SCOTTISHPOWER
CONSULTATION RESPONSE – CAPACITY ASSESSMENT

Introduction

ScottishPower is a major UK energy company with networks, generation and retail interests. It is part of the Iberdrola group, a major international utility and the world's leading renewables developer. Iberdrola is also a partner in the Moorside nuclear project. This response is on behalf of all Iberdrola's interests in the UK and references to "ScottishPower", "we" etc. should be read accordingly.

As the UK's leading wind power developer, we support the electricity market reform process and in particular the need for a market wide capacity mechanism. We therefore welcome Ofgem's planned capacity assessment work as an important input to any scheme that eventually becomes operational.

Executive Summary

We welcome the opportunity to provide input into the design of the system modelling that will inform a new capacity mechanism. Such a mechanism will become essential as older plant is decommissioned and we drive towards low carbon goals. Our main comments are in the four areas below.

- We broadly agree with the proposed modelling approach (our understanding of which we have summarised immediately below the executive summary). We believe the proposal to model demand net of wind for each half hour, based on historic wind speeds and modelled output of the existing portfolio and likely new builds, provides a robust solution to the intermittency issue. We also support the general approach to modelling of stochastic variables.

- Whilst this is not a matter for consultation, we would question whether the four year modelling horizon is sufficient. For some forms of capacity mechanisms, in particular those designed around auctions, a view of capacity adequacy beyond four years will be essential. Indeed future signals, given lead times within the industry, need to be examined further out if demands are going to be met.

- We believe that the scope of the modelling could be limited to the set of half hour periods or months with peak demand. Modelling outside these periods will provide little if any additional benefit in terms of LOLE or EEU accuracy. Focusing on peak periods avoids many of the complexities identified in the consultation, such as modelling of scheduled maintenance and the availability of LCPD/IED opted out plants, pumped storage, hydro and DSR.

- We question the need to model the effect of transmission boundary constraints, assuming the goal of modelling is to analyse capacity adequacy. Capacity shortfalls will inevitably occur during periods of low wind generation, and when wind generation is low, the Cheviot boundary is not envisaged to present a constraint. Omitting the constraint (at least until such time as it becomes material) will reduce model complexity without loss of accuracy.

Understanding of the proposed modelling approach

We summarise below our understanding of the proposed modelling approach, as this forms the basis of our answers.

Each half-hour will be assigned two probability distributions one for demand net of wind power, and one for available generation from technologies other than wind.

The first distribution (net demand) is the difference between gross demand and wind production. Gross demand will be based on historic demand for the relevant half hour period, adjusted for demand growth, and with data for different years combined to give a mean and standard deviation (paragraph 4.15). Wind production is derived from current and future build assumptions and the associated power output, given historical wind speed distributions for the time period in question (paragraph 4.21).

The second distribution (available generation) will be based on views of likely new builds, retirements, demand side response (DSR), interconnector flows as well as both forced and planned outages of plant. The way in which the probability distribution will be derived from the underlying statistics of forced outages, and how interconnector flows and the scheduling of planned outages will be modelled, have yet to be defined. (Whilst each half hour is being examined individually, the granularity of some of the input assumptions may be longer.)

Finally, the magnitude and frequency of capacity shortfalls will be determined by combining the two distributions in each half hour to give the probability distribution of the de-rated capacity margin, using either Montecarlo or convolution methods. The overall Loss of Load Expectation (LOLE) and Expected Energy Un-served (EEU) are then derived by summing over half hour periods. The modelling will examine two zones of the UK system independently and jointly.

Question 1: Do you agree that the de-rated capacity margin is a good indicator of future capacity adequacy?

The de-rated capacity margin is an important signal for market players and it is important that it is communicated in a consistent and easily understandable manner. The underlying methodology must be transparent and one that the market is comfortable with.

The approach that has been outlined for calculating the de-rated capacity appears to be sensible, and together with LOLE and EEU estimates should provide a good indicator of future capacity adequacy. The details of this methodology will have increasing importance in future as intermittent sources account for a growing proportion of total generation.

