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Dear Steven,

**Re. Electricity Capacity Assessment 2014: Consultation on methodology**

I welcome the opportunity to comment on the methodology. First, I make some comments on security of supply indices. Then, I give my own answers to the questions posed in the consultation. Finally, I make some more general comments on additional aspects of security of supply and its quantification.

**Security of supply indices**

The assessment referred to in the consultation concerns the likelihood of there being insufficient generation available and operating to meet demand for electricity.

Loss of Load Expectation (LOLE) is defined in the report of CIGRE Working Group 38.03 on Power system analysis and techniques as follows[1]:

> The expected number of days in the year when the daily peak load exceeds the available [generation] capacity.

A similar definition is given in the report of CIGRE Task Force 38.03.11 though the report of that group[2] also notes that "alternatively, [Loss of Load Expectation] may be the average number of hours for which the load is expected to exceed the available capacity."

In addition, CIGRE Task Force 38.03.11 defines Loss of Load Probability (LOLP) as "the probability that the load will exceed the available generation". In contrast to the now rather old and, in my view, inadequate definitions of LOLE and LOLP[3], one thing that the consultation correctly emphasises is that a number of responses might be

[1] WG 38.03, *Power system reliability analysis application guide*, Technical Brochure 026, CIGRE, Paris, 1987.
[2] TF 38.03.11, *Methods and techniques for reliability assessment of interconnected systems*, Technical Brochure 129, CIGRE, Paris, 1998.
[3] The CIGRE Technical Committee now implicitly agrees that the standard power system reliability indices have been rendered outmoded by more recent power system developments, in particular on the demand side. This is shown by the commissioning of a new CIGRE Working Group, WG C1.27 on "Definition of reliability in light of new developments". One idea is to clearly distinguish between 'authorised' and 'unauthorised' interruptions to demand, the former being associated with demand side contracts such as National Grid's proposed 'demand side balancing reserve'.

made to insufficiency of generation relative to demand, each of which impact in consumers in different ways and only the last of which involves interruption of supply to any demand:

1. Voltage reduction (reducing reference points for voltage magnitudes on the distribution network such that voltages supplied to demand and power consumed will both be reduced).
2. Maximum generation (increasing generation output where possible above the normal continuous capability).
3. Emergency services from interconnectors (reducing export or increasing import, where possible).
4. Controlled disconnections.

What is referred to in the consultation as 'loss of load expectation' is described as the "probability of having to implement [any of] these [mitigation] actions." This particular meaning given to LOLE might be better described as the probability of voltage reduction being implemented. (Voltage reduction is the first of the above mitigation measures that would be applied; the effect depends on the voltage dependency of electric loads, something that is recognised to have changed over the years and should be newly quantified). A separate statistic might also be estimated to indicate the probability of demand disconnection to due to insufficiency of generation. Although the first mitigation measure – application of voltage reduction – is not something that should be carried out on a regular basis since it does impact on consumers, a difference in the value from the probability of demand disconnection may prove useful in communicating to policy makers and the public the nature of the risk. Both of these could reasonably be described as being analogous to standard textbook definitions of LOLE but with a more precise reflection of the practical measures taken by system operators. By using terms other than LOLE to describe both of these indices, any ambiguity about the relationship with established definitions of LOLE could be removed.

**The questions raised in the consultation**

**Question 1**: *Do you agree that the general methodology used for the 2013 report is still valid to analyse GB's generation adequacy in the next five winters from 2014/15 to 2018/19? If not, please explain why and make some specific suggestions for the methodology and their comparative advantages*.

It seems to me that there are two main reasons why any of the mitigation measures discussed above might be required:

1. Sufficient generation capacity exists (has connection rights and is operable) and is apparently 'available' but not enough power can be generated at the right time to meet all demand.
2. Insufficient generation capacity is available so that even if all available power were utilised, it would not be enough to meet all demand.

The first of the above is not a consequence of shortage of generation capacity but rather of uncertain events in the course of daily operation and policy regarding operating reserve such that 'available' generation cannot be utilised *at the right time*. Policy regarding operating reserve is set in the recognition that

a) circumstances change in the course of daily operation – demand might be higher than expected at some particular time, or generating units expected to be available are not, mainly due to forced outages, or wind speeds are not as expected at a particular time; and
b) power from additional or replacement generation takes a finite time to access, e.g. due to the time taken to warm fossil fuelled plant and ramp up its output.

It is my understanding that the National Electricity Transmission System Operator (NETSO) – National Grid – does *not* set its level of contingency and operating reserve such that it will *always* be sufficient to cover uncertainties in daily operation. This is because the cost of carrying sufficient reserve would be excessive whereas the policy presently adopted already gives a very low probability of voltage reduction being required. That the risk has indeed been low (and, with no change in policy and performance, will continue to be low) can be seen by reference to the historic number of voltage reduction events. However, early warnings of possible voltage reduction can be seen by 'notices of insufficient margin' (NISM), and notices of high risk of demand reduction' (HRDR) and 'demand control imminent' (DCI).

