Department of Energy & Climate Change

EMR Panel of Technical Experts' Final Report on National Grid's Electricity Capacity Report

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Executive Summary

1. The Panel of Technical Experts (the Panel) was asked by DECC to impartially scrutinise and quality assure the analysis underpinning National Grid's recommendations for 'Capacity to Procure' for the GB Capacity Market auction scheduled for December 2014. Questions of policy and cost to consumers are explicitly excluded from the Panel's remit.

2. The Panel received presentations, analyses and comprehensive information during the development of National Grid's work between March and June this year. We are very grateful to National Grid and the Panel's Secretariat at DECC for their cooperation, and patience in providing these.

3. The Panel is not a full time body and operates within limited time constraints and therefore sought to prioritise key issues during the course of its work.

4. Overall, the Panel was satisfied that the modelling tools employed, specifically DECC's "Dynamic Dispatch Model" (DDM) and a "Robust Optimisation Tool" are fit for purpose, although we have recommended that the latter should be subjected to further formal Quality Assurance procedures at the same level as the DDM.

5. The Panel, in line with its predecessor[1] strongly endorses the use of the Future Energy Scenarios as a basis for assessing the capacity requirement of GB as they provide alternative possible futures that are self-consistent and represent and accommodate the relatively recently considered views of a very wide range of stakeholders.

[1] An interim Panel of Technical Experts was appointed to scrutinise the analysis undertaken by National Grid that was used to inform strike prices published in the EMR Delivery Plan 2013.

6. The Panel's most significant findings were as follows:

   a. The Panel felt that there was sufficient evidence to challenge National Grid's initial modelling assumptions regarding the reliance that can be placed on interconnectors during periods of system stress, which are the times that create the need for capacity. National Grid presented evidence to support their belief that no reliance could be attributed to interconnectors but the Panel felt that its additional evidence was more persuasive. The Panel suggested that at least 50% of current nameplate capacity should be assumed.

   b. The analysis carried out by National Grid results in different Capacities to Procure for each scenario as well as for each sensitivity within each scenario, leading to a large number of choices. The Panel suggested a well-proven method, known as Least Worst Regrets, which is widely used and understood by National Grid and also across many sectors where choices must be made under conditions of uncertainty. National Grid and DECC adopted this approach and generally have implemented it effectively.

   c. The Panel raised concerns regarding the lack of information and understanding regarding Demand Side Reduction (DSR). The Panel prefers the term Distributed Energy Resources (DER) which imports the full range of contribution that could come from sources other than conventional generation whereas the term DSR appears to constrain demand-side awareness to mere reductions in demand and embedded generation. Noting the importance of building a strong institutional knowledge of DER amongst DECC and NG, the Panel recommended a programme to investigate this area further so that opportunities are captured in the future.

   d. The Panel also noted that there is relatively limited relevant information on plant availabilities at times of system stress and in markets that incentivise

availability. The Panel remains unconvinced that the data available, mainly relating to annual average availability, is an ideal proxy suggesting that it underestimates the contribution that a generating plant can make in an incentivised market.

e. The Panel have commented in this report on a number of other areas and made a number of minor suggestions, which were discussed during meetings, but which have not been considered material enough to report here.

7. The Panel was also asked to comment on potential National Grid conflicts of interest. The Panel recognises that such a conflict potentially exists where National Grid may have a stronger interest in over-procurement, but we are not aware of any specific cause for concern. The Panel attempted to manage this by vigorously and relentlessly challenging National Grid's assumptions and methods in areas where such a conflict might arise.

Introduction

Role of the Panel of Technical Experts

8. The Government commissioned, in February 2014, through an open and transparent procurement process, an independent Panel of Technical Experts (the Panel) for the enduring Electricity Market Reform (EMR) regime. The role of the Panel is to impartially scrutinise and quality assure the analysis carried out by National Grid (NG) in its role as EMR Delivery Body. This Panel replaced the interim Panel of Technical Experts that was commissioned in February 2013 to scrutinise and make recommendations on the analysis that underpinned the strike prices for renewable technologies published in the EMR Delivery Plan in December 2013.

9. The background of the members and terms of reference of the Panel were published on the Government website[2]

10. This report has been prepared for DECC by:

- Andris Bankovskis;
- Dr. Guy Doyle;
- Professor David Newbery CBE FBA;
- Professor Goran Strbac

Scope

11. The scope of the Panel is to impartially scrutinise and quality assure the analysis carried out by NG for the purposes of informing the policy decisions for the EMR enduring regime. This includes scrutinising: the choice of models and modelling techniques employed; the inputs to that analysis (including the ones DECC provides); and the outputs from that analysis - scrutinised in terms of the inputs and methods applied. The Dynamic Dispatch Model (DDM) used by NG for it modelling, is subject to

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

a well-documented Quality Assurance process and the Panel does not comment further on this.

12. The Panel has no remit to comment on EMR policy, Government's objectives, or the deliverability of the EMR programme. The Panel'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 Panel's scope and therefore from this report. The Panel is also not responsible for recommending a Capacity to Procure.

13. This report is the Panel's formal report on the scrutiny of the analysis undertaken by NG on the amount of capacity to procure through the Capacity Market auction in December 2014 for 2018/19.

Approach

14. During the course of the Panel's work, NG has presented its methods, assumptions and outputs in relation to NG's core task of recommending the capacity to procure in the first T-4 auction of the Capacity Mechanism during the course of its development and the Panel has had opportunity to question NG.

15. To carry out its work, the Panel met with NG at DECCs offices, approximately on a weekly basis since mid-March, during which presentations were made by NG and the Panel had an opportunity to ask questions and make comments. Subsequent to the meetings, the Panel produced various interim reports and put many questions to which DECC organised responses.

16. The Panel's initial focus was on gaining an understanding of the methodologies and analytical techniques available to NG to conduct analysis commissioned by the Government for the Capacity to Procure in the first T-4 auction and to scrutinise the assumptions on which the analysis rests. The Panel was already familiar with the Dynamic Dispatch Model (DDM) that is employed to simulate investment decisions in generation in response to various interventions, which critically for this analysis, includes the level of capacity payment. In addition, NG explained its modelling of the

Loss of Load Expectation (LOLE), as a LOLE of 3 hours per year is the target that the Capacity Market is designed to deliver.

17. However, after the delivery of NG's report, the Panel was alerted to the considerable variation in the potential supply of existing plant that might still be available in 2018/19 and which might therefore influence whether it were necessary to commit now to procure new plant, which might considerably increase the market clearing price in the auction. It appears that whether or not existing coal plant will be available depends on the confidence with which they can be assured of reconnection if they choose to disconnect until a capacity payment makes it commercially viable to return, introducing an additional factor that we consider should be addressed.

18. The Panel 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 Panel's developing views. Key areas that emerged included:
    a. the contribution of interconnection;
    b. assumptions around availability of plant, and especially embedded generation, at times of stress;
    c. demand side response in general;
    d. the treatment of extreme peak load events; and
    e. established methodologies for making a rational choice from a large number of possible 'Capacity to Procure' figures under circumstances of uncertainty.

19. The Panel has also drawn from the experience of its members in other Capacity Mechanism markets, such as PJM and New England, as well as its experience in other key areas where the need to procure capacity includes the demand side. The Panel has been somewhat reassured that DECC has drawn on the PJM experience, but the Panel remain concerned that not enough evidence has been provided on the potential contribution that the demand side might make, particularly the extent to which embedded generation might become available, with some retrofitting and aggregation, and the extent to which CHP can deliver additional power to the system over and above its own demand in stress periods.

20. During the course of the Panel's work, the opportunity was taken to participate in a simulation of the new Capacity Market to inform ourselves of the specific rules that play a role in the auction process, as well as possible behaviours that would not be obvious from the information presented by NG. While it was not the main objective of the simulation, we noted that the auction rules were resistant to manipulation through withholding plant in order to manipulate the clearing price, which increased the Panel's confidence in the reliability of NG's modelling approach.

21. During the course of the Panel's work, it also commented on independent analyses carried out by DECC and NG to support the assumptions and in particular, the Panel commented on the report produced by ARUP into plant availabilities, and drew on reports by Pöyry (2012, 2013) and Redpoint (2013) for DECC on interconnectors.

22. As required by the Panel's Terms of Reference, the Panel also kept in mind the potential for NG to be confronted by potential conflicts of interest. The Panel throughout this process has sought to mitigate this by vigorously challenging assumptions. The Panel has commented briefly on conflicts of interest later in this report.

23. This report is not comprehensive and nor is it a due diligence exercise but the Panel believes that it has nevertheless identified some extremely important issues that have significant consequences that are discussed here. Accordingly, the Panel has not overly focussed its attention in this report on the myriad of detail of many matters which were raised and satisfactorily resolved or are part of on-going development.

