Department for
Business, Energy
& Industrial Strategy

PANEL OF TECHNICAL EXPERTS

Independent Report on National Grid's Electricity Capacity Report 2018

June 2018

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Executive Summary and Recommendations

1. The role of the Panel of Technical Experts (“PTE”) is to impartially scrutinise and quality assure the analysis carried out by National Grid (NG) for the purposes of informing the policy decisions for the Capacity Market (CM). In fulfilment of this role, we have scrutinised NG’s 2018 Electricity Capacity Report (ECR 2018) on the target capacity for the T-1 Auction for delivery year 2019/20 and the T-4 Auction for the year commencing 2022/23 and this document presents our findings.

2. In our previous reports (2014-2017) we made 35 recommendations in total (of which 10 were from 2017) for improving the methodology and reliability of the modelling by which target capacities are calculated. NG has taken action on many of these as we report in Annex 1.

3. The PTE has had considerable exchange with NG, BEIS and Ofgem in the process of NG putting its ECR 2018 together and we are content this presents a sound piece of analysis. Subject to the qualifying comments we have made in this report, we are content that the approach to deriving the target capacity, including the inputs to this such as de-rating factors (DRFs) and analytical methods, are as reliable as they could be at this stage of development. As usual, we make a few recommendations for future work.

4. This year we accept the analysis and agree with the final NG recommendations for the volume of capacity to be secured in both the T-1 and T-4 auctions. We agreed on the sensitivities that went into the estimation and their application in the ‘Least-Worst Regret’ evaluation. We believe their approach to the risks of potential non-delivery (ie. plant with existing CM contracts closing or otherwise voiding their contracted contribution), and in particular the new approach to aggregating the various sources of non-delivery based on Root Sum Squares (our recommendation of last year), is a significant improvement. However, we note to BEIS that the recurring concerns about non-delivery risks may suggest a case for the upcoming CM 5-year review to include examination of the adequacy (or not) of the penalty regime for non-delivery.

5. This year we recommend the following DRFs for interconnectors for the T-1 and T-4 auctions:

De-rating Factors	Ireland	France	Belgium	Netherlands	Norway
T-1 PTE Recommendation	44%	74%	69%	Already contracted	(Not yet built)
T-4 PTE Recommendation (with close EU integration)	24-42% (Recommend 33% for either)	73-86%	51-67%	45-62%	95-100%
T-4 PTE Recommendation (without close EU integration)		59-73%	35-51%	27-45%	90-95%

Table 1 – Summary of PTE Interconnector De-Rating Factor Recommendations

6. We are pleased to acknowledge substantial advance in European systems modelling which informs the analysis of interconnector flows conducted by NG, though we continue to view the modelling of interconnector security contributions as a complex area in which further progress is needed. We consider NG's analysis to be the best available basis for decision-making on the DRFs for interconnectors and are comfortable to base our recommendations for DRFs on their ranges, although we accept that their modelling can be improved further. We remain confident that interconnectors offer important and cost-effective contributions to GB security of supply, as well as other benefits to the GB system.

7. We were also consulted by NG during the development of DRFs for duration-limited storage.

8. The PTE was most frustrated with the fact that NG was unable to obtain data on distributed generation output from ElectraLink[1] in a manner or timescale that enabled this to be used in demand forecasting or related aspects of analysis. The quality of the ElectraLink data obtained in the preparation of last year's ECR (ECR 2017) rendered it unusable. This year NG only obtained the data after many months of negotiation, too late for it to be used or scrutinised by the PTE. The PTE felt compelled to write to the Secretary of State expressing our concerns about this in particular, and more generally the wider issue of data availability. We were pleased that Ofgem supported our position. Throughout this process we heard no compelling reason why data on distributed generation should not be made publicly available on a non-attributable basis with the same transparency as data on transmission-connected generation, with due procedures on data protection and we will continue to press this issue with the government and Ofgem.

9. However, through various proxy methodologies we believe that NG were on this occasion able to sufficiently compensate for the lack of this data in their projections of net demand, so we do not believe the situation has yet materially increased the risks in terms of demand projection and capacity to secure. More generally, however, this particular data issue forewarns that the energy sector in general is likely to become increasingly driven by and dependent on greater

[1] https://www.electralink.co.uk/

access to data. With this in mind, there is an emerging need to develop a national strategy for energy data management.

10. Overall we were pleased with the process of engagement with NG and BEIS on capacity to secure and thank them for their extensive efforts to develop clear and timely analysis and address many of the technical issues we raised. During the course of this engagement, we identified some wider methodological issues which reflect the rapidly changing nature of the electricity system and will be pleased to input on these during the course of the forthcoming 5-year review.

New Recommendations

11. The new recommendations in our report are listed below. (The numbering of the recommendations follows on from the 35 recommendations in our previous reports).

NEW RECOMMENDATION 36: We recommend full and transparent disclosure of the construction of NG's Base Case in the ECR, given that it represents NG's view rather than that the whole industry as represented in the FESs and plays a dominant role in the analysis.

NEW RECOMMENDATION 37: In view of the issues in gathering data necessary for assessing national energy security requirements, BEIS, NG and Ofgem should urgently consider whether and when an information strategy might be required. Such an information strategy would be expected to cover a risk register showing activities where data is required, whether data exists and who hold it, impacts of data gaps, and access routes to release data and data processing requirements. The information strategy should draw upon the ongoing work of the Institute of Engineering and Technology's (IET) energy system architect programme.

NEW RECOMMENDATION 38: NG should investigate the evidence for selecting a wider sensitivity band for demand outturns for overall demand both using historical data and its own FES modelling, to confirm that its current approach is appropriate.

NEW RECOMMENDATION 39: NG should undertake a historical analysis to determine the extent to which stress events on its network have been due to combined events and to assess whether such combinations might arise again. The initial focus could be on station outages, using the detailed unit data available from REMIT process. This could for example examine the outages in gas stations experienced during the "beast from the East" on 1 March 2018.

NEW RECOMMENDATION 40: To inform next year's ECR, NG should review the impact of set aside strategic reserves in continental Europe on interconnector contribution to security of supply, and if significant, include this within the 2019 interconnector DRF assessment.

12. Following the publication of this year's ECR 2018 and PTE Report, the PTE will review its previous recommendations together with BEIS and NG in order to reduce the number and prioritise the most important of these.

Introduction

Role of the Panel of Technical Experts

13. The Government commissioned, commencing in February 2014, through an open and transparent procurement process, an independent Panel of Technical Experts (the PTE) for the enduring Electricity Market Reform (EMR) regime. The role of the PTE is to impartially scrutinise and quality assure the analysis carried out by NG in its role as Delivery Body for the Capacity Market (CM).

14. The PTE's first report on NG's analysis to inform CM decisions was published in June 2014. This is the PTE's fifth report, focused on scrutinising the analysis that informed NG's ECR 2018. The report covers the NG recommendation to the Secretary of State on the recommended capacity to secure for the 2022/23 T-4 auction as well as the recommended capacity to secure for the 2019/20 T-1 auction.

15. The background of the members and terms of reference of the PTE are published on the Government website.[2]

16. This report has been prepared for BEIS by:
    a. Professor Michael Grubb
    b. Andris Bankovskis
    c. Dr Guy Doyle
    d. Professor Goran Strbac
    e. Professor Derek Bunn

17. This report has been prepared from information provided by BEIS, NG and Ofgem and the collective judgement and information of its authors. Whilst this report has been prepared in good faith and with reasonable care, the authors expressly advise that no reliance should be placed on this report for the purpose of any investment decision and accordingly, no representation of warranty, expressed or implied, is or will be made in relation to it by its authors and nor will the authors accept any liability whatsoever for such reliance on any statement made herein. Each person considering investment must make their own independent assessment having made whatever investigation that person or organisation deems necessary.

