FES Modelling Methods 2021

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nationalgridESO

Contents

Introduction

Our **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. 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

Process chart keys

The keys to the process charts used in this document are summarised below:

Covid-19 impact

The impact of Covid-19 has been incorporated into our modelling in a number of ways.

Observations of actual energy usage form the starting point for much of our modelling. This year we have had to take account of what we believe to be short-term effects, for example from lockdowns, that are unlikely to feature in medium to longer term forecasting.

Covid-19 has affected overall energy usage and peak usage differently. We have observed reductions in overall energy usage but much less of an impact to peak usage, so we have also had to factor this into our modelling.

Nearly all aspects of the impacts of Covid-19 are expected not to feature in our scenarios for 2022/3 and beyond. Some longer-term impacts, such as the overall impact to the economy, have been included in our modelling through updated forecasts of GDP.

General Approach

The Future Energy Scenarios are not a single prediction of what the future of energy will be, put rather they are intended to form a credible range of possible outcomes based on a set of scenarios. These scenarios reflect the input from a range of stakeholders which informs the assumptions and levers with the various models we use in producing the outputs. More information on these can be found in our "Scenario Framework" document which is published alongside this one on the ESO website.

Figure 1: Overview of general approach to FES modelling

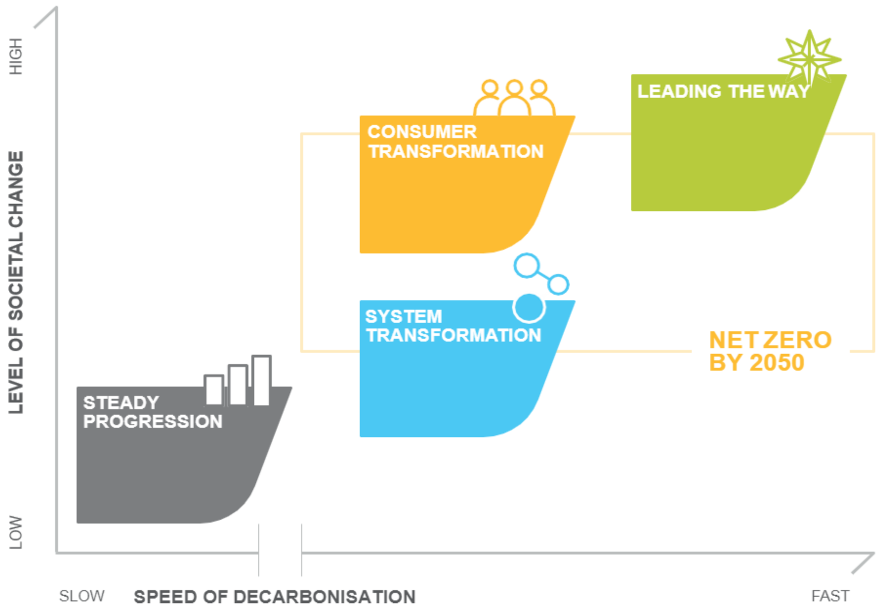

Figure 2: 2020/21 Scenarios

Once the scenarios to be investigated have been agreed, we determine the assumptions to use in our modelling and the "levers" within the models that can be adjusted to reflect those scenarios. As we carry out our modelling, we review the results to ensure that they are credible, updating the levers and assumptions if necessary, to arrive a range of results that fit within the scenario framework with clear differentiation between individual scenarios and the possible outcomes that could be experienced as we approach 2050.

More information on the scenarios and assumptions can be found in the "Scenarios Framework" document published on the Future Energy Scenarios website[1].

Five Year Forecast

We include a Five-year forecast within the FES document and Data Workbook. This is developed differently to the scenario based results. It represents the ESO's best view for demand and supply over the short-term. In most cases, key levers or assumptions are in the middle of the range used in our scenario modelling. The scenarios then reflect uncertainties around this view, projecting beyond the first five years all the way out to 2050.

[1] nationalgrideso.com/future-energy/future-energy-scenarios

End consumer demand

This section describes the methods used to model energy demand. Energy demand modelling is split into five components:

1. Electricity demand overview
2. Gas demand overview
3. Industrial and commercial demand
4. Residential demand
5. Road transport demand

Electricity demand overview

Our future projections for overall electricity demand are created using forecasts and assumptions from other FES models e.g.

- Industrial and commercial demands;
- Residential appliances, lighting, and air conditioning;
- Heat and district heat; and
- Road and rail transport.

As per Figure 3 below, the components are combined to provide a view of the underlying electricity demand on the system before further information is added in to calculate the demand met from the transmission system, or the whole system demand. These additional components include the losses from the transmission or distribution of electricity, exports via interconnectors to other countries and the amount of consumer demand that can be altered in response to price signals or is met through generation sources not connected to the transmission network. This area also includes the electricity needed to produce hydrogen or other non-consumer loads.

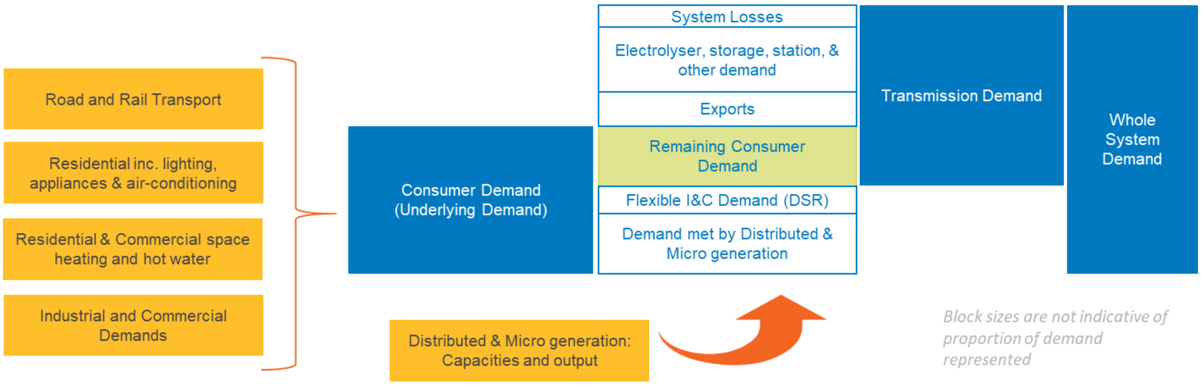

Figure 3: Overview of electricity demand components

These demands are further divided in the total electrical energy needed to meet all demand in a given year, which we refer to as “Annual demand”, and the demand at the maxima/minima points in the year known as the “Peak” or “Minimum” demand respectively.

Annual demand

In the FES document “Consumer View” chapter, we consider “end consumer demand,” regardless of where (transmission, distribution or on site) the electricity is generated. Demand is weather corrected to reflect a “normal” set of seasonal conditions, removing the impact of abnormal weather events. Moreover, it **does not**

include losses, exports, station demand, pumping station demand or other forms of storage demand. Annual losses data is in the FES data workbook.

When we illustrate residential, industrial and commercial, heat, and transport components we have not assigned the distribution or transmission losses. We estimate these losses at the system level to average around eight per cent. Where annual electricity demands are discussed, it is normally given in financial year.

We do not have direct information on the make-up of demand, so these components must be estimated as described in the following sections.

The Department for Business, Energy and Industrial Strategy (BEIS) publishes monthly sales data for residential, industrial and commercial demand and this forms the basis of our demand estimates. For each annual FES, the latest Energy Trends data[2] is used and this frequently brings small revisions to history.

- The Energy Trends residential annual data is annually weather corrected, using information from the Balancing and Settlement Code administrator, Elexon
- Industrial and commercial demand is assumed to make up the remaining underlying demand and is split using ratios from Energy Trends
- Estimated losses are calculated from internal data sources and may differ from other publications

Demand components - historic

We calculate underlying historic demand as follows:

- We start with National Grid transmission system data. We take GB historic, weather corrected, metered "National Demand". This is the total demand seen from the electricity transmission network, excluding interconnector exports, station demand and pumping demand;
- Weather corrected data is published in the Electricity Ten Year Statement (ETYS)[3] and the FES data tables.
- Out-turn "National Demand" data is published on our website.[4]
- We then add an estimate of the output from non-transmission generation, by taking our view of capacity of distribution connected generation, including an estimate for those that are individually <1MW in size.
- Output across the year and at the time of peak demand relative to the installed capacity (i.e. load factor) for these are derived from a number of sources.
  - Our own data (half hourly transmission generation, solar and wind data);
  - ElectraLink;
  - The Digest of UK Energy Statistics (DUKES)[5]; and
  - Datasets purchased from third parties.

[2] https://www.gov.uk/government/collections/energy-trends
[3] https://www.nationalgrideso.com/insights/electricity-ten-year-statement-etys
[4] https://www.nationalgrideso.com/balancing-data/data-finder-and-explorer
[5] https://www.gov.uk/government/collections/digest-of-uk-energy-statistics-dukes

To get historic peak demands for the components of demand:

- We take annual, weather corrected, Energy Trends[6] residential demand data;
- We create a peak using weather corrected residential demand data from Elexon;
- The remaining peak demand is assumed to be industrial and commercial; and
- Remaining peak demand is split using Energy Trends proportions.

Demand components – summer

Summer minimum demands (looking at minimum underlying demand on the system and the impact of solar) are created in a similar fashion to peak. The differences are:

- Summer demands take observed historic demand as a start point.
- Solar generation has a significant effect on demand as installed capacities increase.
- No demand side response is currently assumed due to little information on summer behaviour, particularly demand turn-up.
- Storage is modelled as demand, rather than generation, at times of system minimum demand.

Gas demand overview

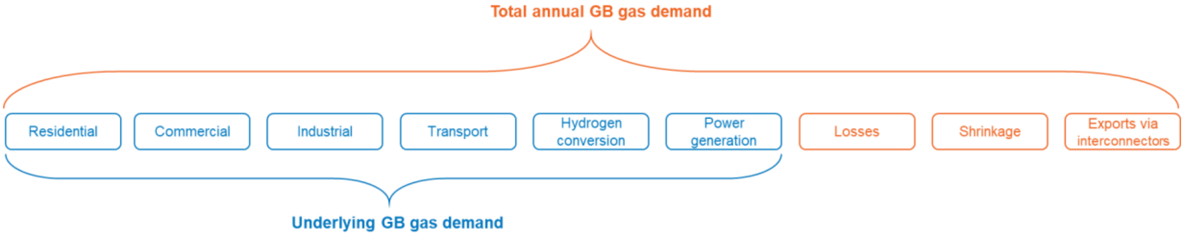

Figure 4: Total annual demand is underlying GB demand plus losses, shrinkage, and exports via interconnectors

The annual gas demand is defined as the total Local Distribution Zone (LDZ) consumption, plus the consumption at sites that are directly connected to the National Transmission System (NTS). Total GB annual gas demand includes gas exported to Ireland via the Moffat interconnector and exports to the continent via Interconnector UK. In the energy demand section of the FES document, demand only refers to underlying GB demand (excluding interconnector exports) whereas in the supply section gas supplies are matched to total. In view of experience from the 1st March 2018 “Beast from the East”, extreme cold weather events could still occur on a fairly regular basis even in a warming climate. It was therefore agreed that it is more appropriate to use the non-climate change adjusted weather data for modelling peak demand whilst we continue to use the adjusted data for modelling average demand.

Our hybrid heat pump modelling capability uses insight from the FREEDOM Project[7] to more accurately represent the upturn in gas demand by these appliances in the winter period and their impact on peak gas demand.

Total underlying GB gas demand is put together by modelling the following individual gas demand components: residential, commercial, industrial, transport and gas for power generation. These components are separated into demand which is connected at distribution and transmission level. We also model the gas demand required for the conversion to hydrogen where is this is appropriate to the scenario.

Exports to Ireland and continental Europe as well as NTS and LDZ shrinkage are added to underlying GB demand to gain total gas demand. The scenario forecasts for Irish exports are based on Gas Network

[6] https://www.gov.uk/government/collections/energy-trends
[7] https://www.westernpower.co.uk/projects/freedom

Ireland's Network Development Plan 2020[8] covering the next 10-year period. To cover the period from then until 2050, we use some regression analysis in the shorter term, and then combine assumptions on alignment with decarbonisation targets and development of Irish gas demand with indigenous supply forecast data.

Gas demand for power station generation is derived from the pan-European BID3 generation dispatch tool which produces an hourly dispatch for the GB electricity system. This is covered in more detail within the electricity supply section.

Losses, and gas used for operating the system, (commonly referred to as shrinkage) are included at the total system level. All values are weather-corrected where appropriate to ensure we don't allow more extreme weather to skew the results. Peak gas demand is calculated for a 1-in-20 day, as described in our Gas Demand Forecasting Methodology[9].

Gas for Hydrogen conversion

Natural gas use for hydrogen conversion is modelled from the total hydrogen demand values from across our heating, transport and generation demand models. The source of the hydrogen is based on framework assumptions for this year's FES and the hydrogen supply modelling described later in this document. These are in turn informed by the research and stakeholder engagement we conduct each year. Once we know how much hydrogen is needed, and how it is assumed to be produced, we can work out the natural gas required to produce the hydrogen. For hydrogen supplied through methane reformation processes, a projected conversion efficiency combining process efficiency and shrinkage from the plant's own use fuel determines the natural gas requirements within the hydrogen supply modelling.

