Department
of Energy &
Climate Change

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

June 2016

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Executive Summary

1. The role of the Panel of Technical Experts (“PTE”) is to impartially scrutinise and quality assure the analysis carried out by National Grid for the purposes of informing the policy decisions for the Capacity Market. In fulfilment of this role, we have scrutinised National Grid’s 2016 Electricity Capacity Report on the target capacity in the T-1 Early Auction for delivery year 2017/18 and the T-4 Auction for the year commencing 2020/21 and this document presents our findings.
2. In our previous reports, we made 15 recommendations for improving the methodology and reliability of the modelling by which target capacities are calculated. National Grid has taken action on these, which we report in detail. We particularly welcome and commend the ‘Power Responsive’ innovation initiated by National Grid in late 2014 and launched in June 2015. ‘Power Responsive’ precedes our previous recommendation 11 to improve analysis and the potential contribution of the demand side. National Grid’s continuing commitment to its development is already demonstrating a valuable contribution to supply security even at this early stage and at relatively small scale compared with its full potential as suggested by similar approaches in some other markets.
3. We also support the response of National Grid in its response to our Previous Recommendation 13 to develop Pan-European modelling of interconnectors. National Grid and DECC engaged Baringa and Pöyry to improve modelling of the historic and future contributions of interconnectors which gives much greater confidence that interconnectors contribute significantly to security of supply and that market coupling appears to be correcting price-flow misalignments. We also present analysis carried out by Imperial College showing that, as non-generating assets, increasing interconnector capacity offers a diminishing marginal contribution to supply security, but only at capacities that exceed the total capacity of our current interconnections.
4. We remain particularly concerned, however, that a feature of the GB electricity system is that, not only does National Grid not have easy access to essential information regarding assets and performance on the demand side, but also there is no established and integrated process for managing and optimising shortage of supply that distinguishes essential and non-essential loads.

5. In this report, our main focus has moved to new areas, partly in pursuit of ever better modelling approaches and partly in response to specific market developments that require analytical accommodation. These new concerns are also reflected in the sensitivity analyses. Most significantly, the early closure or last minute recovery of coal stations gave us concern that the modelling should reflect more realistically the incentives for closure and we recommend that as well as modelling new entry of capacity, there is a need to model exit decisions.
6. Another new area of focus has been the modelling methodology itself. In response to our Previous Recommendation 2, in which we raised concerns about giving all sensitivities equal probabilities, National Grid commissioned very helpful academic analysis to consider methods which would take account of probabilities. The issues involved in this are intrinsically complex and at this point, unresolved, and therefore in our recommendations, we have encouraged further work in this area.
7. The most significant change to the methodology was introduced by National Grid at a late stage in response to Ofgem's requirement that National Grid should provide a financially incentivised forecast of aggregate peak demand measured at transmission (GSP) level. This was included alongside the four FES scenarios and was used as the pivot for the sensitivities rather than the FES scenarios as in previous years. We are satisfied that it would have very marginal impact under the conditions of the present analysis, however further consideration is needed of the implications of this change, generally. We intend to look at this more closely following the publication of this report.
8. In conclusion, 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 and analytical methods, are as reliable as they could be at this stage of development. Furthermore, we are broadly content that the methodology used has been robust, leading to reasonable and justifiable target capacities for the auctions covered in this year's ECR.
9. The new recommendations in our report are shown below. (The numbering of the recommendations follows on from those of our first report, which are also discussed in our report).

NEW RECOMMENDATION 16: National Grid should, in consultation with Ofgem, endeavour to collect information on how DNOs plan to respond to Demand Control orders to ensure security of supply. This may help to inform application of the current estimate for the value of lost load.

NEW RECOMMENDATION 17: Consider ways to take account of the probability of all forms of capacity fulfilling capacity contracts in future, such as by assigning expected values to classes of capacity contract holders differentiated by size of investment required, maturity of technology, whether financial close has been achieved, etc., taking account of new information from past and future auctions. This could feed into base case assumptions on plant not fulfilling their contracts, as well as the delivery risk sensitivity.

NEW RECOMMENDATION 18: If reasonably practicable, National Grid with its consultants should investigate the influence of weather on demand by examining a wider range of weather related factors and whether this can be incorporated into the development of Extreme Value Theory.

NEW RECOMMENDATION 19: In view of the ongoing apparent discrepancies between UK and international station availabilities, further work should be undertaken to explain and, if possible, reconcile these differences.

NEW RECOMMENDATION 20: For future auctions, plant specific charges such as the TNUoS charges, could be applied directly to the analysis underpinning the size of the delivery risk sensitivity to improve understanding around the honouring of capacity contracts or potential availability in future auctions.

NEW RECOMMENDATION 21: In the event that policy changes are being considered, the analysis should incorporate an appropriate sensitivity to assess their likely impact. Equivalently, if it is clear that there will be no substantive changes in transmission and distribution policy for plant already holding capacity agreements, then clarity on this could reduce the risk that such plant will withdraw.

NEW RECOMMENDATION 22: The suite of analytical tools for future capacity assessments should include more robust and detailed demand forecasting. More specifically the acquisition of data on distributed generation and DSR offers opportunities to model the behaviour of this increasingly more important component of aggregate demand, which is likely to behave differently from the more passive end user demand.

NEW RECOMMENDATION 23: National Grid already considers the analytical implications arising from the wider role that Smart Meters could play in demand side participation that extends far beyond the passive roles such as monitoring consumption or time of use tariffs and which extends to active management such as the actuation of energy saving measures at times of stress. It will be critical to establish the impact of scarcity pricing on peak demand in order to ensure that an efficient amount of capacity is secured through the capacity market. It would be helpful also to examine demand responses to high prices in markets that have already begun to roll out such active management tools which would enable appropriate targets and aspirations to be set.

NEW RECOMMENDATION 24: Appropriate actions should be taken to ensure that methods and practices adopted by DNOs for managing supply shortages are comprehensively implemented, while fully considering the criticality / cost of demand to be disconnected during stress events, which would provide further clarity regarding amount of capacity to be secured through the capacity mechanism.

NEW RECOMMENDATION 25: National Grid should review its overall modelling strategy and consider a range of options including the existing “DDM plus Least-Worst Regrets”, “DDM plus Least-Worst Regrets plus probabilistic sensitivities” and a wholly probabilistic approach. This potential modelling improvement is facilitated by the adoption of a short-term central base case that is consistent with demand forecast incentive.

10. Progress against previous recommendations made by the PTE are reviewed in ANNEX 1.

Introduction

Role of the Panel of Technical Experts

11. 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 National Grid in its role as Delivery Body for the Capacity Market.
12. The PTE's first report on National Grid's analysis to inform Capacity Market decisions was published in June 2014 and the second in June 2015. This is the PTE's third report, focused on scrutinising the analysis that informed National Grid's 2016 Electricity Capacity Report. The report covers the National Grid recommendation to the Secretary of State on the recommended capacity to secure for the 2020/21 T-4 auction as well as the recommended capacity to secure for the 2017/18 early year auction and indicative capacity to secure for the 2018/19 T-1 auction.
13. The background of the members and terms of reference of the PTE are published on the Government website[1]
14. This report has been prepared for DECC by:
    - Andris Bankovskis
    - Dr Guy Doyle
    - Professor Monica Giulietti
    - Professor David Newbery CBE FBA;
    - Professor Goran Strbac

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

Scope

15. The scope of the PTE's work is to impartially scrutinise and quality assure the analysis carried out by National Grid 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 DECC provides); and the outputs from that analysis - scrutinised in terms of the inputs and methods applied. They will test whether it is robust and fit for the purpose of Government taking key policy decisions, for example by considering potential conflicts of interest National Grid or others involved might have in influencing the analysis.
16. The PTE has no remit to comment on Capacity Market or wider EMR policy, Government's objectives, or the deliverability of those objectives. 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 Panel 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.
17. This report is the PTE's formal report scrutinising the analysis undertaken by National Grid on its recommendation to the Secretary of State on the recommended target capacity for the 2020/21 T-4 auction as well as the recommended capacity to secure for the 2017/18 early auction and indicative target capacity for the 2018/19 T-1 auction.
18. Last year, as a result of legislative changes on eligibility, interconnectors were allowed to participate in the Capacity Market, and that remains true for 2020/21 delivery, although they remain as virtual participants in the 2018/19 delivery year where their contribution is netted off the target. This report will also comment on the ranges that National Grid have recommended for each interconnector from which the Secretary of State will choose the final de-rating factor.

Supplementary Statement by the Panel of Technical Experts on the impact of the EU referendum

19. The Electricity Capacity Report prepared by National Grid and the Report of the Panel of Technical Experts were both written prior to the result of the referendum regarding whether the United Kingdom should remain in or leave the European Union (EU).
20. The outcome of the referendum may or may not impact the evolution of the electricity markets in a number of ways and it is not the role of the Panel to speculate as to what these might be.
21. Nevertheless, the Panel takes a preliminary view that the analyses and recommendations in both these reports remain valid and reliable for the following principal reasons:
    a. First, the goal of the reports is to recommend the amount of electricity capacity required, regardless of how capacity is provided, to meet the Security Standard. This is largely separable from the economic circumstances that might affect the outcome of an auction.
    b. Second, although some assumptions in the analyses may be affected (such as electricity demand, fuel prices, interconnector development etc.), the analyses are based on scenarios spanning a wide range of economic circumstances. These scenarios are not assigned probabilities because they are differentiated by factors that are hard or impossible to predict or agree upon (such as the result of a referendum). Provided the outcomes from leaving the EU fall within these ranges, there would be no reason to reconsider the analysis.
    c. Third, the capacity market is structured to allow for existing and new capacity to be committed at the T-4 stage and then for finer tuning at the T-1 stage. These are additional to the balancing services developed and successfully deployed by National Grid along with its 'Power Responsive' initiative. These flexibilities allow for considerable short term adjustments to be made as capacity requirements become more certain with the elapse of time.
    d. Finally, there is no suggestion of, or obvious reasons for departing from the goals of the EU single electricity market and electricity interdependence with the EU via interconnection, which together provide a robust framework for co-operation in order to derive very significant benefit for the EU and the UK.

22. Whilst the Panel recommends actively monitoring the potential impact of leaving the EU on electricity supply security, at this moment we see no urgent reason to update our report.

Approach

23. During the course of the PTE's work, National Grid has presented its methods, assumptions and outputs in relation to National Grid's core task of recommending the auction target capacity in the Capacity Market and the PTE has had opportunity to question National Grid during the development of its analysis and recommendation.
24. To carry out its work, the PTE met with National Grid at DECC's offices, approximately on a fortnightly basis since mid-January, during which presentations were made by National Grid and the PTE had an opportunity to ask questions and make comments. Subsequent to the meetings, the PTE produced various interim reports and put many questions to National Grid to which DECC organised responses.
25. The PTE's initial focus was on gaining an understanding of the methodologies and analytical techniques available to National Grid to address the additional aspects of the next auctions.
26. 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. The application of a delivery risk sensitivity on to coal plant previously expected to be available in the relevant delivery years that has disconnected or may exit.
    b. The concept of an *effective* Value of Lost Load reflecting lower cost mitigating actions and its possible implications for the target capacity
    c. the contribution of interconnection;
    d. demand side response in general;
    e. the treatment of extreme peak load events; and
    f. established methodologies for making a rational choice from a large number of possible 'Target Capacity' figures under circumstances of uncertainty.
27. As required by the PTE's Terms of Reference, the PTE also kept in mind the potential for National Grid 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 National Grid would bear some of the loss of reputation for any blackouts, and bears none of the cost of over-securing the system, and so could be expected to argue for a higher level of security and perhaps stress the risks of under-securing more than they might extol the cost-saving advantages of under-securing. The PTE, however, has no evidence to

believe that National Grid has exploited its privileged position and hence there has been no observed conflict of interest up to the time of writing this report.

28. This report is not comprehensive and nor is it a due diligence exercise but the PTE believes that it has nevertheless identified some extremely important issues that have significant consequences that are discussed here. Accordingly, the PTE 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.

29. This report has been prepared from information provided by DECC, National Grid 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.