Scope

18. The scope of the PTE's work is to impartially scrutinise and quality assure the analysis carried out by NG for the purposes of informing the policy decisions for the Capacity Market. This includes scrutinising: the choice of models and modelling techniques employed; the inputs to that analysis (including the ones

[2] https://www.gov.uk/government/groups/electricity-market-reform-panel-of-technical-experts

BEIS provides); and the outputs from that analysis - scrutinised in terms of the inputs and methods applied. The PTE will review whether the analysis is robust and fit for the purpose of Government taking key policy decisions. This will include, for example, considering potential conflicts of interest NG or others involved might have in influencing the analysis.

19. The PTE has no remit to comment on CM or wider EMR policy, Government's objectives, or the deliverability of those objectives, unless otherwise requested. The PTE's Terms of Reference mean it cannot comment on affordability, value for money or achieving least cost for consumers. These matters are excluded from the PTE's scope and therefore from this report. The role of the Panel is a technical function and not a forum for policy commentary or for advising the Government on its objectives, the policies being implemented or policy decisions surrounding them. This means the PTE does not have a role in advising how the analysis should be interpreted for the purpose of those policy decisions, for example, on the Reliability Standard to be set by Government or the mechanisms chosen to achieve its objectives.

20. In this year's report we have indicated several issues which we think should form part of the upcoming CM 5-year review. Whilst we hope that these comments may prove useful to the Government in scoping the review, they do not constitute a formal part of our advice to the Secretary of State on NG's modelling.

21. This report also recommends DRFs or ranges for interconnectors based on the ranges that emerge from NG's modelling for each interconnected country, from which the Secretary of State will choose the final DRFs.

Approach

22. During the course of the PTE's work, NG has presented its methods, assumptions and outputs in relation to NG's core task of recommending the auction target capacity in the CM and the PTE has had opportunity to question NG during the development of its analysis and recommendation.

23. To carry out its work, the PTE met with NG, BEIS and Ofgem several times during the autumn of 2017 and then approximately on a monthly basis since January, during which presentations were made by NG and the PTE had an opportunity to ask questions and make comments. Subsequent to the meetings, the PTE provided various interim views and put questions to NG to which BEIS organised responses. We have also reviewed submissions sent to our e-mail account and considered recent work carried out by Aurora, LCP and UKERC related to the contribution of interconnection to security of supply.

24. The PTE's initial focus was on gaining an understanding of the methodologies and analytical techniques available to NG.

25. The PTE has generally focussed more closely on the areas that appeared to be of highest impact and greatest uncertainty, providing comment and analysis to support the PTE's developing views. Key areas that emerged included:

a. Non-delivery estimation and aggregation
b. Interconnector de-rating – changing conditions in Europe
c. Embedded generation data
d. De-rating of limited-duration storage
e. Greater clarity on details of the Base Case, particularly concerning demand projections and related peak price responses.

26. As required by the PTE's Terms of Reference, the PTE also kept in mind the potential for NG to be confronted by potential conflicts of interest. The PTE, throughout this process, has sought to mitigate this by vigorously challenging assumptions. We note that NG would bear some of the loss of reputation for any blackouts, and bears none of the cost of over-securement, and so could be expected to weight the possible risks of securing less capacity, more than they might credit the cost-savings. The PTE, however, has no evidence to believe that NG has exploited its privileged position and hence there has been no observed conflict of interest up to the time of writing this report.

27. This report is not comprehensive and nor is it a due diligence exercise but the PTE believes that it has nevertheless identified some important issues that have significant consequences. Accordingly, and in line with our approach in previous years, the PTE has not overly focussed its attention in this report on the many details of various matters which were raised and satisfactorily resolved or are part of on-going development.

Brexit

28. In their ECR 2018 NG state that they have assumed "continued market harmonisation between the UK and the Europe once the UK has left the European Union" (ECR 2018, p.5). PTE have also been mindful of Brexit when making our recommendations for this year.

29. For the T-1 delivery year (2019/20), we are comfortable that the proposed Brexit implementation period negates the need to adjust NG's recommendation. Similarly, for the T-4 delivery year (2022/23) we consider that any necessary adjustments could be made at the future T-1 stage once the outcome of the Brexit process is clearer.

30. We do, however, note that the degree to which interconnectors contribute to our energy security could be impacted by Brexit and that the DRFs they are assigned cannot be adjusted after capacity agreements for these resources have been granted. We therefore recommend that the Secretary of State considers the possible impacts of Brexit when setting interconnector DRFs for the T-4 auction this year (as set out below, pp.16-24).

Observations on and Context Provided by Auctions since Last Report

31. To understand the significance of auction results to date, it is important to be aware of the auction and target capacity-setting design. **First**, plant that has a low-carbon or renewable contract (ROC, CfD, FIT and estimated non-CM autogeneration) cannot participate in the auctions, but has their equivalent firm contribution deducted from the target capacity. NG discusses how to make allowance for the contribution of wind in extreme cold weather events in the ECR 2018. **Second**, plant that has opted out of the CM but that remains operational in the delivery year at the T-4 auction stage has its de-rated capacity deducted from the target capacity. **Finally**, capacity that already has a CM agreement covering the delivery year in question (e.g. from 15-year contracts awarded in prior auctions) is normally deducted from the remaining target capacity, unless it is clear that it has cancelled that agreement.

32. We have now seen the results of four T-4 capacity auctions for delivery years 2018/19, 2019/20, 2020/21 and 2021/22 which have cleared at £19.40, £18.00, £22.50 and £8.40 a kW a year, respectively. These prices are all well below the net assumed cost of new entry (CONE) of £49.00/kW/year, which is used to locate the position of the demand curve for capacity. There has been significant liquidity in all these auctions, with most of the awarded capacity going to existing plant.

33. The first T-1 auction for delivery year 2018/19 was held last January and cleared at £6.00/kW/year.

34. There have also been two TAs (Transitional Auctions) specifically for Demand Side Response (DSR) in 2015 and 2016, which produced prices clearing at £27.50 and £45.00/kW/year, respectively, and a special one-off Early Auction, eligible for generation, storage and DSR for delivery in 2017/18, which cleared at just £6.95/kW/year.

35. All these clearing prices were significantly below the prevailing view in the industry, especially last year's auction results where there had been an expectation that the announced changes to embedded benefits, the tighter rules on operations of diesel farms and the reduced de-rating for limited duration storage (batteries) would have lifted auction clearing prices. With the auction prices so far below the net CONE, this has meant that the capacity to secure has been adjusted slightly upwards, which raises the question as to whether more attention needs to be given to the elasticity (or slope) of the demand curve for capacity. This may be something that is considered in the 5-year review.

Analysis and Key Findings

Introduction and context

36. As in its previous ECRs, NG lays out its modelling approach and its scenarios and sensitivities that will frame its findings on the amount of capacity to secure in the auctions. Some of the key changes from previous years include, changes to the Future Energy Scenarios (FES)[3], non-delivery aggregation, European energy modelling, and major changes to DRFs for duration-limited storage.

