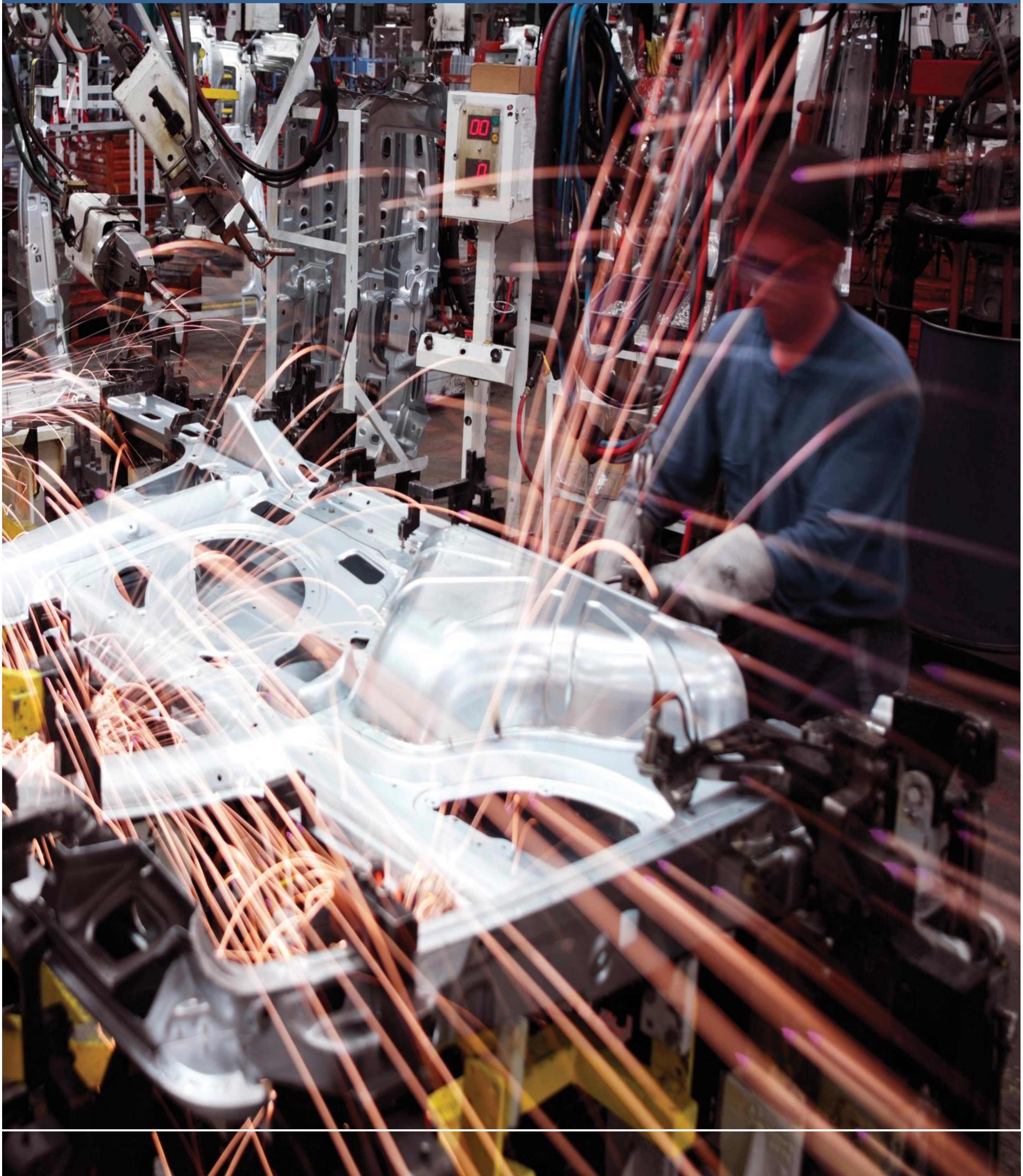
National Grid EMR Electricity Capacity Report

31 May 2018 (submitted to BEIS)

Report with results from work undertaken by National Grid for BEIS in order to support the development of Capacity Market volume to secure.



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Contact

Any enquiries regarding this publication should be sent to National Grid at emrmodelling@nationalgrid.com.

National Grid EMR
Electricity Capacity Report

1. Executive Summary

This Electricity Capacity Report (ECR) summarises the modelling analysis undertaken by National Grid in its role as the Electricity Market Reform (EMR) Delivery Body to support the decision by the Government on the amount of capacity to secure through the Capacity Market auctions for delivery in 2019/20 and 2022/23.

The Government requires National Grid to provide it with a recommendation for each year studied based on the analysis of a number of scenarios and sensitivities that will ensure its policy objectives are achieved.

National Grid has also considered the recommendations included in the Panel of Technical Experts (PTE[1]) report[2] on the 2017 process and adjusted and improved this year's analysis appropriately to try to address their feedback. In addition, there has been a series of workshops with BEIS, PTE and Office of Gas and Electricity Markets (Ofgem) to enable them to scrutinise the modelling approach and assumptions utilised.

Chapter 2 of this report describes the modelling approach including the tools used and enhancements made for this year's analysis. Chapter 3 covers the scenarios and sensitivities modelled. Chapter 4 details the de-rating factors for generating technologies, storage, DSR and interconnected countries. Chapter 5 contains results from the scenarios modelled and the recommended capacity to secure for the 2022/23 T-4 auction. Chapter 6 contains results from the scenarios modelled and the recommended capacity to secure for the 2019/20 T-1 auction. Finally the Annex contains links to or details on demand and generation methodology / assumptions, the modelling approach, matrix of development projects, station availabilities, ineligible capacity, Reserve for Response, storage assumptions, least worst regret approach and the quality assurance process.

1.1 Results and Recommendations

National Grid has modelled a range of capacity options based around meeting the Reliability Standard in different combinations of credible scenarios and sensitivities. The assumption is that the Future Energy Scenarios (FES) and the Base Case will cover uncertainty by incorporating ranges for annual and peak demand, Demand Side Response (DSR), storage, interconnection capacity and generation with the sensitivities covering uncertainty in non-delivery, station peak availabilities, weather, wind levels and peak demand forecast range (based on the Peak National Demand Forecasting Accuracy (DFA) Incentive[3]). Our analysis assumes continued market harmonisation between the UK and Europe once the UK has left the European Union, for example, the UK continues to participate in the Internal Energy Market or similar future arrangements are developed.

[1] https://www.gov.uk/government/groups/electricity-market-reform-panel-of-technical-experts
[2] https://www.gov.uk/government/publications/electricity-market-reform-panel-of-technical-experts-2017-final-report-on-national-grids-electricity-capacity-report-2017
[3] See Special Condition 4L at https://epr.ofgem.gov.uk/Content/Documents/National%20Grid%20Electricity%20Transmission%20Plc%20-%20Special%20Conditions%20-%20Current%20Version.pdf

Scenarios & Base Case

- Base Case (5 year forecast to 2022/23, then Steady Progression from 2023/24 onwards)
- FES Community Renewables (CR)
- FES Two Degrees (TD)
- FES Steady Progression (SP)
- FES Consumer Evolution (CE)

To provide the reference case, which is being used to apply sensitivities, a Base Case has been utilised. For the DFA incentive years up to 2022/23, this consists of a forecast of demand and a generation background which aligns with our DFA Incentive and aims to reduce the likelihood of over or under securing of the capacity, thereby minimising the associated costs to consumers.

Each of the sensitivities is considered credible and is evidence based i.e. it has occurred in recent history or is to address statistical uncertainty caused by the small sample sizes used for some of the input variables. Section 3.10 describes each sensitivity and how it has been implemented.

The decision on the target capacity to secure is made by a cost optimised Least Worst Regret (LWR) methodology. As per previous ECR analysis, it uses a cost of capacity of £49/kW/year net CONE (Cost of New Entry) and an energy unserved cost of £17,000/MWh to select a scenario/sensitivity combination from which the recommended capacity to secure is derived. Note that the Government's Reliability Standard[4] was derived using a slightly different capacity cost of £47/kW/year based on the gross CONE of an Open Cycle Gas Turbine (OCGT).

1.1.1 2022/23 T-4 Auction Recommendation

Results

The outcome of the LWR calculation applied to all of National Grid's scenarios and sensitivities is a recommended capacity to secure for 2022/23 of **46.7 GW** derived from the requirement of the Base Case Cold Winter sensitivity. Our recommended target capacity to secure corresponds to the value on the CM demand curve for the net CONE capacity cost. The clearing price in the auction may be different to net CONE, resulting in the cleared capacity being different to the target capacity. The recommendation excludes any capacity secured in earlier auctions for 2022/23; that is accounted for in the Base Case.

In general, when compared to the analysis for 2021/22 in the 2017 ECR, the 2018 ECR recommendation for 2022/23 is 3.8 GW lower. This difference is the result of changes that fall into two categories; the first category being changes that affect the total de-rated capacity requirement and the second category being changes that affect the split of that total de-rated capacity between eligible and ineligible capacity.

For 2022/23, there is a 1.6 GW net reduction in the total de-rated capacity requirement. In addition to that 1.6 GW lower total, there is a further reduction of 2.2 GW in the eligible capacity required due to a corresponding net increase in the level

[4] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/267613/Annex_C_-_reliability_standard_methodology.pdf

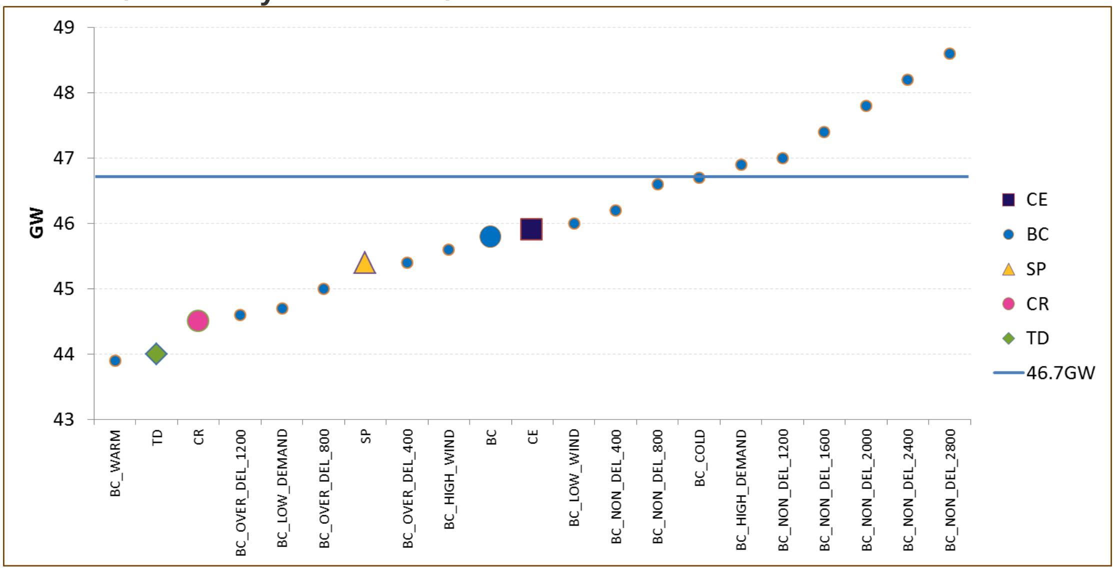
of assumed CM-ineligible de-rated capacity. Chapter 5 contains further details on the changes in each category.

The following waterfall chart, Figure 1, shows how the original 50.5 GW requirement for the 2021/22 T-4 auction (derived from the 2017 Base Case 2000 MW non-delivery sensitivity) has changed into a recommended requirement of 46.7 GW (derived from the 2018 Base Case Cold Winter sensitivity) as a result of the net decrease described above.

Figure 1: Comparison with recommended 2021/22 T-4 requirement in 2017 ECR

Figure 2 illustrates the full range of potential capacity levels (from the scenarios and sensitivities) and identifies the Least Worst Regret recommended capacity.

Figure 2: Least Worst Regret capacities to secure compared to individual scenario/sensitivity runs – 2022/23



Recommendation

The recommended target capacity in this report will not necessarily be the capacity auctioned - this will be a decision for the Secretary of State, included in the Final Auction Guidelines published after prequalification. To obtain the National Grid recommended capacity auction requirement, a number of adjustments to the total recommended figure may be required which are detailed in Chapter 5.

Therefore, the recommended total capacity to secure through the 2022/23 T-4 auction will be:

- 46.7 GW minus any adjustments.

1.1.2 2019/20 T-1 Recommendation

Results

The outcome of the Least Worst Regret calculation applied to all of National Grid's scenarios and sensitivities is a recommended capacity to secure for 2019/20 of **4.6 GW** derived from the requirement of the Base Case 800 MW non delivery sensitivity (see Chapter 6 for further details). Our recommended target capacity to secure corresponds to the value on the CM demand curve for the net CONE capacity cost. The clearing price in the auction may be different to net CONE, resulting in the cleared capacity being different to the target capacity. The recommendation also excludes any capacity secured for 2019/20 in earlier T-4 auctions; that is accounted for in the Base Case.

In general, when compared to the analysis for 2019/20 in the 2015 ECR that ultimately led to the 2.5 GW set aside by the Secretary of State for the T-1 auction, the 2018 ECR recommendation for 2019/20 is 2.1 GW higher than the 2.5 GW set aside. This difference is the result of changes that fall into two categories; the first category being changes that affect the total additional de-rated capacity required since the T-4 auction and the second category being changes relating to ineligible capacity assumptions.

There is a 4.1 GW net increase in total additional de-rated capacity requirement since the T-4 auction. This 4.1 GW net increase in additional capacity requirement is partly offset by a 2 GW reduction in eligible capacity required due to a corresponding increase in assumed ineligible capacity. Chapter 6 contains further details on the changes in each category.

Figure 3 shows how the original 2.5 GW set aside for the 2019/20 T-1 auction (derived from the 2015 Consumer Power High Availability sensitivity) has changed into a recommended requirement of 4.6 GW (derived from the 2018 Base Case 800 MW non-delivery sensitivity) as a result of the net increase described above.

Figure 3: Comparison with original 2019/20 T-1 requirement (de-rated)

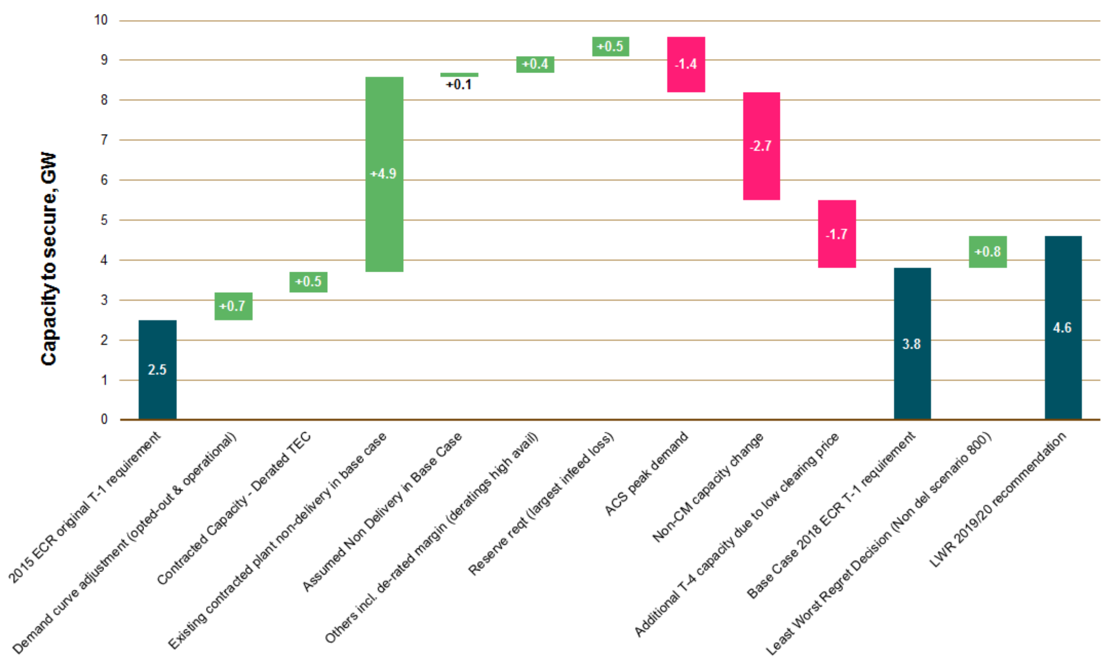
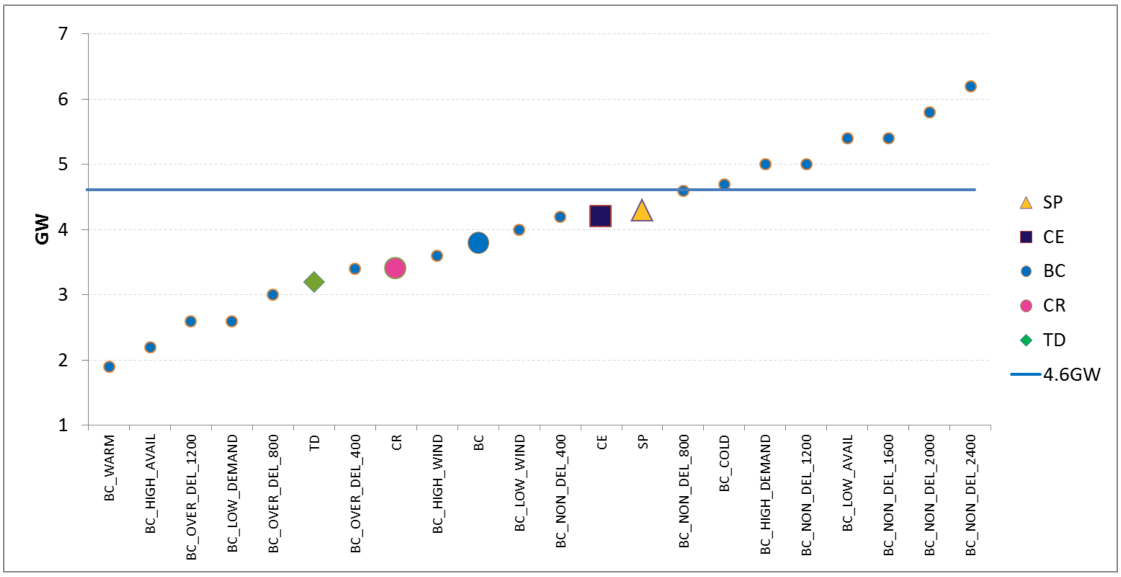


Figure 4 illustrates the full range of potential capacity levels (from the scenarios and sensitivities) and identifies the Least Worst Regret recommended capacity.

Figure 4: Least Worst Regret capacities to secure compared to individual scenario/sensitivity runs – 2019/20



Recommendation

The recommended capacity in this report will not necessarily be the capacity auctioned - this will be a decision for the Secretary of State, included in the Final Auction Guidelines published after prequalification. To obtain the auction capacity requirement, a number of adjustments to the recommended figure may be required which are detailed in Chapter 6.

Therefore, the recommended total capacity to secure through the 2019/20 T-1 auction will be:

- 4.6 GW minus any adjustments.

1.2 Interconnected Countries De-rating factor Ranges

Table 1 shows the historical and modelled country ranges to inform the choice of de-rating factors for the 2019/20 T-1 auction and the 2022/23 T-4 auction for all existing and potential interconnected countries.

These modelled ranges are based around the modelling we have done using BID3, our pan-European market model but also show Pöyry's analysis on historical performance.

This year the modelled ranges are based on the full set of simulation runs including two stress tests. These stress tests increase demand to narrow the margin. This is to adjust for detailed issues not included in the modelling such as random variation in demand and generation and local network issues, such as constraints within countries. In general the modelled ranges for 2019/20 were higher than the historical de-rating factors. Tightening margins across Europe due to closures and mothballing of thermal generation means that, for 2022/23, Belgium and Netherlands have model ranges much lower than the historical de-rating factors.

The modelled ranges do not include an allowance for the impact of interconnector import constraints in GB on the assumption that this is more appropriately allowed for in the adjustments made to individual interconnector de-rating factors along with technical availability.

Table 1: Modelled country ranges

Country	Delivery Year	Historical	Low	High
Ireland	2019/20	5	35	54
	2022/23		24	42
France	2019/20	55	61	92
	2022/23		59	86
Belgium	2019/20	67	65	78
	2022/23		35	67
Netherlands	2022/23	70	27	62
Norway	2022/23	96	90	100

There are no modelled ranges shown for Netherlands for 2019/20 T-1 auction because the Netherlands interconnector was awarded a Capacity Market contract in the T-4 auction and is therefore ineligible for the T-1 auction.

1.3 National Grid Analysis Delivery Timeline 2018

The process and modelling analysis has been undertaken by National Grid with ongoing discussions with BEIS, Ofgem and BEIS's PTE during the development, modelling and result phases.

The work was carried out between September 2017 and May 2018 and builds on the analysis that was undertaken for the previous ECRs. In addition to the analysis around the recommended capacity to secure, the report also presents analysis on the de-rating factors for interconnected countries and conventional plants for use in the auctions.

The following timeline illustrates the key milestones over the different modelling phases of the work to the publication of the ECR:

- Development plan produced in September 2017
- Development projects phase October 2017 to February 2018
- Production plan developed in February 2018
- Modelling analysis March to May 2018
- National Grid's ECR sent to BEIS before 1st June 2018
- Publication of ECR in line with BEIS publishing auction parameters in early July 2018

2. The Modelling Approach

The modelling analysis has been undertaken by National Grid with ongoing discussions with BEIS, Ofgem and BEIS's PTE throughout the whole process.

2.1 High Level Approach

The modelling approach is guided by the policy backdrop, in particular the objectives set by Government regarding security of supply. The modelling looks to address the following specific question:

What is the volume of capacity to secure that will be required to meet the security of supply reliability standard of 3 hours Loss of Load Expectation (LOLE)[5]?

In order to answer this question, it was agreed, following consultation with BEIS and their PTE, that the Dynamic Dispatch Model (DDM)[6] was an appropriate modelling tool. This maintains consistency with the energy market modelling work undertaken by BEIS. The DDM has the functionality to model the Capacity Market and it should also be noted that, when compared to National Grid's capacity assessment model, as utilised for the Winter Outlook, the DDM has been shown to produce the same results, given the same inputs.

The inputs to the model are in the form of scenarios based on the Future Energy Scenarios (FES)[7], and sensitivities around a Base Case which cover a credible and broad range of possible futures. See Chapter 3 for details of the scenarios and sensitivities used in the modelling.

The scenarios are comprised of assumptions around:

- Peak demand – This is unrestricted i.e. no Demand Side Response or Triad avoidance has been subtracted
- Generation capacity – Both transmission connected and distributed (within the distribution networks)
- Interconnector assumptions – Capacity assumptions (note that flows at peak are modelled directly within DDM)

Sensitivities are then created around the Base Case to ensure consistency with National Grid's Peak National Demand Forecasting Accuracy (DFA) Incentive[8].

The modelling process, as shown in Figure 5, determines a capacity to secure and provides a view of capacity which is expected to be delivered outside of the Capacity Market. Each of the scenarios and sensitivities produces a capacity to secure for those given circumstances and these are considered together to produce a recommended capacity to secure in the Capacity Auctions for 2019/20 and 2022/23. Links to the detail describing this process can be found in Annex A.5.

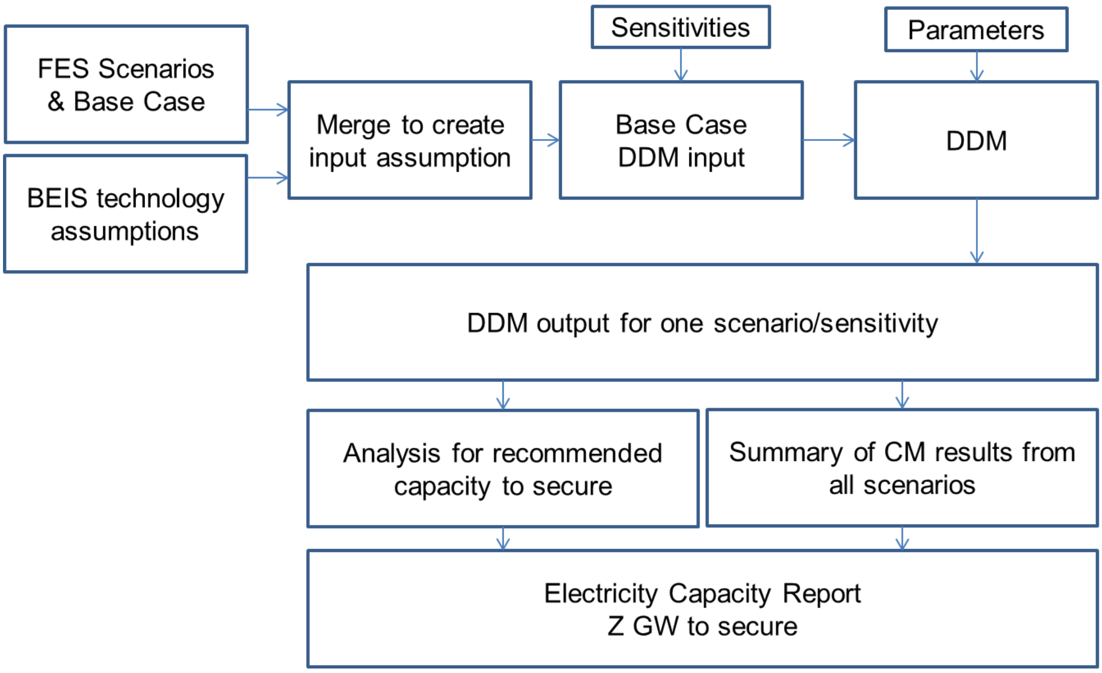
[5] LOLE is the expected number of hours when demand is higher than available generation during the year but before any mitigating / emergency actions are taken but after all system warnings and System Operator (SO) balancing contracts have been exhausted.

[6] DDM Release 5.1.23.3 was used for this analysis

[7] http://fes.nationalgrid.com/

[8] See Special Condition 4L at https://epr.ofgem.gov.uk/Content/Documents/National%20Grid%20Electricity%20Transmission%20Plc%20-%20Special%20Conditions%20-%20Current%20Version.pdf

Figure 5: Process flow chart of approach to calculate target capacity to secure from individual scenario/sensitivity runs



2.2 DDM Outputs Used in the ECR

For the purpose of the ECR, the key outputs utilised from the DDM for each year modelled from 2019/20 to 2032/33 are the aggregate capacity values, specifically:

A. Total de-rated capacity required to hit 3 hours LOLE
B. De-rated capacity to secure in the Capacity Market auction
C. De-rated non-eligible capacity expected to be delivered outside the Capacity Market auction
D. Total nameplate capacity split by CM and non-CM eligible technologies.
E. De-rated capacity already contracted for, from previous auctions (part of C)

Note that A = B + C. Further details on the modelling and aggregate capacities can be found in Annex A.5.

In addition to the aggregate capacity values, for the purpose of calculating the recommended capacity to secure in 2019/20 and 2022/23, the Least Worst Regret tool also utilises the expected energy unserved (EEU) and LOLE values for potential de-rated capacity levels in both years (see Chapters 5 & 6 for more details).

No other outputs from the DDM are utilised directly in the ECR.

2.3 Stakeholder Engagement

National Grid has a well-established and extensive consultation process which is followed on an annual basis to create the Future Energy Scenarios (FES). The process incorporates a summer seminar, webinars, workshops and bilateral meetings with our stakeholders to ensure we are receiving up to date information and feedback for our scenarios. The content of the FES is driven by stakeholder feedback; this results in a range of holistic, credible and plausible scenarios. We publish the outputs of our consultation process each year in the FES Stakeholder Feedback document[9] in line with our licence condition. The document, published annually in February, shows how stakeholder feedback influences the framework, scenario format and the content of the model inputs that underpin the scenarios. This document contains details of topic specific feedback that we have received from stakeholders and how we have taken this forward.

National Grid strives to improve the FES consultation process each year by enhancing engagement activities and finding better ways to record and analyse stakeholder feedback. National Grid also engages with stakeholders to explain its role in relation to EMR through the CM Implementation workshops and at meetings with trade organisations and individual companies as part of our ongoing consultation around the EMR work in general but, in particular, the de-rating factors we modelled for BEIS for use in the auctions e.g. short duration storage technologies.

2.4 High Level Assumptions

There are numerous assumptions which are required for the modelling process.

