FES Modelling Methods 2019

Updated June 2021

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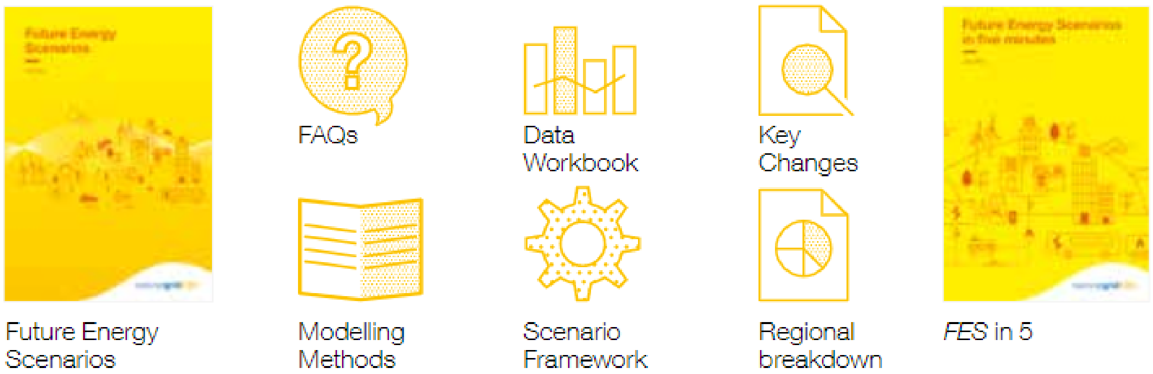
Introduction

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: fes.nationalgrid.com



We have included a Five Year Forecast in FES2019. This is developed differently to the scenarios. 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 scenario range. The scenarios then reflect uncertainties around this view, projecting beyond the first five years all the way out to 2050.

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@nationalgrid.com

Energy demand

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

1. Electricity demand
2. Gas demand
3. Industrial and commercial demand
4. Industrial and commercial demand side response
5. Residential demand
6. Residential electricity demand side response
7. Road transport demand

Electricity demand overview

In the FES document Chapter 4, we consider “end consumer demand,” regardless of where (transmission, distribution or on site) the electricity is generated. Demand is weather-corrected to seasonal normal for annuals. For clarity, 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.

Peak demand is the maximum end consumer demand on the system in any given financial year. Demand is weather corrected to average cold spell (ACS[1]). This is end consumer demand **plus losses**. For clarity, it does not include exports, station demand, pumping demand and storage demand.

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

In order to make long-term ACS peak projections from annual demand we apply a recent historical relationship of annual to peak demand. For the residential sector, there is a further adjustment to take account of weather using background data from Elexon. This creates an initial peak demand, to which we add components that history cannot predict, such as electric vehicles (EVs), heat pumps and time of use tariffs (TOUTs).

1 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”

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 demand (National Demand: No interconnector exports, station demand or pumping demand)
  - weather corrected data is published in ETYS[2] and the FES data tables
  - out-turn "National Demand" data is published on our website[3]
- we then add an estimate of the output from non-transmission generation, by taking our view of
  - capacity of distribution connected and <1MW generation
  - annual and peak load factors derived from a number of sources
- to get underlying peak demand for FES 2019, we add our estimate of pure demand side response (not demand response from generation, as that would double count non-transmission generation). This was a change from previous FES editions starting in 2018. Historically we added total Triad avoidance to peak and in more recent years a view of pure DSR: Our view of pure DSR changes as more information becomes available.

Demand components - annual

We do not have direct information on the makeup of demand so these components have to be estimated.

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 data43 is taken and this frequently brings small revisions to history.

- The Energy Trends residential annual data is annually weather corrected, using information from 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.

Future projections for annual and peak are created using forecasts and assumptions from other FES models e.g.

