SPEN Distribution Future Energy Scenarios

Summary of Methodology

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Version History

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Acronyms

Acronym	Description
ASHP	Air Source Heat Pump
BEV	Battery Electric Vehicle
BtM	Behind the Meter
CCUS	Carbon Capture Utilisation and Storage
CHP	Combined Heat and Power
CVEI	Consumers, Vehicles and Energy Integration Project
DFES	Distribution Future Energy Scenarios
DH	District Heating
DNO	Distribution Network Operator
DSO	Distribution System Operator
DSR	Demand Side Response
ESO	Electricity System Operator
EU	European Union
EV	Electric Vehicle
FES	Future Energy Scenarios
GB	Great Britain
GDP	Gross Domestic Product
GSHP	Ground Source Heat Pump
GSP	Grid Supply Point
HGV	Heavy Goods Vehicle
HP	Heat Pump
HV	High Voltage
I&C	Industry and Commercial
LGV	Light Goods Vehicle
LNG	Liquefied Natural Gas
LV	Low Voltage
NG	National Grid
PHEV	Plug-in Hybrid Electric Vehicle
PSS	Primary Substation
SPD	SP Distribution
SPEN	SP Energy Networks
SPM	SP Manweb
UKCS	UK Continental Shelf
WANDA	Weather Normalised Demand Analytics

Table 1 – Acronyms

1 Scenario development methodology

1.1 Introduction

The SP Energy Networks (SPEN) Distribution Future Energy Scenarios (DFES) are geographically granular forecasts which assess four credible future scenarios covering a range of uncertainties, including differing levels of consumer ambition, policy support, economic growth and technology development.

These scenarios run from 2019 to 2050 and are informed by engagement with industry, government and other key stakeholders. The DFES enables SPEN to understand how generation and consumption may evolve over the next 30 years, and to assess and prepare for the required changes to facilitate the UK's transition to Net Zero greenhouse gas emissions.

SPEN has commissioned Baringa Partners, supported by Field Dynamics[1], to help develop these scenarios. SPEN have specified that the planning scenarios must be holistic from a whole energy systems perspective, and need to consider all generation and demand within SPEN areas – at a granularity of individual Primary Substation (PSS) and Grid Supply Point (GSP) level, including:

- Distribution network connected generation (and storage);
- Distribution network connected consumers;
- "Behind the meter" (BtM) generation (e.g. small-scale solar PV or storage).

This document provides an overview of the scenario methodology, and is structured as follows:

- Section 1.2 provides an overview of the high level principles used to frame the scenarios;
- Section 1.3 provides a high level overview of the approach to create the scenarios;
- Section 1.4 gives a more detailed explanation of the approach for each demand element;
- Section 1.5 provides more detail on the approach for each generation element.

1.2 High level principles

The energy system is evolving at pace. The understanding of future customer needs provided by the DFES enables SPEN to plan, design and prepare their distribution network to meet changing customer needs. Granular regionally reflective scenarios assess a range of credible future pathways including how much electricity will be consumed or generated, as well as indications of where and when. These forecasts will be used by SPEN to underpin detailed network capacity assessments and network planning activities.

The National Grid Electricity System Operator (ESO) 2019 Future Energy Scenarios (FES) are used as a starting point, remaining consistent with the scenario framework and main building blocks. However as these forecasts are for the whole of GB, they need to be significantly augmented to provide a much more regionally reflective view. This is achieved using a combination of extensive top-down and bottom-up assessments to produce detailed forecasts at primary substation and GSP level out to 2050. This uses SPEN's network data combined with project pipeline, regional ambitions and development

[1] https://www.field-dynamics.co.uk/

plans, external geospatial data sources, local knowledge, outputs from innovation projects and incorporates regional Net Zero legislative targets.

This analysis covers both SP Manweb (SPM)[2] and SP Distribution (SPD)[3] licence areas, and the methodology has been designed to apply in a consistent manner across both with regional sensitivities due to different targets.

When developing scenarios, the following high level principles have been adhered to:

- Scenarios cover a wide range of likely possible outcomes, including a number consistent with future Net Zero emissions outcomes;
- Scenarios are holistic and internally consistent as much as possible;
- Assumptions are based on publicly available sources and SPEN network data;
- Methodologies are simple, transparent, and credible;
- Scenarios are informed by engagement with industry, government and other key stakeholders.

1.2.1 Use of GB level FES

National Grid, the Electricity System Operator (NG ESO) produces an annually updated set of energy scenarios for Great Britain, the Future Energy Scenarios[4] (FES). The FES are a range of credible pathways for the GB energy system out to 2050. They represent possible demands for, and sources of, gas and electricity, in an interlinked and holistic manner, whilst also considering the wider set of energy system options that affect these (e.g. the role of bioenergy or district heating). In developing the FES, NG ESO gathers feedback from a wide range of stakeholders on the assumptions and approach taken.

The FES are widely used by industry, academics and government, providing a regularly updated and internally consistent set of whole energy system scenarios. The scenarios are not projections of how the GB energy system will develop and no probabilities for the likelihood of each scenario are given. The scenarios can, however, be used to understand the impact of different potential futures and the sensitivity to different assumptions.

The FES are presented on a GB wide basis, though NG ESO makes assumptions for each transmission zone independently before aggregating this to the GB total.

In developing load planning scenarios for SPEN we have drawn on the FES, as these are generally regarded as being holistic energy scenarios for GB. In some cases, the assumptions in the FES for the SPEN areas have been used directly to develop the scenarios outlined in this document, either because they have been developed with SPEN or because they apply to GB and can reasonably be applied to SPEN areas without adjustment.

However, in many areas the FES assumptions can be refined to better match local knowledge SPEN has of the SPEN areas, and where we can see reason to improve the assumptions we have done so, as documented in the following subsections.

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[2] SP Manweb (SPM) – the Distribution Network Operator for Merseyside, Cheshire, North Shropshire and North Wales, own the distribution network at 132kV, 33kV, 11kV and LV into the home.
[3] SP Distribution (SPD) – the Distribution Network Operator for Central and Southern Scotland, own the distribution network at 33kV, 11kV and LV into the home.
[4] http://fes.nationalgrid.com/

In this report we have used the National Grid 2019 FES as a starting point, which has 4 scenarios as set out in Figure 1. The 2019 FES span two dimensions:

- **Level of Decentralisation:** how close the production and management of energy is to the end consumer.
- **Speed of Decarbonisation:** how quickly reductions in carbon emissions across all sectors are seen, and whether the UK meets the Government's target of an 80% reduction from greenhouse gas emissions from 1990 levels by 2050[5].

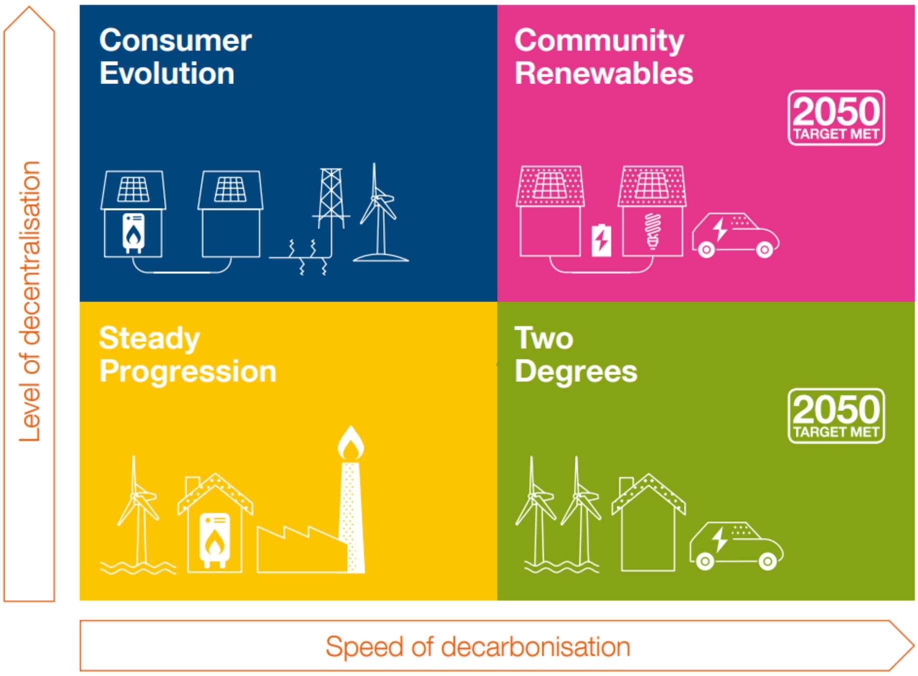

Figure 1 – Future Energy Scenarios 2019[6]

The following scenario descriptions have been reproduced with National Grid's permission from the 2019 FES main document:

Steady Progression (SP)

- This scenario is more centralised and makes progress towards, but does not meet, the 2050 decarbonisation target.
- Electricity demand: With a slower drive to decarbonisation, there are slower improvements in appliance efficiency and little electrification of heat. However, there is significant use of EVs, so smart technology is important for managing peak demand.
- Transport: The Government's aspiration for transport in 2040 is not met, though EVs are still the dominant choice for personal transport by 2050. There is also more of a role for natural gas-powered vehicles, particularly in the commercial sector.

