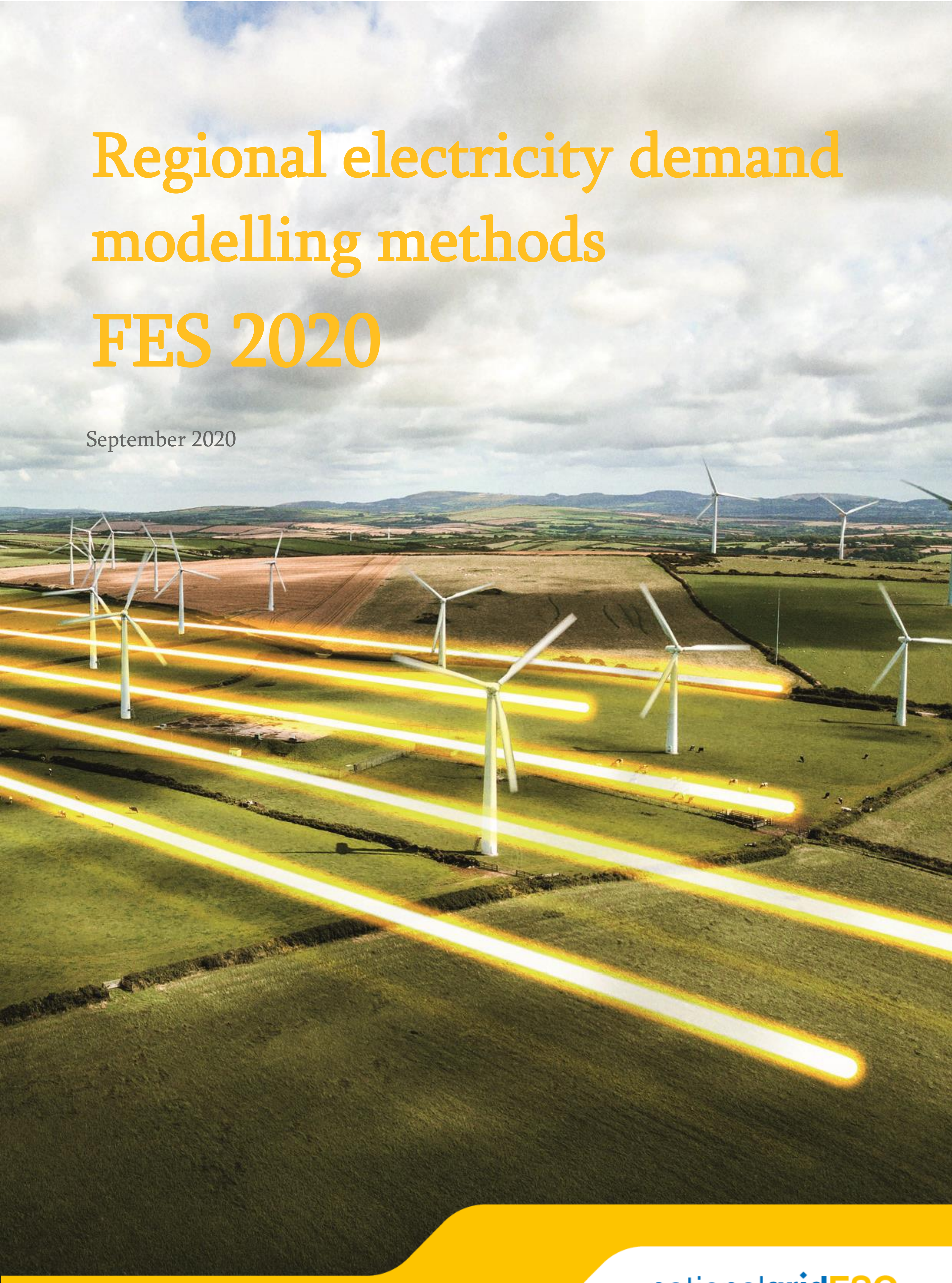
Regional electricity demand modelling methods