2.4.1 Demand and Generation

The starting point for the DDM input modelling assumptions was the set of assumptions used in the latest BEIS modelling e.g. assumptions behind generation levelised costs. However, the key inputs/assumptions are taken by aligning the modelling to the new 2018 FES scenarios and agreed sensitivities. The key assumptions are those that materially affect the capacity to secure, these are:

- Demand Forecasts
    - Peak demand
    - Annual demand forecasts
- Generation Capacity
    - Capacity eligible for the Capacity Market
    - Capacity outside the Capacity Market (including capacity secured via previous auctions)
    - Capacities of existing and new interconnectors

For a detailed breakdown of these key input assumptions see the Annex A.4.

2.4.2 Interconnector Assumptions

Interconnector potential flows are determined by probabilistic modelling in a similar way to generation technologies, i.e. based around a set of flow distributions obtained from our own pan-European electricity dispatch market modelling using BID3[10] (see 2.4.3.4 for further details).

In addition to this modelling work, National Grid will provide modelled ranges of de-rating factors to apply for each connected country participating in the CM auction. See Chapter 4 for more detail around this process and the modelled de-rating factors ranges for each country.

[9] http://fes.nationalgrid.com/media/1346/future-energy-scenarios-2018-stakeholder-feedback-document-published-feb-2018.pdf
[10] http://www.poyry.com/BID3

2.4.3 Station Availabilities

This analysis has been split into four groups: firstly for conventional generation, secondly intermittent generation, thirdly duration limited storage and then finally interconnectors.

2.4.3.1 Conventional generation

Conventional generation capacity is not assumed to be available to generate 100% of the time, due to break downs and maintenance cycles. In order to determine what availability to assume for each generation type, National Grid considers what has been delivered historically, based on the average on high demand days over the last seven winter periods[11]. This approach has been used by National Grid in its entire medium to long term modelling, as well as being used for the EMR Delivery Plan and Ofgem's Capacity Assessment. This methodology is described in detail in the Capacity Market Rules 2.3.5.

National Grid has used the above approach to determine station availabilities for the last few years. While informal consultations on the approach have been conducted through discussions at industry forums and bilateral meetings it is important that all stakeholders have an opportunity to engage in this process. This will help National Grid understand any concerns that stakeholders may have regarding this approach and help to inform any future changes to the methodology. Therefore, National Grid continues to welcome comments and questions on this approach either through email (emrmodelling@nationalgrid.com), industry forums or bilateral meetings.

2.4.3.2 Wind generation

Intermittent renewable plants run whenever they are able to, and so the availability of the fuel source is the most significant factor. When considering these plants, National Grid looks to their expected contribution to security of supply over the entire winter period. For wind, this is achieved by considering a history of wind speeds observed across GB, feeding in to technology power curves, and running a number of simulations to determine its expected contribution. This concept is referred to as Equivalent Firm Capacity (EFC). In effect, it is the level of 100% reliable (firm) plant that could replace the entire wind fleet and contribute the same to security of supply.

The wind EFC depends on many factors that affect the distribution of available wind generation. These include the amount of wind capacity installed on the system, where it is located around the country and the amount of wind generation that might be expected at periods of high demand. It also depends on how tight the overall system is, i.e. as the system gets tighter, the wind EFC increases for the same level of installed capacity as there are more periods when wind generation is needed to meet demand rather than displacing other types of generation in the merit order. It should be noted that the EFC is not an assumption of wind output at peak times and consequently should not be considered as such. For the Base Case wind EFC values calculated by the DDM, please refer to Table 37 of this document.

[11] Specifically these periods are 0700-1900 Monday-Friday, December-February (inclusive) on days with a peak demand greater than the 50th percentile (90th percentile for CCGTs) of demand for that winter

2.4.3.3 Duration limited storage

The market for battery storage is growing fast with many having won Enhanced Frequency Response (EFR) or Firm Frequency Response (FFR) ancillary service contracts and CM contracts for 2020/21, 2018/19 and 2021/22 auctions. During the second half of 2017 (in line with the first part of recommendation 28 in the 2017 PTE report), we undertook an extensive industry consultation on a proposed methodology for calculating appropriate de-rating factors for duration limited storage. The details of this method which utilises an Equivalent Firm Capacity approach and the resulting de-rating factors for the T-1 (2018/19) and T-4 (2021/22) auctions can be found in our final report[12]. This method has been re-run for this year's analysis utilising updated assumptions (see Annex A.6 for details) on the level of storage capacity and duration of that capacity as contained in the Base Case.

2.4.3.4 Interconnectors

In the DDM we have modelled the contribution of interconnectors to GB at peak times in each scenario and delivery year by using a probabilistic distribution, defining the probability of each import / export level for a given level of net system margin. These distributions were derived from our own pan–European market modelling (see Chapter 4). The DDM calculated an EFC for interconnection which was used as an estimate of the aggregate interconnector de-rated capacity. Note that the modelled de-rating factor for interconnection has no impact on the total de-rated capacity (including interconnection), required to meet the Reliability Standard. In the auction, interconnection capacity will compete with other types of new/existing eligible capacity to meet the capacity requirement.

2.4.3.5 Impact of availability assumptions

Given that the recommended capacity to secure is a de-rated value, the assumptions around availability of both conventional and renewable capacity have limited impact on the recommendation. Broadly the same level of de-rated capacity is required to hit the 3 hours LOLE target; however, the name-plate capacity required to achieve that level of de-rated capacity will be slightly different.

2.5 Development projects

The development project phase of the ECR was planned between October 2017 and the end of February 2018 and during this period a series of projects to potentially enhance the modelling process were undertaken. As part of this process we worked closely with BEIS and Ofgem to determine which projects to prioritise and then worked collaboratively and with consultants to deliver against the plan.

2.5.1 Process for selecting which development projects to progress

A key element of this process are the recommendations from BEIS's PTE who identify a number areas of research to be progressed which when combined with National Grid, BEIS and Ofgem's ideas produce a long list of potential projects, far more than can be undertaken (see Annex A.3). Consequently, a method of prioritisation is required to determine which projects go ahead.

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[12] https://www.emrdeliverybody.com/Lists/Latest%20News/Attachments/150/Duration%20Limited%20Storage%20De-Rating%20Factor%20Assessment%20-%20Final.pdf

This is achieved by agreeing criteria around impact, effort and priority and then National Grid, BEIS and Ofgem score each project independently which enables the projects to be ranked. This ranked list is then matched to a high level resource plan to determine how many of the projects can be considered. Project scopes are then developed to flesh out the detail of how and what will be delivered and then matched again against the resource plan to develop a detailed development project plan with delivery timelines identified and agreed.

Clearly flexibility has to be incorporated in the process to deal with unforeseen issues. This is done by agreeing a change control process that allows for new projects to be considered and, if important enough, replace one of the existing planned projects to ensure delivery can still be met with the resources available. This change control process was implemented a couple of times during the development phase.

2.5.2 Key projects undertaken

In their 2017 report[13], the PTE made 10 new recommendations numbered 26 to 35, each of which was considered as a potential development project alongside others for prioritisation. The Annex A.3 (Table 26) contains a list of all the development projects considered and which ones were progressed and why based on their relative scores. Out of the 10 PTE recommendations, those numbered 27, 29, 31 and 33 had high enough scores to be progressed, one of which will be carried out in the summer / autumn when data becomes available. In addition, the first part of recommendation 28 was addressed in summer 2017 (see section 2.4.3.3).

This year's key development projects related to:

Non-delivery analysis

This development project was carried out in response to recommendation 31 in the 2017 PTE report and explored an approach to assessing the risks associated with non-delivery of capacity that has CM agreements but does not deliver that capacity in the target year(s). It also looked at over-delivery of CM-eligible capacity that stays open without a CM agreement in the target year(s). The outputs were used to inform the range of non-delivery and over-delivery sensitivities used in the 2018 ECR. We used the DDM investment decision functionality to estimate the non-delivery and over-delivery risk and potential market response from different conventional technology sources. The analysis used an updated 2017 ECR Base Case and focused on the 2021/22 T-4 auction (one of the target years analysed in the 2017 ECR) and was largely carried out before the result of that auction was known. For other technologies (e.g. unproven DSR and interconnection), alternative sources of data were examined.

We investigated a number of alternative scenarios that met the 2021/22 requirement through different combinations of new / existing generation and interconnection. For each potential contracted capacity mix, the DDM identified capacity at risk of non-delivery [estimated to lose money in some / all of years up to 2021/22] and capacity that may stay open and be profitable without a CM contract (over-delivery). For each scenario, we carried out multiple DDM runs to remove / close capacity at risk in increments up to a maximum amount and add uncontracted capacity in increments up to a maximum to see the impact on the profitability of the remaining capacity.

[13] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/625885/PTE_Report_2017.pdf

The DDM runs provided an estimated range of non-delivery and over-delivery and market response for conventional technologies. The modelled coal and gas non-delivery (and over-delivery) varied across the sets of runs and were not independent – when one went up the other reduced resulting in similar levels of non-delivery. The key drivers for potential non-delivery in both gas and coal plants was the same (profitability) which was influenced by factors such as whether they had CM contracts and whether their running hours were restricted due to environmental regulations. We therefore recommended that the potential values for coal and gas were combined into a single figure for thermal non-delivery and over-delivery which was agreed with BEIS and the PTE in March 2018. Note that the drivers for non-delivery in other technologies such as unproven DSR (e.g. difficulty for aggregators in signing up sites) or new distributed generation (e.g. embedded benefits reform / financing / emissions legislation) were different and hence the non-delivery range for other technologies were kept separate to coal and gas.

We also looked at the CM registers for previous auctions to estimate a range for unproven DSR and reviewed work carried out in 2017 to investigate the impact of embedded benefits reform to provide insight into small scale technologies. For interconnection, a range of de-rating factors was used to estimate a range of non-delivery and over-delivery. The ranges and market response for all technologies were then combined using a Root Sum of Squares (RSS) approach to estimate the maximum levels of non-delivery and over-delivery used in the 2018 ECR as described in Sections 3.10.10 and 3.10.11. Note that, as agreed with BEIS and the PTE in March 2018, the range of market response (by thermal plant) was kept separate to the range of non-delivery or over-delivery in the RSS calculation. Further detail on Additive versus RSS approach can be obtained from Annex A.6

Calculation method for combining Non-delivery sensitivities

This development project was carried out in response to comments in the 2017 PTE report (linked to their recommendation 31)[14] and to inform the range of non-delivery and over-delivery sensitivities to be utilised in the 2018 ECR. Previously when considering the range of potential non/over-delivery and any potential market response we simply added the component parts together. The PTE asked us to consider a more “scientific” approach along the lines of Root Sum of Squares (RSS). Consequently, we undertook a project comparing the impact of the two alternative approaches against a range of combinations of potential categories of non or over-delivery. However, careful consideration was needed when analysing the level of independence or not between the various components to ensure the RSS approach was appropriately applied.

The components were split as follows; coal/gas, embedded benefits, unproven DSR, interconnectors, small scale eligible plant operating outside the CM and any market response [from coal/gas/other] with each component being quantified based on analysis of non/over-delivery (described in the previous development project above), embedded benefits impact on new and existing plant, unproven DSR based on failed meter tests from the TA and EA auctions, interconnectors based around the range of de-rating factors used in previous auctions and analysis of small scale generation currently operating outside the CM. The project concluded that while not perfect, as all the components were not necessarily independent, the RSS approach gave the most robust answer which was endorsed by the PTE (see Annex A.6 for more details).

[14] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/625885/PTE_Report_2017.pdf

The impact of this decision was to both narrow the range of potential non-delivery for this year's analysis and to reduce the size of the maximum non-delivery sensitivity by 1.2 GW for T-4 and 0.4 GW for T-1 when compared to last year's analysis, resulting in a lower target capacity, particularly for the T-4 recommendation (see 3.10.10). This narrowed range was discussed and agreed with BEIS and the PTE in March 2018.

European scenarios

An important development project for this year's interconnector analysis was the development of a set of European scenarios. These scenarios were developed to help us model uncertainty in Europe better and support greater consistency in modelling assumptions that may drive interconnector flows. In previous analysis, we have modelled each of the GB scenarios with a single view of Europe. This year, we have developed European scenarios to extend our assumptions for GB to the continent. This means that if we have a scenario with more renewable generation in GB, then we will have a scenario with more renewable generation in Europe. Scenarios were developed for Belgium, France, Germany, Ireland, the Netherlands, Denmark and Norway based on ones already developed by their respective Transmission System Operators and/or ENTSO-E's Ten Year Network Development Plan. The scenarios for the European countries were aligned to the closest FES 2018 scenarios to extend our assumptions to Europe. Further details of the scenario assumptions, including our sources, will be published in the FES 2018 Modelling Methods document.

Review of historical demand data

This project had two main aims. Firstly, the Capacity Market targets supply to meet all end-consumer or "underlying" demand on the system, and not just that seen at transmission level by the Electricity System Operator (ESO). However, due to lack of access to time series of embedded generation production and demand response activation data in the past, we have been limited to using a transmission demand time series (when appropriately scaled to the relevant underlying Average Cold Spell (ACS) peak demand) to model the historical variations in GB demand over a statistically relevant time period to calculate LOLE etc. This project aimed to create a true historical underlying demand time series if embedded generation and demand response historical data could be made available to us by relevant industry partners. However, delays and other industry structural hurdles prevented us from getting access to this data in time for the 2018 ECR modelling analysis phase, hence we need to wait until next year in order to take account of this data.

Second, a standardised methodology for calculating the Average Cold Spell (ACS) outturn peak demand was introduced in recent years by our ESO colleagues in Commercial Operations Electricity. This allows peak demands from historical years to be directly comparable to each other, and also to be better compared to the process used for forecasting peak demand in future. In the ECR analysis, we use the ratio of the forecasted peak demand to the past outturn peak demands to scale the 12 years of time series of historical demands described in the paragraph above when determining the demand time series input for the LOLE reliability calculation in the relevant T-1 and T-4 target years. This aspect of the development project applied the new standardised methodology to update our historical peak demand outturn estimates to put them on a consistent basis. As it turned out, the new methodology only created a small change in the historical demand values, and the impact on LOLE estimation and capacity to secure was relatively small. Nevertheless, we will use the demands based on the standardised ACS peak demand outturn methodology from now on in our models.

Modelling individual interconnectors

This analysis looked at whether the BID3 model could provide de-rating factors for individual interconnectors instead of countries to answer PTE recommendation 33: "There is a case to estimate interconnector derating factors for individual interconnectors rather than countries". BID3 requires demand, generation and interconnector data for every geographic area modelled. This is not readily available for much of Europe. Although it is theoretically possible to configure BID3 at any geographic split the time required and difficulty of obtaining accurate data and setting up the model combined with increased run times means that at present country level is the most appropriate geographic split.

DSR data availability

This project looked at the availability of DSR data in order to pursue the demand response element of PTE recommendation 29. There is very little DSR data available. The best source of DSR contracts is the CM registers. However, the details of DSR contracts are currently very sparse with DSR providers still unknown in most contracts. National Grid has been actively pursuing access to half-hourly embedded generation and demand data from Electralink (PTE recommendation 27). Once this becomes available one use would be to enable better modelling of DSR.

2.5.3 Projects to be developed over the summer

There was one development project that was not possible to progress due to a combination of shortage of available resource and the required functionality not being present in current models. Consequently it was deferred until the summer. It relates to the calculation of appropriate de-rating factors for renewable technologies potentially entering the Capacity Market.

The two main technologies to be considered are wind and solar which, similarly to the calculation of de-rating factors for limited duration storage, will be based on an incremental Equivalent Firm Capacity approach and will be endorsed by the PTE prior to any production runs. This will require the development of the Unserved Energy Model (UEM) code within the DDM.

Another development project for which progress was not possible before the 2018 ECR modelling analysis phase due to delays in obtaining approval for the release of the data related to recommendation 27 in the 2017 PTE report (improving data and providing access to the best available data on embedded generation). We hope to make progress on this project before the 2019 ECR by obtaining site level data from Electralink (the company that manages half-hourly data for DNOs in England & Wales via its Data Transfer Service). Note that a CM rule change will be required to allow us to utilise this data for calculating de-rating factors for CM eligible small scale generation technologies.

2.6 Modelling Enhancements since Last Report

Section 2.5 describes a number of development projects carried out in response to BEIS, Ofgem and National Grid's ideas along with the recommendations from the PTE. These developments have not led to any material changes to DDM functionality so any enhancements utilised for the 2018 ECR have related to updating data streams and good housekeeping. However, to support the summer project on potential renewable technologies participation in the CM, a development of the Unserved Energy Model (UEM) code within the DDM will be required which will be commissioned in July.

2.7 Quality Assurance

When undertaking any analysis, National Grid looks to ensure that a robust Quality Assurance (QA) process has been implemented. National Grid has previously worked closely with BEIS's Modelling Integrity team to ensure that the QA process closely aligned to BEIS's in house QA process.

The QA checks below are focussed on the points in the process where data is transferred from one model, or system, to another, together with the model outputs. These are:

1. **Interconnector flows** – Check the interconnector flow distribution
2. **Scenario inputs** – Check the model input assumptions
3. **Parameter Inputs / CM Results/ Historic Demand inc. distributed wind** – Check the model setup assumptions
4. **Scenarios to DDM Translation** – Check the input from the FES process into the DDM model
5. **DDM Outputs** - Check model outputs are consistent with inputs and scenario criteria
6. **Capacity to Secure Process** – Check the inputs and outputs used to determine a range and recommended capacity to secure

The PTE carries out a sense check on the modelling input assumptions, reviews the results and reports on the overall process. Internally the process has governance under Director UK System Operation. National Grid has also worked closely with LCP[15] to check and verify the results obtained as part this analysis to reinforce the robustness of the QA process. For details of the QA undertaken by National Grid see the Annex A.8.

[15] Lane, Clark and Peacock LLP – see http://www.lcp.uk.com/

3. Scenarios & Sensitivities

3.1 Overview

National Grid has a well-established and extensive consultation process on issues related to demand, generation and security of energy supply. This involves a continuous stakeholder consultation process with industry workshops, a summer seminar and bilateral meetings. As part of this process, a range of documents are published that are used as catalysts for feedback, they are:

- Future Energy Scenarios Stakeholder Engagement | National Grid
- Future Energy Scenarios | National Grid[16]
- Electricity Ten Year Statement | National Grid
- Gas Ten Year Statement | National Grid

This process results in the development of the Future Energy Scenarios (FES), derived using the latest information available on sources of supply and demand for both electricity and gas. The latest market intelligence is used to create the scenarios; for example, including the Transmission Entry Capacity (TEC) changes announced in March 2018, which are indications to National Grid that power plants have decided to reduce or increase the power that they will supply to the market.

There have been changes to FES 2018 taking account of the engagement feedback and our own analysis. We will have four scenarios structured in a 2x2 matrix against axes of speed of decarbonisation and level of decentralisation (see Figure 6 below).

The **speed of decarbonisation** axis combines policy, economics and consumer attitudes. All scenarios show progress towards decarbonisation from today, with the scenarios on the right of the matrix meeting the 2050 target.

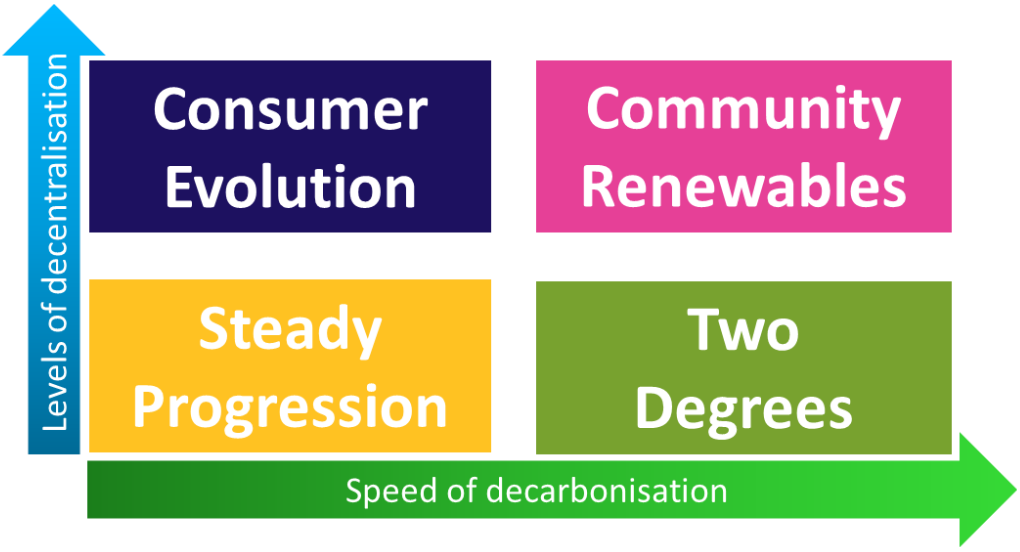
The **level of decentralisation** axis indicates whereabouts on the energy system solutions are physically located, moving up the axis from large scale central to smaller scale local solutions. All scenarios show an increase in decentralised energy compared with today.

This approach allows two of the scenarios to meet the 2050 target, but via different routes, addressing one of the key challenges we had encountered when using the previous matrix and reflecting stakeholder feedback.

Retaining four core scenarios and the 2x2 matrix retains some elements of the previous structure to aid comparison. As in previous years, security of supply for both gas and electricity will be achieved across all the scenarios.

[16] Note that the 2018 document will be published on 13th July 2018

Figure 6: Our scenarios for FES 2018



Given the wide range of applications that the scenarios are already used for, by both National Grid and the wider industry, the logical decision would be to use them for the Capacity Market analysis.

For the purposes of modelling scenarios for the Capacity Market, BEIS's DDM model has been used, as described in the Annex A.5. Thus while the non-Capacity Market technologies are fixed to the levels assumed in each of the FES scenarios, the DDM calculates CM qualified capacity to ensure that the 3 hours LOLE Reliability Standard is met. Hence the capacities shown in this analysis may diverge from those in the original FES scenarios, which reflect what has actually happened in the market post auctions, incorporating any potential for over delivery rather than the theoretical recommended target capacity.

Base Case

In addition to the four FES scenarios and to be compliant with our DFA Incentive, we have used a Base Case from which all the sensitivities will be run. This Base Case follows exactly the same principles using the same modelling approach as the FES scenarios to give a 5-year demand and generation background that is within the four FES scenarios range. Due to the inherent uncertainty across the market beyond 2022/23, the Base Case then follows the FES scenario that is closest to its DFA Incentive demand level in 2022/23 thereafter, which for the 2018 FES, is the Steady Progression scenario.

The Base Case takes account of capacity market units awarded contracts in the previous T-4 auctions that are now known not to be able to honour their contracts. It assumes that other capacity contracted in previous auctions is able to honour contracts over the next five years, with the exception of around 200 MW of new small scale distribution connected capacity by the end of the five-year period.

3.2 Scenario Descriptions

Detailed below are the four scenarios for 2018 using the broad themes of power demand, transport, heat and energy supply.

3.2.1 Community Renewables

For this scenario, we explore how the 2050 decarbonisation target can be achieved through a more decentralised energy landscape.

Power demand: With the drive towards decarbonisation, together with the high use of electric vehicles (EVs) and deployment of heat pumps, smart technology will be extensively used to manage peak electricity demand. Appliance efficiency will improve and we expect to see greater use of demand side response.

Transport: EVs will be the most popular personal vehicle and we explore home and destination charging for this scenario. For commercial vehicles, hydrogen is expected to become more prevalent as the fuel of choice to aid the decarbonisation target. Sharing of vehicles will also feature in this scenario.

Heat: Homes will become more thermally efficient as we drive towards decarbonisation, and the landscape for heat in this scenario will be predominantly heat pumps supplemented by green gas with increased use of district heating.

Power supply: In this decentralised and decarbonised landscape, there is a reliance on green generation. Onshore wind and solar, co-located with storage, will dominate and we will explore whether this pathway can achieve the 2050 target without Carbon Capture and Storage (CCS). Flexibility is provided by small scale storage, small gas fired plant and hydrogen production.

Gas supply: Gas from the UK Continental Shelf (UKCS), Norway and Liquefied Natural Gas (LNG) remains important in the short and medium term. However, in this scenario where we explore achieving the 2050 target without CCS, green gas, predominantly located at the distribution network level will be most prevalent. Hydrogen in this scenario will be produced via electrolysis.

Community Renewables is based on the Consumer Renewables sensitivity from FES 2017.

3.2.2 Two Degrees

This scenario explores how the decarbonisation target can be achieved in a less decentralised way.

Power demand: We expect that this scenario will be similar to Community Renewables with the drive towards decarbonisation, together with the push towards electrification of heat and transport. Smart technology will be extensively utilised alongside greater demand side response to manage peak electricity demand. Appliance efficiency will improve significantly.

Transport: EVs will be the personal vehicle of choice and we will consider the development of autonomous vehicles. We will explore the roll-out potential of rapid charging networks. For commercial vehicles, hydrogen is expected to become more prevalent as the fuel of choice to achieve the decarbonisation target. Sharing of vehicles and increased use of public transport will also feature in this scenario.

Heat: As with Community Renewables, homes will become more thermally efficient as we drive towards decarbonisation. However, the landscape for heat in this scenario will explore a mixture of gas boilers, hydrogen and heat pumps.

Power supply: In this more centralised and decarbonised landscape, there is also a reliance on green generation. Generation based more on the transmission network will dominate such as offshore wind and nuclear together with CCS to allow flexibility to be provided by large scale gas plants, large scale storage and interconnectors.

Gas supply: Gas from UKCS, Norway and LNG remains important in this scenario and we will explore the use of steam methane reforming to produce hydrogen. Some green gas will be available.

This scenario builds on Two Degrees from FES 2017.

3.2.3 Steady Progression

This scenario will show a centralised pathway that makes progress towards, but does not meet the 2050 decarbonisation target.

Power demand: With a slower drive to decarbonisation, there are limited improvements in efficiency, and little electrification of heat. However, there will be significant adoption of EVs so smart technology will be important for managing peak demand.

Transport: EVs and hydrogen fuel cell vehicles will dominate in this scenario. There will also be a role for natural gas powered vehicles, particularly in the commercial sector. EVs will be supported by a rapid charging network.

Heat: Gas boilers will still be the heat source of choice for most residential properties. We will see limited use of heat pumps and decarbonisation of the heating sector will be slow.

Power supply: In keeping with the centralised theme of this scenario, there is greater emphasis on large scale generating technology rather than local generation. We will expect to see development of nuclear power as well as offshore wind. Gas will play an important role in providing flexibility.

Gas supply: Gas will be provided from the UKCS, Norway and LNG, with additional supplies from shale gas.

This scenario combines elements from Steady State and Slow Progression from FES 2017.

3.2.4 Consumer Evolution

This is a more decentralised scenario which makes progress towards the decarbonisation target but fails to achieve the 80% reduction by 2050.

Power demand: We expect that in this scenario there will be a moderate roll-out of smart charging to accommodate the achievement of the 2040 transport target for no further petrol or diesel cars. There are some improvements in energy efficiency with homes, business and communities focused and incentivised towards local generation, notably roof top solar, and local energy management. Appliances will have some efficiency improvements to assist with peak electricity management.

Transport: Private ownership of personal vehicles remains popular with home and destination charging preferred in this scenario to support the uptake of EVs. The commercial vehicle sector makes some progress towards natural gas vehicles, but the internal combustion engine still dominates this sector.

Heat: It is expected that there will be limited progress made towards the difficult area of decarbonising heat within this scenario. There will be some progress in the roll-out of heat pumps and district heating, but the current heating technologies will still remain dominant.

Power supply: In this decentralised world, generation is focused on smaller scale renewable solutions, with small scale gas and batteries providing the majority of the system flexibility. No new nuclear power stations are built after the delayed construction of the contracted plant. More local markets lead to lower levels of electricity interconnection.

Gas supply: Gas from UKCS, Norway and LNG remains important in this scenario. However, we will explore the potential for shale gas within this scenario.

This scenario will build on a blend of Consumer Power and Slow Progression from FES 2017.

3.3 Demand Forecast until 2022/23

The Base Case utilises a demand forecast covering the five year period 2018/19 to 2022/23. It supports the DFA Incentive which is instrumental in recommending a capacity to secure. This forecast is based on current views of Oxford Economics baseline economic growth forecast, energy policy, consumer behaviour and the uptake of new technologies - such as electric vehicles and heat pumps. Figure 7 and Table 2 show the Base Case peak demand forecast together with the projections for the FES over the five year period. The chart also shows historic peak demands since 2012/13.