Caveats

This report has been prepared from information provided by DECC, NG 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 deems necessary.

Analysis and Key Findings

National Grid's Methodology

24. The overall methodology followed by NG was described in a set of work packages in its arrangements with DECC. In summary, these packages required the following steps (amongst others) to be carried out and which were all executed in accordance with the plan:

25. NG used the Dynamic Dispatch Model (DDM) to calculate multiple options for the Capacity to Procure, using a 3 hour LOLE reliability standard, which is driven by peak demand (and not annual averages).

26. NG's recommended scenarios from the available Future Energy Scenarios (including sensitivities) were used. (The analysis also included a scenario specified by DECC but which NG were not obliged to take into account in making their recommendation for Capacity to Procure).

27. NG were then required to find a method to select a final recommended Capacity to Procure arising from the large range of numbers representing possible Capacities to Procure which were produced by the analysis of each of the scenarios and sensitivities.

28. The Panel suggested the method known variously as "Least Worst Regret", "Mini-Max Regret" or "Robust Optimisation", which was accepted and adopted by NG after floating the proposal in industry workshops. This method enables a rational decision based on limited and uncertain information and seeks a solution that minimises regret across all scenarios. It, therefore, corresponds to a low appetite for risk. A "maxi-min" strategy, which selected the strategy with the highest minimum, is the most risk averse and "Maxi-Max" is more risk seeking. In other words, "Mini-Max minimises the maximum regret, but does not minimise the maximum cost.

The Panel's view of the Scenarios and Sensitivities and underlying assumptions

29. In general, the Panel strongly endorses the high level approach employed by NG to solve the inherently difficult problem of calculating the right amount of capacity required to meet the reliability standard for security of supply against a background of many uncertainties over a very long forward period of time. The Panel agrees entirely with its own predecessor's[3] recommendations regarding the use of scenario planning, whereby a limited number of self-consistent futures are constructed through the Future Energy Scenario process and possible solutions are modelled based on the assumptions (or 'axioms') from which the scenarios are developed.

30. The process for developing the Future Energy Scenarios appears very robust as it involves deep discussion and development through broad interaction with a wide spectrum of hundreds of informed stakeholders. The way in which the scenarios have been used by NG as the basis for modelling appears to the Panel to be in accord with the best practice of other industries (such as the oil industry).

31. Turning to the detail, one of the Panel's most important concerns is that the auction clearing price and the cost of the Capacity Market could depend to some degree on whether it will be necessary to procure new plant to be commissioned by 2018/19 (though in practice this will depend on the bidding behaviour of individual plant). It is possible under very reasonable assumptions that the existing and proposed new interconnectors, combined with the anticipated volume of new renewable generation and demand side responses of various sorts, could delay the need for new generation investment.

32. The Panel's appreciation of the sensitivity of the auction price to the assumptions behind the modelling emerged at a relatively late stage, and in turn directed us to the need for further evidence, some of which the Panel has identified and referred to

[3] An interim Panel of Technical Experts was appointed to scrutinise the analysis undertaken by National Grid that was used to inform strike prices published in the EMR Delivery Plan 2013

below, and some of which is still not sufficiently precise to reduce uncertainties over procurement levels and hence the cost. In cases where better information might be collected or become available over the next 12-18 months, and assuming that open-cycle gas turbines or other options could still be procured in time to avoid breaching the target level of reliability, there is a case for reconsidering the way in which the costs of under and over-procurement are treated in the "Robust Optimisation" determination of the amount of capacity to procure.

33. The Panel would also agree that it is difficult to assign probabilities to the broad scenarios, which are all credible futures. Nevertheless, the Panel's strong view is that assuming all sensitivities to be equally likely cannot be justified, and can perhaps be illustrated by looking at Scenario 'No Progression' ("NP"), which is more pessimistic (as to delivering renewables) than 'Slow Progression' ("SP"). The evidence is that between 2009 and 2013, and under the old system of support, which EMR is designed to improve, the average annual addition to wind capacity in UK has been 1.4 GW, and exceeded 2 GW in 2012, according to data from the EWEA.[4] Under 'Slow Progression', we were informed by NG that the projected wind increment is 2.8GW over the same three year period, or a fall of a third in past achievements. Here the difference in assumptions is very material for the amount of new capacity to procure and hence potentially very material to the cost of the auction.

34. The key point that the Panel wishes to stress is that these scenarios have evolved over a considerable period of time, and equally clearly, as time passes the range of uncertainty about the level of renewable capacity in 2018/19 narrows, making some scenarios and sensitivities less probable than others. The opportunity to incorporate learning and information about the probability of sensitivities, and if applicable, scenarios, into on-going analysis should not be lost and this should be systemically provided for.

[4] See http://www.ewea.org/fileadmin/files/library/publications/statistics/EWEA_Annual_Statistics_2013.pdf

35. To test modelling outputs against expectations, the Panel was interested to compare very different levels of coal generation projected for 2018/19, compared to the current level of 18.1 GW. NG provided us with information about the plant capacity assumed to be on the system in each year, from which we were able to deduce that by adding together coal plus biomass (presumably converted coal plant) the capacities in 2016/17 were all essentially similar, but there were large changes by 2018/19. Thus under Gone Green (GG) there was a fall of 4.1 GW in the two years to the Capacity Auction, but only 1.6 GW under 'Low Carbon Life', and only 1.7 GW under 'No Progression'.

36. One of the key considerations in determining the amount of capacity to procure is the amount of old coal plant that could be available during stress periods in 2018/19. At current Carbon Price Floor levels and without a capacity payment merchant plant may struggle to make a profit in the absence of a capacity payment (i.e. in the years before 2018). Their option, assuming they cannot convert to biomass and find upgrading uneconomic, would be to disconnect, avoiding TNUoS charges, and reconnect for delivery in 2018. However, it is apparently the case that they cannot make a forward reconnection agreement with NG and must instead join a queue with no assurance that they will secure a connection agreement in 2018. This imposes risks that merchants may find unattractive unless transmission reconnection arrangements allow them to be mothballed and to re-enter in 2018 when capacity market delivery begins, otherwise irreversible exit decisions may be made.

37. Another concern of the Panel relates to NG's concept of the difference between scenarios and sensitivities, and NG's interpretation of "Robust Optimisation". To quote from the NG Report:

"When deciding on an option, the Robust Optimisation method aims to minimise the cost implications of any decision made when there is uncertainty over the future. ***One benefit of this approach is that it is independent of the probabilities of the various potential future outcomes and therefore it can be used when the***

probabilities of these outcomes are unknown, providing that the cases considered cover a range of credible outcomes." (Emphasis added).

38. The Panel indeed endorses this approach in respect of scenarios, but that does not extend to sensitivities within scenarios. The Panel would therefore argue that it is inappropriate to include different levels of interconnector trade and different winter conditions (cold or warm) without having regard to the relative probabilities of such events. Thus an extreme weather event should be given much less weight than more typical weather conditions. This would be consistent with the very definition of LOLE (long term average) and established international practices. Indeed, the whole concept of the LOLE is that it is an average over a large number of possible winter conditions, both very cold and very mild, as reflected in the concept of the Average Cold Spell (ACS) demand. The actual loss of load probability (LoLP) will vary from higher than average in cold winters to lower than average in warm winters, and thus weather sensitivity is already covered to some extent, although this would not capture the range of outputs that could be achieved using a full distribution.

39. This is even more important in the case of interconnectors. Interconnectors can deliver power to GB and as such they should be treated in the same way as generation, with some probability, to be assessed, that they will be unable to deliver imports during GB stress events. We discuss this critical issue in the next section, as whether or not interconnectors are correctly modelled (perhaps with a high and low availability as a sensitivity) will make a material difference to how much new plant to procure. Under 'Slow Progression' and 'Low Carbon Life', 2.6 GW of new CCGT is anticipated. This is roughly the amount of expected import that might be available compared to the currently assumed import.

Treatment of Interconnectors

Physical Interconnections

40. At present, Great Britain is connected to Northern Ireland via the Moyle Interconnector and to the Republic of Ireland via Eirgrid's East-West interconnector ("EWIC"), to France via the Interconnexion France Angleterre ("IFA"),[5] and to the Netherlands via BritNed.

