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Modelling Methods

Version 2.0 | July 12th 2018

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: www.fes.nationalgrid.com

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

Contents

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
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5. Residential Demand
6. Residential electricity Demand Side Response
7. Road Transport Demand

Electricity demand

In FES we consider underlying demand. That is end consumer demand, regardless of where (transmission, distribution or on site) the electricity is generated, plus network losses. Demand is weather-corrected to seasonal normal for annual and average cold spell (ACS[1]) for peak. For clarity it does not include exports, station demand, pumping station demand or other forms of storage demand. When we illustrate residential, industrial and commercial 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 demand on the system in any given financial year. This is end consumer demand plus losses. For clarity it does not include exports, station demand, pumping demand, 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 EVs, heat pumps and time of use tariffs (TOUTs).

Further information on the makeup of electricity demand is in the Annex – Electricity Demand Creation.

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

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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"

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[2].

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 scenario 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 2017[3] 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 includes gas and electricity demand for offices, shops, hotels, agriculture, manufacturing, construction, high intensity production processing, as well as onsite power generation

Two economic scenarios comprised of 24 sub-sectors, and two retail energy price cases from Oxford Economics were used to create energy demand for the industrial and commercial sectors.

The model examines 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 new and different heating technology.

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.

[2] https://www.nationalgrid.com/sites/default/files/documents/8589937808-Gas%20Demand%20Forecasting%20Methodology.pdf
[3] https://www.gasnetworks.ie/corporate/gas-regulation/system-operator/publications/GNI-Network-Development-Plan-2017.pdf

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:

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.

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[4] and Energyst reports[5] 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 70.6 million and that the number of homes grows to 31.4 million by 2050 in all of our scenarios. These compare to a population of 64.3 million and 27.9 million homes today.

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[6]. We also gather information on mobile phones, tablets and wi-fi routers from Ofcom's Communications Market Reports.[7]

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:

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

- 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.

This year we have introduced Hydrogen into the residential heating demand for Two Degrees for the first time. In keeping with the FES framework, hydrogen has been developed through centralised technology of Steam Methane Reformation (SRM) and Carbon Capture & Storage (CCS). Principally following the roll out approach of H21 study[8], 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[9].

Key current assumptions in this work are as follows:

- 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 (under review). In a change to previous FES scenarios, storage reduces peak electrical demand by ~10%. The previous assumption that heat storage would reduce electrical heat pump demand to zero at peak is no longer used. Initial modelling indicates this would create additional demand at the same time as high EV demands
- 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[10] work and other trial results[11] in future.

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

Residential electricity DSR and Smart Meters Roll-Out

Smart Meters: Scenarios modelling uses latest BEIS and Ofgem information on smart meters installations as a reference. 2050 compliant scenarios in FES 18 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 FES18 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[12] and then ranges were adjusted to reflect the levers of each scenario.

Consumer Engagement: Consumers are split into six segments defined by Ofgem in 2017[13]. 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. 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.
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 met in the 2050 compliant 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.

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

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

[12] http://www.eco-smartappliances.eu/Pages/documents.aspx
[13] https://www.ofgem.gov.uk/publications-and-updates/consumer-engagement-survey-2017

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 Pure 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[14] and above) is included within the scenarios; and where they are shared vehicles this influences the number of other cars they displace.

For domestic electric vehicles we assume that where possible home charging will occur and that the chargers will be 7kW and smart enabled; which along with consumer engagement influences the peak demand values. For non-residential charging it is assumed that commercial depot operations would be very heavily engaged with moving charging outside peak demands periods for economic reasons. For those private vehicles expected to charge at non-residential locations, such as destination chargers or forecourt style chargers, we have calculated the daily energy demand for these vehicles and profiled it over the day based upon the road use survey patterns using the assumptions that individuals would charge whilst on the road and are unlikely to make separate trips to charge their vehicle.