Industrial and commercial demand

Our industrial and commercial (I&C) demand model, ARUP, forecasts gas and electricity demand for 24 sub-sectors of I&C activity including offices, hotels, retail, agriculture, manufacturing, construction and high intensity production processing. An overview of this model is shown in Figure 5, below.

The primary part of the model, Macroeconomic Module (MEM) uses regression analysis, where economic output and energy prices are the principal explanatory variables. Once these two variables are determined, they feed into the second module, Energy Demand Module (EDM). Two economic scenarios comprised of 24 individual sub-sector output forecasts, and one retail energy price from Oxford Economics were used to create energy demand for the industrial and commercial sectors.

[8] https://www.gasnetworks.ie/corporate/gas-regulation/regulatory-publications/GNI-2020-Network-Development-Plan.pdf
[9] https://www.nationalgrid.com/sites/default/files/documents/8589937808-Gas%20Demand%20Forecasting%20Methodology.pdf

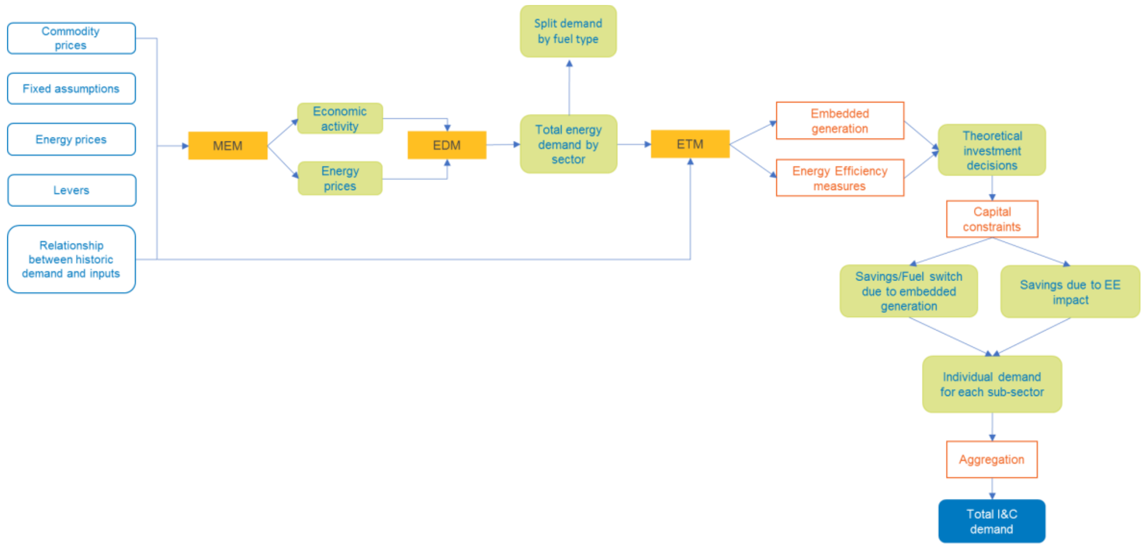

Figure 5: ARUP model for industrial and commercial demand.

The model examines these 24 sub-sectors and their individual energy demands, giving a detailed view of GB demand, and uses an error-correcting model to produce projections for each sub-sector individually. The model then has two further components in the Energy Technology Module (ETM), a bottom-up tool, that analyse how energy demand is affected by the increase in energy efficiency, and the deployment of onsite electricity generation and alternative lower carbon heating technologies.

These modules consider the economics of installing particular technologies from the capital costs, ongoing maintenance costs, fuel costs and incentives. These are used along with macro-financial indicators such as gearing ratios and Internal Rate of Return (IRR) for each sub-sector to consider if the investment is economically viable and incorporates the likely uptake rates of any particular technology or initiative. This allows us to adjust the relative costs and benefits to see what is required to encourage uptake of alternative heating solutions and understand the impact of prices on onsite generation, which give our scenarios a wider range.

We also incorporate energy efficiency improvements in certain end uses of gas and electricity for any energy efficiency improvements not covered in the main model.

The individual sub-sector forecasts are then aggregated and the trends in gas and electricity demand forecasts are applied to the latest year of actual gas and electricity demand.

Residential demand

Residential demand is the energy use in our homes and is affected by our activities and choices. Individually these choices can vary dramatically but tend to form relatively predicable patterns as a whole.

A key driver of residential demand is simply how many people and houses there are in the country. Our base housing and population assumptions, developed from analysis from Oxford Economics, are consistent across our modelling scenarios.

We create residential electricity demand from individual data sources which are then summated to a national level and use deterministic scenario modelling where we wish to illustrate policy outcomes, or current social trends, which may not be reflected in historic data.

The component parts we use to model residential energy demand in this way are:

- Appliances
- Lighting
- Heating technologies
- Insulation
- Air conditioning
- Home energy management systems

For each component part, we use historical data, where available, as our starting point. The main source is BEIS' Energy Consumption in the UK[10] data. We also gather information on mobile phones, tablets and wi-fi routers from Ofcom's Communications Market Reports.[11]

Appliances

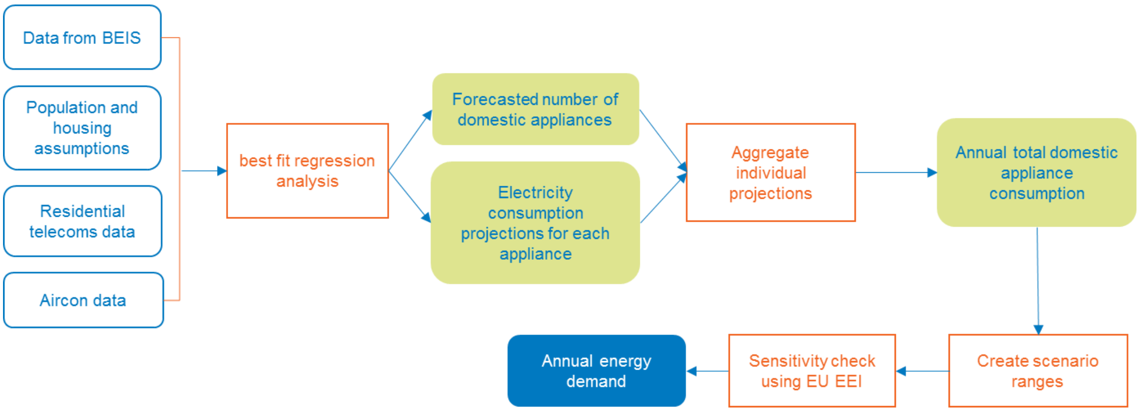

Figure 6: General appliances model

For demand from appliances, we create projections of annual energy demand using:

- A selection of historic assessments;
- Household projection data provided by external consultants;
- Outcomes from reported external projects.
- Regression analysis, based on 5 to 20 years history depending on the data quality
- Deterministic factors like social trends, government policy or global events
- Econometric methods to determine trends against social-economic factors such housing, population, GDP, productivity, household disposable income.

Source data used in these projections is cleansed to remove outliers. We benchmark these against stakeholder feedback and trial outcomes. We adjust each projection with our scenarios' assumptions to create the final results for each component.

[10] DECC, Energy Consumption in the UK, April 2016, https://www.gov.uk/government/collections/energy-consumption-in-the-uk
[11] https://www.ofcom.org.uk/research-and-data/multi-sector-research/cmr

Lighting

Residential light modelling uses Energy Consumption in the UK (ECUK) data[12] to model possible outcomes in demand from light. Historic trends in number of bulbs and demand per bulb are modified using the potential outcomes from social trends in lighting (so called mood lighting, multiple LEDs on decorative pieces) and light bulb policy (e.g. EU Halogen legislation).

Space Heating and Hot Water

Heat is a major component of end consumer demand and incorporates both heat to warm the home or workplace (space heating) and provide hot water plus heat for industrial or commercial processes (process heat).

Process heat demand is covered within our Industrial and Commercial model described earlier in this document. Space heating and heat to produce hot water are covered by the Spatial Heat model introduced from FES21.

This model was developed by Element Energy, National Grid & National Grid ESO through Network Innovation Allowance funding[13]. This new tool represents a major step change in the detail and approach to how we model this important element of the pathways to a net-zero future.

Simplistically, the spatial heat model carries out the steps in Figure 7, below.

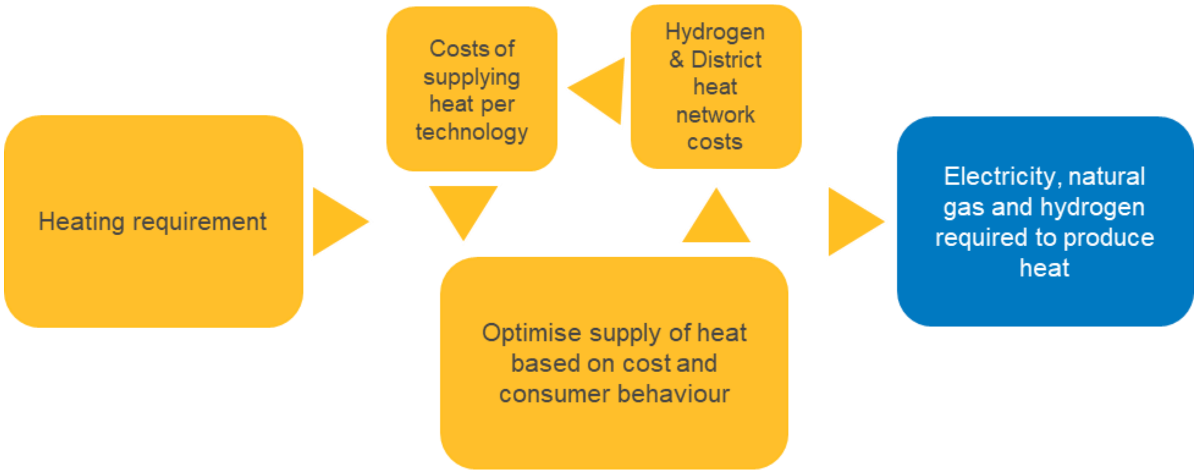

Figure 7: Overview of Spatial Heat model

Heating Requirement

Domestic and non-domestic heating requirements are calculated based on building types and associated efficiencies, when in the day heat is required, and climate data. These are performed at the level of “lower layer super output areas” (LSOA) in England and Wales and the equivalent “Data Zone” (DZ) in Scotland. These areas are defined by the Office of National Statistics (ONS).

New build and demolition of properties are represented through growth rates input to the model for each region. New properties receive the lowest cost heating technology for their region.

[12] https://www.gov.uk/government/collections/energy-consumption-in-the-uk
[13] https://smarter.energynetworks.org/projects/nia_nggt0154/

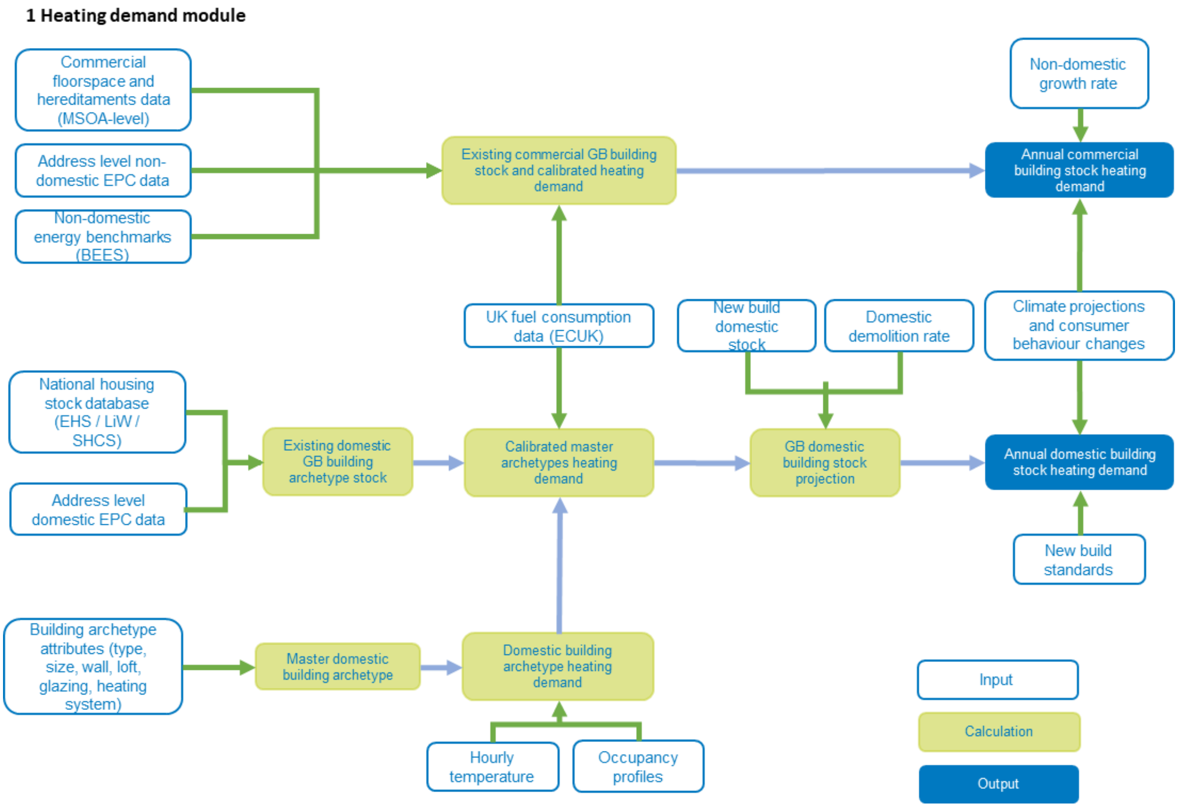

Figure 8: Spatial Heat model heating demand module. Diagram based on original supplied by Element Energy.