41. There are active proposals to build a new interconnector to Belgium (NEMO) and proposals to put another interconnector, Eleclink, through the Channel Tunnel.[6] Beyond the 2019 time horizon, there are further plans for interconnection. The Northconnect interconnector (1.4 GW) between Norway[7] and Scotland has applied for planning permission and seeks to commission in 2020.[8] Another interconnector, NSN, from England to Norway with a capacity of 1.4GW could be in service by 2020[9] according to NG, (See the National Grid Interconnector Register for further details of all interconnectors.[10]) The capacities and dates of commissioning prior to 2019 as they appear in NG's Interconnector Register are shown in Table 1 below:

[5] Two other French interconnector projects looking to start operation around the turn of the decade and which are European Projects of Common Interest: Fablink and IFA2

[6] See http://www.eleclink.co.uk/information/appendix1-eleclinksexemptionrequest.pdf

[7] We are advised by DECC that that Norwegian law currently requires Statnett to have exclusive or majority control of all interconnector projects and Statnett is not involved in Northconnect.

[8] http://www.allengordon.co.uk/News/757/NorthConnect+Progresses/

[9] http://www2.nationalgrid.com/Media/UK-Press-releases/2014/National-Grid-and-Statnett-move-forward-with-interconnector/

[10] http://www2.nationalgrid.com/UK/Services/Electricity-connections/Industry-products/TEC-Register/

Table 1: Current and proposed Interconnectors and their capacities to GB:

IFA	to France	2.00 GW	Built
Britned	to NL	1.20 GW	Built
Moyle	to NI	0.45 GW	(0.215 GW offline. Return Nov. 2017)[11]
EWIC	to RoI	0.50 GW	Built
NEMO	to Belgium	1.00 GW	Scoping, completion October 2018
Eleclink	to France	1.00 GW	Scoping, completion October 2016
Total by 2019		**6.15 GW**	

Market Coupling in the Near Term

Ireland's Single Electricity Market ("SEM")

42. The island of Ireland is run as the Single Electricity Market, which has a centrally dispatched pool with a Bidding Code of Practice that requires generators to offer at their marginal variable costs, to which is added a capacity payment. SEM generators are not subject to the UK's Carbon Price Floor.

European Union Market Coupling

43. Since February 2014 BritNed and IFA have been coupled to GB in the day-ahead timeframe, which means that their capacity is cleared through the North West Europe auction and common algorithm, Euphemia, so that if an interconnector is not congested in any hour, the day ahead (DA) prices at each end will be the same for that hour, and if there is congestion, the interconnector will be fully used flowing power from the low to high price zone. (The SEM has a derogation that allows it to delay coupling to GB until 2016, after which time their market design is also due to have changed[12]). Once the Day Ahead auction has cleared trading can continue in the IntraDay (ID) market to adjust positions and flows to better reflect real time reality, and finally the System Operators can take balancing actions, although the details of the ID and balancing markets are still not finalised.

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[11] There is an 80MW export limit to Scotland and the exports of Scotland to England are constrained, although in the event that the Moyle could export more and England were short of power, it is likely that the Scotland-England constraint would not be binding, in which case more could be imported provided the respective SOs had suitable emergency arrangements in place. In practice the connections to the SEM are more likely to facilitate exports from Scotland that otherwise might be constrained from delivery into England being routed via exports over the Moyle and imports over EWIC, thus effectively releasing extra capacity to GB load centres and reducing stress.

[12] See I-SEM draft decision paper, 6th June 2014:
http://www.allislandproject.org/en/wholesale_overview.aspx?article=79e244a0-4c06-4729-bd20-92873869df82

Interconnector Evidence Used in NG Modelling

44. For most scenarios and sensitivities, NG assumes that interconnectors are at 'float', with 0.75GW exports to Ireland and 0.75GW imports from continental Europe. Other scenarios such as Slow Progression typically involve a delay of a year or more in commissioning the new interconnectors.

45. On an optimistic assessment, therefore, GB could import up to 6 GW in stress periods. The Panel was particularly interested to examine the assumptions used for interconnection in NG's modelling because of their scale and significance.

46. Table 1 suggests that the potential swing at times of system stress at first sight could, therefore, be as much 12 GW or about 20% of peak demand. This could mean that the assumption of "float" (i.e. that there are no net imports or exports into GB) may over-estimate the capacity market procurement requirement by around 6 GW[13] if interconnectors could be fully relied upon to provide full import, or under-procurement of 6 GW if the interconnectors were at full export, even during GB blackouts.

47. These are the outer extremes of the envelope of uncertainty and we would not expect that in reality the actual uncertainty is this great, (not least because, as the Panel was informed, the System Operator has the power to bring the interconnectors back to float) but this illustrates that interconnectors are a material issue deserving close attention.

48. The Panel reviewed the main evidence that was considered by DECC and NG in relation to interconnection. (At this point we note that NG's modelling, and specifically the DDM, is unable to endogenously estimate the contribution of the interconnectors

[13] Note that this is a maximum in the event that a number of projects are delivered on time, which is unlikely. The Panel does not suggest that this total will be available in reality.

to GB capacity adequacy, as it lacks a model of available spare capacity abroad which is deliverable to GB in different hours).

49. The key evidence presented to the Panel was a report by Pöyry (2012).[14] The report develops various scenarios using 'Zephyr', Pöyry's proprietary electricity dispatch model. Pöyry state that: "The Zephyr power model is an economic dispatch model based on optimisation of all power stations and renewables in Europe, allowing detailed investigation of the impact of wind and intermittent renewables, plant generation and profitability, wholesale market prices, emissions and interconnector usage and revenues."

50. Zephyr runs at hourly resolution and can simulate various wind and demand configurations, and so can simulate the hourly prices in each country (not the same as predicting them) and hence model interconnector flows (probably reasonably well over a year, less well over any hour). At the time of writing, the Panel have not reviewed the Quality Assurance assessment materials that have been separately assessed by DECC. The Panel was told that although there is good evidence for back-casting calibration, the equivalent for interconnection flows at times of system stress is not available and therefore the Panel would recommend that this is followed up by DECC as soon as possible.

51. The Pöyry report devotes a whole section (Section 4.7) to the capacity credit that interconnectors provide. They first estimate the LOLE with the interconnectors, then remove them and ask what additional capacity would be needed to provide the same LOLE. **Pöyry finds that in relevant conditions total current interconnection links provide 2.3 GW of effective capacity or 62% of their nominal 3.7 GW capacity**

[14] IMPACT OF EMR ON INTERCONNECTION: A report to Department of Energy and Climate Change 3 December 2012 available at https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/252744/Poyry_Report_on_Impact_of_CM_on_Interconnection.pdf

even in the worst case of tight conditions abroad.[15] Their report shows that BritNed has a 97% contribution but France has only 65%, which reflects the tighter margins in France in cold periods. Pöyry does, however, note: "Since load loss in the SEM and GB often coincide (or to put it another way the SEM has load loss when Britain is unable to supply it with power), the capacity credit of interconnection with Ireland is negative" although in their Fig 97 the SEM is shown contributing a positive amount of 11% of the 740MW interconnection (and higher in some other scenarios).

52. In terms of additional interconnectors, Pöyry notes on p62: "6 GW of additional interconnection leads to about 3 GW less firm capacity built." **That suggests that the proposed incremental interconnectors have a de-rated value for the CM of at least 50% so that the proposed 2 GW additional capacity in Table 1 might contribute an extra 1 GW to the existing 2.3 GW effective capacity to give 3.3 GW by 2018**.[16] While it is not clear yet when this capacity will be commissioned, Pöyry's estimates of the 2012 capacity suggest that interconnectors are equivalent to 2 GW of domestic de-rated capacity, which is equivalent to 100% of the existing Continental Interconnection Capacity (and exporting 750 MW to the SEM). This reduces the amount of capacity to procure by 2.3 GW, while any additional interconnection commissioned by 2018/19 would reduce this further. It would be difficult to model accurately the effect of procuring less capacity because the clearing price might cross a significant tipping point as we transition from the assumed Net Cost of New Entry (say £49/kW per year) to the potentially much lower cost required to keep an existing station on line.[17] Whether such a tipping point could be triggered is of course unknown in advance of an auction, but awareness of this is important in recognising the potential risks of unnecessary over-procurement.

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[15] Pöyry assumes that in many scenarios there is a price cap in GB of £500/MWh. As the Balancing Code reform proposes to use £6,000/MWh for demand side actions, which is the level from which the missing money that justifies the capacity auction is justified, this price cap is not relevant.

[16] Pöyry's model calculates how much GB generation capacity would be needed if the interconnectors cannot be relied upon

[17] The new clearing price could be at least the "Price Taker" level of £25/kW, and may be higher if stations submit a Directors' letter requesting "Price Maker" status and the clearing price would be discovered by the auction.