Observations on and Context Provided by Auctions since Last Report

Auction Results

30. It is important to be aware of the auction and target capacity-setting design in order to understand the significance of subsequent events. First, plant that has a low-carbon or renewable contract (ROC or CfD) has its equivalent firm contribution deducted from the auction demand schedule. Thus National Grid discusses how to make allowance for the contribution of wind in extreme cold weather events in the ECR. Second, plant that has opted out and stated to be operational in the delivery year at the T-4 auction stage has its de-rated capacity deducted from the target capacity. This applies, for example, to Longannet. As it opted out of previous auctions and subsequently closed, its expected contribution must be replaced by other plant. Finally, capacity that already has an agreement covering the delivery year in question is normally deducted from the remaining target capacity, unless it is clear that it has cancelled that agreement or is at high risk of doing so before the delivery year.
31. We have now seen the results of three capacity auctions. The December 2014 auction for 2018/19 cleared at £19.40/kWyr, compared to the net CONE of £47/kWyr used to locate the position of the demand curve for capacity. Seventy-seven new-build CMUs secured agreements, totalling 2,621 MW. Of this, 1,656 MW was from CCGT and 787 MW from 67 “OCGT and reciprocating engines”, some burning diesel and others gas as fuel, with an average capacity of 11.7 MW (range 2.3-22.4 MW). Interconnectors were excluded from the auction, and their contribution to security of supply was understated in determining the capacity to secure (in the view of the PTE and the subsequent revision by National Grid).
32. The 2015 December auction for 2019/20 cleared at £18/kWyr, and interconnectors were allowed to participate. 1,936 MW new-build capacity (74 CMUs) secured agreements, as did 1,862 MW of existing interconnectors. Again there were a large number (168) and volume (2,430 MW) of “diesels” and some gas reciprocating engines, (existing and new) securing agreements.

33. The January 2016 Transitional Arrangements auction ("TA") for "DSR" cleared at £27.5/kWyr with 57 CMUs securing agreements for 803 MW. Of this 315 MW came from 19 existing generating CMUs, 13 MW from 2 new build generating CMUs and the rest from unproven DSR. The TA auction brought forward small scale/embedded generation and unproven DSR, which includes generation assets.
34. Since these auctions, at the time of writing, Trafford has not secured financing, and there has been much concern around market developments, embedded benefits and low wholesale price forecasts.
35. In addition, coal stations that subsequently exited did so mainly due to adverse energy market conditions, but in part to save paying TNUoS charges. If the real opportunity cost of keeping coal plants connected to the grid were substantially less than the TNUoS charges (as seems possible in some specific cases) then the combination of the higher auction price and a lower avoided TNUoS cost of exit may well have allowed the coal stations a higher probability of being available for all the auctions under consideration. That in turn might well have affected the sensitivities to run and the target auction capacities, although it is difficult to say how the Least-Worst Regrets approach would have changed, nor what probability to attach to the risk of plant not being available.

NEW RECOMMENDATION 17: Consider ways to take account of the probability of all forms of capacity fulfilling capacity contracts in future, such as by assigning expected values to classes of capacity contract holders differentiated by size of investment required, maturity of technology, whether financial close has been achieved, etc., taking account of new information from past and future auctions. This could feed into base case assumptions on plant not fulfilling their contracts, as well as the delivery risk sensitivity.

Analysis and Key Findings

National Grid's Recommended 'Target Capacity'

Introduction and context

37. As in its previous ECRs, National Grid 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. The key change in the latest edition is the choice of scenarios and sensitivities: the modelling approach essentially remains largely unchanged, although there have been enhancements in treatment of wind and some updates in the data, particularly regarding distributed generation. The main changes relate to the inclusion of a Base Case, which effectively replaces the Future Energy Scenarios as the pivot for sensitivities. The four core FES (for 2016) are included for completeness, but no sensitivities are run on these.
38. The new Base Case is very much a 'trends continued' projection that represents National Grid's best estimate of its transmission-connected demand. This is the projection by which National Grid is judged and rewarded under Ofgem's demand forecasting incentive. National Grid argues that given this projection is its best assessment, this should take precedence over the FES for the short term, which covers our focus of interest to 2020/21.
39. The other key change compared with the previous ECRs is the inclusion of non-delivery (of coal generation capacity) sensitivities. These become very significant in the more distant projections, with inclusion of a sensitivity of up to 3.6GW taken off the base case in 2020/21 and 2.8GW for 2017/18.

Availability of capacity before CM delivery years

40. In our first 2014 report (paragraphs 35-36) we noted that there was considerable uncertainty about how much coal plant would remain on the system that would be in a position to bid into the first T-1 auction in December 2017 for delivery in 2018/19. We noted that this might depend on, amongst other matters, whether they could drop TEC and be assured of reconnecting in time for winter 2018/19 delivery. The Future Energy Scenarios did not make sufficient accommodation for the unforeseen but credible dramatic changes in oil and gas prices that have moved coal plant from earning good dark spreads to the

current situation of negative dark spreads. (This once again illustrates the power of using scenarios in relation to unpredictable events providing they are appropriately stretching). This together with the rapid growth of renewables has resulted, for the first time since electricity was commercially generated in Britain in the 1880s, to having no coal-fired plant generating in some periods. If all coal plants were to permanently disconnect, then the capacity margin in 2018/19 could become very tight, as it would probably be too late to commission new replacement plant.

41. Ofgem and National Grid have responded to this concern by introducing, first, Contingency Balancing Reserves for 2014/15, 2015/16 and 2016/17 and then DECC introduced an additional auction for delivery in 2017/18, which we discuss in this report. This should allow plant that is needed in 2018/19, and which will also be needed before then, to be secured in the year leading up to, and hence to be available for bidding in the T-1 auction in December 2017 for delivery in 2018/19.

42. We comment on the waterfall diagram outlining the indicative target for the T-1 auction for 2018/19 in Figure 1.

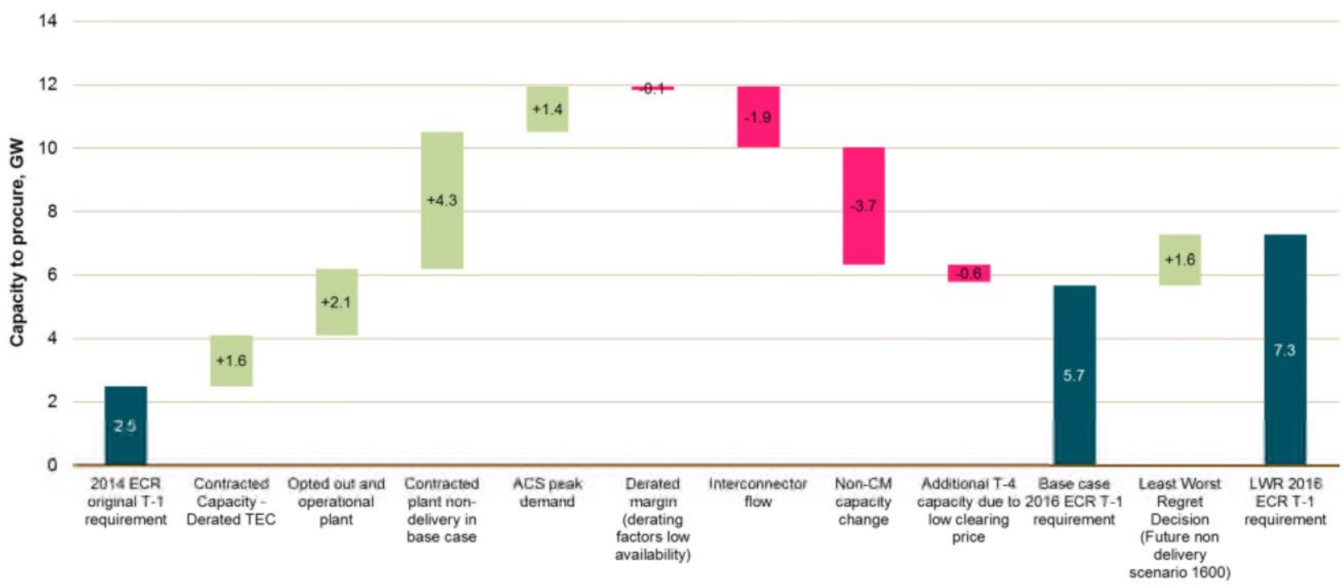

Figure 1 - ECR Figure 33: Comparison with original 2018/19 T-1 requirement (de-rated)

43. Figure 1 shows that there is a need to replace an anticipated shortfall of 2.1 GW of opted-out and operational plant that was expected to be present and was therefore deducted from the demand schedule in the 2014 auction. At least some of this plant has irrevocably closed and will therefore need to be replaced. In addition, apparently 4.3 GW of plant that secured capacity agreements has indicated that it may exit. Clearly if it does exit it will need to be

replaced, but if not, then the indicative amount to secure at T-1 will be reduced. At this stage National Grid is not finalising its recommended capacity to secure, but primarily indicating the risks to be aware of.

44. We note that in the 4.3 GW of existing contracted plant that may fail to deliver, 1.6 GW is the CCGTs from the first auction and that is more than offset by the interconnectors providing an estimated 1.9 GW (although National Grid have not made an assumption about the contribution at peak).

45. The results of the 2017/18 auction will therefore be important in estimating what existing plant is kept on the system and available to bid into the T-1 2018/19 auction.

Demand

46. The suggestion that demand forecast accuracy is likely to improve in future can be supported in view of the recent improvements in modelling demand made since the ECR 2015. These improvements in accuracy will also be facilitated by the adoption of a shorter time horizon for the central base case, as opposed to the long-term perspective of the FES scenarios, which are influenced by expectations about economic, technological and policy developments. The central base case approach removes the uncertainty about what features of the different scenarios are likely to be observed in the near future and offers an opportunity to develop demand forecasts that rely on observable variables likely to affect future demand.

47. A short term forecasting horizon makes it possible to identify and measure key drivers of demand in the near future, at a time when technology and market developments are producing critical changes in demand patterns, away from a passive demand behaviour and towards more interactive and dynamic patterns. These developments in the energy system are likely to produce new modelling challenges but also offer the opportunity to develop new approaches to the inclusion of sensitivities in the analysis, on the basis of a more rigorous probabilistic assessment of their likelihood to occur.

Weather (temperature) and Impact on Demand

48. We note the consulting report provided by Zachary et al to National Grid, which we commented on in detail during its development and we are happy with National Grid's approach to date, subject to ongoing refinements, if reasonably practicable, to take account of a fuller range of relevant weather parameters. (Zachary et al carried out their study fully

in accordance with terms of reference provided by National Grid and the initial scope was limited to consideration of wind-temperature-demand triplets). Such further studies could consider incorporating correlation coefficients that cover, in addition to temperature and wind speed, precipitation, humidity and air pressure for example, which other studies (outside the UK) have shown to be correlated. Intuitively, these factors would seem to be important because for the same wind speed, but under differing atmospheric conditions (which may be correlated with temperature, such as air pressure for example) which might affect wind generation.

NEW RECOMMENDATION 18: If reasonably practicable, National Grid with its consultants should investigate the influence of weather on demand by examining a wider range of weather related factors and whether this can be incorporated into the development of Extreme Value Theory.

Station Availabilities

49. National Grid has updated its plant availability figures for the latest ECR. Given the estimates are based on a 7 year moving average the change is negligible, showing a very slight increase for CCGTs. National Grid has also extended its analysis using GB historical genset data and has concluded that new CCGTs have not performed any better than their old vintages and that extra cycling of CCGTs has not had a material impact on plant availability. This is consistent with technical advisors' observations and probably reflects the fact that plant operators have (after a short lag) learnt how to more reliably operate plant in a cycling mode. National Grid's analysis further showed that coal units approaching the end of their lives or operating in a cycling mode show no statistically significant difference in their availability performance compared with all other similar stations.
50. Availabilities for CCGTs are still reported at about 88%, for the top decile of weekday (7am-7pm) demand periods in December to February. We note that National Grid projects that CCGT availabilities will increase to 90% over a three-year period from 2018/19; achieving the 90% plateau in 2020/21. The PTE's view, based on third party involvement in monitoring CCGTs in many other jurisdictions where generators are paid an availability fee is that this is a conservative availability target, even allowing for a certain amount of inherited legacy problems. Their view is that a reasonable target in the second year of CM would be 93%, using National Grid's definition. There may also be scope for increasing

availabilities on other plant types, however this is unlikely to be anything like as significant, given much of the coal and to a lesser extent nuclear will be near retirement and a previous study by ARUP did not find such evidence within the scope of their study.