Costs to Supply Heat

The costs to produce heat from a variety of potential technologies are calculated. Included within these costs are those associated with building or developing hydrogen and/or district heat networks, along with the costs of producing hydrogen or district heat, as well as the directly input costs of natural gas and electricity. The cost calculations in this area also incorporate the use of storage for hydrogen. These are also calculated at LSOA/DZ level, incorporating the costs to supply that individual area.

For FES we assume an "unconstrained" electricity and natural gas network, that is effectively an infinite capacity to transport electricity or gas where it is needed. Network upgrade costs for electrification and natural gas networks are not included. Hydrogen and district heat networks are "grown" within the model from the relevant source location to meet demand as part of the optimisation stage.

Table 1: Sources of heat and hydrogen in use in the heat model

Item	Technologies
District Heat Sources	Air Source Heat Pump, biomass, biomethane, Ground Source Heat Pump, Gas CHP
Hydrogen Sources	Steam Methane Reformation, electrolysis, imports
Property Heat Sources	District Heat, air source heat pump, ground source heat pump, natural gas boiler, hydrogen boiler, biomass boiler, electric boiler, electric storage, electric resistive, hybrid heat pump with gas, bioliquid, electric resistive or hydrogen. Gas or biomass CHP. Solar thermal + other technology.

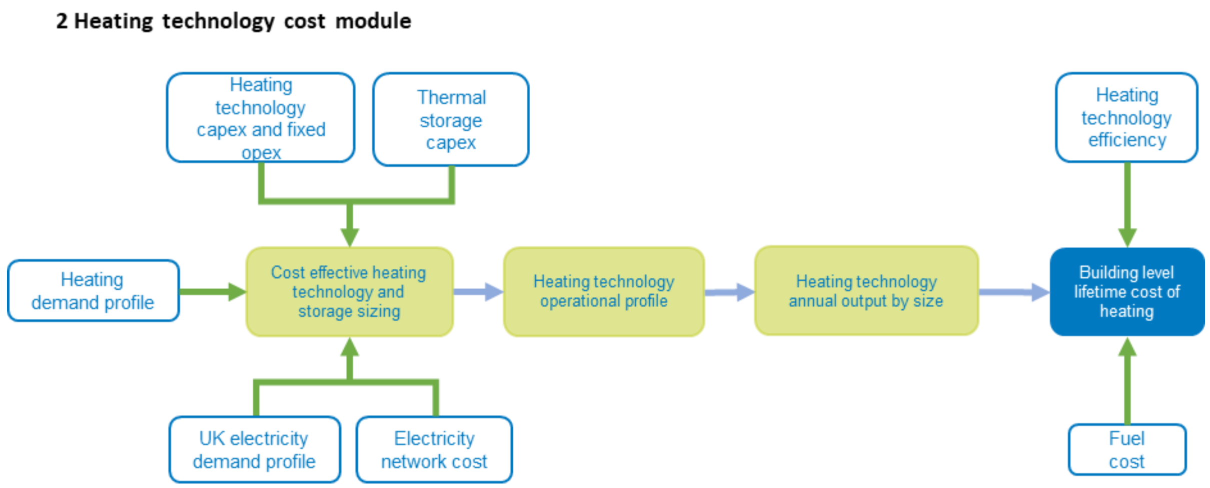

Figure 9:Building level heating costs. Original diagram supplied by Element Energy.

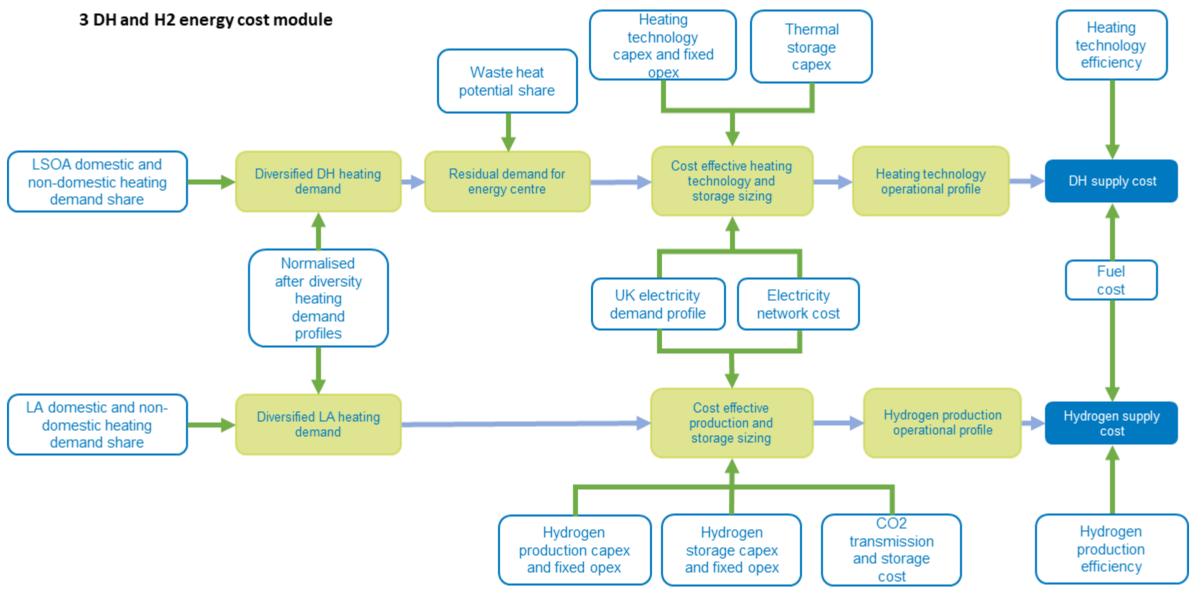

Figure 10: District Heat and Hydrogen energy costs. Original diagram supplied by Element Energy.

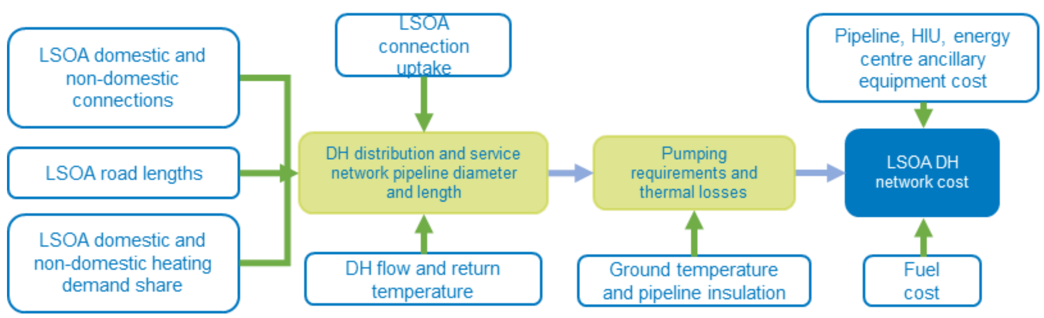

Figure 11: Network costs to supply district heating. Original diagram supplied by Element Energy

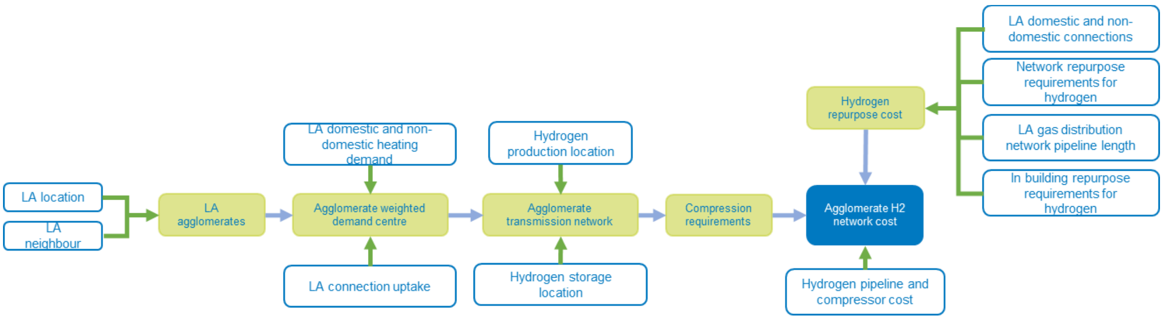

Figure 12: Network costs to supply hydrogen. Original diagram supplied by Element Energy

Optimise Pathways

Having calculated a set of heating requirements and costs to supply heat, the next stage is to optimise which technologies meet the heating requirements in each area. This is an iterative process aiming to supply heat at the lowest cost for each building type within the modelled area and also incorporates a view of consumer behaviour such as level of disposable income for that area and willingness to pay. This provides a view on the uptake of heating technologies, energy efficiency and thermal storage across GB. Policies, such as the date for no new natural gas boilers, are also applied as part of this optimisation, and can vary between scenarios.

A component of this iterative process is to grow the networks that supply either District Heat or Hydrogen. These would begin with the local area that contains a source of DH or hydrogen then test how the costs to supply heat to properties changes as adjoining areas are grouped together and the relevant network costs are recalculated. This will ultimately reach a balance between the network size and the cost effectiveness in supplying heat through the technology supported by that network.

District Heat sources and hydrogen supply sources are calculated within the model from the lowest cost production method per area within any constraints applied to the model. An example of these constraints is the availability of renewable energy sources to supply green electricity for hydrogen production. This also incorporates the optimisation and use of storage of hydrogen, or thermal storage in the case of district heat, such that production does not have to equal demand at time of use.

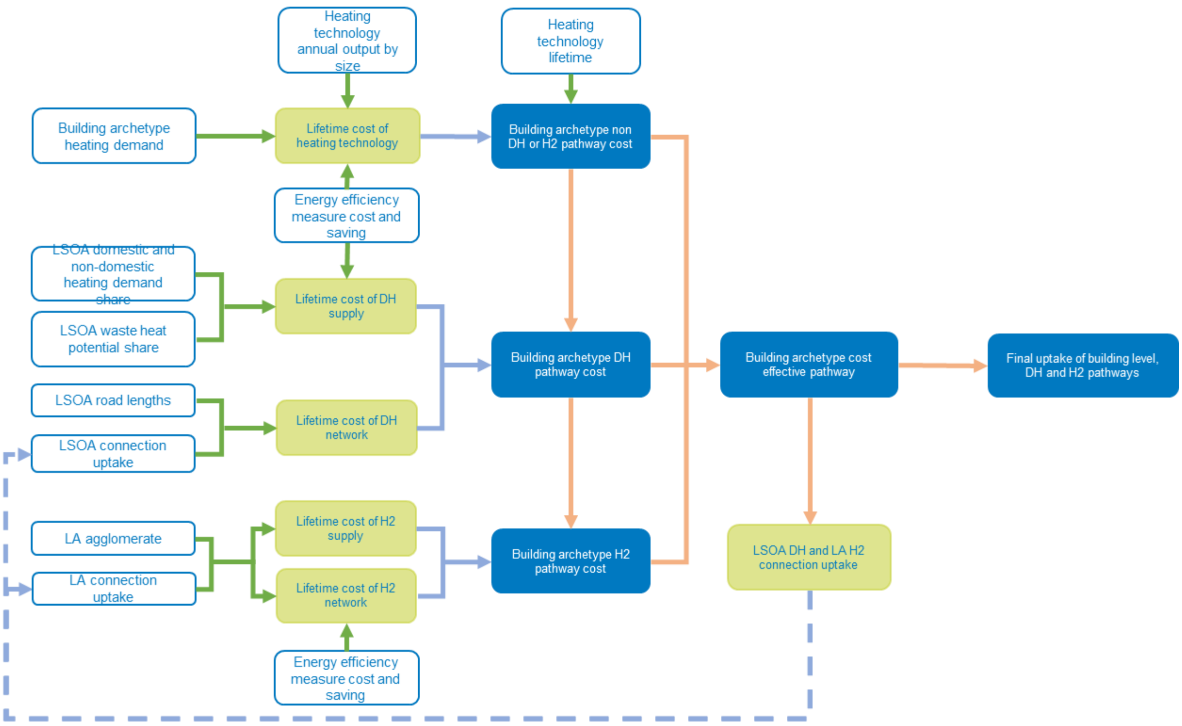

Figure 13: Pathway optimisation. Original diagram supplied by Element Energy

Time step

The modelling performs each of the above elements for each time step, currently set at 5 years. At each time step end-of-life heat sources are replaced at a property level and new properties added with the most cost-effective heating technology for their area at that time. These then retain that heat source until it again becomes end-of-life.