53. During our discussions on the outcomes of various possible situations on both sides of the interconnectors, The Panel encountered a seemingly unresolved issue that makes estimation of interconnector flows at times of stress even more difficult. This was the way the Euphemia auction may work if there is simultaneously a stress period on both ends of interconnectors. There is a cap of €3,000/MWh on the day-ahead auction, and no caps for intra-day and balancing have been set as far as we know.

54. France has a €3,000/MWh cap already (in all timeframes The Panel understands) and has reached that level in more than 3 hours in some cold winters recently, given its high electric heating load. While it is unlikely that both France and the Netherlands would simultaneously hit the cap, France currently provides 2 of the 3 GW from GB to the Continent (and might provide 3 of the future 5 GW), so it becomes important to determine how demands into the Euphemia are met if both France and GB experience system stress and whether caps are in place or will be set for intra-day trading.

55. The Euphemia rules state (in part):[18]

> *6.5.2. Curtailment sharing*
>
> *This step guarantees that the curtailment is distributed in respect to identical curtailment ratio among bidding areas initially in curtailment, except for those bidding areas that are not willing to share curtailment. The supply or demand orders within a bidding area being in curtailment at maximum (minimum) price are shared with other bidding areas in curtailment at maximum (minimum) price. For those markets that share curtailment, if they are curtailed to a different degree, the markets with the least severe curtailment (by comparison) would help the others reducing their curtailment, so that all the bidding areas in curtailment will end up with identical curtailment ratios in line with all network constraints.*

[18] At https://www.n2ex.com/digitalAssets/89/89745_euphemia---public-description---nov-2013.pdf

56. The Panel remains unsure how to interpret this important rule, since we do not know which bidding areas might be unwilling to share curtailment, and how demands are aggregated across interconnectors and bidding zones. France may wish to import 6 GW knowing that only 2 GW might flow over IFA at best, and GB may wish to import 3 GW at the cap price, also knowing that only 2 GW can flow over IFA, so are France and GB curtailed back to zero or does France get a smaller proportional claim allowing GB to acquire net imports?

57. The Panel contacted Ofgem for clarification and we received an informal but nevertheless helpful and detailed response. The Panel was reassured that the issue is understood and in hand and also that the events that give rise to our questions are unlikely.

58. For present modelling purposes, however, the Panel concluded that there is no immediate urgency to resolve this question as these events of joint stress should be considerably less common that a single GB stress event (which may happen only 3 hours per year), the Panel recommends that the rationing rules and curtailment sharing agreements are kept under close observation, and that price caps on Euphemia are at least raised on the intra-day and balancing markets to allow sudden scarcities to be resolved in a timely and efficient way.

PTE Comment on Interconnector Evidence and Assumptions

59. The Panel raised the need to seek the best evidence for the contribution from interconnectors at the earliest possible stage in our review of the modelling and assumptions. Given the very high emphasis put on the security value of interconnection by the European Commission, the UK Government and NG, the Panel was uncomfortable with what seemed to be quite thin evidence and the lack of recognition of any capacity credit at times of system stress. Within the very limited time available, the Panel looked for further sources of evidence and reasoning to test the modelling assumptions. In this part the Panel comments on potential further evidence to support an interconnector capacity credit at system stress, the credibility of exporting through interconnectors during times of GB system stress and blackouts

(as was assumed in some sensitivities) and also the additional work the Panel asked NG to carry out where a capacity credit (rather than float) was assumed.

Evidence for Interconnector Capacity Credit

60. The Panel readily found evidence both for the scale of interconnector capacity between GB, continental Europe and Northern Ireland and also evidence suggesting that interconnectors may contribute an effective capacity credit at times of system stress. The Panel discusses some of these in more detail elsewhere in this section and they include:

a. The report by Pöyry, which was the main evidence provided by DECC and which the Panel has discussed in some detail above at paragraph 49 et seq.[19]

b. A Government commissioned report by Redpoint,[20] *Impacts of further electricity interconnection on Great Britain* which is discussed further at para 61 et seq. This report concluded that "greater levels of interconnection are generally associated with better security of supply. Although both low wind and high demand conditions can be correlated across markets, forced plant outages are generally uncorrelated and hence in times of extreme system stress in GB, most interconnectors are likely to be supplying energy to GB at near full capacity. This finding, however, assumes that there are no provisions in the market or regulatory arrangements which prevent interconnectors from flowing energy in the direction which is most economic. We believe that this is consistent with current draft ENTSO-E network codes". (The latter point also supports the Panel's concerns regarding the clarity of the rules of Euphemia.)

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[19] IMPACT OF EMR ON INTERCONNECTION: A report to Department of Energy and Climate Change 3 December 2012 available at https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/252744/Poyry_Report_on_Impact_of_CM_on_Interconnection.pdf

[20] Impacts of further electricity interconnection on Great Britain. Redpoint, November 2013 https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/266307/DECC_Impacts_of_further_electricity_interconnection_for_GB_Redpoint_Report_Final.pdf

c. An Ofgem commissioned report by Pöyry (2013)[21] (also cited by NG at p77) which concluded that "GB low capacity margins (below 20%) show a medium level of correlation with low capacity margins in Ireland and France. On the other hand, very low capacity margins (below 10%) in GB do not show a definite correlation with any of the other systems." The report also notes that "Thus in considering the role of interconnectors in contributing to GB security of supply we conclude that:

• Historical net interconnector flows to GB have not been driven by system parameters in GB or other included systems and could have been influenced by a number of co-occurring system (and/or market) conditions in GB and Europe." This again cautions against using past interconnector behaviour as a guide for the potential for interconnectors to relieve GB stress events where the underlying (low) stress hour correlations is more relevant.

NG accepts this in its Report at p82, which states:

"This section, however, considers a re-basing of the GB float assumption by assuming no exports to Ireland and increased exports from continental Europe based on the high imports line in Figure 28 (Figures refer to those in NG's Report). This 75% imports figure is just above the highest cluster of imports and just below the 4 extreme values and thus represents a credible outer limit. Figure 31 shows French demand on the vertical axis and INDO demand on the horizontal axis. The colours show different winters. This figure shows that at high demand levels there is not a strong correlation between French and UK demand.

"This suggests that on many days with high GB demand it may be possible for significant imports from France. This is supported by the Baringa report to DECC which ran stress tests through their interconnector model and concluded that "interconnectors are likely to be supplying energy to GB up to their full capacity in

[21] Analysis of the Correlation of Stress Periods in the Electricity Markets in GB and its Interconnected Systems: A report to Ofgem, March 2013 at https://www.ofgem.gov.uk/ofgem-publications/75231/poyry-analysis-correlation-tight-periods-electricity-markets-gb-and-its-interconnected-systems.pdf

times of extreme stress".[22] It is also supported by Pöyry, in a report for DECC,[23] which said

- Increased interconnection leads to higher flows into GB, and hence lower requirement for new capacity to be built – 6GW of additional interconnection leads to about 3GW less firm capacity built.

- Irrespective of the level of interconnection tested, the interconnectors operate close to baseload imports – the carbon price floor leads to such a large differential in wholesale prices that even a significant increase in interconnection is not sufficient to alleviate it."

d. A report by Booz&Co commissioned by DG ENER[24] concluded that an EU-wide approach to sharing security of supply through interconnection, in contrast to a member state centric approach in which individual states are self-secure, would save about 100 GW of peaking generation plant across EU in 2030. This is equivalent to a fully efficient EU-wide capacity market and the savings in generation capacity to be procured would be attributable to interconnection only. This is also consistent, in principle, with the study conducted by Pöyry for DECC.

e. NG's Interconnector Register.[25] This is NG's own public register which is published alongside the TEC register. This register indicates at least intention for the new interconnector capacities shown in Table 1 above. (The Panel recognises, however, that the presence of capacity on this register of itself is not a significant predictor of new capacity in particular. TEC, for example, has suffered a high rate

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[22] This is the Redpoint report already cited above and discussed further below: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/266307/DECC_Impacts_of_further_electricity_interconnection_for_GB_Redpoint_Report_Final.pdf

[23] http://www.poyry.co.uk/sites/poyry.co.uk/files/poyry_report_on_impact_of_cm_on_interconnection.pdf

[24] Benefits of an integrated European energy market for DG Energy, EC, Booz&Co, July 2013 http://ec.europa.eu/energy/infrastructure/studies/doc/20130902_energy_integration_benefits.pdf

[25] http://www2.nationalgrid.com/UK/Services/Electricity-connections/Industry-products/TEC-Register/

of attrition due to project failure and delay. This has been reported on by NG[26] in relation to TEC, which showed that 52% of projects were either delayed or never delivered).

f. NG Interconnectors Ltd.'s[27] position paper "Getting More Connected",[28] which stresses the importance of doubling interconnector capacity by 2020 and which notes the primary purpose for interconnectors as follows: "Most importantly, additional interconnectors provide mitigation against shortages at times of 'system stress'; these could arise, for example, through a combination of cold weather and unexpected shutdowns at power stations."