FES 2020

September 2020



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Introduction

Our **FES Regional electricity demand modelling methods** publication is just one of a suite of documents we produce as part of our Future Energy Scenarios (FES) process. A huge amount of work including modelling, analysis and interpretation goes into the production of the main document. For ease of use, we only highlight significant changes to our modelling methods in the main FES document. Alongside this publication, we have the **Scenario Framework** that details all the assumptions and levers that are used as input into our models. The **Modelling Methods** describe the models used to populate the scenarios. Our **Data Workbook** contains all the outputs from the numerous models; the detailed tables, graphs and charts. We also publish a summary document **FES- in- 5** and our FAQs. For more information and to view each of these documents visit our website: nationalgrideso.com/future-energy/future-energy-scenarios

As our modelling continues to evolve we will update this document to reflect those changes, ensuring our latest methods, models and techniques are shared. As with our other FES documents we welcome your feedback, please contact us at: fes@nationalgrideso.com

Overview of the data

The Future Energy Scenarios (FES) are intended to illustrate a broad range of credible, holistic outcomes from now to 2050. To support further analysis within the electricity industry, the scenarios are broken down to regional datasets.

The datasets include an initial draft view of gross (underlying) and net (transmission) demand for each scenario out to 2050. Each year includes three study periods, namely Winter Peak, Summer Minimum AM and Summer Minimum PM. Details of the scenarios and the study periods are provided in Appendix A and you can select the year, scenario and study period via the drop-down boxes on the Main Data worksheet.

The data is provided for each Grid Supply Point (GSP) and demand Direct Connect (DC). A GSP is a connection between the Transmission network and the Distribution network, whilst a DC is a connection between the Transmission network and a large energy user. To support backwards compatibility with last year's publication, we have included the major and minor FLOP zone. These are defined within the Electricity Ten Year Statement 2019[1].

Modelling method (Active Demand)

The modelling approach is described in more detail below. At a high level we start by working out the current demand split in our start year (2019/20) at each GSP and DC. This is achieved by taking demand as metered at the transmission network and adding to this the component of demand that is supplied by non-transmission connected generating assets. The result is the total Gross demand.

This Gross demand is then split by demand subcomponents so that in our starting year (2019/20) we know what proportion of each GSP's demand is residential, industrial, commercial, heat and transport. Our FES growth rates are then applied to these subcomponents and therefore the change in demand at each GSP will reflect the portfolio of demand subcomponents seen at each GSP.

Your feedback

This year we have adopted many new methods and datasets and as such, this data should be considered as an initial draft which is subject to change. We welcome your views and comments on our draft regional projections. Please share your comments via our Box.FES@nationalgrideso.com email address – your feedback will be used to inform our future work.

Current demand split

Our Future Energy Scenarios show how electricity demand will change between now and 2050. Our analysis considers the sub-components of demand. These are Residential (non-heat), Industrial, Commercial and electrification of heat and transport. This year we've also included demand for hydrogen production via electrolysis and steam reformation.

[1] https://www.nationalgrid.com/uk/publications/electricity-ten-year-statement-etys

Before we can apply our growth rates, we must first understand how the current electricity demand is split regionally according to these sub-components. This is a two-step process: first we determine the gross demand at each GSP, and then we apportion this across the sub-components.

Step 1: Gross demand

Gross demand is the total underlying consumption that you would observe if you were to add up all electricity use irrespective of which network the customer connects to or where the energy is supplied from. Until the deployment of smart meters is complete it is difficult for us to determine this demand during the study period of interest. We must make use of the metered data we have access to and apply some assumptions.