Vehicle to Grid (V2G) is included directly within the scenarios this year. For V2G we have taken 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

[14] https://www.smmt.co.uk/wp-content/uploads/.../SMMT-CAV-position-paper-final.pdf

the peak period. We further assume that only a proportion of the most engaged consumer segments will take part in vehicle to grid.

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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). See annex for more details on how LOLE is calculated.

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[15], Embedded Register[16], Interconnector Register[17] and data procured from third parties. In addition, we take into account 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 is very little market intelligence available so we rely more on our framework assumptions that are used to create the scenarios. These can be accessed in the **Scenario Framework** document.

The electricity supply analysis in FES does not include network or operability constraints. 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 particular 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 System Operator publications, which use the FES assumptions. Network capability is assessed as part of the Electricity Ten Year Statement (ETYS)[18] and Network Options Assessment (NOA)[19]. Future operability challenges are analysed in the System Operability Framework (SOF)[20].

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, taking into account 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.

15 https://www.nationalgrid.com/uk/electricity/industrial-connections/registers-reports-and-guidance
16 https://www.nationalgrid.com/uk/electricity/industrial-connections/registers-reports-and-guidance
17 https://www.nationalgrid.com/uk/electricity/industrial-connections/registers-reports-and-guidance
18 https://www.nationalgrid.com/uk/publications/electricity-ten-year-statement-etys
19 https://www.nationalgrid.com/uk/publications/network-options-assessment-noa
20 https://www.nationalgrid.com/uk/publications/system-operability-framework-sof

The placement of a power station is determined by a number of factors, such as market intelligence, energy policy and legislation. Project status and economics, which are applicable to that particular power station, are also taken into account. 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 the majority 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 taken into account.

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 the 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[21] and the Renewable Energy Planning Database[22]. For thermal generation we use the Combined Heat and Power Quality Assurance (CHPQA) register[23] 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:

Biogas CHP	mCHP	Gas CHP	Hydro	Solar

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

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 2018 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)

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 graph 5.2.5.3 in the FES 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[24] will only include those sites that National Grid has visibility of[25]; 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 decentralised solutions.

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[26], 4C Offshore[27] and the European Commission[28]. 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 an Annex at the end of this document. 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.

Electricity interconnector annual and peak flows

For FES 2018, 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, France, Germany, Ireland, Italy (north), Netherlands, Northern Ireland, Norway, Poland, Spain, Slovakia, Sweden and Switzerland. All of 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

[24] http://electricityinfo.org/forecast-carbon-intensity/
[25] http://electricityinfo.org/real-time-fuel-mix-and-carbon-intensity-methodology/
[26] ENTSO-e, Ten-Year Network Development Plan 2016, https://www.entsoe.eu/major-projects/ten-year-network-development-plan/ten%20year%20network%20development%20plan%202016/Pages/default.aspx
[27] 4C Offshore, Offshore Interconnectors, http://www.4coffshore.com/windfarms/interconnectors.aspx
[28] European Commission, Projects of Common Interest candidates for electricity, https://ec.europa.eu/energy/sites/ener/files/documents/pci_candidates_for_electricity.pdf

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.

We modelled all future years until 2030, every two years from 2032 until 2040 and 2045 and 2050 and calculated both annual flows and flows we might expect at winter peak. We modelled each future year until 2030 six times and 3 times for 2032 onwards to look at the impact of different weather conditions based on those we experienced in the years 1985, 1993, 2006, 2010, 2012 and 2013. The future years that are simulated under 3 weather years used the three most recent ones. These six recent years provided a good mix of cold and milder spells for our analysis. To create stress events that reflect the lack of capacity for electricity supply we increase demand by 5% in the countries we assessed having a significant impact on GB interconnector flows. This also ensured we considered a range of conditions in neighbouring markets, which is particularly important for peak times. The values that we present in FES are averages taken over all historic weather cases. For further information on how interconnectors are modelled see the Electricity Capacity Report[29].The market fundamentals of the neighbouring countries are strongly inspired by reports from national electricity transmission system operators and the ENTSO-E Ten Year Network Development Plan (TYNDP) edition for 2018[30]. Scenarios were developed for: Belgium, Denmark, France, Germany, Ireland, the Netherlands, Northern Ireland and Norway.