Figure 7: Peak Demand - FES Scenarios and Base Case to 2022/23

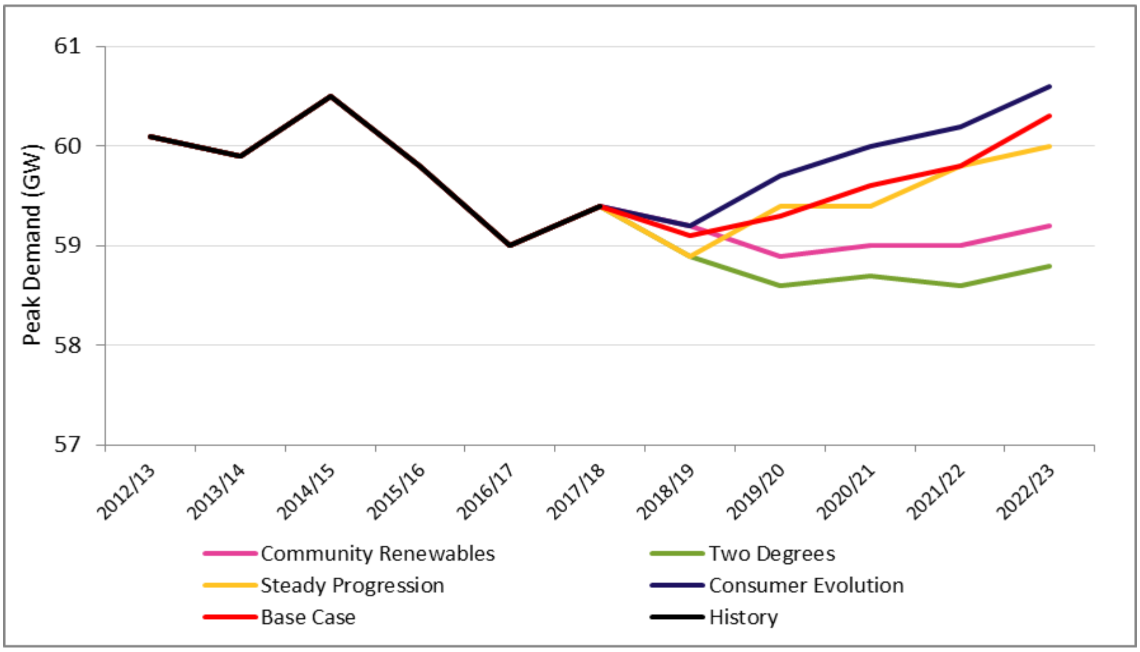


Table 2: Peak Demand to 2022/23

Peak Demand GW	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
Base Case	59.4	59.2	59.3	59.6	59.8	60.3
Community Renewables	59.4	59.2	58.9	59.0	59.0	59.2
Two Degrees	59.4	58.9	58.6	58.7	58.6	58.8
Steady Progression	59.4	58.9	59.4	59.4	59.8	60.0
Consumer Evolution	59.4	59.1	59.7	60.0	60.2	60.6

Community Renewables and Two Degrees have the lowest peak demands, as high energy efficiency (required for decarbonisation) offsets high GDP growth and higher demands from electric transport and heat. Steady Progression and Community Evolution have higher peak demands, due to less energy efficiency, despite low GDP growth and slower uptake of electric transport and heat. The scenarios differ from one another due to assumptions on fuel usage in the industrial & commercial sectors and to a lesser extent, electric transport uptake.

3.4 Demand Forecast 2023/24 onwards

Each of the FES scenarios has its own annual demand projection; these are based on the underlying scenario narrative and together reflect a range of credible demand scenarios.

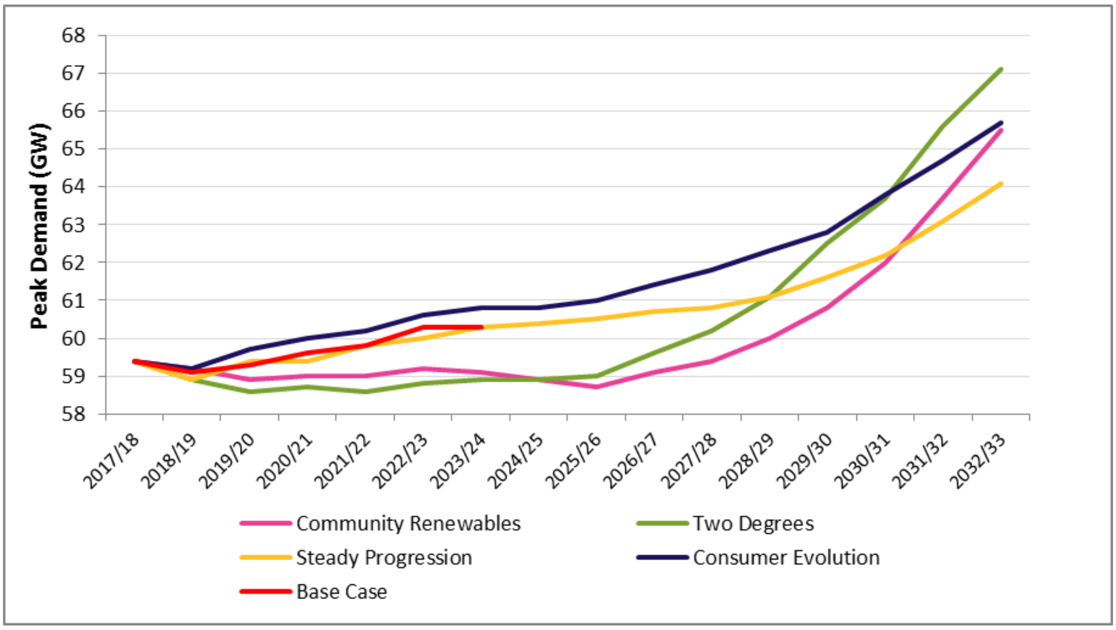
The definition of peak demand used in the modelling is Unrestricted GB National Demand[17] plus demand supplied by distributed generation. Reserve required to cover for the single largest infeed loss is not included in the demand definition but is included in the modelling.

[17] National demand is defined in the Grid Code “Glossary and Definitions” https://www.nationalgrid.com/uk/electricity/codes/grid-code?code-documents

Demand is based on the Average Cold Spell[18] (ACS) peak demand and is consistently applied within the sensitivities based on the Base Case. The only adjustments to ACS peak demand are within the high and low demand sensitivities. All forms of DSR greater than 2 MW are eligible for the Capacity Market. This can include DSR through the use of an aggregation service (including DSR <2 MW). Note that this includes DSR at times of Triad charging periods. Therefore unrestricted peak demand is modelled i.e. no DSR or Triad avoidance has been subtracted.

See the Annex A.1 for details on the demand assumptions used in the FES scenarios and Section 3.8 for more details on DSR. Figure 8 shows the peak demands used in the DDM modelling to 2032/33.

Figure 8: Peak Demand - FES and Base Case to 2032/33



3.5 Generation Capacity until 2022/23

Our generation capacity forecast from 2018/19 to 2022/23 is based on the latest market intelligence and an economic assessment, providing a potential view of the generation background over the next five years.

The Base Case sits within the uncertainty envelope provided by the FES 2018 Future Energy Scenarios as shown in Figure 9. Transmission nameplate capacities are shown in Table 3.

[18] The Average Cold Spell (ACS) peak demand is the demand level resulting from a particular combination of weather elements that give rise to a level of peak demand within a financial year (1 April to 31 March) that has a 50% chance of being exceeded as a result of weather variations alone. The Annual ACS Conditions are defined in the Grid Code.

Figure 9: FES 2018 Transmission connected nameplate capacity to 2022/23

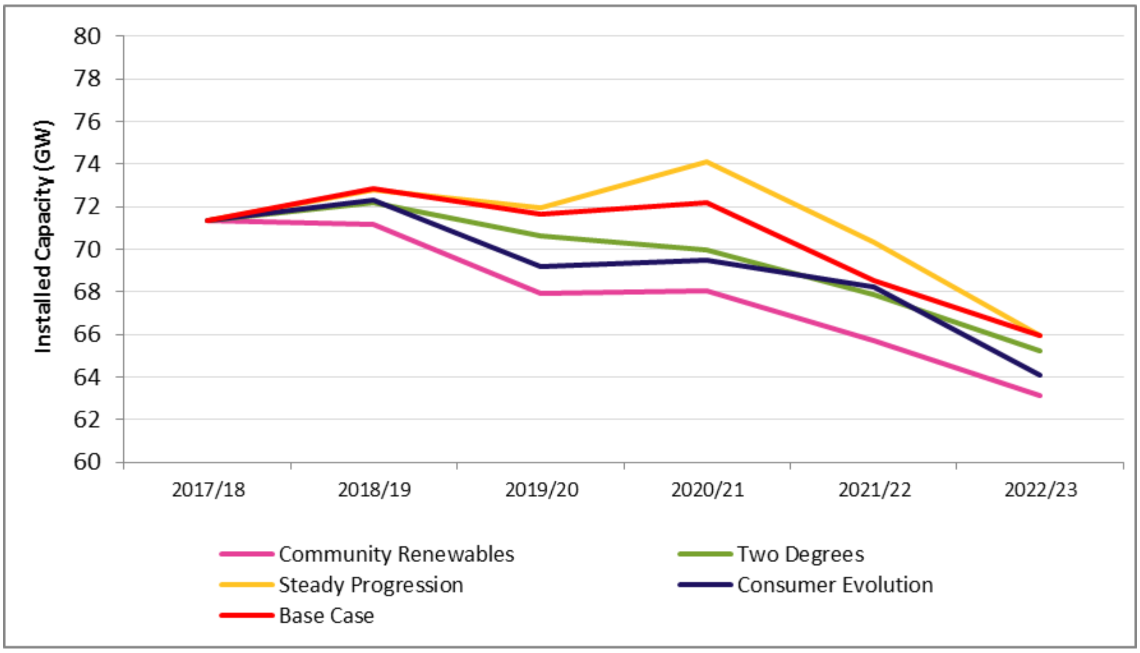


Table 3: Transmission connected nameplate capacity (GW) to 2022/23

Capacity GW	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
Base Case	71.3	72.9	71.7	72.2	68.5	66.0
Community Renewables	71.3	71.2	68.0	68.1	65.7	63.1
Two Degrees	71.3	72.2	70.6	70.0	67.9	65.2
Steady Progression	71.3	72.8	72.0	74.1	70.4	66.0
Consumer Evolution	71.3	72.3	69.2	69.5	68.2	64.1

3.6 Generation Capacity 2023/24 onwards

Each of the FES scenarios has a generation background that is based on the underlying scenario assumptions. These generation backgrounds include varying amounts of renewable / low carbon capacity, and differing volumes of Capacity Market eligible plant.

Capacity Market eligibility

Any generation capacity which is currently receiving, or will receive, support under the following initiatives is not eligible for the Capacity Market:

- Contracts for Difference (CfD)
- Final Investment Decision Enabling Regime (FIDeR)
- Feed in Tariffs (FiT)
- Renewables Obligation (RO) now closed to new applications, but some capacity will continue to receive support.

However, once a plant stops receiving support under these schemes, it will become eligible for the Capacity Market.

In addition, any generation capacity that is under a total capacity of 2 MW is assumed not to be eligible for the Capacity Market in this modelling – although any plant under 2 MW not receiving support from the above schemes can enter the auction if combined with other capacity by an aggregator. This latter group is estimated to range from 1.0 GW to 1.2 GW in the period to 2022/23 depending on the FES scenario and year and includes some onsite autogeneration above 2 MW assumed to opt out of the Capacity Market. Note that small scale renewable technologies are assumed to receive FiT support and therefore are excluded from this range.

Lastly, any capacity that is receiving a Capacity Market Agreement for longer than one year will not be eligible for successive auctions until its existing CM Agreement(s) end.

Assumptions

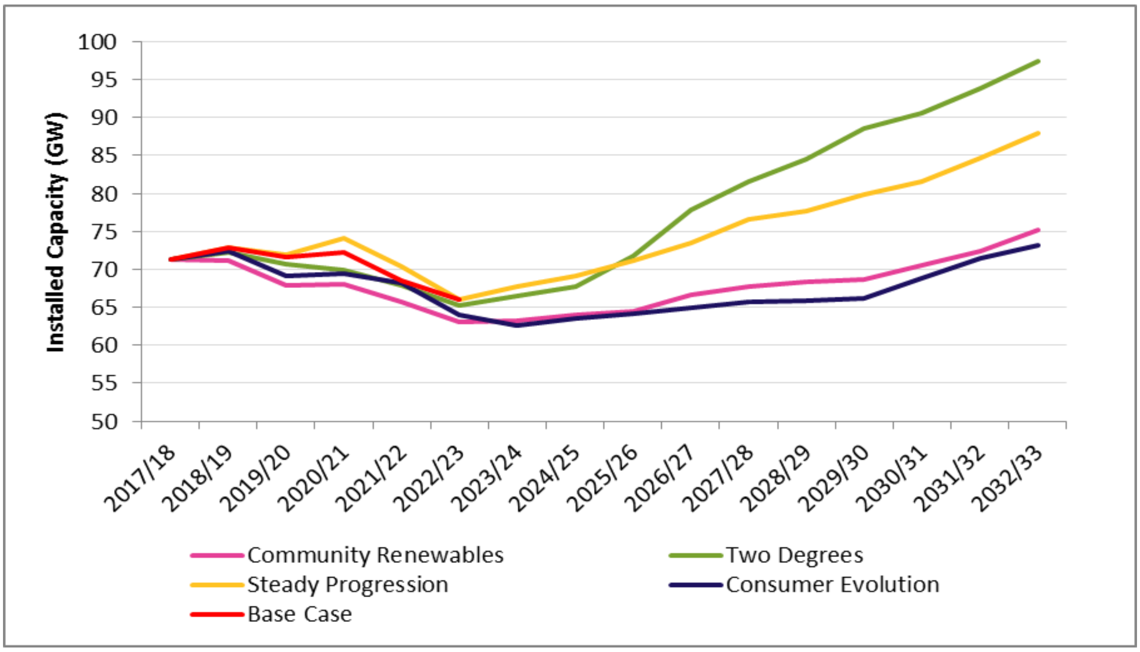
Barring these exceptions based on size and support mechanism, all other forms of generation capacity are eligible for the Capacity Market. For the purposes of our modelling, we assume that:

- All eligible capacity will enter the Capacity Market and
- No capacity will opt-out and remain operational

However, the recommended capacity to secure will be adjusted for known opted out plant following the pre-qualification process.

The focus of the modelling is to estimate the total eligible de-rated capacity that needs to be secured in order to achieve a reliability standard of 3 hours LOLE or lower. The final mix of generation technologies that make up this total capacity will be decided by the capacity auction and is not predetermined as a result of the modelling. A breakdown of installed capacity for each FES scenario is shown in Figure 10.

Figure 10 : FES 2018 transmission connected nameplate capacity to 2032/33



For a breakdown of generation between CM and non-CM see Annex A.4. A detailed breakdown will be available when the 2018 FES document is published on 12 July 2018

3.7 Distributed Generation

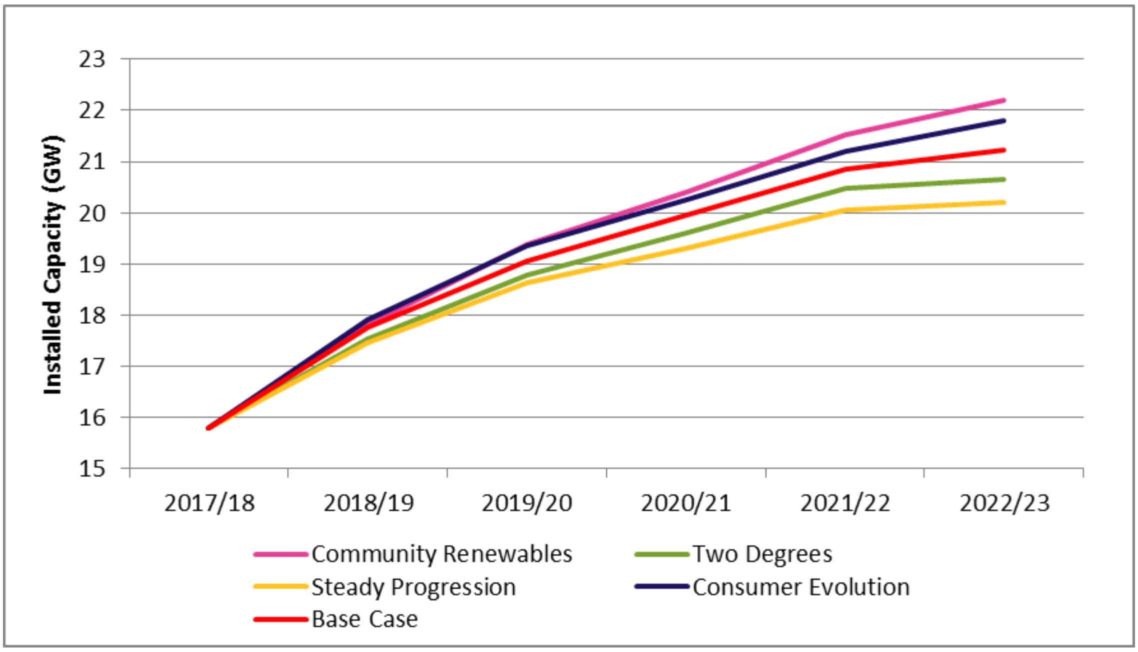
The scenario projections for distributed generation (generation which is connected to the lower voltage distribution networks) considers what plant is currently operating, and what plant may close and open in the future.

The scenarios consider 30 different existing technologies, as well as considering new types of generation that may connect in the future. The contribution of each of these technologies to peak demand is also taken into account – so for example, solar is excluded from these projections, due to the assumption that it is unable to contribute to peak demand which currently takes place in the hours of darkness.

A variety of data sources[19] are used to develop a list of projects for existing generation above 1 MW in size. We are continually seeking to improve the data available, as well as our analysis, in order to have an improved picture of how distributed generation operates over the year. This will help us to improve our understanding of how small scale plant contributes to demand across the seasons.

The ECR uses overall underlying demand (See Section 3.4). For other purposes, demand on the transmission network can be calculated using the output from distributed resources netted off overall demand. Figure 11 and Table 4 show nameplate capacities (excluding solar) for distributed generation out to 2022/23. Figure 12 extends the capacities out to 2032/33.

Figure 11: Distributed generation nameplate capacity (excl. solar) to 2022/23

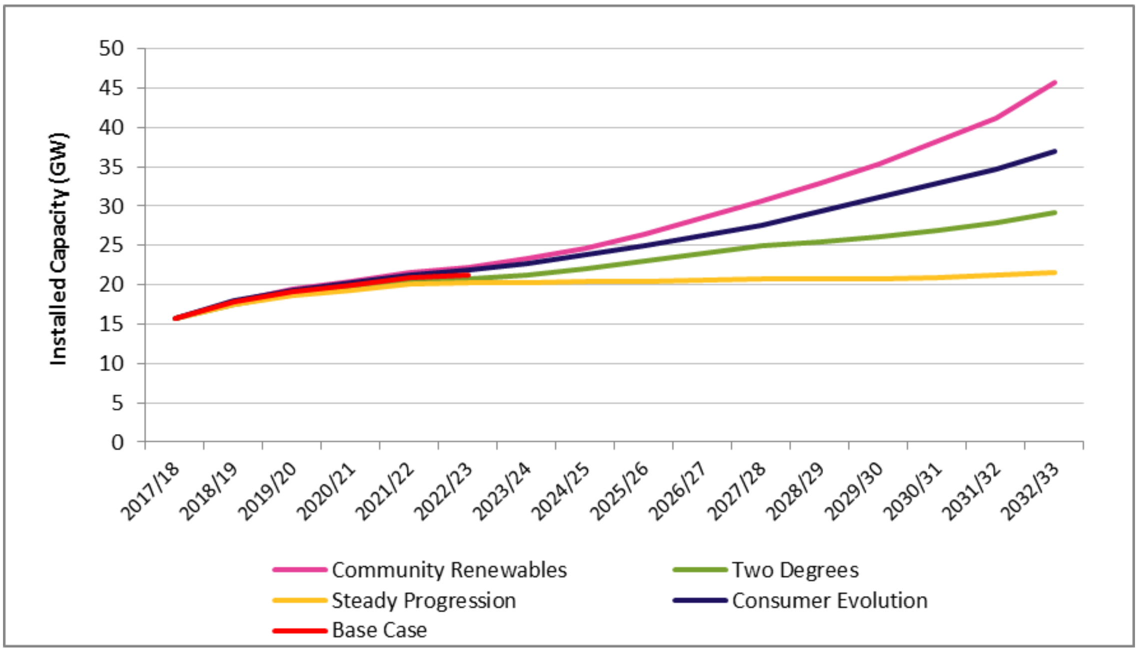


[19] For example Renewable Energy Planning Database, CM register, DNO long term development statement and others

Table 4: Distributed generation nameplate capacity (excluding solar) (GW)[20]

Capacity GW	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
Base Case	15.8	17.8	19.1	19.9	20.8	21.2
Community Renewables	15.8	17.8	19.4	20.4	21.5	22.2
Two Degrees	15.8	17.5	18.8	19.6	20.5	20.7
Steady Progression	15.8	17.5	18.6	19.3	20.1	20.2
Consumer Evolution	15.8	17.9	19.4	20.3	21.2	21.8

Figure 12: Distributed Generation (excluding Solar) to 2032/33 (GW)



3.8 Demand Side Response

In the FES, DSR has been defined as a deliberate change to an end user's natural pattern of metered electricity consumption brought about by a signal from another party. That is, demand shifting or demand reduction and not the use of generators to substitute the supply source. So, for instance, Triad avoidance is made up of both demand reduction (we estimate about 50%) and switching to an alternative supply source (which is included in the distribution connected generation technologies). Within our definition of DSR we consider only the demand reduction element.

Domestic Peak Response

We believe there are three other factors which must work in tandem to give the most flexibility at the lowest cost to consumers. These are:

Smart Meters: These only have a short-lived behavioural impact by themselves. Their impact is enhanced where they are supported by appropriate marketing and education around energy use. We see this happening more in the greener

[20] Includes capacity <1 MW

scenarios. Only in Two Degrees and Community Renewables do we see the government's roll-out plan being delivered on time.
Smart Technology: These are appliances that have two-way communication capability and interact with the consumer and other parties; for instance Hive or Nest. As the technology improves, service providers such as aggregators have a greater role to play.
Smart Pricing: The appropriate use of time of use tariffs (TOUTs). TOUTs incentivise consumers to move those energy demanding activities, which can be moved, to off peak times. The more engaged consumers, energy suppliers and government are, the greater the effects of TOUTs.

Industrial and Commercial DSR

In FES, we define DSR as the turning up or down or turning off or on of electricity consumption in response to external signals. In our scenarios, we are modelling end use demand. Therefore if a consumer chooses not to reduce their demand but instead switches to an alternative energy source, such as an onsite diesel generator or batteries, then we do not regard this as DSR.

Figure 13 shows the industrial and commercial DSR for the scenarios to 2033, with Table 5 showing the next 4 years of projection together with spot years 2027/28 and 2032/33. There is little change in the overall DSR for the next few years but post 2020 some barriers, such as the complexity of the market place, ease off allowing for a divergence in the scenarios' pathways.

For the next ten to fifteen years, in all the scenarios, there is a growth and development in the enabling systems, such information communications technology, which permit DSR to evolve. Thereafter, this growth tails off and so dampens the initial rate of increase.

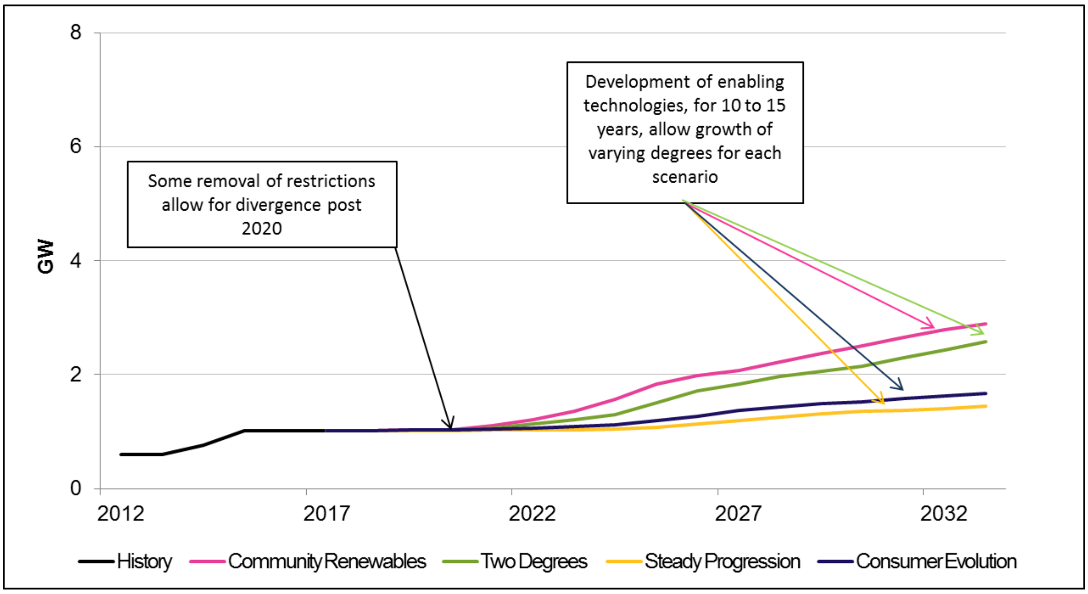
The most significant differentiator between the DSR take up is decarbonisation. More DSR products enter the market place in the scenarios with more renewable generation, Consumer Renewables and Two Degrees. These products are used by businesses as income generators, for supplying balancing services, or as cost saving by reducing their exposure to more expensive charges.

In the scenarios with lower decarbonisation, there are fewer drivers of DSR and subsequently there are fewer DSR products in the market place. The more ambitious scenarios have sharp growth during the 2020s (as shown in the two extra years in Table 5) but initial take-off is slow: The range of industrial and commercial DSR over the four FES scenarios in 2022/23 is from 1.0 GW to 1.2 GW.

Table 5: Industrial and Commercial DSR (GW)

GW reductions (I&C)	2019/20	2020/21	2021/22	2022/23	2027/28	2032/33
Community Renewables	1.0	1.1	1.2	1.2	2.2	2.9
Two Degrees	1.0	1.1	1.1	1.2	2.0	2.6
Steady Progression	1.0	1.0	1.0	1.0	1.2	1.4
Consumer Evolution	1.0	1.0	1.0	1.1	1.4	1.7

Figure 13: Industrial and Commercial DSR to 2033



Power Responsive

Power Responsive is a stakeholder-led programme which National Grid is facilitating. The purpose is to facilitate growth of participation of flexible technologies, including demand side response and storage, in GB energy markets. It involves all stakeholders in the value chain, including the customers from the flexible technologies.

Since the programme launched in summer 2015, there has been a substantial momentum growth across the industry in the desire to facilitate the growth of participation of flexible technologies in energy markets. Around 1500 individuals have signed up to be informed on the programme so far and informative materials on opportunities to participate have been published, including a "comprehensive guide to DSR" for energy managers in collaboration with the Major Energy Users Council. There are also regular open forum working groups which are run quarterly for both DSR and storage sectors.

3.9 Interconnector Capacity Assumptions

We derived our interconnector capacity assumptions from an analysis of individual projects. We have anonymised the data by showing only the total capacity per year, due to commercial sensitivities. Our analysis assumes continued market harmonisation between the UK and Europe once the UK has left the European Union, for example, the UK continues to participate in the Internal Energy Market or similar future arrangements are developed.

We identified potential projects and their expected commissioning dates to connect to GB. This information was derived from a range of sources including National Grid's interconnector register, the electricity European Network of Transmission System Operators (ENTSO-e) Ten-Year Network Development Plan, 4C Offshore and the European Commission. Where only a commissioning year was given, we assumed the date to be 1 October of that year. We assessed each project individually against political, economic, social and technological factors to determine which interconnector projects would be built under each scenario. If it did not meet the minimum criteria, we assumed it will not be delivered in the given scenario, or that it will be subject to a commissioning delay. We calculated this delay using a generic accelerated high-voltage direct current (HVDC) project timeline. All projects which have reached final investment decision are delivered, though they may be subject to delays in some scenarios. In addition, all projects are assumed to be available in any year that they have already secured a capacity market agreement in all scenarios.

In all scenarios, we assumed that the supply chain has enough capacity to deliver all interconnector projects. For the Base Case, we have selected the Steady Progression scenario.

Table 6 depicts the import capacity levels of interconnection for each scenario. Interconnector capacity is assumed to be higher in scenarios that meet decarbonisation on time. Furthermore, interconnector capacity is assumed to be lower in scenarios with greater levels of decentralisation. As such, the highest electricity interconnector capacity is in Two Degrees and the lowest is in Consumer Evolution. Interconnector capacities in both Community Renewables and Steady Progression fall in between these limits.