Demand Forecasting

37. Forecasting peak demand is the natural starting point for the ECR, and the methodology undertaken by NG follows the same principles as in previous years, with a few notable developments upon which we comment. The FES provide the top down overview and these result from an extensive process of analysis and stakeholder engagement by NG. They provide a forward outlook for the industry at large and serve many other purposes in addition to the ECR. The latest FES 2018 developed a different conceptualisation for the scenarios, being a 2x2 matrix, dimensioned by speed of decarbonisation and level of decentralisation. We think these are sensible new constructs and from a resource adequacy perspective, they identify axes of critical concern in the ECR analysis. Greater decarbonisation is mainly associated with the intermittency of renewables and more decentralisation requires greater clarity on the effects of distributed resources and consumer response.

38. Although the four FES scenarios provide a useful longer-term overview and way of thinking about the energy transition, their role in the actual ECR calculations is actually minor. The crucial methodological element for the assessment of the capacity to secure is the short-term Base Case, together with its sensitivities. The Base Case is a bottom-up, feedforward projection of current trends supplemented with market information. We therefore do not offer a critique on the four FES scenarios, but focus our comments on the Base Case and its Sensitivities.

39. Within the horizon of the ECR, the Base Case is showing a slight dip in peak demand from 59.4GW in 2017/18 to 59.2GW in 2018/19, and then a steady growth to 60.3GW in 2022/23. It is interesting to see that the 2 FES scenarios associated with greater decarbonisation are substantially below this growth rate. This Base Case is a cautious view of change, being closest to the "Steady Progression" scenario which, in the longer term, does not envisage meeting the 2050 decarbonisation target. "Steady Progression" does envisage substantial growth in electric vehicles (EVs) and assumes that gas retains an important role in power generation and heat. We agree that this scenario may be most realistic for the next five years and are comfortable with the Base Case appearing to be

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

close to these assumptions despite its longer-term divergence from a policy target.

40. We observe that the ECR 2018 report provides useful descriptions of the assumptions underlying the four FES scenarios, but it does not adequately summarise the actual Base Case assumptions. It would therefore be helpful if NG were to provide a fuller description of the Base Case in future ECR documentation.

NEW RECOMMENDATION 36: We recommend full and transparent disclosure of the construction of NG's Base Case in the ECR, given that it represents NG's view rather than that the whole industry as represented in the FESs and plays a dominant role in the analysis.

41. Since NG estimates unrestricted demand, as distinct from load on the transmission network which it directly measures and which forms the starting point, this requires data on embedded generation, as well as estimates of consumer demand-side response, to be added to the transmission load. We note that the access to such data has been an impediment to NG during the production of ECR 2018, as it was for ECR 2017. By late January, the lack of progress in acquiring the necessary data from ElectraLink for this year's ECR prompted us to write to the Secretary of State about both this specific matter, and more generally the issue of availability and wider access to energy data particularly below the transmission level. Going forward, we anticipate that the agreement eventually reached by NG to purchase distribution level data from ElectraLink will remedy this problem for future ECRs. We are also pleased to learn that the Secretary of State shares our wider concerns about data availability, and that an ambition for data to be made publicly accessible wherever possible, in a sensible way that respects issues eg. relating to data protection, is now under discussion between BEIS and Ofgem.

42. The PTE has been concerned for the past two years that in modelling the response of demand to prices (elasticity) in the Base Case, the assumed elasticity at peak is limited to DSR contracts and an adjustment based upon potential smart meter roll-out numbers. At times of stress, wholesale prices will be very high and, going forward, price elasticity might increase especially with the introduction of substantially higher and more volatile Imbalance Prices in November 2018. We therefore continue to be concerned that peak demand may be over-estimated given future potential demand responses to such 'scarcity pricing' in the wholesale and balancing markets.

43. We note the technical work that has been undertaken to standardise the Average Cold Spell (ACS) calculation methodology. This will ensure better time-series consistency. Whilst it made little difference to the Loss of Load Expectation (LOLE) estimation, we agree that it was a worthwhile improvement in being able to compare historical, and forecast future, peak demand data over time.

44. More generally, this particular data issue forewarns that the energy sector in general is likely to become increasingly driven by and dependent on greater access to data. With this in mind, there is an emerging need to develop a national strategy for energy data management.

NEW RECOMMENDATION 37: In view of the issues in gathering data necessary for assessing national energy security requirements, BEIS, NG and Ofgem should urgently consider whether and when an information strategy might be required. Such an information strategy would be expected to cover a risk register showing activities where data is required, whether data exists and who hold it, impacts of data gaps, and access routes to release data and data processing requirements. The information strategy should draw upon the ongoing work of the Institute of Engineering and Technology's (IET) energy system architect programme.

Sensitivities

45. As usual, during the preparation for this year's ECR 2018, the choice of sensitivities (described in detail in the NG report) was discussed with NG and agreed between NG, BEIS and the PTE prior to modelling. The following summarises our key observations.

46. NG runs a number of sensitivities around its Base Case to 2022/23 (and the Steady Progression scenario beyond this), rather than running them around each of the four FES. This reduces the number of sensitivities and also the range, however for a five year horizon considered in the ECR, we agree with NG's approach.

Low and high wind at times of Cold Weather

47. Analysis of GB historical wind patterns shows some weakening in the general linear correlation between demand and wind at high demand periods. NG's central case applies a scaling factor on wind output where demand exceeds 92% of peak that increases linearly to 0.9 at 102% of peak. The low wind sensitivity assumes a greater decoupling to 0.8, while the high wind case applies no scaling factor. This seems a reasonable approach, although we note the impact is likely to be less pronounced running this variation on the Base Case than the Two Degree scenario, which has a significantly higher contribution from wind.

Plant availabilities

48. NG has run availability sensitivities for 2019/20 only, as it finds there is no material impact in 2022/23. This reflects NG's reliance on historical data. It applies a symmetrical variation equal to one standard deviation for both CCGTs and nuclear (which works out to +/-3% and 4% (percentage points) respectively.

49. PTE's view is that the historical data may not be the best guide to future availabilities, as the future regime with CM in place should sharpen the incentive regime for generators. Coupled with the expected increase in incidence of high prices during periods of high residual demand (demand net of renewables) arising from balancing market ("cash-out") reforms and increased volatility (due to

variable renewable supply), it would be reasonable to expect plant availabilities to increase during these periods.

50. On the other hand, while the incentive to make plant available during peak demand periods is projected to increase, there is a question whether the remaining coal and older CCGT stations will see decreasing reliability and hence availability due to degradation from wear and tear, especially as maintenance is pared back due to low operating profit margins (reflected in price differentials known as clean "dark/spark spreads" for coal and gas respectively) and limited remaining lives for these stations. Major plant breakdowns, which can force station closures will be captured through the non-delivery sensitivities.

51. Consequently, we are content with the availability assumptions based on current evidence, noting also that the impacts on the volume of capacity to secure for the range of plausible uncertainty are not material.

Weather

52. NG's weather sensitivities include demand during the warmest and coolest periods observed in the last 12 years, which were 2006/07 and 2010/11 respectively. These winters represented 1 in 14 years and 1 in 9 years events respectively, according to NG's analysis. NG points out that the Met Office itself uses 30 years when calculating average temperatures. For its gas adequacy planning NG uses a 1 in 20-year standard, which reflects the fact that gas demand is very strongly correlated to temperature.