The French power market outlook integrated into FES18 follows the latest publication of RTE's *Bilan prévisionnel de l'équilibre offre/demande (2017 edition)*[31] and the recent French government announcements on energy policy. The *Bilan prévisionnel* is "a detailed study of the evolution of electricity generation and demand and the solutions that enable balance between them"[32]. For the future years of the study in FES18 that the *Bilan prévisionnel* doesn't cover we assume the furthest year in the *Bilan prévisionnel* is extended to 2050.

The Belgian system assumptions for FES18 are informed by the *Electricity Scenarios for Belgium towards 2050*[33], published by ELIA in November 2017. The objective of the report is "*to provide a solid basis for the choices that Belgian authorities will make for the development of the electricity sector in the three dimensions of the 'Energy Trilemma'*". For the future years of FES where the assumption in ELIA's report are not explicitly published we interpolate the projections given and add generation to meet the reliability standards following the Belgian need for it as announced in the study.

The Tomorrow's Energy Scenario[34] (TES) published in November 2017 provides a consistent projection for the Republic of Ireland's electricity market. Eirgrid, The Irish electricity system operator, has the role of planning "*the development of the electricity transmission grid to meet the future needs of society. […] The key to this process is considering the range of possible ways that energy usage may change in the future"*. It makes the TES a source that entirely fits for FES purposes, being commissioned to a similar objective.

The scenarios for Denmark, Germany, the Netherlands and Northern Ireland are based on those in the ENTSO-E TYNDP 2018 report[32].

All other countries in Europe are modelled with a single scenario based on Pöyry's Central European Scenario. The one exception to this was Norway, where the Pöyry scenario was supplemented with

[29] https://www.emrdeliverybody.com/Lists/Latest%20News/Attachments/116/Electricity%20Capacity%20Report%202017.pdf
[30] http://tyndp.entsoe.eu/tyndp2018/
[31] https://www.rte-france.com/fr/article/bilan-previsionnel
[32] Translated from French from the first paragraph in the introduction of the document
[33] http://www.elia.be/~/media/files/Elia/About-Elia/Studies/20171114_ELIA_4584_AdequacyScenario.pdf
[34] http://www.eirgridgroup.com/site-files/library/EirGrid/EirGrid-Tomorrows-Energy-Scenarios-Report-2017.pdf

additional renewable generation and electric vehicles based on government targets[35] in the two decarbonised scenarios (Two Degrees and Community Renewables). The table below summarises this information.

Scenario / Markets	Source	Community Renewables	Two Degrees	Consumer Evolution	Steady Progression
Belgium	ELIA *"Electricity Scenarios for Belgium towards 2050"*, Nov 2017	Large Scale RES	Large Scale RES	Decentral	Base Case
Denmark	ENTSO-E TYNDP 2018	Global Climate Action	Global Climate Action	Distributed Generation	Steady Transition
France	RTE "*Bilan Prévisionnel*", Jan 2018	Ampere	Ampere	Watt	Hertz
Germany	ENTSO-E TYNDP 2018	Global Climate Action	Global Climate Action	Distributed Generation	Steady Transition
Northern Ireland	ENTSO-E TYNDP 2018	Global Climate Action	Global Climate Action	Distributed Generation	Steady Transition
Republic of Ireland	Eirgrid "*Tomorrow's Energy Scenarios*", 2017	Consumer Action	Low Carbon Living	Steady Evolution	Slow Change
Netherlands	ENTSO-E TYNDP 2018	Global Climate Action	Global Climate Action	Distributed Generation	Steady Transition
Norway	Pöyry's Central European Scenario (2017) supplemented with Norwegian Government targets	Pöyry Central & wind targets	Pöyry Central & wind targets	Pöyry Central	Pöyry Central
All other countries	Pöyry's Central European Scenario (2017)				

The criteria for the scenario alignment went through a process of evaluation of achievement of emissions targets and technology development on the supply and demand side. The assessment targeted not only what electricity generation technologies are deployed, but what needs these assets could fulfil, such as reduced carbon intensity, flexible response and scale among others.