- industrial & commercial demands
- residential appliances and air conditioning
- heat and district heat
- road and rail transport
- hydrogen production ("transformation")
  - electrolysis is assumed not to run at peak but does run at other times
  - other (less electricity intensive) hydrogen production processes are assumed to run all year round
- annual and peak smart meter efficiency effect

[2] https://www.nationalgrideso.com/insights/electricity-ten-year-statement-etys
[3] https://www.nationalgrideso.com/balancing-data/data-finder-and-explorer

Demand components – peak

Peak demands are created using our ACS Peak demand history as a basis (National Demand: Demand on the transmission system, not counting interconnector exports, station demand or pumping demand). We then:

- add an estimate of the output from non-transmission generation (including storage)
- add an estimate of pure demand side response (true demand reduction)
- this process creates a total underlying peak demand.

To get historic peak demands for the components of demand:

- we take annual, weather corrected, Energy Tends residential data
- we create a peak using weather corrected residential data from Elexon
- the remaining peak demand is assumed to be industrial and commercial
- 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
- additional air conditioning load due to the potential impact of climate change is not currently modelled in system planning – in future we will model this once we have sufficient quantitative evidence from various academic research projects

Gas demand

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 annual gas demand (including interconnector exports). 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[4], but with the following updates:

1. In consultation with the Gas Distribution Networks, we have used a non-climate change adjusted weather history for forecasting undiversified peak 1 in 20 demand at LDZ level. In

[4] https://www.nationalgrid.com/sites/default/files/documents/8589937808-Gas%20Demand%20Forecasting%20Methodology.pdf

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 agreed that it is more appropriate to use the non-climate change adjusted weather data for modeling peak demand whilst we continue to use the adjusted data for modeling average demand.

2. We have improved our hybrid heat pump modelling capability using insight from the FREEDOM Project 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. For the Two Degrees and Steady Progression scenarios we also model the gas demand required for the conversion to hydrogen. This is covered further under residential demand.

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 Ireland’s Network Development Plan 2018[5] 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.

Industrial and commercial demand

Our industrial and commercial (I&C) demand modelling 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.

The primary part of the model uses regression analysis, where economic output and energy prices are the principal explanatory variables. Two economic scenarios comprised of 24 individual sub-sector output forecasts, and two retail energy price cases from Oxford Economics were used to create energy demand for the industrial and commercial sectors.

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 modules to investigate the economics of increasing 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.

[5] https://www.cru.ie/wp-content/uploads/2018/12/CRU18269a-GNI-Network-Development-Plan-2018.pdf

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.

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 sources such as the Capacity Market, and Balancing Service contracts. This then forms two different modelled components:

3. 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.
4. 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.

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[6] and Energyst reports[7] were used to understand the current status of 'load reduction only DSR' and the trends were then replicated for the future potential.

Residential demand

The component parts we use to model residential energy demand are: appliances, lighting, heating technologies, insulation and home energy management systems.

Our base housing and population assumptions, developed from analysis from Oxford Economics, are consistent across our modelling scenarios. We assume that the population of GB reaches 70.7 million and that the number of homes grows to 31.1 million by 2050 in all of our scenarios. These compare to a population of 64.7 million and 28.1 million homes in 2018.

We create residential electricity demand using a bottom-up method and deterministic scenario modelling. For each component part we use historical data, where available, as our starting point. The main source is the department of Business Energy and Industrial Strategy's (BEIS) Energy Consumption in the UK[8]. We also gather information on mobile phones, tablets and wi-fi routers from Ofcom's Communications Market Reports.[9]

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[6] https://www.emrdeliverybody.com/CM/Registers.aspx
[7] https://theenergyst.com/digital-editions/market-reports/
[8] DECC, Energy Consumption in the UK, April 2016, https://www.gov.uk/government/collections/energy-consumption-in-the-uk
[9] https://www.ofcom.org.uk/research-and-data/multi-sector-research/cmr

From this point, we create projections using a selection of historic assessments; household projection data provided by external consultants; outcomes from reported external projects; regression analysis; deterministic and econometric methods. 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.