Table 6: Import Capacity Levels for Interconnection (GW)

Capacity GW	2019/20	2020/21	2021/22	2022/23	2025/26	2030/31
Base Case	4.8	5.8	6.7	8.4	11.2	15.1
Community Renewables	4.8	6.8	6.7	8.4	13.7	16.5
Two Degrees	4.8	6.8	8.1	9.8	16.5	19.8
Steady Progression	4.8	5.8	6.7	8.4	11.2	15.1
Consumer Evolution	3.8	4.8	6.7	7.0	9.8	9.8

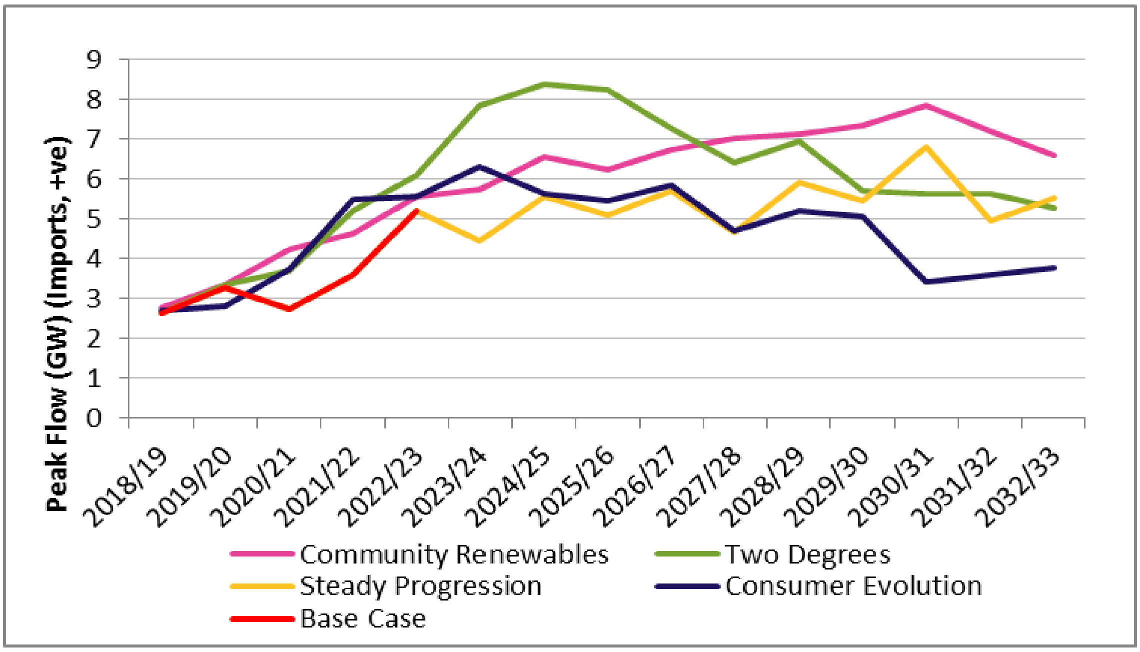
Building on from the work in FES 2017, the analysis to assess interconnector flows has been conducted using a pan-European model called BID3 that we have procured from Pöyry[21]. Flows were modelled for each scenario based on the latest available FES 2018 data for Great Britain. The assumptions for other European countries were informed by our European scenarios as described in Section 2.5. These assumptions were based on reports published by other European Transmission System Operators and ENTSO-E.

The FES 2018 analysis for peak interconnector flows is shown in Figure 14. These flows represent the flows that we might expect to flow to Great Britain when domestic margins (excluding interconnectors) begin to tighten (below 2000 MW). Typically, these periods occur during the winter peak period i.e. 17:00 – 20:00 GMT, Monday – Friday, November – February. All scenarios show net imports at times of peak GB demand over the whole time period. Actual flows during these times could vary significantly from these values due to the impact of other factors such as wind generation and the system tightness of connected markets.

It should be noted, however, that these flows at peak are not used in the CM modelling. For 2019/20 and 2022/23, the CM modelling uses the probabilistic distributions from the BID3 simulations rather than the single snapshot shown in Figure 14.

[21] http://www.poyry.com/BID3

Figure 14: Peak interconnector flows



3.10 Sensitivity Descriptions and Justifications

The analysis assumes that the Future Energy Scenarios (FES) will cover multivariate uncertainty by incorporating ranges for annual and peak demand, Demand Side Response (DSR), storage, interconnection and generation.

While there are many variables that change across the FES scenarios, the sensitivities vary only one at a time. Each of the sensitivities is considered credible as it is evidence based, i.e. it has occurred in recent history or is to address statistical uncertainty caused by the small sample sizes used for some of the input variables. The sensitivities cover uncertainty in plant availability, weather, wind, peak demand, over-delivery and non-delivery of contracted capacity.

To provide the reference case to which the sensitivities have been applied, a Base Case has been utilised. Up to 2022/23, the Base Case consists of our “central view” of the demand and generation backgrounds which aligns with the DFA Incentive and aims to reduce the likelihood of over or under securing capacity, thereby minimising the associated costs to consumer. From 2023/24, the Base Case takes the demand and generation mix from the Steady Progression scenario.

The sensitivities are described below. However, there are small differences in the way that these sensitivities were applied to each of the individual year runs: the elements that are different in each year are described in the chapters relating to those years. These sensitivities were discussed at length with BEIS, PTE and Ofgem and were agreed in April 2018.

3.10.1 Low Wind (at times of cold weather)

As detailed in Section 2.5 of the 2016 ECR, statistical analysis undertaken by Durham University and Heriot Watt University recommended the inclusion of a low wind sensitivity. In line with the recommendation, this sensitivity models the impact of lower wind generation than the base assumption at times of cold weather (i.e. at times of high demand). To model this sensitivity, a scaling factor of 0.8 is used (compared to a base assumption scaling factor of 0.9) in the DDM. This results in the modelled wind generation on days of high daily peak demand being scaled back. The scaling applied to the wind generation varies linearly from 100% on days with peak demands below 92% of the ACS value to 80% scaling on days with peak demands above 102% of ACS peak demand.

3.10.2 High Wind (at times of cold weather)

As detailed in Section 2.5 of the 2016 ECR, statistical analysis undertaken by Durham University and Heriot Watt University recommended the inclusion of a high wind sensitivity. In line with the recommendation, this sensitivity models the impact of higher wind generation than the base assumption at times of cold weather (i.e. at times of high demand). To model this sensitivity, a scaling of 1.0 is used, i.e. this sensitivity assumes that wind output is independent of daily peak demand.

3.10.3 High Plant Availabilities

Availability sensitivities have been included for 2019/20 only as they have no material impact on 2022/23 analysis as only a small amount of capacity has already been secured for that year. The high and low plant availability sensitivities address the statistical uncertainty associated with determining the mean availabilities of each fuel type. The mean availabilities are determined based on the last 7 years, which is too small a sample size (i.e. just 7 data points) to be confident that the means of these distributions will be statistically representative of what could happen in the future. The plant availability sensitivities are not intended to address concerns of whether the base availability assumptions are too high or too low, and nor are they intended to make predictions as to what levels of plant availability we believe will occur. These are purely statistical sensitivities to address the uncertainty in calculating mean values from a small number of points. To allow for this in the modelling, it assumes for two of the largest contributing generation technologies (nuclear and CCGT) a higher mean availability than the base assumption. This higher availability is also applied to any capacity for these technologies contracted in previous auctions.

For existing nuclear, the availability increases from just over 84% to 89% and for CCGTs from 89% to 92% in 2019/20. These higher availabilities are based on one standard deviation above the mean of observed figures from the last seven years. Coal availabilities have not been flexed as coal availabilities have been relatively stable over the last seven years. In addition, other technologies have not been flexed to allow for diversity as it would be unlikely all technologies would be simultaneously at their high availability levels.

In 2019/20, for example, adjusting availabilities has an impact on the de-rated capacity of previously contracted plant and therefore an impact on the de-rated total required. However, it clearly has a large impact on the name plate capacity total. These adjustments have been applied to the technologies that are both large in aggregate GWs and have shown variance across the sample.

3.10.4 Low Plant Availabilities

Availability sensitivities have been included for 2019/20 only, as they have no material impact on 2022/23 analysis. The low plant availability sensitivity assumes for two of the largest contributing generation technologies (nuclear and CCGT) a lower mean availability than the base assumption. For nuclear, the availability reduces from 84% to 79% and for CCGTs from 89% to 86% in 2019/20. These lower availabilities are based on one standard deviation below the mean of observed figures from the last seven years.

3.10.5 Interconnector Assumptions & Sensitivities

In the 2018 ECR, interconnector capacities are based on the FES scenarios. For both the 2019/20 and 2022/23 model runs, the flows are calculated as part of the probabilistic modelling, hence there is no requirement for separate interconnector sensitivities other than already incorporated within the non-delivery and over-delivery sensitivities.

3.10.6 Cold Weather Winter

The cold weather sensitivity addresses the uncertainty in demand due to cold winter weather conditions. Demand is highly sensitive to weather and a cold winter will lead to higher demand which increases the risk of loss of load. This sensitivity is included because the modelling uses a relatively short history of demand in the LOLE calculation, which is based on 11 years. This is too small a sample to be confident that the demand distributions will be statistically representative of future weather conditions. For example, the Met Office uses a much longer period of 30 years when calculating average temperatures.

The cold weather sensitivity is based on a recent cold winter and calculates LOLE assuming that the weather that occurred in 2010/11 is repeated. This winter was not extreme compared to the last 30 years; we would expect similar weather every 1 in 9 years. In addition, the weather data is “pooled” rather than being conditional on each winter which is standard practice in many countries. Hence it is statistically sound to run this sensitivity as well as the warm winter sensitivity.

3.10.7 Warm Weather Winter

This warm weather sensitivity is included on the same statistical basis as cold weather, and ensures that the treatment of the uncertainty of demand due to weather is unbiased. The warm weather sensitivity is based on a warm winter from within the last 12 years and calculates LOLE assuming that the weather that occurred in 2006/07 is repeated. This winter was not extreme and when compared to the last 30 years, we would expect similar weather every 1 in 14 years.

3.10.8 High Demand

In the 2015 ECR, the high and low demand sensitivities were based around the range of historical forecasting performance for Transmission level demand for the winter ahead (see 2015 ECR for the rationale behind this). This produced an asymmetric range of demand sensitivities reflecting, firstly, the tendency to over forecast Transmission level demand mainly due to the rapid growth in distributed generation and the lack of visibility of both distributed capacity and generation data and, secondly, the prolonged economic recession which suppressed demand longer than expected. These two factors may be less relevant in the future due to improved access to data on distributed generation and the view by economists that a recession in GB of the magnitude seen a decade ago is unlikely.

National Grid now has the Demand Forecasting Incentive (DFA) Incentive and an obligation to publish how it plans to improve the demand forecasting process every year. Consequently, the demand sensitivities have been aligned with the ranges used within the incentives rather than historical performance. The DFA Incentive for the T-1 auction has a symmetric range of +/- 2% which forms the basis of the sensitivities in the 2018 ECR. We have not used the T-4 incentive range of +/- 4% as the incentive is weighted towards the T-1 demand given that there is an opportunity (in the T-1 recommendation) to correct any forecast errors in the T-4 demand.

The high demand sensitivity covers the upper end of the range of uncertainty of the underlying (i.e. weather-corrected) ACS peak demand forecast. This assumes peak demand values that are 2% above the FES ACS peak demands.

3.10.9 Low Demand

The low demand sensitivity covers the lower end of the range of uncertainty of the underlying (i.e. weather-corrected) ACS peak demand forecast. This assumes peak demand values that are 2% below the FES ACS peak demands.

3.10.10 Non-delivery

Previously, non-delivery sensitivities were dominated by the risk around coal closures given their challenging economic situation and environmental legislation. With the decline of the coal fleet the volume of future uncertainty is lower however, new risks have materialised that could add to the non-delivery, e.g. gas plant closures, policy around Ofgem's embedded benefits review, non-delivery risk from unproven DSR failing to materialise (as seen in the TA and EA auctions) and lower than expected imports from interconnectors.

We considered creating separate sensitivities for each element of the non-delivery risk but decided against this as they all interact resulting in an aggregated non-delivery. This approach was supported by any subsequent market response to countervail the non-delivery being related to the total non-delivery rather than the individual elements, i.e. wholesale prices rise as more stations close thus limiting the level of closures. In addition if the elements were separated out how far do we go e.g. down to individual stations? If so this would result in non-delivery sensitivities having virtually no impact on the LWR calculation and therefore CM auction recommendation as the sensitivities would only have small adjustments away from the Base Case and thus the risk of non-delivery would not have been incorporated in the modelling.

Consequently, the non-delivery risks was analysed separately for coal and gas plant, small scale embedded plant (from previous auctions), unproven DSR and interconnectors. The level of market response was analysed against the aggregated total of non-delivery. During this process, we discussed the various options with BEIS and the PTE to determine the final range, e.g. additive or Root Sum Square approach which concluded with the Root Sum Square method being adopted due to the interaction of the various elements (see 2.5.2 and Annex A.6 for more details). The range of this risk was set at 2.4 GW for 2019/20 and 2.8 GW for 2022/23.

The non-delivery sensitivities deal with uncertainty risks and also assist with the granularity in the LWR calculation. A range of non-delivery sensitivities with incremental steps of 0.4 GW (around the de-rated capacity of a typical coal power station unit) have therefore been modelled.

3.10.11 Over-delivery

This sensitivity considers the possibility of over delivery, i.e. stations staying open that do not have CM contracts and interconnectors importing more than their CM contracted de-rated capacities. The former is more likely to apply to the shorter time period associated with the T-1 auction as stations are less likely to stay open in the market for the longer T-4 period without a CM contract in any of the intervening years. However for the latter interconnectors, assuming capacity is available in the connected markets, can deliver higher imports supported by market coupling across physical boundaries within the internal energy market. Consequently, we have agreed with BEIS and the PTE to include up to 1.2 GW over delivery for 2019/20 and 2022/23.

3.10.12 Sensitivities Considered but Rejected

A number of alternative sensitivities were considered for inclusion but following discussions with BEIS and the PTE were rejected. These are listed below.

Dependence of Generating Units – The DDM implicitly assumes independence in availability of generating units. A number of commentators/consultancies have suggested that this assumption is optimistic. For example, a fault in one unit can affect the other units on site or a station transformer fault could affect more than one unit or the operation of a station within a portfolio could be affected by the other stations in that portfolio. However, the data available associated with these issues is either very limited or difficult to interpret and translate for use into the future, making it very difficult to quantify for modelling purposes. Hence this sensitivity was not included.

Renewable Plant Non-Delivery – This sensitivity was to reflect slippage in non-CM plants away from their connection and contract dates similar to the CM non-delivery sensitivities. However, following discussions with BEIS and the PTE, it was agreed not to include this sensitivity since there is a credible range in the level of renewable generation connecting across the four FES scenarios and Base Case.

Black Swan Events – These are defined as events that 'deviate beyond what is normally expected of a situation and are extremely difficult to predict, being typically random and unexpected',[22] and which we consider to have very low probability but high potential impact. We have investigated nuclear type faults before and concluded that they were low probability and historically had been rectified ahead of the following winter (albeit with stations operating at a reduced capacity but this would be covered in the scenarios). We have also considered extreme cold weather (e.g. January1986/87) combined with low wind, but this would involve changing more than one element which violates the principles behind the sensitivities of only including

[22] https://www.investopedia.com/terms/b/blackswan.asp

credible outcome by changing one variable. Extreme weather events may be most likely to impact first the transmission and distribution systems; insofar as ‘black swan’ events impact generation, the first recourse would be to “latent capacity” on the system discussed in last year’s PTE report. Given this and the economic or policy events relating to uncertainty around coal will be addressed through the non-delivery sensitivities, we agreed with BEIS and the PTE not to include any “black swan” event sensitivities.

CMU misalignment to TEC – This sensitivity relates to the CMUs (Capacity Market Units) connection capacity being greater than TEC (Transmission Entry Capacity) values for some transmission connected stations so that when the de-rating factors are applied, they result in nearly 100% availabilities for many stations. This clearly puts security of supply at risk, as no plant is 100% available in reality, thus the auction has under secured capacity. However, our modelling mitigates this risk by only using capacities based on TECs, so all our recommendations take account of this anomaly as best it can, with only the T-1 auction potentially under securing if the stations successful in that auction have CMUs greater than TECs. Hence we have agreed not to include this sensitivity.

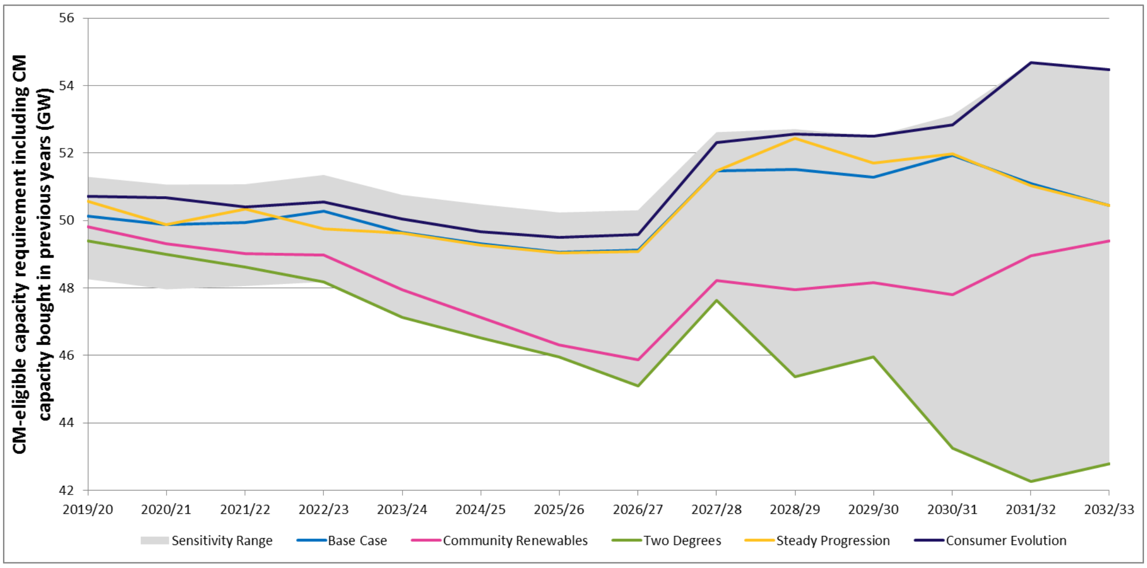
Combined Sensitivities – A number of system operators around the world consider combined sensitivities within their process for calculating the required capacity to meet their respective reliability standards. Consequently we investigated whether this was appropriate for the GB process, particularly in relation to the use of a potential hybrid approach (see the 2017 ECR). First of all, we considered the potential use of combined sensitivities within the LWR decision tool. We concluded that this would, if included, result in lower probability sensitivities such as combined sensitivities being given equal weightings as sensitivities with only one variable changed which would be inappropriate. Secondly, we considered it as part of the hybrid approach but to change the answer materially required such a low probability sensitivity that it may be considered more like a “black swan” event and was thus decided not to include.

3.11 15 Years Horizon

This section considers the overall level of de-rated capacity requirement in future years, not just the years of interest for this report (2019/20 and 2022/23). It focuses on the total requirement for CM-eligible capacity and does not split each year’s requirement into capacity secured in earlier years, T-1 and T-4 auctions. The requirement in 2019/20, 2020/21 and 2021/22 was derived from the 2019/20 model runs (see Chapter 6) and the capacity requirement from 2022/23 to 2032/33 from the model runs for 2022/23 (see Chapter 5). This section is included before the main results chapters to illustrate the ongoing requirement for CM-eligible capacity.

Figure 15 shows the range in modelled CM-eligible capacity requirement in future years including any new / refurbished capacity secured in previous years.

Figure 15: Total CM-eligible Capacity required in Future Years



The total requirement for the non-delivery and over-delivery sensitivities is the same as the Base Case. For non-delivery cases, the increase in capacity required is offset by the reduction in contracted capacity closing before the target year. Similarly for over-delivery cases, the decrease in capacity required is compensated for by CM-eligible plants providing additional capacity without a contract.

As can be seen in the chart, the Steady Progression scenario has a relatively stable capacity requirement over the period whilst the Two Degrees scenario shows a gradual decline over most of the period as the level of de-rated RO/CfD-supported capacity increases by more than any growth in peak demand (plus reserve for largest infeed loss). For the other scenarios, the picture is mixed over the next ten years with a gradual rise in the later years as peak demand increases. All scenarios show an increase in 2027/28 when RO and CFD support for biomass conversion ends.

There could be a risk of stranded assets receiving support if new capacity is built for one year and then not required in the future. However, given the current emissions regulations, in particular the Industrial Emissions Directive (IED), a number of power stations will have to close by 2023 or when they have exhausted their allocated 17,500 running hours. Furthermore, in the case of coal power stations the Government's policy is to close all unabated units by 2025. The current nuclear fleet will also see a number of closures over this period, due to units reaching the end of their safe operational life. These closures of existing capacity will ensure that any new capacity built in the first few years of the capacity market will still be required in later years.

The chart shows the level of CM capacity required to meet the Reliability Standard in all years from 2019/20. For 2018/19, we did not model the capacity requirement in each scenario / sensitivity as the T-4 and T-1 capacity auctions for that year have already happened, securing around 53.3 GW of de-rated capacity[23] across both auctions. The forthcoming 2018/19 Winter Outlook Report[24] will include a view of electricity security of supply for the coming winter.

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[23] https://www.emrdeliverybody.com/Lists/Latest%20News/Attachments/174/Final%20Results%20T-1%202017%20(13.01.2018).pdf
[24] https://www.nationalgrid.com/uk/publications/winter-outlook

4. De-rating Factors for CM Auctions

4.1 Conventional Plants

Conventional plant de-rating factors, based on the station availabilities, are updated annually. Table 7 below shows the proposed de-ratings factors for 2019/20 and 2022/23 by the conventional generation technologies and includes a comparison with those used last year for the 2017 Capacity Market Auctions[25].

Table 7: Conventional Plant De-rating Factors

Name for technology class	Plant Types Included	De-rating factor (ECR 2017) plus storage DRF as used in 2018 auctions	De-rating factor (ECR 2018)
Oil-fired steam generators	Conventional steam generators using fuel oil	88.04%	89.13%
OCGT and reciprocating engines (non-autogen)	Gas turbines running in open cycle fired mode Reciprocating engines not used for autogeneration	94.81%	95.14%
Nuclear	Nuclear plants generating electricity	85.24%	84.20%
Hydro	Generating Units driven by water, other than such units: driven by tidal flows, waves, ocean currents or geothermal sources; or which form part of a Storage Facility	87.92%	90.09%
Storage by duration in hours for T-1 and T-4 auctions[26]	Conversion of imported electricity into a form of energy which can be stored and the re-conversion of the stored energy into electrical energy. Includes hydro Generating Units which form part of a Storage Facility (pumped storage), compressed air and battery storage technologies.	Dura'n: T-1: T-4: 0.5hrs 21.34% 17.89% 1.0hrs 40.41% 36.44% 1.5hrs 55.95% 52.28% 2.0hrs 68.05% 64.79% 2.5hrs 77.27% 75.47% 3.0hrs 82.63% 82.03% 3.5hrs 85.74% 85.74% 4.0+hrs 96.11% 96.11%	Dura'n: T-1: T-4: 0.5hrs 17.50% 14.91% 1.0hrs 34.21% 29.40% 1.5hrs 50.00% 43.57% 2.0hrs 62.80% 56.68% 2.5hrs 71.96% 66.82% 3.0hrs 78.09% 73.76% 3.5hrs 81.57% 77.78% 4.0hrs 95.52% 80.00% 4.5+hrs 95.52% 95.52%
CCGT	Combined Cycle Gas Turbine plants	T-1: 88.54% T-4: 90.0%	T-1: 89.05% T-4 90.00%
CHP and autogen (de-factors provided by BEIS)	Combined Heat and Power plants (large and small-scale) Autogeneration – including reciprocating engines burning oil or gas	90.00%	90.00%
Coal/biomass/ EfW	Conventional steam generators using coal or biomass or waste	87.58%	86.56%
DSR[27]		86.34%	84.28%

[25] https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/Capacity%20Market%20Auction%20Guidelines%20%2016th%20January%202018.pdf

[26] Details of the Storage De-rating Methodology can be found on the EMR delivery body website https://www.emrdeliverybody.com/Lists/Latest%20News/Attachments/150/Duration%20Limited%20Storage%20De-Rating%20Factor%20Assessment%20-%20Final.pdf

[27] Details of the DSR De-rating Methodology can be found on the EMR delivery body website https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/DSR%20De-rating%20Information.pdf

4.2 Interconnectors

Interconnectors will be eligible to participate in both the 2019/20 T-1 and 2022/23 T-4 auctions except where they already have a Capacity Market contract. The future of potential flows through interconnectors is very complex and as a consequence, there is no single answer to the question of what can be assumed to flow through the interconnectors at times of system stress. This section outlines the various approaches National Grid, in agreement with BEIS and the PTE, has considered in determining an appropriate country's de-rating factor range for the Secretary of State to then decide the factors to apply to individual interconnectors.

4.2.1 Methodology

As with previous years, there are two elements to the methodology for informing interconnector de-rating factors: an analysis of historical flows and price differentials between the two markets and stochastic modelling of the future European electricity market. BEIS commissioned Pöyry to update their analysis of historical de-rating factors used to inform last year's ranges. Schedule 3A of the Capacity Market Rules states that the Equivalent Firm Interconnector Capacity will be the greater of the historical and forecast de-rating factors[28], unless there are publicly reported concerns about the supply of electricity in the connected territory, in which case the Secretary of State may decide on a value that is less than the historical de-rating factor. The modelled ranges for 2022/23 indicate that the historical de-rating factors may no longer be appropriate for Belgium and Netherlands.

National Grid has a pan-European market modelling team which uses the BID3[29] program to model flows between GB and connected countries for each scenario. BID3 is a dispatch model based on short-run marginal costs. It simulates hourly demand and renewable generation based on historical weather patterns and then allocates flows between countries using linear programming to optimise the cost of generation to meet demand across all modelled countries. This year, scenarios were developed for Belgium, France, Germany, Ireland, the Netherlands, Denmark and Norway based on scenarios developed by their respective Transmission System Operators and/or ENTSO-E's Ten Year Network Development Plan. Flows were modelled for each scenario based on FES 2018 demand and generation data and FES 2018 electricity interconnector capacities for GB combined with the best matching scenario for each connected country and a single scenario for the remaining European countries. The demand history was increased to 31 years (1985 to 2015), which is correlated across Europe and with wind generation. This increases the number of periods with extreme weather across Europe, giving greater confidence in the ability of interconnectors to import when required.

The model assumptions were stress tested by running additional simulations with demand increased by 5% and 10% to check the impact of tighter margins on flows.

All hours with GB demand exceeding domestic generation, excluding interconnector flows, were selected to represent times when imports were required. The average flow as a percentage of capacity was calculated for each connected country and FES scenario. We tested different threshold levels and found the results to be stable. Table 8 lists the simulations.

[28] These historical de-rating factors refer to de-rating factors implied from historical flows or price differentials and not to de-rating factors applied in past auctions. Similarly the modelled de-rating factors are potential country values derived from pan-European modelling and not the final interconnector de-rating factors to be applied in the auctions.
[29] http://www.poyry.com/BID3

For 2019/20, the modelled range is the highest to the lowest of the 5 scenario runs under the two stress conditions. The non-stress runs do not provide enough observations from which to calculate a de-rating factor.

For 2022/23, the forecast range is the highest to the lowest of the 5 scenario runs under the non-stress and 5% stress conditions. For Belgium and Netherlands the range falls significantly below the historical value suggesting that the historical de-rating factors may no longer be appropriate. These lower values are driven by the tightening of margins across Europe as coal and nuclear plants close. These countries all have good interconnection with Germany which plans to phase out their remaining nuclear reactors by 2022.

Table 8: Pan-European modelling runs

Simulation	Graph name	Description
Poyry historical analysis	Historical	Highest 50% of peak demand periods during winter quarter (7am-7pm business days, Dec-Feb, 2011-2017)
Average of FES scenarios	Average	Average of de-rating factors for BC, CR, TD, SP & CE
Base Case	BC	2018 Future Energy Scenarios - Base Case
Community Renewables	CR	2018 Future Energy Scenarios - Community Renewables
Two Degrees	TD	2018 Future Energy Scenarios - Two Degrees
Steady Progression	SP	2018 Future Energy Scenarios - Steady Progression
Consumer Evolution	CE	2018 Future Energy Scenarios - Consumer Evolution

4.2.2 BID3 Pan-European Model Results

The imports as a percentage of interconnector capacity, from all the pan-European simulations, are shown in Table 9 for 2019/20 and Table 10 for 2022/23.