[35] 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 2017:

- Various battery technologies
- Pumped hydroelectricity storage (PHES)
- Compressed air electricity storage (CAES)
- Liquid air electricity storage (LAES)

As some electricity storage technologies at large scale 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 consider Gas Supply which enters the National Transmission System (NTS) and the Distribution Networks (DN). Total gas supply is derived from different gas supply elements that are described in more detail below. The models we use are supported by market intelligence, historical data and assumptions developed from knowledge gathered from stakeholders.

Principally gas supply ranges are derived from bottom up analysis of the maximum and minimum supplies into the GB market across the full FES modelled years (present to 2050). These ranges take account of the physical infrastructure to transmit the gas 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 and environmental factors. The following describes each supply component in more detail.

UK continental shelf (UKCS)

The UKCS is the name given to 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. The scenarios are derived using a mixture of gas producers' future projections which are gathered through an annual questionnaire process, stakeholder feedback gathered during our stakeholder consultation period, and commercial market intelligence. We create ranges to be used within each of the scenarios by making adjustments to future field developments based on historic production and the economic and political conditions as laid out in the **Scenario Framework**.

Norwegian supplies

Norwegian gas comes from the Norwegian continental shelf, usually divided in to the North Sea, the Norwegian Sea and the Barents Sea and is exported to countries, including the UK. The Norwegian flows to the UK are calculated by creating a total production range for existing and future Norwegian fields. Our primary data source is the Norwegian Petroleum Directorate[36]. 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 natural gas occurring within or extracted from shale. No UK shale gas production information is currently available. Due to this we believe that the Institute of Directors (IoD) Report[37] from 2013 remains the best source on which to base our projections. This report assesses the potential GB shale gas production from 100 onshore drilling sites (pads) based on the flow rates experienced from the US shale gas industry. Our high range is based on each onshore development

[36] http://www.npd.no/en/
[37] https://www.igasplc.com/media/3067/iod-getting-shale-gas-working-main-report.pdf

having 10 vertical wells and 40 horizontal wells while the medium case has half the number of wells. For FES 2018 we have assumed that the drilling rate is slower than that used in the IoD Report which has resulted in the time required to drill a 40 horizontal well pad increasing to 6 years The low range will remain zero until test wells prove the commercial and technical viability of UK shale.

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 for FES 2018 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 outputs 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 is planned for operation in 2018 with finding from Ofgem's Network Innovation Competition (NIC). The supply range is based upon the flow information published in the NIC[38] 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. The deliveries of LNG are therefore 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 compare the potential gas available in North West Europe available for export to GB via the interconnectors to the historic interconnector imports observed over the last 3-4 years.

Generic imports

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

The generic import is a volume of gas that is required in order to meet the remaining annual demand after other sources have been utilised. This gas can be made up of either LNG imports or Continental interconnector imports, or both.

Annual supply match

The primary function of the supply match is to match supply to demand on an annual basis. To do this we apply the supply sources in a ranking order. We apply 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, . Following this we apply 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 applying generic import, which as mentioned above can be made up of either LNG or continental pipeline gas or both.

Peak gas supply

The purpose of the peak match is 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 applied. This is based on observed values from offshore UKCS production. For onshore shale gas there is insufficient data to derive a likely difference between maximum and minimum. As these sources are likely to be base load, but with outages for maintenance, the UKCS difference between maximum and minimum was seen as the most appropriate to use.

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 are 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 a large piece of import infrastructure from the supply mix and again calculate the margin of supply over demand; this is referred to as an N-1 assessment[39].