For residential gas demand, we use the outcomes of our heating technology model, which creates projections of a variety of heating technologies:

- gas boilers
- heat pumps, including air source, hybrid, ground source and gas
- fuel cells
- micro-combined heat and power (mCHP)
- biomass boilers
- electrical resistive heating
- oil boilers

The model takes into account housing segmentation and energy needs as well as additional economic and social factors. This is combined with a whole-house energy efficiency model which looks at the change in space heating energy consumption per house to reach the final residential gas demand. The energy efficiency model splits existing and new build houses into Energy Performance Certificate (EPC) Bands. A rate of change of Standard Assessment Procedure (SAP) rating is then applied to the housing population which will alter the EPC bands over time. In turn thermal energy demands are calculated based on the changing EPC position of the housing stock.

We include hydrogen for residential heating in Two Degrees and this year we have introduced hydrogen blending in steady Progression for the first time. In keeping with the scenario framework, hydrogen has been developed through centralised technology of steam methane reforming (SMR) and autothermal reforming (ATR), both of which must also include carbon capture, usage and storage (CCUS). Principally following the roll out approach of H21 study[10], where over time a hydrogen network develops and enables the conversion of more and more major cities to hydrogen. Our modelling assumes the conversion of all residential heating to hydrogen boilers within each city at the time of roll out. To do this we determine the displacement of thermal demand resulting from the hydrogen roll out and then process the remaining demand through the heating technology model,

Peak heat pump demand

Peak electrical demand from heat pumps is modelled by applying the annual outputs from the heating technology model to heat pump demand profiles. The profiles were obtained from the Customer Led Network Revolution (CLNR) trials[11].

Key current assumptions in this work are as follows:

[10] https://www.northerngasnetworks.co.uk/wp-content/uploads/2017/04/H21-Report-Interactive-PDF-July-2016.compressed.pdf
[11] Customer Led Network Revolution: Project Library. Dataset TC12
http://www.networkrevolution.co.uk/resources/project-library/

- peak demands are based on the CLNR findings but are not yet calibrated to ACS conditions (under review)
- 25% of heat pump installations have additional thermal storage which allows residential demand side response and head demand smoothing. In a change to FES18 but a return to the assumption in previous scenarios, storage reduces peak electrical demand by ~100%. Feedback received in 2018 and 2019 indicated that home thermal storage technologies could be more capable by 2030 than previously thought.
- hybrid heat pumps are not running on electricity at peak

We will look to continue to enhance our modelling in this area – for instance in consideration with recent BEIS[12] work and other trial results[13] in future.

Residential electricity DSR and smart meters roll-out

Smart Meters: Scenarios modelling uses latest BEIS and Ofgem information on smart meter installations as a reference. 2050 compliant scenarios in FES 2019 meet the 2020 smart meters target whereas the non-compliant scenarios provide a range which extends beyond these projections based on historic installation rates.

The residential DSR scenarios are built on the assumption that DSR's effect on reducing peak demand relies on a combination of smart appliances adoption and the presence of smart pricing in the market. The engagement levels will grow as participation with smart technology develops. The residential DSR comprises of the modelling of 4 key components:

- Smart Appliances Market Deployment
- Consumer Engagement with smart appliances
- Smart Appliances shiftable load
- Flexible pricing (dynamic pricing, or static TOUTs)

Smart appliances – market deployment: In FES17 all the smart appliances were treated in the same way and had the same deployment curves. Following stakeholder feedback, in FES 2018 the smart appliances are split into groups: EV smart chargers, smart cold appliances (fridges, freezers, and refrigerators), smart wet appliances (washing machines, dishwashers, dyers and tumble dryers) and smart heat pumps. For each of these groups market deployment trends were developed based on European trends and forecasts and then ranges were adjusted to reflect the levers of each scenario. This approach was not changed in FES 2019

Consumer engagement: Consumers are split into six segments defined by Ofgem in 2017[14]. Engagement levels are applied to each market segment individually based upon the **Scenario Framework** and developed assuming that certain consumer segments will involve differently under the four scenarios according to their interest to the market advancement and circumstances. The engagement levels are different for different appliances and also for consumer price flexibility.