Where there are blanks in these tables, either that country is not connected to GB in that scenario and delivery year or there are not enough observations, where the GB margin is negative, to be able to calculate a de-rating factor. The only interconnector to the Netherlands obtained a CM contract for 2019/20 in the 2015 T-4 auction so results are only shown for 2022/23. For 2022/23, Norway is delayed in the Consumer Evolution scenario.

The FES results use FES forecasts for GB and the closest scenario for the rest of Europe. The 5% stress test increases demand across Europe by 5% and 10% in Ireland. The 10% stress test increases demand in GB and Ireland by 10% and 5% in the rest of Europe. These stress test demand increases were discussed and agreed with the PTE. The de-rating factors are not very sensitive to the exact value selected. The increases in demand do not always reduce the de-rating factor because there are more hours that are brought into the calculation, so whilst the original selection of hours may have lower imports, the additional hours may be less stressed over the whole of Europe enabling higher imports.

Table 9: Simulation results: 2019/20 imports as percentage of interconnector capacity

		Stress 5%							Stress 10%					
Country	**Historical**	**Average**	**BC**	**CR**	**TD**	**SP**	**CE**		**Average**	**BC**	**CR**	**TD**	**SP**	**CE**
Ireland	5	54		54			54		40	45	35	41	41	36
France	55	68		61			74		81	72	87	77	79	92
Belgium	67	68		68					70	65	78	67	69	

Table 10: Simulation results: 2022/23 imports as percentage of interconnector capacity

		FES							Stress 5%					
Country	**Historical**	**Average**	**BC**	**CR**	**TD**	**SP**	**CE**		**Average**	**BC**	**CR**	**TD**	**SP**	**CE**
Ireland	5	30	42	26	24	26	30		33	36	31	30	31	37
France	55	78	59	77	81	85	86		75	68	73	77	79	77
Belgium	67	56	36	55	57	67	65		42	35	39	43	44	49
Netherlands	70	47	27	41	45	62	57		34	28	31	33	39	40
Norway	96	98	100	98	98	98			92	92	93	93	90	

4.2.3 Pöyry historical analysis

BEIS commissioned Pöyry to update their analysis of historical flows. The methodology is specified in schedule 3A of the capacity market rules[30]. Table 11 shows this year's 7-year average historical de-rating factors compared to last year's figures. The historical data used was the top 50% of peak demand periods during the winter quarter, 7am to 7pm business days from 2011 to 2017. For the existing interconnectors, the average de-rating factors are calculated for those periods where the price differential was positive and the interconnector was importing to GB. For new interconnectors, the factors are calculated from the percentage of periods with a positive price differential. Interconnectors that have operated for less than 7 years are treated as new interconnectors and so their historical de-rating factors are based on price differentials only. This year the Netherlands has been operating for 7 years so the methodology switches from price differential to historical flows, resulting in a small reduction in historical de-rating factor. Table 12 shows the annual historical de-rating factors. France, Belgium and Netherlands all recover from the large falls in 2016 caused by French nuclear outages for additional safety checks.

Table 11: 7-year average historical de-rating factors

%	Ireland	France	Belgium	Netherlands	Norway
2010-2016	4	48	65	75	85
2011-2017	5	55	67	70	96

[30] https://www.gov.uk/government/publications/capacity-market-rules

Table 12: Annual historical de-rating factors

%	2010	2011	2012	2013	2014	2015	2016	2017
Ireland	0	2	0	3	0	12	13	9
France	20	26	50	68	69	79	25	70
Belgium	59	63	64	75	79	87	31	70
Netherlands	n/a	31	57	75	83	90	63	91
Norway	35	89	92	100	99	93	100	99

4.2.4 Country de-ratings

The results for each scenario compared with the Pöyry historical averages are shown in Figures 16 to 23. The modelled de-rating factor ranges do not include an allowance for technical de-rating.

As this methodology is based around the modelling of European markets, step changes in results could potentially occur between years due to changes in demand, generation mix and the resulting capacity margin. A problem in one country can impact flows from surrounding countries, as can be seen by the impact of German nuclear closures on Belgium and Netherlands interconnector flows. Modelling flows across Europe for the auction year gives confidence that these interactions have been reflected in the modelled range of de-rating factors. However, there is still uncertainty in the demand and generation numbers which we have addressed through stress tests. For example, some countries have higher capacity margins than required to meet their stated security of supply. As older thermal generation closes and capacity markets are used to support generation at the target LOLE level, de-rating factors are likely to fall. The recent ENTSO-E Mid-Term Adequacy Report shows average LOLE increasing for a number of countries between 2020 and 2025 including Belgium (0.31 to 5.97) and Netherlands (0.09 to 1.25)[31]. The 5% increase in demand gives an indication as to the impact of tighter margins, which may be caused by lower than expected generation, higher than expected demand or higher than expected non-delivery. For Ireland demand was increased by 10% to better reflect the potential loss of a single generator.

The FES scenarios for 2019/20 have high margins for GB, assuming unsuccessful generation without CM contracts stays on line in order to compete for capacity payments in later years. This means that in all scenarios, there are very few hours that meet the low margin criteria for calculating de-rating factors. To reflect the possibility of some of this excess generation closing, a further stress test was run for 2019/20 only that had demand increased by 10% in GB as well as Ireland with demand for the rest of Europe increased by 5%.

For 2019/20, the modelled range is the highest to the lowest of the 5 scenarios under each of the two stress conditions. The non-stress run does not provide enough observations from which to calculate de-rating factors. For 2022/23, the modelled range is the highest to the lowest of the 5 scenarios under the non-stressed and 5% stressed conditions. Tables 13 to 20 depict the interconnectors de-rating factors for 2019/20 and 2022/23 for FES results and 5% and 10% stress tests.

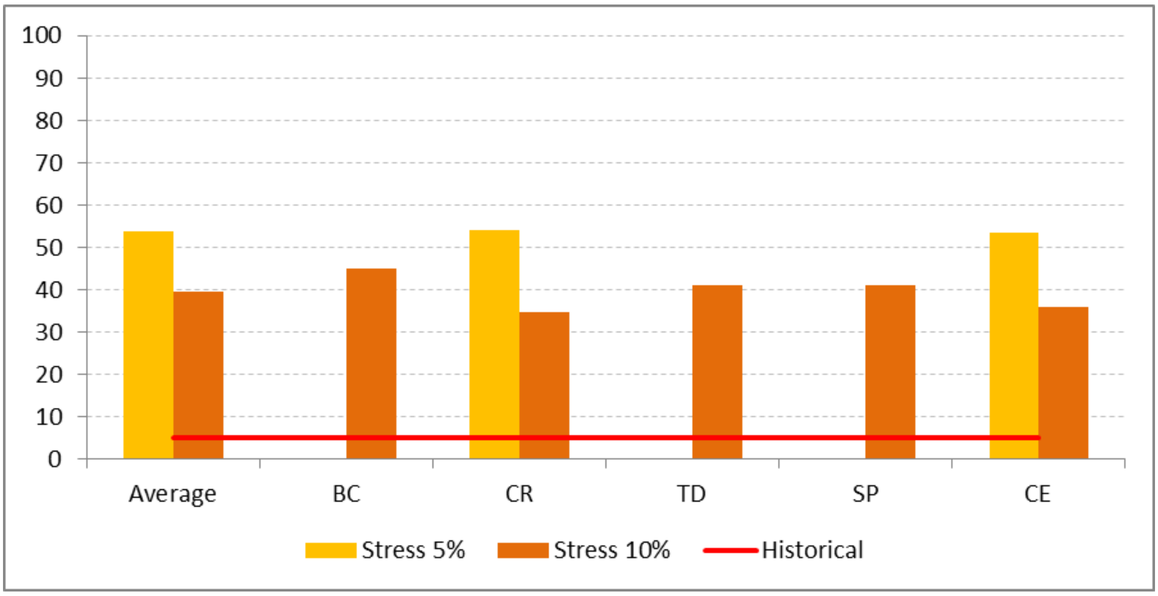
[31] Table 5 (page 61) https://docstore.entsoe.eu/Documents/SDC%20documents/MAF/MAF_2017_report_for_consultation.pdf

Ireland:

The modelled ranges for Ireland are 35% to 54% for 2019/20 and 24% to 42% for 2022/23. These ranges assume no outages or network constraints. BEIS will make an allowance for outages and constraints in their de-rating factors for each interconnector. Ireland is a single energy market economically but currently there is limited physical links between the north and south. This is expected to be rectified with an additional North/South link, which is anticipated to be operational before 2022/23. Ireland was modelled as a single price area so Ireland's North/South constraint had no impact. The modelling assumed that I-SEM would remove the current incentive for flows from GB to Ireland during the peak winter hours. We have assumed that by 2022/23, there will have been several years of market coupling, in which case the Pöyry history should no longer be relevant for setting the low level of the modelled range. However, there is also a risk that intra-day auctions do not take place which will impact on the effectiveness of the market to respond to prices. In those circumstances, it may be better to consider the Pöyry history as the lower bound. ISEM is due to be implemented in 2018 but the North/South link will not be in operation for 2019/20. This year for Ireland, the modelled ranges have been calculated using the modelled capacity, not export capacity. For Moyle, the import capacity was assumed to be constrained to 307 MW for 2019/20 but not for 2022/23. This enables BEIS to adjust for constraints as well as technical de-rating for each interconnector.

Recently Ireland has shown strong growth in electricity demand, which Eirgrid is forecasting to continue in its 2017 All-Island Generation Capacity Statement[32]. Also, there will be downward pressure on generation as the Irish capacity market currently targets 8 hours LOLE through capacity market auctions. As Ireland is a smaller market than continental Europe, and individual power stations are larger compared to the size of the system, a 10% stress test was applied in Ireland instead of the 5% applied in the rest of Europe.

Figure 16: Irish interconnector de-rating factors 2019/20



[32] http://www.eirgridgroup.com/site-files/library/EirGrid/4289_EirGrid_GenCapStatement_v9_web.pdf

Table 13: Irish interconnector de-rating factors 2019/20

Scenario	Average	Base Case	Community Renewables	Two Degrees	Steady Progression	Consumer Evolution
Stress 5%	54		54			54
Stress10%	40	45	35	41	41	36

Figure 17: Irish interconnector de-rating factors 2022/23

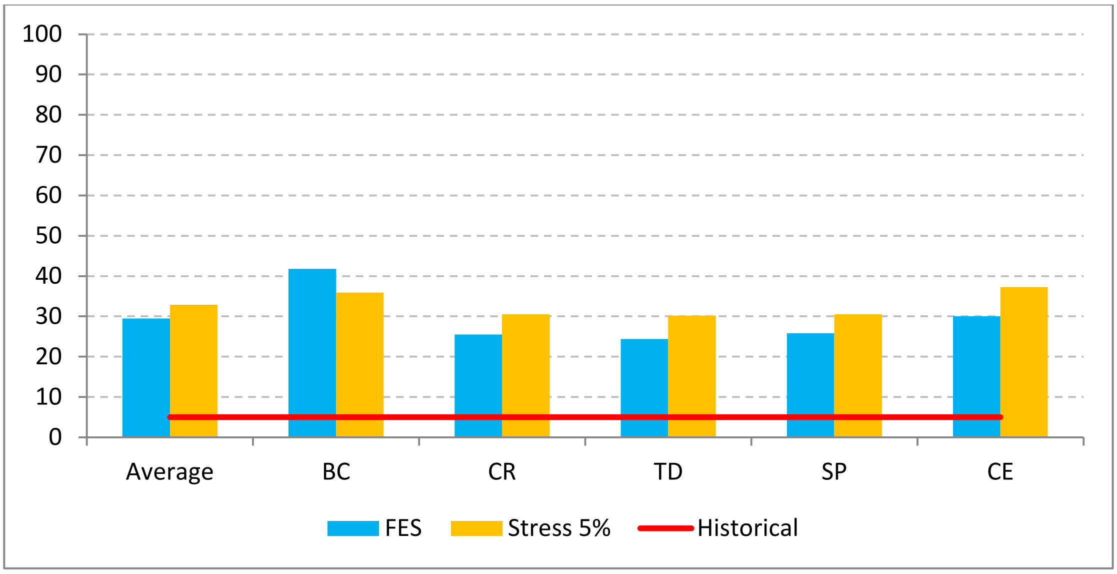


Table 14: Irish interconnector de-rating factors 2022/23

Scenario	Average	Base Case	Community Renewables	Two Degrees	Steady Progression	Consumer Evolution
FES	30	42	26	24	26	30
Stress 5%	33	36	31	30	31	37

France:

The modelled ranges for France are 61% to 92% for 2019/20 and 59% to 86% for 2022/23. France maintains stable de-rating factors across the years because the phased closure of nuclear capacity has been pushed back. The French generation margin is generally positive, although French demand is very weather sensitive, so very cold weather results in demand exceeding domestic generation. As the interconnector capacity with France grows and nuclear capacity is curtailed, we may see de-rating factors falling in the future.

Figure 18: French interconnector de-rating factors 2019/20

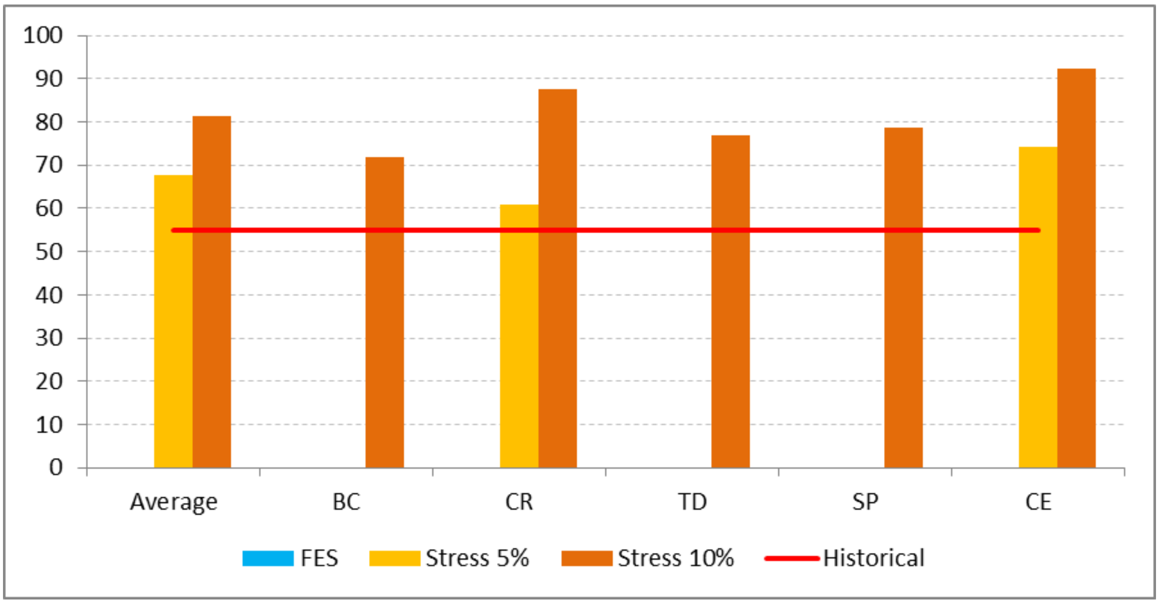


Table 15: French interconnector de-rating factors 2019/20

Scenario	Average	Base Case	Community Renewables	Two Degrees	Steady Progression	Consumer Evolution
Stress 5%	68		61			74
Stress10%	81	72	87	77	79	92

Figure 19: French interconnector de-rating factors

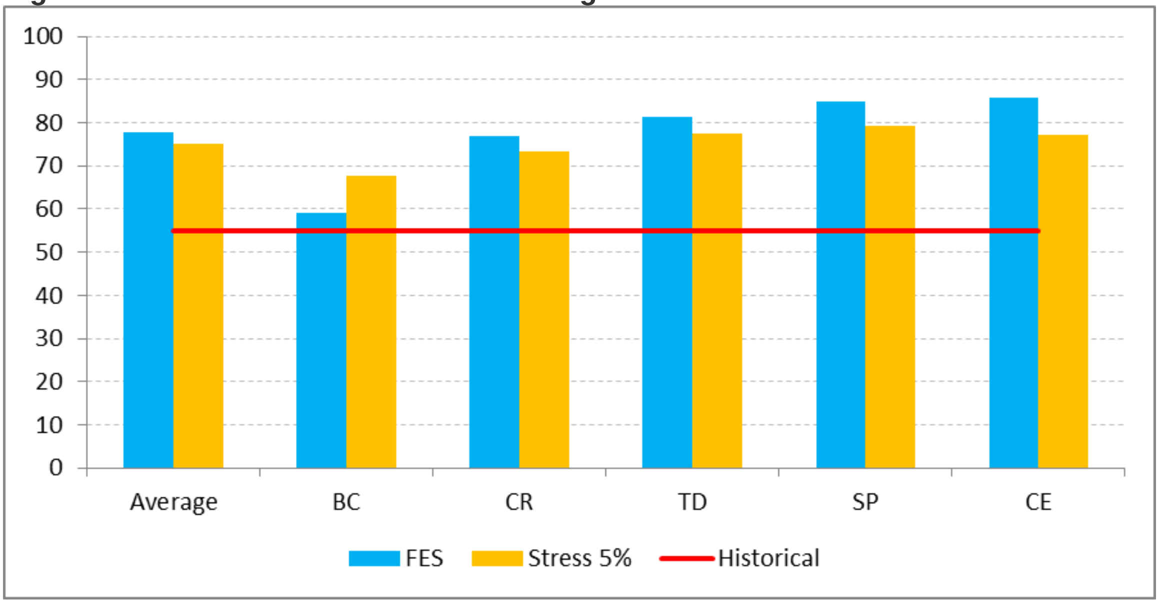


Table 16: French interconnector de-rating factors 2022/23

Scenario	Average	Base Case	Community Renewables	Two Degrees	Steady Progression	Consumer Evolution
FES	78	59	77	81	85	86
Stress 5%	75	68	73	77	79	77

Belgium:

The modelled ranges for Belgium are 65% to 78% for 2019/20 which is in line with last year's analysis for 2021/22. This year's historical value is slightly higher than the lower bound of the modelled range at 67%. The range drops significantly for 2022/23 to 35% to 67%. This is below the historical de-rating factor for all but the non-stressed Steady Progression scenario. Belgium plans to phase out nuclear power by 2025. This is in progress for 2022/3 with reduced nuclear capacity compared to 2019/20. The drop in de-rating factors is due to the reduction in European margins driven partly by the phase out of German nuclear generation and partly by generation removed from the market as strategic reserve.

Figure 20: Belgium interconnector de-rating factors 2019/20

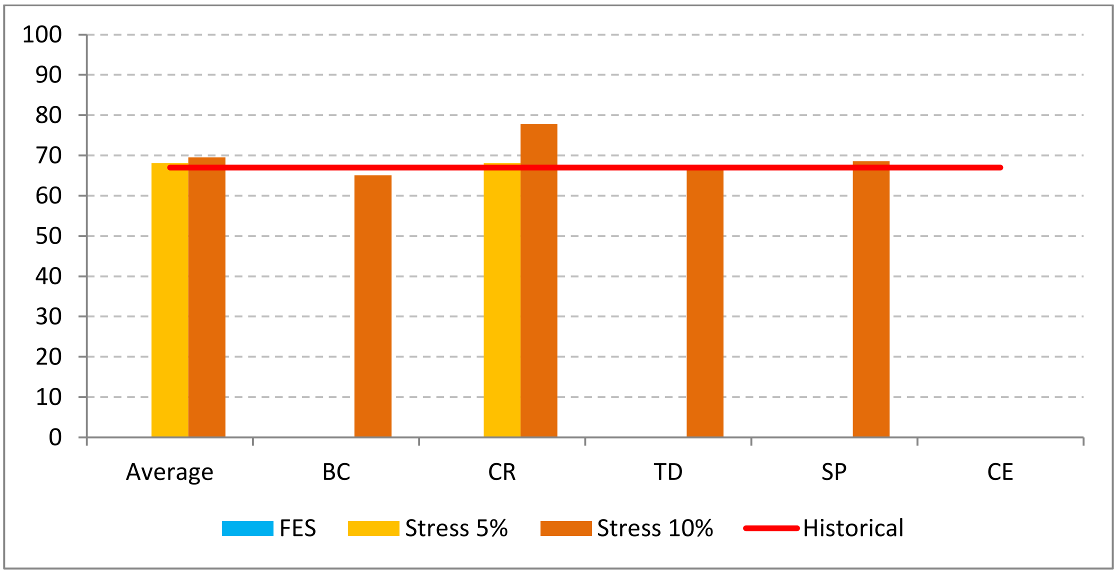


Table 17: Belgium interconnector de-rating factors 2019/20

Scenario	Average	Base Case	Community Renewables	Two Degrees	Steady Progression	Consumer Evolution
Stress 5%	68		68			
Stress10%	70	65	78	67	69	

Figure 21: Belgium interconnector de-rating factors 2022/23

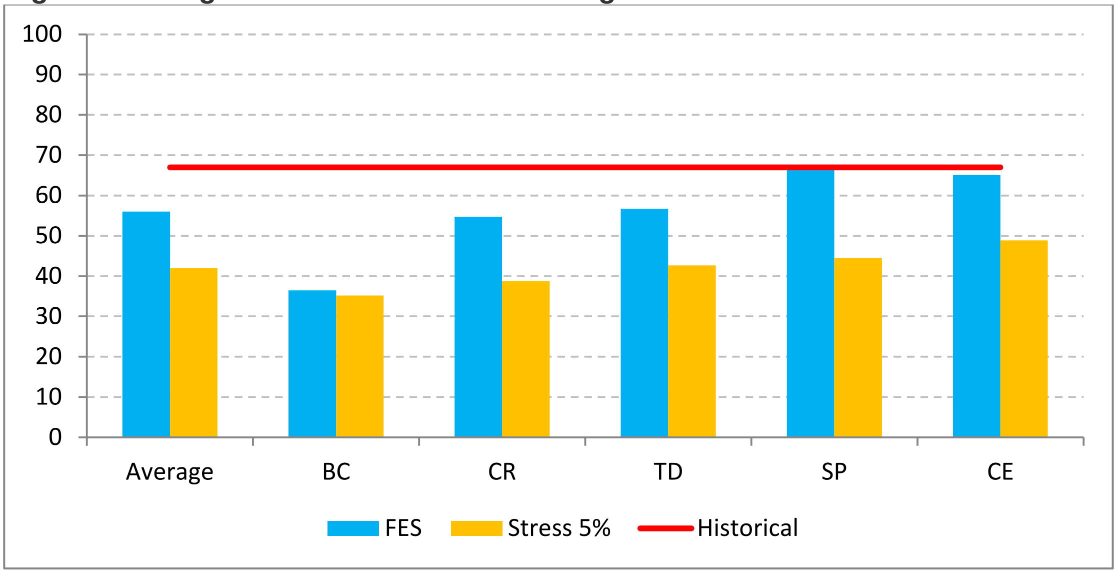


Table 18: Belgium interconnector de-rating factors 2022/23

Scenario	Average	Base Case	Community Renewables	Two Degrees	Steady Progression	Consumer Evolution
FES	56	36	55	57	67	65
Stress 5%	42	35	39	43	44	49

Netherlands:

The Netherlands interconnector already has a CM contract for 2019/20 from the 2015 T-4 auction and there are no further interconnectors to Netherlands planned for this year. Therefore modelled ranges are only required for 2022/23. The modelled range for 2022/23 is 27% to 62%. All scenarios are below the historical de-rating factor. Mothballing of CCGTs and reduced transit flows from Germany due to government policy to close all nuclear plants by 2022 are two of the reasons for this reduction.

In most countries, the TEC, CMU (Capacity market Unit) and firm import capacities are the same. This is not the case with Netherlands. The modelling assumed a firm import capacity of 1000 MW and the de-rating factor range is based on this capacity. The maximum historical imports have been 1200 MW although this can only be sustained for a very short time. In the T-4 auction for 2021/22, the CMU capacity was 1320 MW. BEIS will consider whether it is appropriate to adjust the de-rating factors for differences in capacities as well as technical availability.

Figure 22: Netherlands interconnector de-rating factors 2022/23

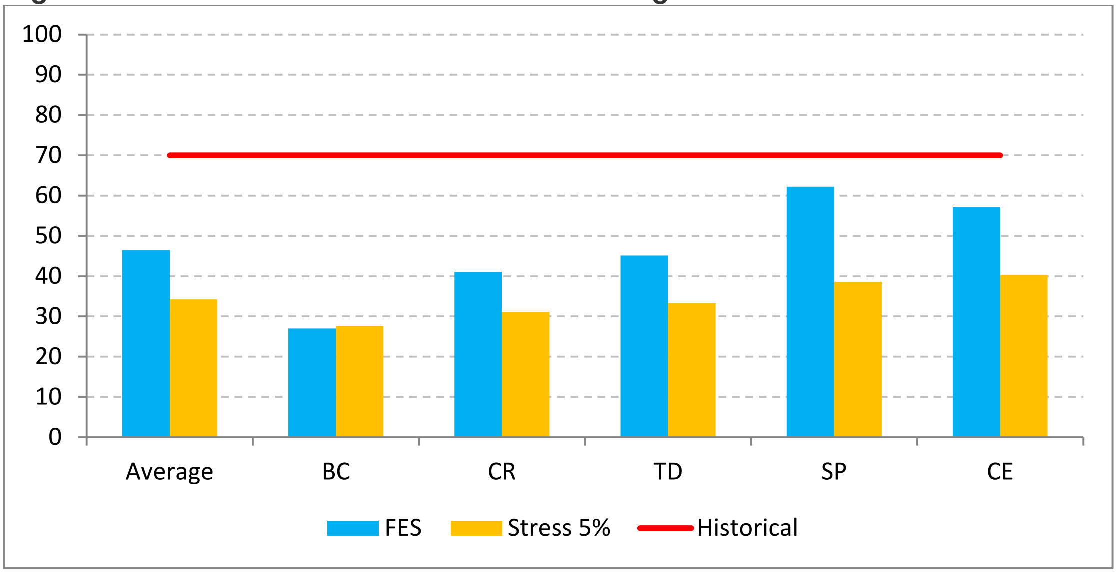


Table 19: Netherlands interconnector de-rating factors 2022/23

Scenario	Average	Base Case	Community Renewables	Two Degrees	Steady Progression	Consumer Evolution
FES	47	27	41	45	62	57
Stress 5%	34	28	31	33	39	40

Norway:

Interconnectors with Norway are not expected to be completed for 2019/20 but appear in all scenarios for 2022/23 except Consumer Evolution. The modelled de-rating factors are high across all scenarios giving a range of 90% to 100%. The historical de-rating factor, based on price differentials, is also high falling mid-way within the modelled range at 96%.

Figure 23: Norway interconnector de-rating factors 2022/23

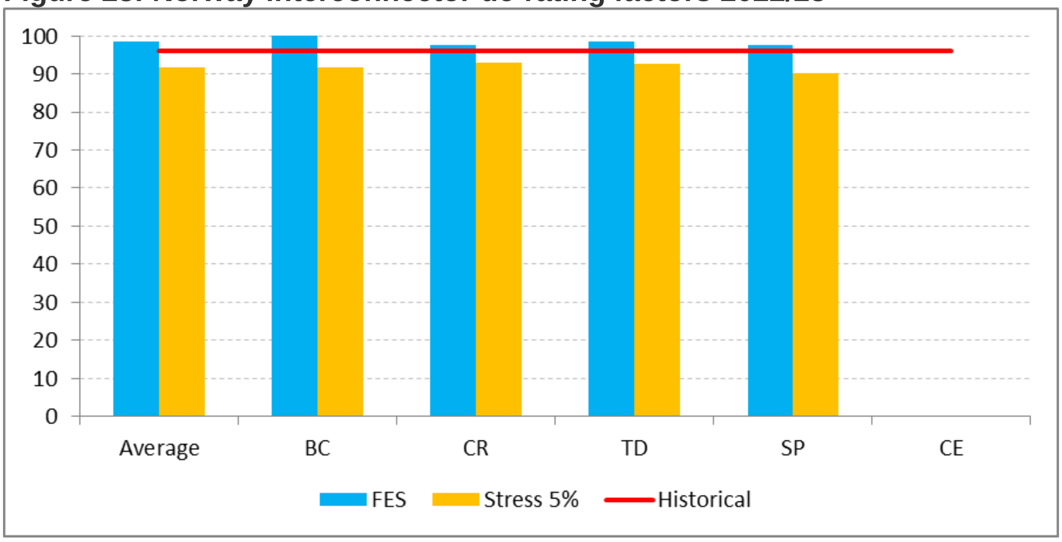


Table 20: Norway interconnector de-rating factors 2022/23

Scenario	Average	Base Case	Community Renewables	Two Degrees	Steady Progression	Consumer Evolution
FES	98	100	98	98	98	
Stress 5%	92	92	93	93	90	

Summary

This year the modelled ranges are based on the full set of simulation runs. For 2019/20, there were two stress test sets of European simulations because the high GB margins in the FES scenarios meant that there were too few observations from which to calculate de-rating factors in both the non-stress run and some scenarios with the 5% demand increase. In general, the modelled ranges for 2019/20 were higher than the historical de-rating factors. Tightening margins across Europe due to closures and mothballing of thermal generation means that, for 2022/23, Belgium and Netherlands have model ranges much lower than the historical de-rating factors. Therefore, the modelled ranges have not been adjusted to always be above the historical de-rating factor[33]. Table 21 shows the modelled ranges for each interconnector. Historical de-rating factors are also depicted.