It may be helpful in scoping the model development for Ofgem to specify the required accuracy (‘error bars’) for the estimates of LOLE and EEU.

It is likely that differing de-rating factors will need to be used for different technologies and it may also appropriate to have bandings within these technologies depending on the age of the plant. Indeed there are instances where de-rating factors may need to be specific to particular plants. Such assumptions should be transparent as far as possible, subject to commercial confidentiality.

The proposed four year modelling horizon is at the discretion of the Secretary of State, so outside the scope of this consultation. However, we would question whether four years is sufficient. For some forms of Capacity Mechanisms, in particular those designed around auctions, a view of capacity adequacy over a longer time period will be essential. Indeed, in order to reward future value of security of supply, it may well be necessary to carry out auctions that span beyond a four year period[1]. In the case of new investment, the time horizon from concept to build completion is likely to be longer than four years; so six to seven years is therefore likely to be a better benchmark for the investment signal.

Question 2: Are there any measures of risk other than LOLE and EEU that we should report and what are their comparative advantages?

We agree that LOLE and EEU are both valid methods of communicating capacity adequacy and are not aware of any other measures of risk that would need to be calculated.

However, it may also be helpful if Ofgem or DECC were able to offer guidance as to what it considers to be acceptable values of LOLE and EEU. For example PJM's current target level for LOLE is one occurrence every ten years.

We support the proposed focus on capacity adequacy as opposed to short term flexibility. It is capacity adequacy – the ability to serve the system during, very cold, prolonged, anti-cyclonic weather conditions – that will be most relevant to the capacity mechanisms introduced through EMR. There will also be a need to model short term flexibility under future scenarios with increasing renewables penetration, but we support Ofgem's decision to separate the two needs

If the difficulties noted around the complexities of modelling half-hourly cross-correlations are not overcome (or Ofgem chooses to omit them for simplicity), there may be a need to report additional risk measures alongside the output from the capacity modelling. For example, periods of extended system tightness may exhaust the running duration of pumped storage, hydro or DSR. It may therefore be pertinent to track and report the level of utilisation of such resources, as unusually heavy use may act as an early warning of a need for additional capacity.

From the consultation document we understand Ofgem's thoughts around scenario work and stress tests are still nascent. Although the true loss of load risk may be dominated by extreme events (fuel shortages, transmission system failures), we do not believe there is sufficient data to measure the contribution from such events with any degree of accuracy. We therefore believe the LOLE should be calculated and reported in the absence of such events, as proposed in the consultation document.. We look forward to further industry

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[1] If auctions are limited to short to medium turn outlooks, and bidding is not policed, the outcome of overall revenues to plant is likely to remain cyclical and similar to those in an energy only market, such that security of supply objectives would not be achieved.

engagement on shaping these scenarios and any associated risk measures that may be deemed necessary.

Question 3: Are there any additional key input assumptions that we should consider in the modelling?

We believe that the proposal to model all half hours of the entire year has the potential to be too onerous, with many periods providing little benefit. We are aware of other markets that only analyse the period from December through March for planning purposes, and we believe there may be merit in limiting this assessment to peak periods. In the UK a period of November to March would appear most appropriate.

As discussed in response to Question 12 below, there may be a need for supplementary modelling of pumped storage, hydro and DSR, to adjust for potential cross-correlation between half hour periods resulting from the limited running duration of these technologies. If so, this will introduce a further set of input assumptions that will need to be considered.

Some thermal generation may be subject to limits on the maximum number of start ups or running hours in a year. Although these limits could in theory affect the capacity margin at times of system stress, it is likely that generators would keep in reserve sufficient start-ups or hours to exploit the high wholesale prices that would be expected at times of stress – and in any event, the prices associated with an incipient loss of load event might allow such limits to be over-ridden. Hence, we believe it may be possible to ignore such factors. However, this specific feature of the market should be continually monitored, to ensure no issues arise in practice.