[39] https://www.gov.uk/government/publications/uk-risk-assessment-on-security-of-gas-supply-2016

Annex - Modelling carbon reduction target and costing

For our Two Degrees and Community Renewables scenarios, 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.

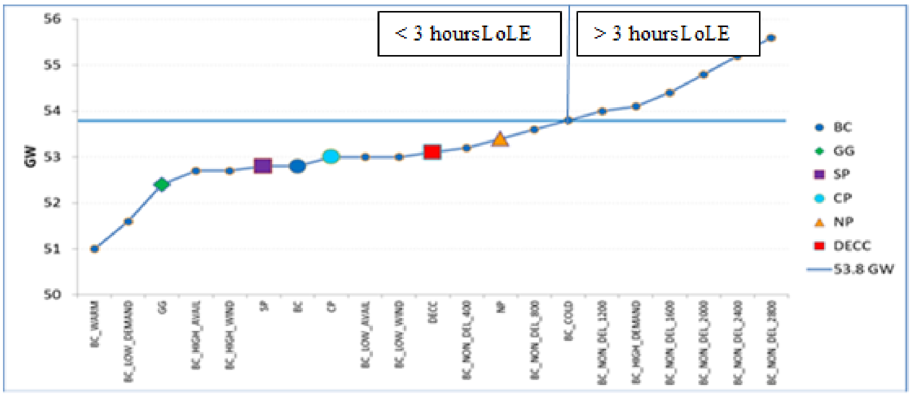
Using UKTM to cost the scenarios is just the first step to costing the whole energy system. The complexity of accounting for the whole system necessitates that analysis is undertaken using a variety of tools. UKTM by accounting for the cost of energy production and end consumer appliances provides the starting point. Further analysis is required on the possible network investments required for each scenario together with an understanding of the balancing requirements. This is the first year National Grid has undertaken to cost the scenarios and as of July 18, the work is still at an early stage and will be progressed during the summer and autumn 18.

Annex – Electricity security of Supply

The 2018 FES generation backgrounds have been developed to reflect the particular scenario assumptions, the latest market information and to target the GB Reliability Standard of 3 hours LOLE per year. In doing so the backgrounds reflect the latest market signals, the Capacity Market (CM) auction results and thereafter the capacity calculated to meet the Reliability Standard.

Although the Reliability Standard is set at 3 hours LOLE the recommended capacity to procure in the CM auctions is not based on one scenario of the future but addresses the inherent uncertainty by considering a range of alternative scenarios of the future.

This can best be illustrated by the following chart of the alternative scenarios and sensitivities considered for the 2017/18 Early Auction (EA) (x-axis) and the level of capacity required to meet the Reliability Standard (y-axis). It shows the four FES 2016 scenarios, Base Case, BEIS scenario and the sensitivities around the Base Case.



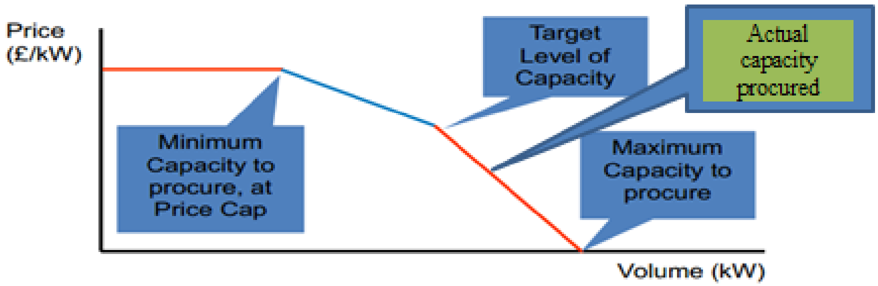
Source: 2016 Electricity Capacity Report – 17/18 EA (National Grid)

The process for determining the capacity to procure is known as Least Worst Regret (LWR) and is a cost optimisation of the potential outcomes to ensure the consumer receives the best value for money. It does this by assuming costs consistent with the Reliability Standard (~£49/kW for capacity and £17,000/MWh for loss of load) and then calculates for all combinations the least worst cost if a scenario or sensitivity is assumed and another one occurs.