The generation capacity assessment methodology adopted by Ofgem implicitly assumes that operating reserve is always sufficient and is utilised perfectly. This includes the utilisation of pumped storage and is a consequence of treating each time interval as being independent of every other time interval (meaning that the links between time intervals that are critical to the adequate *scheduling* of reserve are neglected) and not building into the basic characteristics of each generator any additional unavailability due to timing issues. Such an approach very much simplifies the analysis. In light of (a) the very small number of historic voltage reductions (or other measures to mitigate the impact of shortage of generation) and (b) the main purpose of the assessment – which I understand to be to give a general indication of the impact of a particular level of generation capacity, not necessarily how it is utilised – my opinion is that the approach taken is adequate, at least for the next few years. However, after that when wind generation becomes a more significant part of the national portfolio, the NETSO's policy regarding operating reserve may need to change although the extent of change is likely to be somewhat mitigated by improvements in the accuracy of wind forecasting. Whether it can continue to be assumed that imperfect scheduling of reserve adds only a small additional level of risk of voltage reduction will depend on the future reserve policy, the type of generation that is available and how the policy is implemented. In the meantime, I would recommend that Ofgem monitors any work by National Grid on scheduling of reserve and any related academic work that happens to be ongoing.

**Question 2**: *Do you agree with using a qualitative approach to assess the impact of interconnector flows on LOLE and EEU in our Reference Scenario and sensitivities? If you disagree, please provide justification and suggestions for alternative approaches*.

In the 2013 capacity assessment methodology consultation, it was argued that the patterns of interconnector flows and their relationships with possible explanatory variables were too complex for a quantitative model to be developed that would be useful. Although my understanding is that clearer patterns of influence on interconnector flows are now starting to emerge, my judgment would be that the argument used last year is likely to still be valid.

The 2013 consultation argued in favour of a 'qualitative model' (complemented by sensitivity analyses)[4] but, in my view, did not explain sufficiently well what such a model would be like. It would be useful for its outputs to be described.

**Question 3**: *Do you agree with our proposed approach to capture the uncertainties of a potential relationship between wind availability and high-demand on the level of risk? Please justify and provide suggestions for alternative options and their comparative advantages*.

The consultation document states that "There is not yet sufficient data for wind generation during winter in GB to enable us to understand the relationship, if any, between wind availability and high demand." Given that a wind power synthesis based on reanalysis wind speeds is apparently being used elsewhere in the assessment methodology, this assertion seems strange to me. If the builders of the methodology believe that only observations of wind power output are valid to be used, why are they using a wind synthesis elsewhere? If they believe a wind power synthesis is valid, why can it not be used to assess the correlation between demand and wind power? It is true that there will be difficulties both on the wind power synthesis side and the demand modelling side. However, National Grid already uses a model that relates demand to weather conditions. Could this not be used with the reanalysis weather data already used in the wind power synthesis? (If nothing else, it is already well known that there is a diurnal dimension to wind speeds and also to demand for electricity).

**Question 4**: *Do you agree with the use of sensitivities to represent the main uncertainties facing the electricity security of supply outlook at the moment? If not, please provide specific reasons and alternatives*.

Yes.

[4] A 'qualitative model' was described in the 2013 methodology consultation as "a formal representation of the structure and interactions between the components of a system that helps to identify possible results (as opposed to precise results)."

**Question 5**: *Do you agree that our proposed sensitivities around interconnector flows, generation capacity, and peak demand capture the uncertainties that have the most significant impact on the level of risk? If not, what other sensitivities should we consider and why?*

I believe there could be greater clarity in respect of what is meant by peak demand sensitivities. As I see it, there are two main influences on what the annual peak demand will be in a particular year:

1. How electrical energy is being used, this being dependent on societal trends and economic activity.
2. What the weather is like in the particular peak demand half-hour.

One way of separating the two influences and to concentrate just on the former is to consider only an 'average cold spell' (ACS) demand, i.e. the demand that is exceed 50% of the time due to weather effects alone. Relationships between ACS demand and econometric indices can, in principle, be identified to allow forecasts to be made.

Quantification of ACS peak demand, along with generation capacity, is part of the scenarios development process in which it should be possible for stakeholders to have confidence. It does seem appropriate to me that dimensions of scenarios that are particularly subject to uncertainty should also be subject to sensitivity analysis. I agree that such dimensions include ACS peak demand, generation capacity and interconnector flows though the last two of these will be subject to two influences: the installed capacity and how that capacity is used at different times. (I discussed the utilisation of generation briefly under questions 1. See my answer to question 3 above for some discussion of how interconnector capacity might be used. For further discussion on scenarios, see my answer to question 6 below).

