plan to tender for flexibility at all these sites in order to ensure that we can react quickly to higher load growth and facilitate net zero. Our approach will ensure that opportunities for flexibility providers are maximised and that all primary network needs are market tested before any reinforcement is undertaken. For sites which only require intervention under the high scenario we will seek to procure flexibility under our dynamic product which is utilisation only.

2) Assess where we are likely to be successful with flexibility tenders

We have a strong track record in securing flexibility via our flexibility tender process. Close to 75% of tenders were successful in our last tender round. Consequently, we are confident of securing flexibility at the vast majority of sites needed. However, our experience of running flexibility tenders over the last five years also highlights that there will be some sites where flexibility cannot be secured or where it is uneconomical do so. We cannot be definitive on the sites where we can and can't source flexibility until we have run the tender rounds and understand the prices which parties are willing to be paid for flex. We have used our experience of previous tender to assess where our tenders are more likely to be successful. This is based on the following criteria:

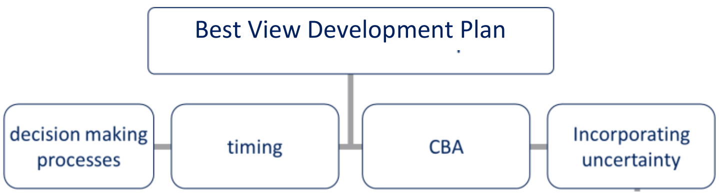
- **Level of capacity shortfall**: Our experience is that it becomes challenging to secure flexibility (at an economic price) if capacity is required beyond 20-25MW.
- **Duration of capacity shortfall**: Very long capacity shortfalls are challenging for flexibility providers to meet. Our experience to date has been that flexibility providers can't provide a service for much longer than three or four hours.
- **A combination of the above**: Sites which have both a high level of capacity shortfall and long duration have proved challenging to source flexibility.
- **Faults:** Where the driver for reinforcement is related to faults, it has proven challenging to source flexibility due to the unpredictable nature of when faults will occur and their duration. Our experience has been that flexibility providers like predictability in order to plan around and are not keen on products which are reactive in nature.

- **Other drivers for investment:** There can be additional drivers for investment which mean that the benefits of flexibility are limited. For instance, if an asset is due to require replacement in the near future, it curtails the benefits of deferring investment through using flexibility and means that reinforcement is a more attractive option.

In developing our business plan we have considered the key drivers for investment as well as specific programmes of work to ensure asset replacement is optimised and we only 'touch the network once'. These drivers include:

- Asset Replacement programmes based on condition and health monitoring indices;
- Customer connections;
- PCB replacement programme targeted at removing PCB contaminated transformers from the networks;
- Transmission network investments, where whole system efficiencies can be leveraged;
- Working with IDNOs and neighbouring DNOs to optimise investment at network interfaces; and
- Off gas grid investments to remove barriers and avoid delays in the decarbonisation of heat.

By considering the impacts on individual sites from the aforementioned drivers we will ensure that in upgrading LV/HV equipment, sizing of assets is commensurate in providing sufficient capacity for all homes in the area connected to that equipment. This will mean that future decarbonisation can be achieved without triggering more reinforcement works.



The previous sections have covered the high-level components of how our best view development plans are created as shown above. It explains how alternative network solutions are assessed and compared to decide the best view network development plan.

The best view and other scenarios are used together in the development of robust network development plans. This includes how consideration of the best view forecast and other scenarios are used to ensure that options for responding to an uncertain future are not foreclosed but avoid stranded assets and investing too early. Approaches for the development of optimal development plans considering synergies with other load and non-load network to avoid inefficient disruptive piecemeal development are also explained.

For planning purposes, UK Power Networks currently uses the Consumer Transformation scenario as its best view scenario. The choice of best view scenario is based on justification criteria related to:

- Alignment with existing/announced policies
- Alignment with stakeholder engagement inputs, and
- Alignment with regional and local characteristic inputs.

In the Network Development Reports, infrastructure interventions in the best-view development plan are assigned to a phase of the delivery lifecycle according to the progress through UK Power Networks' internal approval stages

- Signposting (pre – Gate A and Gate A)
- Approved plan with secured financing (Gate B)
- Planned for delivery (Gate C)
- In delivery (Gate C and D, work started)

Optioneering across different energy pathways

For our best-view network development plan we have undertaken analysis on costs and volumes in the context of the requirement to meet Net Zero by 2050.

This confirms that a pathway more closely aligned to Consumer Transformation is not only the most cost efficient over RIIO-ED2 but also out to 2035. After this period there is significant variance between Consumer Transformation and both the System Transformation and Leading the Way pathways, due to their assumption that hydrogen will play a more major role.

The Government's Hydrogen strategy[4] indicates that hydrogen is not expected to play a major role in decarbonising the UK's economy in the 2020s, yet there is significant uncertainty on the role hydrogen will play in the 2030s and beyond. In informing our LRE for the RIIO-ED2 period we have considered the different Net Zero pathways. As we do not know which one will play out, we have focused on being able to adapt to all whilst avoiding a piecemeal approach.