As the cost associated with LOLE is a non-linear function then it will almost certainly recommend a higher capacity than the Base Case, as for the EA above, which shows the cost optimised results (solid blue line) being higher than the Base Case (dark blue dot). This is because LOLE increases exponentially as margins become tighter whereas capacity costs increase linearly i.e. 1 GW will always cost £49/kW while LOLE per GW of capacity will increase as margins tighten and will cost more even though the unit cost is unchanged at £17,000/MWh.

This therefore means that the CM auction will target a capacity higher than the Base Case requirement resulting in a higher capacity being procured and therefore higher margin and lower LOLE than 3 hours for the Base Case. This can be illustrated in the above chart where all the scenarios and sensitivities (including the Base Case) below the target capacity will have less than 3 hours LOLE and for all the scenarios and sensitivities above the target capacity will have more than 3 hours LOLE. This confirms why the later years (beyond the auctions) in the FES scenarios tend to be between 1-2 hours LOLE for all scenarios, as they have capacity requirements lower than the target capacity i.e. to the left of the vertical blue line.

In addition to the target capacity being higher than the Base Case requirement to meet 3 hours LOLE the actual capacity procured in the auction can be different. This is due to the sloping nature of the Demand Curve (see below) that allows procurement up to ±1.5 GW either side of the targeted capacity depending on whether the auction clears at a price below or above the capacity cost assumed (£49/kW). So far all auctions (EA and 18/19, 19/20 & 20/21 T-4) have cleared at a low price and have therefore resulted in more capacity than targeted being procured. This increases the capacity and further reduces the LOLE for the Base Case in the early years although adjustments made to the T-1 auction target capacity should limit this increase.



Source: EMR Delivery Body Portal – Demand Curve (National Grid)

The previous two explanations cover the theoretical implementation of the Reliability Standard and the auction delivering additional capacity over the medium term. There is also another more practical reason which relates to what the market outside the CM has delivered e.g. unsuccessful plants in the auction deciding to stay open and thus increasing the margin over the short term and further reducing the LOLE.

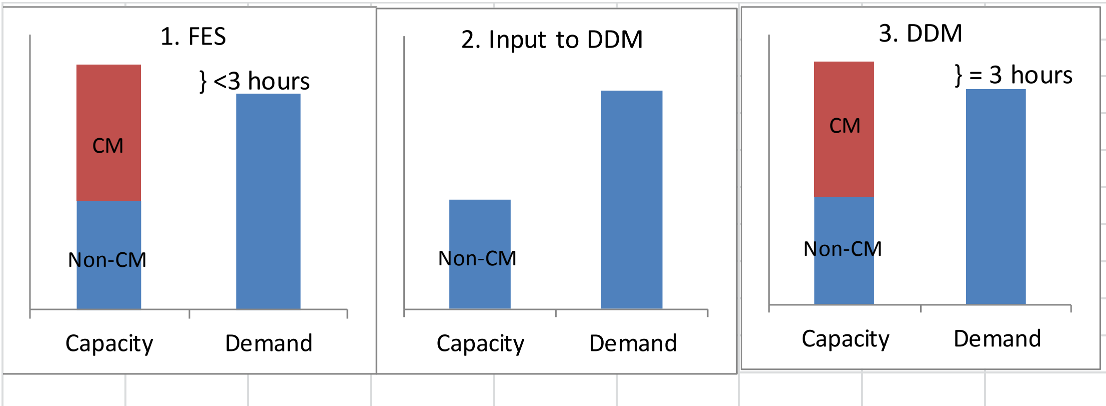
The final element is a technical and/or timing one around wind EFC (Equivalent Firm Capacity) and the storage EFC (this is a new step introduced this year to reflect changes to the duration limited storage treatment in the capacity market), both of which in the FES scenarios are based on a proxy from the previous year's probabilistic modelling which can lead to an over / under estimate of EFC (when margins are higher / lower when compared to the previous year) which isn't updated until the following year as the probabilistic modelling is undertaken after the deterministic FES modelling is completed.