Outputs

From the above steps, the sources of heat and associated fuels are returned such that we have a view of the electricity, natural gas and hydrogen demand at each time step. Values between the time steps are derived from a straight line between the calculated data points.

Results for regional areas above LSOA/DZ are calculated by summing the LSOA/DZ areas that make up a local authority area, Grid Supply Point, or all of GB.

Road transport

The road transport model, including battery electric, plug-in hybrid electric, natural gas and hydrogen vehicles, utilises multiple strands to produce the annual demand for each fuel type. The model looks at passenger cars, light goods vehicles, heavy good vehicles, motorbikes and buses or coaches.

To model the uptake of various road transport types and fuels we use a total cost of ownership model. Assumptions on the increase and decrease of various factors include fuel costs and vehicle efficiency for different scenarios, and any changes to legislation such as the ban on sales of internal combustion engines. These uptake rates for the different scenarios, in relation to the expected sales projections for all vehicles, determined by the total cost of ownership gives the expected number of low carbon vehicles on the road.

The number of miles driven per year, determined from previous average mileage, along with the propulsion ratio (kWh/Mile), produces the kWh/year of the low emission vehicle fleet.

The influence of autonomous vehicles (level 4 automation[14] and above) is included within the scenarios; and where they are shared vehicles this influences the number of other cars they displace.

Transport demand at system peak and minimum

The peak and minimum demand calculation method changed from FES19 with the introduction of a full year's profile, developed under a National Innovation Allowance (NIA) project[15], covering both residential and non-residential charging. The study informed that at that time, 75% of charging events occurred at the home, with the remainder at workplace and public charge points. Assumptions on the split of annual charging amounts between different charging locations are included on a scenario basis; for example, more residential charging is included in decentralised scenarios; whilst more public charging is included in centralised scenarios.

Autonomous taxis are assumed to charge at depots, off peak time. Buses and HGV charging is assumed to equally split between work and public charging locations. At the evening winter peak on the transmission system (5pm-6pm), home charging is assumed to be influenced by time of use tariffs, whereas public and workplace charging is assumed to be non-smart as drivers prioritise their journey home.

Vehicle-to-Grid

During 2019 we consulted on our Vehicle-to-Grid (V2G) analysis and carried out a "Bridging the Gap"[16] information gathering exercise on future road transport. Following feedback received through these, we have built on our assumptions from the conservative approach taken in 2019 and have considered a wider range of outcomes from FES20 for V2G.

[14] https://www.smmt.co.uk/wp-content/uploads/sites/2/SMMT-CAV-position-paper-final.pdf
[15] https://www.smarternetworks.org/project/nia_ngso0021
[16] https://www.nationalgrideso.com/news/future-energy-scenarios-bridging-gap-net-zero

We assume that:

- Only a proportion of the most engaged consumer segments will participate in vehicle to grid services due to the additional cost of the charger and awareness or inclination to make use of V2G Technology.
- Private cars with 7kW smart bi-directional chargers are available – based on a typical mass market charger and cars on sale in 2020.
- On average, owners offer 50kWh in their battery for V2G use.
- There is a slight delay between adopting an electric vehicle and adopting a time of use tariff or Vehicle to Grid Tariff.
- V2G becomes a mass market option from the mid- 2020s (EU: CCS V2G standard planned for rollout).[17]

[17] https://theenergyst.com/evs-v2g-vehicle-to-grid-battery-storage-smartgrid/

Whole system view

Whole system demand

Whole system demand looks at the demand that must be met across end consumers plus the demands from power or hydrogen production, system losses, exports to other countries and filling energy storage systems.

Annual Electricity Demand Assessment

Our Annual Electricity Demand Assessment tool (AEDAS) has been created to collate all the demand components in one place to calculate annual electricity demand, peak and minimum electricity demand, and system losses.

The table below summarises inputs and their suppliers.

Table 2: Suppliers and inputs of AEDAS

Supplier	Inputs
Appliances Model	• Annual electrical demand from cold, computing, cooking, consumer entertainment, lighting, wet and air conditioning appliances
ARUP	• Raw electricity demand with industrial & commercial heat pumps included
BEIS - Energy Trends	• Annual residential, industrial and commercial demand
Spatial heat	• Annual, peak and minimum demands from space heat and hot water. Includes district heat and heat pumps.
Distributed generation	• Total capacity • Annual generation • Peak and minimum generation • Summer generation output under normal and average warm spell conditions
DSR Model	• Residential Demand Side Respond (DSR) • Industrial and commercial DSR • Triad split of generation and DSR
BEIS - ECUK	• Heat and rail demand
Electricity supply team	• Distribution wind double count correction
Elexon	• Outturn and weather corrected data • Annual demand • Half hourly residential profiles • Direct connects demand
ETYS	• Peak transmission losses
EV	• Annual demand, peak demand, summer min am/pm, V2G data

Hydrogen	• Annual SMR demand • CCS demand (non hydrogen) • Electrolysis demand • Hydrogen Storage Demand
Storage	• Capacity (storage) • Power (charge/discharge) • Annual demand • Peak and minimum demand and load factors
UKTM	• Soft guidance on demand levels for 2050 compliance
Week 24	• Distribution losses (~6%)
ESO short term demand forecast	• Historic demand • Transmission losses (~2%) • Station demand (600MW at peak, 400MW Summer, 5TWh/yr) • Pumping demand (5TWh/yr) • Annual/Minimum/Peak demand on the transmission system

In bringing the demand information together from these separate models, the overall level of demand is calibrated against historic data and other forecasts made by the National Grid ESO short term demand forecasting team. This ensures alignment of FES with the best data available to National Grid ESO.

Demand scenarios are compared against historic out-turn data and scenarios, and projections made by Committee on Climate Change, UKTimes and BID3 to ensure that demands within the FES are credible and consistent with other views.

Model of Annual Gas Demand

Similarly to AEDAS, our Model of Annual Gas Demand (MAGDEM) system aggregates total gas demand from individual components, and then splits it by LDZs. Each model from the table below feeds into MAGDEM.

Table 3: Suppliers and models that feed gas demand data into MAGDEM

Model components	
• LDZ monitor	• BID3
• Large loads	• Gas supply match
• NTS shrinkage	• ARUP
• Gas distribution networks	• Spatial heat
• Moffat interconnector	
• BEIS – planning	

Electricity supply

Electricity supply components include electricity generation installed capacity, electricity generation output, interconnectors and storage. Our scenarios consider all sources and sizes of generation, irrespective of where and how they are connected; from large generators connected to the National Electricity Transmission System (NETS), medium-size industrial and commercial generation connected at the distribution level, through to small-scale, sub-1 MW generation connected directly to commercial premises or domestic residences throughout GB.

In addition, in all scenarios there is enough supply to meet demand. This means all scenarios meet the reliability standard as prescribed by the Secretary of State for Business, Energy and Industrial Strategy – currently three hours per year loss of load expectation (LOLE). Details on how LOLE is calculated are given in the annex to this document.

The electricity supply analysis covers all years between now and 2050. In the first few years of the time horizon, our analysis is largely driven by market intelligence, including the Transmission Entry Capacity (TEC) Register[18], Embedded Register[19], Interconnector Register[20] and data procured from third parties. From FES 2021 we are also making use of the Embedded Capacity Registers (ECR) published by Distribution Network Operators (DNOs) to extract current and planned storage capacities. Links to each DNOs ECR can be found on the Energy Networks Associate "Databases" page[21] or directly from each DNO. These registers represent DNOs current best view of connected generation within their licence area and we intend to use these for other generation types in future FES analysis as this becomes more reliable. If you have information that may assist in developing the view of generation, please contact the relevant DNO.

In addition, we consider commercial contracts such as Capacity Market (CM) Contracts and Contracts for Difference. Between 2020 and 2030, there is a mixture of market intelligence and assumptions, with assumptions playing an increasing part towards the end of the decade. Examples of these assumptions are that there is no coal fired generation after 2025 and that the 30GW of offshore wind targeted by 2030 will be met in all the net-zero compliant scenarios. Beyond 2030, less market intelligence is available so we rely more on our framework assumptions that are used to reflect uncertainty across the scenarios. These can be accessed in the **Scenario Framework** document.

The electricity supply analysis in FES does not include network or operability constraints on the transmission or lower voltage networks. As an example, to illustrate what this means, we assume there are no internal network constraints on the GB network. In terms of operability, this approach means we don't constrain our scenarios to include plant that may be required to provide system services such as inertia, frequency response or voltage support. These challenges are assessed as part of our other National Grid Electricity System Operator publications, which use the FES assumptions. Network capability is assessed as part of the ETYS[22] and Network Options Assessment (NOA)[23]. Future operability challenges are analysed in the System Operability Framework (SOF)[24].

Transmission installed capacities

The electricity supply transmission installed capacities uses a rule based deterministic approach. This consists of an individual assessment of each power station (at a unit level where appropriate) is completed, considering a wide spectrum of information, analysis and intelligence from various sources, such as those mentioned above.

The scenario narratives provide the uncertainty envelope that determines the emphasis placed on the different types of generation technology within each scenario. Each power station is placed accordingly within their technology group in order of likelihood of that station being available in each year.

The placement of a power station within this likelihood is determined by several factors, such as market intelligence, energy policy and legislation. Project status and economics, which are applicable to that power station, are also considered. The contracted capacity or TEC Register provides the starting point for the analysis of power stations which require access to the NETS. It provides a list of power stations which are using, or planning to make use of, the NETS. Although the contracted capacity provides the basis for most of the entries into the total generation capacity, the analysis is not limited to generators with a signed connection

[18] https://data.nationalgrideso.com/data-groups/connection-registers
[19] https://data.nationalgrideso.com/data-groups/connection-registers
[20] https://data.nationalgrideso.com/data-groups/connection-registers
[21] https://www.energynetworks.org/industry-hub/databases
[22] https://www.nationalgrideso.com/insights/electricity-ten-year-statement-etys
[23] https://www.nationalgrideso.com/insights/network-options-assessment-noa
[24] https://www.nationalgrideso.com/insights/system-operability-framework-sof

agreement. Other projects where information has been received in the very early phases of scoping (i.e. pre-connection agreement) are also considered.

Distribution installed capacities

Our distributed generation installed capacities include those non-transmission sites that are greater than 1MW and are typically connected to one of the 14 distribution networks. We also include sites that are less than 1MW ("micro generation") and the smallest of these sites may be connected directly to properties behind the meter (e.g. rooftop solar).

For sites greater than 1MW we consider 30 technologies covering both renewable and thermal generation:

Table 4: Technologies considered in the Distributed generation model, 1MW or above

Technologies for renewable and thermal generation		
• Gas CHP • Advanced Conversion Technology (ACT) CHP • Anaerobic Digestion CHP • Biomass CHP • Geothermal CHP • Sewage CHP • Waste CHP • Onsite Generation • CCGT • OCGT	• Diesel reciprocating Engines • Gas Reciprocating Engines • Fuel Oil • Advanced Conversion Technology (ACT) • Anaerobic Digestion • Coal CHP • Biomass Dedicated • Hydro • Landfill Gas • Sewage	• Tidal • Waste • Wave • Solar • Wind Onshore • Wind Offshore • Battery • Compressed Air • Liquid Air • Pumped Hydro

To determine the current volumes of renewable generation we obtain data from various sources including the Ofgem Feed in Tariffs (FiT) register[25] and the Renewable Energy Planning Database[26,27] and the CM register. The projections per technology capacity are based on growth rates that reflect historical trends and any changes in the market conditions. Where available, growth of known future projects is used.

[25] https://www.ofgem.gov.uk/environmental-programmes/fit/electricity-suppliers/fit-licensees
[26] https://www.gov.uk/government/collections/renewable-energy-planning-data
[27] https://www.gov.uk/guidance/combined-heat-power-quality-assurance-programme

For those sites less than 1MW, including generation or storage at residential levels, we consider 11 technologies:

Table 5: Technologies included in sub 1MW generation

Technologies for renewable and thermal generation, sub 1MW capacity	
• Biogas CHP	• Battery
• Biomass CHP	• Hydro
• V2G	• Fuel Cell
• mCHP	• Solar
• Anaerobic Digestion	• Wind
• Gas CHP	

Baseline data, from Renewable Obligation Certification Scheme and FiT data, at GB level per technology has been used to determine the starting point and historical trends have been used to project the deployment of sub 1MW generation in the future.

Electricity generation output

BID3

Since the FES published in 2017, we have calculated power generation output using a model created by AFRY[28] called BID3. This is a pan-European electricity dispatch model capable of simulating the electricity market in GB and other countries.

The model uses the supply and demand assumptions as inputs. This includes all of our capacity assumptions, annual demands and fuel prices. The full list of inputs and outputs is summarised in Table 6 below. The simulations are based on end-user consumption meaning that generation connected to both transmission and distribution networks are considered as supply.