Electricity Demand

53. The electricity demand sensitivities which are applied to ACS peak underlying demand are +/- 2% of the Base Case for both 2019/20 and 2022/23. NG says that it has not used the +/- 4% range for T-4, which is also outlined in its Demand Forecasting Accuracy (DFA) incentive, on the grounds that the incentive is weighted to T-1 given that there is an opportunity to correct forecast errors in the T-1 auction. This is true, but it also applies for various other variables, so the PTE will be pressing NG to clarify its argument in future ECRs. Also, the PTE is unconvinced that running the sensitivity on transmission connected demand rather than overall demand is reducing the impact of these demand sensitivities.

NEW RECOMMENDATION 38: NG should investigate the evidence for selecting a wider sensitivity band for demand outturns for overall demand both using historical data and its own FES modelling, to confirm that its current approach is appropriate.

Non-delivery

54. NG states that last year's non-delivery sensitivities were dominated by the risk around coal closures, however the position has now become more nuanced as the uncertainties relating to coal have reduced (largely as result of previous, planned and expected plant closures) while others relating to aging gas plant, embedded generation and DSR have increased. In addition, NG recognised the interdependences between non-delivery of plant, in that withdrawal of capacity improved the situation for the remaining "at-risk" capacity. In discussion, with

BEIS and the PTE, NG decided to apply a Root Sum Square (RSS) approach to assessing the combined non-delivery risks across four types of capacity: thermal generation, embedded generation, DSR and interconnectors. The PTE sees this new approach and the supporting DDM modelling analysis of non-delivery as a positive response to last year's PTE recommendation no. 31.

55. The application of RSS led to maximum non-delivery levels of 2.4 GW in 2019/20 and 2.8 GW in 2022/23, versus a simple additive sum of 3.2 GW and 4.4 GW, respectively (See Annex A6, ECR 2018).

56. The PTE reviewed the individual components used in the RSS calculation and concluded that these were reasonable, although it was noted that there was considerable uncertainty around the values selected, especially for embedded generation.

Over-delivery

57. This sensitivity reflects the possibility that there may be more non-CM contracted capacity available and interconnectors may import more than their contracted CM capacity. This is to provide balance to the non-delivery, although there is a clear and justifiable asymmetry in the magnitude of the uncertainty, with this upside being just a third of the downside.

Other Sensitivities Considered and Dismissed

58. NG has provided good reasons for not considering other specified sensitivities; we have discussed this in detail and support the exclusion of these sensitivities for the same reasons.

Dependence of generating units

59. NG treats unplanned outages at multi-unit stations as being independent. Our view is that this is reasonable as it is comparatively rare for two or more units at a station to experience unplanned outages, because units are normally designed to run independently and where infrastructure is shared there is normally a degree of redundancy.

60. However, earlier this year (1st March 2018, which falls just outside the winter season and outside the Triad response period, December to February) it was reported that several CCGTs coincidently experienced unplanned outages during a particular cold wet spell, which resulted in several GW being taken out[4]. In the end, higher than average wind generation meant a system stress event was avoided. While these units were operating independently they appear to have been impacted by a common cause (peculiar weather) and so the PTE looks forward to reviewing NG's investigation and report as to what should be learned from this incident.

[4] NG (2018) Winter Review and Consultation, page 18. (https://www.nationalgrid.com/sites/default/files/documents/2018%20Winter%20Review%20and%20Consultation.pdf)

Renewable plant non-delivery

61. Initially NG had intended to consider a sensitivity on non-delivery of non-CM plant, however it was agreed that the four FES already included sufficient variation in such capacity, so this was excluded. As in previous years the PTE accepts this is reasonable.

Black Swan Events

62. Extreme outlier events, which tend to be the result of a combination of two or more already low probability events, were excluded based on their low probabilities, inclusion of which would distort the LWR results (see ECR 2018 for discussion).

CMU misalignment to Transmission Entry Capacity (TEC)

63. In previous years NG stated that original rationale for this sensitivity (in the early years of the CM) was to correct for the excess of offered capacity over the TEC offered by CM participants, however NG has in recent years allowed for this in its modelling by capping capacities at TEC levels, so negating the need for this sensitivity. In addition, Ofgem has implemented some CM rule modifications that reduce this bidding tactic.

Combined sensitivities

64. Almost by definition these combined events would have low probability, comparable to "black swan" events, therefore according to NG's academic advisors[5] such events should be not included in the LWR approached applied to determine capacity to secure. The PTE accepts this as a plausible approach; however, we consider that there would be value in a historical analysis of the extent to which stress events on its network have been due to combined events and whether such combinations might arise again.

NEW RECOMMENDATION 39: NG should undertake a historical analysis to determine the extent to which stress events on its network have been due to combined events and to assess whether such combinations might arise again. The initial focus could be on station outages, using the detailed unit data available from REMIT process. This could for example examine the outages in gas stations experienced during the “beast from the East” on 1 March 2018.

15-year horizon

65. The ECR 2018 includes a 15-year projection of CM eligible capacity for the four FES. The chart (ECR 2018 Figure 15, p.43) shows the capacity requirement is broadly stable or declining. This trend considers commissioning of new CfD-supported capacity (renewables and nuclear), the expiring of existing CfD-supported generation (such as biomass in 2027) and the different demand outlooks.

[5] Dr. Stan Zachary (Hariot-Watt University), Dr. Amy Wilson (University of Edinburgh) and Dr. Chris Dent (University of Edinburgh)

66. It is interesting to note that NG comments that there could in principle be a risk that plant awarded 15-year contracts in a T-4 auction may become stranded assets should the demand for this capacity decline markedly in future. This raises a question as to the permanence of the demand for capacity beyond the T-4 delivery year and therefore the type of capacity that might be secured in that year. This is an area that the PTE believes should be considered in the forthcoming 5-year review.

Comments on Target Capacity

The T-1 auction for 2019/20

67. The PTE through its engagement with NG has reviewed the analysis, data and assumptions adopted by NG in estimating the capacity to secure for 2019/20 and accepts this as reasonable and therefore agrees with this year's recommendation of the capacity to secure.

The T-4 auction for 2022/23

68. The PTE through its engagement with NG has reviewed the analysis, data and assumptions adopted by NG in estimating the capacity to secure for 2022/23 and accepts this as reasonable and therefore agrees with this year's recommendation of the capacity to secure.

Conclusion

69. On the basis of the information that the PTE has seen, we agree with the recommendations of the capacity to secure for both T-1 and T-4 as outlined in the ECR 2018.

Choosing a De-Rating Factor for Interconnectors

General

70. The PTE has been asked by BEIS to recommend specific DRFs for GB interconnectors, taking into account the modelling results presented by Pöyry (historical floor analysis) and NG (modelled ranges for each of the relevant EU markets).

71. The PTE also considered submissions sent to our e-mail account, as well as recent work carried out by Aurora, LCP and UKERC related to the contribution of interconnection to security of supply. The key areas we considered include the reduction of DRFs as interconnector capacity increases, uncertainties surrounding interconnector performance, significant change in generation portfolio and policy risks.

72. The PTE supports the analysis carried out by NG. We welcomed this year's development of EU scenarios, making use of plans developed by corresponding local Transmission System Operators and ENTSO-E. These included consideration of demand history of 31 years (1985 to 2015), which is correlated

across Europe and with wind generation, giving greater confidence in the ability of interconnectors to contribute to security of supply in GB when needed.