In conclusion the FES generation backgrounds will all target initially what the market has delivered post CM auctions resulting in the first 1 to 4 years a LOLE closer to 1 hour; however, thereafter LOLE is closer to 2 hours to reflect the agreed methodology for calculating the target capacity for the CM auctions. The only way the FES scenarios could target 3 hours is if the uncertainty in the future becomes significantly less and the range of the scenarios and sensitivities becomes very narrow resulting in the LWR target capacity being close the Base Case; however, this doesn't appear a realistic assumption for the near term horizon at least.

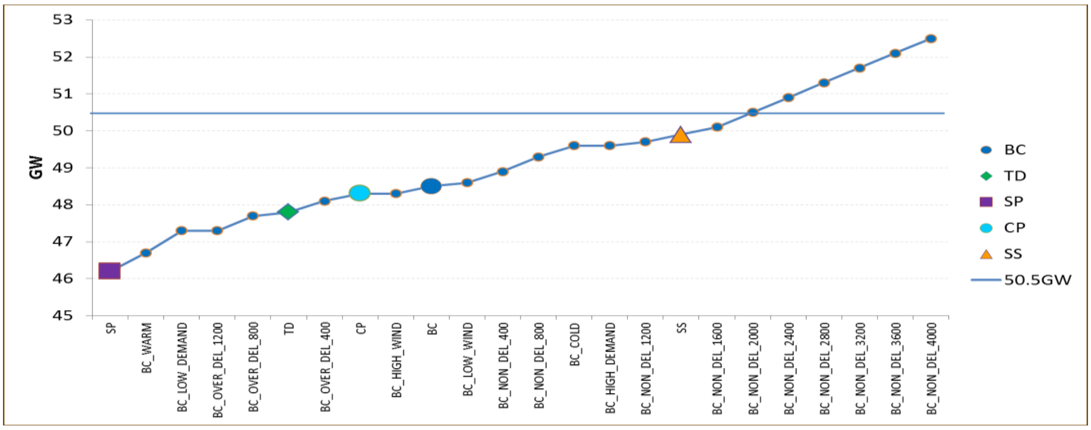
Annex – LOLE step by step guide

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)[40] 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)
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.

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

Annex – List of interconnector projects considered in our scenarios

This annex lists all of the potential interconnector projects that we have considered in our scenarios. Projects in this list may appear in all of 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.

Project name	Connecting country
ANAI	Spain
Aquind	France
BritIB	Spain
Britned	Netherlands
Channel Cable	France
East-West Interconnector	Ireland
ElecLink	France
Eurolink	Netherlands
FAB Link	France
Gallant	Ireland
Greenconnect	Ireland
Greenlink	Ireland
GridLink	France
IFA	France
IFA2	France
Maali	Norway
Moyle	Ireland
Nautilus	Belgium
Nemo Link	Belgium
NeuConnect	Germany
NorthConnect	Norway
North Sea Link (NSL)	Norway
Viking Link	Denmark

Annex – Electricity Demand Creation

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[41] and the FES data tables
    - Out-turn "National Demand" data is published on our website[42]
- 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 2018, we add our estimate of pure demand side response (not demand response from generation, as that would double count non-transmission generation) This is a change from previous FES editions. 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

National Grid does 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 data[43] 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 are created using forecasts and assumptions from other FES models e.g.
- Industrial & Commercial
- Residential appliances and air conditioning
- Heat and district heat
- Road and rail transport
- Hydrogen production
- Annual and peak smart meter efficiency effect

Demand Components – Peak

[41] Electricity Ten Year Statement, Appendix E – Spatial Transmission Level Data
https://www.nationalgrid.com/uk/publications/electricity-ten-year-statement-etys

[42] National Grid Half Hourly Data (Data Explorer)
https://www.nationalgrid.com/uk/electricity/market-operations-and-data/data-explorer

[43] Energy Trends Electricity Statistics
https://www.gov.uk/government/collections/electricity-statistics

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 peak demands:

- 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

Future projections are created using forecasts and assumptions from other FES models.