[28] Formally known as Pöyry. https://afry.com/en/service/bid3-afrys-power-market-modelling-suite

Table 6: Inputs and outputs of BID3 model

Inputs	Sources
• Installed and projected generation capacity data • Interconnector capacity data and projections • Forecast annual demand data • Demand Side Response volume & prices	**Capacity Market Registers** • Generation data • Interconnector data **Internal FES modelling** • Annual demand data • Demand Side Response **AFRY** • Plant information • Historic weather profiles **ENTSO** • European scenario data **ENTSO, AURORA, Oxford Economics, BEIS, Wood Mackenzie, Ofgem** • Fuel and carbon prices
Outputs	
• Power station generation • Interconnector flows • Emissions	

BID3 works by seeking to find the optimised way to meet demand using available generation, based on minimising total cost. It can analyse the impact of different weather conditions using profiles based on historic actual demand. The electricity generation output modelling for FES20 is based on the historic year of 2012 as this is deemed to be a fairly average year with colder and milder spells. BID3 creates an hourly time series of demand using the annual value from FES and the relevant historic hourly profile according to:

BID3 hourly demand = FES annual demand / (24 * 365 * hourly profile value)

The total generation output from BID3 may be slightly different from the annual demand numbers published in FES. There are several contributing factors, which include that the BID3 output is used to meet demand from interconnector exports and storage and the fact we use actual weather from a particular year.

All electricity generation is modelled with an average availability to allow for maintenance and to simulate forced outages. This varies on a monthly or quarterly basis to allow for seasonal variations and is based on observed patterns from history. The electricity generation output is calculated by modelling GB and Europe. The outputs from the dispatch model are used to produce the FES annual power generation outputs for different generation technologies including interconnector annual flows. In addition, the outputs from Combined Cycle Gas Turbines (CCGTs) are used as an input for the gas demand modelling.

Electricity power generation carbon intensity

The electricity generation output modelling done within BID3 also calculates the amount of carbon emitted for each plant in tonnes. The model calculates CO_2 emissions for boiler use, no-load, start up and generation as part of the calculation for meeting hourly demand. Utilising the same dispatch data from the BID3 model as for electricity generation output, the CO_2 intensity is calculated according to:

$$\text{CO2 intensity (g/kWh)} = \frac{\text{CO2 emissions from generation (g)}}{\text{Electricity generation output (kWh)}}$$

Electricity generation output refers to GB generation only. Please see more information in the FES Data Workbook.

This carbon will include all generation within the supply assumptions that are dispatched to run by the BID3 model. The current carbon intensity forecast by National Grid Electricity System Operator[29] will only include those sites that the ESO has visibility of[30]; therefore, there will be differences between the two values as the methods and data are different.

[29] http://electricityinfo.org/forecast-carbon-intensity/
[30] http://electricityinfo.org/real-time-fuel-mix-and-carbon-intensity-methodology/

Natural gas supply

In the FES, we model natural gas that enters the National Transmission System (NTS) and natural gas that is injected directly into the Distribution Networks (DN). We do not include gas that does not enter either the transmission or distribution networks. This could include, for example, gas used offshore in oil or gas production, or small amounts of biogas generated and used on the same site. Both these categories appear in BEIS's Digest of UK Energy Statistics, but we do not include them in either demand or supply.

The gas supply pattern for each scenario is created from the different gas supply components, described in more detail below. The models we use are supported by market intelligence, historical data and assumptions developed from knowledge gathered from stakeholders.

Potential supply ranges are derived for each supply component from bottom up analysis of the maximum and minimum supplies into the GB market across the all FES modelled years. These ranges take account of the physical infrastructure and the possible gas volumes arriving at each supply point. Once the gas demand is determined for each scenario the supply components can be matched. The **Scenario Framework** drives the level of each supply type based on political, economic, social and technological factors. In the rest of this section we describe each supply component in more detail.

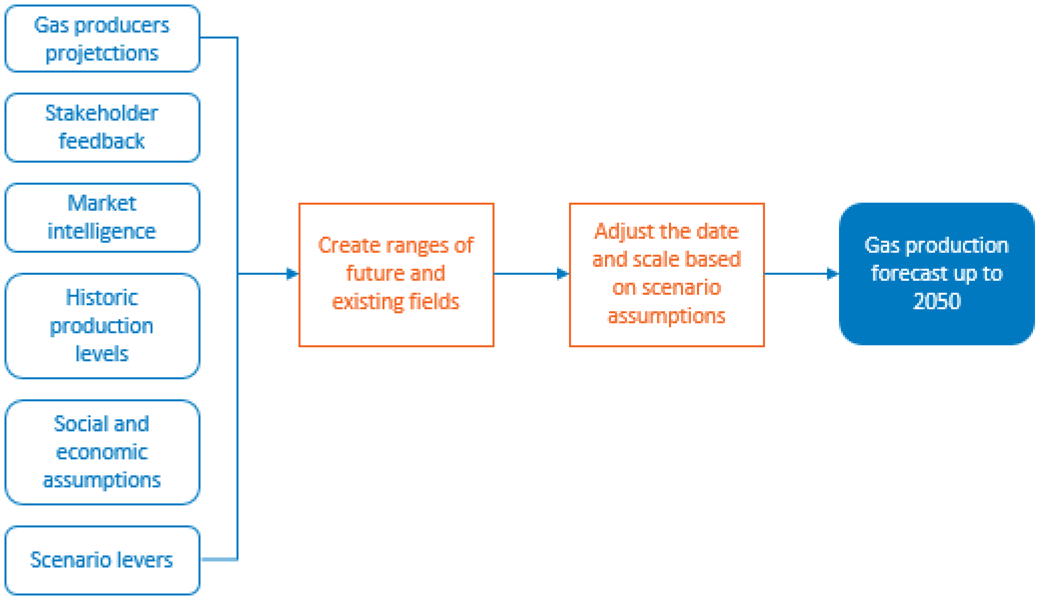

Figure 14: General gas supply process chart. Note, for continental interconnectors add European gas demand and supply data as input.

UK continental shelf (UKCS)

The UKCS is the seabed surrounding the United Kingdom. From this region gas producers extract natural gas which is mostly sent to the UK. A small amount of gas from the UK sector of the North Sea flows to the Netherlands rather than to GB, but we do not consider that in FES. Our projections for UKCS production are derived using a mixture of gas producers' future projections, stakeholder feedback gathered during our stakeholder consultation period, and commercial market intelligence. We create ranges by making adjustments to the date and scale of future field developments based on historic production and the economic and political conditions as laid out in the **Scenario Framework**. For example, in the high case we might assume that all projected field developments happen on schedule. In the low case, we assume that some new developments will be delayed or not go ahead at all.

Norwegian supplies

Our analysis of Norwegian gas is usually divided into the North Sea, the Norwegian Sea and the Barents Sea. Gas is exported by pipeline to several countries in NW Europe, including the UK, and also as LNG.

Norwegian LNG is included in our LNG analysis. First, we create a total production range for existing and future Norwegian fields. Our primary data source is the Norwegian Petroleum Directorate[31]. The range is derived by making separate assumptions for future field development based on historic production and the future economics. For example, in the high range we assume a high level of production in the Barents Sea, whereas in the low range we have no production from this area. Once we have created a production range, we then calculate how much will come to the UK, using a mixture of historic flows and existing contracts as a guide. Finally, we test our projections with industry experts to ensure our projections are credible.

Shale gas

Shale gas is still at a very early stage of development, and there are no wells in commercial production. For several years we have based our projections on analysis by the Institute of Directors. For FES2021, the analysis is based on a report[32] by UK Onshore Oil and Gas (UKOOG), the trade body for onshore developers. This makes use of data published by Cuadrilla following the fracking of the Preston New Road site. We use flow rates based on this report and create our high and low cases by using different assumptions on the number of wells that will be drilled.

Liquefied natural gas (LNG)

LNG is traded in a global market connecting LNG producers to natural gas users. As such, the deliveries of LNG are subject to market forces such as the arbitrage between global market prices and particular weather spikes driving a change in gas demand. We assume that a minimum level of LNG will always be delivered to the GB market, and our assessment of this is based on historic levels. These levels are flexed based on the volume of GB gas demand and indigenous supply.

Continental interconnector imports

The GB market is connected through the IUK interconnector to Belgium and the BBL interconnector to the Netherlands. For future continental interconnector imports we look at gas supply and demand across north west Europe and estimate the potential gas available for export to GB. Projected flows through the interconnectors are compared to the historic interconnector imports observed over the last 3-4 years. We recognise that gas can be both imported to GB and exported through IUK, and from 2019 also through BBL.

Generic imports

The balance between LNG and continental gas is very hard to predict for the reasons described in the sections above. For example, in mid-2018 we were expecting low deliveries of LNG to GB for the coming winter. In fact, conditions in the world market were such that deliveries to GB reached near record levels, catching nearly all industry commentators and players by surprise. By mid-2019 deliveries had fallen again, but then picked back up again later in the year and in to 2020. As projections for future years carry even more uncertainty than for the season ahead, we project only a maximum and minimum range for both LNG and continental gas, and leave the balance to be made up by generic imports. This is gas that can be any mixture of LNG and continental gas. The calculation ensures that if all the generic import were to be LNG then the generic plus the minimum LNG already assigned must not be greater than the capacity of the LNG terminals. A similar calculation ensures that the interconnector capacities will not be breached.

[31] http://www.npd.no/en/
[32] http://www.ukoog.org.uk/images/ukoog/pdfs/Updated%20shale%20gas%20scenarios%20March%202019%20website.pdf

Annual supply match

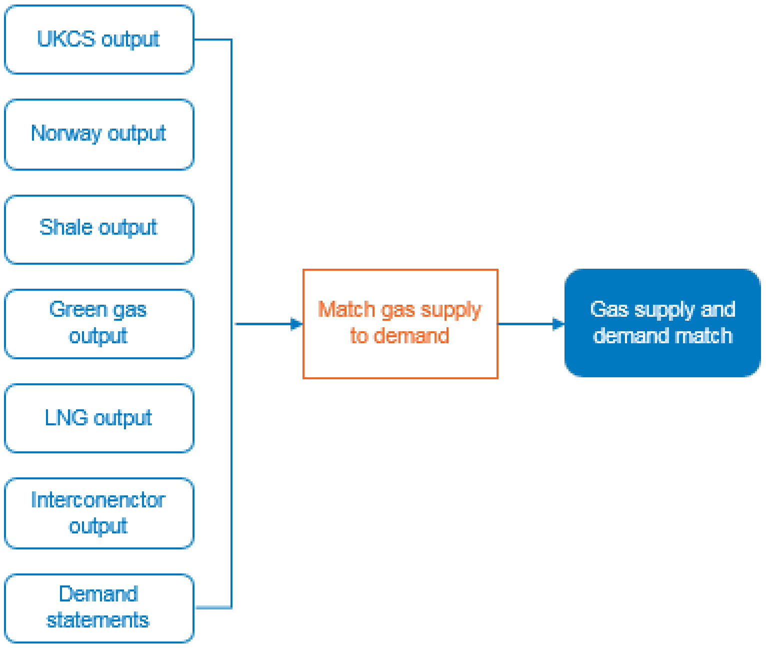

Figure 15: Annual match process chart

The annual supply match allocates gas supplies to meet demand using a ranking order. We allocate indigenous gas production — UKCS, shale and green gas — to our supply match first, because it is all UK based and will have large domestic supply chain investments in place. There is also less opportunity for these supplies to reach other markets, unlike LNG for example. Following this we allocate the Norwegian imports, the levels of which are driven by the **Scenario Framework**. Then minimum levels of LNG and continental gas imports are added. Finally, a supply/demand match is achieved by allocating generic import, which as mentioned above can be made up of either LNG or continental pipeline gas or both.

Peak gas supply

We carry out the peak supply match to ensure current domestic production and import infrastructure can meet a peak demand day. For indigenous gas production — UKCS shale and green gas — there is a 20% difference between maximum and minimum production levels across the seasons. This is based on observed values from offshore UKCS production. For onshore shale gas there is currently no data to derive a likely difference between maximum and minimum. As these sources are likely to be base load, but with outages for maintenance, we have used the same maximum to minimum swing as for the UKCS.

For imported gas and storage, the design capability of the import facility is used to determine the capacity. This may differ from the approach in shorter-term documents, such as the Winter Outlook, which are based on near-term operational expectations.

The total of these supplies is then matched to the peak demands to calculate the margin of supply over demand. We also carry out security of supply analysis where we remove the largest piece of infrastructure from the supply mix and again calculate the margin of supply over demand; this is referred to as an N-1 assessment[33].

[33] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/753170/BEIS_Ofgem_Statutory_Security_of_Supply_Report_2018.pdf

Bioenergy supply

Biomethane

Biomethane is a naturally occurring gas that is generated from anaerobic digestion (AD). AD is a biological process where microorganisms break down organic matter such as sewage, plant material and food waste in the absence of oxygen to produce biomethane. The unrefined product is usually referred to as biogas. It is not suitable for injection into gas networks but can be used for on-site electricity generation and heating. When biogas is refined to make it suitable for network injection we refer to it as biomethane. The biomethane range is derived using the latest information available from biomethane sites currently connected to a gas network, and the distribution network owners' latest information on possible future connections. To derive the high and low case we apply different growth rates and assumptions to new connections due to the differing economic and political conditions within each scenario. To support our projections we use market intelligence and test our results with relevant industry experts.