[5] The National Grid 2019 FES was produced before the Scottish 2045 Net Zero target and the UK 2050 Net Zero target were introduced.
[6] Image reproduced with permission of National Grid.

- Heat: Most residential properties rely on gas boilers. There is limited use of heat pumps and smaller improvements in the thermal efficiency of houses. Decarbonisation of the heating sector is slow.
- Electricity generation: There is greater emphasis on large scale, rather than local, generation. There is development of nuclear power and offshore wind. Gas plays an important role in providing flexibility and gas-fired generation fitted with carbon capture utilisation and storage (CCUS) develops through the 2040s.
- Gas supply: Gas comes from the UK Continental Shelf (UKCS), Continental Europe, Norway and liquefied natural gas (LNG), with additional supplies from shale gas.

Consumer Evolution (CE)

- This is a more decentralised scenario which makes progress towards the decarbonisation target but fails to achieve the 80% reduction by 2050.
- Electricity demand: There is a moderate rollout of smart charging of EVs. There are some improvements in energy efficiency with homes, businesses and communities focused and incentivised towards local generation, notably roof top solar, and local energy management.
- Transport: Private ownership of personal vehicles remains popular. The Government's aspiration for transport in 2040 is not met, though EVs are still the dominant choice for personal transport by 2050. There is a greater role for natural gas-powered vehicles, particularly in the commercial sector.
- Heat: Limited progress is made towards decarbonising heat. There are only small improvements in thermal efficiency. There is some progress in the rollout of heat pumps, but current heating technologies remain dominant.
- Electricity generation: Generation is focused on smaller scale renewables, with gas and batteries providing most of the system flexibility. Some new large-scale nuclear power stations are built but there are also a number of small modular reactors. Greater emphasis on domestic and national energy solutions leads to lower levels of electricity interconnection.
- Gas supply: Gas from the UKCS, Continental Europe, Norway and LNG remains important in this scenario. However, by 2050, shale gas is the largest source of supply.

Two Degrees (TD)

- In this scenario, NG explore how the decarbonisation target can be achieved using larger and more centralised technologies.
- Electricity demand: The use of hydrogen for heating helps reduce electricity demand, despite the widespread use of EVs. Smart technology is extensively used, alongside greater demand side actions to manage peak electricity demand. Appliances are more energy efficient to meet EU targets.
- Transport: The Government's 2040 transport aspiration is met. EVs become the most popular choice for personal transport. Increased use of public transport features in this scenario. For commercial vehicles, use of natural gas, and then hydrogen, become more widespread.
- Heat: As with Community Renewables, homes become more thermally efficient as there is a drive towards decarbonisation. By 2050 the dominant heat source is hydrogen, supported by a mixture of gas boilers, district heating and heat pumps.

- Electricity generation: Generation, such as offshore wind and nuclear, is based more on the transmission network. Flexibility is provided by interconnectors, larger scale storage and later, some large-scale gas-fired plants fitted with CCUS technology.
- Gas supply: Gas from the UKCS, Norway and LNG remains important and NG explore the use of steam methane reforming to produce hydrogen. Some green gas is available.

Community Renewables (CR)

- In this scenario, NG explore how the 2050 decarbonisation target can be achieved through a more decentralised energy landscape.
- Electricity demand: With the drive towards decarbonisation, together with the high use of EVs and use of heat pumps, smart technology is used extensively to manage peak electricity demand. Appliance efficiency improves to meet EU targets and greater use of demand side actions are seen.
- Transport: The Government's aspiration to end sales of conventional petrol and diesel powered cars and vans by 2040 is met. EVs become the most popular personal mode of transport. Natural gas is used in heavy goods vehicles but, by 2050, hydrogen becomes the fuel of choice in this sector to aid the decarbonisation target.
- Heat: Homes become more thermally efficient, and heat pumps are the dominant technology. Green gas and increased use of district heating also have a role.
- Electricity generation: Onshore wind and solar, co-located with storage, dominate the picture. This achieves the 2050 target without CCUS. Flexibility is provided by small scale storage, small gas-fired plant, some interconnection, and hydrogen production by electrolysis.
- Gas supply: Gas from the UKCS, Norway and LNG remain important in the short and medium term. However, in this scenario, where the 2050 target is met without CCUS, there is significant development of green gas. In Community Renewables, hydrogen is only produced by electrolysis.

The NG FES use three time periods per year to assess how generation and demand may change. These periods are based on a coincident set of times for peak and minimum demand seen on the GB transmission system. Effect of all distribution connected and behind the meter generation are also considered. The SPEN DFES stays consistent with these time periods.

- **Winter Peak:** Period of peak demand on the distribution system, assumed to be 17:00-18:00 on a winter (Nov-Feb) weekday.
- **Summer Minimum (AM):** Period of very low demand on the distribution system, assumed to be 5:00-6:00 on a summer (Jun-Aug) Sunday morning. This is the period of current minimum demand on the transmission system.
- **Summer Maximum (PM):** Period of very low demand on the distribution system, assumed to be 13:00-14:00 on a summer (Jun-Aug) Sunday afternoon. For regions with significant volumes of solar PV capacity, their high expected output in the middle of the day could result in distribution demand being at a minimum at this time.

1.2.2 Macro assumptions

The NG FES include several macro assumptions that influence the scenarios. In the main these have been left unchanged when developing scenarios for the SPEN areas. The key assumptions in terms of driving changes to generation and demand that have been inherited from the NG FES are:

- **Population Growth:** In the FES the population growth is consistent across all scenarios.
- **Energy efficiency:** The FES uses the EU's 2030 Climate and Energy Framework[7] as a benchmark for the rate of decarbonisation, assuming that in the two high decarbonisation scenarios (CR and TD) there is a large improvement in energy efficiency at least equivalent to the EU 2030 target. For the two other scenarios there is limited progress. A similar split in improvement across the scenarios exists for building appliance efficiency.
- **Economic Outlook:** I&C demand in the FES is modelled assuming Gross Domestic Product (GDP) grows at a rate of 2.0% for the high growth scenarios (CR and TD) and 0.9% for the low growth scenarios (CE and SP).
- **EV population:** The EV uptake in the FES is influenced by the Government's target for nearly all new cars and vans sold by 2040 to be zero emission[8]. Two of the FES scenarios (CR and TD) comply with this target and show strong EV uptake, for the other two scenarios uptake is slower, but EVs are still expected to become dominant by 2050.
- **Generation technology load factors:** The FES uses load factor assumptions for the expected output of generation and storage technologies at different times of the year. These assumptions are based on observed output from recent years, and are selected to reflect stress on the system at periods of peak and minimum demand.

In developing the SPEN DFES the following additional high level assumptions have been made:

- **GSPs and PSSs:** The SPM and SPD DFES results are provided for all current GSPs and PSSs, without assuming any splitting or new substation sites. The changes in generation and demand at existing sites identified in the SPEN DFES will be used by SPEN when planning investment, which may include splitting sites or other changes – but any changes will be a result of the analysis described in this report rather than being an input to it.
- **Network constraints are not a barrier to change:** Changes in generation and demand technologies for the DFES have been applied without consideration of current or future network constraints. SPEN are committed to providing a network that is not a barrier to changes in energy production and consumption, in particular with respect to facilitating future decarbonisation targets, and will use the SPEN DFES to ensure that appropriate investments are made to allow this at lowest cost.

[7] https://ec.europa.eu/clima/policies/strategies/2030_en
[8] https://www.gov.uk/government/news/plan-for-roadside-no2-concentrations-published

1.2.3 Net Zero FES adjustments

We have made a number of key adjustments to the original FES to reflect better the UK target of Net Zero greenhouse gas emissions by 2050[9]. In addition, the Scottish Government has introduced a legally binding target for Scotland to become Net Zero by 2045, which is five years ahead of the UK.

In the NG 2019 FES provided a single Net Zero *sensitivity* whereas the next set of FES, due in summer 2020, will contain a broader set of Net Zero compliant scenarios[10]. While these changes have not resulted in all the adjustments necessary to produce internally consistent scenarios as in original NG FES, the assumptions made present credible Net Zero pathways.

These changes have been made to decarbonisation centric scenarios only (CR and TD). This means the DFES will still contain an appropriate spread of scenarios representative of credible futures. The applied changes are summarised in Table 2.