61. The analysis carried out by Redpoint for DECC uses different models than Pöyry (2012). The Panel leaves it to the reader to examine the report, but we draw attention to some of the key findings and analysis and the Panel refers here to a sample of modelling output that appears on page 121 of the Redpoint report.

62. Redpoint carried out two stress tests to analyse the impact of changes in GB interconnection on security of supply in GB under different sets of extreme conditions. Each stress test represented a different combination of events that are likely to challenge security of supply in GB. The stress tests conducted are as follows:

- Stress test 1: Combination of low wind output, plant outages and high demand due to cold weather that challenge the ability of the system to supply all firm demand and maintain voltage on the grid.

- Stress test 2: Large and rapid changes in wind power output and demand combined with line outages that challenge the ability of the network to respond.

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[26] http://www.nationalgrid.com/NR/rdonlyres/75619E92-B1E5-4957-BB59-0353DCD32C58/46659/18_April11Actions.pdf

[27] National Grid Interconnectors Ltd is a for-profit, ring-fenced arm of NG with a strong incentive to see that the contribution of IC is valued highly in the capacity assessment

[28] www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=32371

63. The assumptions for the stress tests were designed to represent extreme but realistic sets of outcomes that are internally consistent within each stress test. In deriving the assumptions for the stress tests, Redpoint also gave consideration to the likelihood of stressed situations in GB being correlated with stressed situations in countries to which GB would be connected. This is likely to be crucial to the difference that interconnectors are likely make in such situations.

64. Stress test 1 showed energy and unserved energy, generally decreasing with the level of GB interconnection. This is as expected given that, while there is a positive correlation between low wind and high demand conditions in GB and in other European markets, this correlation is not perfect and there is no correlation between plant outages in GB and other markets. Hence, at times of high stress in GB, interconnectors can be expected to flow electricity to GB and contribute significantly to a reduction in unserved energy. Stress test 2 showed the overall levels of unserved energy are lower, which is as expected given that half of the period is characterised by average or above average wind conditions.

65. Redpoint further shows the utilisation of every individual interconnection with respect to flows into GB during periods when there is some unserved energy in GB. The numbers are calculated as an average across all configurations and periods in which the relevant interconnection capacity is above zero (i.e. that there is an interconnection to that market) and unserved energy is also above zero.

66. The results show that the majority of interconnectors are flowing to GB at times of extreme stress. The only exception to this is interconnection with France, which achieves import utilisation below 100%. Redpoint suggest two possible drivers for this: that France (along with Ireland) is the market that shows the greatest extent of correlation with GB in terms of system stress; and France is the market which has the greatest amount of interconnection with GB on average across all modelled configurations, and hence full exports to GB at times of system stress are themselves likely to put the French electricity system under stress.

67. It would seem that NG, as it is charged to provide security of supply studies for DECC, should widen its analysis to include relevant aspects of neighbours to clarify the contribution that interconnectors could make to GB in stress events. France already undertakes an evaluation of availability from neighbouring states (e.g. the appendices of RTE, *Generation Adequacy Report on the electricity supply-demand balance in France, 2011* and subsequent updates).[29] That report adopts a similar approach to the Pöyry report in modelling demand and supply in France, Spain, Italy, Switzerland, Austria, Germany, the Netherlands, Belgium, Luxembourg and the UK, and it would seem sensible to NG to cooperate with RTE in updating that report (which RTE needs to do annually) and sharing access to the modelling and data.

Interconnector Import to GB at Times of System Stress

68. The model that NG uses for capacity adequacy assessment (i.e. the DDM) has to make assumptions about the availability of various sources of supply, such as wind, nuclear, gas and coal. These are based on an analysis of past availabilities and experience of similar plant in other markets, as provided by the Arup Report. NG provides some useful illustrative evidence of import capability in its figure on p78, which shows that as demand tightens, the proportion of the time that very high imports occur rises. With the expected higher prices that are likely to emerge in the future compared to the past on which this evidence was provided, and with more efficient market coupling already in place, it is reasonable to assume a higher import capacity availability. The evidence so far does not give an unambiguous answer to the question as to exactly how much interconnection can contribute to improving security of supply of the GB system, through reducing the amount of capacity to be procured via the capacity mechanism. It would appear, however that 'float' would be an extremely conservative assumption and that the evidence supports considering a majority of interconnector capacity as importing to GB during system stress.

[29] http://www.rte-france.com/en/mediatheque/documents/operational-data-16-en/annual-publications-98-en/generation-adequacy-reports-100-en

69. NG accepts that it is valid to consider imports that reduce the capacity required in GB but defends its assumption of float at p83 by stating that "from 2019/20 interconnectors will be eligible to participate in the capacity market. The capacity to procure will include capacity provided by interconnectors. A float assumption provides consistency with future years." The Panel's view is that the correct approach, as with other plant not offering in the T-4 auction but expected to be on the wires in 2018/19, is to net them off demand.

70. From the analysis of the status of electricity system in EU countries that Ofgem conducted, positive capacity margins are identified on the Continent, which indicates that GB system could benefit from Interconnection through reduced LOLE driven by imports during peak demand conditions. Quantifying this contribution is not within the capability of the DDM, and therefore conducting sensitivities with different levels of imports during stressed supply conditions in GB, is the best that can be done under the circumstances.[30] France already undertakes an evaluation of availability from neighbouring states as we noted above.

Further Evidence for Baseline Assumption of 50% Capacity Value of Interconnection during System Stress in the GB

71. A base case of 50% imports through interconnection during stressed condition is also in line with the National Electricity Transmission System Security and Quality of Supply Standard[31] (GB-SQSS) that is used by NG to design transmission capacity between regions within GB. The standard defines the network capacity margin, called the interconnection allowance that should be established on the boundary between two network areas within GB to deliver secure supplies at peak through enabling generation in one area to contribute to security of supply of other areas.

[30] Last year, as a part of our study for DECC: "Understanding the Balancing Challenge", we demonstrated that GB interconnection could bring significant capacity adequacy benefits to the UK and EU (http://www.nera.com/nera-files/PUB_DECC_0812.pdf)

[31] http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=12494 (Appendix D)

72. Originally the concept was developed by CEGB in late 1940s when almost all regions within GB were largely balanced in terms of generation and demand. This is very similar to the present status in Europe given that most of the member states are broadly energy neutral as overall energy exchanges are modest because the installed capacity of interconnection is only a relatively small proportion of the peak demand (particularly for larger countries such as UK, France, Germany, etc.) This standard was created to establish the principles for the design of cross-boundary network capacity to facilitate both (a) economically efficient operation of the system (through the concept of planned transfer) and (b) security of supply (interconnection allowance) to enable one area to assist another with security of supply.

73. The network design standard indicates that for the relatively small interconnection ratings, the capacity value of interconnection (interconnection allowance) is proportionally high, while the capacity value saturates for higher levels of interconnection (because there is a limit to the ability of interconnection to displace generation, as interconnection does not generate electricity). In this context, the base line proposition of assuming 50% imports during stress condition in GB appears robust, given the amount of interconnection and that historical levels of capacity margins are present in Ireland and on the continent.

Exports from GB during a GB stress event

74. NG assumptions admit sensitivities where GB is exporting during stress periods. NG would therefore appear to be suggesting that interconnection could reduce security of supply in GB, as GB would be exporting while load is curtailed in GB although emergency SO actions should reduce exports to zero in such cases. This has two very significant consequences:
    a. If exports from GB during curtailment in GB could occur (for example, as a result of the underdevelopment of EU market and TSO coordination and price signals across interconnectors), we understand that the System Operators will take action to limit interconnector flows to float. It will be critical to establish the *likelihood of such event*s. From what we already know, the assumption that, during a GB blackout, the export from the GB is of equal likelihood as import is clearly flawed. This is critical as the LOLE is a probabilistic index and all events that are relevant

to be considered should have likelihoods attached. In considering the value of sensitivities that envisage export during blackouts, we suggest that the probability of such an event should be taken into account, and that this sensitivity has little value in informing the capacity to procure. NG accepts that "… any time high demand coincides with exports significant mitigating actions will probably be required to avoid any loss of load." (NG, p55.)

b. Furthermore, if NG were to continue to assume that exports from GB during periods of curtailment in GB have an equal likelihood as imports to GB that might prevent such curtailment, it is hard to see any rationale for interconnectors to participate in the Capacity Auctions as they would be regarded as having no capacity credit to offer.