[12] BEIS: Hybrid heat pumps Study
https://www.gov.uk/government/publications/hybrid-heat-pumps-study

[13] Project Freedom: Hybrid heat pumps Study
https://www.westernpower.co.uk/Innovation/Projects/Current-Projects/FREEDOM.aspx

[14] https://www.ofgem.gov.uk/publications-and-updates/consumer-engagement-survey-2018

The engagement levels will change over time 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 lack of data to understand consumer 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.

To be noted that in FES we do not predict the consumer behaviour but we model possible consumer behaviours according to the FES Framework.

Smart appliances – shiftable load: The load reduction that can be achieved by each appliance when DSR is applied, is estimated following literature reviews and applied to the consumer engagement and the market development figures to get the total DSR potential due to smart appliances.

Flexible pricing: Flexible pricing refers to any form of pricing schemes where electricity price varies during the day. In 2050 non-compliant scenarios, it was assumed that flexible pricing is limited to static TOUTs (time-of-use tariffs). In the 2050 compliant scenarios, flexible pricing extends to dynamic pricing (real time pricing, critical peak pricing) and assumed Half-Hourly settlements will be developed for residential customers. The deployment of flexible pricing and the consumer engagement with it in each scenario varies based up on Scenario Framework.

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/coaches.

To model the uptake of various road transport types and fuels we utilise a total cost of ownership model. Assumptions on the increase and decrease of various factors including battery costs, fuel costs, vehicle efficiency for different scenarios; for example, to meet transport targets for Two Degrees, 100% of vehicles must be low emission by 2050. These uptake rates for the different scenarios, in relation to the expected sales projections for all vehicles (determined by the total cost of ownership and the rate of which older vehicles are scrapped, 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[15] and above) is included within the scenarios; and where they are shared vehicles this influences the number of other cars they displace.

For V2G we have continued to take a conservative approach, assuming that private cars with 7kW smart bi-directional chargers are available; and assuming that each vehicle that takes part has 4 hours' worth of energy each day over the peak period. We further assume that only a proportion of the most engaged consumer segments will take part in vehicle to grid.

The peak method has been changed this year with the introduction of a full year's profile developed under a National Innovation Allowance (NIA) project[16]; covering both residential and non-residential charging. Assumptions on the split of annual charging amounts between different charging locations were included on a scenario basis; for example more residential charging was included in decentralised scenarios; whilst more public charging was included in centralised scenarios.

[15] https://www.smmt.co.uk/wp-content/uploads/.../SMMT-CAV-position-paper-final.pdf
[16] https://www.smarternetworks.org/project/nia_ngso0021

Energy supply

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[17], Embedded Register[18], Interconnector Register[19] and data procured from third parties. 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. Beyond 2030, there less market intelligence 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 Electricity System Operator publications, which use the FES assumptions. Network capability is assessed as part of the Electricity Ten Year Statement (ETYS)[20] and Network Options Assessment (NOA)[21]. Future operability challenges are analysed in the System Operability Framework (SOF)[22].

Electricity supply transmission installed capacities

The electricity supply transmission installed capacities uses a rule based deterministic approach. 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.

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.

[17] https://www.nationalgrideso.com/connections/registers-reports-and-guidance
[18] https://www.nationalgrideso.com/connections/registers-reports-and-guidance
[19] https://www.nationalgrideso.com/connections/registers-reports-and-guidance
[20] https://www.nationalgrideso.com/insights/electricity-ten-year-statement-etys
[21] https://www.nationalgrideso.com/insights/network-options-assessment-noa
[22] https://www.nationalgrideso.com/insights/system-operability-framework-sof

The placement of a power station 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 National Electricity Transmission System (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 agreement. Other projects where information has been received in the very early phases of scoping (i.e. pre-connection agreement) are also considered.