73. NG's modelling shows, as indicated in our report last year, that increasing interconnector capacity from the present level will tend to reduce the DRFs (as interconnection capacity increases and saturation effect begins to manifest). Thus, there is a growing need to consider the interactions between DRFs among interconnectors.

74. Our recommendations this year reflect our expectation that interconnectors' proportionate contribution to security of supply will decline, as overall GB interconnector capacity grows and as neighbouring countries retire surplus capacity over the 5-year period covered by these upcoming auctions.

75. We also note that NG have encountered methodological issues with the historical analysis this year, which have not presented themselves previously in any significant way. In light of this, we would suggest that the 5-year review offers an important opportunity for a detailed assessment of options to improve the methodology which is set out in the CM Rules[6].

76. For the 2019/20 auction, we recommend defining DRF as the average of all DRFs, historical and BID3 modelling, which reduces the weight accorded to historical DRFs. Given the improved modelling capabilities and significant changes in the EU system beyond 2020, we recommend using only BID3 modelling ranges for determining DRFs for the 2022/23 auction, as historical flows and price differentials would not be relevant.

77. The contribution of interconnection to the GB electricity system will also depend on the closeness of GB/EU integration. However, we conclude and reiterate that interconnectors continue to make an important contribution to the GB electricity system and enhance its security, and that increased interconnection will be valuable to the GB electricity system.

78. The PTE therefore recommend splitting the range of DRFs for the T-4 auction, with higher DRF values corresponding to the case of close integration between GB and the EU, and lower DRF values reflecting the case with more loose EU integration. As Ireland is not connected to mainland Europe, our recommendation is based on the assumption that Brexit would not impact the integration between GB and Ireland.

79. A further concern, as demonstrated by recent analysis, is the uncertainties relating to the management of stress events in the medium/longer term. Although uncertainty is not very material in the short term, when the capacity of interconnection increases it will be important that TSOs at either end of each

[6] Schedule 3A of the Capacity Market Rules: "Methodology for Determining the De-Rating Factor of an Interconnector CMU", inserted by amendment 16 to the Capacity Market (Amendment) Rules, 2015. (https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/431843/Capacity_Market_Rules_Amendments_2015_Signed.pdf)

interconnector draw up and publish the rules that would govern their actions. This includes the potential availability of plant retired from the market but available in national strategic reserves. This is an important future consideration.

> **NEW RECOMMENDATION 40:** To inform next year's ECR, NG should review the impact of set aside strategic reserves in continental Europe on interconnector contribution to security of supply, and if significant, include this within the 2019 interconnector DRF assessment.

80. Our recommendations for T-1 (2019/20) are presented in Table 2 and for T-4 (2022/23) in Table 3.

De-rating Factors	**Ireland**		**France**	**Belgium**	**Netherlands**	**Norway**
Historical (from last 7 years' peaks)	5% (Actual available flows)		55% (Actual available flows)	67% (Actual available flows)	70% (Based on observed price differentials)	96% (Based on observed price differentials)
Modelled Range	35-54% (Average 44%)		61-92% (Average 78%)	65-78% (Average 70%)	41-79%	N/A
2017 Values	Moyle N/A	EWIC 60%	70%	77%	78%	92%
PTE Recommendation	**44%**		**74%**	**69%**	**Already contracted**	**(Not yet built)**

Table 2 - Interconnector De-Rating Factor Recommendations for T-1 (2019/20)

De-rating Factors	**Ireland**		**France**	**Belgium**	**Netherlands**	**Norway**
Historical (from last 7 years' peaks)	5% (Actual available flows)		55% (Actual available flows)	67% (Actual available flows)	70% (Based on observed price differentials)	96% (Based on observed price differentials)
Modelled Range (With mean of runs without and with +5% demand uplift)	24-42% (Means: 30% / 33%)		59-86% (Means: 78% / 75%)	35-67% (Means: 56% / 42%)	27-62% (Means 47% / 34%)	90-100% (Means: 98% / 92%)
2017 Values	Moyle N/A	EWIC 60%	70%	77%	78%	92%
PTE Recommendation (with close EU integration)	**24-42% (Recommend 33% for either)**		**73-86%**	**51-67%**	**45-62%**	**95-100%**
PTE Recommendation (without close EU integration)			**59-73%**	**35-51%**	**27-45%**	**90-95%**

Table 3 - Interconnector De-Rating Factor Recommendations for T-4 (2022/23)

81. For explanation of NG's modelling, please see the ECR 2018: for historical analysis, ECR 2018 Tables 11 and 12; and for interconnector flows modelling, ECR 2018 Tables 9 and 10. The reasons for substantially lower historical numbers for Ireland and France are discussed in the ECR 2018. Note that NG's 2019/20

analysis did not generate sufficient statistical samples of stress periods without uplifting demand by 5% (10% for Ireland).

82. In this section, we explain the rationale for our recommendations.

Overview of the approach for determining the De-rating Factor ranges

83. As in previous years, two approaches are applied for informing interconnector DRFs. First is analysis of historical data between the two markets over seven years of actual flows (where available) or price differentials (where not), which in the CM Rules[7] and in previous years has been used to determine the minimum DRF of interconnectors.

84. The second approach is scarcity modelling of the future European electricity market, carried out by NG using the pan-European BID3 model to produce DRF ranges for each interconnected country.

85. In previous years, the approach for determining the DRF for each interconnector was generally based on the average between the minimum and maximum DRF values, based on historical and BID3 modelling respectively.

86. This year we propose different approaches for the T-1 and T-4 auctions.

87. **For the T-1 (2019/20) auction, we define DRF as the average of all DRFs, historical and BID3 modelling.** This reduces the weight accorded to the historical DRFs, which reflects several considerations including:
    a. the high volatility and trends of the historical DRFs, including particular factors which explain these and which should not in principle be relevant to forward-looking DRFs; and
    b. the far greater sophistication of modelling now available.

88. This is applied to France and Belgium interconnectors only, as the DRF for Ireland does not consider historical modelling. Interconnectors for Netherlands and Norway cannot participate in the T-1 auction hence we do not provide DRFs for these.

89. **For the T-4 (2022/3) auction, we exclude consideration of historical values of DRFs.** This is primarily driven by the expected reduction in capacity margin across Europe due to mothballing and decommissioning of gas, coal and/or

[7] Schedule 3A of the Capacity Market Rules: "Methodology for Determining the De-Rating Factor of an Interconnector CMU", inserted by amendment 16 to the Capacity Market (Amendment) Rules, 2015 (https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/431843/Capacity_Market_Rules_Amendments_2015_Signed.pdf). These state, *inter alia*: "The EFIC of an Interconnector CMU for a calendar year ("Year Y") will be the greater of: (1) the Historical De-rating Factor of that CMU for Year Y, and (2) the Forecasted De-rating Factor of that CMU for Year Y, unless there are publically [*sic*] reported concerns about the supply of electricity for Year Y in the country or territory in which the Non-GB Part will be located ("the Interconnected Country"), in which case the Secretary of State may decide on a value for EFIC that is less than the Historical De-rating Factor."

nuclear generation. The modelling also considers the implication of the phasing out of remaining nuclear generation in Germany by 2022. The BID3 modelling ranges presented in the ECR 2018 for 2022/23 reflect the combination of rising interconnector capacity and expected changes in continental systems beyond 2020. Therefore, most of the modelled DRFs are below the historical level. We emphasise that this does not in any way negate the value of interconnectors or their contribution to security of supply, but it does suggest that the historical floor no longer remains relevant. Therefore we recommend that the historical estimates should not form a floor when determining the T-4 DRFs.