Assumption adjusted	Community Renewables	Two Degrees
Increased generation	Matched to the FES Net Zero sensitivity (additional distribution connected generation matches the underlying CR percentage of distribution versus transmission generation).	Matched to the FES Net Zero sensitivity (additional distribution connected generation matches the underlying TD percentage of distribution versus transmission generation).
Heating electrification	*Very high* – Increased rate of electric heating uptake at the maximum uptake rate from FES, achieving very high penetration of domestic and non-domestic buildings by 2050.	*High* – Increased rate of electric heating uptake at the maximum rate in FES until 2032, from then on, the rate slows as hydrogen begins to play a major role in heat provision; i.e. the level of heat electrification is not as significant as under the adjusted CR scenario in later years.
Transport decarbonisation	In FES decarbonisation scenarios light transport is electrified by circa 2040. In line with the Scottish Government's ambition of phasing out the need for new petrol and diesel light vehicles by 2032, and the UK's Government target of 2040. It is assumed that remaining carbon based heavy transport uses other mediums to provide zero carbon transport (e.g. hydrogen/biofuel) rather than electrification.	
Hydrogen production	It is assumed that hydrogen production will predominantly be via gas or biomass routes with CCS and so does not influence electricity demand. There might also be small pockets of hydrogen production via electrolysis co-located with generation and storage, which are not anticipated to be distribution network connected. Therefore no impact of hydrogen production on the distribution network from a perspective of electricity demand has been considered.	

Table 2 – Assumptions made for Net Zero scenarios

[9] http://www.legislation.gov.uk/ukpga/2008/27/contents

[10] http://fes.nationalgrid.com/media/1460/introducing-the-fes-2020-scenarios.pdf

1.2.4 Technologies considered

In developing the scenarios, we have considered a wide range of demand and generation technologies, at different levels of the distribution network (both at PSS-level and connected above this at GSP-level). We have divided demand and generation into the categories shown in Figure 2.

Demand	Distribution connected generation

• Domestic
• Industrial and Commercial (I&C)
• Heat Pumps (separated by heat pump technology)
• Electric Vehicles (separated by charging type)
• District Heating
	• Wind
	• PV
	• Hydro
	• CHP
	  - Renewable
	  - Non-Renewable
	• Other generation
	  - Dispatchable Renewable
	  - Dispatchable Non-Renewable
	• Storage
	• Behind the Meter PV
	• Behind the Meter Storage

Figure 2 – Technologies considered

For each technology the key metric is the generation/demand on the system at specific points in time, specifically at winter peak, summer minimum and summer maximum. We have developed capacity projections for each technology and also an understanding of how each technology may operate, to understand how much generation could help offset peak demand.

1.3 High level overview of approach

A high level overview of the approach to developing the scenarios is shown in Figure 3 below. The first **Step [0]** uses available base year data from SPEN for both generation and demand elements.

- The approach to scenario demand elements in **Steps [1]** to **[5]** is to weather normalise the starting year demands, consider historic data and current project pipeline in the short term, for each element in line and combine with FES scenario growth rates (adjusted for Net Zero as described in Table 2) and spatially allocate these (e.g. underlying I&C demand or number of EVs) to PSS and GSP level. Load factors are then applied to each element to estimate demand at winter peak and summer minimum/maximum.
- In parallel **Steps [6]** to **[9]** undertake a broadly analogous approach for the scenario generation elements excluding flexible technologies (dispatchable technologies and storage). Considering the existing generation baseline, current project pipeline in the short term are combined with the FES scenario growth rates (again adjusted for Net Zero as described in Table 2). Additional capacity from growth rates, (on top of anything in the pipeline) is then spatially allocated and load factors are applied to estimate generation output at winter peak, etc.
- **Step [10]** creates an initial view of aggregated net demand (or generation) at each PSS/GSP and then calculates the implied headroom given capacity ratings for the network provided by SPEN. This headroom is a key spatial proxy for allocating the flexible technologies in **Step**

[11], for example being prioritised in areas of low or high headroom depending on the scenario and year.

- Once the flexible technologies are spatially allocated, load factors are applied to these in **Step [12]** and the final net demand (or generation) position is recalculated in **Step [13]** considering all generation and demand scenario elements, for each PSS/GSP, at winter peak and summer minimum/maximum, for each year.

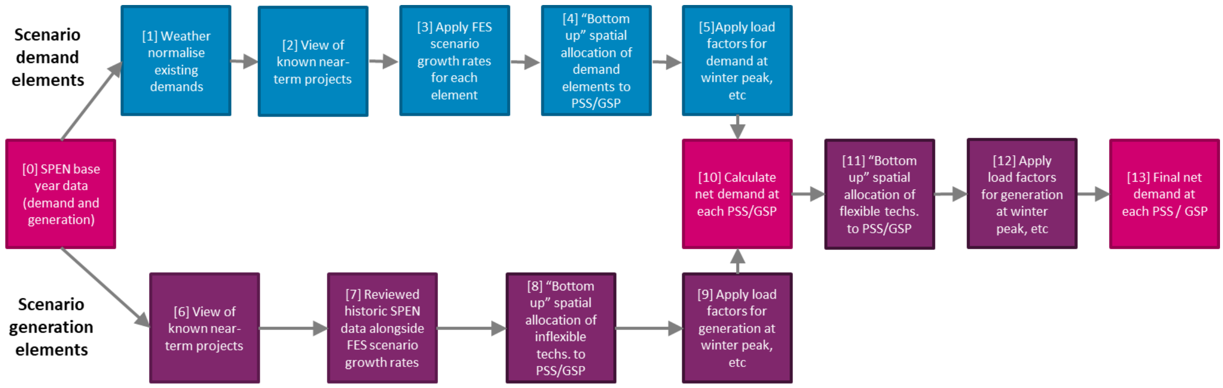

Figure 3 – High level overview of approach

1.3.1 Spatial mapping

In the 2019 FES, data of many components were provided at GSP level by National Grid. Some of these data could be used directly by the model (for GSP analysis), but in the vast majority of cases extra analysis was performed to improve the spatial allocation based on a more in-depth understanding of the SPEN areas. This was also required for the analysis to be taken down to a PSS level.

For the required spatial disaggregation of demand and generation components, a key requirement was to understand – at a granular level – the associated areas which are connected to each PSS. This would allow an understanding of suitable proxies (e.g. wind speed or postcode level data on historic electricity consumption) allocated to each PSS, which helps to spatially disaggregate scenario components (e.g. wind generation or underlying domestic building demand) from the FES in a more robust manner given the specific circumstances within the SPD and SPM licence areas. A mapping of local area customer data to PSS was used to inform the analysis.

This approach of having a mapped area to each PSS/GSP allowed for various spatial proxies to collected from a broad array of data sources. These were then used for the allocation of the different scenario demand and generation components and are described in sections 1.4 and 1.5, respectively. The spatial mapping of PSSs for SPM is shown in Figure 4, and for SPD in Figure 5.

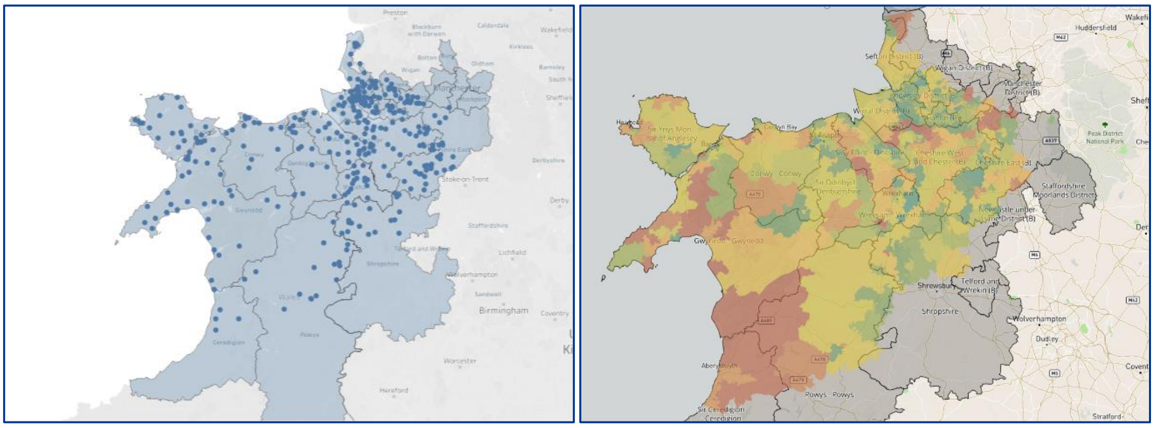

Figure 4 – SPM area with PSSs and arbitrary exemplar values to show boundaries of PSS areas

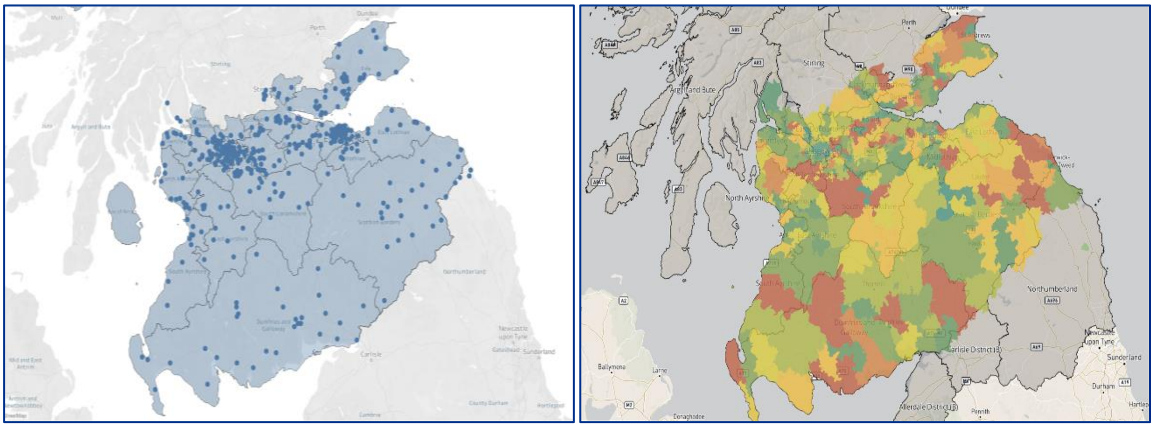

Figure 5 – SPD area with PSSs and arbitrary exemplar values to show boundaries of PSS areas

1.4 Demand

1.4.1 Introduction

Several demand elements were modelled for each of the scenarios:

- Underlying domestic demand (e.g. lighting, appliances, electric resistive heating);
- Industry and Commercial (I&C) demand;
- Electric Vehicles (EVs);
- Behind the Meter Photovoltaics (BtM PV);
- Behind the Meter Storage (BtM Storage);
- Heat Pumps (HPs);
- District Heating (DH).