NEW RECOMMENDATION 19: In view of the ongoing apparent discrepancies between UK and international station availabilities, further work should be undertaken to explain and, if possible, reconcile these differences.

Sensitivities

51. During the preparation for the 2016 ECR, the choice of sensitivities was discussed with National Grid and agreed between National Grid, DECC and the PTE and these are described in detail in the National Grid report. However, we are concerned that the sensitivities are all being run on the base case, and not on a number of FES. Given that we have a new base case this year, we have concerns as to why these sensitivities are treated as equiprobable to the base case. The PTE's view is that there is sufficient data to be able to undertake a statistical analysis to reasonably confidently assign a probability to the weather related (demand/wind) sensitivities. There is also a strong case for applying differing weightings to the non-delivery sensitivities to test the sensitivity of the results to differing degrees of confidence in such possible events.

Non-delivery Risk of Coal Capacity Sensitivity

52. National Grid's 2016 FES consider a range of different scenarios for coal plant closures to 2020/21, with a generally faster closure schedule than in the 2015 scenarios. With some 5GW of closures effective or announced since last year, coal capacity in 2016/17 may be 12GW, with the upper and lower bands of the FES seeing 4.5-10 GW of further closures by 2020/21 compared to 2016/17. This leaves 2.0-7.5 GW of operating coal plant in 2020/21. These figures include some large units which have been converted to biomass firing, and assumed to still be running.
53. Is it arguable that the deterioration in market conditions (trading spreads) and policy announcements about closing coal plant by 2025 may lead owners to close stations much sooner? Few stations are understood to be making an operating profit – a term relating to cumulated fuel spreads exceeding fixed operating costs including TNUoS charges. However, it is probably extremely unlikely that all the loss-making coal stations would close

simultaneously (until 2020/21 at which point, if coal stations still face negative clean dark spreads, simultaneous closure is much more likely even with a capacity payment). This is because one or more owners would probably retain some units on in the expectation of capturing higher trading margins and capacity prices in a significantly tighter market, as well as keeping open the option of bidding in later capacity auctions.

54. The upper end of ECR's delivery risk sensitivity case reflects this risk, with 3.6 GW of extra closures of contracted coal capacity (broadly equivalent to two large 2 GW stations) applied in both 2018/19 and 2020/21. For the early auction for delivery in 2017/18, National Grid assumes a sensitivity of 2.8 GW of closures.

55. The PTE believes that National Grid has adopted a prudent approach here, for which the values are appropriate. However, we are concerned that this issue of large closure sensitivity should be considered as a lower probability than National Grid's central case in the next five years. The impact of this assumption is explored in the next section.

56. Furthermore, whilst we believe the delivery risk sensitivity incorporated in this year's analysis is appropriate, we recognise there is scope for further improvement in taking into account further factors within the underpinning analysis around the risk of coal plant delivery. For example, exit charges relating TNUoS are not adequately reflected in the analysis feeding into the delivery risk and we believe consideration should be given to doing so.

NEW RECOMMENDATION 20: For future auctions, plant specific charges such as the TNUoS charges, could be applied directly to the analysis underpinning the size of the delivery risk sensitivity to improve understanding around the honouring of capacity contracts or potential availability in future auctions.

Wider Non-Delivery of Capacity with CM Agreements

57. The first two capacity auctions resulted in contracting around 2.5GW of new distributed generation. While some of this capacity is already under construction (and a small amount even already commissioned), it is understood that a small share of this is caught up in issues of securing connections, as the DNOs are struggling to connect the applications. Many developers are also incurring extra costs (due to unexpected connection charges), which raises questions regarding delivery of this tranche of new distributed generation. These challenges and potential future policy changes that may affect either transmission or

distribution-connected generation should therefore be considered in the setting of capacity targets.

NEW RECOMMENDATION 21: In the event that policy changes are being considered, the analysis should incorporate an appropriate sensitivity to assess their likely impact. Equivalently, if it is clear that there will be no substantive changes in transmission and distribution policy for plant already holding capacity agreements, then clarity on this could reduce the risk that such plant will withdraw.

58. National Grid is aware of these issues but has not considered this as a specific delivery risk for now, and we agree that this particular cause of non-delivery of distributed generation with existing capacity agreements is unlikely, although other reasons for a failure to deliver may materialise. The PTE is satisfied that this risk will be partly captured by the coal non-delivery sensitivity but that it should be looked at again next year.
59. In an ideal world, National Grid would be able to capture these new plant and legacy plant delivery risks by attaching probabilities that are neither 100% nor 0% and is another reason why the PTE would prefer that sensitivities are treated probabilistically in determining the target capacity. We accept that it is challenging to attach probabilities to such events but the need to do so directs attention at examining the business case for closure more closely.

EMR Demand Forecasting Incentive

60. National Grid is subject to demand forecast accuracy incentives (within ±2% of central forecast for the T-1 and ±4% for the T-4 forecast horizon) for each forecast year for the period 2016-2021[2]. The 2016 ECR is based on a base case which replaces the two central scenarios used in previous years, with associated low and high demand sensitivities, which now reflect the permissible range of forecast error in the demand forecast incentive. This approach addresses the problems associated with demand sensitivities, which were previously based on historical forecast errors.
61. For the purpose of being auditable by Ofgem, National Grid's demand forecast used in the base case is based on the aggregate peak demand measured at transmission (GSP) level.

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2 https://www.ofgem.gov.uk/sites/default/files/docs/2015/09/decision_on_revenue_outputs_and_incentives_for_nget_plcs_roles_in_electricity_market_reform_0.pdf

The start position for forecast peak National Demand is obtained from the forecast of annual end user demand under the assumption of a stable historical relationship between annual and peak demand. Further to these, adjustments are made for future trends, such as electric vehicles, heat pumps and improved energy efficiency e.g. LED lights. This predicted level of peak demand is then further adjusted on the basis of forecasts about the behaviour of distributed generation and demand side response at peak to determine National Demand. Furthermore, the predicted level of peak demand is determined on the basis of forecasts about the behaviour of distributed generation at peak. While end user demand can be rigorously predicted on the basis of economic and climatic factors, the behaviour of distributed generation is more challenging to predict as it is likely to be more price sensitive and able to operate as either demand or supply. The use of GSP data for the purpose of the demand forecast incentive is necessary due to the current lack of reliable information about distributed generation. However, National Grid are in the process of investigating the procurement of such data on a historical basis from DNOs and therefore we would strongly recommend undertaking statistical analysis of the distributed generation data in order to take account of it in future analyses. That would allow National Grid to develop an analytical tool to model this important component of aggregate demand, as energy systems start witnessing more interactive patterns of demand behaviour at the industrial, commercial and residential level (see also comments about Smart meters – para 106).

62. Academic work (Zachary and Wilson) has shown that the sensitivities at the extreme points of the distribution have a direct influence on the outcome of the Least-Worst Regrets process. One of these extreme points is likely to be associated with the low demand sensitivity (the warm winter sensitivity was the low extreme in the 2016 ECR analysis), which implies that large forecast errors could directly affect the recommended target capacity potentially leading to over-securing the system. Therefore, the reliability of demand forecasts and their use in the Least-Worst Regrets process should be monitored in future as they represent a key component in the process of selecting the appropriate capacity.

NEW RECOMMENDATION 22: The suite of analytical tools for future capacity assessments should include more robust and detailed demand forecasting. More specifically the acquisition of data on distributed generation and DSR offers opportunities to model the behaviour of this increasingly more important component of aggregate demand, which is likely to behave differently from the more passive end user demand.

Interconnectors

63. Interconnectors are eligible for CM auction participation for the delivery year 2017/18 and from 2019/20 on, but not for 2018/19. Interconnectors raise two problems for delivering capacity. The first is to assess their de-rated value, which is intended to measure their average contribution to GB capacity adequacy in stress periods. The second, arguably still somewhat hypothetical as not reflecting any imminent risks, is to understand how they will flow in out-of-market events. To clarify, interconnectors from the Continent to GB are already coupled in the Day Ahead Market (DAM), and the expectation is that they will also be coupled to the island of Ireland when their Integrated Single Electricity Market (I-SEM) goes live in October 2017. As such the EU-wide market-coupling auction (EUPHEMIA) will determine the direction of flows in the DAM. If scarcity is anticipated, GB bids will rise, and if they are higher than those in the I-SEM, France and Belgium, the interconnectors will deliver their full available capacity into GB. In the unlikely event that markets on both sides of interconnectors anticipate significant and simultaneous stress events, some other means will be required to determine directions of flow in such events.
64. In practice, stress events are more likely to emerge after the DAM has closed, and the Intra-Day Market (IDM) or Balancing Market (BM) has taken over (and in any case, the final determination of flows on interconnectors will depend on the last market to close, i.e. the BM). At present, neither the IDM nor the BMs are formally coupled to GB, and while the expectation is that the IDM should be live by 2017 there is less certainty about the BM. Even now, there is a lack of clarity about whether GB and other European countries will participate in the IDM through periodic auctions or via continuous trading. It is also not yet settled what the price caps in the IDM or BM might be, and how interconnector flows are determined if those price caps are reached. As stated in earlier PTE reports, there remains a level uncertainty in the amount of de-rated capacity that can be delivered in this manner until TSOs at either end of each interconnector draw up and publish the rules that govern such out-of-market actions.

65. In principle, GB appears to have a higher Value of Lost Load (VoLL) than its neighbours, although the relevant price is the one fed into the relevant market in stress events. Not all Member States (MSs) have calculated VoLLs, but the Commission notes that "Where VOLL has been estimated by MSs it ranges from EUR 11,000/ MWh to EUR 26,000 / MWh, so significantly higher than existing European price caps."[3] Without knowing how our interconnected neighbours will price their bids and offers in stress periods it is hard to know whether we can rely on importing in such simultaneous stress events.

66. If the interconnector reverts to float in joint stress events, then the question of de-rating interconnectors comes down to assessing the joint probability that GB stress events will not face price caps in interconnected neighbour markets, and that the interconnector has not failed. The latter probability can be estimated fairly accurately from evidence on sub-sea DC links around the world, and is likely to be very high.

67. Baringa has undertaken simulations and scenario studies for National Grid to address this question and has concluded from a range of deterministic and stochastic analyses that, "During GB stress periods, which are defined as those hours during which the GB de-rated capacity margin is negative if interconnector capacity is excluded, the interconnectors flow into GB at greater than 80% of capacity in most years and scenarios. … GB is able to import during stress periods because its power price is higher than in neighbouring countries (especially during those periods). This is partly because of 'scarcity premia' …" The associated graphs suggest that if GB does apply these scarcity premia then in 2020/21 prices in GB might be above £350/MWh in all four FES scenarios when those in our neighbours are all below £125/MWh.

68. Baringa also undertook correlations of residual demand between interconnected neighbours and reassuringly concluded that, for the island of Ireland "During stress periods, the degree of correlation is significantly lower than during all periods together. As a result, GB stress periods are unlikely to coincide with Irish stress periods." Similar studies for other neighbours found that "the conclusion is that weak correlation during GB stress periods means the direction of flow is largely imports to GB" (from our neighbours).

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[3] Commission Staff Working Document SWD(2016 119 *Interim Report of the Sector Inquiry on Capacity Mechanisms*, 13.4.2016 at http://ec.europa.eu/competition/sectors/energy/capacity_mechanisms_swd_en.pdf

69. The PTE is reassured that at least until after 2021, the likelihood of simultaneous stress events across interconnectors is small, and that by the time reliability in our neighbours becomes an important issue, the IDM and BM should be complete, and with it the full rules of engagement between System Operators for out-of-market events.

70. National Grid is debarred from recommending a particular set of de-rating factors and instead proposes plausible ranges, essentially taking the Baringa estimates as the high end and Pöyry's historical numbers for the low end. We note that National Grid has decided to use the full seven years' historical data, although the last few years show consistently higher capacity factors as the interconnectors became coupled at the day ahead stage. This is a clear case where a longer data series covering an historical period that is no longer relevant may be less useful than a shorter and inevitably less reliable data series. The effect of this would be to raise the lower values for France to 67%, for Netherlands to 76%, for Belgium to 76% and for Norway to 92%.

71. The PTE agrees that the supplied National Grid ranges are credible and has been asked to comment on the possible choice of de-rating factors, and the arguments for taking higher or lower values.