The modelled ranges do not include an allowance for interconnector import constraints in GB on the assumption that this is more appropriately allowed for in the adjustments made to individual interconnector de-rating factors along with technical availability.

Table 21: De-rating factor ranges by country

Country	Delivery Year	Historical	Low	High
Ireland	2019/20	5	35	54
	2022/23		24	42
France	2019/20	55	61	92
	2022/23		59	86
Belgium	2019/20	67	65	78
	2022/23		35	67
Netherlands	2022/23	70	27	62
Norway	2022/23	96	90	100

There are no de-rating factors shown for Netherlands for 2019/20 T-1 auction because the Netherlands interconnector was awarded a Capacity Market contract in the T-4 auction and is therefore ineligible for the T-1 auction. Denmark is not included as we have assumed it will be unlikely to bid for 2022/23 following recent delays to its final investment decision.[34]

[33] Section 3A of https://www.gov.uk/government/publications/capacity-market-rules
[34] http://viking-link.com/news/investment-decision-to-be-rescheduled/

5. Results and Recommendation for 2022/23 T-4 Auction

This chapter presents the results for 2022/23 only from the modelling of the scenarios and sensitivities relevant to 2022/23. Results for 2019/20 can be found in Chapter 6. Further information on capacity requirements in years out to 2032/33 can be found in Section 3.11.

5.1 Sensitivities to model

The analysis assumes that the FES scenarios will cover multivariate uncertainty by incorporating ranges for annual and peak demand, DSR, storage, interconnection and generation with the sensitivities covering uncertainty in single variables. Chapter 3 describes the scenarios and sensitivities modelled for the 2018 ECR. The agreed sensitivities to model for 2022/23 cover non delivery, over delivery, weather, wind and demand:

- Low Wind Output at times of cold weather (LOW WIND)
- High Wind Output at times of cold weather (HIGH WIND)
- Cold Weather Winter (COLD)
- Warm Weather Winter (WARM)
- High Demand (HIGH DEMAND)
- Low Demand (LOW DEMAND)
- Non Delivery (NON DEL): 7 sensitivities in 400 MW increments up to 2800 MW
- Over Delivery (OVER DEL): 3 sensitivities in 400 MW increments up to 1200 MW

5.2 Results

Table 22 shows the modelling results sorted in order of de-rated capacity required to meet the 3 hours LOLE Reliability Standard. It also shows the capacity outside of the CM (including previously contracted capacity assumed for each case), the total de-rated capacity and ACS peak demand.

All the scenarios and sensitivities modelled take account of capacity market units awarded multi-year capacity agreements covering 2022/23 in previous T-4 auctions that have had their contracts terminated – this totals 1.8 GW (de-rated). In addition, since the 2020/21 T-4 auction, the de-rating factors for duration limited storage technologies have been revised. As a result of these revisions, our estimate of the de-rated capacity of duration limited storage capacity awarded multi-year contracts in the 2020/21 T-4 auction has been reduced by around 0.3 GW. These two changes have reduced the estimated previously contracted capacity for 2022/23 by 2.1 GW from the reported[35] figure of 6.7 GW down to 4.6 GW.

Furthermore, the scenarios assume between 0 and 0.4 GW (de-rated) of additional distributed generation (DG) units awarded multi-year capacity agreements covering

[35] See page 9 of https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/Final%20T-4%20Results%20(Delivery%20Year%2021-22)%2020.02.2018.pdf

2022/23 in previous T-4 auctions that are not able to honour their agreements. Lowest non-delivery is assumed in Consumer Evolution (0 GW) while Two Degrees assumes a higher level of DG non-delivery (0.4 GW) with the Base Case in between (0.2 GW).

Table 22: Modelled de-rated capacities and peak demands - 2022/23

Name	Graph Code	Capacity to Secure (GW)	Outside CM (GW)	Previously Contracted Capacity (GW)	Over Or Non Delivery (GW)	Total derated capacity (GW)	ACS Peak (GW)
Warm Winter	BC_WARM	43.9	18.0	4.4	0.0	61.9	60.3
Two Degrees	TD	44.0	18.3	4.2	0.0	62.3	58.8
Community Renewables	CR	44.5	18.4	4.5	0.0	62.9	59.2
Over Delivery Scenario: 1200	BC_OVER_DEL_1200	44.6	19.3	4.4*	1.2	64.0	60.3
Low Demand	BC_LOW_DEMAND	44.7	18.1	4.4	0.0	62.8	59.1
Over Delivery Scenario: 800	BC_OVER_DEL_800	45.0	18.9	4.4*	0.8	64.0	60.3
Steady Progression	SP	45.4	17.6	4.4	0.0	63.0	60.0
Over Delivery Scenario: 400	BC_OVER_DEL_400	45.4	18.5	4.4*	0.4	64.0	60.3
High Wind	BC_HIGH_WIND	45.6	18.3	4.4	0.0	63.9	60.3
Base Case	BC	45.8	18.1	4.4	0.0	64.0	60.3
Consumer Evolution	CE	45.9	18.2	4.6	0.0	64.1	60.6
Low Wind	BC_LOW_WIND	46.0	17.9	4.4	0.0	63.9	60.3
Non Delivery Scenario: -400	BC_NON_DEL_400	46.2	17.7	4.4*	-0.4	64.0	60.3
Non Delivery Scenario: -800	BC_NON_DEL_800	46.6	17.3	4.4*	-0.8	64.0	60.3
Cold Winter	BC_COLD	46.7	18.3	4.4	0.0	65.0	60.3
High Demand	BC_HIGH_DEMAND	46.9	18.2	4.4	0.0	65.1	61.5
Non Delivery Scenario: -1200	BC_NON_DEL_1200	47.0	16.9	4.4*	-1.2	64.0	60.3
Non Delivery Scenario: -1600	BC_NON_DEL_1600	47.4	16.5	4.4*	-1.6	64.0	60.3
Non Delivery Scenario: -2000	BC_NON_DEL_2000	47.8	16.1	4.4*	-2.0	64.0	60.3
Non Delivery Scenario: -2400	BC_NON_DEL_2400	48.2	15.7	4.4*	-2.4	64.0	60.3
Non Delivery Scenario: -2800	BC_NON_DEL_2800	48.6	15.3	4.4*	-2.8	64.0	60.3

Scenario Colour Key
Two Degrees
Steady Progression
Community Renewables
Consumer Evolution
Base Case

Total derated capacity (GW) =
Capacity to Secure (GW)
+ Outside Capacity Market (GW)

* The previously contracted capacity figure assumes full delivery. Any over or non delivery would be split between plants contracted in previous auctions and plants contracted in future auctions. As such this has accounted for in a separate column

N.B. ACS Peak demand excludes reserve for largest infeed loss. Capacity to secure excludes any capacity assumed in the modelling with multi-year contracts secured for 2022/23 in the 2018/19, 2019/20, 2020/21 and 2021/22 T-4 auctions – this capacity is included in the "Outside CM" capacity and is also shown in a separate column. Note that the non-delivery sensitivities have been modelled by reducing the "Outside CM" capacity and over delivery sensitivities by increasing the "Outside CM" capacity.

The Base Case warm sensitivity and 2800 MW non-delivery sensitivity define the extremes of the capacity to secure range for 2022/23 (43.9 GW to 48.6 GW).

5.3 Recommended Capacity to Secure

Table 22 shows the de-rated capacity required to meet 3 hours LOLE in each model run. However, if the capacity was selected based on one model run, but in 2022/23, the actual conditions matched a different model run then capacity will have either been over or under secured, resulting in an LOLE lower or higher than 3. The impact of over or under securing capacity can be estimated from the cost of capacity and the cost of unserved energy. The Least Worst Regret (LWR) methodology, agreed with BEIS and the PTE, has been used to select a recommended capacity to secure value in 2022/23, taking account of the costs of under or over securing for all potential outcomes.

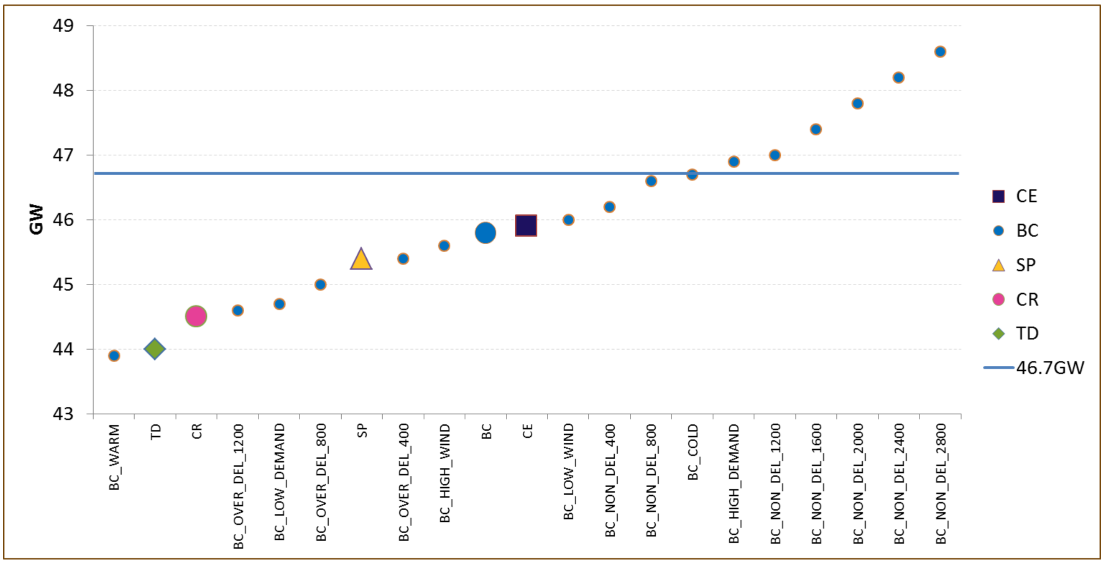
Links to details on the LWR methodology are provided in the Annex. As per previous ECR analysis, it uses a net Cost of New Entry (CONE) of £49/kW/year and an energy unserved cost of £17,000/MWh (consistent with the Government's Reliability

Standard) to select a scenario / sensitivity from which the recommended capacity to secure is derived.

The outcome of the LWR calculation applied to all of National Grid's scenarios and sensitivities is a recommended capacity to secure for 2022/23 of **46.7 GW** derived from the requirement of the Base Case Cold Winter sensitivity. Our recommended target capacity to secure corresponds to the value on the CM demand curve for the net CONE capacity cost. The clearing price in the auction may be different to net CONE, resulting in the cleared capacity being different to the target capacity. The recommendation also excludes any capacity secured for 2022/23 in earlier T-4 auctions that is assumed in the Base Case.

Figure 24 illustrates the full range of potential capacity requirements (from the scenarios and sensitivities) and identifies the LWR recommended capacity. Individual scenarios are highlighted with larger markers and each scenario and sensitivity is colour coded. Note that National Grid's recommendation concentrates on the target capacity alone.

Figure 24: Least Worst Regret recommended capacity to secure compared to individual scenario/sensitivity runs – 2022/23



N.B. The points point on this chart represents the de-rated capacity required for each scenario / sensitivity to meet the Reliability Standard of 3 hours LOLE.

5.3.1 Covered range

We consider a scenario or sensitivity is covered by the capacity secured if the LOLE is at or below the Reliability Standard of 3 hours per year. If a scenario or sensitivity is not covered, and it was to occur in 2022/23, then the LOLE could be greater than 3 hours. This could increase the deployment of mitigating actions (voltage reduction, max gen service and emergency assistance from interconnectors) more frequently and/or in higher volumes to reduce the risk of any controlled disconnections. If the loss of load is higher than the level of mitigating actions, this may lead to controlled customer disconnections.

As can be seen from the chart, securing a capacity of 46.7 GW would result in 15 out of 21 cases being covered.

5.3.2 Adjustments to Recommended Capacity

The recommended capacity in this report will not necessarily be the capacity auctioned - this will be a decision for the Secretary of State, included in the Final Auction Guidelines published after pre-qualification. To obtain the capacity auction requirement, a number of adjustments to the recommended figure or range will need to be made (e.g. denoted by v, w, x, y and z below) including a potential adjustment to the previously contracted capacity assumed in the modelling (in z):

- Capacity with Long Term STOR contracts that opts not to surrender those contracts needs to be excluded (pre-qualification could change this) – vGW.
- Government (upon confirming auction parameters to National Grid prior to auction guidelines) will determine how much capacity to hold back for the 2022/23 T-1 auction– wGW.
- Government (either upon confirming auction parameters to National Grid prior to auction guidelines or post pre-qualification) will determine DSR to opt-out but remain operational – xGW.
- Government (either upon confirming auction parameters to National Grid prior to auction guidelines or post pre-qualification) will determine distributed generation to opt out but remain operational – yGW.*
- Government (either upon confirming auction parameters to National Grid prior to auction guidelines or post pre-qualification) will determine large scale generation to opt out but remain operational or adjustment due to previously contracted plants with different closure assumptions to the Base Case – zGW.*

Therefore, the recommended total capacity to secure through the 2022/23 T-4 auction could be:

- 46.7 GW - v - w - x - y - z.

* National Grid's modelling assumes no eligible generation or DSR opts out as no data is currently available to inform the modelling process but will hopefully become available through the pre-qualification process.

The auction will select from a range of capacity levels depending on the demand curve, determined by the Government, and the cost of capacity which enters the auction.

Given that it is unlikely that the marginal capacity in the auction will result in an LOLE of exactly 3 hours, the demand curve for the auction will result in a capacity from a range around the target capacity. Thus a recommended de-rated capacity of 46.7 GW could result in a differing capacity volume depending on the clearing price set by the marginal capacity. The tolerances are set by BEIS based on the size of a typical CMU and to limit gaming opportunities. Any issues with this value can be reconciled appropriately in the T-1 auction.

5.3.3 Comparison with 2021/22 recommendation

In our 2017 Electricity Capacity Report, we recommended a capacity to secure for 2021/22 of 50.5 GW, 2 GW above our Base Case requirement of 48.5 GW which assumed 4.3 GW of previously contracted capacity (net of non-delivery).

In general, when compared to the analysis for 2021/22 in the 2017 ECR, the 2018 ECR recommendation for 2022/23 is 3.8 GW lower. This difference is the result of changes that fall into two categories; the first category being changes that affect the total de-rated capacity required and the second category being changes that affect the split of that total de-rated capacity between eligible and ineligible capacity.

There is a reduction (1.6 GW) in the total capacity requirement due to:

- A decrease of 1.1 GW due primarily to a lower range of non-delivery sensitivities (a maximum of 2.8 GW in the 2018 ECR compared to a maximum of 4 GW in the 2017 ECR) resulting in a different sensitivity (Cold Winter) setting the LWR requirement (compared to the 2 GW non-delivery sensitivity setting the LWR requirement in the 2017 ECR).
- A 1 GW lower peak demand in 2022/23 offset by
- A 0.1 GW net reduction due to other changes (e.g. change in de-rated margin required for 3 hours LOLE compared to the 2017 Base Case and rounding).
- Offset by a 0.6 GW increase in reserve for largest infeed loss compared to the 2017 Base Case.

In addition, there is a further reduction of 2.2 GW in the eligible capacity required due to a corresponding net increase in the level of assumed CM-ineligible de-rated capacity. This is a result of the following:

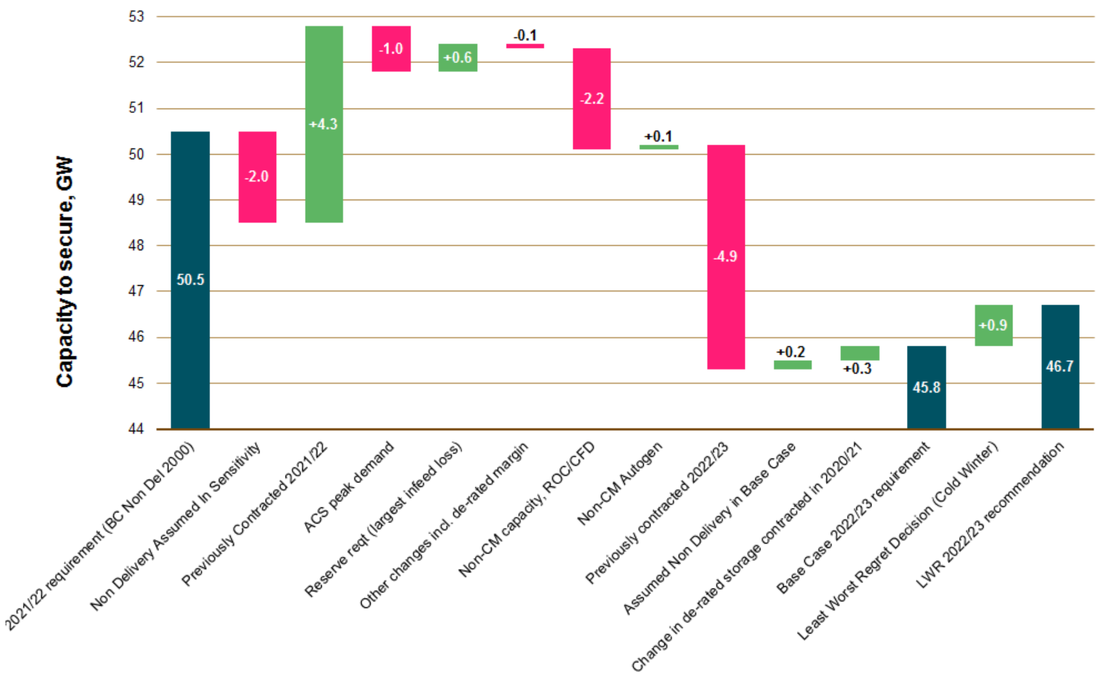
- An increase of 2.2 GW in renewable contribution at peak largely due to an increase in biomass capacity and offshore wind capacity (see Annex A.4.3 for a breakdown of the ineligible capacity).
- 0.1 GW higher assumed levels of net previously contracted capacity (4.4 GW net in the 2018 ECR compared to 4.3 GW net in the 2017 ECR). In the 2018 ECR, the net previously contracted capacity of 4.4 GW for 2022/23 is derived from 4.9GW contracted in previous T-4 auctions minus 0.2 GW of DG non-delivery minus 0.3 GW storage de-rated capacity adjustment (see 5.2 for more details).
- Offset by a 0.1 GW reduction in assumed opted-out or ineligible (below 2 MW) autogeneration[36].

This analysis highlights the risk of further non-delivery (0.2 GW in the Base Case plus up to a maximum of 2.8 GW in the most extreme non-delivery sensitivity). However, we note that by highlighting the risk in this report, some of this non-delivery may be prevented. This in turn would reduce the demand curve target in the T-1 auction, which will be reassessed in the 2021 ECR.

The following waterfall chart, Figure 25, shows how the original 50.5 GW requirement for the 2022/23 T-4 auction (derived from the 2017 Base Case 2000 MW non delivery sensitivity) has changed into a recommended requirement of 46.7 GW (derived from the 2018 Base Case Cold Winter sensitivity) as a result of the 3.8 GW net reduction described above.

[36] Note that unsupported capacity under 2 MW can enter the auction if it is combined with other capacity by an aggregator to give a total above 2 MW

Figure 25: Comparison with recommended 2021/22 T-4 requirement in 2017 ECR



5.3.4 Robustness of LWR approach to sensitivities considered

During previous discussions around the potential for non-delivery (ND) and over delivery (OD) sensitivities a question was raised around how sensitive the LWR decision was to the sensitivities included e.g. maximum level of non-delivery. To address this we ran the LWR tool with some of the highest and lowest cases removed. In doing this, if the LWR tool selected the requirement from a FES scenario, the requirement for the nearest Base Case sensitivity requirement was selected (as per the methodology outlined in Section 2.6 of the 2016 ECR). The results from this are shown in Table 23 below.

Table 23: Sensitivity of LWR outcome (46.7 GW) to LWR range

Sensitivities Added (+) or Removed (-)	-Warm	-TD - Warm	-TD - Warm +1.6 OD	-2.8 ND	-2.8 ND -2.4 ND	+3.2 ND
2022/23 outcome	46.9	47.0	46.9	46.6	46.2	47.0

Removing the lowest case (Warm winter) increased the outcome by 0.2 GW to 46.9 GW. Removing the next lowest case (TD) as well increased the requirement to 47.0 GW. Adding an additional over-delivery case (1.6 GW) to this brought the requirement back down to 46.9 GW. For a maximum non-delivery of 2.4 GW (i.e. removing the 2.8 GW ND case), the impact on the LWR outcome was a net reduction of 0.1 GW to 46.6 GW. For a maximum non-delivery of 2.0 GW, the reduction was 0.5 GW to 46.2 GW. Increasing the maximum non-delivery to 3.2 GW increased the outcome by 0.3 GW to 47.0 GW. Hence the outcome remains stable when removing either the lowest or highest sensitivity.

Although the LWR outcome is relatively stable when the maximum non-delivery is reduced or increased, we still believe the most robust maximum non-delivery sensitivity is 2.8 GW to address the risk associated with coal and gas closures, embedded benefits, unproven DSR and interconnection.

To set this in context, for the 2019/20 T-4 auction around 4.9 GW of non-delivery has been observed including capacity awarded 3 or 15 year contracts in the 2018/19 T-4 auction[37] that no longer has multi-year contracts.

[37] Note that the CM rules and penalty regime have changed since the 2018/19 T-4 auction

6. Results and Recommendation for 2019/20 T-1 Auction

This chapter presents the results for 2019/20 only from the modelling of the scenarios and sensitivities relevant to 2019/20. Results for 2022/23 can be found in Chapter 5. Further information on capacity requirements in years out to 2032/33 can be found in Section 3.11.

6.1 Sensitivities to model

The analysis assumes that the FES scenarios will cover multivariate uncertainty by incorporating ranges for annual and peak demand, DSR, storage, interconnection and generation with the sensitivities covering uncertainty in single variables. Chapter 3 describes the scenarios and sensitivities modelled for the 2018 ECR. The agreed sensitivities to model for 2019/20 cover non delivery, over delivery, weather, wind, plant availability and demand:

- Low Wind Output at times of cold weather (LOW WIND)
- High Wind Output at times of cold weather (HIGH WIND)
- Cold Weather Winter (COLD)
- Warm Weather Winter (WARM)
- High Plant Availabilities (HIGH AVAIL)
- Low Plant Availabilities (LOW AVAIL)
- High Demand (HIGH DEMAND)
- Low Demand (LOW DEMAND)
- Non Delivery (NON DEL): 6 sensitivities in 400 MW increments up to 2400 MW
- Over Delivery (OVER DEL): 3 sensitivities in 400 MW increments up to 1200 MW

6.2 Results

Table 24 below shows the modelling results sorted in order of de-rated capacity required to meet the 3 hours LOLE Reliability Standard. It also shows the capacity outside of the CM (including previously contracted capacity assumed for each case), the total de-rated capacity and ACS peak demand.

All cases modelled take account of capacity market units awarded contracts covering 2019/20 in previous T-4 auctions and units awarded multi-year contracts in the 2018/19 T-4 auction covering 2019/20 that are now known not to be able to honour their contracts – this totals 4.9 GW (de-rated).

In addition, for contracted transmission connected units, the scenarios and sensitivities (except high and low availability) assume a previously contracted capacity based on de-rated Transmission Entry Capacity (TEC) values that are around 0.5 GW lower in aggregate than the contracted values in the CM register.

These two changes have reduced the estimated previously contracted capacity for 2019/20 by 5.4 GW from the reported[38] figure of 51.9 GW down to 46.5 GW.

Furthermore, the scenarios assume between 0 and 0.3 GW (de-rated) of additional distributed generation (DG) units awarded multi-year capacity agreements covering 2019/20 in previous T-4 auctions that are not able to honour their agreements. Lowest non-delivery is assumed in Consumer Evolution (0 GW) while Two Degrees assumes a higher level of DG non-delivery (0.3 GW).

Table 24: Modelled de-rated capacities and peak demands – 2019/20

Name	Graph Code	Capacity to Secure (GW)	Outside CM (GW)	Previously Contracted Capacity (GW)	Over Or Non Delivery (GW)	Total derated capacity (GW)	ACS Peak (GW)
Warm Winter	BC_WARM	1.9	58.7	46.3	0.0	60.6	59.3
High Availability	BC_HIGH_AVAIL	2.2	60.0	47.7	0.0	62.2	59.3
Over Delivery Scenario: 1200	BC_OVER_DEL_1200	2.6	59.9	46.3*	1.2	62.5	59.3
Low Demand	BC_LOW_DEMAND	2.6	58.8	46.3	0.0	61.5	58.1
Over Delivery Scenario: 800	BC_OVER_DEL_800	3.0	59.5	46.3*	0.8	62.5	59.3
Two Degrees	TD	3.2	58.8	46.2	0.0	62.0	58.6
Over Delivery Scenario: 400	BC_OVER_DEL_400	3.4	59.1	46.3*	0.4	62.5	59.3
Community Renewables	CR	3.4	59.0	46.4	0.0	62.4	58.9
High Wind	BC_HIGH_WIND	3.6	59.1	46.3	0.0	62.7	59.3
Base Case	BC	3.8	58.7	46.3	0.0	62.5	59.3
Low Wind	BC_LOW_WIND	4.0	58.5	46.3	0.0	62.6	59.3
Non Delivery Scenario: -400	BC_NON_DEL_400	4.2	58.3	46.3*	-0.4	62.5	59.3
Consumer Evolution	CE	4.2	58.7	46.5	0.0	63.0	59.7
Steady Progression	SP	4.3	58.4	46.3	0.0	62.7	59.4
Non Delivery Scenario: -800	BC_NON_DEL_800	4.6	57.9	46.3*	-0.8	62.5	59.3
Cold Winter	BC_COLD	4.7	59.0	46.3	0.0	63.7	59.3
High Demand	BC_HIGH_DEMAND	5.0	58.9	46.3	0.0	63.9	60.5
Non Delivery Scenario: -1200	BC_NON_DEL_1200	5.0	57.5	46.3*	-1.2	62.5	59.3
Low Availability	BC_LOW_AVAIL	5.4	57.5	45.0	0.0	62.9	59.3
Non Delivery Scenario: -1600	BC_NON_DEL_1600	5.4	57.1	46.3*	-1.6	62.5	59.3
Non Delivery Scenario: -2000	BC_NON_DEL_2000	5.8	56.7	46.3*	-2.0	62.5	59.3
Non Delivery Scenario: -2400	BC_NON_DEL_2400	6.2	56.3	46.3*	-2.4	62.5	59.3

Scenario Colour Key
Two Degrees
Steady Progression
Community Renewables
Consumer Evolution
Base Case

Total derated capacity (GW) =
Capacity to Secure (GW)
+ Outside Capacity Market (GW)

* The previously contracted capacity figure assumes full delivery. Any over or non delivery would be split between plants contracted in previous auctions and plants contracted in future auctions. As such this has accounted for in a separate column

N.B. ACS Peak demand excludes reserve for largest infeed loss. Capacity to secure excludes any capacity assumed in the modelling with contracts covering 2019/20 in the 2018/19 and 2019/20 T-4 auctions – this capacity is included in the "Outside CM" capacity and is also shown in a separate column. Note that the non-delivery sensitivities have been modelled by reducing the "Outside CM" capacity and over-delivery sensitivities by increasing the "Outside CM" capacity.

The warm winter and 2400 MW non-delivery sensitivity define the extremes of the capacity to secure range for 2019/20 (1.9 GW to 6.2 GW).