Identification of the ACS equivalent figure for a particular observed demand depends on a statistical model that relates demand to various weather indices, e.g. temperature and cloud cover. A similar statistical model could be used to assess the distribution of possible actual demands around a particular ACS figure. In Monte Carlo simulation, the weather-related level of demand is one of the variables that could be sampled (alongside forced outages of generation and the available wind generation) though care should be taken to ensure that correlations between variables are adequately captured in the sampling process. It is not clear to me if weather-related variation of demand is part of the current capacity assessment methodology or how much difference it would make to the quantified security of supply indices. However, even if it is not very significant now, one would expect its significance to grow in future if there is considerably more electric heating and if climate change leads to wider variations in weather. (In passing, it can be observed that one of the main societal impacts of unavailability of electric power is in respect of unavailability of electric heating. A comparison has sometimes been made between the LOLE or LOLP adopted in France as a reference to underpin generation capacity planning and a security of supply standard that might be adopted in Britain. However, it may also be observed that France currently has considerably higher dependency on electric heating than Britain).

One further sensitivity that I believe will be very important is the availability of generation. Some of my own 'quick and dirty' analyses suggest that LOLP or LOLE figures are highly sensitive to changes in the assumed availability of the main part of the generation portfolio. I assume that Ofgem's capacity assessments use availability figures provided by National Grid. In addition, I note that availability factors are published by National Grid in section 2.11 of the 2013 Electricity Ten Year Statement (ETYS) and one assumes that these will be the same as those given to Ofgem for use in the capacity assessment. However, the lack of explanation of the derivation of the factors in the ETYS is likely to lead readers to question the validity of the values quoted.

An additional issue that I have heard suggested could be important is the dependency of combined cycle gas turbines' maximum outputs on ambient temperatures. Comments from the industry on whether this is significant would be welcome.

**Question 6**: *Do you agree that the Reference Scenario and associated sensitivities provide a sufficient range of possibilities for the electricity security of supply outlook? Please provide suggestions for alternative options and their comparative advantages*.

Future scenarios – the generation and demand 'background' – clearly have a critical influence on security of supply, and it is my understanding that Ofgem is heavily dependent on National Grid for advice regarding future scenarios. In order that analyses based on particular scenarios, e.g. the 'Reference Scenario', can be regarded as credible, it is very important that information about any future scenarios that are used is made public. In respect of National Grid's "Future Energy Scenarios", good progress has been made in this regard in recent years. However, in my view, the production and publication of scenarios remain problematic, in many respects unavoidably so as a consequence of disaggregation of the electricity supply industry.

- As noted in National Grid's "Future Energy Scenarios" document, a great many uncertainties impact on generation development and demand for energy.
- Published detail in National Grid's scenarios down to the level of individual generation projects, while useful to independent analysts, might be seen as prejudicing individual projects and should therefore be treated with caution. However, totals, for example by generation type and region, are still important outputs.
- Although it might seem as if a single numerical optimisation in which the total cost of electrical energy, including the capital cost of new generation developments, is minimised over a given period of time, is the best way to construct credible, self-consistent scenarios given a set of input assumptions,
    - they can be very sensitive to the input assumptions due to the nature of a cost minimisation, and
    - they do not necessarily reflect the way in which investment actually happens where, for example, investors have different portfolio strategies and financing or planning constraints that are not easy to model, or investors deliberately hedge between different technologies rather than going exclusively for the technology that appears cheapest.

  Nonetheless, provided the input assumptions are stated clearly and the effects of sensitivity tests are shown, such models can be very useful to probe interactions and produce one or more scenarios on a rational and consistent basis. It would be useful to know if National Grid uses or would consider using such models, perhaps as a counterpoint to other methods.
- There will be lots of different opinions on real investment and demand effects that may be difficult to capture in a cost minimisation model. Thus, the extensive consultation process National Grid undertakes in the production of its "Future Energy Scenarios" document is welcome. However, the process by which consultation responses and 'key axioms' are turned into scenarios could be better explained, with particular attention to factors that are relatively amenable to numerical analysis such as availability of power from all classes of generation, the weather correction of demand and the relationships of annual energy demand and peak power demand with underlying economic conditions. Furthermore, wherever possible, the sources of data used should be cited or published.

**Question 7**: *Do you agree that the different demand projections presented in the report provide a sufficient range of possible demand outcomes? If not, please suggest alternatives and their comparative advantage*.