For England and Wales the starting point is Elexon Settlement data flows CDCA I030 (GSP volumes) and CDCA I042 (metered volumes for each BM unit); both available on the Elexon Portal. These represent metered Net demand as measured at the transmission network. Because we are looking at typical demand during each study periods (rather than demand at a specific historic half hour), we use the average of the data over the last 5 years. From this we calculate the percentage that each GSP typically contributes to Net demand during each study period. These percentages are then applied to the GB level Net demand calculated earlier in our FES analysis to get an energy value (in MW) for our starting year 2019/20.

For Scotland, we have continued to use Week 24[2] as the source of demand data, with the settlement data being available for benchmarking. In a few cases GSPs from the Elexon list have been replaced by an alternate list. This is generally the case for split busbar sites and both of these steps in Scotland are a transitional arrangement as we move to using Elexon data.

Once we have Net demand by GSP we can determine the underlying Gross demand[3] by GSP by adding the energy generation output of non-transmission connected power stations (Embedded and sub 1 MW) for 2019/20 financial year. Once again this is an area we have limited data for and as such we make a number of assumptions in this process.

We map each large individual (Embedded) generation site to a GSP. In many cases this mapping is per the Distribution Network Operator (DNO) or Transmission Owner (TO) data, but where gaps existed we mapped to the nearest GSP geographically. For micro-generation (sub 1 MW) the relevant Feed-in-Tariff and Renewable Obligation data was mapped to the nearest GSP. This is then scaled up to match the total micro-generation installed capacity. The installed capacity at each GSP is then converted to a generation output by multiplying with technology specific load factors. It is these generation output values that are added to the Net demand in order to give us a Gross demand for each GSP (and DC) for starting year 2019/20.

Step 2: Gross demand subcomponents

[2] Week 24 submissions are part of the Data Registration Code and are submitted by the DNOs. Here we use the schedule that relate to the demand on the day of GB peak demand and GB minimum demand.
[3] Note: Gross demand in this dataset does not include station demand, pumping demand or exports. We have not modelled these Direct Connects. We also do not include transmission losses at this stage.

To estimate the split of domestic and non-domestic demand to be used per GSP in our analysis start year (2019/20), electricity consumption data from BEIS was used[4]. This data provides the breakdown of 2016 electricity consumption by output area. The output areas are: Middle Super Output Areas (MSOAs) for England and Wales; and Intermediate Geography Zones (IGZ) for Scotland.

We map these output areas to our Grid Supply Points according to a nearest neighbour approach. That is, we assumed that the electricity demand of each IGZ and MSOA is supplied by the closest GSP. This is a process that we are keen to approve on and welcome your feedback on how we can improve it.

Once we have allocated each output area to a GSP we can use the BEIS data to calculate a percentage split of domestic and non-domestic demand in each GSP. This percentage was then applied to our start year (2019/20) GSP gross winter peak to estimate the current domestic and non-domestic demand of each GSP.

For the summer minimums, some scaling was required so that the regional data reflected the FES GB dataset. This is required because the BEIS data gives an annual split and, whilst this annual split is reflective of the Winter peak split, it is not reflective of Summer Minimums.

The BEIS data does not split non-domestic demand down into its constituent parts. Therefore, to obtain commercial and industrial demands, we split the non-domestic component according to the Great Britain split as published in the Future Energy Scenarios.

This process produced the gross demand of the GSP for each demand component in our starting year 2019/20 (for electric transport treatment, please see below).

Forecasts

Demand

Having determined the demand sub components for each GSP (and DC) in our starting year (2019/20) we are now able to apply our forecasts to calculate the demand by GSP out to 2050.

Residential, industrial and commercial

Our residential demand trends for each scenario were applied to the starting year residential demand at each GSP. This gave a GSP level residential forecast for every scenario and year. The same process was applied to commercial and industrial trends.

It should be noted that our industrial demand forecasts also include electricity demand for hydrogen production (via electrolysis). As such we are assuming that hydrogen is produced via electrolysis in alignment to current industrial demand across the country.