Electricity supply 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 13 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:

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

To determine the current volumes of renewable generation we obtain data from various sources including the Ofgem Feed In Tariffs (FiT) register[23] and the Renewable Energy Planning Database[24]. For thermal generation we use the Combined Heat and Power Quality Assurance (CHPQA) register[25] and the Capacity Market 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.

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

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

Biogas CHP	mCHP	Gas CHP	Hydro	Solar
Biomass CHP	Anaerobic Digestion	Battery	Fuel Cell	Wind
Vehicle to grid				

Baseline data, from Renewable Obligation Certification Scheme and Feed in Tariff 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

Since FES 2017, we have calculated power generation output using a model called BID3, which is a pan-European electricity dispatch model capable of simulating the electricity market in Great Britain 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 simulations are based on end-user consumption meaning that generation connected to both transmission and distribution networks are considered as supply.

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 FES 2019 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 forced outages. This varies on a monthly or quarterly basis to allow for seasonal variations. 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:

CO_2 intensity (g/kWh) = CO_2 emissions from generation (g) / 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[26] will only include those sites that the ESO has visibility of[27]; therefore, there will be differences between the two values as the methods and data are different.

Electricity interconnector capacities

We 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 across the scenarios. The range is informed by considering a number of different sources of information. These include: Interconnector Register, analysis and approval of projects for cap and floor regimes by Ofgem, optimum level of GB interconnection in the Network Options Assessment (NOA), benchmarking against other published scenarios and stakeholder engagement with industry. The total level of interconnection in each scenario is informed by the Scenario Framework. We assume that there is more interconnection in the decarbonised scenarios. We also assume that there is less interconnection in scenarios with greater focus on decentralisation.

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[28], 4C Offshore[29] and the European Commission[30]. 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 the table 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

[26] http://electricityinfo.org/forecast-carbon-intensity/
[27] http://electricityinfo.org/real-time-fuel-mix-and-carbon-intensity-methodology/
[28] ENTSO-e, Ten-Year Network Development Plan 2018, https://tyndp.entsoe.eu/tyndp2018/
[29] 4C Offshore, Offshore Interconnectors, http://www.4coffshore.com/windfarms/interconnectors.aspx
[30] https://ec.europa.eu/energy/en/topics/infrastructure/projects-common-interest

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.

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

Note: Kulizumboo appeared on the Interconnector Register after the FES 2019 analysis was completed and will be considered for FES 2020.

Electricity interconnector annual and peak flows

For FES 2019, BID3 has been used to model all markets that can impact interconnector flows to GB for our four scenarios. This includes: Belgium, Czech Republic, Denmark, Finland, France, Germany, Ireland, Italy, Netherlands, Northern Ireland, Norway, Poland, Portugal, Slovakia, Sweden and Switzerland. 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 above 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[31]. 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.

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

The market fundamentals of the neighbouring countries are strongly inspired by reports from national electricity Transmission System Operators (TSOs) and the ENTSO-E Ten Year Network Development Plan (TYNDP) edition for 2018[32]. In FES 2018, we used scenarios from these sources to model uncertainties such as the speed of decarbonisation in Europe. In FES 2018, scenarios were developed for: Belgium, Denmark, France, Germany, Ireland, the Netherlands, Northern Ireland and Norway. In response to stakeholder feedback, we have extended the geographical scope to cover Italy (north), Poland, Spain and Sweden. As most European TSOs and ENTSO-E update their longer-term scenarios every two years, there has been no significant update to our supply and demand assumptions in Europe since FES 2018. We anticipate that these assumptions will be revised again for FES 2020, particularly with ENTSO-E's TYNDP scenarios expected to be published in late 2019.