Each of these components is modelled at both PSS and GSP levels and then combined to determine the total demand per PSS/GSP at the winter peak, summer minimum, and summer maximum demand periods. This aggregate demand is then combined with distribution connected generation (see section 1.5) to determine the net demand/generation balance at PSS/GSP level.

The following subsections describe the methodologies used for each of the components and discuss how the FES data has been combined with other sources to ensure appropriate disaggregation of projections for each component to each of the SPEN areas. There are two methodologies used shown in Figure 6:

- The first "top down" approach, where accurate GSP level data is provided, involves taking the given breakdown at GSP directly from the FES scenario and disaggregating to PSS using spatial proxies. Examples of this include underlying domestic demand (section 1.4.2), and underlying I&C demand (section 1.4.3).
- The second "bottom up" approach, where GSP level data is not available, would be starting with the SPEN Licence area figures, disaggregating directly to the more granular PSS level, to get the highest level of accuracy, and then aggregating up to GSP by summating values for all connected PSSs. An example of this would be EVs (section 1.4.6).

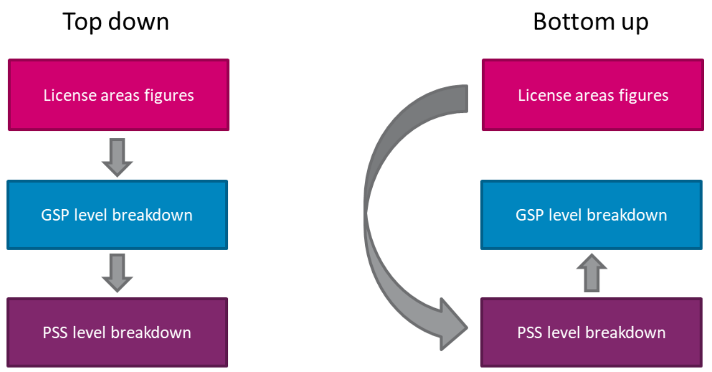

Figure 6 – Schematic of different allocation methodologies

1.4.2 Underlying domestic demand

Recent outturn demand readings from SPEN have been used for the starting point of total demand at both PSS and GSP levels. A weather normalisation was also applied to the datasets, using data collected from SPEN's Weather Normalised Demand Analytics (WANDA) project[11] to correct for any natural weather variance between years to provide a more consistent picture of how demand and generation will evolve under "typical" conditions over time.

To understand how the split of domestic versus I&C demand develops over time, FES projections of growth were used to forecast domestic and I&C demand. The FES projections make assumptions around improvements in energy efficiency and demand response to avoid peak. A schematic representation of the process is shown in Figure 7.

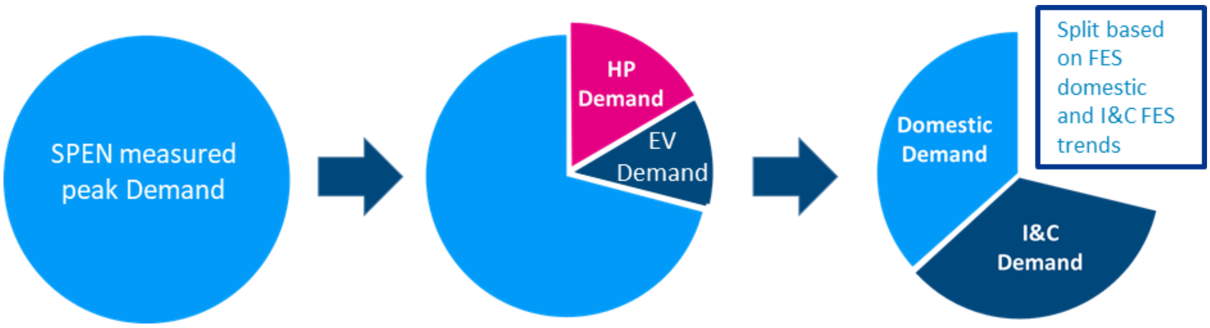

Figure 7 – Schematic underlying domestic and I&C peak demand methodology

The same approach is taken to calculate underlying domestic demand at PSS, with an additional step that uses spatial proxies to determine where domestic versus I&C load is allocated amongst PSSs. The GSP split is used as a starting point for how much domestic or I&C should be allocated between the PSSs connected to the GSP. Spatial proxies associated with the PSSs are then used to decide how this is allocated.

Underlying domestic demand was disaggregated from the FES GSP level splits based on postcode level household demand data from BEIS[12]. This study provides the most up to date data available at postcode level about household estimated total kWh annual usage. With all PSSs having an associated total household demand this spatial proxy was used for the allocation.

Rather than implementing a fixed split of domestic and I&C peak demand per GSP over the period to 2050, the model reflects the expectation that demand will develop differently in these sectors over time – based on varying assumptions for changes in efficiencies and Demand Side Response (DSR) – and therefore adjusts the split accordingly.

It is important to note that electric storage heater demand is captured directly within the underlying domestic demand values within the FES data, alongside others such as appliances and lighting. The contribution to winter peak, summer minimum and summer maximum from these storage heaters is proportionally very small, due to the way they operate – only in the winter, and requiring demand during the night.

[11] https://www.smarternetworks.org/project/nia_spen0022

[12] https://www.gov.uk/government/collections/sub-national-electricity-consumption-data#postcode-level-data

1.4.3 Underlying I&C demand

I&C underlying demand also follows a top down approach for disaggregation. The process is nearly identical to the domestic procedure described in the underlying domestic demand section above. However, when determining the share of underlying I&C demand per PSS, the model uses the spatial proxy of I&C floor space for the allocation, based on building-level Ordnance Survey data[13] rather than the aforementioned BEIS postcode household demand. The underlying FES data that is used as an input to underlying I&C demand includes assumptions around peak avoidance measures, demand response and improvements in energy efficiency, hence these are by definition included within the DFES.

1.4.4 Heat Pumps

The HP demand at winter peak is provided by the FES at GSP level. This is used to disaggregate the national level figures on HP numbers down to the two SPEN licence areas. Starting with SPEN's baseline, spatial proxies are used to allocate additional HP numbers from the licence areas down to individual PSS regions. This is an example of the bottom up approach mentioned in section 1.4.1.

The approach taken in this analysis ensures that the total demand in the SPEN areas stays in line with the FES but improves the spatial allocation at PSS and GSP level to make the data more representative of the SPEN region. In order to make the HP demand more representative several spatial proxies were used as suitability factors, chosen to appropriately spatially allocate the HP demand. These are different for different types of HPs:

- Air Source Heat Pump (ASHP);
- Ground Source Heat Pump (GSHP); and
- Hybrid Heat Pump (Hybrid HP), which is an electric HP operating to supply baseload, with a gas boiler operating at peak times.

There are several factors influencing HP allocation:

- GSHPs are in general most likely to be installed in rural areas where homes are larger and less clustered, given the garden area needed for installation. This is determined using Ordnance Survey data.
- GSHPs/ASHPs are more likely to be installed in buildings off the gas grid, which are likely to be using relatively expensive fuels (e.g. oil-fired heating). Off-gas postcode data from Xoserve[14] has been used to determine the number of off-gas grid homes per PSS, which has been used as one of the suitability factors. This does not apply to Hybrid HPs which require gas to operate.
- HPs perform best in well-insulated highly efficient buildings, and are therefore more likely to be installed in new builds. Statistics on the new builds[15] have been mapped down to PSS level to come up with the growth of new build housing per PSS, based on recent historic growth in number of meter termination points from SPEN's data.
- Finally, the type of residential building is also important for HP allocation. While ASHP are more suited to smaller buildings, and flats, GSHP and Hybrid HPs are more suited for larger detached buildings where there is an appropriate amount of area for installation.

[13] OS AddressBasePremium, and OS MasterMap
[14] www.xoserve.com
[15] From the Ministry of Housing, Communities and Local Government (MHCLG)

Baringa
Brighter together

Building count and off-gas grid areas are shown in Figure 8 for the SPM licence area and in Figure 9 for the SPD licence area. Table 3 below is a summary of which of these spatial proxies was used for the allocation of each HP type.