[4] https://www.gov.uk/government/statistics/lower-and-middle-super-output-areas-electricity-consumption

Heat demand

We understand that heat pumps uptake is dependent on many factors such as type of house; ground and environmental conditions, existence of garden (for GSHP), noise considerations (for ASHP) and heat pumps installations are also subject to planning permissions.

Our modelling does not go into all these details which are not part of the current scope. To forecast heat pumps in each scenario, we assumed that heat pumps demand will follow residential demand trends. We therefore allocate heat pumps demand in each GSP based on each GSP's contribution to total residential demand.

The same process used for heat pumps was also applied to our district heat demand forecasts.

In our Two Degrees scenario, we restrict the deployment of heat pumps in cities which deploy hydrogen as a fuel for heat decarbonisation. That is, in this scenario, cities that have undergone a conversion to hydrogen by 2040, or will switch to hydrogen between 2040 and 2050, do not see a growth in heat pumps. These cities are listed in Appendix B.

Transport demand

We model domestic electric vehicles according to the following process. Electric vehicles used in commercial or industrial processes are covered by the general process set out above for those sectors.

Our start year split is based upon the DVLA[5] values for "vehicle registration by postcode and body type and propulsion in 2015". When the scenario reaches 5 million cars the locational split is based on whole fleet numbers from Department for Transport (DfT) Statistic table VEH0122. By moving to whole fleet numbers, we solve potential population growth issues that occur when creating splits based on just today's EV registration locations. The period in between the two split methods is calculated as a smooth curve (not a straight line) between the two splits.

Direct Connects

Rail network direct connects follow the growth of rail as assumed in GB FES. Hydrogen production direct connects (steam reformers and electrolysers) follow FES projections for hydrogen demand growth. The demand of the other types of direct connects stays constant across the years. We continue to revise these assumptions and we welcome your views on alternative approaches.

Supply

The Embedded and Sub 1MW Generation forecasts are apportioned according to the existing geographical distribution for all technologies except solar. Our solar spatial forecast is designed to reflect the fact that as solar installed capacity increases it will spread more evenly across the country. Today solar is most prevalent in the South and East of England.

[5] Driver and Vehicle Licensing Agency (dval.gov.uk)

For storage, the existing capacity and new sites with a known location were allocated to a GSP using a nearest neighbour approach. Future growth that does not yet have a known location is split out to GSP level based upon the year by year increase in wind and solar by GSP.

Reactive power

Current view

For England and Wales the starting point of the net reactive power (Qnet) is the National Demand Data (NDD)[6], due to resolution of reactive power metering in Elexon datasets not aligning with the active demand datasets we have used. These represent metered Net reactive demand as measured at the transmission network. Where NDD was missing metering for certain GSPs or DCs, Week 24 data was used.

For Scotland, we have continued to use Week 24 for the net reactive power as the source of demand data, with the NDD being available for benchmarking.

The gross reactive power (Qgross) in each GSP includes the metered net reactive power with the additional network's losses and gains (including DNO network).

Reactive power forecasts

To understand the trends of the gross reactive power, power factors were applied to the active demand of each demand sub- component. These trends were then applied to the starting point of the gross reactive power and produced the gross reactive power forecast for the 4 scenarios.

The power factors for each subcomponent were produced based on literature reviews and in-house modelling.

The net reactive power was modelled, using Pgross, Qgross, Embedded Generation and Sub 1 MW Generation and network characteristics.

[6] NDD is part of National Grid's operational demand metering.

Appendix A

The scenarios

Our spatial modelling follows on the GB analysis undertaken as part of our Future Energy Scenarios. These are described in more detail in our Future Energy Scenarios publication. We again feature four core scenarios mapped on a 2x2 matrix. To test possible outcomes, we've changed one of the scenario framework variables from the level of decentralisation to the level of societal change. This reflects the impact of an engaged, end-consumer on the possible routes to net zero. It also shows the scale of change required to meet net zero.