National Grid's models used to forecast ACS peak demand do not seem to be very accurate – if one reads back through past editions of the Seven Year Statement (SYS) and the ETYS and compares the forecast with the outturn, it rarely comes especially close. In particular years, e.g. in the period 2008-2009, this may be due to unforeseeable, or at least unforeseen, changes to the economy. However, my own contacts through CIGRE with power system planners in other parts of the industrialised world suggest that even planners who have hitherto been quite good at forecasting peak demand are now finding that their models do not work as well as they used to even when they take out economic uncertainty. For example, at least one utility in Australia effectively rewound the clock and plugged in data for a previous year plus what were subsequently observed as actual outcomes of economic variables, and still made a poor 'forecast' relative to what was observed.

In light of the above, I feel that the additional ACS peak demand sensitivities proposed by Ofgem are reasonable, though also note they might not be consistent with market drivers influencing generation development elsewhere in the scenarios that are used.

**Question 8**: *What sensitivities do you think would be most appropriate to include in our main summary graphs (e.g. Executive Summary), and why?*

In common with my answers to questions 5 and 7, I believe summary results could usefully highlight sensitivities to different assumptions on generation capacity, demand, interconnector flows and assumed generator availabilities. As discussed under question 1, I believe there would be value in quoting a probability of voltage reduction (or the expected number of half-hours in which voltage reduction is required) separately from the probability of demand disconnection (or the expected number of half-hours in which demand disconnection is implemented).

**Different dimensions of security of supply**

As noted above, my understanding of the purpose of Ofgem's capacity assessment is that it is to give a general indication of the impact of a particular level of generation capacity, and not to address whether it is the 'right' level of capacity, how it is delivered or how it is utilised. However, although not central to the purpose of the capacity assessment, there are a number of other aspects of security of supply in which industry stakeholders may be interested and which I take the opportunity to mention.

*Timescales*

In my answer above to question 1, I discussed the time dimension of an assessment of security of supply and the difference between enough generation being available and enough reserve being available at the right time in the course of daily operation. I mentioned above that some warnings of lack of reserve are given by the GBSO through the balancing mechanism – 'notices of insufficient margin' (NISM) and warnings of 'high risk of demand reduction' (HRDR) and 'demand control' being imminent (DCI). As a general indication of operational performance and a complement to National Grid's annual security of supply report to Ofgem, it may be useful for summaries of NISMs, HRDRs and DCIs to be given periodically along with explanations of what underlay them. Such information might also be useful in confirming some of the assumptions made in Ofgem's capacity assessment, in particular that voltage reduction and other emergency interventions only occur in winter months (which, in the case of Ofgem's capacity assessment, I understand to be regarded as October to March inclusive).

*Regional aspects*

Ofgem's capacity assessment is concerned only with whether there is enough generation to meet GB demand and not where it is. However, voltage reduction and other interventions by the NETSO may also be necessary if there is a regional shortage of available generation relative to demand in that region and the power that can be imported from a neighbouring region; these interventions would have a significant impact. One dimension of the transmission system design standard articulated in the Security and Quality of Supply Standard (SQSS) concerns such a possibility and the requirement that sufficient transmission system power transfer capability is provided such that the risk of regional emergency measures being required is not excessive. One of the purposes of the ETYS is to report transmission system capability. Even though the present and forecast 'security-driven' capability for most boundaries is more than adequate and, depending on the nature of the transmission limitation, an increase in import capability can be relatively straightforward and inexpensive to achieve, it seems to me that the 'security-driven' requirement could be more fully explained for all the main system boundaries to give stakeholders in all regions confidence that their interests are being safeguarded.

*Interactions with other systems*

Clearly, as well as forced outages, one cause of unavailability of generation is lack of fuel, e.g. coal or gas. The "Statutory Security of Supply Report 2013" produced jointly by DECC and Ofgem seemed generally relaxed about GB gas security of supply believing that the market had shown itself to be very capable of responding quickly to apparent shortages. Although there was scant discussion of interactions between the gas and electricity systems, with the electricity system being one of the main consumers of gas, the Report may be taken as meaning that electricity stakeholders need not be worried about gas shortages. However, even though that may be fair comment, I feel that there would be value in future in addressing gas and electricity system interactions, not least in respect of long periods of cold weather with high demand for heating and low wind speeds where CCGT generation might be relied on much more than normal for a period of some days.

Ofgem’s capacity assessment methodology consultation does discuss interconnectors and interactions with other markets. Although the gas system is not the subject of the capacity assessment, this is relevant to both gas and electricity. However, what Ofgem has proposed for its capacity assessment in the short term is, I believe, adequate

In the longer term, deeper consideration should perhaps be given within the electricity supply industry and by its stakeholders to European market interactions. This should include the possibility of a Europe-wide reserve market that ought to permit more efficient scheduling of reserve across the continent but may also provide greater confidence with respect to the availability of support from outside GB when there is a risk of voltage reduction being required in GB.

Yours sincerely,

Prof Keith Bell