75. Regarding the topic of simultaneous shortages of capacity in both EU and GB markets, this is theoretically well defined (however, given healthy capacity margins at present in EU, the materiality of this is not significant). In the context of the Capacity Market, this can be simply accommodated by defining a de-rated capacity for interconnectors that would include both (a) the failure rate of each interconnector and (b) the probability of shortage in the relevant delivery zone at the other end of each interconnector. We understand that this is exactly what National Grid Interconnectors Ltd is proposing to DECC for the inclusion of the interconnection in the Capacity Market. We fully endorse this, but also highlight that this is inconsistent with the sensitivity analysis being conducted for the capacity market. Similarly, the likelihood of market imperfections (i.e. buying at €3,000/MWh and selling at £60/MWh) can be included in determining the de-rated capacity of interconnection, but the input data for these calculations would need to be provided.

76. The amount that interconnectors could contribute to expected availability is comparable to the amount of new CCGT that NG predicts would be required in the auction, so this is a very real concern in the view of the Panel. The materiality of this will also depend on the actual clearing price in the CM, DSR (or distributed energy resources - "DER" - as the Panel prefers to call it) and imports via interconnectors.

One concern with NG's Report is that the assumption for 2018/19 of 3.75-4.75 GW is clearly conservative compared to the estimates in Table 1 above.

77. While it may be reasonable to assume that GB should be prepared to deliver power to the SEM when they have a stress event, and if needs be import that from the Continent, what is required in the capacity assessment is a measure of the de-rated import capacity of the interconnectors on a par with that of domestic generation. This is not simple to calculate, as unlike domestic sources of supply, interconnector flows are subject to market forces not just in GB but also by market forces at the other ends, which are not readily visible to the GB System Operator (SO).

78. Nevertheless, it is clear that interconnectors increase security against generation failures, as the joint risk of simultaneous failures in two zones is lower than the risk of a failure in any one zone. A considerable part of the derating of GB generators is based on forced outages, where imports can, with high probability, deliver power to replace local losses. In estimating the contribution to capacity in stress events it is therefore not enough to look at the normal direction of flows, but at what is their ability to deliver to GB in GB stress events.

79. For example, GB has traditionally exported to the SEM because of higher gas prices and smaller less efficient generating capacity in the SEM. In addition, flows are based on the ex-ante SEM prices that are determined more than a day ahead (when the expectation is that prices will be higher in the SEM than in GB).[32] As the markets will not be coupled until 2016 at present trading is inefficient (about 40% of trade moves from high to low price zones). Market coupling should eliminate that inefficiency while the higher carbon price in GB and higher wind in the SEM may well reverse flows in future. While there is more likelihood of high demand peaks coinciding in GB and the SEM than in GB and the Continent (as they are in the same time zone), the likelihood of outages simultaneously in each market is not obviously higher, and wind is less

[32] Although settlement is at ex post prices calculated several days later, creating an additional risk and barrier to efficient trading that should be eliminated once the markets are coupled.

correlated the further apart the wind farms are located, reducing the chance of low wind in both GB and the SEM.

80. We note also that the SEM as a whole has spare capacity until after 2020, although there is inadequate future capacity in Northern Ireland and a greater surplus in the Republic of Ireland, which it may be inhibited in using unless the North-South Interconnector is commissioned in time. This in itself should not necessarily matter provided NI can import from Scotland through the Moyle and the RoI can simultaneously export through the EWIC to Wales, but we are not clear if market coupling rules will allow this.

Quantifying the Possible Contributions of Interconnectors to Capacity Adequacy

81. In the light of the considerations above, we requested that NG carry out analyses which the Panel believes reflect more realistically the reliability of the interconnectors at times of system stress. The impact of taking the same 'derating' approach to interconnection as for all other sources of generation and ascribing the 2.3GW of derated interconnector capacity (as suggested by Pöyry and which adds weight to the Panel's suggestion of an assumption of at least a derated interconnector contribution of 50% of capacity), is reflected by the figure at the bottom of the range recommended by NG. We were not presented with evidence to support NG's position that "considerable uncertainty exists around the potential flows (including direction) through GB interconnectors into the future…" The evidence that the Panel is aware of for the dependability of interconnectors at times of system stress is presented in this report under the heading 'Treatment of Interconnectors'.

Plant availabilities

82. The Panel had in its previous deliberations raised a question as to whether the availabilities used by NG (and DECC and Ofgem) in their modelling are too low, especially for a future situation where plant would be strongly incentivised to be made available. The Panel was pleased to see that DECC/NG commissioned an independent analysis to assess whether the assumptions used were valid.

83. The Arup report provides an interesting survey of overall power plant availabilities across a range of OECD jurisdictions. It has focused where the data is easily available, however, and it has not clarified what availabilities could reasonably be

expected at times of system stress and where there are severe penalties for non-performance. It concentrates its analysis on the ENTSO-E area and North America, in system with generally weak incentives to make plant available.

84. The Panel's view is that a more appropriate source of evidence would be the historical availabilities of plant operating under long term power purchase agreements (PPA) in central buyer systems in the Middle East, North Africa and Asia

85. Traditional PPAs tend to be structured in two components: an energy fee and a capacity fee. The capacity fee is the component that gives investors' confidence that they can get their money back and where the payment relates to availability, also provides a strong incentive to perform. The energy fee is normally a pass-through of fuel and other variable operating costs. Nevertheless, these capacity fees still provide a weaker incentive than the proposed GB CM as the penalties associated with the latter can result in loss of all the fees for a few incidents of non-delivery in stress periods. Operators would therefore be remiss if they were not to make exceptional efforts to ensure availability at times when they are likely to be called in accordance with legitimate incentives.

86. While traditional PPAs provide the most appropriate benchmark there is a major challenge in getting data on these, given that the performance on these PPAs are normally not publically disclosed. Leading global technical advisors in the power sector do have access to this data but again it is confidential. An alternative way to look at this is to ask active lenders in the project finance sector (or their financial/technical advisors) what they regard as a prudent level of availability. For example, Mott MacDonald's experience in this area (which spans more than 20 years and over 50 GW of capacity) indicates annual average lifetime plant availabilities of 96% for CCGT and 93% for coal. OCGTs have slightly higher availability than CCGTs, but evidence on nuclear is inconclusive. (Availability at peak would be the correct data to look at but annual averages are mentioned here as a way to make direct comparison with Arup figures).

87. This is for plant that has and is incentivised (often contracted) to have strong maintenance programmes and so has been kept in good shape. Much of the GB fleet has had periods (sometimes extended) of minimal maintenance, especially when spark and dark spreads have been low. The GB fleet has also had periods of operating in 'two-shifting' mode, shutting down for nights/weekends or else modulating between full output and minimum stable generation, all of which increases wear and tear on the plant. Most plant operating under traditional PPAs have run at high load or at least have had moderate need to modulate, although this is becoming increasingly common.

88. NG has used the Arup analysis to amend its availability assumptions as far as the evidence allows. But given the focus for CM is on system stress events, and there is a heightened incentive to perform, it is the Panel's view that NG's higher case availability levels should be attainable by GB gas and coal plants once the CM is introduced. This suggests that NG is still adopting overly prudent assumption for plant availabilities, and so is under representing plant availabilities for both new and legacy plant during stress events. The Panel's view is that NG's high plant availability sensitivity is at least as probable as it base assumption, assumed for all cases except the two plant availability variants. This would suggest that the high availability assumptions in the Arup report for CCGT, OCGT and coal are more appropriate (corresponding to a lower capacity to procure), bearing in mind that further evidence as to how plant availability responds in the UK market is desirable. In any event, DDM runs show that the capacity to procure is not highly sensitive to plant availability.

Triad Demand

89. The Panel questioned how Triad Avoidance is treated in modelling and the Capacity Auction. The Panel also inquired into the baseline setting for DER. The Panel was satisfied that the responses received from DECC, who checked with NG, that adding Triad Avoidance capacity back into demand projections will not alter what is procured in the T-4 auction, and therefore this will not mean the over-procurement of new plant.

Extreme Peak Load

90. Extreme peak demand conditions (driven by extreme weather conditions) have been historically taken into account by allocating associated probabilities / weighting to their occurrence. In earlier studies used to calculate LOLE, a *probabilistic* approach was used, and this was appropriate as the extreme high and low peaks had associated *probabilities (weightings)*.

91. As stated in recent Ofgem document published on 28 November 2013 “Electricity Capacity Assessment 2014: Consultation on methodology”, section 2.9 on page 7 states: “To calculate the LOLE and EEU, in the relevant winter modelling period, the model constructs probability distributions of winter demand, wind power and available conventional generation. The LOLE and EEU are calculated by combining (i.e. through convolution) the three distributions; this represents the main risk calculation….”