This approach allows three of the scenarios to meet the 2050 net zero target, but via different routes. The fourth scenario allows us to explore a credible level of decentralisation in a world where the 2050 target is not met.

- **System Transformation:** This scenario meets the net zero carbon target in 2050 and shows a pathway that has the least consumer impact to do so. This scenario includes a high use of hydrogen for heating and other energy demands.
- **Consumer Transformation:** This scenario meets the net zero carbon target in 2050 and shows a pathway that has a relatively high consumer impact, compared to the System Transformation scenario. This scenario uses a high level of electrification for heating and other energy demands.
- **Leading the Way:** This scenario shows the credible earliest date when the net zero target is met. This will comprise the most favourable carbon reductions from each sector and will likely have geographical variances in the way this is done - to suit the regional differences.
- **Steady Progression:** This scenario shows the credible least progress with decarbonisation - thus resulting in the highest carbon output.

The regional data is provided for each Grid Supply Point (GSP) and demand Direct Connect (DC). A GSP is a connection between the Transmission network and the Distribution network, whilst a DC is a connection between the Transmission network and a large energy user. To support backwards compatibility with last year's publication, we have included the major and minor FLOP zone. These are defined within the Electricity Ten Year Statement 2019[1].

Study periods

- Winter Peak is a view of peak demand between the hours of 17:00 and 18:00 – typically November-February on a week day.
  - The peak demand is Average Cold Spell (ACS) – a high demand condition, which has a 50% chance of being exceeded
  - Electric vehicles are a demand – smart charging behaviour assumed.
  - Some vehicle to grid considered as supply
  - All storage considered as a supply
  - This period is of interest as these are the maximum demands on the system
  - Note EV smart behaviour is an assumption but demands could be higher or lower under certain circumstances.

- Summer Minimum AM is a view of demand between 0500-0600, typically in June-August on a Summer Sunday morning.

    - Electric vehicles are a demand – no smart behaviour assumed (people charge how they would charge assuming todays behaviour)
    - All storage considered as a demand – spread over 4-6 hours to avoid creating a new low demand point
    - This period is of interest as these are the currently minimum demands on the system

- Summer Minimum PM is a view of demand between 13:00-1400, typically June-August, Summer Sunday afternoon.
    - Electric vehicles are a demand – no smart behaviour assumed (people charge how they would charge assuming todays behaviour)
    - All storage considered as a demand – spread over 4-6 hours to avoid creating a new low demand point
    - This period is of high interest due to solar PV which peaks at this time and reduces transmission demands – but flows around the system may still be high.

Appendix B: Location of hydrogen production

FES 2020 scenarios cover a wider range of hydrogen usage, including for heating buildings, process heating, shipping, transport, and for power generation. Hydrogen has unique advantages when it comes to decarbonizing hard to treat sectors like heating but also enables integration of variable renewable electricity generation by providing a means for long term energy storage and flexibility.

FES 2020 has also explored a more diverse range of hydrogen production or supply methods. Table below summaries hydrogen production methods by scenario.

	Methane reformation +CCUS	Electrolysis – Grid connected	Electrolysis – Non-grid connected	Biomass Gasification with CCS	Imports
System Transformation	✓	✓		✓	
Consumer Transformation	✓	✓			
Leading the Way		✓	✓		✓
Steady Progression		✓			

The hydrogen production methods of most importance for electricity demand regional breakdown are methane reformation and grid-connected electrolysis. The geographical locations of production sites are highly uncertain but FES 2020 assumes that both reformers and electrolysers will most likely be sited either close to demand (e.g. industrial clusters, main transport corridors) or near generation (e.g. solar or wind farms). Table below gives a summary across the four scenarios.

