To generators, distribution and transmission network operators, suppliers and other interested parties

Promoting choice and value for all gas and electricity customers

Direct Dial: 020 7901 7304
Email: Socrates.mokkas@ofgem.gov.uk

Date: 23 January 2012

Dear Colleagues,

Decision document – Electricity Capacity Assessment: Measuring and modelling the risk of supply shortfalls

This decision document sets out our views on measuring and modelling the risks of electricity supply shortfalls in Great Britain (GB). These modelling decisions take into account and reflect responses to our October 2011 consultation which closed on 7 December 2011.[1] We received 16 responses, 14 from industry participants, and two from consultancies and academics. One response was confidential. The full list of non-confidential responses is published on our website.

Overall, the model methodology was well received by industry and other stakeholders. A number of respondents were supportive of the need for a capacity assessment model and welcomed the opportunity to contribute to the methodological design.

We would like to take this opportunity to thank those who responded to the consultation as well as industry and academic stakeholders who participated in workshops over the last few months.

This document is structured as follows. Section 1 presents the background to the Electricity Capacity Assessment. Section 2 sets out the high level methodology and modelling principles. Section 3 outlines some of the key issues identified in the consultation responses and Ofgem's views. In the appendix, for each consultation question we summarise responses and set out our views.

1. Context and background

The December 2010 Energy Bill amended the Electricity Act 1989 (Electricity Act) to insert a new section which obliges Ofgem to provide the Secretary of State with a report assessing different electricity capacity margins and the risk to security of supply associated with each alternative. Ofgem's capacity assessment report is to be delivered to the Secretary of State by every September, starting in 2012.

[1] Electricity Capacity Assessment: Measuring and modelling the risk of supply shortfalls. Ref: 132/11. http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=180&refer=Markets/WhlMkts/CompandEff

Fulfilling the obligations set out in the new section of the Electricity Act will require the conduct of a one-off exercise to develop a model which assesses the security of supply risks associated with different electricity capacity margin levels. The Electricity Act allows for the modelling to be delegated to a transmission licence holder.

2. Methodology and modelling principles

Our October 12th document consulted on a proposed approach to measuring and modelling the security of electricity supply in GB.

In particular we proposed that the report for the Secretary of State would include an assessment of the de-rated capacity margin. The report would also show the risk of supply shortfalls associated with different levels of de-rated capacity margin. We proposed to measure this risk using two measures: Loss of Load Expectation (LOLE) and Expected Energy Unserved (EEU).

Our proposed modelling approach involves the development of a base case scenario primarily based on available data from National Grid Electricity Transmission (NGET). Recognising long term uncertainty in key inputs, a small set of alternative scenarios around the base case would also be presented. For the base case scenario and the alternative scenarios the model would produce a range of plausible forecasts of the de-rated capacity margin and the associated LOLEs and EEUs for the next four years. To capture short term variability in inputs, the model would use stochastics (probability distributions).

We also suggested that NGET is best placed to carry out the modelling that will inform Ofgem's annual report to the Secretary of State.

In general, the consultation responses received were supportive of the proposed approach. Therefore, our final view is to maintain the broad modelling principles outlined above. In particular, we have decided to report the de-rated capacity margin and the associated measures of LOLE and EEU through the year, but particularly at times of system stress (see questions 1 and 2).[2] In addition, we will consider reporting some added value metrics such as:

- equivalent firm capacity from wind and imports via the interconnectors required to achieve a given level of demand security;
- the variability of the de-rated capacity margin, LOLE and EEU; and
- frequency and duration of unserved events.[3]

Furthermore, we intend to capture the impact of uncertainty in interconnection flows and commissioning/decommissioning dates by using scenarios. We will also run a gas supply stress test (see questions 4 and 9).

With regard to short-term variability, we will use stochastics for variables such as electricity demand, wind generation and forced outages. As regards wind generation, we have decided to use wind speeds data coming from Nasa's MERRA reanalysis, and convert them into generation output (see question 5).

Industry participants made detailed suggestions on input assumptions and the modelling methodology. In the appendix we set out how we plan to take them into account and to

[2] This may involve reporting at a seasonal level.
[3] The method to estimate these metrics will be presented at the forthcoming industry workshop (see footnote 4).

The Office of Gas and Electricity Markets
9 Millbank London SW1P 3GE **Tel** 020 7901 7000 **Fax** 020 7901 7066 **www.ofgem.gov.uk**

reflect them in our modelling. Furthermore, industry respondents raised concerns not directly related to the modelling principles, to which we now turn.

3. Key issues identified in responses

There were a number of key issues raised in the consultation responses which were not directly linked to the 13 questions posed.

Transparency and industry engagement

For some aspects of the capacity assessment modelling, some degree of subjective judgement may be required such as with the design of the statistical estimation processes (e.g. treatment of wind), the choice of scenarios (e.g. flows through the interconnectors) and other assumptions (e.g. decommissioning dates). In light of this, six respondents stressed the need for transparency in both the model methodology and assumptions used. In addition, three respondents also declared a willingness to engage in the model build process.

Given the importance of the capacity assessment project we agree that transparency is essential. In addition, receiving industry's input during the construction of the model would be beneficial. Therefore, we will continue to follow a transparent process regarding our modelling approach. To that end, we are proposing to hold an industry workshop in conjunction with NGET.[4] The purpose of this workshop will be for NGET to present the methodology and to seek feedback from industry. The intended workshop would cover the methodology, a demonstration of the model, a summary of consultation response issues and a feedback session. If required an additional workshop could be organised to give stakeholders another opportunity to provide feedback.