72. Analysis carried out in 2016 by Imperial College[4] provides further insight into de-rating

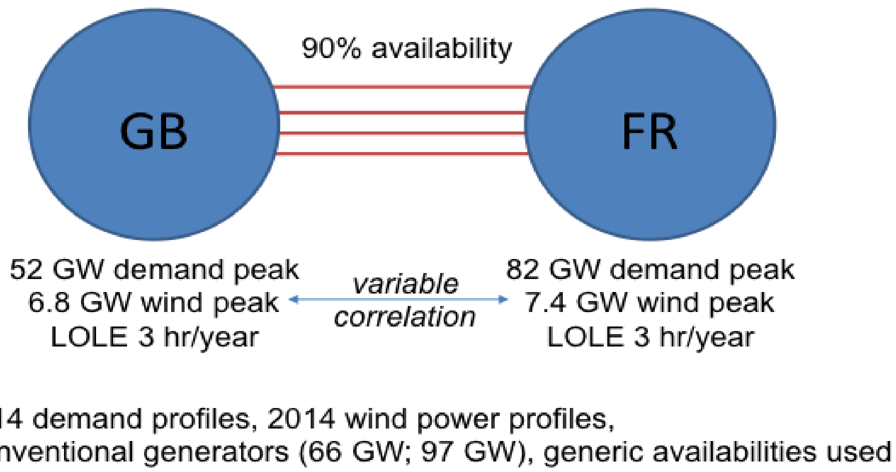

Figure 2 - Demonstration system for high-level quantitative analysis

[4] "Security contribution of interconnection" http://energysuperstore.org/esrn/wp-content/uploads/2016/06/Security-contribution-of-interconnection_IMP_May2016.pdf

interconnectors. The primary purpose of the analysis was to investigate the impact of different policies and market designs for handling coincident loss of load at both end of a notional interconnector between two systems that are similar to those of the GB and France. Figure 2 shows the main characteristics of the two notional systems.

73. The results of the analysis show that as more capacity is added, its marginal contribution reduces, eventually to zero. This in turn implies that the higher the amount of interconnection, the smaller should be the percentage representing de-rated capacity. Since interconnectors do not generate, consume or store electricity but only transmit, it can be seen that the contribution of an interconnector to each end depends critically on the scale and balance of supply and demand at each end (as well as other factors such as the end to end correlation of forced outages of plant, wind generation etc.). Figure 3 illustrates this saturation effect.

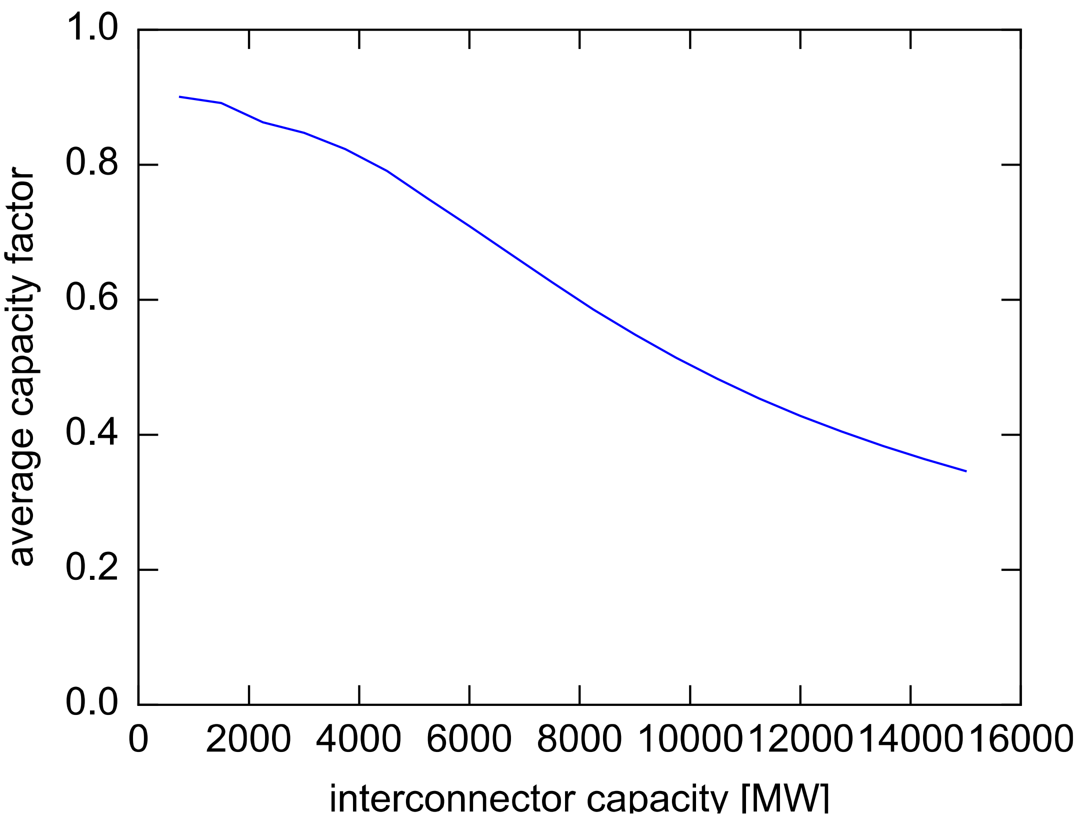

Figure 3 - Average Capacity Value as a function of Interconnection Capacity

74. Figure 3 suggests that increasing interconnector capacity will lead to a reduction in the de-rating as interconnection capacity increases and the saturation effect begins to manifest. For the auctions that are the subject of the 2016 ECR, however, the analysis also shows that the saturation effect can be discounted, as levels of interconnection to each country are lower than sizes highlighted in the above. In the future, as GB interconnection to continental Europe increases, this effect could be incorporated into the analysis. The saturation effect should, however, be included in the Pan-European model development. (See paragraph 133 in this report for more detail on the Pan-European modelling).

Conclusions on Choosing a De-Rating Factor for Interconnectors

General

75. From a purely technical perspective, the fact that interconnector capacity at the GB end has not reached levels that lead to the emergence of the saturation effect (where each increment of new interconnector capacity provides increasingly smaller amounts of capacity for security and ultimately none at all) means that the upper end of the National Grid ranges would achieve the technically optimal capacity required in GB. This would be sourced from a combination of indigenous and interconnected resources and would be most consistent from the European perspective of maximising the value of interconnection.

76. A key trade-off, however, in relation to de-rating existing interconnectors when selecting a low percentage value for de-rating compared with a high percentage value, given that all capacity is priced at ‘pay-as-clear’, is as follows:

    a. A lower value implies a conservative approach to the risk of correlated stress events while this evidence base is still being compiled. It also means a higher target capacity to be delivered within GB unless offset by making less provision for non-delivery sensitivities, which were selected by the Least-Worst Regrets analysis. This would provide revenues to more GB resources to provide additional capacity, but also may imply a higher auction clearing price if these resources are more expensive than interconnection. Unless the overall target were reduced commensurately with the notionally available above-de-rated values for interconnectors, it may also lead to over-securing capacity and depressed energy prices and DSR; whereas

b. a higher percentage for an interconnector de-rating value implies that the equivalent capacity located outside the UK is potentially available at the same or lower clearing price as they provide liquidity and competition but which capacity is subject to the market, laws, policies and regulations of other states. A decision to prematurely close European nuclear power stations might be an example of a policy measure that is completely out of the control of the UK authorities, but it could have a considerable impact on flows in stress periods. It is important that DECC keeps a watching brief on such policies in interconnected markets.

77. Given the cost equivalence of paying interconnectors compared with rewarding GB resources directly, in addition to the purely technical factors, national strategic considerations and specific risks on the other side of interconnectors appear to be the main criteria upon which upon which to gauge de-rating values. In a more mature and fully harmonised market, net welfare of the whole European system might become the only criterion but we are far from that point at present.

78. Given that the saturation effect and capacity surpluses at the other end of interconnectors at times of GB stress may become more significant both with the progression of time and with the addition of new interconnector capacity, it must be stressed that de-ratings should be open to being changed in the future in response to such changing conditions.

Ireland

79. Regarding the EWIC, the region to which the interconnector is coupled to a part of the I-SEM region that has spare capacity and should be in a position to export to the GB, assuming that I-SEM becomes operational as intended. The risk of the I-SEM becoming operational in time is probably the key consideration in selecting the de-rated capacity. There are no reasons we have identified to doubt that the I-SEM will become operational and therefore there is little technical reason not to rely on a higher value for the de-rating factor, with a modest allowance for this risk. One complication is that until the North-South interconnector in Ireland is completed, Northern Ireland is locally short of power and reliant on the Moyle Interconnector for imports. If the wind farms in Northern Ireland and Scotland are operating, the GB system does not need imports via Moyle (whose exports to GB are limited to 80MW in such cases) because wind from Scotland will be available at the same time. In such cases there is unlikely to be a stress event. If the wind is not available, then it

is possible that both the GB and Northern Ireland could be short due to the highly correlated simultaneous lack of wind, and, given that demands are also correlated, simultaneous stress events in Northern Ireland and GB may be more likely (although not those caused by plant failure).

80. We conclude that treatment of Ireland as an uncongested single market is highly dependent on the North-South interconnector which is experiencing delays. We therefore advise caution on the expected market response of Ireland to a stress event in GB until it is clear that the North-South interconnector will be built and commissioned on time and until the intraday trading arrangements between Ireland and GB are settled.

France

81. The main consideration in relation to interconnection with France is the impact of extremely cold winters with attendant very high electrical heating demand and the very high levels of imports that have been required historically in such cases. This suggests that while the security of supply standard could be met at higher values of de-rating, the susceptibility of the GB to a shock from a very large interconnector exporting brought on by a very cold winter in France during a period of GB system stress would be reduced by choosing a lower value for de-rating. The Pöyry analysis showing increased flow-price direction correlation over the recent two-year period of market coupling is encouraging. However, recognising that this is an extremely small data-set upon which to rely and the longer, seven-year period is distorted by the lack of market coupling we face a dilemma in either facing the risk of confirmation bias in selecting favourable recent data, or using data that does not reflect the current market coupling. The issue essentially comes down to a view on whether to aim at a low contribution and drop the cold weather sensitivity (which arguably reflects the risk that IFA will not be contributing much then) or a higher contribution but include the cold weather risk.

Netherlands

82. The high and low bands represent a narrow spread and flow-price correlations are consistent over all periods of available data. Further, there are no compelling reasons that we have identified and National Grid have taken account of the known mismatch between the capacity offered to the market and the higher registered TEC. Therefore a higher factor within the recommended band would seem most appropriate.

Belgium

83. Belgium has also shown improved price-flow correlation following market coupling. The key technical risk that would suggest a lower value for interconnection with Belgium is the availability of its ageing and poorly performing nuclear reactors, which recently restarted after a two-year shutdown. Age-related problems, including the discovery of reactor casing cracks have affected multiple reactors. Belgium also has a wavering recent history on its commitment to nuclear power and remains under considerable pressure from worried neighbouring countries to close reactors. For these reasons, it would seem imprudent to gamble on Belgium's capacity going forward until there is more clarity and reassurance regarding both the nuclear fleet and its stance on nuclear in general.

84. However, Belgium can act as a transit route to supply interconnectors from outside Belgium. According to Elia,[5] "The Elia grid currently has a technical import capacity of around 3,400 MW at the Dutch border and 3,900 MW at the French border. … (The) **import scenario for winter 2015-2016**, which applies at critical times when the electricity market is under pressure:

    a. Capacity at the Dutch border (3,400 MW) will be used entirely for import.
    b. Transit to France will result in the export of 700 MW at the French border. The Elia grid's net import balance is therefore: 3,400 – 700 = 2,700 MW.

85. It is therefore not clear what additional exports Belgium could flow over NEMO when the Belgium market is under pressure. That is where Belgium's domestic security of supply situation is potentially critical, although we also note that Belgium is taking steps to enhance its domestic capacity and has announced the extension of the period of operation of its nuclear fleet.