	System Transformation	Consumer Transformation	Leading the Way	Steady Progression
Grid-connected electrolysers	Near Motorways*	Near Industrial Clusters	Near Generation	Near Generation
	Near Train Depos	Near Motorways		
		Near Train Depots		
		Near Ports		
		Near Generation		
Steam Reformers	Near Industrial Clusters	Near Industrial Clusters		

*We have used the EU's Ten-T Core transport network and freight tonnage statistics to to mapp the major points to the closest GSPs.

Table below shows the approximate locations of the major industrial clusters hosting methane reformers and CCUS plants (which are assumed to be co-located).

			Start date			
Reformers/CCUC sites	**FLOP**	Share of reforming capacity	**System Transformation**	**Consumer Transformation**	**Leading the Way**	**Steady Progression**
Peterhead	T2	5%	2039	2039	2039	2039
Teesside	P6	20%	2030	2030	2030	2030
Cheshire salt basin	N3	20%	2035	2035	2035	2035
White Rose (Humber)	P8	15%	2032	2032	2032	2032
Kingsnorth	C4	20%	2040	2040	2040	2040
Don Valley	P4	5%	3033	3033	3033	3033
Grangemouth	S6	5%	2037	2037	2037	2037
Longannet	S5	10%	2038	2038	2038	2038

Compared to methane reformers, electrolyser sites are assumed to be more numerous as well as being more geographically spread out. The full list of the sites can be found in the reginal breakdown workbook[7]. Below is a summary of the number of electrolyser sites in each scenario broken down by the type of connection to the electricity grid.

Connection types	**System Transformation**	**Consumer Transformation**	**Leading the Way**	**Steady Progression**
Embedded (GSP)	41	42	0	0
Transmission DC (Direct Connect)	23	33	18	18

[7] https://www.nationalgrideso.com/document/173816/download

Appendix C: Regional building blocks

Building block demand data summary and methodology

Template		Building Block ID Number	Technology Detail	Units	Detail	Comments	Data Quality	Comments on methodology
Demand		Dem_BB001b	Domestic	MW	Annualised Peak Demand MW		Reasonable	Includes appliances & lighting, EVs, Heat Pumps and Consumption from DH Networks serving domestic properties
		Dem_BB002c	I&C	MW	Annualised Peak Demand MW (TBC)		Reasonable	Industrial and commercial demand, inlcuding commercial Evs and commercial Heat Pumps. It excluded electrolysis
Demand Low Carbon Technologies	Electric Vehicles	Lct_BB001	Pure Electric (cars & motorbikes)	Number of	Number of EVs registered in the specific geographical area	Cars and Motorbikes Includes number of EVs in the specific geographical area	Reasonable	Includes botg domestic and commercial vehicles
		Lct_BB002	Plug-in-hybrid (cars and motorbikes)	Number of	Number of EVs registered in the specific geographical area	Cars and Motorbikes Includes number of EVs in the specific geographical area	Reasonable	Includes botg domestic and commercial vehicles

		Lct_BB003	Pure Electric (road vehicles other than cars and motorbikes)	Number of	Number of EVs registered in the specific geographical area	Vans, HGVs, Buses Includes number of EVs in the specific geographical area	Derived	Includes botg domestic and commercial vehicles
		Lct_BB004	Plug-in-hybrid (road vehicles other than cars and motorbikes)	Number of	Number of EVs registered in the specific geographical area	Vans, HGVs, Buses Includes number of EVs in the specific geographical area	Derived	Includes botg domestic and commercial vehicles
	Heat Pumps	Lct_BB005	Domestic - Non-hybrid	Number of	Number of Heat Pumps registered in the specific geographical area		Derived	Includes ASHPs and GSHPs
		Lct_BB006	Domestic - Hybrid	Number of	Number of Heat Pumps registered in the specific geographical area	Electrical vs Gas bias	Derived	Includes ASHPs and GSHPs
	Storage	Srg_BB001	Batteries	MW	Installed capacity	>= 1MW capacity	Reasonable	