Bio substitute natural gas (BioSNG)

Bio substitute natural gas (BioSNG) is a gas that is derived from household waste. The process uses high temperatures to produce a synthetic natural gas which, after cleaning and refining, can be injected into a gas network. BioSNG is in the early stages of development. A commercial demonstration plant has been under development with funding from Ofgem's Network Innovation Competition (NIC). The supply range is based upon the flow information published in the NIC[34] documentation plus assumptions on the number of facilities, based upon the economic and political conditions for each scenario.

Hydrogen supply

**** New for FES21 ****

The new Hydrogen Supply model builds upon the that embedded within the Spatial Heat model described in the Space Heating and Hot Water section of this document. This has been further developed to include a wider range of hydrogen production technologies and to set limits on the capacity of certain types so as to permit a range of scenarios to be explored.

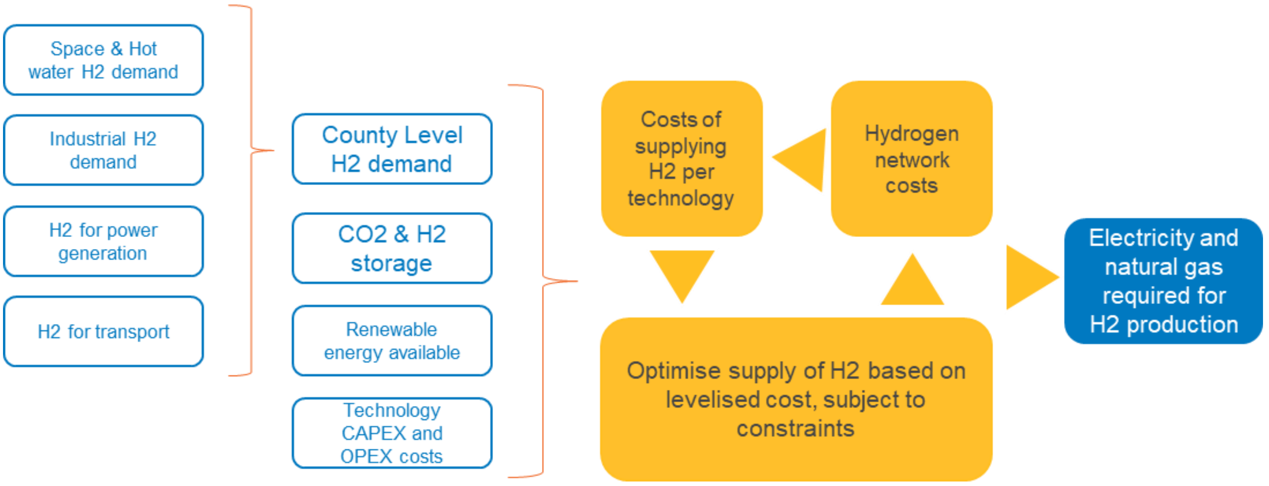

Figure 16: Hydrogen Supply model overview

As when modelling hydrogen sources for space heat and hot water, the hydrogen supply model attempts to build a network to connect demand with sources of hydrogen and optimise storage. This aims to balance the costs of additional network components against the demand for hydrogen.

In doing this, the model calculates a number of locations for hydrogen production which are termed "Production Local Authorities" (LAs) and connects these to demand areas. This aims to achieve the lowest

[34] https://www.ofgem.gov.uk/publications-and-updates/network-innovation-competition-project-direction-biosng

cost hydrogen and production system given the parameters that it has been given to work within. The number of groups, or “agglomerates”, is defined within the model and we use the same number of agglomerates for heat and separate hydrogen supply modelling.

The mix of hydrogen production technologies within an agglomerate is derived within the model based on the cost of those technologies, any limits placed on capacity of a particular technology, and the availability of storage and/or “fuel” such as renewable electricity or nuclear power.

Various approximations and assumptions are made. As a first step in the optimisation process, areas are clustered into 16 representative groupings. For each of these grouping, typical hydrogen demand profiles are identified, based on the peak-to-average ratio of the heating demands. These profiles are then used to cost and select generation technologies. Another assumption is that of straight-line pipelines, with Euclidean distances between the production areas, demand areas, salt caverns, CCS terminals and hydrogen import terminals used to calculate the costs of the transmission network. Agglomerates are defined in the first year, currently 2020, and are assumed not to change in future years.

As with the heat model, calculations are made for each 5 year time step with intermediary values calculated as a straight line between the calculated points. Small external adjustment of output is also carried out between these timesteps such that differences between supply and demand can be accounted for in the non-modelled years.

Modelling is carried out at the agglomerate level, with GB level outputs being the sum of these smaller areas. The GB level outputs include the electricity and natural gas demand needed for production of hydrogen which is then incorporated into the demand values being met in the power generation or gas supply modelling.

The hydrogen supply modelling includes the production technologies in Table 7 below.

Table 7: Hydrogen production technologies considered within the FES modelling

Methane to Hydrogen conversion	Electrolysis
• Steam Methane Reforming (SMR) • Autothermal Reforming (ATR) • Biomass gasification All with Carbon Capture and Storage (CCS)	• Grid-connected Proton Exchange Membrane (PEM) • Directly connected wind/solar PV PEM • Directly connected nuclear PEM

+ Imports of hydrogen from outside of GB

Variability in Production

Hydrogen production technologies have different levels of flexibility in when they produce hydrogen which is largely technology specific.

For SMR, it is assumed that production can be varied at most on monthly timescales. This is connected to constraints relating to CCS. Within the model five different dispatch profiles are created. This ranges from the flattest profile which uses a constant dispatch over the entire year (average yearly dispatch) to one that changes every month (using the average monthly dispatch). The corresponding storage requirements and use are calculated for each dispatch profile to allow the flexibility to meet demand changes.

The dispatch for electrolysers, however, can vary on hourly timescale. Four electrolyser sizes are considered, ranging from the maximum hourly demand to the maximum average monthly demand. There are thus four dispatch profiles, ranging from hourly load without any storage, through daily fuel-cost optimised profiles. Profiles with seasonal storage and yearly fuel-cost optimisation are also considered. As with SMR, the corresponding storage profiles are calculated.

For electrolysers that are not connected to the electricity network but powered directly by renewable (solar or wind) or nuclear generation, the model considers a range of different capacities for the electrolysers meaning the optimal balance between available hydrogen production, curtailment of renewable sources, and capital costs can be determined. Differences in wind/solar generation profiles across the country are represented in the model.

After determining all sizes, dispatch profiles and storage requirements, all different combinations are costed to give levelised costs of H_2 generation. This is followed by the optimisation of the agglomerates and distribution networks.

Whole system modelling (UKTM)

For our net zero scenarios, we use a cost-optimisation model, the UK Times Model[35] (UKTM), to guide them towards the target. UKTimes was developed at UCL with support from WholeSEM, the UKERC, and UK Government, to provide analysis of future energy systems. In meeting the carbon reduction target, UKTM selects the least-cost solution among all the possible sector and technology developments, through calculating all cost components including capital cost, fixed and variable operational cost etc., transferring future costs into present value using a discount factor.

UKTM simulates the whole energy system, considering energy demand, supply, electricity and gas networks and interconnectors. On the demand side, it uses the specific demand profiles for different products in residential, commercial and industrial sectors, as well as various vehicle types in transport sector. Efficiency factors for different products in all future years are included. The model also contains seasonal demand profiles. This combines to give an annual view of demand and supply. These inputs from the standard UKTM database are augmented with key inputs from the data gathered during the FES process and outputs of the models. These inputs override values in the “standard” UKTM database where they exist.

Table 8: Key inputs and outputs of the UKTM model based on FES modelling

Input	Output
Transport • Distance per vehicle • Total number of vehicles • Fuel demand limit	**Transport** • Electricity and hydrogen fuel demand for road and rail transport
Domestic Heat • Total number of dwellings • Average thermal demand • Energy efficiency of heat pumps and non-heat appliances	**Domestic Heat** • Thermal demand • Electricity, natural gas, hydrogen fuel demand
I&C Heat • Total demand index • Fuel demand limit	**I&C Heat** • Electricity, natural gas, hydrogen fuel demand
Hydrogen Production • Electrolysis limit • SMR+CCUS limit	**Hydrogen** • Hydrogen volume produced • Electricity, natural gas demand
Power Generation • Capacity limit • Generation volume limit	**Power Generation** • Capacity and generation volume for main generation type
Emissions • Limit in each sector	**Total Bio and natural gas**

On the supply side, it considers gas supply and electricity generation from different sources and different technologies. Existing capacities and load factors are available for each technology, and operational cost

35 https://www.ucl.ac.uk/energy-models/models/uk-times

information is also included, for future development, minimum and maximum capacity constraints as well as growth rate constraints are set up, to make sure all the developments are within realistic ranges.

Overall, more than 2000 processes are included for each model run, to ensure energy flow is within network capacity, supply meets demand, and the whole system is balanced on an annual, seasonal, and daily peak basis. Given specific assumptions for particular technology development, different scenarios that meet 2050 carbon reduction target at lowest cost can be generated.

UKTM is used to provide guidance for the scenarios that meet the 2050 decarbonisation target. We also use the extensive carbon emission data and economic data contained within the model to determine the emission level within the scenario.

We carry out further validation of the electricity supply pattern produced by UKTM by replicating the electricity demand and generation in the BID3 model described in the Electricity generation output section. BID3 models the electricity generation in considerably more detail than UKTM and this check ensures that we have an acceptable mix of generating capacity.

Flexibility

Energy systems need to continuously match supply to demand, we call this energy balancing. Energy system flexibility is the ability to adjust supply and demand to achieve that energy balance.

To meet net zero, flexibility will become more important in all areas due to factors such as growth in levels of renewable generation, increasing electrification of heat and transport and changes in consumer behaviour. Electricity system flexibility is the area that has the greatest need for change due to the significantly increased demand we expect due to the way we heat our homes and go about our lives and the lower amount of spare capacity this leaves on the existing network at peak times. We expect electricity demand to increase in all scenarios, and in a net zero world we expect increased consumer engagement, particularly in scenarios with higher levels of societal change. This increased demand presents an opportunity for greater levels of flexibility.

Modelling of flexibility covers:

- Residential Demand Side Response (DSR);
- Industrial and commercial DSR;
- Vehicle-to-Grid;
- Electricity peaks; and
- Hydrogen production.

Electricity peak system demand

Peak System demand is the maximum end consumer demand and taken from the distribution and transmission systems in any given financial year. Demand is weather corrected to Average Cold Spell (ACS[36]). This is end consumer demand plus losses. For clarity, it does not include exports, station demand, pumping demand and storage demand.

FES End User or FES Customer demand is intended to reflect customer end use demand and differs from “system demand” by not including losses and demand for electrolysis.

Industrial and commercial load reduction is not deducted from this total to ensure a full understanding of unconstrained peak. Residential (non- EV) load reduction, however, is deducted from this total as this response is behavioural (rather than a large response to real time price signals).

[36] https://www.emrdeliverybody.com/Lists/Latest%20News/AllItems.aspx?&&p_Created=20161115%2011%3a17%3a12&&PageFirstRow=1&FilterField1=Category&FilterValue1=CM&&&View={C0855C66-F67D-4D84-9C26-CD4CAE25D06A}&InitialTabId=Ribbon%2ERead&VisibilityContext=WSSTabPersistence – under “Electricity capacity Report 2017”

In order to make long-term ACS peak projections from annual demand we carry out the following steps:

- Historic National Grid ESO weather corrected transmission annual and ACS peak demand data is the start point.
- FES system demand is created by adding our assessment of the annual and peak output from non-transmission generation.

To work out peak and annual demand by component:

- We start with historic public domain residential data from Energy Trends (published by BEIS)
- We weather correct this on an annual basis using information from Elexon.
- An annual to peak ratio derived from weather corrected Elexon data is then applied to the resulting residential annual demand to create a residential peak.
- This data is assumed to be true for history. Future residential peaks are calculated assuming the Elexon annual to peak ratio remains fixed, and we add on peak demand from other future technologies like heat and transport, as well as the influence of trends from appliances, heat and light.
- Residential annual demand takes this start point and the projections use the trends indicated by the other FES models
- The residential annual to peak ratio is assumed to be true, and the Industrial and Commercial annual to peak ratio is derived from the remaining peak demand
- The remaining annual industrial and commercial I&C) part of demand is split using ratios from Energy Trends, and our assessment of total non-residential demand.
- Again, trends from our modelling are used to project future I&C demand on an annual basis, and the I&C annual to peak ratio applied
- Finally, we add an estimate of pure demand side response (true demand reduction) – currently we believe of the 2.4GW of triad response observed, 1.4GW is due to behind meter generation, and 1,0 GW is due to pure demand side response. So 1GW of demand is added to the peaks derived above
- this process creates a total underlying ACS peak system demand, as well as a weather corrected annual average demand.
- For summer minimum calculations a similar process is followed using Elexon data and observed/forecast demands on the transmission system

Heat pump demand at peak

**** Updated for FES21 ****

From FES 2021, heat pump demand at the time of the demand peak is an output from the Spatial Heat model described in the “Space Heating and Hot Water” section of this document.