Norway

86. We agree with National Grid that a long period should be considered in the case of Norway to take a more representative sample of weather events, upon which its resources are highly dependent (such as droughts). We also note that the 2003 drought was a one in 50-

[5] At http://www.elia.be/en/about-elia/questions-about-the-risk-of-shortage-in-Belgium#32

year event, which, although it led to high domestic prices, was largely handled by a very substantial demand side response.[6]

Conclusions:

87. On the whole we recommend that DECC takes the mid-point of National Grid’s range although some caution on Ireland may be advisable. Least-Worst Regrets would be an alternative but we note that: the cost curves underlying would not be particularly stable, which would impact the de-rating factor selected; and to justify and defend the de-rating factor would be harder than taking an average; it would be less transparent than an average. In our view, the mean is a better approach for this purpose than a Least-Worst Regrets approach and although the main issue with using a simple average as a methodology is that it does not factor in risk, National Grid’s ranges already do this.

Other Sensitivities Considered and Dismissed

88. National Grid has provided good reasons for not considering other specified sensitivities, which we have discussed in detail and support for the same reasons.

Demand Side Response

89. We have noted above in our response to National Grid’s actions on our previous recommendations that its “Power Responsive” initiative is a welcome measure. This has provided ‘proof of concept’ that the demand side can play a role in mitigating an excessive generating capacity and utilising the system infrastructure more efficiently and smartly by engaging all types of demand side resources. We strongly endorse this as one of what should be a number of approaches in moving ultimately to a level playing field for transmission-connected generation and the demand side to compete eventually on equal terms.

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[6] V.d. Fehr, N-H., E.S. Amundsen and L. Bergman, 2005. The Nordic Market: Signs of Stress, *The Energy Journal Special Issue.* (ed. D. Newbery)

Comments on Target Capacity

The 2017/18 auction

90. We are content that the methodology used in the ECR for 2017/18 has been robust, leading to reasonable and justifiable target capacity for 2017/18 early auction.
91. The underlying figures for the derated target capacity for 2017/18 show changes from those previously used for the 2018/19 delivery year (used as a benchmark) in minor ways, as follows: National Grid has identified 1.5 GW of distributed generation that was previously not visible. The effect of this is to increase final peak demand by 1.5 GW, which is exactly offset by the 1.5 GW of distributed generation. The residual difference from the National Grid recommendation for 2018/19 is the increase in requirement resulting from the Least-Worst Regret outcome of securing to a base case cold winter sensitivity. We accept the outcome of the Least-Worst Regrets process for this year, but discuss the potential for further improvements in applying probability weighting to sensitivities in the section below titled 'Probabilistic versus Least-Worst Regret concept'.

The T-1 auction for 2018/19

92. We accept the target capacity for 2018/19 T-1 auction, noting that CCGT capacity that secured a capacity contract has not secured finance in time is fortuitously offset by a more realistic assessment of the interconnector contributions.
93. On the indicative T-1 amounts for 2018/19, we refer again to Figure 1 shown previously at paragraph 42.
94. Consider the changes in detail:
    a. De-rated TEC: this reflects the large over-statement of nominal capacity measured by TEC, and which therefore overstates the de-rated capacity. It reflects either or both of: the optimism of the generators that the de-rating was too pessimistic; or the inadequacy of the penalty for non-delivery. In either case it is legitimate to correct for this, if we accept that the de-ratings were not excessively pessimistic. If we consider they were somewhat excessively pessimistic, then one might reduce this correction somewhat.
    b. Some station capacity that previously stated that they were "Opted out and operational" are no longer assumed to be "Opted out and operational" for

2018/19. Stations that closed will need to be replaced in due course and hence added to the amount to secure.

c. Even if the CCGTs with capacity agreements are not available in 2018/19, they would be more than offset by the revised de-rated interconnector capacity.

d. 2.7 GW of specific station capacity had capacity agreements but have announced an intention to close, unless their revenues improve in the near term and remain available for the 2017/18 auction. We shall have a clearer picture after that auction, but if they remain for the 2017/18 auction and are required then, presumably they are more likely to honour their agreements and would not need to be replaced in the 2018/19 T-1 auction. Together with certain CCGT, these make up the 4.3 GW “existing contracted plant non-delivery in the base case”.

e. 1.4 GW ACS peak demand reflects the under-estimate of distributed generation and is cancelled out in one of the red decrements

f. De-rating margin is negligible

g. Interconnector contributions are now recognised and more than compensate for non-delivery of CCGT

h. -3.7 GW “Non-CM capacity change” presumably includes the 1.4 GW newly found distributed generation that offsets the increase in ACS peak demand of 1.4 GW, leaving 2.3 GW for the extra contribution of renewables, which should be an automatic calculation from their capacity and de-rating.

i. -0.6 GW extra resulting from the low clearing price is a bonus, and an auction outcome, so accepted.

95. Any change in this indicative target will be signalled to the market in the next ECR, and the present assessment is mainly to provide the market with improved estimates.

The T-4 auction for 2020/21

96. Using the 2019/20 target requirement as a comparator, we consider here the changes from the 2019/20 recommendation. Part of the change is a revised ACS peak demand, based on an updated view of demand forecasts. Another part is a justified increase in reserves required to meet the higher largest loss of in-feed. The other justified adjustments are for increased volumes of plant holding ROCs or CfDs whose de-rated capacity is netted from final demand, as are the volumes of those holding capacity agreements (and who are not at

high risk of relinquishing them). However, adjustments have also been made for autogeneration (behind the meter) not assumed to bid into the Capacity Market and growth in renewables that do not already have support. These would not, in our view, provide a reliable basis on which to calculate the capacity to secure to the extent that regression-based growth utilises potentially inappropriate historical trends and the assumption that autogeneration doesn't partake in the Capacity Market as aggregated DSR. We are informed, however, that the growth projection is based on specific projects, which is reassuring. This further highlights the need for ever-better 'behind the meter' visibility for National Grid which is the subject of discussion and recommendation in this report.

97. That leaves an increase of 2 GW relative to the base case requirement, which is attributed to non-delivery risk, and whose status will become clearer as time passes. If we are discussing the total target capacity, and leave to one side the 'truing up' allowed for at the T-1 stage, then we would argue for considering how best to deal with its possible non-delivery.

98. Plant that may exit between now and 2020/21 needs a closer study of the comparative costs of keeping it on the system to deal with stress periods compared to replacing it with possibly more versatile plant. Both entering and exiting plant will be guided in their decisions by trading conditions in the energy market but also by the various use-of-system charges. If it appears cheaper to keep existing plant on the system, then the sequence of T-1 auctions should suffice in which case it would not be necessary to add the 2 GW and increase the target capacity.

99. If replacement plant appears more economic than continuing with existing plant, then the main question is the balance to secure at T-4 and the amount to leave to T-1 when a more accurate prediction of requirements will be available. This decision will incorporate a balance of risk between under- or over-securing capacity. However, given the large uncertainty regarding the speed of the trajectory of coal closure, we understand that guarding against under-securing and the risk of non-delivery are currently higher priorities as signalled in DECC's consultation in March 2016.

Interaction between scarcity pricing in Balancing Market and the target capacities

100. As energy prices increase to reflect scarcity in the system at times of system tightness, consumers facing half-hourly charges are likely to reduce their demand. Suppliers are likely to develop more responsive contracts that provide both a hedge against high prices and an incentive to reduce demand in high price periods. Some larger customers may be attracted to such contracts and hence be in a position to reduce demand in high price periods as they forego electricity uses.

101. It is hence critically important to link the impact that scarcity pricing will have on the peak demand and the corresponding capacity to be secured through the capacity market. At present, however, the interaction between short-term measures aimed at demand reduction and the projection of peak demand used in in the capacity market is considered by National Grid but is difficult to quantify due to a lack of access to essential demand side information, which will generally lead to over-securing of capacity. To put this in perspective, if stress period prices rise to £5,000/MWh compared to past prices of less than £100, and if 20% of consumers (larger loads) face these marginal prices, and if the short-run elasticity of demand is -0.01, the 50-fold increase in price would lead to a 2 GW reduction in demand. This would be a market demand response[7] and so would reduce the number of "Loss of Load" Events, and hence the capacity secured would lead to a higher reliability standard than that intended.

102. As noted above, there is an element of self-fulfilling prophecy here, as if too much capacity is secured and the system is more reliable than de-rating factors suggest, then prices will not rise as much when markets are tight and so demands will not respond so much. This bears on the asymmetry of risks of under or over-securing. Over-securing exacerbates the "missing money" problem and requires higher auction prices to make up for lower energy prices, while under-securing leads to higher prices and encourages more vigorous demand responses that may deliver the reliability potentially standard at lower cost but at increased security of supply risk to consumers.

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[7] There is a range of demand side response assumed across the scenarios. The definition of peak demand used is Average Cold Spell (ACS) "unrestricted" underlying demand – it is a "1 in 2" definition of peak demand (not an extreme stress period demand) that does not have any demand response deducted as DSR can participate in the auctions.

103. Detailed analysis carried out by Imperial College[8] demonstrates that LOLE would reduce from 3h/year to 1h/year if, through scarcity pricing and/or exercise of balancing services, the peak demand is reduced by 1.5 GW. Similarly, this analysis also shows that the likelihood of a power shortage exceeding 2 GW would only be one-quarter as high if scarcity pricing were to reduce peak demand by 1.5 GW.

104. As indicated above, understanding the value of different uses of electricity and hence the amount of load that would be shed at higher prices may have a major impact on the amount of capacity that needs to be secured to meet the reliability standard. In this context it is important to stress that Value of Lost Load (VoLL) of £17,000/MWh used in the capacity market, is based on the assumptions that all demand of affected customers is disconnected (assuming a certain composition of domestic and commercial demand). Clearly, the marginal VoLL could be much lower and in this context, smart scarcity management that would enable differentiation between essential and non-essential demand will have a major impact. The VoLL might also be higher in situation where electricity is not available for central heating systems for example. This emphasises the urgency of establishing a process by which essential and non-essential demand can be identified and separately curtailed if necessary during periods of system stress as would be the case in many advanced electricity systems.

105. Figure 4 illustrates how scarcity pricing, at much lower cost than VoLL, should incentivise peaking DSR to avoid loss of load events occurring and conversely, that the suppression of scarcity prices will underutilise the DSR response leading quickly to more expensive mitigating action taken by the System Operator which would be classified as an emergency measure and therefore a loss of load event.

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[8] "Security target: LOLE = 3hours - What does it actually mean?" http://energysuperstore.org/esrn/wp-content/uploads/2016/06/LOLE_Security-Performance_April2016_IMP1.pdf

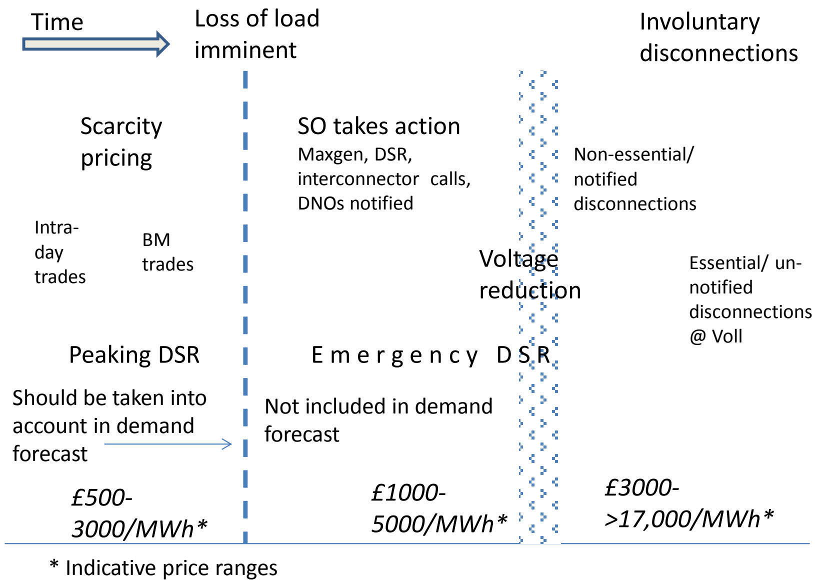

Figure 4 - Role of Scarcity Pricing to Incentivise DSR and Avoid Expensive Loss of Load

106. In this context, the rollout of smart metering to residential customers (together with price incentives) will reinforce the opportunity for smarter management by switching off non-essential loads when the system is stressed while maintaining supply to essential loads. Indeed, the concept of 'security of supply' makes most sense in relation to demand that actually requires such security. This would result in a significant enhancement of the security of supply delivered, as all consumers will have their essential loads supplied at times of system tightness. Even if only some customers adopt such automatic load shedding the impact on peak demand or demand in high price periods could be significant, and may well be business-as-usual by the time of the delivery periods under study here. The FESs make assumptions about such developments leading to corresponding reductions in assumed demand.