90. NG carried out pan-European market modelling using the BID3 model that was applied for each scenario for 2019/20 and for 2022/23 and electricity interconnector capacities for GB (this year the analysis involved the Base Case plus four FES scenarios: Community Renewables, Two Degrees, Steady Progression and Consumer Evolution). The PTE welcomed the addition of EU scenarios in the modelling, making use of plans developed by local Transmission System Operators and ENTSO-E for Belgium, France, Germany, Ireland, Netherlands and Norway. These include consideration of demand history of 31 years (1985 to 2015), which is correlated across Europe and with wind generation and hence giving greater confidence in the ability of interconnectors to contribute to security of supply in GB when needed.

91. Moreover, stress tests[8] have been analysed to check the impact of tighter margins on interconnector flows. It is interesting to observe that the stress tests do not always reduce interconnector DRFs. This is because more hours are considered by the model, so that whilst the original selection of system conditions may be associated with lower level of imports, the additional hours may be less stressed over the whole of Europe, thereby enabling higher imports. However, whilst this was visible particularly for T-1 (2019/20 analysis) and some specific scenarios for T-4 (2022/23), on average the 'stress tests' did reduce DRFs for T-4.

92. NG's analysis results in broad ranges of DRFs for each interconnector. The choice of the exact position within the range depends on a number of factors: which of the FES scenarios is most likely, assumptions on the rate of change in European generation, and any impacts that might result from Brexit. In the context of Brexit we recommend that the DRF ranges for the T-4 should be split, with higher DRF values corresponding to close GB and EU market integration, amongst other factors, and lower values reflecting looser EU integration. Close EU integration could include intra-day electricity trading, TSO access to balancing markets, security access to strategic reserves, and/or participation in the EU Risk Preparedness Regulation, with respect to neighbouring countries, all of which are associated with the EU Internal Energy Market and/or the EU's Clean Energy Package.

93. Whilst the FES scenarios which define the full range are *not* explicitly reflecting different integration scenarios, our rationale includes the following. The NG scenarios generating lower DRFs tend to be the ones in which (often for

[8]Stress tests of 5% were used for all countries except Ireland, for which a 10% stress test was required.

environmental reasons) more conventional plant is retired, which drives the tighter margins that reduce the DRFs. However, these countries will be equally keen to ensure security, and several continental countries have or are establishing strategic reserves (plant taken out of normal market operation but still available to ensure supply security); Belgium explicitly intends that plant retired for environmental reasons will be placed in its strategic reserve to help ensure security for as long as needed[9]. Continuing close integration should encourage countries to supply their neighbours if needed, including if necessary for mutual security needs, utilising such strategic reserve capacity. In this sense, the lower DRFs in NG's more environmentally-driven scenarios – which only account for in-market capacity – in our view give an unduly pessimistic picture of the value of interconnection for security purposes, provided close integration is maintained after Brexit. Moreover, we note that the more environmentally-driven scenarios are precisely the ones in which we would expect interconnectors to have a higher overall value to the system, to manage the variability of very high levels of renewables.

94. The PTE view the island of Ireland's electricity market slightly differently to those electricity markets on the continent. Ireland is not directly connected to the electricity network of mainland Europe and does not have plans for a strategic reserve. Therefore the PTE are of the view that it is less exposed to the direct impacts of the continental electricity markets, and we recommend using the full NG range of DRF for Ireland irrespective of Brexit considerations.

95. We now discuss the rationale for our recommendations for each country in turn.

Ireland

96. The historical modelling indicates a DRF for Ireland of 5%.

97. The low historical DRF is the result of several factors:
   a. a history of high Irish electricity prices, which meant that GB has been generally exporting to, rather than importing from Ireland, despite significant surplus capacity in Ireland; and
   b. substantial technical faults with the Irish interconnectors which affected historical availability.

98. The Integrated Single Electricity Market (I-SEM) in Ireland is also due to be implemented in 2018. We believe that these factors make the historical figure largely irrelevant for Ireland. This is reflected in the NG modelling, which produces DRFs far higher than the historical modelling in all cases.

99. For 2022/23, further changes are expected, supporting our view that the historical modelling will not be relevant: growth in Irish demand and the Irish capacity market targeting 8 hours LOLE, reducing the current capacity surplus. For these reasons (and also considering the large scale of some individual plants in context

[9] Public consultation on the methodology, hypotheses and data sources for the dimensioning of the volumes of strategic reserve needed for winter 2019-2020, *elia*, Consultation period 23 April 2018 to 21 May 2018. (http://www.elia.be/~/media/files/Elia/About-Elia/Publication/SR2019-20_Public-consultation-on-methods-and-data-sources.pdf)

of a relatively small system) we support the use of a 10% stress test in Ireland instead of the 5% applied in the rest of Europe.

100. Last year we proposed separate DRFs for the two Irish interconnectors: Moyle, the link between Northern Ireland and Scotland and EWIC, the southern Irish interconnector.

101. This year, we recommend the same DRFs for both interconnectors. A key factor is that the capacity of Moyle to which the DRF has been applied – which we linked to its TEC – is being updated periodically. Last year 80MW was used, while 307 MW is now used for 2019/20 and 500MW for 2022/23.

102. This year, Ireland was modelled as a single price area so Ireland's North/South constraint had no impact. Current limits between the North and South will be rectified with an additional North/South link, which is anticipated to be operational before 2021/22. We do not differentiate between EWIC and Moyle for either 2022/23 or 2019/20, but acknowledge that this approach may be less accurate for 2019/20 due to the current constraints identified.

103. As Ireland is not directly interconnected with the rest of Europe, the potential for imports to GB from Ireland will be limited to its domestic system. As such, there is far less potential for the Irish trading relationship to be affected by Brexit. Hence for 2022/23 we propose a single range, based on BID3 modelling of FES scenarios, and recommend the mid-point of this range.

104. This leads us to recommend a DRF for Ireland of 44% for 2019/20, and 33% (mid point of the BID3 modelled range) for 2022/23.

France

105. The historical modelling indicates a DRF for France of 55%.

106. Given the expected reduction in capacity margin across the EU, primarily driven by the decommissioning of conventional generation in Belgium, Netherlands, Denmark and Germany, and their strong interconnection with France, the historical modelling may not be relevant for determining DRFs for France for the 2022/23 auction. Furthermore, we also recognise that France is strongly interconnected and could feed power through from other regions in case of shortages in GB (assuming that the GB price would be high enough). We therefore propose the use of DRFs determined by BID3, rather than the historical modelling.

107. We also note that BID3-based scarcity analysis for 2019/20 did not generate sufficient statistical samples of stress periods without uplifting demand by 5-10%.

108. NG's BID3 modelling suggests DRFs for France of 61-92% for 2019/20, and 59-86% for 2022/23. For 2019/20 our methodology delivers a recommended DRF of 74%. For 2022/23, based on the NG modelled ranges, we recommend a DRF range of 73-86% in the case of close GB and EU market integration and 59-73% in the case of more loose integration.

Netherlands

109. The historical modelling indicates a DRF for Netherlands of 70%.

110. BritNed interconnector was awarded CM contract in the 2015 T-4 auction for 2019/20 and hence we do not provide a DRF recommendation for the 2019/20 T-1 auction.