The Spatial heat model uses flexibility tools like thermal storage and hybrid boiler systems to optimise fuel consumption based on hourly price sensitivity. The output includes expected electricity use including any secondary heating requirements.

Industrial and commercial electricity demand side response (DSR)

The analysis and modelling of the potential DSR from the I&C sectors starts with a qualitative assessment of the available market intelligence including stakeholder engagement and available literature. Quantitative assessment is undertaken using contracted and observed demand side response information from the EMR Capacity Market Register, and Balancing Service contracts. This then forms two different modelled components:

1. DSR through contracted flexibility (when parties trade and directly contract with one another to procure flexibility). Two factors are analysed; the deployment of business engagement with DSR through contracted flexibility and the shiftable load that business can offer, considering limitations due to their operating profile.
2. DSR due to price flexibility (occurring when any party varies its demand or generation in response to the price of energy at a particular time and/or location). Two factors are analysed; the deployment of business engagement with pricing flexibility schemes (i.e. dynamic TOUTS, Critical Peak Pricing etc.) and the shiftable load that business can offer, considering limitations due to their operating profile.

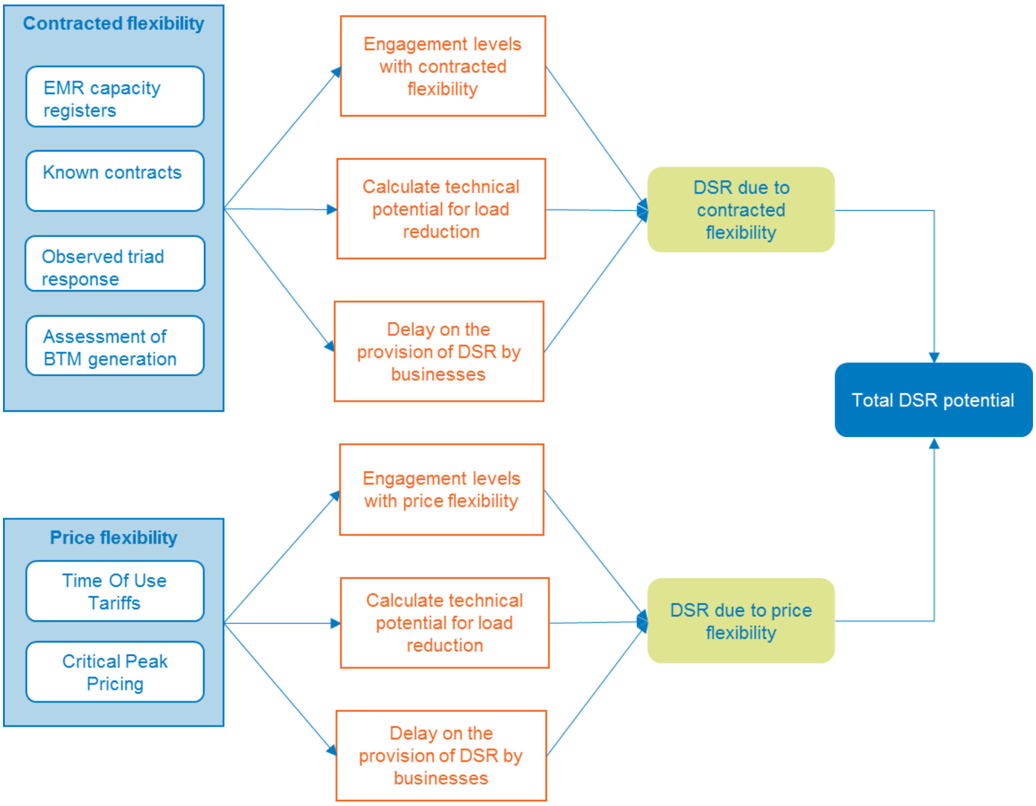

Figure 17: Industrial and commercial DSR process chart

The above steps produced the results of the total DSR potential. To assess the pure DSR potential, namely DSR due to load reduction only (excluding storage and on-site generation), existing data is very limited. Capacity Market registers[37] and Energyst reports[38] were used to understand the current status of 'load reduction only DSR' and the trends were then extrapolated for the future potential.

[37] https://www.emrdeliverybody.com/CM/Registers.aspx
[38] https://theenergyst.com/digital-editions/market-reports/

DSR from commercial heat pumps is modelled separately to this process, within the Industrial and Commercial modelling process. In the FES scenarios, annual heat demand is assumed to be electrified where economic to do so. Commercial heat pumps for space heating are now part of the Spatial Heat model described earlier in this document. These heat pumps will replace gas heating where economic to do so and the Spatial Heat Model returns annual and peak electricity demands from these. This model also considers the operation of these heat pumps with respect to price signals to deliver demand side response.

From FES 2020, Industrial heat pumps are assumed to be part of a larger end to end manufacturing process. No DSR from heat pumps in this sector is assumed. If further information becomes available we will begin to make assumptions for this sector.

Residential electricity Demand Side Response

The modelling of changes in residential load in response to either price signals or direct participation in balancing services was revised in FES 2020 and continues to be used in FES 2021.

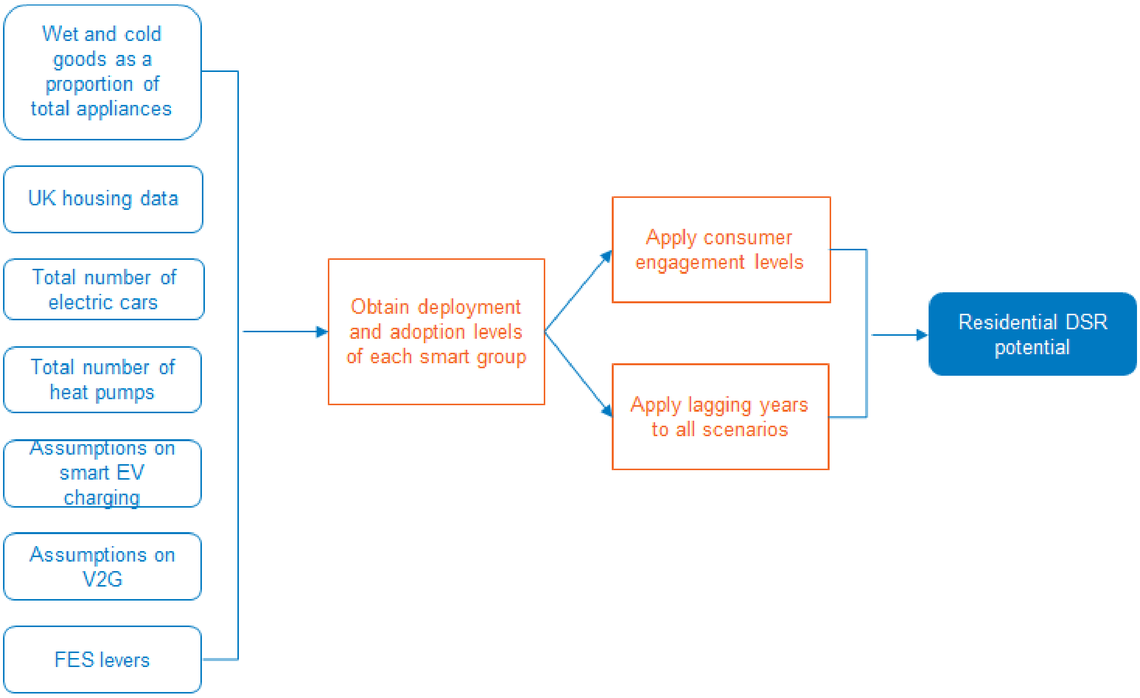

Figure 18: Residential Demand Side Response

Prior to FES 2020, we had a general market model which used generic, relevant levers and historic comparators to model residential demand side response uptake. We have built a new DSR model for use since FES 2020.

Stakeholder feedback gathered in 2018 and 2019 strongly indicated the first and strongest consumer adoption of time of use tariffs (TOUTs) occurs on ownership of their first electric vehicle as this is a significant electrical demand and proportion of a household electricity bill. TOUTs introduce consumers to the concept of DSR which may be controlled and monitored via a mobile phone app. TOUTs are introduced to consumers in car-show rooms, electric vehicle brochures and energy supplier information. We also believe a similar effect will occur if a homeowner adopts a heat pump heating system as this will have the same drivers of increased electricity demand and hence costs.

Based on this feedback, it is now assumed in our modelling that consumers begin mass adoption of TOUTs as they begin to use electric vehicles. Once a consumer is introduced to TOUTs for EV charging, it is then assumed that as their household appliances are replaced over following years, smart energy using devices have an increased presence within the home.

The residential DSR scenarios are built on the assumption that DSR's effect on reducing peak demand relies on a combination of automated smart appliance adoption and the presence of smart pricing in the market. Our modelling reflects levels of consumer engagement with demand side response grow as participation with smart technology develops and varies depending on the specific scenario modelled.

The residential DSR model now comprises of the following inputs:

- Number of GB homes – which allows us to model penetration of TOUTs and DSR in homes over time;
- A high electricity demand technology which encourages consumers to consider a TOUT.
- First adoption of one of the following technologies is the trigger:
  - Electric car ownership levels from the FES Road Transport Model
  - Heat Pump (HP) ownership levels from the Spatial Heat Model
- Consumer Switching behaviour data from Ofgem, used to differentiate the scenarios
- Residential Demand: Proportion of demand from white goods (refrigeration/washing appliances) of total residential demand. It is assumed these appliances can be placed under a DSR regime, with the consumer retaining visibility and control of DSR activity. At peak it is assumed that only these home appliances might perform DSR – other appliance classes are seen as too disruptive to lifestyles to assume they will regularly DSR.
- Annual demand savings for appliances only in the range 1%-4% are assumed, reflecting evidence from trials.[39]

Further Assumptions:

- Number of years lag between purchase of an Electric Vehicle (EV) or Heat Pump (HP) and adoption of a time of use tariff.
- Number of years lag between purchase of an EV or HP and adoption of a Vehicle to Grid (V2G) tariff and 2-way charger. Set to a minimum of 5 years as the EU V2G standard ("CCS") is expected in 2025.
- Number of years lag between purchase of an EV or HP and purchase of a smart white appliance – 10-12 years being the average lifetime of white goods, with shorter delays in faster decarbonising scenarios.
- Consumer tendency to adopt TOUTs and DSR behaviour.
- No DSR is currently assumed for summer minimum periods due to a lack of data from real world trials that measure what consumers might do in circumstances with low, or negative electricity prices. Further data to support this modelling would be welcomed.

Model outputs are in the form of demand reduction percentages, which are then applied in EV, Heat and Peak demand modelling.

The effect of Economy 7/10 tariffs is captured within the Elexon Residential profile that is included within the peak demand calculations. Further information on this area would help us model home heat with a greater level of sophistication and would be welcome.

[39] AECOM Review of Smart Meter Trials for Ofgem: https://www.ofgem.gov.uk/gas/retail-market/metering/transition-smart-meters/energy-demand-research-project

Consumer Engagement with smart technologies and DSR

Within our modelling, we use data from Ofgem to split consumers into the six segments defined since 2017[40]:

- Happy shoppers;
- Savvy researchers;
- Market sceptics;
- Hassle haters;
- Anxious avoiders; and
- Contented conformers.

This information is updated every year. We vary the level of engagement applied to each market segment individually based upon the **Scenario Framework** and assuming that certain consumer segments will evolve differently under the four scenarios according to their level of interest. The engagement levels modelled vary for different appliances and for consumer price flexibility. The engagement levels change over time within the models in response to both technology development and changes in attitude and will reflect the landscape of each scenario. Despite the adoption of smart appliances, the decrease in peak demand is delayed as it follows learning and adaptation curves i.e. the appliances once purchased are not utilised to their full potential straightaway.

Future consumer behaviour is difficult to model due to the current lack of real world data to understand behaviour or adoption of pioneering products that have not been tested in the past (i.e. EV smart chargers). Therefore, we model possible consumer behaviours according to the FES Framework levers and scenarios' landscapes.

With regard to smart EV charging for example, high levels of engagement are assumed in all scenarios, where it is assumed that smart charging is the least disturbing option for the consumers, widely promoted by market trends and policy. In general, we believe that where possible conditions will be established that encourage consumers to participate in avoiding peak time charging.

Our modelling FES is not a prediction of future consumer behaviour however we are aiming to represent a credible range of possible consumer behaviours within the FES Framework.

Electricity storage

The electricity storage technologies which have been included in our scenarios this year are the same as those used since FES 2018:

- Various types of battery technologies;
- Pumped hydroelectricity storage (PHES);
- Compressed air electricity storage (CAES); and
- Liquid air electricity storage (LAES).

As some large-scale electricity storage technologies have not been present in the market for very long, such as lithium-ion batteries, there is limited data available for modelling and analysis based on observed behaviour or long-term trends. We have examined several different data sources including the Capacity Market register, Embedded Capacity Registers, and data procured from a third party to better understand the potential of storage as well as those currently underway or under development. To create a range of outcomes we have examined the current deployment of storage technologies, the potential revenue streams available, as well as pairing storage with renewable technologies such as wind and solar PV. From this we have created a range of transmission and distribution connected technologies as well as some at domestic level.