The table below shows the sources we have used for countries in Europe and how we have aligned the scenarios in those reports with those for Great Britain in FES. The alignment of scenarios in Europe to those in FES was based on consideration of several factors including the speed of decarbonisation, level of decentralisation as well as other supply and demand drivers.

Country	Source	Community Renewables	Two Degrees	Steady Progression	Consumer Evolution	Five Year Forecast
Belgium	ELIA[33]	Large Scale RES	Large Scale RES	Base Case	Decentral	Pöyry Central
France	RTE[34]	Ampere	Ampere	Hertz	Watt	Pöyry Central
Ireland	Eirgrid[35]	Consumer Action	Low Carbon Living	Slow Change	Steady Evolution	Pöyry Central
Denmark, Germany, Northern Ireland, Italy (north), Netherlands, Poland, Spain, Sweden	ENTSO-E[36]	Global Climate Action	Global Climate Action	Steady Transition	Distributed Generation	Pöyry Central
Norway	Pöyry Central[37]l	Pöyry Central plus wind targets[38]	Pöyry Central plus wind targets	Pöyry Central	Pöyry Central	Pöyry Central
All other countries	Pöyry Central	Pöyry Central	Pöyry Central	Pöyry Central	Pöyry Central	Pöyry Central

32 http://tyndp.entsoe.eu/tyndp2018/
33 http://www.elia.be/~/media/files/Elia/About-Elia/Studies/20171114_ELIA_4584_AdequacyScenario.pdf
34 https://www.rte-france.com/fr/article/bilan-previsionnel
35 http://www.eirgridgroup.com/site-files/library/EirGrid/EirGrid-Tomorrows-Energy-Scenarios-Report-2017.pdf
36 https://tyndp.entsoe.eu/tyndp2018/
37 Scenario data we procured from Pöyry as part of our supplier contract for BID3
38 https://ec.europa.eu/energy/sites/ener/files/documents/dir_2009_0028_action_plan_norway__nreap.pdf

Electricity storage

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

- various battery technologies
- pumped hydroelectricity storage (PHES)
- compressed air electricity storage (CAES)
- liquid air electricity storage (LAES)

As some large-scale electricity storage technologies are new such as lithium-ion batteries, there is limited data available for modelling and analysis. We have examined several different data sources including the CM register 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.

We utilised an economic dispatch model to examine the usage of storage on the system to determine the potential utilisation under the generation mix for each scenario and year.

Gas supply

In FES we model gas that enters the National Transmission System (NTS) and 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.

UK continental shelf (UKCS)

The UKCS is the sea bed 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 in to 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[39]. 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, with a mixture of historic flows and existing contracts. 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. This year the analysis is based on a report[40] by UKOOG, the trade body for onshore developers. This makes use of data published by Cuadrilla following the fracking of the Preston

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39 http://www.npd.no/en/

40 http://www.ukoog.org.uk/images/ukoog/pdfs/Updated%20shale%20gas%20scenarios%20March%202019%20website.pdf

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.

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)

BioSNG is a gas that is derived from household waste. The process uses high temperatures to produce a synthetic 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[41] documentation plus assumptions on the number of facilities, based upon the economic and political conditions for each scenario.

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, as mentioned 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. 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

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

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.

Annual supply match

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[42].

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

Whole system modelling

For our Two Degrees and Community Renewables scenarios and for the Net Zero sensitivity, we use a cost-optimisation model, the UK Times Model (UKTM), to guide them towards the target. It 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 finest granularity in UKTM is 3 hours, which captures the within day demand change. The model also contains seasonal demand profiles.

On the generation 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 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 two scenarios that meet the 2050 decarbonisation target. Once the FES demand and supply models are completed, UKTM is used to replicate the analysis and check that the targets have been met. We use the extensive carbon emission data and economic data contained within the model to determine the emission level and costs of the scenarios.

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.