107. Such an understanding of the effect of scarcity pricing would then provide a better basis for establishing the amount of mitigation margin to be secured, and provide further clarity on the actual meaning of the LOLE based Reliability Standard.

108. The implications of all this for the target 2020/21 capacity is that the incorporation of full delivery risk into any delivery year may be misguided. This is because there needs to be a

more careful assessment of the economics of replacing high-risk existing plant with new plant or an extension of DSR or other existing plant that would otherwise close.

NEW RECOMMENDATION 23: National Grid already considers the analytical implications arising from the wider role that Smart Meters could play in demand side participation that extends far beyond the passive roles such as monitoring consumption or time of use tariffs and which extends to active management such as the actuation of energy saving measures at times of stress. It will be critical to establish the impact of scarcity pricing on peak demand in order to ensure that an efficient amount of capacity is secured through the capacity market. It would be helpful also to examine demand responses to high prices in markets that have already begun to roll out such active management tools which would enable appropriate targets and aspirations to be set.

Conclusion on Target Capacities

109. Over the past three years, the process by which National Grid develops its recommended targets has evolved such that DECC, Ofgem and the PTE have the opportunity to comment in real time and at many stages. This means that by the time National Grid's report is published, there are fewer or no major surprises and except for any fundamental difference of opinion, the PTE have every reason to concur with National Grid's analysis.

110. On this occasion, apart from caveats regarding the limitations of present analytical tools and suggestions for future analytical improvements, which are generally expressed as recommendations in this report, as well as some reservations regarding the approach to setting the reliability standard, which in any case is beyond a strict interpretation of our remit, the PTE generally concurs with the target capacities for the two relevant auctions. We believe the methodology has been robust, leading to reasonable and justifiable target capacities.

Methodology

Modelling Enhancements Incorporated

111. Several improvements to the modelling methodology have been implemented in the process of producing the 2016 ECR, in particular with respect to interconnector availability and correlation with GB demand, demand-wind relationship and dynamic analysis of demand outside the DDM framework. The development of these modelling enhancements has shed light on critical issues which can contribute to a more rigorous selection process for the capacity to be secured through the Capacity Market.

112. On the modelling side we have concerns about the lack of probabilities being assigned to the Least-Worst Regrets sensitivities. In particular, the inclusion of additional non-delivery sensitivities has led the Least-Worst Regrets process to select a target capacity which is significantly higher than the level which would be generated by applying a different set of probabilities for the size of non-delivery (as illustrated in the Table below para 119).

Management of generation capacity shortage

113. Managing generation capacity shortages would require reductions in demand, after the mitigation measures secured are fully used. At present this would be carried out by Distribution Network Operators that would disconnect some consumers from the electricity supply networks to match the level of electricity generation available. The efficient management of shortages should involve reducing consumption by or disconnecting less-essential loads when the system is stressed while keeping supply to essential loads. This should be possible as our analysis demonstrates that only a very small proportion of demand would need to be reduced during generation capacity shortages: expected demand that would need to be curtailed per event of capacity shortage is normally less than 1.5GW (and may exceed 5GW only once in 20 years), compared to a peak demand of about 60GW. The efficient management of demand reduction would result in a significant enhancement of the security/reliability of supply delivered to consumers, as consumers would then have their essential load supplied during supply capacity shortages (system stresses), rather than experiencing indiscriminate demand curtailment.

114. It is hence very concerning that the approaches and processes of managing generation capacity shortages are not clearly established at present. We propose that appropriate actions are taken to ensure that methods and practices adopted for managing supply shortages are comprehensively implemented, while fully considering the criticality / cost of demand to be disconnected during stress events, which would provide further clarity regarding amount of capacity to be secured through the capacity mechanism.

NEW RECOMMENDATION 24: Appropriate actions should be taken to ensure that methods and practices adopted by DNOs for managing supply shortages are comprehensively implemented, while fully considering the criticality / cost of demand to be disconnected during stress events, which would provide further clarity regarding amount of capacity to be secured through the capacity mechanism.

The Value of Lost Load and the net Cost of New Entry

115. Zachary and Wilson (2015) have shown in an elegant consulting report commissioned by National Grid how to calculate the Value of Lost Load (VoLL) used to secure capacity (the effective VoLL). They have responded to the argument that the underlying VoLL (the cost of the market failing to balance the system before System Operator (SO) interventions) may be substantially below the cost of actually disconnecting customers. This cost might increase from negligible values when the market-offered margin of supply over demand first becomes zero and SO begins the least costly mitigating actions, up to the full value of actual disconnections (the true VoLL). This level of less costly mitigating actions should be thus applied to the level of VoLL included in the Least-Worst Regrets function which trades off the cost of capacity and VoLL.

116. The second important result in Zachary and Wilson (2015) is that the net CONE is equal to the effective VoLL times the LOLE. This is the point at which the auction demand curve should pivot. As the effective VoLL is less than the value of VoLL based on disconnections, the resultant level will be lower than current estimates of net CONE, and the demand curve will shift down. The amount to be secured for any given supply curve from CMUs could be reduced by about 0.5 GW.

Further Observations on Recommended Target Capacities

Probabilistic Sensitivity Tests of Capacity Target at Constant LOLE

117. While we understand the reliability standard should be enduring (and so the ratio of VoLL to net CONE should be retained at 3 hours per annum) we have argued that the current approach of considering the currently applicable value of VoLL to take effect as soon as there is a shortfall of generation to demand is inappropriate. Not only would National Grid be able to take actions at much lower costs but also we would expect that there would be a market response in bringing forward “near emergency DSR”. Our view is that this last recourse DSR should be incorporated in the DDM, such that this extra “supply” would delay the point where there would be a loss of load event. National Grid has previously informed the PTE that this facility is not available in the DDM, but our suggestion is that it could be replicated by adding a peaking generator category (provided that reliable estimates of generation costs could be made).

118. It is clear from the charts in the ECR that the non-delivery sensitivities run on the National Grid base case are the main drivers of the capacity to secure. In order to understand the impact of the inclusion of these sensitivities, we ran some tests using National Grid’s Least-Worst Regrets tool for 2020/21. We examined what would happen if we set probabilities lower than one, that might reflect the chances of the non-delivery occurring. Since the sensitivities are included in steps of 400MW, we decreased (in a linear fashion) the probability as more capacity was taken out such that probability increased from a low number at 400MW to the highest number at the worst case (2300MW). We experimented with a range of probabilities for the worst case from 15% to 50% in each case adjusting the intermediate case in a linear fashion. We kept the values for everything else unchanged. This showed, that if the probability of the worst case was 15% (approximately 1 in 7) then this would reduce the target capacity by 1.4 GW, the same value as excluding the non-delivery cases altogether.[9] If the worst case were 33% (1 in 3) and 50% (1 in 2) the

[9] Clearly a 15% probability of worst case also lower the capacity requirement by 1.4GW.

capacity to secure is reduced by 0.9GW and 0.6 GW respectively. We also tested other variables such as the VoLL and net CONE (but still retaining the LOLE ratio of 3 hours per annum), but these had a much less marked impact. Also excluding extreme cases, such as the two weather (cold/warm winters) and wind cases had a minimal impact compared with non-delivery.

119. Please note that while we have taken every care to ensure the robustness of this analysis, which has been tested for accuracy, these should be regarded as an observation that should prompt further discussion and investigation rather than being a final conclusion.

Sensitivities using the Least-Worst Regrets tool for 2020/21

Sensitivity	Voll: £/MWh	Net CONE: £/kW/year	Scenario/ sensitivity weights	Capacity to secure: GW	Delta from base: GW
Base	17000	49	all 100%	49.5	0.0
Revised VoLL/CONE pair	11333	34	all 100%	49.3	0.2
Exclusion of FES	17000	49	all 100% except for FES at 0%	49.3	0.2
Exclusion of all non-delivery cases	17000	49	all non-delivery set to 0%, others at 100%	48.1	1.4
Scaled weights for non-delivery to 50% in worst case	17000	49	Weights on non-delivery reduced to 50% in steps	48.9	0.6
Scaled weights for non-delivery to 33% in worst case	17000	49	Weights on non-delivery reduced to 33% in steps	48.6	0.9
Scaled weights for non-delivery to 25% in worst case	17000	49	Weights on non-delivery reduced to 25% in steps	48.5	1.0
Scaled weights for non-delivery to 20% in worst case	17000	49	Weights on non-delivery reduced to 20% in steps	48.5	1.0
Scaled weights for non-delivery to 15% in worst case	17000	49	Weights on non-delivery reduced to 15% in steps	48.1	1.4
Scaled weights for non-delivery to 15% in worst case	11333	34	Weights on non-delivery reduced to 15% in steps	48.1	1.4

Probabilistic versus Least-Worst Regret concept

120. As discussed in our previous report, the Least-Worst-Regret concept as applied for ECR purposes fundamentally assumes that all cases (sensitivities) considered when identifying the optimal target capacity are equally probable. We discussed this in the table above which compares the results of a full probabilistic assessment to the standard Least-Worst Regrets approach that ignores the actual probabilities of extreme scenarios, particularly non-delivery conditions. In another exercise we considered selecting extreme demand

scenarios taken from the years with highest and lowest peaks in a 17-year period, and then treating them as equally probable as the peak in an average year. As expected, the Least-Worst Regrets-based solutions were very significantly different from the balanced probabilistic methodology. In this particular exercise, the Least-Worst Regrets approach suggested that the target capacity should be materially larger than optimal probabilistic model that delivers an average LOLE of 3h/year over the long term (with some years having lower and some higher LOLE values). Depending on the actual shape of the probability distribution of peak demand, the difference in results between optimal probabilistic approach and Least-Worst Regrets could vary significantly.

121. Although it may be difficult or impossible to allocate probabilities to different scenarios, it will be important to ensure that the way in which Least-Worst Regrets concept is applied in future would not lead to distortions and corresponding material increase of unnecessary capacity secured. For example, whilst we accept the argument of National Grid's consultant statisticians Zachary and Wilson that it is reasonable to make extra allowance for extreme weather events, but that does not mean giving them 100% weight. Therefore, it would be useful to know the amount to secure that keeps the *expected* LoLE at 3 hours/yr while attaching a more realistic probability to the risk of a cold winter. National Grid accept that for the weather sensitivities, weightings could be calculated (based on statistical analysis of history) although they chose not to do so. They argue that if both the warm and cold sensitivities were to be removed for the 2017/18 analysis (or if they are given a very low weighting) the Least-Worst Regrets tool selects 54.0GW (the Non-delivery (-1.2GW) sensitivity) i.e. 0.2GW more capacity. This would also happen if the cold winter were given a lower weighting than 100% so long as it moves the required capacity for that sensitivity by more than ~0.2GW. The worked example in the ECR Appendix A gives some insight into how this may happen.

122. The adoption of a central base case as the reference case to which sensitivities are now applied offers the opportunity to exploit the relative visibility of near future events for modelling purposes, as opposed to the more uncertain nature of the technological and political factors influencing the development of the FES scenarios.

NEW RECOMMENDATION 25: National Grid should review its overall modelling strategy and consider a range of options including the existing "DDM plus Least-Worst Regrets", "DDM plus Least-Worst Regrets plus probabilistic sensitivities" and a wholly probabilistic approach. This potential modelling improvement is facilitated by the adoption of a short-term central base case that is consistent with demand forecast incentive.

Quality Assurance

123. Previously followed procedures continue to provide QA, these are closely aligned with DECC's internal QA processes. Compared to previous ECRs additional checks have been introduced for the implementation of modelling extensions introduced in the 2106 ECR. These checks are related to the new methodological approach for the analysis of historical demand and embedded wind, which produces a demand distribution to be included in the DDM. An additional check is also associated with the CM results included in the DDM input template.
124. Support has been provided by LCP for the additional DDM simulations required for the early and T-1 auction. This technical support further contributes to the modelling validation process.
125. The PTE requested details of the ECR Quality Assurance methodology, which is reproduced here at a high level in ANNEX 2.