We are taking a demand-led approach and aside from our off-gas grid programme we will avoid reinforcements until we have clear evidence of the capacity requirement. However when we do need to reinforce we will uprate assets to accommodate for demand levels forecasted out to 2050. Whilst such demand levels are not guaranteed, the relatively low incremental cost associated with upsizing assets makes this a sensible approach. Should, for example, a high electrification pathway occur in the 2030s our approach will make it easier to accommodate this. Whereas, the alternative would risk taking a piecemeal approach to 2050, creating higher LRE overall and greater disruption. Moreover the additional capacity headroom created will help to reduce losses in the interim period.

[4] https://www.gov.uk/government/publications/uk-hydrogen-strategy

6. Consultation on the NDP

Consultation requirement and process

The Network Development Plan licence condition (LC25b) requires all licensees to

(a) consult interested parties on the proposed Network Development Plan for a period of at least 28 days before publishing on or before 1 May 2022 (and every two years thereafter); and

(b) publish the non-confidential consultation responses received, a summary of the responses and how it has taken them into account.

As part of preparing the proposed NDP for consultation, a new website landing page was created to provide easy access to both the Long Term Development Statement and the Network Development Plan.

Long Term Development Statement and Network Development Plan Landing Page — UK Power Networks (opendatasoft.com)

The new page provides easy access to the LTDS and NDP documents and also onward access to the LTDS tables and DFES NSHR tables in the Open Data Portal's document catalogue.

We created an online consultation form, which was available from 23 March – 20 April 2022 on the new landing page. As well as asking open questions about whether there were questions or suggestions for improvement on the report, the 2022 consultation asked:

- Do the Network Development Reports provide clear visibility of our proposals for infrastructure development and flexibility services procurement?
- Is it useful to include the Network Headroom Report data on our Open Data Portal? We are planning to make the data sets available by the end of April.
- Do the Network Development Reports provide clear visibility of our proposals for infrastructure development and flexibility services procurement?
- Is it clear that the Network Headroom Report indicates physically unused capacity over time per year per scenario, rather than contractually available capacity? i.e. that physically unused capacity may be committed to a customer.
- Is the information useful to your organisation/role? (Tick any that apply)
  - ☐ Yes – visibility of flexibility services procurement
  - ☐ Yes – visibility of infrastructure development
  - ☐ Yes – visibility of scenarios for unused capacity
  - ☐ Yes – visibility of methodology
  - ☐ No
  - ☐ Don't know

Responses were also invited via the email address networkdevelopment@ukpowernetworks.co.uk

The new landing page and the consultation form were advertised externally via:

- Email to stakeholders who had previously registered for access or interest in the Long Term Development Statement,
- Links provided in a presentation by UK Power Networks at the 24 March 2022 ENA Open Networks Dissemination Forum; and
- Promotion on the UK Power Networks LinkedIn page and individual LinkedIn posts.

However no responses were received via the consultation form or by email.

The draft NDP consultation was also promoted internally within UK Power Networks by email to interested stakeholders, and via the internal steering group for the Strategic Forecasting System.

Via the ENA Open Networks group on Network Development Plans (WS1b P5), UK Power Networks has led on the development of a pre-publication debrief document. It gathers experience from DNOs on the experience of building and publishing the first NDPs, confirms that the 'form of statement'[5] was fit-for-purpose to support the first publication and flags areas of potential clarification and development of the form of statement.

This pre-publication debrief document also reflects stakeholder questions on the NDP raised in the 24 March 2022 Open Networks Dissemination Forum e.g. would interventions over the next 10 years on the high voltage 11kV and 6.6kV networks be detailed in the report, would secondary network substations be included? This suggests that the lower voltage boundary could be more clearly shown in the form of statement and the NDP documents. The debrief document informed the updated form of statement published in December 2022, including future recommendations for the NDP.

Updates from the draft NDP

For the final version of the 2022 NDP, a number of minor updates were made to the draft NDP published in March 2022.

1. Updates of firm capacity values in the demand NSHR tables to reflect latest figures to be published in the May 2022 LTDS, or confirmed future changes.
2. Confirmation of values in the generation NSHR tables (previously shown as N/A) for sites with fault-level exceeding rating in the base year, and which are flagged in Table 8 of the LTDS
3. For the tables of infrastructure and flexibility services proposals in the NDR, and the tables of decommissioned sites listed in the NDR, conversion to consistently use the same substation naming conventions as in the LTDS.
4. Minor updates to the flexibility services proposals for consistency with the latest plans as submitted to Ofgem in the March 2022 LC31 flexibility services procurement statement and latest publications on our Flexibility Hub
5. Updates to show the documents as final rather than draft
6. Upload of the final NSHR tables to the Open Data Portal's data catalogue for easy stakeholder access.

[5] ON21-WS1B-P5 NDP Form of Statement Template and Process (22 Dec 2021) Published.pdf (energynetworks.org)