ASHP	GSHP	Hybrid HP
New build	Off-gas grid	Not off-gas grid
Off-gas grid	Residential building type (larger)	Residential building type (larger)
Residential building type (smaller)		

Table 3 – Heat pump allocation spatial proxies

These suitability factors were used in combination to produce a relative suitability score for each PSS. This was then used to disaggregate SPEN licence areas total number of HPs determining the fraction of the total HPs demand that are assigned to each PSS. The number of available suitable properties is also tracked, so that HPs are not over allocated to certain areas.

It is worth noting that even in the high uptake scenarios a large percentage of HP allocation is driven by new build, due to the high numbers compared to off-gas grid properties.

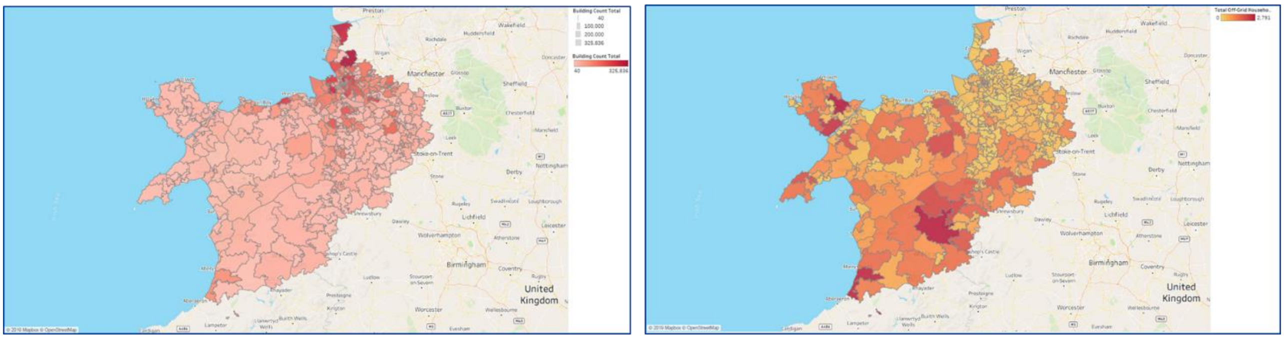

Figure 8 – SPM area building count (left) and off-gas grid areas (right)

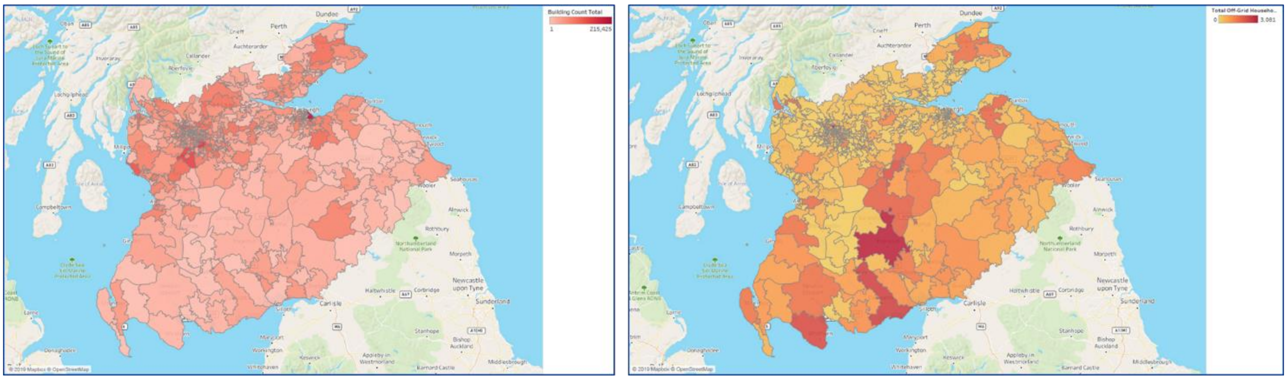

Figure 9 – SPD area building count (left) and off-gas grid areas (right)

1.4.5 District Heating – large scale Heat Pumps

The electricity demand of District Heating (DH) at winter peak, summer minimum and summer maximum is provided at GSP level in the 2019 FES data, i.e. for the proportion of heat networks that are being supplied by large-scale heat pumps.

To disaggregate this spatial allocation to PSS level, domestic heating demand density has been used as a spatial proxy. Domestic heating demand density was calculated by dividing the area covered by a PSS boundary by the number of domestic buildings in that area. This comparable number was then used to allocate the DH demand – i.e. proxy for heat density assuming an average heat demand per building. A minimum scale was also selected to avoid unrealistically small DH systems.

1.4.6 Electric Vehicles – residential charging

In the 2019 FES multiple EV types are taken into account. Privately owned electric cars are expected to have the majority of the impact on the network at peak time. The total number of vehicles to be allocated to the SPEN areas was calculated using FES national numbers adjusted to reflect regional targets (section 1.2.3). The percentage of EVs in the SPEN areas was then calculated using the regional breakdown FES data, which provides data on peak EV contribution specific GSPs. The proportion of total peak allocated to these SPEN GSPs, was used as a proxy to decide the number EVs situated in the SPEN areas, for all scenarios.

Spatial allocation of residential EVs

This process was undertaken at PSS level using the EV-Up tool developed by Field Dynamics for SPEN[16]. EV-Up enables SPEN to map additional demand from new EVs as consumers continue to replace conventional internal combustion engine (ICE) vehicles, delivering an increased understanding of individual households' ability and desire to transition to low carbon transport. It also provides an indication of the potential increased demand and impact on the LV network.

At the foundation level the methodology assumes that the ability to park off-street will be a core driver for EV uptake. Using detailed Ordnance Survey MasterMap data, domestic properties are identified and tagged with the corresponding available parking area established. Key metrics are reviewed to determine a parking opportunity score base on several variables measurements, such as proximity to road or pavement, ability to park multiple vehicles and type of property.

EV-Up also combines the physical ability of consumers to park off-street with key demographic information derived from Experian Mosaic data which provides a pin-sharp picture of today's UK consumer, reflecting consumer and societal trends. By obtaining a deep understanding at the household level of the geodemographic group and type, the household can be linked to a probability to own a type of vehicle. This enables an improved understanding of ownership likelihood of EVs according to income and lifestyle and changing behaviours.

The allocation of the foundation data set has been developed based on UK statistics of mileage, EV efficiency and average underlying domestic demand based on the demographic groups identified. In addition, it assumes early EV adoption will be dominated by owners who live in properties with off-street parking where they can park their EV and charge using their own electricity supply. The methodology ensures that the results can be justified and backed up with credible evidence rather

[16] https://www.field-dynamics.co.uk/sp-energy-data-modelling-tool/

than a series of subjective assumptions. Figure 10 displays EV-Up uptake distribution for both SPM and SPD areas in the early 2030s.

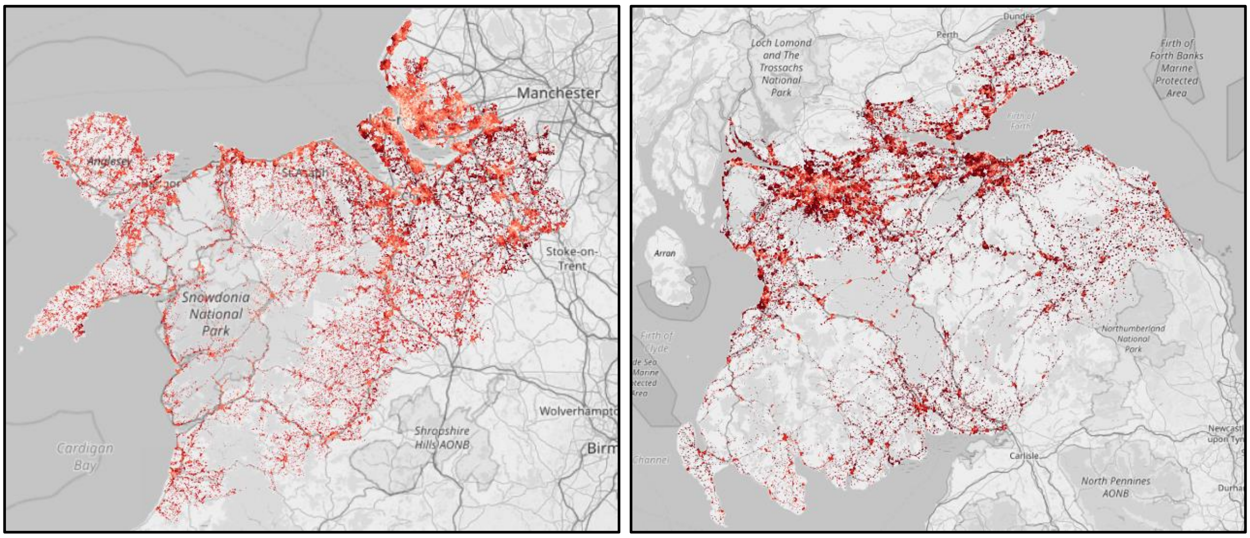

Figure 10 – SPM (left) and SPD (right) illustrative EV uptake distribution in the early 2030s

Contribution to system load

The winter peak and summer minimum demand per EV have been derived directly from the FES for residential charging. The FES data also accounts for the change in efficiency of cars over time. The number of EVs per GSP that charge at home is multiplied by the demand per EV to calculate the total residential EV demand at the time of winter peak and summer minimum. A portion of this charging demand is assumed to be “flexible”, based on FES assumptions, and can be shifted away from peak demand periods.