92. Such an approach is the appropriate basis for establishing the multi-year demand probability distribution that should be used in the capacity mechanism, as the extremely low and high peaks would have appropriately lower weightings. However, the consequence of the fact that DDM has not carried out probabilistic assessment (as pointed out at the first meeting this year), and given the context of the Min-Max Regret approach, all states considered are effectively equiprobable. Giving that extreme peaks and average peaks have equal weights is fundamentally incorrect and this will artificially increase demand for capacity to be procured, significantly above efficient levels.

93. It is important to remember that LOLE of 3 hours is a very long run average figure, and that there will be years when LOLE will be lower and years when it will be higher than the average. For example, CEGB planned the capacity and allowed, on average, supply shortage once in 10 years, as this was economically efficient. Similarly, LOLE of 3 hours on average is now considered to be economically efficient.

94. The Robust Optimisation approach could be adapted by attributing lower weightings to extreme cases to reflect the lower probability of these events. As mentioned above, as a minimum, the case with very warm winter should be included to reflect the proper impact of this risk. There are standard approaches to carrying out such analysis based on expectation values that are readily accessible. This is of concern because different extreme weather conditions have different weightings.

CHP Capacity Assumption

95. The experience amongst the Panel of industrial co-generation own modelling assumptions is that availability at peak times would be well over the 60% assumed by NG and at 85% Q1 availability (and 80% for Q4) for industrial co-generation, so peak would be above these numbers. The impact of this on peak demand reduction might be in the order of 200 - 250MW per GW of co-generation capacity installed.

Participation of Distributed Energy Resources

Context

96. Distributed Energy Resources ("DER") is the term we prefer to use when discussing the contribution that can be made to managing situations when transmission connected generators are unable to meet the demand for electricity. We prefer this term to the commonly used "Demand Side Response", which possibly imports a preconception that the only (or main) contribution of the demand side is the temporary reduction in demand. DER, on the other hand, implies the full range of resource that can mitigate the need for solving capacity problems other than building new power stations. There is a pressing need to initiate the gathering of more information in this area to inform future decisions, especially as there is no over-arching organisation analysing the totality of the electricity system. These resources include:

a. Direct load control
b. Embedded generation
c. Standby generation
d. Demand response
e. Energy Efficiency

f. Fuel substitution (burn gas instead of electricity for example)
g. Interruptible loads
h. Integrated DSM project (such as using the batteries of parked electric cars as reserve power)
i. Load shifting
j. Smart metering
k. Power factor correction

97. It is important to recognise that the list of candidates who could provide demand side capacity is quite extensive so as to be aware of what is being modelled. It is also important to note that there are qualitative differences between these resources.

98. For example, load shifting could involve a user of electricity for refrigeration being incentivised to curtail its demand for electricity for a few hours and to rely on thermal inertia to avoid harm. Such a user may well have a supply contract for perhaps two years that is renegotiated annually or biannually, in which case that consumer would be responsive to short term auction signals.

99. On the other hand, another potential resource may be considering installing a co-generation plant or building energy management system to optimise demand side response, but needs the certainty of a long term capacity contract to secure finance. The essential point is that in estimating demand side response, it is essential to identify the potential resources which are likely to respond to capacity market signals and those who will not because the incentives do not meet their needs.

100. We note that the DECC methodology for determining the level of contribution to capacity made by DSR is very much in line with approaches adopted in New England and PJM (except impact on losses). To this extent this precipitates an opportunity to validate assumptions by using those systems as a means to compare and contrast.

101. In conversations with DECC and NG, we were made aware that the demand side is not yet understood as well as conventional generation. This is not a criticism as it has not been part of NG's role. NG is quite separate from the Distribution Network Operators and licensed electricity suppliers, and there is no-one who has both an overall detailed understanding of, together with the incentive to, marshal demand side data. For example, the answers to questions such as 'what is the average availability of embedded CHP at times of system stress' is not known, even if annual averages are known.

102. For all these reasons, we fully appreciate that NG were unable to carry out analysis on the demand side with the rigour and distinction that has been the hallmark of much of their other work. Nevertheless, this implies an urgent need to create a systematic process for ensuring that the resources of the demand side are not wasted only for new generation to step into the inefficiency gap.

103. We need to stress that in estimating peak demand at the transmission level, NG assumed that all eligible embedded generation would participate in the Capacity Mechanism. This led to an increase in peak demand for more than 5GW. This may not be a problem, provided that the actual increase in demand is adjusted before the auction takes place (in the pre-qualification period) once it becomes clear how much of distributed generation will actually take part in the Capacity Mechanism. This is important given the experience from New England and PJM that demonstrates that a relatively small proportion of embedded generation decided to participate in their Capacity Mechanisms due to additional costs that accompany participation in CM associated with meeting the qualification process rules, including monitoring and verification plan, financial assurance requirements etc.

104. Although the Panel does not claim to know the full potential demand side resource that might be available, the Panel believes that the design as it stands necessitates relatively modest assumptions regarding the capacity that can be sourced. One aspect of this is that the capacity mechanism is more suited to some behaviours, methods and technologies than others.

105. Therefore, although the international experience of DER, particularly in the US, that the Panel circulated[33] suggest the potential for significant and successful participation of DER in the capacity markets, which in turn led to the reduction in the need for additional generation capacity, the expectations in the current UK design need to be more modest. We would argue as further evidence for modest expectations is that, for example, conventional generation that will receive TNUoS related payments and revenues from the capacity mechanism, whereas distributed generation could be in a position that is less incentivised than conventional generation if it cannot access both triad avoidance benefits and capacity mechanism revenues.

Summary and impact

106. Based on the Panel's interpretation of the proposed capacity market for DER, we believe that there will be limited uptake of the total potential that has been demonstrated in other markets with capacity auctions, particularly those in the US and that, the cure to understanding this would be a greatly enhanced understanding of the range of demand resources available. The key modelling impact is that its impact on the assumed level of peak demand, which is the primary driver of the capacity to procure, is not as open to challenge as might be expected.

[33] (1) Demand Response as a Power System Resource, Program Designs, Performance, and Lessons Learned in the United States, Synapse Energy Economics Inc, May 2013; (2) Emergency Demand Response (load management) Performance Report, PJM, December 2012

The Panel's view on the approach to recommending the capacity required

107. NG has adopted a two stage approach to analyse the capacity to procure for the CM. The first stage is to use the DDM model to generate a set of capacity figures for a range of different economic and power sector outlooks that would each achieve the same LOLE target of 3 hours. Since, in principle these are regarded as equally probable, the second stage is to apply a method to select a single value. This is done by applying a game theory approach, which NG has called Robust Optimisation. It is also known as "Least Regret", "Least Worst Regret" or "Mini-max Regret" approach, based on the most commonly applied selection criteria.

108. This method enables a rational decision based on limited and uncertain information and selects the strategy with the lowest level of regret (disappointment) as indicated by the difference between the best and worst outcome. It therefore corresponds to a low appetite for risk, but is not the most risk averse, which is to choose the strategy with the highest minimum (the so-called "maxi-min"). Other selection criteria are highest average value and the highest maximum (maxi-max), the latter being the least risk averse.

109. NG has developed a simple spreadsheet model to select the DDM scenario run which represents the "Robust Optimisation" position. This is outlined in NG's report.

110. The Panel is content that this is a reasonable approach to selecting among the DDM cases however, we believe there is an important issue regarding the selection of an appropriate balance of cases in which to run the analysis, which we address below.

111. The Panel has run a few tests on the Robust Optimisation model, such as changing input values and exploring the impacts on results and it appears to perform logically, but this does not represent a formal audit. The Panel recommends that NG

and DECC ensure that a proper quality assurance review is undertaken to provide comfort that the model is sound.

112. NG and DECC may also wish to consider some enhancements to the Robust Optimisation model. For instance, the Panel carried out some simple sense checks on [a sandpit / offline] copy of the model and to that end, added a facility to the NG model to consider the impact of changing the selection of scenarios/sensitivities included in calculation of the capacity level which provides the Robust Optimisation This is an area which the Panel believes needs further evaluation, most probably led by DECC.

113. In addition, the Panel also believes that DECC should explore the impact of applying different probability weights to the scenarios/sensitivities to examine the impact on the Robust Optimisation capacity selected. The standard Robust Optimisation approach treats all scenarios as equiprobable, which is reasonable as long as none of the cases are clear outliers. The Panel would recommend that DECC explore the impact of giving these scenarios much lower weightings than the more "central" cases: perhaps 5% compared with 100%. Of course, the extent of impacts will be constrained by the assumptions embodied in the DDM runs themselves: for instance most runs assume interconnectors running at float and plant availability at base.