ANNEX 1 - Progress on the PTE's Previous Recommendations and Further Observations

126. The PTE made a number of recommendations in its 2014 and 2015 reports. This section briefly summarises progress against all the recommendations from 2015 and Recommendation 2 from 2014 (all other actions having been satisfactorily progressed and which can be found in our 2015 report). National Grid have provided a progress report on all these actions, as well as commentary made by the PTE in relation to the Value of Lost Load. National Grid's report is reproduced below in this section in italics.

127. **Previous Recommendation 2**: In applying the Robust Optimisation (*i.e. Least-Worst Regrets*) methodology, account should be taken of any further information relating to the relative **likelihood of scenarios and sensitivities** in order to minimise distortion.

    a. ***Progress (National Grid Response)****:" One recommendation from their 2014 report (Recommendation 2) which the PTE felt hadn't been fully addressed last year related to the use of the relative likelihood of scenarios and sensitivities used within the Least-Worst Regrets decision tool. In particular, they referred to the inclusion of the extreme weather events sensitivities.*

    b. *As part of last year's analysis we undertook a series of stress tests of the Least-Worst Regrets approach that considered various levels of probabilities or weightings being applied to different sensitivities. All scenarios and sensitivities that were included had to be credible and based on real examples, as with this year's methodology. Notwithstanding the imprecise nature of assigning probabilities to most scenarios and sensitivities, the analysis found that to change the outcome of the Least-Worst Regrets required very low probabilities to be used which meant they would need to be non-credible sensitivities and therefore wouldn't have been included anyway. Academic analysis from our academics from Durham University and Heriot Watt University (Zachary, Wilson & Dent) supported this conclusion; however, this work also suggested considering as part of any future development work the potential use of a*

Bayesian approach. Consequently, we will investigate this as a development project for next year's analysis.

c. *To provide some practical insight to the potential application of assigning probabilities to sensitivities a recent example highlights the difficulty associated with such an exercise. When we were carrying out analysis on the capacity to procure through the Contingency Balancing Reserve products for 2016/17 we incorporated coal closure sensitivities up to 2.8GW within the Least-Worst Regrets tool (similar to the non-delivery sensitivities used in this report). At the time it was suggested that we should assign probabilities but it was decided against it given the challenging economic climate for coal stations and feedback from the station operators. This proved to be the correct action because within a short time of this analysis two coal stations announced closure in line with that sensitivity. This reinforces the arbitrary nature of assigning probabilities or weightings to credible sensitivities as they can in a very short timeframe be proved incorrect.*

d. *With regard to the inclusion of the extreme weather sensitivities which, in theory, can be apportioned a probability; firstly, we have addressed the PTE's concerns over their inclusion in our analysis in the response to the second bullet above and secondly, their position within the current range of potential capacity requirements prevents them from affecting the outcome as the sensitivities at the ends of the range determine the outcome of any Least-Worst Regrets calculation. Consequently, while providing important information that enable non-statisticians to assess risk unless these sensitivities are at the end of the potential range of credible outcomes (only the warm weather sensitivity has that possibility and if removed could actually increase the capacity to secure) they don't affect the recommended capacity to secure".*

128. **PTE Comment on response to Previous Recommendation 2**:

a. We are unconvinced that the larger capacity requirement sensitivity cases should be given equal weighting to the base case and core scenarios. This is especially the case for the cold weather case and for the worst case sensitivity for non-delivery of contracted coal capacity. We have tested the impact of varying assumptions on this (see paras 117 - 122), setting a probability (in the

Least-Worst Regrets tool) for the worst non-delivery case of 15% to 50%, which lowers the target capacity by 0.6-1.4 GW in the 2020/21 delivery year.

b. National Grid presented us with an excellent paper written for it by Zachary and Wilson,[10] who compare a Bayesian approach with Least-Worst Regrets. They concur in arguing that it is hard to assign even subjective probabilities to scenarios. They compare the Least-Worst Regrets results with a range of probabilities assigned to the scenarios, a show that the resulting target capacity might be +/- 0.4 GW different from the Least-Worst Regrets choice. They argue that the choice of scenarios can have a strong impact on the target capacity, and hence those chosen have to be reasonably probable, so there is thus an implicit probabilistic approach lying behind the Least-Worst Regrets. We therefore support National Grid's proposed future study following up on Zachary and Wilson's contribution as it applies to scenarios, and perhaps more importantly, to sensitivities such as extreme weather for which probabilities can more readily be attached. We note, however, that there are additional virtues in the Least-Worst Regrets approach in that it remains agnostic about the relative probabilities of the scenarios that have survived extensive consultation and stakeholder input, and there might be concerns about subsequently attaching what might to many seem arbitrary probabilities that bias the target in one way or another.

c. Regarding point 127.d above, we accept the argument that the inclusion of weather sensitivities is consistent with the relatively short (in meteorological terms) horizon of the analysis, which covers only a 10-year period. We continue to question, however, whether a probabilistic weight of 100% should be attached to such weather events.

129. **Previous Recommendation 11**: Additional analysis should be undertaken to understand the **potential contribution from DSR and distribution connected generation.**

a. **Progress (National Grid Response)**: *"As part of the 2016 FES process we have carried out extensive searches across a range of sources to obtain a more accurate figure for the levels of installed distribution connected*

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[10] Zachary, S. and A. Wilson, 2015. Least-Worst Regret Analysis

generation. This has provided detailed capacity figures for all technologies but unfortunately not their levels of generation. We are currently in negotiation with ElectraLink (a commercial company owned by a group of Distribution Network Operators (DNOs)) to secure half hourly data for the last few years for each distribution connected plant. This data should provide insight into how patterns of generation have changed over the recent past as financial incentives have improved and should deliver the increased knowledge and understanding the PTE sought. This latter point will address the follow up to the PTE's Recommendation 10 from their 2014 report which requested more analysis on distributed generation availabilities."

b. *National Grid has been working closely with industry via its Power Responsive campaign to help inform and facilitate greater participation in both true DSR (i.e. demand shifting or demand reduction) and distributed generation. This campaign has included extensive engagement, industry workshops and published documents all highlighting the financial incentives and ways to participate. This campaign appears to have successfully contributed to the increased participation of both DSR and distributed generation seen in the market during 2015/16.*

130. **PTE comment on Previous Recommendation 11**:

a. Regarding point 129.a above, we understand that National Grid has been faced with very high charges that have deterred them from requesting a longer data series of half-hourly information. This limits National Grid's ability to have line of sight on the behaviour of distributed generation, thereby affecting its ability to accurately model this for Capacity Market and other analysis. National Grid has undertaken a significant development project to gather more information on the levels of embedded generation capacity in GB, leading to an assumption of an extra 2.5 GW of non-CM embedded capacity in the 2016 modelling for the T-4 auction. However, due to a lack of data on its performance, we have some doubt as to how this non-CM capacity would respond in a stress event and encourage National Grid to improve the evidence base. It is not within the scope of the PTE's remit to suggest how this issue can be solved, but we note it with considerable concern as National Grid not having straightforward access to information about activities on DNO networks that can affect its analysis on security of supply, and also access to past data, where available, for loads and distributed generation output for each half-hour presents an impediment to the optimisation of the electricity system.

b. Regarding point 129.b above, we are aware of the significant efforts made by National Grid to facilitate demand side participation through the 'Power Responsive' programme. We note that around 700 respondents have signed up for regular information bulletins and the very helpful "Comprehensive Guide to DSR",[11] which gives extremely helpful guidance to help demand side participants, such as owners of back-up diesel generation, industrial plant operators with flexible loads, voltage control and many other classes of participant to provide services such as STOR and Enhanced Frequency Response that can significantly improve asset and network utilisation and quality. The evidence of an increase in Triad Avoidance for the past winter rising to 2 GW from 1 GW in the preceding year, as well as 310 MW of the new demand turn-up service strongly indicate that National Grid has played a strong role in encouraging more effective demand side participation.

131. **Previous Recommendation 12**: National Grid should expand its **analysis of loss of load events** to take account of the volume, frequency, duration, forewarning and predictability of loss of load events.

a. **Progress (National Grid Response):** *"This recommendation can be addressed in two parts; the modelling of loss of load events (which in the past we have undertaken some work for Ofgem) and the details around emergency procedures that would be utilised leading up to controlled disconnections by the DNOs.*

b. The functionality of the DDM version currently utilised for the Capacity Market work doesn't produce information on frequency and duration as it is time collapsed rather than sequential. While a module of DDM has a sequential

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[11] Details of National Grid's campaign can be found at: http://www.powerresponsive.com/media/1140/ng_meuc-dsr-book.pdf

capability there are limited reliable data sources currently available to enable the model to be effectively run. Also the run time of any sequential model would need to be carefully considered due to the practicality of delivering the analysis given the limited time available to undertake and deliver the work. However, we have run our own time collapsed Capacity Assessment model in a way that enables an approximation of frequency and duration metrics to be calculated. When we shared this analysis with DECC and the PTE they felt that while interesting the frequency metrics could be misinterpreted, as verification required sequential modelling, and as it doesn't impact the resulting capacity to secure figure, we agreed not to re-produce the analysis in our report.

c. *The PTE have presented work undertaken by Imperial College London that modelled the GB market sequentially using a range of data including an Institute of Electrical & Electronic Engineers (IEEE) dataset to produce frequency and duration statistics. This work provided interesting insight in to the potential shape of loss of load events under a 3-hour loss of load expectation Reliability Standard. Any future development projects will centre on how these findings could be potentially translated into running the DDM in a practical way and ensure appropriate model run times to enable timely delivery of outputs. Consequently, we would be happy to work with the PTE and DECC to agree a development project for the autumn to review any potential options.*

d. *To address the second part; in addition to providing information on the mitigating actions the System Operator can take we also provided a summary of the Demand Control operating code, Demand Control decision and communication process, Demand Control instruction formats, data on the last occasions when it was utilised, data on historical Notification of Inadequate Supply Margin (NISMs) and an overall summary. The PTE also were interested in understanding the process by which DNOs disconnect consumers which unfortunately we were unable to provide as that is something each DNO will undertake (potentially using different approaches which best suit their particular network), not National Grid.*

e. *While all the above information is important, it has no effect on our capacity requirement recommendation as that is measured before any mitigating or* *emergency actions are taken. There are two practical reasons for this; firstly, these actions aren't firm and therefore can't be guaranteed and secondly, these are emergency actions and shouldn't be planned to be utilised otherwise they are no longer emergency actions. Note all ancillary service contracts we have are assumed to be utilised in the calculation to meet the Reliability Standard with these mitigating and emergency actions being on top of those.*"

132. **PTE comment on Previous Recommendation 12**:
    a. We accept that, given the definition of a Loss of Load Event, what happens after that may not appear to affect the target capacity to secure. However, as we discuss later, the fact that many of the mitigating actions have lower costs than the assumed Value of Lost Load may lead to indirect effects on the choice of target capacity in the Capacity Market auction.
    b. We are concerned that there is little visibility about the actions that DNOs may take, and hence on their likely impact and cost. If, as seems likely with increased intermittent generation and tight capacity margins, and with the advent of increasingly sophisticated smart meters and communications between large loads and system operators (either NGET or with the cooperation of DNOs' own control centres), there are cheaper ways of managing lost load, then it is important to reflect that learning in decisions on the capacity needed to deliver the Reliability Standard.

NEW RECOMMENDATION 16: National Grid should, in consultation with Ofgem, endeavour to collect information on how DNOs plan to respond to Demand Control orders to ensure security of supply. This may help to inform application of the current estimate for the value of lost load.