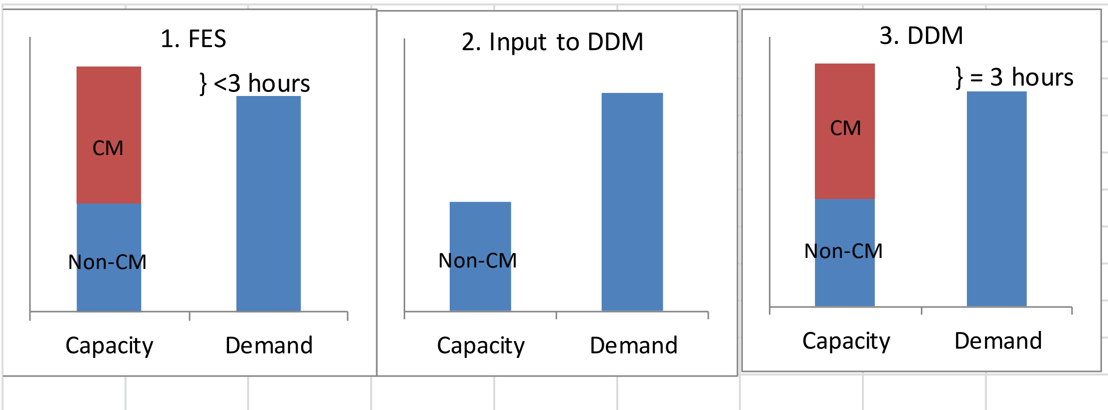
Using UKTM to cost the scenarios is just the first step to costing the whole energy system. The complexity of accounting for the whole system necessitates that analysis is undertaken using a variety of tools. UKTM by accounting for the cost of energy production and end consumer appliances provides the starting point. Further analysis is required on the possible network investments required for each scenario together with an understanding of the balancing requirements. Our analysis of the costing of the 2018 scenarios was released in a webinar, available on our website[43].

[43] http://fes.nationalgrid.com/media/1402/fes18-costing-webinar-march19-v10.pdf

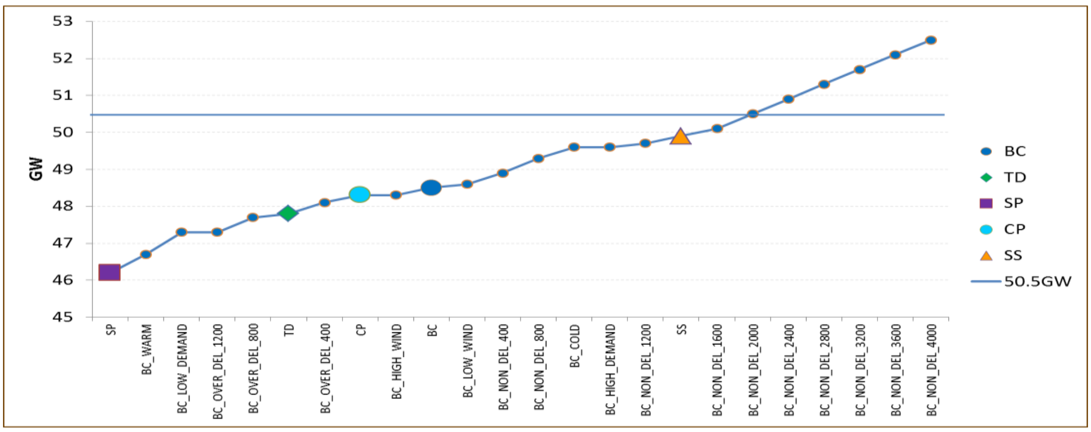
Annex – LOLE step by step guide

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)[44] 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



7. Resulting capacity(50.5GW) > Base Case (48.5GW) hence Base Case <3 hours LOLE
8. 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)

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

9. 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.

Faraday House, Warwick Technology Park,
Gallows Hill, Warwick, CV346DA

nationalgrideso.com