AFRY's BID3 software is used to examine the usage of storage on the system to determine the potential utilisation under the generation mix for each scenario and year.

[40] https://www.ofgem.gov.uk/publications-and-updates/consumer-survey-2020-update-consumer-engagement-energy

Interconnectors

Electricity interconnector capacities

We have developed electricity interconnector capacity projections to establish the level of interconnection we expect in each scenario and its associated build profile. There is a range of electricity interconnector capacity represented across the scenarios. The range is informed by considering different sources of information. These sources include:

- Interconnector Register;
- Analysis and approval of projects for cap and floor regimes by Ofgem;
- Optimum level of GB interconnection in the NOA; and
- Benchmarking against other published scenarios and stakeholder engagement with industry.

The total level of interconnection in each scenario is informed by the **Scenario Framework**. Interconnector capacities are higher in the scenarios with greater levels of societal change, as high levels of non-flexible generation favour more flexible sources such as interconnection. Interconnectors play an increasingly important role providing flexibility in the net zero scenarios.

Our analysis starts by identifying all the potential projects and their expected commissioning dates to connect to GB. This information is from a range of sources including the electricity European Network of Transmission System Operators (ENTSO-e) Ten-Year Network Development Plan[41], 4C Offshore[42] and the European Commission[43]. Where only a commissioning year is given, we assume the date to be 1 October of that year. Following stakeholder feedback, we have included the full list of projects that we have considered in Table 9 below. It should be noted that this only states which projects have been considered in our scenarios and not whether they have actually been included. Projects in this list could appear in all our scenarios, no scenarios or at least one scenario.

We assess each project individually against political, economic, social and technological factors to determine which interconnector projects would be built under each scenario. If it does not meet the minimum criteria we assume it will not be delivered in the given scenario, or that it will be subject to a commissioning delay. We calculate this delay using a generic accelerated High Voltage Direct Current (HVDC) project timeline. All projects which have reached final sanction are delivered, though they may be subject to delays in some scenarios.

In all the scenarios, we assume that the supply chain has enough capacity to deliver all interconnector projects. While we analyse individual projects, we anonymise the data by showing only the total capacity per year, due to commercial sensitivities.

The table below lists all the potential interconnector projects that we have considered in our scenarios. This also shows the neighbouring markets that we assume the project will connect to. Projects in this list may appear in all our scenarios, no scenarios or at least one scenario. In addition to the projects in this list we also consider additional ‘dummy’ projects to neighbouring markets that may not have started development yet. It should be noted that we only consider projects as interconnectors if they are connected to both the GB network and another European network. Projects that are being developed that connect generation located in another country directly to GB but not to that country’s network (e.g. some wind projects) are considered as electricity generation in our scenarios.

[41] ENTSO-e, Ten-Year Network Development Plan 2018, https://tyndp.entsoe.eu/tyndp2018/
[42] 4C Offshore, Offshore Interconnectors, https://www.4coffshore.com/transmission/interconnectors.aspx
[43] https://ec.europa.eu/energy/en/topics/infrastructure/projects-common-interest

Table 9: Potential interconnector projects considered in FES21. This only states which projects have been considered in our scenarios and not whether they have actually been included. Projects in this list could appear in all our scenarios, no scenarios or at least one scenario

Country	Projects considered
Belgium	Cronos, Nautilus, Nemo Link
Denmark	Aminth, Viking Link
France	Aquind, Channel Cable, Eleclink, FAB Link, Gridlink, IFA, IFA2, Kulizumboo
Germany	NeuConnect, Tarchon
Iceland	Atlantic Superconnection
Ireland	East-West Interconnector, Gallant, Greenconnect, Greenlink, MARES, Moyle, Greenwire N&S, LirIC
Netherlands	Britned, Eurolink, Seneca
Norway	Continental Link, Maali, NorthConnect, NSL
Spain	ANAI, BritIB, Abengoa
Morocco	Xlinks

Electricity interconnector annual and peak flows

BID3 has been used to model all markets that can impact interconnector flows to GB for our four scenarios. As with FES19, this includes: Belgium, Czech Republic, Denmark, Finland, France, Germany, Ireland, Italy, Netherlands, Northern Ireland, Norway, Poland, Portugal, Slovakia, Sweden and Switzerland. From FES20 Austria, Slovenia, Luxembourg and Spain are also included. All our pan-European modelling assumes that Great Britain continues to be in the Internal Energy Market (IEM) or has arrangements very similar to the IEM once the UK leaves the European Union. These assumptions may change in future as we get greater clarity on the future relationship between the UK and the rest of the EU.

Interconnector annual flows are modelled on the same basis as the electricity generation output described in the earlier section to ensure consistency. Peak flows, on the other hand, are modelled slightly differently. The interconnector peak flows are modelled using a similar approach to that used to calculate EMR de-rating factors, which look to assess the contribution from interconnectors at times of system stress (these periods mostly occur between 5 and 8 pm in winter). This approach is described in the Electricity Capacity Report[44]. However, there are a few differences between the EMR and FES analysis. Firstly, because the FES covers a much longer time horizon, we can’t use the full 30 years of weather history used for EMR (essentially the simulations would take too long). Therefore, we select between 3 and 6 historic weather years that lead to the highest number of stress periods. Secondly, the timing of the process means that the interconnector flows in FES are calculated on draft data because they are needed to help complete the generation mix and ensure the 3 hours’ loss of load expectation criteria is met (although the draft data will be close to the final values at this point). The EMR de-rating factors are based on the final, published, FES assumptions.

The market fundamentals of the neighbouring countries are strongly inspired by reports from national electricity Transmission System Operators (TSOs), national regulators and the ENTSO-E Ten Year Network Development Plan (TYNDP). Since FES 2019, we have used data that covers an extensive number of countries: Belgium, Denmark, France, Germany, Ireland, the Netherlands, Northern Ireland, Norway, Italy (north), Poland, Spain and Sweden.

[44] https://www.emrdeliverybody.com/Lists/Latest%20News/Attachments/189/Electricity%20Capacity%20Report%202018_Final.pdf

Regional Electricity Demand

Overview of the data

The Future Energy Scenarios (FES) are intended to illustrate a broad range of credible, holistic outcomes from now to 2050 at a GB level. 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 B 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 2020[45].

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 (2020/21) 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 (2020/21) 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.

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.

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 net demand, 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[46] and Elexon Open Settlement data[47]. 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

[45] https://www.nationalgrid.com/uk/publications/electricity-ten-year-statement-etys
[46] https://www.elexonportal.co.uk/
[47] https://www.elexon.co.uk/data/open-settlement-data/

level Net demand calculated earlier in our FES analysis to get an energy value (in MW) for our starting year 2020/21.

For Scotland, we have continued to use Week 24[48] as the source of embedded generation data, with the settlement data being available for benchmarking.

Once we have Net demand by GSP we can determine the underlying Gross demand[49] by GSP by adding the energy generation output of non-transmission connected power stations (Embedded and sub 1 MW). 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 the starting year.

Step 2: Gross demand subcomponents

To estimate the split of domestic and non-domestic demand to be used per GSP in our analysis start year, electricity consumption data from BEIS was used[50]. 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 (for electric transport treatment, please see below).

Forecasts

Demand

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

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[48] 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.
[49] 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.
[50] https://www.gov.uk/government/statistics/lower-and-middle-super-output-areas-electricity-consumption

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.

Heat demand

We understand that heat pump 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.

The electrical demand from heat pumps, and district heating, comes from the Spatial Heat model introduced in FES 2021 and as described earlier in this document. This model considers housing types and relevant technology, policy, and economic factors with the results presented at different levels of geographical granularity (e.g. LSOA, LA, GOR, LDZ, GB) or network boundaries (e.g. GSP, NTS Offtake).

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 on values of registered EVs per GSP provided to us by Distribution Network Operators via the latest years “Building Block” data. By 2027 in Leading the Way and Consumer Transformation, and 2030 in System Transformation and Steady Progression, the locational split of registered EVs is based on current whole fleet splits. This data is from Department for Transport (DfT) Statistic table VEH0122. The proportions in the interim years from the current day figures to the whole fleet figures are 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.

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)[51], 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.

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

Appendix A

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.

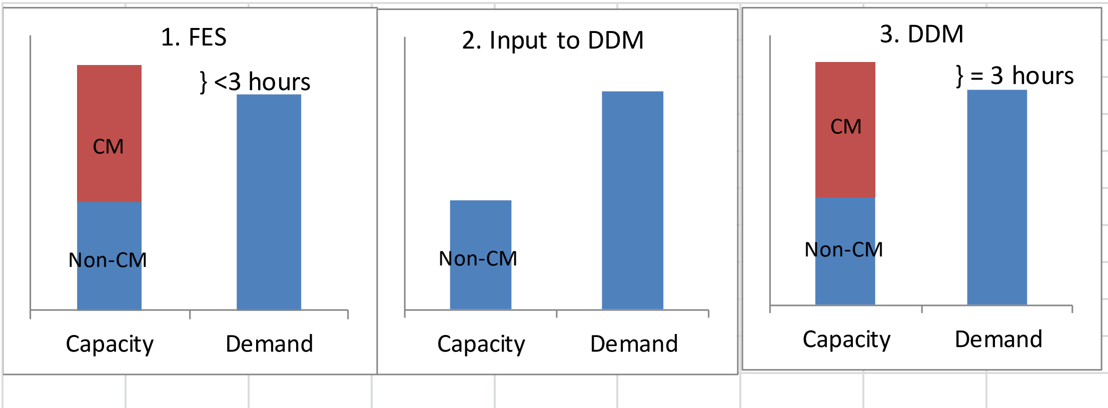
- Summer Minimum AM is a view of demand between 0500-0600, typically in June-August on a Summer Sunday morning.
  - Electric vehicles are a demand – no smart behaviour assumed (people charge how they would charge assuming todays behaviour)
  - All storage considered as a demand – spread over 4-6 hours 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.

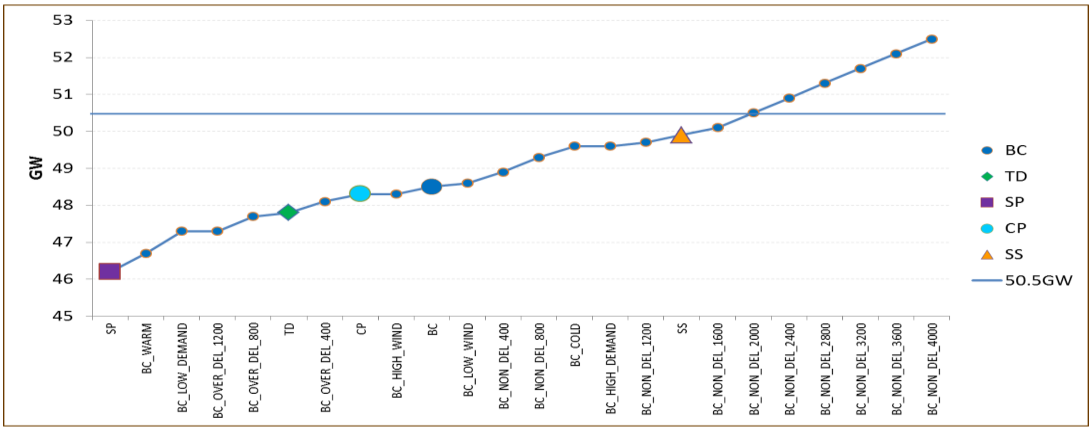
Annex – LOLE step by step guide

This annex illustrates why the theoretical implementation of the GB Reliability Standard leads to a CM Base Case with LOLE <3 hours (steps 1 to 7) and then the market delivers a LOLE lower than that (steps 7-1) but can still be said to target the market implementation of the Reliability Standard. This process can be summarised into 9 steps:

1. FES scenarios plus Base Case have <3 hours LOLE
2. Input into the Dynamic Despatch Model (DDM)[52] Non-CM capacity for a scenario along with the demand
3. DDM run to give CM capacity required to give 3 hours LOLE



4. Repeat 1 to 3 for all scenarios and sensitivities
5. Input all scenarios and sensitivities (all = 3 hours LOLE) into LWR tool
6. Run LWR tool to give cost optimal answer



6. Resulting capacity(50.5GW) > Base Case (48.5GW) hence Base Case <3 hours LOLE
7. Auctions result so far have delivered low prices and more capacity has been procured resulting in Base Case <2 hours LOLE for the period of the auctions (note Sec of State adjustments to Demand Curve can increase the capacity targeted and reduce LOLE still further e.g. 20/21)

[52] Software modelling tool used for the production of the Electricity Capacity Report (ECR)

8. Update auction results for known developments e.g. unsuccessful CM plant remaining open, higher availabilities etc. which result in the Base Case and FES scenarios with LOLE initially <1 hour LOLE thereafter within range of 0.5 to 2.5 hours LOLE which then returns you to step 1.

Note, virtually all electricity markets around the world deliver more capacity than required to meet their Reliability Standard some significantly more e.g. Netherlands and Ireland.