1.4.7 Electric Vehicles – other

The FES details many other types of EV types in its analysis, these include: buses, coaches, commercial vehicles, Light Goods Vehicles (LGVs) and Heavy Goods Vehicles (HGVs). While home charging personal EVs are likely to be the cause of the majority of grid impacts, there are significant point loads that are likely to occur from the other EV types and charging behaviours.

To allocate other EV charging types OS Address Base data was used to inform where existing buildings are that are likely to result in increased charging demand, these were then used as spatial proxies for allocation.

Table 4 below details the different types of EVs that are included, and a brief overview of how they are modelled, and what data was used to inform their allocation in the bottom up process covered in section 1.4.1.

EV type	Charging location	Spatial proxies used from OS database
Consumer owned EV (charging away from home)	Work Public Rapid	*"Office"* *"Public convenience"* *"Maintenance depot"* *"Petrol filling station"*
Buses & Coaches	Depot	*"Public coach parking"* *"Bus/Coach station"* *"Bus/Coach depot"*
Heavy Goods Vehicle (HGV)	Depot	*"Maintenance depot"* *"Petrol filling station"*
Light Goods Vehicle (LGV)	Depot	*"Maintenance depot"* *"Petrol filling station"*

Table 4 – EV type allocation metrics

The contribution to system load is based on data from the Energy Technologies Institute's Consumers, Vehicles and Energy Integration (CVEI) project[17], in terms of the:

- Share of consumer owned EVs (charging away from home) and associated charging profiles at work, public and rapid locations; and
- Charging profiles for other non-residential EVs.

1.4.8 BtM PV and storage

BtM PV and storage are spatially allocated according to the distribution of residential EVs. The logic is that the socio-economic factors and preferences that would incentivise households to purchase an EV are also well aligned with those for PV/Storage.

1.4.9 Demand flexibility

1.4.9.1 Introduction

The numbers outputted by the model represent the "actual peak demand" as assumptions on DSR, peak avoidance and smart charging are already taken into account prior to this. In order to get a better understanding of the impact of flexible demand, information on the assumed flexibility that has been provided by National Grid enables us to present how flexibility assumptions vary over time and understand the impact of these.

It should be noted that this flexibility is assumed to be based around the winter peak analysis which has the greatest need for flexibility. At summer minimum and maximum, it is assumed that no flexibility is active, consistent with the FES. In reality there is the potential for demand turn up, but this is expected to be small and hence is not explored in this analysis.

There is significant uncertainty around what the level of future demand flexibility will be. Ofgem's ongoing review of network access and forward looking charges could change the incentives on consumers to provide flexibility. However, the nature of such incentives, and the behaviour of consumers in response to such incentives, are very uncertain. The FES do not explicitly document all of the underlying assumptions on flexibility, but have a wide range across the four scenarios, reflecting

[17] https://www.eti.co.uk/programmes/transport-ldv/consumers-vehicles-and-energy-integration-cvei

the current uncertainty. By looking at these in conjunction with what would happen to peak demand without flexibility, how much peak demand is mitigated by can be understood – and hence the impact of the specific FES flexibility assumptions.

1.4.9.2 Underlying domestic demand

In the case of underlying domestic demand flexibility, National Grid's assessment of the impact of smart appliances, time of use tariffs and consumer behaviour has been used directly. The FES model has a wide range of flexibility and peak avoidance for underlying domestic demand, depending on various factors. These are included in the underlying FES data for domestic contribution to peak demand, and are therefore included in this modelling.

1.4.9.3 I&C demand

The FES provide the total GW that will become available through I&C DSR in GB as a whole, and this has been scaled to calculate the percentage of DSR based of the total I&C peak demand. The current levels of flexibility for I&C demand are already significant and larger than the flexibility of underlying domestic demand. The main reasons for this are that larger I&C customers are easier to engage with and their electricity consumption is half-hourly metered, which is required to determine the actual amount of demand reduced and hence the payment. For the two most highly decarbonised scenarios it is assumed that the percentage of flexible load will increase significantly towards 2050, whilst for the other two scenarios little change is expected. It should be noted that the increase in flexibility between now and 2050 is significantly less prominent for I&C than domestic, because of the relatively higher "starting point".

1.4.9.4 Electric Vehicles

National Grid provides flexibility assumptions for EV charging within the 2019 FES data, the DFES assumptions have been kept consistent with these. For residential EV charging, engagement with smart charging is expected to develop over time in all scenarios, which results in a large amount of flexible EV load available to the network particularly in terms of shifting load away from peak for overnight charging, the same is true for fleet vehicles charging at depots overnight. For non-residential (i.e. destination and forecourt) charging the flexibility of the non-residential EV demand is assumed to be 0% for all scenarios, as these are likely to be on demand requirements, where flexibility is therefore not appropriate. This lack of flexibility for non-residential charging is based on analysis undertaken as part of the CVEI study.

1.4.9.5 Heat Pumps

HP demand is assumed to be entirely inflexible in the non-decarbonisation centric scenarios in the 2019 FES, because consumers are expected to not be engaged with reducing their heating demand at peak times. One of the principal reasons for this is that few consumers have dedicated thermal storage and therefore cannot shift their heating demand without reducing their comfort levels, which they are unlikely to do. In the decarbonisation centric FES scenarios there is some peak demand reduction for HPs, which assumes hot water tank storage that can be used to provide some amount of heating demand peak avoidance.

1.4.10 Summary

The underlying scenario demand elements have been modelled in close alignment with the 2019 FES. Taking FES numbers but adjusting them where appropriate to reflect better the specifics of the SPEN licence areas. Numerous adjustments have been made to current values based on better informed SPEN data. Growth rates have been directly taken from the FES, and various separate data sources were used to significantly improve the spatial allocation down to the required PSS granularity to inform network modelling (summarised in Table 5).

Scenario element	Spatial disaggregation proxy	Granularity	Source
Underlying domestic demand	Household annual electricity demand	Postcode	BEIS
I&C demand	Building floor area	Building level	Ordnance Survey
Heat pumps	On/Off-gas grid properties	Postcode	Xoserve
	Building type (large/small)	Building level	Ordnance Survey
	New build	PSS	MHCLG/SPEN
District Heating – Large Scale HPs	PSS area and number of domestic buildings	PSS	Ordnance Survey
Electric Vehicles – Residential	Bespoke EV-Up model developed for SPEN	Building level	Field Dynamics
Electric Vehicles - Other	Non-domestic buildings by type (e.g. office, filling station)	Building level	Ordnance Survey
BtM PV and storage	Aligned with distribution of residential EV uptake		

Table 5 – Summary of key spatial disaggregation proxies for demand

Based on the information provided by National Grid on the flexibility assumptions in the 2019 FES data, the model is also able to provide a picture of what would happen to demand if flexibility assumptions were omitted, and the relative impact that this would have on the network given those circumstances.

1.5 Distribution connected generation and storage

1.5.1 Introduction

Generation and storage technologies that connect directly to the distribution network contribute to offsetting increases in demand seen on SPEN's network through PSSs and GSPs. Estimating the quantities and locations of these technologies is critical to planning investment on the SPEN network. We have separated distribution connected technologies into the following types:

- Wind;
- PV;
- Hydro;
- CHP (renewable and non-renewable);
- Other generation (dispatchable renewable and dispatchable non-renewable); and
- Storage.

In the following subsections we discuss the overall approach taken when applying the FES assumptions for technologies to the SPEN areas, and the specific methodologies used for each of the technology types above. At a high level generation capacity uptake has been modelled in three phases. An overview of this can be seen in Figure 11.

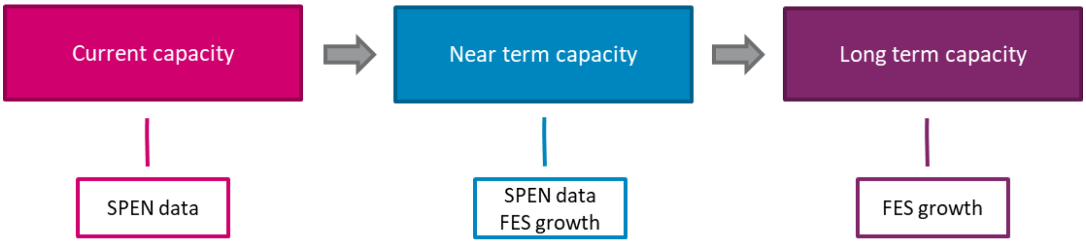

Figure 11 – Generation and storage capacity methodology

Current Capacity

The approach for all technologies has been to use SPEN capacity by PSS and GSP for 2019 directly, without alteration, as these represent the SPD and SPM internal view of current capacity (as of late 2019), which is more up to date than that contained in the 2019 FES. Total capacity for a SPEN region is calculated as the sum of all SPEN GSPs. This total capacity for SPEN serves as the starting point from which near term capacity, and long term capacity are built upon.