6.3 Recommended Capacity to Secure

Table 24 above shows the capacity required to meet 3 hours LOLE in each model run. However, if the capacity was selected based on one model run, but in 2019/20 the actual conditions matched a different model run then capacity will have either been over or under secured, resulting in an LOLE higher or lower than 3 hours. The impact of over or under securing capacity can be estimated from the cost of capacity and the cost of unserved energy. The Least Worst Regret (LWR) methodology, agreed with BEIS and the PTE, has been used to select a recommended capacity to

[38] See page 9 of https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/Final%20T-4%20Results%20(Delivery%20Year%2021-22)%2020.02.2018.pdf

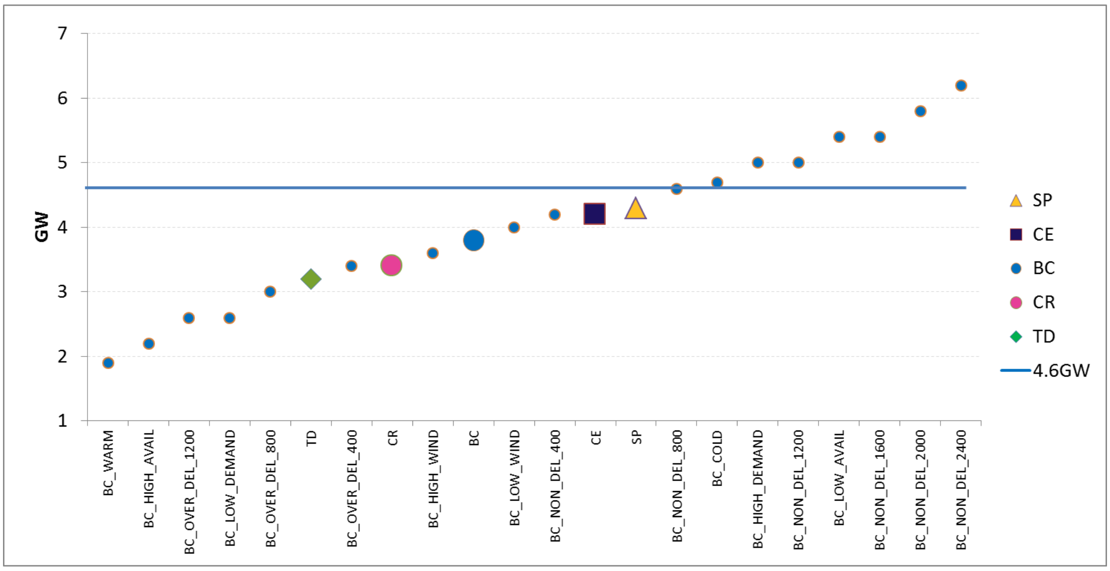
secure value in 2019/20 taking account of the costs of under or over securing for all potential outcomes.

Links to details on the LWR methodology are provided in the Annex. As per previous ECR analysis, it uses a net CONE of £49/kW/year and an energy unserved cost of £17,000/MWh (consistent with the Government's Reliability Standard) to select a scenario / sensitivity from which the recommended capacity to secure is derived.

The outcome of the Least Worst Regret calculation applied to all of National Grid's scenarios and sensitivities is a recommended capacity to secure for 2019/20 of **4.6 GW** derived from the requirement of the Base Case 800 MW non delivery sensitivity. Our recommended target capacity to secure corresponds to the value on the CM demand curve for the net CONE capacity cost. The clearing price in the auction may be different to net CONE, resulting in the cleared capacity being different to the target capacity. The recommendation also excludes any capacity secured for 2019/20 in earlier T-4 auctions assumed in the Base Case.

Figure 26 illustrates the full range of potential capacity requirements (from the scenarios and sensitivities) and identifies the LWR recommended capacity. Individual scenarios are highlighted with larger markers and each scenario and sensitivity is colour coded. Note that National Grid's recommendation concentrates on the target capacity alone.

Figure 26: Least Worst Regret recommended capacity to secure compared to individual scenario/sensitivity runs – 2019/20



N.B. The points point on this chart represents the de-rated capacity required for each scenario / sensitivity to meet the Reliability Standard of 3 hours LOLE.

6.3.1 Covered range

We consider a scenario or sensitivity is covered by the capacity secured if the LOLE is at or below the Reliability Standard of 3 hours per year. If a scenario or sensitivity is not covered, and it was to occur in 2019/20, then the LOLE could be greater than 3 hours. This could increase the deployment of mitigating actions (voltage reduction, max gen service and emergency assistance from interconnectors) more frequently and/or in higher volumes to reduce the risk of any controlled disconnections. If the loss of load is higher than the level of mitigating actions, this may lead to controlled customer disconnections.

As can be seen from the above chart, securing a capacity of 4.6 GW would result in 15 out of 22 cases being covered.

6.3.2 Adjustments to Recommended Capacity

The recommended capacity in this report will not necessarily be the capacity auctioned – this will be a decision for the Secretary of State, included in the Final Auction Guidelines published after prequalification. To obtain the T-1 auction target, a number of adjustments to the indicative figure or range may need to be made (e.g. denoted by v, x, y and z below) including a potential adjustment to the previously contracted capacity assumed in the modelling (in z):

- Capacity with Long Term STOR contracts that opts not to surrender those contracts needs to be excluded (pre-qualification could change this) – vGW.
- Government (either upon confirming auction parameters to National Grid prior to auction guidelines or post pre-qualification) will determine DSR to opt out but remain operational – xGW.
- Government (either upon confirming auction parameters to National Grid prior to auction guidelines or post pre-qualification) will determine distributed generation to opt out but remain operational – yGW.*
- Government (either upon confirming auction parameters to National Grid prior to auction guidelines or post pre-qualification) will determine large scale generation to opt out but remain operational or adjustment due to contracted plants with different closure assumptions to the Base Case – zGW.*

Therefore, the recommended capacity to secure through the 2019/20 T-1 auction could be:

- 4.6 GW - v - x - y - z.

*National Grid's modelling assumes no eligible generation or DSR opts out as no data is currently available to inform the modelling process but will hopefully become available through the pre-qualification process.

The auction will select from a range of capacity levels depending on the demand curve, determined by the Government, and the cost of capacity which enters the auction.

Given that it is unlikely that the marginal capacity in the auction will result in an LOLE of exactly 3 hours the demand curve for the auction will result in a capacity from a range around the target capacity. Thus a recommended de-rated capacity of 4.6 GW could result in a differing capacity volume depending on the clearing price set by the marginal capacity. The tolerances are set by BEIS based on the size of a typical CMU and to limit gaming opportunities.

6.3.3 Comparison with 2019/20 recommendation

In our 2015 Electricity Capacity Report, we recommended a capacity to secure for 2019/20 of 47.9 GW of which the Secretary of State decided to hold back 2.5 GW for the 2019/20 T-1 auction leaving a target capacity of 45.4 GW for the T-4 auction. Following pre-qualification, the 2019/20 T-4 auction target was reduced by around

0.7 GW to around 44.7 GW to take account of 0.6 GW of transmission connected capacity that was opted out but operational in 2019/20 and around 0.1 GW of long-term STOR opted out capacity expected to be operational in 2019/20.

In general, when compared to the analysis for 2019/20 in the 2015 ECR that ultimately led to the 2.5 GW set aside by the Secretary of State for the T-1 auction, the 2018 ECR recommendation for 2019/20 is 2.1 GW higher than the 2.5 GW set aside. This difference is the result of changes that fall into two categories; the first category being changes that affect the total additional de-rated capacity required since the T-4 auction and the second category being changes relating to ineligible capacity assumptions.

There is a 4.1 GW net increase in total additional de-rated capacity required from:

- A wider range of sensitivities (including non-delivery) that increases the requirement in the LWR analysis by 0.8 GW.
- Known non-delivery, totalling 4.9 GW in 2019/20 in the Base Case (see 6.2).
- 0.1 GW assumed additional DG non-delivery in the Base Case.
- The remaining contracted capacity in the T-4 auction being 0.5 GW greater than the de-rated TEC.
- A 0.5 GW increase due to a higher reserve for largest infeed loss compared to the 2015 Consumer Power (CP) High Availability sensitivity.
- A 0.4 GW net increase due to other changes (e.g. change in de-rated margin required for 3 hours LOLE compared to the 2015 CP High Availability sensitivity and rounding).
- A 1.4 GW reduction due to a lower peak demand in 2019/20 for the Base Case compared to the 2015 CP High Availability sensitivity (see below).
- A reduction in requirement from over-securing in the 2019/20 T-4 auction by 1.7 GW.

This 4.1 GW net increase in additional capacity requirement is partly offset by a 2 GW reduction in eligible capacity due to a corresponding net increase in assumed ineligible capacity as described below:

- A 2.7 GW higher non-CM capacity (see Annex A.4.3 for breakdown). This is largely comprised of increased biomass capacity, higher wind contribution at peak (due in part to the new offshore power curve introduced in the 2016 ECR and in part increased wind capacity) and slightly higher levels of assumed opted-out or ineligible (below 2 MW) autogeneration[39].
- A 0.6 GW reduction in opted out but operational capacity deducted from the T-4 auction target already being included in the 2.7 GW non-CM capacity above.
- A 0.1 GW reduction in opted-out long-term STOR deducted from the T-4 auction target that now has an opportunity to opt in to the T-1 auction.

The analysis highlights the risk of contracted plant defaulting (4.9 GW of known non delivery in the Base Case plus up to a further 2.4 GW in the most extreme non delivery sensitivity).

The following waterfall chart, Figure 27, shows how the original 2.5 GW set aside for the 2019/20 T-1 auction (derived from the 2015 Consumer Power High Availability sensitivity) has changed into a recommendation of 4.6 GW (derived from the 2018

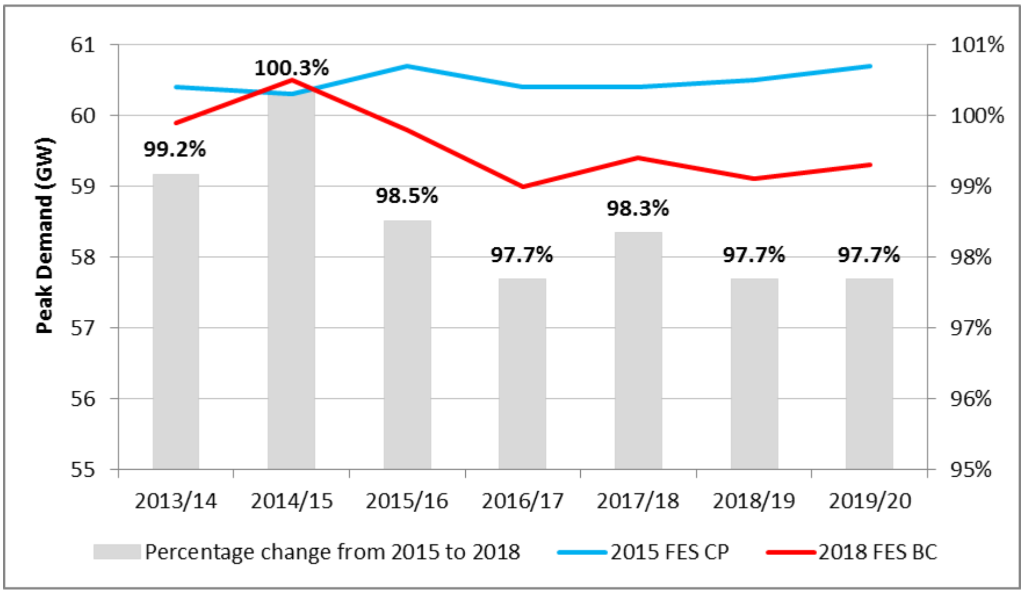
[39] Note that unsupported capacity under 2 MW can enter the auction if it is combined with other capacity by an aggregator to give a total above 2 MW

Base Case 800 MW non-delivery sensitivity) as a result of the 2.1 GW net increase described above.

Figure 27: Comparison with original 2019/20 T-1 requirement (de-rated)

As highlighted above, since the 2015 ECR, the peak demand for 2019/20 has reduced by 1.4 GW. Figure 28 compares the underlying ACS peak demand in the 2018 Base Case (2018 BC) to the underlying ACS peak demand in the 2015 Consumer Power (2015 CP) scenario over the period from 2013/14 to 2019/20, which illustrates that the 2015 Consumer Power peak demand was projected to remain relatively flat while the 2018 Base Case peak demand dropped in 2015/16 and 2016/17 before flattening off.

Figure 28: Peak Demand Comparison (2018 ECR v 2015 ECR)



The fall in demand in 2015/16 and 2016/17 predominantly occurred in the residential and industrial sectors. 2015 CP was a high consumerism scenario where energy efficiency was not important and it was a high GDP scenario; whereas 2018 BC is more efficient and utilises 'base view' of GDP growth. These differences resulted in the diversity between 2015 and 2018 demand forecasts. Other factors contributing to this gap include changes in data, assumptions and processes.

This highlights the need to continue to develop our methodologies and data sources to enhance our understanding of peak demand. The letter written under Special Condition 4L.13 gives an explanation of how we are developing our demand forecasting methodology[40].

6.3.4 Robustness of LWR approach to sensitivities considered

During previous discussions around the potential for non-delivery (ND) and over delivery (OD) sensitivities, a question was raised around how sensitive the LWR decision was to the sensitivities included e.g. maximum level of non-delivery. To address this we ran the LWR tool with some of the highest and lowest cases removed. In doing this, if the LWR tool selected the requirement from a FES scenario, the requirement for the nearest Base Case sensitivity requirement was selected (as per the methodology outlined in Section 2.6 of the 2016 ECR). The results from this are shown in Table 25 below.

Table 25: Sensitivity of LWR outcome (4.6 GW) to LWR range

Sensitivities Added (+) or Removed (-)	-Warm	-Warm -H.Avail	- Warm -H.Avail +1.6 OD	-2.4 ND	-2.4 ND -2.0ND	+2.8 ND
2019/20 outcome	4.7	5.0	4.7	4.2	4.0	5.0

Removing the lowest case (Warm winter) increased the outcome by 0.1 GW to 4.7 GW. Removing the next lowest case (High Availability) as well increased the requirement to 5.0 GW. Adding an additional over-delivery case (1.6 GW) to this brought the requirement back down to 4.7 GW. For a maximum non-delivery of 2.0 GW (i.e. removing the 2.4 GW ND case), the impact on the LWR outcome was a net reduction of 0.4 GW to 4.2 GW (from the nearest Base Case sensitivity). For a maximum non-delivery of 1.6 GW, the reduction was a further 0.2 GW to 4.0 GW. Increasing the maximum non-delivery to 2.8 GW increased the outcome by 0.4 GW from 4.6 GW to 5.0 GW. Hence the outcome remains fairly stable when removing either the lowest or highest sensitivity.

Although the LWR outcome is relatively stable when the maximum non-delivery is reduced or increased, we still believe the most robust maximum non-delivery sensitivity is 2.4 GW to address the risk associated with coal and gas closures, embedded benefits, unproven DSR and interconnection.

To set this in context, for the 2019/20 T-4 auction around 4.9 GW of non-delivery has been observed including capacity awarded 3 or 15 year contracts in the 2018/19 T-4 auction[41] that no longer has multi-year contracts.

[40] To be published at https://www.emrdeliverybody.com/cm/home.aspx
[41] Note that the CM rules and penalty regime have changed since the 2018/19 T-4 auction

A. Annex

A.1 Demand Methodology

The demand projections are developed using in-house analysis which has used stakeholder feedback to inform it. Annual demands can be considered with the following breakdown:

- Domestic
- Industrial
- Commercial
- Transport
- Other/Sundry

Domestic

The domestic demand is created by using a bottom up method. Each of the component parts of the sectors demand is modelled individually. Where there is a history then this is used as the starting point for the modelling. If a component part is novel then research, projects' outcomes and proxy data are applied as appropriate. These components are listed below and each is projected individually which, when aggregated, form domestic demand for each scenario.

- **Appliances, including lighting:** A regression trend method flexed by the application of primary assumptions and appliance number caps. We have assumed energy efficiency gains in all our scenarios but with varying degrees depending on the scenario.

- **Resistive heat:** A new methodology has been applied where we use the thermal efficiency of the housing stock rather than just the insulation to inform our modelling. In our greener scenarios the average household thermal efficiency will be much improved on today's average. We have previously seen heat pumps as being the main alternative sources for heating as opposed to gas in our greener scenarios although this year's Two Degrees scenario also sees some heat decarbonised by use of hydrogen produced by Steam Methane Reforming of natural gas.

- **Resistive hot water:** the current hot water electrical heat demand comes from published statistics[42]. Due to the projected increase in heat pumps and the increase in the housing stock we expect the power demand for hot water to rise.

- **Heat pumps:** We see heat pumps as being the main source of non-gaseous heating. In order to decarbonise heating there is now a more complex interplay of different types of heat pumps with air-source and hybrid heat pumps vying for dominance. Energy efficiency improvements are assumed annually based on manufacturer engagement feedback.

[42] https://www.gov.uk/government/statistics/energy-consumption-in-the-uk

- **Consumer Flexibility –** This year, similarly to last year, Ofgem's updated retail market review data has been, used alongside research from recent studies, to forward project customer engagement rates. This percentage is applied to the underlying domestic demand and also plays a role in engagement in relation to transport demand.

Industrial

Economic data provided by Oxford Economics in December 2017 was used to create economic cases for GB economic growth. Retail energy price forecasts are also provided.

The model examines 24 sub-sectors (Industrial and commercial) 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 (e.g. heat recovery) and new technologies such as onsite generation (e.g. CHP) or different heating solutions (e.g. biomass boilers).

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 for each sub-sector to consider if the investment is economical and the likely uptake rates of any particular technology or initiative. This allows us to adjust the relative cost benefits to see what is required to encourage uptake of alternative heating solutions and understand the impact of prices on onsite generation.

Commercial

The same approach as described in the paragraphs above (in the industrial section) has been adopted this year.

Transport

- Road transport – a new model based on economics and a Bass Diffusion approach has been utilised this year to forecast uptake rates of different vehicles (i.e. natural gas and hydrogen as well as electric vehicles) that may replace the Internal Combustion Engine as transport is decarbonised. This is combined with statistics on journey length in order to assess the associated electrical demand. We continue to incorporate the concept of vehicle sharing and autonomous vehicles.
- Rail – three projections are applied to the electric rail demand based on stakeholder feedback. One is a continuation of historical growth (low) and the others are an enhanced growth rate and a mid-range value.

Other/Sundry

These are the demand components which do not fall directly into the categories above. For example, losses which are a function of the total demand figure, interconnector flows or micro-generation which is required in order to translate the FES total energy demand into a distribution or transmission demand definition.

Peak Demands

Once the assessment of underlying annual demand is created a recent historical relationship of annual to peak demand is applied. This creates an underlying peak demand to which peak demand components that history cannot predict are added. For example, electric vehicle charging or heat pump demand at times of peak demands on the transmission system.

For each of the scenarios we also applied a consumer engagement factor which increases in our greener scenarios.

The overlays to peak demand are:

- Electric vehicles: Based on the projected numbers, the potential user groups are assessed, how and when they could be charging (constrained and unconstrained), and data from recently published trials are incorporated. This year we continue to assume a size of charger unit of 7 kW.
- Heat pumps: The number of heat pumps and heat demand, data from manufacturers, and trial within day profiles combined with performance statistics and historical weather trends are used to determine the electrical heat demand at peak.
- Losses: As with annual demand, this is a function of total peak demand.
- Industrial & Commercial Demand Side Response: Created using desktop research and assumptions of future efficiency improvements, consumer engagement and information technology improvements.
- Domestic peak response – as with annual demand this starts with the smart meter roll-out numbers, project outcome data and perceived customer engagement rates. From this results a percentage peak demand reduction. This percentage factor is then applied to the peak demand.

Calibration

Both annual and peak demands are calibrated. Annual demands are calibrated to the previous year's historical annual demand figures as published by BEIS. Peak demand is calibrated with weather corrected metered transmission demand.

Results

The results of the described methods provided are defined and shown in the Annex (Section A.4.1). For a more detailed description of the methodology and FES scenarios please refer to the FES document or its workbook[43]. Note that the demand is defined on unrestricted basis as Demand Side Response can participate in the auction.

[43] http://fes.nationalgrid.com/fes-document/

A.2 Generation Methodology

The power supply transmission backgrounds use a rule based deterministic approach. An individual assessment of each power station (at a unit level where appropriate) was 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 was placed accordingly within their technology stack.

The placement of a power station was 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 background or Transmission Entry Capacity (TEC) Register[44] 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 background provides the basis for the majority of the entries into the generation backgrounds, 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.

For power generation connecting to the distributed system (including capacity < 1 MW), alternative sources of data will be used as the starting point for assessment, such as the Ofgem Feed In Tariffs register or BEIS Planning Base.

The generation backgrounds are then built up to meet the Reliability Standard in line with the FES Framework (i.e. all scenarios ensure security of supply is met).

A.2.1 Contracted Background

This contracted background provides a list of power stations which have an agreement to gain access rights to NETS; now and in the future. It provides valuable up to date information regarding any increase or decrease to a power station Transmission Entry Capacity which provides an indication of how a particular plant may operate in future years. This is then overlaid with market intelligence for that particular plant and/or generation technology type.

A.2.2 Market Intelligence

This section covers how market intelligence gathered through stakeholder engagement along with more general information is used to help determine which generation is likely to connect during the FES study period.

Developer Profile

This information relates to the developer of a certain project, or portfolio of projects, and provides an insight into how and when these projects may develop. Examples of information taken into account under this area are:

- Is the developer a portfolio player who may have a number of potential projects at different stages of the process in which case intelligence is gathered on the developers “preferred” or “priority” projects, or is it a

[44] https://www.nationalgrid.com/uk/electricity/industrial-connections/registers-reports-and-guidance

merchant developer who is looking to become active within the electricity market?
- How active is the developer in the GB electricity market?

Technology

This area looks specifically at future and developing technologies to gauge how much of a part certain emerging generation types may play in the generation backgrounds. Examples of information taken into account in this area are:

- At what stage of development or deployment is the technology, e.g. has the technology been proven as a viable source of electricity generation?
- Have there been trial/pilot projects carried out as with technologies such as wave and tidal?
- Has there been a commercial scale roll-out of the technology following successful trial/pilot schemes?
- Is there Government backing and support for the new technology?
- Are there any industry papers or research regarding the roll-out of new technologies in terms of the potential scale of deployment should the technology be proven?

Financial Markets

Information relating to the financial markets is also a consideration in terms of how easy it will be for the developer to raise the capital to fully develop the project e.g. off the balance sheet or via the capital markets.

Consideration is also given to the economics for different types of generation, in terms of electricity wholesale prices, fuel prices and the impact of the carbon price (i.e. clean dark and spark spreads) which may impact the operational regime on a technology and/or plant-specific basis.

A.2.3 FES Plant Economics

This area is a key feed-in to the power generation backgrounds and explores economic viability and how a particular plant or group of plants could operate in the market now and in the future. The results of the analysis inform the transmission generation backgrounds, particularly plant closure profiles.

A.2.4 Project Status

The project status is especially important when determining at what point in time a new generator may become operational. For a new plant, factors such as whether a generator has a signed grid connection agreement, where in the consenting process the project is and if the developer of the project has taken a financial investment decision are all key in determining the timing of future projects. Depending on the project status, a likelihood rating is then given to the plant. For example, if the plant only has a grid connection agreement and no consents it will be ranked far lower than a power station that has these or is physically under construction. For existing power generation, it is important to consider any decommissioning dates (for example nuclear), potential replanting of stations (for example wind) and the lifecycle for the particular technology.

A.2.5 Government Policy and Legislation

It is important that the power supply scenarios reflect Government policy and initiatives for particular generation projects and/or technology. This may be in the form of financial support for selected technologies that are targeted and developed, such as the low carbon technologies; nuclear, offshore wind, marine energy and CCS. Alternatively it could be in the form of market-wide mechanisms to develop, for example flexible generation, such as the Capacity Market.

Energy legislation enacted at the European and national level will impact which power supply sources are developed and connected to the NETS. For example, renewable energy targets are intended to reduce reliance on high carbon fossil fuels by promoting renewable sources, therefore making it very likely in FES scenarios with a high green ambition that the NETS will experience much more intermittent renewable capacity. Another example is the plant that may have to be modified to comply with environmental directives, such as the Industrial Emissions Directive (IED) and the Medium Combustion Plant Directive (MCPD). This legislation places restrictions on the number of running hours for fossil fuel power generation plants with regard to the harmful waste gases that they emit, unless investments are made to reduce this impact, and will affect decisions on whether to invest in new plants or maintain existing facilities.

A.2.6 Reliability Standard

The power generation backgrounds were developed for each of the scenarios based on the information gathered. The 2018 power generation backgrounds are developed to both meet demand and to reflect the implementation of the GB Reliability Standard of 3 hours Loss of Load Expectation (LOLE) / year. In the early years of the FES study period, the generation backgrounds were driven by relatively more granular intelligence and therefore LOLE could potentially vary significantly year to year within this period. This can, for instance, be caused by plants without CM contracts staying open.

As a result, the LOLE calculation within the generation backgrounds has been slightly amended to ensure that it is consistent with the implementation of the CM Reliability standard and any short term market perturbations around this metric. The modelling has also now moved from a pure transmission focus (i.e. assessing LOLE based on transmission-level generation against transmission-level demand) to a more whole-system approach whereby all generation (including units connected to the distribution networks) is assessed against total underlying demand.

A.3 EMR/Capacity Assessment Development Projects Matrix

Table 26 lists all the development projects and their respective scores. Based on the process described in Section 2.5.1, only projects 1-16 attracted high enough scores to qualify for this year’s analysis. Table 27 shows the scoring matrix.

Table 26: Development Projects Matrix

Development Project Description	Materiality*	Resources*	Priority*	Total
1) Improving data and providing access to the best available data on embedded generation (PTE Recommendation 27).	9	-7	20	22
2) Estimate interconnector derating factors for individual interconnectors (NI and ROI) (PTE Recommendation 33)	7	-3	18	22
3) Provide support to and engagement with the BEIS/Ofgem review of GB reliability standard / VoLL	9	-4	15	20
4) Clarify interconnectors rules regarding (a) variable interconnector capacity and (b) the impact of historical analysis.	6	-4	18	20
5) To investigate how, in the event of non-delivery , the delivery may change in relation to other sources (PTE recommendation 31)	8	-7	18	19
6) Review interconnector de-rating factor analysis a) sensitivities and data selection b) Analysis of BID3 results.	8	-6	16	18
7) Revisit definition of GB margin - interconnection should not appear in denominator as well as numerator	7	-5	16	18
8) Develop a sequential reliability module of the Capacity Assessment model (Due to resource constraints, this was deferred and is a potential summer project)	6	-6	16	16
9) Additional follow on work on battery storage de-rating factor methodology	7	-8	16	15
10) Develop a fundamental review of historical demand time series and ACS outturn peaks	7	-9	16	14
11) Review if other sources of distributed generation data could be used to supplement Electralink data	6	-6	14	14
12) Develop a better understanding of how scarcity rent (price escalator) works in BID3. (#This project was de-prioritised by project 13 using change control process).	8	-8	14	14
13) Interconnector Scenarios for CM. (#This project was prioritised over project 12 using change control process)				
14) Develop a range of European scenarios in BID3 to capture variability and uncertainty	8	-9	14	13
15) Review and quantify Dynamic Dispatch Model (DDM) developments. Commission LCP, test and implement DDM Developments for 2018 ECR (This project was not required)	6	-6	12	12
16) DSR data availability (PTE Recommendation 29) (This Project was carried out following request at PTE Meeting)				
17) Review treatment of non-CM capacity in the DDM to better account for capacity in later years	4	-6	14	12
18) Consider including extreme weather conditions in capacity requirement analysis as requested by BEIS	6	-8	14	12
19) Review the process for GB and European fuel prices and the sensitivity of the results in BID3 to fuel price profiles	8	-6	10	12
20) Consider whole system modelling to estimate the change in wholesale, balancing and other operational timeframe costs for different levels of security of supply (planning margin).	6	-7	12	11
21) National Grid should seek to include a review of their past forecasts, focusing particularly on periods of peak demand and system stress, along with key points from their Demand Forecasting Incentive report, which could be included along with the other Quality Assurance notes.(PTE Recommendation 26)	4	-6	10	8
22) Review how we model plant and interconnector availability in BID3- average availability profiles vs random	6	-8	10	8

Development Project Description	Materiality*	Resources*	Priority*	Total
outages - evaluate options, test and implement				
23) Consider the extent to which Distributed Energy Resources (including embedded generation, energy storage and demand side response) incur lower network losses and the possible implications on de-rating factors (PTE Recommendation 28)	4	-7	10	7
24) Currently there is an adjustment for additional capacity in T-1 auction due to many stations setting their CMU at a higher level than their TEC to maximise CM payment. Energy UK has asked us to review this as they think it is better to include an allowance for this in T-4	3	-5	8	6
25) Review materiality and impact of splitting distributed generation into smaller units in the DDM (increasing granularity)	4	-4	6	6
26) Assess whether we should model network constraints (GB and / or Europe) for FES / EMR work.	5	-8	10	6
27) Undertake a historical analysis to determine the extent to which stress events on its network have been due to combined events and then assess whether such combinations might arise again. (PTE Recommendation 32)	5	-8	8	5
28) How best to treat less extreme events, for example, through weighting sensitivities (as outlined in last year's PTE 2016 report, p43) and the insights this can yield. (PTE Recommendation 34)	7	-8	6	5
29) Review offshore wind power curves if additional data available for large offshore wind turbines	4	-5	6	5
30) Consider the range of additional forms of 'latent capacity' (such as various possible responses of DNOs to demand reduction requests) in addition to previous Recommendation 16 (PTE Recommendation 35).	3	-7	8	4
31) Develop a better understanding of the geographical scope of our modelling, including the impact of fixed price / flows	3	-5	6	4
32) Review the content of the Electricity Capacity Report for 2018 (including potentially updating the format to align better with the publications of other System Operators Documents)	3	-5	4	2
33) Undertake a pro-active role in informing the public about the issues in maintaining security of electricity supply, including the nature of risk and probability, and associated trade-offs. Co-ordinate through the Energy Networks Association (ENA) or code group with support from Energy UK and Association of Distributed Energy (ADE) (PTE Recommendation 30)	2	-4	3	1
34) Consider implementation of enduring recommendation of NG academic consultants on modelling wind demand relationship and/or revisit the peak-demand/wind relationship 0.9 scalar and/or update to a "demand net of wind" Capacity Assessment model / DDM version	3	-7	4	0

*represents total scores based on scorings provided by National Grid, BEIS and Ofgem. The individual score provided by each organisation was based on Table 27 below.