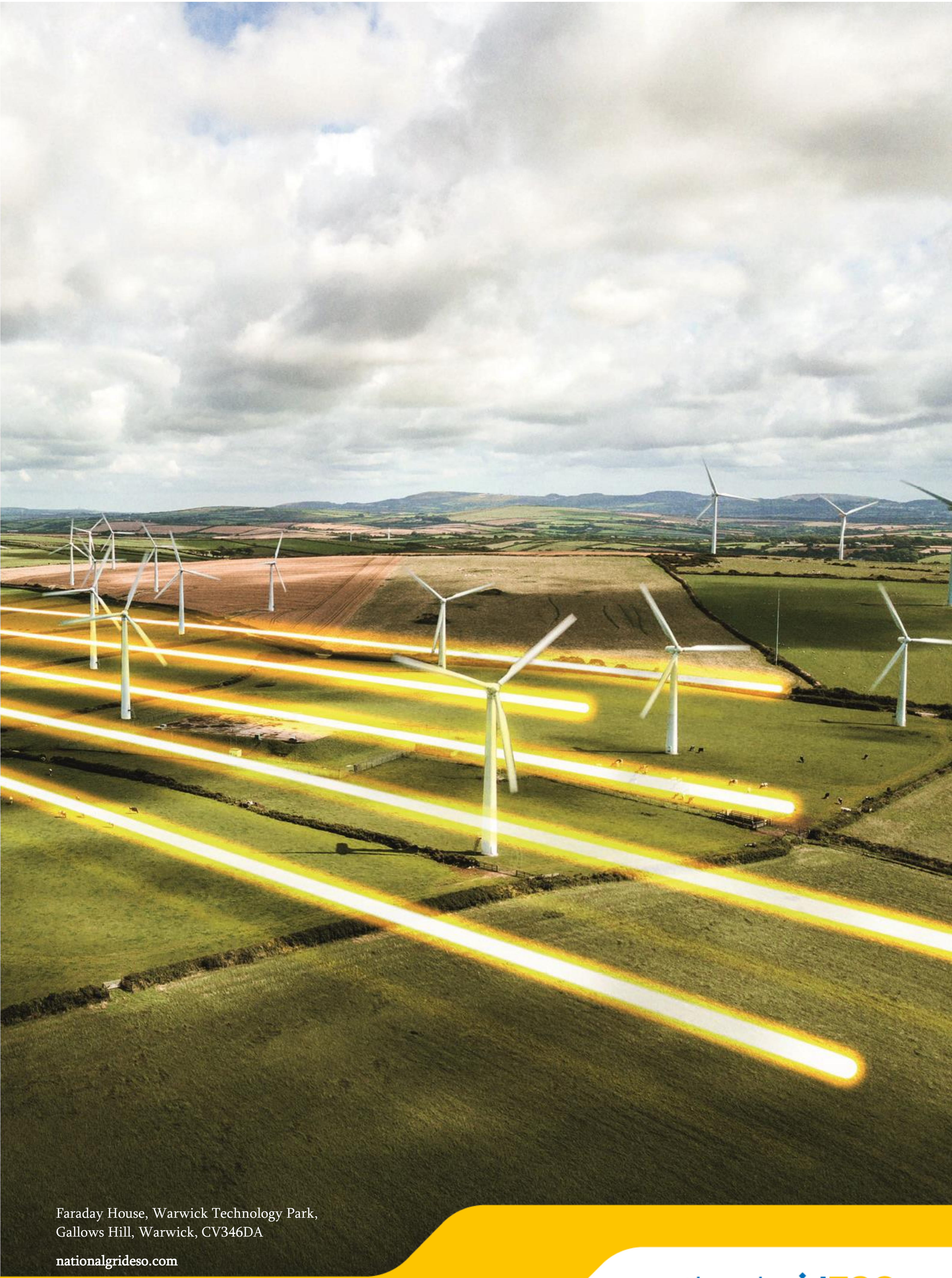
Storage & DSR	Storage	Srg_BB002	Domestic Batteries (G98)	MW	Installed capacity	< 1MW capacity	Reasonable	Includes all storage duration batteries with export capacity < 1 MW
	Storage	Srg_BB004	Other	MW	Installed capacity			CAES & LAES (Compressed Air Energy Storage & Liquid Air Energy Storage)
	V2G	Srg_BB005	V2G	MW	Installed capacity		Derived	Includes domestic and commercial vehicles
	I&C DSR	Srg_BB006	Load shifting (Increase / Decrease of load)	MW availability	Potential MW available to participate in DSR	Keep MW availability in the initial year and remove MW shifted from peak (revisit this in future years)	Derived	
	Domestic DSR	Srg_BB009	Electric Vehicle Smart Charging	MW availability	Potential MW available to participate in DSR	Keep MW availability in the initial year and remove MW shifted from peak (revisit this in future years)	Derived	Difference between constrained and unconstrained res EV peak