The Panel's view of the overall CM Modelling process

114. NG has been tasked with estimating the amount of capacity to procure under the CM auction relating to delivery in 2018/19 in order to achieve a certain reliability standard. The reliability standard is measured by the Loss of Load Expectation (LOLE), set at 3 hours per year for an average cold spell (ACS) year. That means that if there is the right amount of plant, this standard will be met on average over a long period of time, but in a cold winter the LOLE may be considerably higher, but that would be offset by many years with a considerably lower LOLE, as noted above. NG's Report explains how it models LOLE in commendable detail in its chapter 3. While we may have some reservations about some of the assumed plant availabilities (which

are based on average winter availabilities over the past seven years during which there was relatively little incentive to maintain high reliability compared to the incentives provided by a capacity payment) the approach itself is appropriate.

115. NG has undertaken this analysis drawing upon the latest release of its four Future Energy Scenarios (FES), which are long-term plausible projections of GB power system development, as well as DECC's Scenario 1 (from the Delivery Plan). The four NG scenarios present a range of cases which combine different levels of success in decarbonisation and economic growth in a classic 2 x 2 matrix. NG says the four scenarios are equally probable, but it acknowledges that most industry stakeholders consider the No Progression (slower decarbonisation, slower economic growth) to be most likely. We would argue that NP appears inconsistent with the purpose of the EMR and the reason for a capacity auction.

116. While the scenarios diverge substantially in the longer run, the spread of end user demand is moderate for winter 2018/19, varying from a low of 58.8 GW in GG (with more aggressive efficiency targets) to a high of 60.5 GW in LC (with extra electricity demand coming from heat and transport). Indeed, the demand projection included in DECC's own 2013 Delivery Plan scenario falls well below the lowest FES outturn. The difference is largely attributable to a lower level of energy efficiency uptake assumed by NG compared with that assumed by DECC. It is understandable that DECC may wish to present greater success here, while NG may have an unintentional tendency to upward bias in demand. In preparing its scenarios NG has consulted widely with industry (mainly electricity generators and suppliers and large industry) which has generally provided a positive endorsement

117. In order to consider a wider spread of cases, in addition to the four core FES cases NG has run a number of sensitivity cases on its two lower decarbonisation scenarios (Slow Progression and No Progression). These included higher and lower variants for winter temperatures, generation plant availabilities, embedded generation and interconnector flows. A low wind case was also considered, though not a high one.

The DECC Delivery Plan scenario was included, so in effect offsetting the low wind case, given its lower demand level. The sensitivities around interconnectors included three cases of net imports and two of net exports, while all other cases assumed interconnectors at float (i.e. no net flow into or from GB). In total, 31 cases were run, each producing a single capacity required figure for 2018/19.

118. Given the obligation to recommend the capacity to procure (within a range), NG has after consideration of other approaches, accepted the Panel's preferred suggestion to apply a "Robust Optimisation" approach, which it prefers to call Robust Optimisation. An alternative term used in the academic press is mini-max or least regret. This approach has been discussed and applied in many contexts from electricity network expansions to climate policy formulation[34],[35],[36],[37]. The Panel believes it is a reasonable approach, assuming the inputs are appropriately selected and particularly if quantifiable probabilities for weather and interconnector import availability are embedded in the model and not treated as separate sensitivities with roughly equal weight. It is therefore generally considered the best practice selection approach where it is difficult to assign probabilities to event outturns (the scenario cases) and also one can easily test the impact of adding or reducing cases. We are sceptical that this principle has been followed and we would rather view the sensitivities as illustrative, rather than being given equal weight.

Conclusion

119. NG's overall Scenario and model-based approach is in principle sound, and it has sought to take account of evidence and stake-holders' views. However, the Panel's consensus view is that NG tended to take an overly conservative view on a few key

[34] Optimal investment strategy under uncertainty in the Belgian energy system, Aertsens et al, January 1999 http://www.belspo.be/belspo/organisation/publ/pub_ostc/CG2131/rappCG22annII_en.pdf

[35] *Recent advances in Robust Optimisation: An Overview*, Gabrel et al, May 2013

[36] A risk based approach for transmission network expansion planning under deliberate outages, Arroyo et al, August 2010 http://www3.uclm.es/area/pearl/sites/default/files/Natalia/regret.pdf

[37] *Decision support for climate policy*, Iverson, June 2010 http://www.webmeets.com/files/papers/WCERE/2010/1494/TIverson_CommunicatingTradeoffs_June2010.pdf

assumptions, most notably interconnector flows, and by treating that (and weather) as sensitivities rather than including interconnector capacities based on their estimated availability probabilities (as with generation plant), it exaggerated the amount to procure. If instead the expected net interconnector flows are 2.25 GW (described as 75% imports) then the range of capacity to be procured would correspondingly decrease and, with a little more effort to procure DSR and accelerate interconnector commissioning, as well as expecting more coal plant to be offered into the auction, could be enough to avoid new CCGTs.

Conflicts of Interest

120. In the Panel's view, the current exercise whereby NG has been engaged by DECC to recommend the capacity to procure in the capacity market auction, inevitably precipitates a potential conflict of interest because the consequences for NG of blackouts might be regarded by NG as more consequential than increases in cost to consumers, especially as the costs are transferred directly to consumers while the opprobrium of black-outs accrues to the System Operator.

121. This of itself does not imply in any way that NG actually seeks to exploit their unique command of data, modelling capability, influence and know-how in this area to their advantage and we stress that we do not suggest that. Nevertheless, we have attempted to be alert to matters that might give the appearance of a conflict at work.

122. The Panel has been relentless in challenging NG's assumptions, especially where, if unguarded, there potentially would be openings for conflicts to find scope and the Panel has done its best to mitigate this risk. We have no evidence that should give cause for concern.

Recommendations

123. The Panel of Technical Experts makes the following recommendations:

In relation to selecting a capacity to procure:

124. Recommendation 1: that in deciding its final recommended "capacity to procure", NG should take full account of the evidence available on interconnector capacity credit, such as that mentioned in this report. This includes the reports it commissioned from Pöyry (2012)[38] and Redpoint (2013), both of which NG cites in its report.

125. Recommendation 2: that in applying the Robust Optimisation methodology, account should be taken of any further information relating to the relative likelihood of scenarios and sensitivities in order to minimise distortion.

126. Recommendation 3: that a proper quality assurance review is undertaken of the Robust Optimisation model to provide comfort that the model and associated procedures are fit for purpose.

In relation to understanding better interconnector capacity credits:

127. Recommendation 4: that NG is encouraged to commission further theoretical work on, and statistical analysis of, the deliverability of UK-Continent interconnectors during GB stress hours alongside and in support of the ENTSO-E programme.

[38] IMPACT OF EMR ON INTERCONNECTION: A report to Department of Energy and Climate Change 3 December 2012 at https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/252744/Poyry_Report_on_Impact_of_CM_on_Interconnection.pdf

128. Recommendation 5: that the rationing rules and curtailment sharing agreements for interconnectors are kept under close observation, and that DECC should, either directly or through Ofgem's membership of CEER, request ACER to ensure that price caps on Euphemia are at least raised on the intra-day and balancing markets to allow sudden scarcities to be resolved in a timely and efficient way.

129. Recommendation 6: that NG work with RTE and more widely, continue to work through ENTSO-E to further develop a proper regional model to assess the deliverability of UK-Continent interconnectors during GB stress hours, and that as part of that it reports on the relationship between GB day-ahead and balancing prices during past periods of stress.

130. Recommendation 7: that NG continue to work with SEMO and the SEM Market Monitoring Unit to evaluate the joint probabilities of stress events in GB and the SEM, and that they further analyse the ability of the SEM to import over the Moyle while exporting over the EWIC under the Euphemia rules, and ensure that if necessary this is an option that is readily called upon without it being deemed an emergency action.

131. Recommendation 8: that NG and/or Ofgem be required to keep and maintain full information about past system performance, including information about prices (contract, day ahead, balancing for wholesale power, fuel and carbon), generation availability and output by plant, demand, and congestion, interconnector use (and prices at the other end of interconnectors) beyond the apparently current seven year cut-off, to ensure that data for longer time period analysis remains accessible for analysis.

In relation to Distributed Energy Resources

132. Recommendation 9: that a programme to research the full potential of DER should be instituted as soon as possible to inform future auctions with particular focus on the full range of peak demand mitigation resources that are referred to in this report.

In relation to key generating plant metrics to enable the assessment of security of supply:

133. Recommendation 10: that the average forced outage rate during periods of system stress calculated against the full net rating of the plant (TEC) should be established as a key reportable indicator of the contribution of all types of controllable generating plant (including embedded generation).