It is worth noting that the generation connected at GSP level is significantly higher than the aggregated numbers at PSS. This is because of a lot of larger scale generation is connected directly at the 33kV and 132kV networks which are aggregated directly at the GSP level, which continues to be the case throughout the scenarios.

Near Term Capacity

For the near-term period, over which SPEN have a pipeline of contracted development projects, these values of capacity and locations take precedence over the FES growth assumptions. Hence capacity for these contracted developments is allocated according to the SPEN pipeline. The remainder, representing currently future applications, is then allocated using a spatial allocation methodology.

Long Term Capacity

Capacity growth beyond SPENs pipeline of known projects in their areas grows according to the annual growth rates as seen in the 2019 FES. These rates vary by year and by scenario, for each technology. These growth rates are derived by NG for GB as a whole, for a more granular definition of technologies than used in this report. For the SPEN areas the capacity weighted average growth rate is calculated, reflecting the current mix of technologies in the SPEN areas with GB growth rates applied thereafter.

The GB growth rate does not reflect local conditions in the SPEN areas, but there is no strong evidence that the SPEN areas will see systematically different growth than the GB average over the longer term. However, the growth rates across the FES provide a reasonable range with which to test the SPEN network, and so have been used directly. The growth rates used are calculated by using year on year growth in nameplate capacity (MW) in the FES data.

Total SPEN capacity over full horizon

Figure 12 shows how the total SPEN capacity over the full horizon is calculated from the three constituent methodologies mentioned above (with two illustrative examples of expected near term project capacity – A and B). By matching the FES growth rate in the long term means that the final capacities for the SPEN areas from the analysis presented in this report do not necessarily match the absolute outturn values in the raw FES data directly. For some technologies and scenarios this approach results in higher calculated capacities for the SPEN area than in the raw FES data, for other technologies and scenarios it will be less. Were all DNOs to apply the approach outlined here, we would expect total capacity calculated to broadly match the raw FES GB capacity assumptions at national level similar.

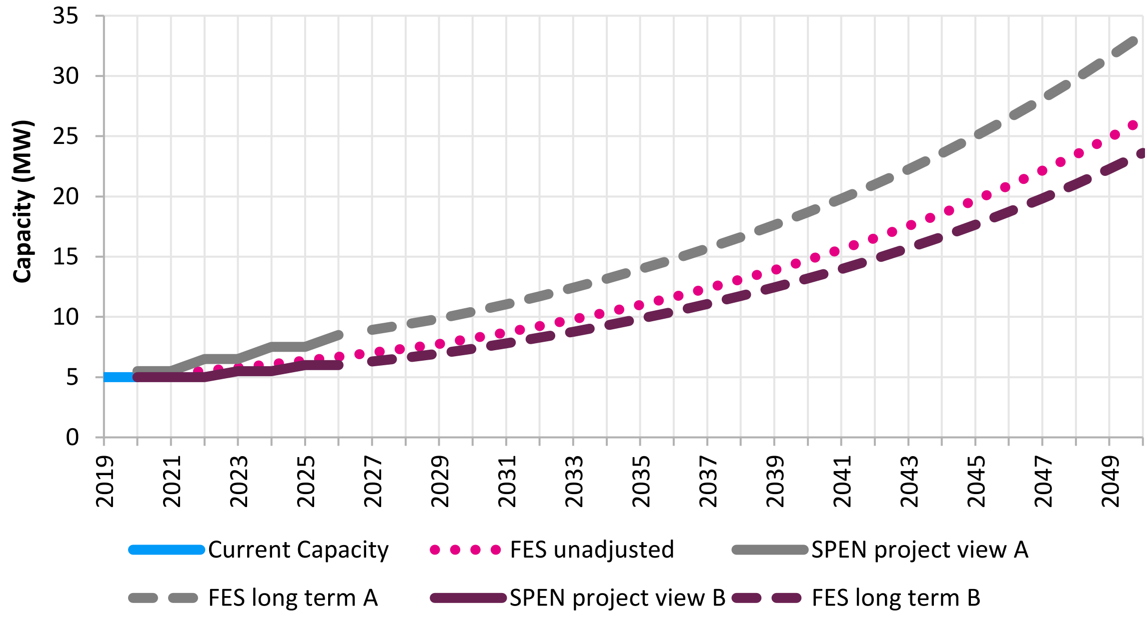

Figure 12 – Exemplar approach for calculating capacity for the SPEN areas over the full horizon

An alternative approach would have been to match the absolute capacity (MW) in the FES in the long term. Our view is that the FES has a GB wide growth assumption which encapsulates the average of many small projects over GB, and can be ignored when project specific data is available. When working at a more granular level, where better visibility of specific projects is available, these should be used (i.e. near term SPEN project pipeline) before deferring to the GB average growth rate thereafter.

1.5.2 Capacity siting

All distribution generation and storage capacity must be assigned to a PSS or GSP, to allow the net demand/generation at each point to be calculated for winter peak and summer minimum and be used by SPEN in its load planning. For other generation (dispatchable technologies) and storage the remaining headroom at the PSS/GSP is itself a key determinant of the spatial allocation (e.g. to be sited at a location with substation remaining headroom to provide national level balancing services or with limited remaining headroom and where the technology itself can be used to help resolve constraints. To do this a two-step process is needed to i) allocate all demand and generation scenario elements excluding other generation and storage, and ii) calculate the net load position and headroom (given substation capacity rating) and use this metric to help spatially allocate the flexible technologies.

The approach to spatially siting the SPEN areas capacities to individual PSS/GSPs varies depending on the stage in the horizon:

- **Current**
  - Use SPEN data available at GSP/PSS level, which matches SPEN view.
- **Near term**
  - SPEN likely project data described above is at GSP/PSS level.
  - Various technology specific spatial allocation methodologies used as below, to allocate "excess" FES capacity.
- **Long term**
  - Various technology specific spatial allocation methodologies are used, and described in subsequent subsections.

The capacity required for each year is first calculated by applying the FES growth rate (%) to the previous year's capacity total for the area as a whole. This capacity is then allocated using various spatial proxy weightings. Spatial proxies for each technology type are used for each different PSS and GSP to spatially disaggregate the total capacity to be allocated. These proxies are detailed in the following sections, and are all formed from relevant geospatial data assigned to a PSS/GSP, by the area mapping mentioned in section 1.3.

There are number of common features that can apply to the generation side spatial mapping:

- In some cases, multiple spatial proxies are combined to create a single weighting for each PSS/GSP region. The capacity that is then required to be allocated for that particular technology is then spread across all PSS/GSPs according to the weighting.
  - One spatial proxy that is consistent across all technology types is if there is already connected capacity at the relevant PSS/GSP. The logic being that this indicates that the area is a relatively more "attractive" area, with existing sited connections, and hence increases the likelihood of future connected capacity.
- When capacity is allocated spatially, this is subject to set minimum allocation sizes, to make sure that immaterially small amounts of capacity are not assigned to an area.
- Spatial maximum caps are also set so that there is a limit to the amount of generation that can be allocated to a single area – these spatial caps are technology dependent and representative of the technology type e.g. wind takes up considerably more room than storage.

These weightings and spatial caps are then calibrated to a point where a sensible selection of allocated generation was allocated to particular areas. This essentially results in more “favourable” areas receiving more connected generation – up to any imposed cap – allowing each of the scenarios to build up accurate likely projections of how capacity will be allocated within the SPEN regions.

It is important to note that PSS allocations are modelled first, and then a second iteration to allocate the additional capacity connecting directly at GSP second. The PSS connected generation is also aggregated up to its corresponding GSP.

1.5.3 Wind

The main spatial proxy used to allocate capacity is wind speed, the data collected from the Met Office datasets for each PSS/GSP area[18]. This is the primary measure used to drive an allocation weighting – the assumption being that more windy areas are more attractive for generation buildout.

As well as existing capacity as previously mentioned, the final proxy used is rurality. Rurality is calculated from the ONS census on households[19], and a Scottish Government’s source in Scotland[20]. To calculate our rurality percentage these sources were used to understand how many households classified as either “urban” or “rural” and using this to understand the split for each PSS/GSP. This rurality percentage is then applied to the model as a threshold, of which an area must reach before it is possible to allocate to that area. This stops wind capacity being allocated to overly urban areas, where it would be unrealistic.

1.5.4 Large-scale PV

The main spatial proxy used to allocate capacity is bright sunlight hours with the data collected from the Met Office/CEDA datasets for each PSS/GSP area as per wind. This is the primary measure used to drive an allocation weighting – with the assumption that sunnier areas are more attractive for generation buildout. As well as existing capacity as previously mentioned, the final proxy used is rurality. This calculated in the same manner as for wind, however, PV has a lower threshold due to smaller space requirements.