111. For 2022/23, the historical DRF is above scarcity based DRFs for all scenarios, which are between 27% to 62%. The key reasons for this reduction are the mothballing of conventional gas plant and reduced transit flows from Germany due to government policy to close all nuclear plants by 2022. The historical modelling is therefore not considered relevant to our DRF recommendation.

112. In case of close GB and EU market integration post Brexit, we recommend a DRF of 45-62%, while in case of more loose integration we propose lower values of 27-45%.

Belgium

113. The historical modelling indicates a DRF for Belgium of 67%.

114. For 2019/20 the scarcity modelling across FES scenarios produced a range between 65% to 78% (average being 70%), which is in line with last year's analysis for 2021/22. We also note that BID3 based scarcity analysis of FES scenarios for 2019/20 generated sufficient statistical samples only for stress periods when demand was increased by 10%. Our methodology delivers a recommended DRF of 69% for 2019/20.

115. For 2022/23, NG's BID3 modelling provides a range of 35-67%. All scenarios except for the non-stressed Steady Progression case fall below the historical DRF. Hence we do not consider the results of historical modelling relevant to our recommendation. This significant reduction in the contribution to security of supply of the Belgian interconnector is driven by the reduction in European generation capacity margins, partly caused by phasing out German nuclear generation and partly by generation removed from the market as strategic reserve. We recommend a range for DRFs of 51-67% in the case of close GB and EU market integration and of 35-51% in case of more loose integration.

Norway

116. The historical modelling indicates a DRF for Norway of 96%.

117. The interconnector with Norway is not expected to be completed for 2019/20 but is considered in all scenarios for 2022/23 except Consumer Evolution. The historical DRF for Norway remains very high as hydro based historical electricity prices during the relevant system stress periods in GB remain lower than the GB prices.

118. Similarly, the DRFs based on BID3 modelling are high across all scenarios giving a range of 90-100%.

119. Though Norway is not an EU Member State, it is part of the European Economic Area and the Internal Energy Market and would be bound by the Risk Preparedness Regulation and thus is in practice no different from an EU member state for electricity purposes. Our approach therefore yields a recommend range for the DRF of between 95-100% in the case of close GB and EU market integration, and of 90-95% in case of more loose integration.

Methodology

Modelling Enhancements Incorporated

120. Numerous improvements to the modelling methodology have been implemented or initiated during the development of NG's formal assessment of capacity requirements, most of which are referred to in other sections of this report or in ECR 2018, and some of which have been a result of our recommendations.

121. Not covered elsewhere in this report is the re-evaluation of the de-ratings of duration limited storage, including batteries and pumped storage. This followed from our Recommendation 28 in 2017 as well as wider industry concerns (see Section 2.4.3.3 of the ECR 2018).

122. Batteries previously only had to prove half an hour duration to qualify for a very high DRF even if they would not be capable of sustaining the tested capacity beyond half an hour. With stress events expected to last for up to four hours (or even longer in some cases), this was analytically untenable. Some stress events could have much shorter duration, however, and therefore very short duration batteries could still make a contribution. Following significant analytical investment by NG and public consultation, a more appropriate method for estimating the de-rating of duration limited storage was developed. In broad terms, the de-rating is assigned according to the statistically derived "Equivalent Firm Capacity" ("EFC") that could be displaced during periods of system stress.

123. This method is far better than the preceding approach, although still has shortcomings. These include storage which is capable of extracting benefits through multiple markets, some of which overlap in time and therefore represent 'either/or' trade-off options for the storage operator. For example, frequency response and balancing may require the exhaustion (or filling to capacity) of a storage unit shortly before it may have been required to respond to a capacity stress event. Since storage is self-dispatched and the cost of failure to deliver is never more than the capacity payment, the more immediate and potentially higher revenues from other markets may reduce the availability of limited duration storage. Such behaviours are not yet accounted for.

124. We strongly caution that while EFC is a useful metric from modelling output to convey in simplified language (in accordance with the principle mentioned in the introduction to this section) the statistical expectation of the contribution of a technology to supply security in a defined system state (such as a particular generation and demand mix), it is not necessarily an appropriate input for analytical purposes. The EFC is particular to the specific set of conditions in which it was calculated and the EFCs of a number of technologies pertaining to a specific system state cannot be then used as additive, firm capacities in a different system state because the underlying statistical correlations may also change. EFC should therefore NOT be used as a simplistic substitute for capacity outside of a very limited context. One implication of this is that EFCs calculated in one set of

conditions should not be relied upon to assess, for example, the capacity of a system under different conditions. Use of EFCs for auction purposes should therefore be considered with extreme caution and scepticism. We are satisfied, however, that for the purpose of limited duration storage, the concept represents a welcome enhancement to the previous method and that NG continues to use the concept appropriately.

Quality Assurance

125. Quality assurance (QA) procedures followed in previous years are employed again this year. These procedures are closely aligned with BEIS's internal QA processes.

126. Reference to the detail of the ECR Quality Assurance methodology can be found in ECR 2018.

Annex 1 - Progress on the PTE's Previous Recommendations

127. The PTE made a number of recommendations in its four previous reports. Last year's (2017) PTE report made 10 new recommendations, numbered from 26 to 35 (continuing on from the previous years' numbering). All these recommendations, along with others raised by BEIS, Ofgem and NG's internal post review/update process were considered in the project evaluation, whereby all recommendations received by NG are scored by NG, BEIS and Ofgem according to their impact/materiality, resources/effort and priority – see ECR 2018 Annex A3. In the end, the resources available to NG allowed 5 of these proposals outlined in Table 4 to be taken forward.

PTE 2017 Recommendations	PTE Comment
Recommendation 27. Improving data and providing access to the best available data on embedded generation (including for NG) should be prioritised as a matter of urgency, if possible before next year's ECR.	**Acted upon and ongoing.** This action was pursued vigorously by NG, but by the time the analysis for 2018 was locked down, the level of detail required was not available. The PTE wrote to the Secretary of State expressing concern regarding access to data. Progress has since been made and NG expects that the data will be available for use when preparing ECR 2019.
Recommendation 29. We reiterate the importance of our previous recommendation no.23 (PTE 2016): "Analyse the impact of scarcity pricing on peak demand and also examine demand responses to high prices in markets that have already begun to roll out active management tools." and suggest that this be prioritised for development prior to next year's ECR, and extended to consider evidence around the extent to which different segments of potential demand response might or might not participate in the CM.	**Acted upon and ongoing.** This action is to a degree dependent upon the outcome of Recommendation 27.
Recommendation 31. NG should advance analysis to estimate how, in the event of non-delivery (closures leading to cancellation of capacity contracts) by one source of capacity, the incentives and probability of delivery would change in relation to other sources.	**Acted upon and completed.** NG's project to address this Recommendation[10] marshalled the best available data and established an analytical methodology to use the DDM to investigate non-delivery and over-delivery very thoroughly and painstakingly. The quantum of individual generation units and how they are affected by a range of sensitivities, as well as our developing knowledge of the impact of DSR and the possible combinations of delivery outcomes made this challenging but the results provided significant new insights.

[10] See ECR 2018, Section 2.5.2.