Our views on other input assumptions are set out below in response to specific questions.

Question 4: Do you agree that the use of stochastics (probability distributions) to model short-term variation of key input variables is the best available method? Do you agree with the use of scenarios and stress tests for capturing long term uncertainty in key input variables?

Whilst we believe it is valid to estimate probability distributions for demand net of intermittent generation and available capacity, we have concerns that calculating this data for each half hour of the year is too complex and unnecessary. If this method is used, all assumptions used regarding outage rates etc must be clearly defined to allow the results of the model to be transparent(subject to confidentiality).

Yes, we agree with the use of scenarios and stress tests for capturing long term uncertainty in key input variables.

Question 5: Do you agree with the proposed approach to modelling wind availability?

We broadly agree with the methodology suggested in the consultation, in particular the proposal to convert wind speeds into wind generation availability by looking at the technical specifications of wind turbines. This is preferable to the alternative approach of looking at correlations between wind speed and historical wind farm output, given the rate of technology change. However, it would also be advisable to check that the two approaches give consistent results in respect of more recent technology.

As stated already, we feel that the complexity of modelling all half hours is unnecessary, and that peak periods are all that is required in examining the capacity margin (November-March). Whilst we support and see merits of the in the wind modelling methodology, a possible further simplification would be to heavily de-rate intermittent generation capacity on an incremental basis, and observe if a critical point is reached.

Question 6: Do you agree with the proposed use of NGET's existing data and assumptions, regarding, in particular, commissioning and decommissioning dates and embedded generation?

The TEC register is only starting point, and contains projects still subject to change, as such any assumptions regarding the available capacity should include an assessment of such risks. It should be noted that generators are only required to make any updates to their capacity one year and one day in advance, and the register may not therefore provide a completely accurate view more than a year ahead. For this reason, other information providers in the market that track specific project progress and offer a view on likely commission dates should also be engaged, and a combination of all available information used.

Question 7: Do you believe that Ofgem should require industry stakeholders to submit up-to-date data with regard to commissioning and decommissioning dates and embedded generation? Which industry process will ensure the confidentiality of information provided?

We are unclear of what additional value can be gained from generators providing information regarding dates. We believe it is you intention to model the uncertainties that will exist within each company. We therefore, do not believe it should be a requirement for generators to supply information regarding commissioning dates. As noted in the consultation, commercial output starting dates are often delayed. This risk should be treated in the same way as forced outages and the probability of the plant not being available on the commissioning date should be factored in. Similarly, scheduled decommissioning dates may be subject to extension, if economic conditions improve and there are no hard technical or legal limits.

As a result of these factors, we believe that these risks should be accounted for in the model, perhaps with additional stress tests performed on extreme circumstances. Indeed market participants have had to work and invest in security of supply on this basis for many years.

In addition, we believe that embedded generation assumptions should be laid out in as much detail as possible. As embedded generation grows as forecast, the running patterns and nature of the technologies becomes very important.

Question 8: What are your views on how best to model LCPD opt-out plants restricted running regimes?

Again, this will be very dependent on what model is used to investigate capacity adequacy. If the model takes the form described in the consultation, it may be necessary to run a separate model of LCPD opt-out plants to look at the expected economics of the plant over the entire period to decommissioning and the optimal usage profile. Although dispatch decisions will be dominated by wholesale prices and spreads, fixed costs would also have to be considered as it may be advantageous to reduce fixed costs by moving through the hours quicker than the spreads alone suggest.

If physical attributes are not being modelled, the best approximation would be to assume summer outages and then continuous running through the winter peak periods. A simpler methodology would again be to just model the peak periods. In this instance it is a reasonable hypothesis that opted out stations will run if not on a forced outage during periods where the system is under the most stress.

Question 9: Which of the two approaches for modelling electricity interconnection flows will provide the most realistic flows? If you favour the scenario based approach, what are your views on reasonable scenarios to run?