1.5.5 Hydro

Number of waterways was the spatial proxy used to allocate hydro power, the data collected from the Ordnance Survey[21]. The logic is that the larger the number of waterways in an area the higher the probability that new hydro capacity would be allocated. The increase in likelihood of allocation due to existing capacity was removed for this measure as it less plausible that multiple hydro stations could be accommodate in the same area.

1.5.6 CHP

CHP capacity is assigned to GSPs according to different types of expected heat demand. CHP is split into renewable (i.e. biomass) and non-renewable (i.e. gas) variants, with a differing approach for each.

[18] Met Office / CEDA (Centre for Environmental Data Analysis) HadUK-Grid – 2017 Data
[19] Office for National Statistics (ONS) Census 2011 in England & Wales (Table RUC2011)
[20] Scottish Government in Scotland (Table SCUrbanRural2016)
[21] OpenRivers 2019 database

Renewable CHP

We assume that due to air quality restrictions renewable CHP (likely biomass fired) will be sited away from residential areas, and will instead be sited near large industrial centres to cover significant industrial heat demand. As a proxy for the industrial heat requirement, which is not spatially disaggregated in the FES data, we have used the I&C electricity load for each GSP, calculated as described in section 1.4.3.

Non-Renewable CHP

Non-renewable CHP is assumed to be built primarily for district heating, which we assume is likely to be located in areas of high heat density. We calculate a proxy for heat density per PSS/GSP in a similar manner to that for district heating – large scale heat pumps in section 1.4.5.

Increases in non-renewable CHP capacity at the SPEN area level are then spatially allocated to individual PSS/GSPs based on the relative heat density of each, i.e. with more capacity being built in areas of high heat density. There is also a minimum threshold heat density, which a PSS/GSP must exceed in order to have any heat density allocated.

1.5.7 Other generation (dispatchable technologies)

Dispatchable generating capacity (and battery storage) can be classed as “flexible”, in that the output can be increased or decreased quickly in response to price signals and/or system need.

The approach sites all forms of demand first as per section 1.4 followed by all inflexible generation (i.e. renewable and CHP which is assumed to be heat load following), then sites flexible plant to GSPs after that – according to the calculated thermal constraints of each GSP and need for flexible plant to provide reserve services. Other technologies are split into renewable (i.e. biomass) and non-renewable (i.e. gas) variants, with a slightly different approach for each.

Where flexible technologies are sited is dependent on the system need/opportunity they are being built for. Currently, much of the new flexible capacity on the distribution system is built to either supply power at the system peak load, or be used for system services (e.g. primary and secondary response). As a result, there is an incentive to be sited in areas of low distribution network constraint, to ensure that there is full access to national-level balancing markets.

As the Distribution System Operator (DSO) model evolves, there will likely be incentives for flexible assets to site in areas of high constraint, as DSOs seek to manage local balancing issues, reducing the need for investment in the distribution network itself.

The analysis presented here, assumes that initially capacity is sited in GSPs of low constraint (matching what is seen currently) but that after a user-defined year SPEN will be able to provide the necessary incentives to encourage capacity to site in areas of high constraint.

There is a high degree of uncertainty around the pace of evolution to a DSO model. We have reflected this uncertainty through varying the assumed year implementation of local balancing for each scenario. The SPEN DSO Vision document from 2016[22] states an ambition to have a full DSO model (i.e. including local balancing) implemented within 7 years. 2023 aligns with the start of price control period for RIIO-ED2, and it is likely that local balancing mechanisms would be linked to incentives coming from new price control periods. A range of years were used across scenarios, to capture the uncertainty of

[22] https://www.spenergynetworks.co.uk/userfiles/file/SPEN%20DSO%20Vision%20210116.pdf

when a full DSO model will emerge: 2023 for CR and CE, 2033 for SP and 2028 for TD. These are years at which the spatial siting of dispatchable (and storage) capacity switches focus from areas with greater headroom to those with limited headroom.

Using the dates above, the high level methodology for siting dispatchable (and storage) capacity is as follows:

1. Calculate the headroom of each PSS/GSP in each year
    a. Take **thermal capacity** of each GSP, using SPEN supplied data, assume this stays constant over the horizon (i.e. no reinforcement). Thermal capacity staying static is a logical simplifying assumption because of difficulty predicting exact locations for reinforcement;
    b. Take calculated metered **demand** for each PSS/GSP in each year, for winter peak, summer maximum and summer minimum periods;
    c. Take calculated distribution connected **generation** for Wind, PV, Hydro, CHP and BtM PV technologies, using load factors at all appropriate time periods – consistent with FES assumptions, to calculate the total generation at each PSS/GSP;
    d. Calculate the thermal **headroom** for both winter peak and summer minimum at each PSS/GSP using the following parameters: **thermal headroom**, **thermal capacity** of substations, **distribution generation** at peak, and **metered peak demand**.
    e. Find the constraining headroom by taking the lowest of the time periods (this is nearly always at winter peak when demand is high);
2. For years prior to the local balancing model implementation, share new capacity over the PSS/GSPs with the higher thermal headroom;
3. For years after the local balancing model implantation, share new capacity over the PSS/GSPs with the lowest thermal headroom.

This process is performed for other generation (renewable dispatchable), other generation (non-renewable dispatchable) and storage technologies – in that order – to calculate the available headroom. The headroom calculated to allocate storage capacity spatially will itself be a function of renewable dispatchable and non-renewable dispatchable capacity siting.

Renewable Dispatchable

As with CHP, we assume that a new renewable plant (i.e. biomass or biogas) is only sited in more rural areas for air quality reasons. Where there is an increase in capacity, the PSS/GSPs are filtered to include only those with high I&C load, and then the annual capacity increase is assigned to PSS/GSPs with highest or lowest headroom, as described above.

Non-Renewable Dispatchable

For a non-renewable dispatchable plant (i.e. gas engines) a similar approach is followed as for renewable controllable plant, but without the focus on the constraint that new capacity must be sited in industrial areas only, and including any renewable dispatchable plant on the supply side when calculating the PSS/GSP headroom. Where there is an increase in capacity, annual capacity increase is assigned to PSS/GSPs with highest or lowest headroom, as described above.

1.5.8 Storage

By storage we mean battery storage, there being limited additional potential for pumped storage within the SPEN areas. Storage is a flexible technology and is treated in the same way as a dispatchable plant when siting capacity changes, but including any dispatchable plant (renewable and non-renewable) on the supply side when calculating the PSS/GSP headroom. Where there is an increase in capacity, the annual capacity increase is assigned to PSS/GSPs with highest or lowest headroom, as described above.

1.5.9 Load factors

To understand how technologies contribute to generation, we use "load factors" assumptions to scale nameplate capacity into expected output, taking into account diversification effects, intermittency, and outages.

Load factor assumptions for all generation or storage technologies are taking directly from the FES GB wide assumptions. These vary by technology and year (though many technologies do not change by year), and are given for winter peak, summer minimum and summer maximum periods.

Where multiple FES technologies have been aggregated into the categories used in this study, we have taken the capacity weighted load factor across all grouped technologies for each year, to ensure the same energy output as assumed in the FES.

1.5.10 GSP net demand and generation

Using technology load factor and capacity assumptions, the total expected generation output for each GSP can be calculated for winter peak and summer minimum periods. By subtracting the total generation from the metered demand at each GSP, the net demand (or generation) from each GSP to the SPEN network can be calculated.

1.5.11 Summary

The FES provide a reasonable range of possible capacity evolutions for generation and storage technologies in the SPEN areas, subject to the adjustments for creating more Net Zero aligned scenarios described in Table 2. Our approach has been to:

- Use current SPEN data at both PSS and GSP level, to provide a baseline for all known connected generation capacity.
- Use local project status knowledge for named projects (assigned to GSPs) for the near term connections.
- Assume the same growth rates at a total SPEN licence area level as seen in the FES for the period 2020-2050, but use bespoke methodologies for siting capacity to GSPs and PSSs based on various spatial data to give insight into local suitability (summarised below in Table 6).
- Use the FES data for load factors of all generation and storage technologies to create net-load positions for specific time periods.

Scenario element	Spatial disaggregation proxy*	Granularity	Source
Wind	Wind speed	Postcode	Met Office
	Rurality		ONS, Scottish Government
Large-scale PV	Sunlight hours	Postcode	As per wind
	Rurality		
Hydro	Number of waterways	PSS	Ordnance Survey
CHP Renewable	I&C demand	GSP	As per demand proxies
CHP Non-Renewable	PSS area and number of domestic buildings	PSS	Ordnance Survey
Dispatchable renewable	Network headroom	GSP/PSS	Calculated in DFES
	Rurality	Postcode	ONS, Scottish Government
Dispatchable non-renewable	Network headroom	GSP/PSS	Calculated in DFES
Battery storage	Network headroom	GSP/PSS	Calculated in DFES

***Note:** the table does not include the presence of existing capacity, which is also a key driver for siting of additional capacity for all technologies excluding hydro.

Table 6 – Summary of key spatial disaggregation proxies for generation and storage