Table 27: Development Projects Scoring Matrix

Score	Low	Medium	High
Impact	1	2	3
Effort	-1	-2	-3
Priority	1	3	5

A.4 Detailed Modelling Assumptions

The following sections describe in more detail the modelling assumptions outlined in the main report. National Grid provides the details of the key inputs for the DDM model. Other assumptions (e.g. technology costs) were provided by BEIS.

A.4.1 Demand (annual and peak)

Table 28 shows the annual demand while Table 29 shows the peak demand used for the 4 FES scenarios and Base Case covering the next 15 years. All sensitivities use the same annual and peak demand as their corresponding scenario.

Table 28: Annual Demand* by scenario

Annual Demand TWh	2018	2019	2020	2021	2022	2023	2024	2025
Base Case	318	318	317	318	319	319	322	322
Community Renewables	317	315	314	312	312	310	310	310
Two Degrees	317	315	313	311	309	308	305	304
Steady Progression	319	320	321	321	321	322	322	322
Consumer Evolution	319	320	321	321	322	322	322	323

Annual Demand TWh	2026	2027	2028	2029	2030	2031	2032	2033
Base Case	322	322	323	324	325	327	329	332
Community Renewables	311	312	315	318	320	326	332	340
Two Degrees	304	305	307	309	311	316	321	327
Steady Progression	322	322	323	324	325	327	329	332
Consumer Evolution	323	324	325	327	328	331	332	335

*The definition of annual demand is GB National Demand plus demand supplied by distributed generation. Annual Demand is in DDM years (Dec to Nov).

Table 29: Peak Demand* by scenario

Peak Demand GW	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26
Base Case	59.1	59.3	59.6	59.8	60.3	60.3	60.4	60.5
Community Renewables	59.2	58.9	59.0	59.0	59.2	59.1	58.9	58.7
Two Degrees	58.9	58.6	58.7	58.6	58.8	58.9	58.9	59.0
Steady Progression	58.9	59.4	59.4	59.8	60.0	60.3	60.4	60.5
Consumer Evolution	59.2	59.7	60.0	60.2	60.6	60.8	60.8	61.0

Peak Demand GW	26/27	27/28	28/29	29/30	30/31	31/32	32/33
Base Case	60.7	60.8	61.1	61.6	62.2	63.1	64.1
Community Renewables	59.1	59.4	60.0	60.8	62.0	63.7	65.5
Two Degrees	59.6	60.2	61.1	62.5	63.7	65.6	67.1
Steady Progression	60.7	60.8	61.1	61.6	62.2	63.1	64.1
Consumer Evolution	61.4	61.8	62.3	62.8	63.8	64.7	65.7

*The definition of peak demand is unrestricted[45] GB National Demand plus demand supplied by distributed generation.

A.4.2 Generation Capacity Mix

Tables 30 to 34 below show the generation mix (name plate capacity at winter peak, excluding solar PV) for the 4 FES scenarios and Base Case from the DDM model. There is a drop in non-CM capacity in 2019/20, partly due to interconnection which is not eligible to participate in the CM in 2018/19 but can participate in other years. Non-CM capacity shows increases in most years after 2019/20, but falls again in 2027/28 due to the end of RO and CFD support for biomass conversion.

Table 30: Base Case generation capacity mix

Base Case Capacity Mix (GW)	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26
CM eligible	62.2	63.6	66.0	63.5	60.4	59.4	58.9	59.2
Non-CM	33.3	31.3	32.2	32.9	34.7	36.4	38.4	40.9
Total peak capacity	95.5	94.9	98.2	96.5	95.1	95.7	97.2	100.1

Base Case Capacity Mix (GW)	26/27	27/28	28/29	29/30	30/31	31/32	32/33
CM eligible	59.8	63.0	62.7	62.4	62.7	61.8	61.0
Non-CM	43.3	42.8	44.8	47.6	49.2	52.6	55.8
Total peak capacity	103.1	105.8	107.4	110.0	111.9	114.3	116.9

Table 31: Community Renewables generation capacity mix

Community Renewables Capacity Mix (GW)	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26
CM eligible	60.5	62.0	64.0	61.3	58.3	57.5	57.0	56.5
Non-CM	33.3	30.7	32.2	33.6	35.6	37.5	41.0	44.4
Total peak capacity	93.9	92.7	96.1	95.0	93.8	95.0	98.0	100.9

Community Renewables Capacity Mix (GW)	26/27	27/28	28/29	29/30	30/31	31/32	32/33
CM eligible	56.8	59.7	59.2	59.7	58.8	60.2	60.4
Non-CM	48.8	48.8	52.5	55.4	61.2	63.0	68.2
Total peak capacity	105.7	108.5	111.7	115.1	120.0	123.1	128.6

[45] i.e. no demand side response or Triad avoidance has been subtracted

Table 32: Two Degrees generation capacity mix

Two Degrees Capacity Mix (GW)	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26
CM eligible	61.4	61.7	64.4	62.5	56.0	55.6	55.6	55.0
Non-CM	33.2	31.6	32.8	35.0	37.8	41.7	45.7	49.4
Total peak capacity	94.6	93.3	97.3	97.5	93.8	97.4	101.3	104.4

Two Degrees Capacity Mix (GW)	26/27	27/28	28/29	29/30	30/31	31/32	32/33
CM eligible	54.2	57.6	55.1	55.5	53.5	52.2	52.8
Non-CM	55.8	56.1	62.1	65.5	70.8	76.1	79.9
Total peak capacity	110.0	113.7	117.1	121.0	124.3	128.3	132.6

Table 33: Steady Progression generation capacity mix

Steady Progression Capacity Mix (GW)	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26
CM eligible	62.1	63.5	66.1	63.7	59.5	59.1	58.7	59.0
Non-CM	33.0	30.8	31.8	32.8	34.1	36.4	38.4	40.9
Total peak capacity	95.1	94.3	97.9	96.4	93.6	95.5	97.0	99.9

Steady Progression Capacity Mix (GW)	26/27	27/28	28/29	29/30	30/31	31/32	32/33
CM eligible	60.2	62.7	63.6	63.2	63.4	61.8	61.0
Non-CM	43.3	42.8	44.8	47.6	49.2	52.6	55.8
Total peak capacity	103.5	105.5	108.4	110.7	112.6	114.3	116.8

Table 34: Consumer Evolution generation capacity mix

Consumer Evolution Capacity Mix (GW)	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26
CM eligible	62.1	61.0	63.4	62.9	58.2	57.5	56.8	56.8
Non-CM	33.0	30.3	31.0	32.7	34.1	35.4	37.7	39.5
Total peak capacity	95.1	91.3	94.5	95.6	92.4	92.9	94.5	96.3

Consumer Evolution Capacity Mix (GW)	26/27	27/28	28/29	29/30	30/31	31/32	32/33
CM eligible	56.8	60.0	60.4	60.4	60.0	62.0	65.4
Non-CM	41.5	39.9	41.2	43.3	46.3	47.9	51.5
Total peak capacity	98.3	99.9	101.6	103.7	106.3	109.9	116.9

A.4.3 CM-ineligible Capacity

Tables 35 and 36 give a breakdown of de-rated CM ineligible capacity (excluding previously contracted capacity) for the Base Case in 2022/23 and 2019/20. The total capacity is lower than the nameplate capacity shown in A.4.2 since it is de-rated.

Please note that the capacities by technology may not sum to the total ineligible capacity due to rounding.

Table 35: Breakdown of De-rated CM ineligible capacity for 2022/23

Generation type	Capacity (GW)
Onshore Wind	3.0
Offshore Wind	2.7
Biomass	3.9
Autogeneration	1.1
Hydro	1.1
Landfill	0.5
Other	1.4
Total	**13.7**

Table 36: Breakdown of De-rated CM ineligible capacity for 2019/20

Generation type	Capacity (GW)
Onshore Wind	2.9
Offshore Wind	2.2
Biomass	3.6
Autogeneration	1.0
Hydro	1.0
Landfill	0.6
Other	1.2
Total	**12.3**

A.4.4 Station Availabilities

Table 37 shows the station availabilities used for the 4 FES scenarios, Base Case and the High and Low availability sensitivities (rounded to the nearest %). Note the two sensitivities cover the two most uncertain technologies of CCGT and Nuclear.

In last year's ECR, all small scale / embedded technologies were mapped to the closest equivalent transmission connected technology class. This year for the 2018 ECR, small scale/embedded CM-eligible technologies are again kept consistent with this basis as required by the CM rules. However, for some small scale non-CM technologies (which are modelling assumptions as opposed to a CM rules requirement), we have amended the de-rating factors based on the best range of data sources available to us at this time. Further development work and engagement with industry/government/regulator stakeholders will continue next year to improve the modelling of such small scale embedded technologies that are connected at distribution level and for which we have no direct visibility.

Table 37: Station availabilities by sensitivity

	Base	High Availability	Low Availability
CCGT 2019/20	**89%**	**92%**	**86%**
CCGT 2020/21 onwards	**90%**	**93%**	**87%**
Coal	87%	87%	87%
Nuclear (Existing)	**84%**	**89%**	**79%**
Nuclear (New)	90%	90%	90%
ACT Advanced	87%	87%	87%
ACT CHP	87%	87%	87%
ACT Standard	87%	87%	87%
AD 2019/20	66%	66%	66%
AD 2020/21	68%	68%	68%
AD 2021/22 onwards	70%	70%	70%
AD CHP 2019/20	66%	66%	66%
AD CHP 2020/21	68%	68%	68%
AD CHP 2021/22 onwards	70%	70%	70%
Autogeneration	90%	90%	90%
Biomass CHP	87%	87%	87%
Biomass Conversion	87%	87%	87%
Coal CCS	87%	87%	87%
CHP (large scale)	**As CCGT**	**As CCGT**	**As CCGT**
Dedicated Biomass	87%	87%	87%
EfW	87%	87%	87%
EfW CHP	87%	87%	87%
Gas CCS	**As CCGT**	**As CCGT**	**As CCGT**
Gas Turbine	95%	95%	95%
Geothermal	87%	87%	87%
Geothermal CHP	87%	87%	87%
Hydro	90%	90%	90%
Landfill	59%	59%	59%
OCGT	95%	95%	95%
Oil	89%	89%	89%
Pumped storage*	96%	96%	96%
Sewage Gas	49%	49%	49%
Solar PV	0%	0%	0%
Tidal	22%	22%	22%
Wave	22%	22%	22%
Wind EFC 2019/20	22%	22%	22%
Wind EFC 2022/23	23%	23%	23%

*See Section 4.1 for de-rating factors for duration limited storage.

Note that the High and Low Availability only adjust CCGTs and existing nuclear as shown above in bold.

A.4.4.1 Conventional Transmission Station Availabilities

Table 38 shows the station availabilities based on the last 7 winters (2011/12 – 2017/18) for each type of generation. The availability is defined as the mean of each of the last 7 winter's availability values.

Table 38: Station Availabilities

Generation Type	Availability
CCGT	89.05%
OCGT	95.14%
Coal	86.56%
Nuclear	84.20%
Hydro	90.09%
Pumped Storage	95.52%

Previous comments[46] from BEIS's PTE stated that the availability of CCGT plant was low when compared to other markets with similar support mechanisms and recommended that National Grid undertake analysis to benchmark CCGT and other technology availabilities from around the world.

Previously, National Grid commissioned ARUP, in 2014, to produce a report on the availability of plant, particularly CCGTs, in markets that incentivise availability. For the main generation technologies of CCGT, OCGT, coal and nuclear, Arup provided an availability assumption. Table 39Table 40 shows the two views of availabilities.

Table 39: Availability Comparison

Generation Type	National Grid	Arup
CCGT	89%	87% - 93%
OCGT	95%	94%
Coal	87%	87%
Nuclear (Existing)	84%	77%

Based on the international benchmark data provided in Arup's report and further discussions with BEIS and the PTE, the availabilities for each type of generation have been revised to the values as shown in Table 40:

Table 40: Availabilities Used

Generation Type	Availability
CCGT Pre 2020/21	89%
CCGT 2020/21+	90%
OCGT	95%
Coal	87%
Nuclear (Existing)	84%

[46]https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/267624/Annex_E_-_PTE_draft_report_FINAL.pdf

Given the historical plant economics, age and mode of operation it is not surprising that GB CCGT availabilities were at the lower end of the international range. However, availabilities have been marginally increasing reflecting the improved economics of plant and increased maintenance. This supports what we assumed would happen over the last few ECRs with availabilities rising to 90% by 2020/21.

A.4.5 Reserve for Response (to cover largest infeed loss)

National Grid has to hold capacity in reserve in order to maintain system operability if a loss of generating capacity occurs. This capacity has to be accounted for in the LOLE calculation and is added to the peak demand assumptions. Table 41 shows the reserve requirement to cover the largest in-feed loss for each scenario. Note that the largest infeed loss increases as new capacity connects to the network, requiring a higher level to be held.

Table 41: Reserve to cover largest infeed loss by scenario

In Feed Loss MW	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26
Base Case	1400	1400	1500	1500	1600	1000	1000	1000
Community Renewables	1400	1500	1500	1500	1600	1100	1100	1200
Two Degrees	1400	1500	1500	1600	1600	1100	1100	1100
Steady Progression	1400	1400	1400	1400	1600	1000	1000	1000
Consumer Evolution	1400	1400	1400	1500	1500	1100	1100	1100

In Feed Loss MW	26/27	27/28	28/29	29/30	30/31	31/32	32/33
Base Case	1000	1000	1000	1900	2300	2300	2200
Community Renewables	1200	1200	1200	1200	2100	2100	2200
Two Degrees	2000	2000	2000	1900	1900	1900	2300
Steady Progression	1000	1000	1000	1900	2300	2300	2200
Consumer Evolution	1100	1100	1200	1200	1200	2500	2500

Note: the largest infeed loss above is not included in the peak demand values shown earlier.

A.5 Detailed Modelling Approach

Details for this section can be found in page 81 of last year's ECR[47]

A.6 Alternative methods for calculating combined non/over delivery sensitivities - Additive versus Root Sum of Squares

Within Section 2.5.2, we provide a summary of this development project covering why it was undertaken, what analysis was undertaken and finally the conclusions. This annex provides some more detail around the analysis including a direct comparison of the two approaches and the potential difference in the outcomes.

[47] https://www.emrdeliverybody.com/Lists/Latest%20News/Attachments/116/Electricity%20Capacity%20Report%202017.pdf

One key assumption that needs to be considered is the degree of independence between the various component parts to enable the appropriate use of the alternative approaches. A separate development project was undertaken to estimate the non/over-delivery of plant which identified that the drivers for different components were different e.g. profitability (coal & gas plant), environmental legislation around IED (coal & gas plant), failed meter test (DSR), embedded benefits changes and environmental legislation around emissions (small scale generators) and previous de-rating factors (interconnectors). In addition there would be a market response (potentially made up from a combination of technologies) to any non/over-delivery which would need to be considered separately as it would be negatively correlated. This meant that the application of the root sum of squares (RSS) approach was possible but had to be combined with market response in an additive way. Where the drivers for non/over-delivery were the same then they were combined e.g. coal and gas plant otherwise their impact would have been understated by the RSS approach.

The following Table 42 illustrates the potential impact for 2019/20 of using the two alternative approaches to estimating non/over delivery sensitivities. The additive approach covering all the independent non-delivery categories results in a maximum net non-delivery of 3.2 GW whereas for the Root Sum of Squares approach the maximum sensitivity is 2.4 GW i.e. giving a 0.8 GW lower figure. While it was acknowledged that both methods incorporate some degree of subjectivity it was agreed with BEIS and their PTE that the Root Sum of Squares approach was the most suitable when supported with evidence for each independent component and thus enabled the use of a well-established approach to modelling uncertainty across a number of independent variables.

Table 42: Comparison of Additive & Root Sum of Squares approaches

Technology (GW)	2019/20 Additive	2019/20 Root Sum Square
Coal / Gas	3.0	9.0
Small Gen. (Embedded Benefits)	0.8	0.6
Unproven DSR	0.2	0.0
Interconnectors	0.2	0.0
Maximum Gross Non-Delivery	**4.2**	**3.1**
Market Response*	-1.0	-0.7
Maximum Net Non-Delivery	**3.2**	**2.4**

*Market Response prorated to RSS of non-delivery

A.7 Storage De-rating Factor Data Assumptions

As reported in Sections 2.4.3.3 and 4.1, we have calculated the de-rating factors for duration limited storage in the 2018 ECR based on the most up to date information that we have (see Table 43). Last year we ran an industry consultation[48] on the methodology and modelling assumptions for the new approach to de-rating the sub-categories of this technology type. The final derating factor number for each duration limited storage class sub-category is (amongst other modelling assumptions) influenced by each of the following methodology attributes:

[48]https://www.emrdeliverybody.com/Lists/Latest%20News/Attachments/150/Duration%20Limited%20Storage%20De-Rating%20Factor%20Assessment%20-%20Final.pdf

- (EFC) The incremental Equivalent Firm Capacity (EFC) of a perfectly reliable storage unit (of each respective duration) and of a relatively small capacity added to the margin of a Base Case targeted at 3 hours LOLE, the GB Reliability Standard. The Base Case is set up to reflect the expected composition of the GB power system in each T-1 and T-4 target year in question. One key issue is that as indicated by our report to industry last year, then the assumption of the amount and composition of storage in the Base Case in each target year will influence the EFC of incremental storage units added thereafter – more shorter duration storage in the Base Case will tend to reduce the incremental EFC of storage units added thereafter. The assumptions in the 2018 EMR Base Case for the penetration of storage by capacity and duration are listed in Table 43 below. This year, there is slightly more storage capacity overall projected in the T-1 and T-4 Base Case than last year (as the years have advanced by one, and it is assumed that storage penetration will increase in to the future), and also the durations are a slightly lower than what was assumed last year based on observations in the recent Capacity Market auctions, whereby 0.5 hour and 1-hour storage durations were primarily successful amongst the new build entrants.
- (TA-PS) The technical breakdown parameter to be applied to the storage technology class overall, namely that which is calculated as the historical technical availability of pumped storage over the last 7 years' winter periods - calculated as 95.52% this year
- The histogram of stress event durations of the same Base Case, whereby all durations above that duration which corresponds to longer than 95% of potential stress events shall receive the same de-rating factor of pumped storage (TA-PS), and those that are shorter than this duration will receive a derating factor equivalent to the product of the incremental EFC and the technical availability of the storage class overall i.e. namely (EFC)*(TA-PS).

Table 43: Duration limited storage assumptions in the Base Case

Duration Category (Hours)	2019/20 T-1 Capacity (MW)	2022/23 T-4 Capacity (MW)
0.5	394	485
1	433	944
1.5	57	57
2	5	8
4	50	206
6	2,004	2,004
21	300	300
22	440	440
Total	3,683	4,444

A.8 Least Worst Regret

Details of Least Worst Regret approach and methodology can be found in page 87 of last year's ECR[49]

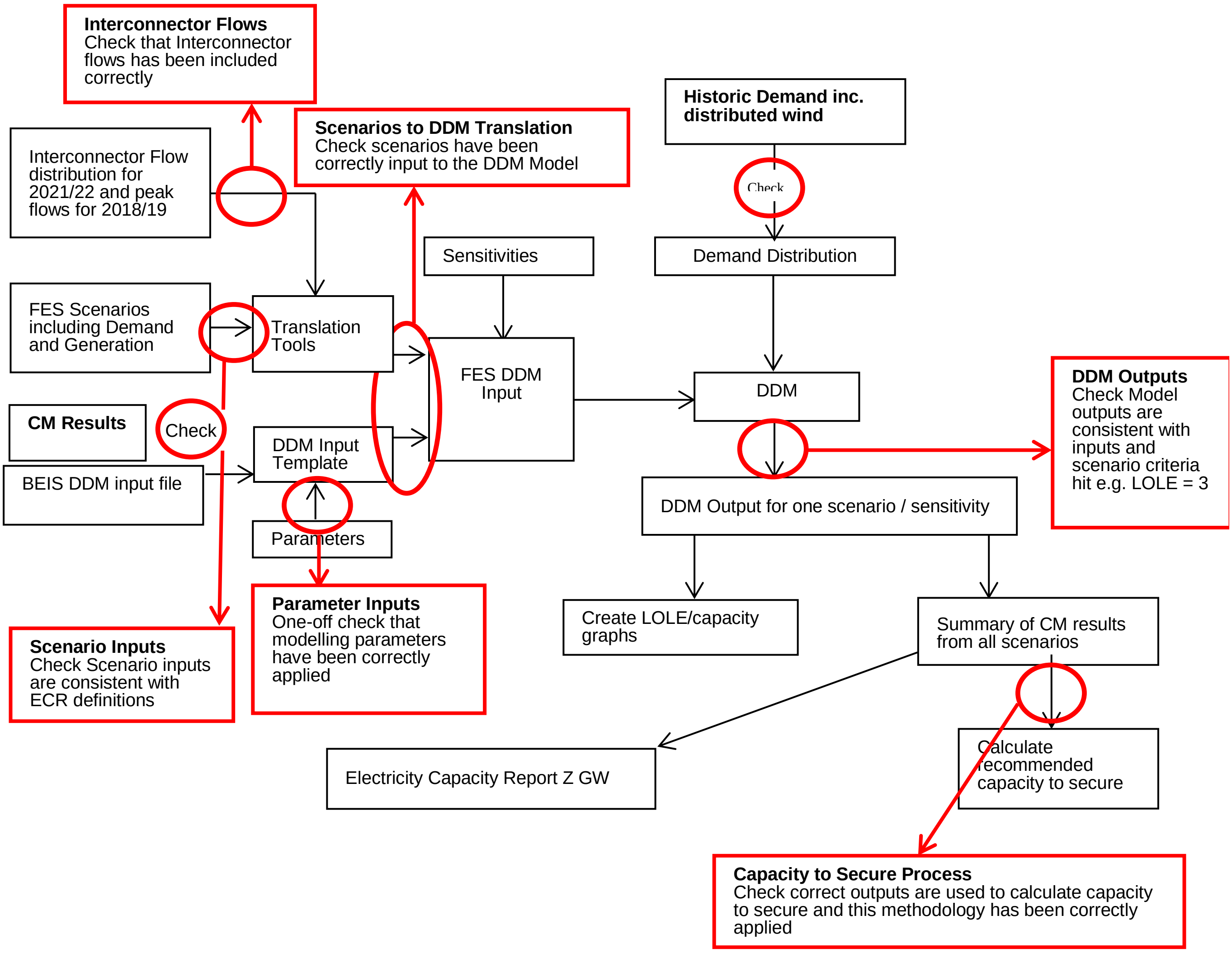
[49] https://www.emrdeliverybody.com/Lists/Latest%20News/Attachments/116/Electricity%20Capacity%20Report%202017.pdf

A.9 Quality Assurance

When under taking any analysis, National Grid looks to ensure that a robust Quality Assurance (QA) process has been implemented. National Grid has worked closely with BEIS's Modelling Integrity team to ensure that the QA process closely aligned to BEIS's in house QA process[50]. We have implemented the QA in a logical fashion which aligns to the project progression, so the elements of the project have QA undertaken when that project "stage gate" (such as inputting data in to a model) is met. This approach allows any issues to be quickly identified and rectified.

The high level process and the points within the process where QA checks have been undertaken are shown in the following process diagram (Figure 29):

Figure 29: QA checks process diagram for each target year



The QA checks above (bordered in red) are centred on the points in the process where data is transferred from one model, or system, to another along with the model outputs. The QA is undertaken in this way as it is more straight-forward to follow which QA step is being applied at which step in the process. These steps are:

[50] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/358356/DDM_QA_Summary.pdf

1. **Interconnector flows** – Check the interconnector flow assumptions / distribution

2. **Scenario inputs** – Check the model input assumptions

3. **Parameter Inputs / CM Results / Historic Demand Including Distributed Wind** – Check the model setup assumptions

4. **Scenarios to DDM Translation** – Check the input from the FES process into the DDM model

5. **DDM Outputs** – Check model outputs are consistent with inputs and scenario criteria

6. **Capacity to Secure Process** – Check the inputs and outputs used to determine a range and recommended capacity to secure

Below is detailed QA process for each of these steps.

Interconnector flows

Interconnector flow assumptions / distributions have been discussed with BEIS, PTE and Ofgem at various bilateral meetings. We have also consulted the results with the industry at various stakeholder events. For each scenario, the modelled interconnector flows and results are checked throughout the QA checklist process.

Scenario Inputs

The FES process is driven by extensive stakeholder engagement[51], workshops and bilateral meetings; this engagement leads to the creation of the scenarios. The constituent parts of the scenarios, for example electricity demand, are subject to internal challenge and review to ensure that they consistent and robust. Sign off is then required at senior manager level and formal sign off is then required from the SO Executive Committee. The assumption and outputs will be published in the annual FES document on 12th July 2018.

For the purposes of the ECR process a check is undertaken that the inputs are consistent with the requirements of the ECR process.

Parameter Inputs / CM Results/ Historic Demand Including Distributed Wind

The parameters are set to ensure that the model runs as is required for the ECR process. These parameters are checked and documented by analyst to ensure that they are correct and then a final template is created (with a backup) which all runs are then based on. This step also includes checking of the inputs like historic demand, demand met by distributed wind and CM Results are correctly included in the model.

[51] http://fes.nationalgrid.com/media/1346/future-energy-scenarios-2018-stakeholder-feedback-document-published-feb-2018.pdf

Scenarios to DDM Translation

The tool for translating the FES scenarios into DDM has been documented and available for scrutiny by BEIS and the PTE. The tool includes checks that the correct information has been inputted to the model.

DDM Outputs

Each run of the analysis, including inputs and outputs, has been checked and documented internally by an analyst not involved in the ECR modelling, but familiar with the DDM and the ECR project. These documents and the associated files have been shared with BEIS to allow it to perform its own QA process.

QA Check List Process

Each run of the analysis, including inputs and outputs, is checked and documented internally by an analyst through a QA Check List process.

Capacity to Secure Process

Once all the runs have been completed the key results are used to determine the recommended capacity to secure using Least Worst Regret (LWR) tool. This process has been checked and documented internally by an analyst not involved in the ECR modelling, but familiar with the DDM and ECR project. Again, these files have been shared with BEIS to allow it to perform its own QA process.

Dynamic Dispatch Model (DDM)

In addition to checks described in above figure, the DDM has been reviewed and had QA performed a number of times including a peer review by Prof. Newbery and Prof. Ralph, a review of the code by PwC and an internal reviews by BEIS.

Details of these can be found in the 2013 EMR Delivery Plan document. These imply that a further QA of the DDM is not required as part of the ECR QA process. However, to ensure that the DDM is the correct model to use, and that it is being used correctly, the PTE have been specifically asked to QA the use of the DDM for ECR. In previous years, the owners of the DDM, consultants Lane Clark & Peacock (LCP[52]), were asked to ensure that National Grid was both using the model, and interpreting the outputs, correctly. This involved a bilateral meeting between National Grid and LCP to discuss in detail the modelling being undertaken. This highlighted some minor issues which have been resolved. LCP produced a report of their QA process. The report concluded that National Grid is using the model correctly and correctly interpreting the output results.

Process Overview and Governance

The process will be overseen by the PTE and they will review and report on the overall process. Internally the process has governance under Director UK System Operator.

[52] http://www.lcp.uk.com/

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National Grid plc
National Grid House
Warwick Technology Park
Gallows Hill
Warwick
CV34 6DA

https://www.nationalgrid.com/uk