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 – this will be reviewed in 2018
- 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

Annex – Fuel type and technology categorisation

Category	Fuel Type	Sub fuel type / Technology	Tx / Dx
Thermal	Coal	Coal	Tx
		Coal CHP	Dx
	Other Thermal	Diesel	Tx
		Diesel Reciprocating Engines	Dx
		GT_Gas_Oil	Tx
		Fuel Oil	Dx
	Gas	(micro) Gas CHP	Dx
		(micro) mCHP	Dx
		CCGT	Dx
		CCGT_Exist	Tx
		CCGT_New	Tx
		CHP_Gas	Tx
		Gas CHP	Dx
		Gas Reciprocating Engines	Dx
		GT_Gas	Tx
		OCGT	Dx
		OCGT_Existing	Tx
		OCGT_New	Tx
		Onsite Generation	Dx
Interconnector	Interconnector	Interconnector_Existing	Tx
		Interconnector_New	Tx
Low Carbon	CCS	CCS_Biomass	Tx
		CCS_Coal	Tx
		CCS_Gas	Tx
	Nuclear	Nuclear_ABWR	Tx
		Nuclear_AGR	Tx
		Nuclear_EPR	Tx
		Nuclear_PWR	Tx
		Nuclear_SMR	Tx
Renewable	Other RES	(micro) Anaerobic Digestion	Dx
		(micro) Biogas CHP	Dx
		Advanced Conversion Technology (ACT)	Dx
		Advanced Conversion Technology (ACT) CHP	Dx
		Anaerobic Digestion	Dx
		Anaerobic Digestion CHP	Dx
		Biofuel	Dx
		Biofuel CHP	Dx
		Geothermal	Tx
		Geothermal CHP	Dx
		Landfill Gas	Dx
		Sewage	Dx
		Sewage CHP	Dx
	Biomass	(micro) Biomass CHP	Dx
		Biomass	Tx
		Biomass - Co Firing	Dx
		Biomass - Dedicated	Dx
		Biomass CHP	Dx

Renewable	**Biomass**	Biomass Conversion	Tx
		CHP_Biomass	Tx
	Hydro	(micro) Hydro	Dx
		Hydro	Dx
		Hydro	Tx
	Marine	Tidal	Dx
		Tidal_Array	Tx
		Tidal_Lagoon	Tx
		Wave	Dx
	Solar	(micro) Solar	Dx
		Solar	Dx
		Solar	Tx
	Waste	CHP_Waste	Tx
		Waste	Dx
		Waste	Tx
		Waste CHP	Dx
	Offshore Wind	Offshore_Wind	Tx
		Offshore_Wind 1	Tx
		Offshore_Wind 2	Tx
		Offshore_Wind 2.5	Tx
		Offshore_Wind 3	Tx
		Offshore_Wind STW	Tx
		Wind Offshore	Dx
	Onshore Wind	Onshore Wind	Tx
		Wind Onshore	Dx
		(micro) Wind	Dx
Storage	**Storage**	(micro) Battery Storage	Dx
		(micro) Fuel Cells	Dx
		Battery Storage	Dx
		Battery Storage	Tx
		Compressed Air	Dx
		Compressed Air Storage	Tx
		Liquid Air	Dx
		Liquid Air Storage	Tx
		Pumped Hydro	Dx
		Pumped_Storage	Tx
	V2G	V2G	Dx

Version

Version number	Date of update	Description of update
1.0	13/07/2017	First upload for FES 2017 launch on 13th July 2017
2.0	12/07/2018	First upload for FES 2018 launch in July 2018

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