When assessing security of supply of the GB system we believe the best starting point is the first option: assume zero flows to and from mainland Europe, with electricity flowing to Ireland.

However this will need to be kept under review in the light of market developments. For example, the interaction between new capacity mechanisms and interconnector rules in Europe may lead to a change in view of the risks associated with interconnector flows.

Question 10: Under what conditions would users respond by curtailing their demand and how would you go about modelling this? Is it worth Ofgem requesting data from DNOs on self-interruption and interruptible contracts?

We believe it is very likely that curtailment will become a more integral and dependable part of the system, and one of the first areas where concrete activity will become evident is in the STOR market.

The uncertainties around the potential role of DSR are evident from industry reports (Demand Side Market Participation Report, Global Insight 2009). As participation becomes more frequent, it may be worthwhile for Ofgem to obtain data on the reliability of DSR in practice.

With regard to interruptible contracts, we note that some of these contracts are very much in their infancy and should not be relied on at the early stage. Where DNOs have interruptible contracts this will typically be in the form of connection agreements which only permit the DNO to interrupt supply for operational purposes (such as network faults) rather than for commercial purposes. We are unclear at this stage whether there would be any merit in Ofgem seeking data from DNOs.

Question 11: Is historical data of scheduled outages a good indicator of future patterns of scheduled maintenance timings?

Whilst we have some concerns that there may not be sufficient data points to derive an accurate statistical model of scheduled maintenance, we believe that if full use is made of the available data, this should be as good as is possible.

A decision will have to be made regarding the range of outage cycles that will be modelled, ie a major outage every X years. Modelling of infrequent scheduled outages can perhaps be omitted, as it is likely that any planned outage would be deferred by a generator if at all possible during times of stress where revenues are likely to increase. As a result of this most planned outages are likely to occur in summer periods, when net of wind demand is lower.

It is difficult to forecast how additional intermittency will affect future maintenance cycles of thermal plant of different technologies and age. Whilst system demands will lead to more stress due to intermittency, plants are also likely to have lower load factors.

Question 12: Will treating half-hour periods independently have significant effects on our estimates of the de-rated capacity margin and risk of supply shortfalls and how should the model take into account half-hourly cross-correlations?

Cross-correlation between half hour periods can arise in principle through various mechanisms:

a) pumped storage and hydro generation availability depending on water consumption in previous half hour periods;

b) DSR contribution depending on contribution in previous half hour periods;

c) the risk of forced outages depending on how much stress the unit has been subjected to in previous half hour periods.

In practice these effects are likely to be mitigated by the fact that (if the capacity margin is dangerously low) pumped storage (and potentially DSR) can be 'recharged' at off peak periods, eg pumping water back into the reservoir over night. Similarly, maintenance strategies will be designed to maximise the availability of thermal plants at times when wholesale prices are highest. Nevertheless, it cannot be ruled out that cross correlation will affect the risk assessment, or at least the shape of the associated probability distributions.

We would suggest that further investigation is undertaken to check the materiality of these effects, particularly for the periods of prolonged low wind and cold weather characteristic of winter anti-cyclonic conditions. Should they prove material, it would be necessary to conduct a separate statistical analysis of wind and demand data, to understand the statistics of critical weather and demand conditions and perhaps derive additional season-dependent adjustment factors. Separate modelling (for example Montecarlo simulations) might be required to calculate such an adjustment factor.

Question 13: Are there any boundaries other than Cheviot that may significantly affect the risk of supply shortfalls?

We do not believe that modelling the Cheviot boundary will provide any additional benefits in respect of the stated goal of modelling capacity adequacy. Within the foreseeable future, any capacity shortfalls will almost certainly occur during periods when wind generation is low, and when wind generation is low, this boundary is not envisaged to present a constraint. Unless this situation changes, modelling the constraint will introduce a complexity that does not provide any significant benefit.