133. **Previous Recommendation 13**: Develop a Pan-European dispatch model with the functionality to simulate the **behaviour of interconnectors** in a variety of market coupled scenarios.
    a. **Progress (National Grid Response)**: "*To support our interconnector modelling for FES and EMR we commissioned Baringa to undertake analysis of annual and peak flows across interconnectors utilising their Plexos pan-European model with flows being determined predominantly by the relativity of generation*

short run marginal costs (SRMCs) in each country. This modelling was enhanced from that used last year by the inclusion of scarcity premia, number of historical years utilised and a larger number of simulations. More detail on this can be found in Chapter 4.

b. *For our 2017 analysis and to support our role in Integrated Transmission Planning & Regulation (ITPR) we have procured a pan-European market and network model from Pöyry which will enable us to run European demand and generation scenarios in a similar way to those run for GB with dispatch based on relative SRMCs.*"

134. **PTE Comment on Previous Recommendation 13**:

a. The PTE welcome the improvements that Baringa's modelling of peak flows provides in relation to the inclusion of scarcity pricing, the increased demand data history to 9 years correlated across Europe with wind generation and the increased number of model runs which we believe should significantly improve the reliability of the modelling work. We also note, however, that the European Commission is concerned at the lack of consistency in measuring reliability and generation adequacy across Europe.[12]

135. **Previous Recommendation 14**: Further work should be carried out on the methodologies to select a single **de-rating factor for each interconnected system**. And **Previous Recommendation 15**: in choosing these factors DECC should err on the high side. (Both recommendations taken together):

a. **Progress (National Grid Response)**: "*Our report provides advice to DECC on the range of potential de-rating factors that could be used for each interconnected country. This analysis is based on work from a range of consultants as well our own analysis of weather and the benefits from connected systems. However, due to a perceived conflict of interest with our Business Development subsidiary that owns and operates interconnectors it was determined to be inappropriate for us to recommend any de-rating factors for any individual existing or proposed interconnectors. With regard to the*

[12] See e.g. *Interim Report of the Sector Inquiry on Capacity Mechanisms* at http://ec.europa.eu/competition/sectors/energy/capacity_mechanism_report_en.pdf

ranges we provide for interconnected systems and countries we have taken on board these comments when developing the higher end of the range for this year's report.

b. *Consequently, DECC with the support of the PTE undertook the analysis to produce each interconnector de-rating factor last year, with input from us when requested. This means we are unable to comment on how these recommendations will be addressed this year but are happy to support DECC in their analysis."*

136. **PTE Comment on Previous Recommendation 14**:

a. We are impressed with the quality of analysis that Baringa has provided in assessing the appropriate de-rating factors, although we note that the actual operation of interconnectors in stress events will likely depend on the way in which the Intra Day and Balancing Markets operate, neither of which has yet been fully settled as far as interconnectors are concerned. We also note that if the interconnectors are to flow to GB in stress events, then the prices fed into whatever auction or other platform is developed to handle cross-border flows will need to reflect GB scarcity. We note that plans for the Integrated Single Electricity Market of the island of Ireland propose that the System Operator will introduce a floor price that will rise to the Value of Lost Load at the moment that customer disconnections are anticipated (although prices offered in stress events may be higher than this graduated floor price before disconnections). We remain unclear how simultaneous stress events at each end of interconnectors will be handled, while accepting that for the next few years such events may be quite rare.

137. **PTE Observations on Value of Lost Load**:

a. **Progress (National Grid Response)**: "*Concerns over the value of VoLL being utilised in the Least-Worst Regrets calculation not reflecting the lower cost of mitigating actions and therefore distorting the calculation resulting in a potential over procurement of capacity.*

b. *There are two aspects to consider around these concerns; firstly, the process by which VoLL was estimated and secondly, the wider context around how VoLL is used within the Reliability Standard.*

c. *We agree with the PTE that in reality the VoLL would start lower than the average figure used for the Least-Worst Regrets analysis of £17,000/MWh as mitigating actions are taken, e.g. voltage reduction, but would then progressively increase as further actions are taken before rises above £17,000/MWh as loads are disconnected. Consequently, when London Economics estimated the average VoLL they took account of the increasing cost of different components of VoLL at the level of customer disconnections. There is inherent uncertainty in setting the level of VoLL and it is dependent on the questions asked of consumers and whether the wider economic impacts are considered. The determination of VoLL is currently outside the scope of this analysis.*

d. *The other metric utilised within the LWR calculation is the Cost of New Entry (CONE) which is also based on an average figure when in reality it would also have a cost/supply curve. Consequently, adjustments in VoLL cannot be considered in isolation without considering CONE. As a development project we asked our academic consultants (Zachary, Wilson & Dent) to review the Least-Worst Regrets process and one of their conclusions was that the ratio of VoLL to CONE would need to remain consistent with that used when defining the Reliability Standard (i.e. ratio of close to 3 ((£47/kW/yr / £17,000/MWh). This means that if VoLL was reduced then CONE would also need to be reduced to maintain the same ratio otherwise the analysis would be basing its calculations on a different Reliability Standard.*

e. *In addition to enable the Least-Worst Regrets decision tool to run effectively we need a single value for both VoLL and CONE. To try and use cost/supply curves that vary these values would prove difficult to implement as it would make the calculation extremely complex but more importantly would have no impact on the recommended capacity to secure as the ratio of the two would always need to be 3.*

f. *DECC undertook some analysis in this area and concluded that any review of VoLL would need to align with the review of the Reliability Standard to be undertaken which will consider a more sophisticated representation of both VoLL and CONE.*"

138. **PTE Comment on National Grid’s comments on PTE Observations on Value of Lost Load**: Regarding point f, we are aware of, and impressed by, the analysis of Zachary and Wilson (2015). They show that in the case in which there is a range of relatively low-cost mitigating actions before disconnections this will translate into a lower effective Value of Lost Load. This in turn will require setting a lower net Cost of New Entry to maintain the Reliability Standard (at least, if this standard means actual losses of load, which is what the Value of Lost Load is supposed to reflect). We discuss the possible implications of this in paras 115- 116.

ANNEX 2 - Quality Assurance of ECR

139. When under taking any analysis National Grid looks to ensure that a robust Quality Assurance (QA) process has been implemented. National Grid have worked closely with DECC's Modelling Integrity team to ensure that the QA process closely aligned to DECC's in house QA process13. We have implemented the QA in a logical fashion which aligns to the project progression, so the elements of the project have a QA undertaken when that project "stage gate" (such as inputting data in to a model) is met. This approach allows any issues to be quickly identified and rectified.
140. The high level process and the points within the process where QA checks have been undertaken are shown in the following process diagram:

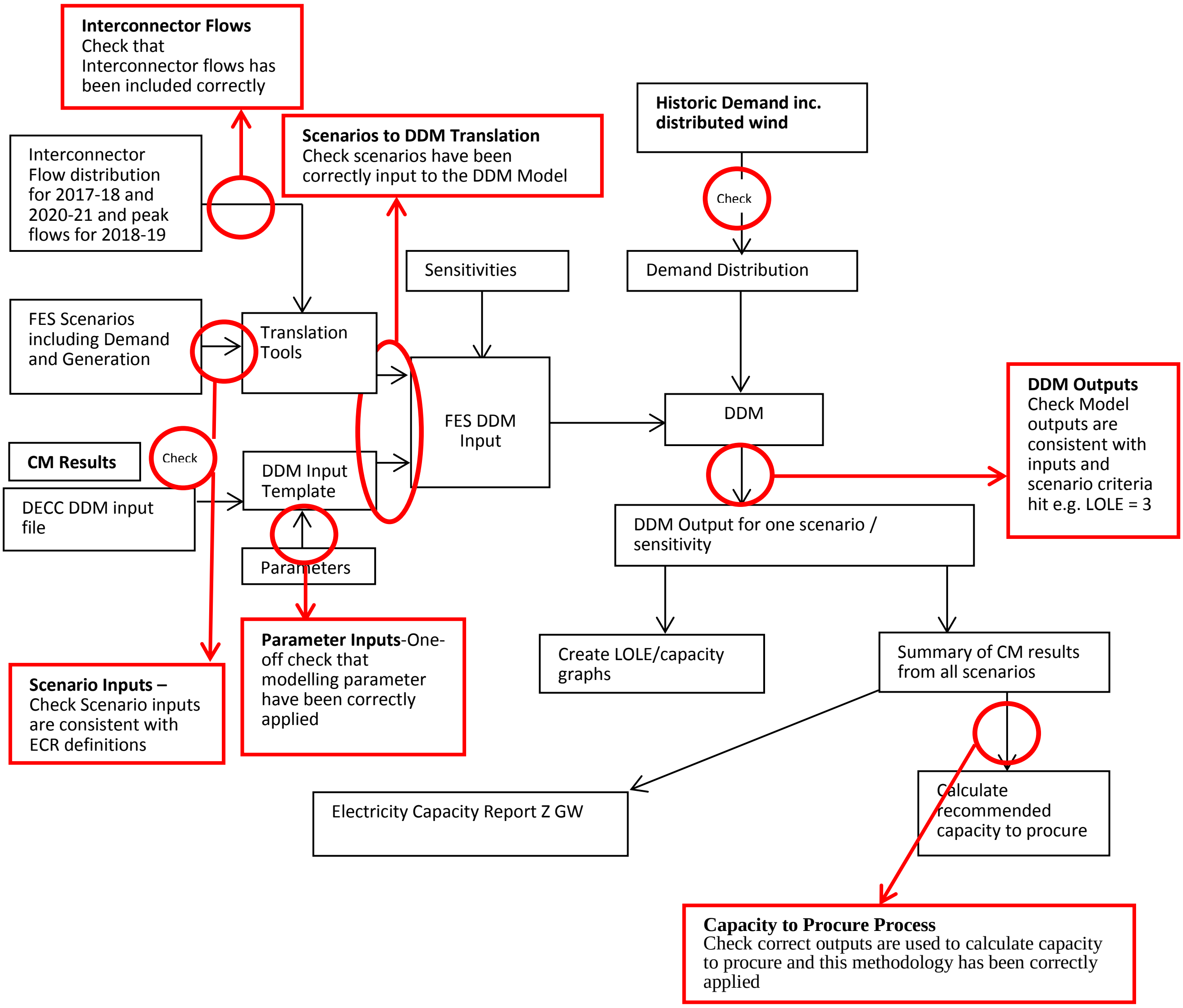
141. The QA checks (bordered in red) are centred on the points in the process where data is transferred from one model, or system, to another along with the model outputs. The QA is undertaken in this way as it is more straightforward to follow which QA step is being applied at which step in the process.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

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

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

142. Below is detailed QA process for each of these steps.

Figure: QA checks process diagram for each target year



Interconnector flows

143. Interconnector flows assumption/distribution have been discussed with DECC, PTE and Ofgem at various bilateral meetings. We have also consulted the results with the industry at various stakeholder events. For each scenario modelled interconnector flows and results are checked through QA checklist process.

Scenario Inputs

144. The FES process is driven by extensive stakeholder engagement[14], workshops and bilateral 1-2-1 meetings; this engagement leads to the creation of the scenarios. The constituent parts of the scenarios, for example electricity demand, are subject to internal challenge and review to ensure that they consistent and robust. Sign off is then required at senior manager level and formal sign off is then required form the SO Executive Committee. The assumption and outputs will be published in the annual FES document on July 11th 2016.
145. For the purposes of the ECR process a check is undertaken that the inputs are consistent with the requirements of the ECR process.

Parameter Inputs / CM Results/ Historical Demand inc. distributed wind

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

Scenarios to DDM Translation

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

DDM Outputs

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

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[14] http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/FES/Engagement/

QA Check List Process

149. Each run of the analysis, including inputs and outputs, is checked and documented internally by an analyst through a QA Check List process. A draft template of QA checklist is included as Appendix 1 of the document.

Capacity to Secure Process

150. Once all the runs have been completed the key results are used to determine the recommended capacity to secure using Least-Worst Regret tool. Again, these files have been shared with DECC to allow it to perform its own QA process.

DDM model

151. In addition to checks described in above figure, DDM model has been reviewed and had QA performed a number of times including:

- A peer review by Prof. Newbery and Prof. Ralph
- A review of the code by PwC
- Internal reviews by DECC

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

Process Overview and Governance

153. The process is overseen by the PTE and they will review and report on the overall process. Internally the process has governance under Director UK System Operator. Final sign-off of analysis, results and report is by the Executive Director, UK.

Glossary

CfD	Contract for Difference
CM	Capacity Mechanism
CONE	Cost of New Entry
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
EEU	expected energy unserved
EMR	Electricity Market Reform, as set out in the Energy Act 2014
IA	Impact Assessment
ICRP	Investment Cost-Related Pricing (for setting grid charges)
IFA	The interconnector from France to England (Angleterre)
LoLE	Loss of Load Expectation
LWR	Least-Worst Regrets
MS	Member State (of the EU)
PTE	Panel of Technical Experts
PV	(solar) photo-voltaic
RSP	Reserve Scarcity Pricing
SEM	Single Electricity Market of the island of Ireland
TA	Transitional Arrangements to help DSR to participate in the main Capacity Market
TEC	Transmission Entry Capacity – the amount on which a generator pays TNUoS
TNUoS	Transmission Network Use of System (of charges levied on Generators)
VoLL	Value of Lost Load