Recommendation 33. There is a case to estimate interconnector de-rating factors for individual interconnectors rather than countries; in particular, NG should refine the inclusion and presentation of internal transmission constraints within both GB and the island of Ireland, so as to facilitate estimation of de-rating factors for the Moyle and EWIC interconnectors separately in future years.	**Acted upon and completed.** NG reviewed the case for de-rating individual interconnectors[11] and credibly established that whilst it is possible, obtaining reasonable data, setting up the model and increased run times make this prohibitive at present. Whilst our view is unchanged, we accept that the current method is acceptable for now but if and when the burden of this calculation sufficiently reduces, we hope that this action can be revisited.
Recommendation 34: We welcome the response from NG in addressing last year's recommendation to consider the application of weightings to Least-Worst Regrets assessment (Recommendation 25) which concluded that extreme events should be assigned low weights or excluded. However, we believe there is merit in considering further how best to treat less extreme events, for example, through weighting sensitivities (as outlined in our PTE 2016 report, p43) and the insights this can yield.	**Acted upon and completed** NG have investigated whether this investigation would be fruitful and produced cogent reasons not to do so[12], which we accept.

Table 4 – PTE 2017 Recommendations Progressed

128. The PTE 2017 Recommendations that were not actioned or deferred are set out in Table 5.

PTE 2017 Recommendations	**PTE Comment**
Recommendation 26. NG should seek to include a review of their past forecasts, focusing particularly on periods of peak demand and system stress, as a regular item, along with key points from their Demand Forecasting Incentive report, which could be included along with the other Quality Assurance notes.	We accept that this has not been the most consequential item of analysis during 2017/2018. It seems that this should be "business as usual" for NG in order to ensure good performance against the Demand Forecasting Incentive. **PTE VIEW: WITHDRAW THIS RECOMMENDATION**
Recommendation 28. We recommend that NG develop a de-rating methodology for energy storage that considers the size of the storage tank in relation to de-rating factors; In addition, NG should 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 of this for the estimation of de-rating factors.	The first part of this recommendation has been superseded by the extensive work on establishing DRFs for "duration limited storage"[13]. The second part of this recommendation, according to the scoring, did not achieve a high enough score on grounds of materiality/impact and priority. We accept this for now but expect the matter to resurface if distributed energy resources increase in abundance. The review of duration limited storage DRFs was in part stimulated by this recommendation and we were pleased with the progress in this area. **PTE VIEW: ACCEPT NG POSITION FOR NOW BUT REVISIT IF DISTRIBUTED ENERGY RESOURCES BECOME MORE ABUNDANT.**

[11] See ECR 2018, Section 2.5.2.
[12] See ECR 2018, Section 3.10.12.
[13] See ECR 2018, Section 2.4.3.3 and "Duration Limited Storage De-rating Factor Assessment – Final Report", NG, December 2017. (https://www.emrdeliverybody.com/Lists/Latest%20News/Attachments/150/Duration%20Limited%20Storage%20De-Rating%20Factor%20Assessment%20-%20Final.pdf)

Recommendation 30. NG should consider taking a more 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. Perhaps this could be co-ordinated through the Energy Networks Association (ENA) or code group with support from Energy UK and Association of Distributed Energy (ADE).	The PTE still believes that an appropriately designed information campaign on risk and security of supply issues would bring considerable value in informing the wider public and industry stakeholders/ commentators and hence indirectly leading to more informed decision-making. Moreover, public acceptance of and engagement in measures that secure supplies while reducing costs and the expansion of networks should have material potential impact on welfare. **PTE VIEW: NG TO RECONSIDER IN 2018**
Recommendation 32. In due course, NG should undertake a historical analysis to determine the extent to which stress events on its network have been due to combined events and the assess whether such combinations might arise again.	We accept that a detailed and exhaustive analysis of this kind would require effort that would be difficult to justify in terms of cost because the expectation of combined improbable events is very low indeed. We would ask that NG consider an initially lighter approach of New Recommendation 39 to derive insights rather than firm conclusions. We think it important, not least because we ignore Black Swan events in the analysis because of low probability and violation of the rules to select sensitivities. Such events, however, have no regard for the rules of sensitivity studies and do occur. **PTE VIEW: WITHDRAW AND REPLACE WITH NEW RECOMMENDATION 39**
Recommendation 35: We are keen that NG consider again our previous Recommendation 16 but broadened to include consideration of the range of additional forms of 'latent capacity' (such as various possible responses of DNOs to demand reduction requests).	This was the lowest scoring action in the ECR 2018 in Table 22. We do not accept that hidden resources measurable around a value of a GW can be regarded as having very little materiality or impact. We recognise that currently there are limits on how much of this could be accessed or accounted for, but this may change going forward, especially if there is awareness of its scale and capabilities. The PTE believes that NG should be asked to reconsider this aspect as a development project for this year alongside the wider review by stakeholders of the security standard and VOLL as part of the 5-year review. **PTE VIEW: NG TO RECONSIDER**

Table 5 – PTE 2017 Recommendations Not Actioned or Deferred

129. Which recommendations to pursue or defer are assessed using a multi-criteria scoring system[14]. This gathers a number of projects that have been suggested by NG itself, BEIS and Ofgem as well as our recommendations and orders these for action within a limited resource envelope according to subjectively awarded scores against the criteria of "Impact / Materiality", "Effort/Resource" and "Priority", with Priority being double-weighted.[15]

[14] See ECR 2018 Section 2.5 for full details.
[15] See ECR 2018 Annex A.3 EMR/Capacity Assessment Development Projects Matrix.

130. The PTE is generally very pleased with NG's responses to our recommendations. Given the number and diversity of our recommendations over several years, we believe we can best assist NG by rationalising the PTE's cumulative recommendations into a simpler set which, where possible, is co-ordinated and subsumed within projects that NG might be doing anyway. In this way, we hope to make recommendations in the most efficient way possible and such that they are more likely to be acted upon. Following the publication of this year's ECR 2018 and PTE Report, the PTE will therefore review its previous recommendations together with BEIS, Ofgem and NG in order to reduce the number and prioritise the most important of these.

Glossary

ACS	Average Cold Spell
BEIS	Business, Energy and Industrial Strategy (Department for..)
BID3	Poyry's European electricity market model
CCGT	Combined cycle gas turbine (power stations)
CfD	Contract for Difference
CM	Capacity Market
CONE	Cost of New Entry
DDM	Dynamic despatch model developed by LCP
DNO	Distribution Network Owner
DRF	De-rating Factor, the ratio of the amount of reliable deliverability to the nominal or nameplate capacity or TEC, whichever is lower
DSR	Demand side response or resource
ECR	Electricity Capacity Report
EEU	Expected energy unserved
EFC	Equivalent Firm Capacity
EMR	Electricity Market Reform, as set out in the Energy Act 2014
ENTSO-E	European electricity networks association
EVs	Electric vehicles
FES	Futre Energy Scenarios (developed by National Grid)
FIT	Feed-in-tariff
IA	Impact Assessment
ICRP	Investment Cost-Related Pricing (for setting grid charges)
IET	Institute of Engineering and Technology
IFA	The interconnector from France to England (Angleterre)
I-SEM	Integrated Single Electricity Market (of Ireland)
LOLE	Loss of Load Expectation
LWR	Least-Worst Regrets
MS	Member State (of the EU)
NG	National Grid
PTE	Panel of Technical Experts
PV	(solar) photo-voltaic
RSP	Reserve Scarcity Pricing
SEM	Single Electricity Market of the island of Ireland
ROC	Renewable Obligation Certificate
RSS	Root Sum Squares
TA	Transitional Arrangements to help DSR to participate in the CM
TEC	Transmission Entry Capacity – the amount on which a generator pays TNUoS
TNUoS	Transmission Network Use of System (of charges levied on Generators)
TSO	Transmission system operator
VOLL	Value of Lost Load