		Srg_BB010	Smart Appliances (TOUT)	MW availability	Potential MW available to participate in DSR	Keep MW availability in the initial year and remove MW shifted from peak (revisit this in future years)	Derived	Includes only white goods (cookers, washing machines, refrigerators). Excludes heating appliances

Building block generation data summary and methodology

Template	Technology	Building Block ID Number	Technology Detail	Units	Detail	Comments	Data Quality
Generation	Non-renewable CHP	Gen_BB001	>=1MW	MW	Installed capacity	Non-renewable	Reasonable
		Gen_BB002	<1MW	MW	Installed capacity	Non-renewable excluding domestic Micro CHP	Reasonable
	Micro CHP	Gen_BB003	Domestic (G98/G83)	MW	Installed capacity	Domestic Micro CHP only	Reasonable
	Renewable Engines (Landfill Gas, Sewage Gas, Biogas)	Gen_BB004		MW	Installed capacity	Reciprocating Engines, Gas Turbines & CHPs. Includes Anaerobic Digestion & Advanced Conversion Technologies	Reasonable
	Non-renewable Engines (Diesel) (non CHP)	Gen_BB005		MW	Installed capacity	Reciprocating engines	Reasonable
	Non-renewable Engines (Gas) (non CHP)	Gen_BB006		MW	Installed capacity	Reciprocating Engines, Gas Turbines	Reasonable
	Fuel Cells	Gen_BB007		MW	Installed capacity	Hydrogen or Gas as fuel input	Reasonable
	OCGTs (non CHP)	Gen_BB008		MW	Installed capacity	Open Cycle Gas Turbines	Reasonable
	CCGTs (non CHP)	Gen_BB009		MW	Installed capacity	Closed Cycle Gas Turbines	Reasonable
	Biomass & Energy Crops (including CHP)	Gen_BB010	Includes Biomass Conversions	MW	Installed capacity	Includes micro biomass CHPs	Reasonable
	Waste Incineration (including CHP)	Gen_BB011		MW	Installed capacity		Reasonable
	Solar Generation	Gen_BB012	Large (G99)	MW	Installed capacity	Solar >= 1MW	Reasonable
		Gen_BB013	Small (G98/G83)	MW	Installed capacity	Solar < 1MW	Reasonable

	Wind	Gen_BB014	Offshore Wind	MW	Installed capacity		Reasonable
		Gen_BB015	Onshore Wind >=1MW	MW	Installed capacity		Reasonable
		Gen_BB016	Onshore Wind <1MW	MW	Installed capacity		Reasonable
	Marine	Gen_BB017	Tidal Stream, Wave Power, Tidal Lagoon	MW	Installed capacity		Reasonable
	Hydro	Gen_BB018	Not pumped hydro	MW	Installed capacity		Reasonable
	Geothermal	Gen_BB019		MW	Installed capacity		Reasonable
	Nuclear	Gen_BB020		MW	Installed capacity		Reasonable



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