Finally, soon after NGET has completed the modelling in May, it should be publishing a document with the detailed description of the methodology, the model and assumptions[5] used.

Validation of methodology, model, and governance

2012 Report to the Secretary of State

Four respondents raised concerns about the validation of the methodology and model and how Ofgem would ensure the quality of the outputs.

A number of measures have and will be put in place to seek to ensure this. Further to the informal industry workshop we ran in September, NGET and Ofgem will jointly organise the industry workshop to which we referred above.

Additionally, NGET commissioned Dr. Stan Zachary, Department of Actuarial Mathematics and Statistics of Heriot-Watt University to review the statistical techniques used in the methodology. NGET is also considering the use of other industry experts to review the model.

Ofgem will review and sign-off the model built by NGET. To do so, an internal panel of experts is reviewing the project, and will continue to do so at regular intervals. In addition, an academic panel, which consists of Prof. Goran Strbac, Imperial College London, Prof.

[4] We are expecting this workshop to be held the week commencing 20 February 2012 and will provide more details in due course.
[5] Some data may be commercially sensitive and would thus not be published.

The Office of Gas and Electricity Markets
9 Millbank London SW1P 3GE **Tel** 020 7901 7000 **Fax** 020 7901 7066 **www.ofgem.gov.uk**

Derek Bunn, London Business School, and Prof. Michael Grubb, University of Cambridge and Ofgem, is also continuously providing feedback at various stages of the methodology development.

Beyond 2012

DECC, in its *Planning our Electric Future: Technical Update*[6], states that "the decision on how much capacity to contract for will be taken by Government on an annual basis, drawing on expert advice from the System Operator and possibly other technical experts (including Ofgem)". Furthermore, DECC "is considering the role that any future [capacity assessment] reports could play in the process for deciding how much capacity to contract for."

Ofgem is conducting a robust process to specify the modelling approach for assessing the electricity capacity and the risk of supply shortfalls. We believe that our high level methodological principles are fit for purpose. Consequently, even if institutional arrangements change in future years, we do not currently anticipate that a change in the high level modelling principles will be needed. We believe that the modelling methodology applied for 2012 should be equally applicable for assessing capacity requirements in future years.

In addition, we believe there should be set governance rules relating to updates in the modelling and assumptions. However, the details on the governance rules will have to be determined at a later stage and in conjunction with DECC.

Flexibility

Four respondents raised the issue of capturing plant flexibility in the capacity assessment. In contrast, three respondents underlined the fact that the capacity assessment project relates to capacity adequacy[7] and not flexibility.

Ofgem acknowledges that having sufficient flexibility on the system is important. Flexibility can for instance be addressed by having appropriate imbalance signals and by the System Operator procuring short term flexibility services and operating reserve. We raised the issue of incentivising flexibility in our November 2011 electricity cash-out issues paper, and believe issues in this area could be addressed in any future Significant Code Reviews.

However, addressing plant flexibility is outside of the capacity assessment remit as specified in the Electricity Act. In addition, any capacity mechanism will be based on capacity *adequacy.* Moreover, it is also worth noting that the development of flexibility metrics is still in its infancy and is mostly limited to the academic sphere at this point in time. Consequently, the focus of the report for the Secretary of State and the modelling supporting the report should be capacity adequacy and not plant flexibility.

Four year timeline

Four respondents suggested that four years was not sufficiently forward looking for the capacity assessment given the amount of time required to build a new plant. In addition, two respondents suggested that the capacity assessment report should go out at least seven years.

[6] DECC, Planning our Electric Future: Technical Update, 15 December 2011. http://www.decc.gov.uk/en/content/cms/legislation/white_papers/emr_wp_2011/tech_update/tech_update.aspx
[7] Capacity adequacy of the power system is defined as the ability of generation to match demand at all times.

The Office of Gas and Electricity Markets
9 Millbank London SW1P 3GE **Tel** 020 7901 7000 **Fax** 020 7901 7066 **www.ofgem.gov.uk**

The Electricity Act specifies that the forecasting period for the report should be four calendar years. The Electricity Act does allow flexibility for the time horizon to be modified by the Secretary of State. Until such time, Ofgem's report will look at risks of shortfalls for four years ahead. However, the model is being developed in such a way that changes can be made if specified by the Secretary of State.

Should you wish to discuss any aspect of this document, please contact Socrates Mokkas (socrates.mokkas@ofgem.gov.uk).

Yours sincerely,

Andrew Wright,

Senior Partner, Markets, Ofgem

The Office of Gas and Electricity Markets
9 Millbank London SW1P 3GE **Tel** 020 7901 7000 **Fax** 020 7901 7066 **www.ofgem.gov.uk**

4. Appendix: Consultation questions and responses

Chapter 3 – Question 1: Do you agree that the de-rated capacity margin is a good indicator of future capacity adequacy?

We suggested reporting the de-rated capacity margin rather than the simple capacity margin in our report. We proposed to estimate the annual profile of the de-rated capacity margin in addition to the margin at peak demand.

There was general agreement that the de-rated capacity margin was a useful indicator of security of supply. Respondents also asked for more clarity on how the de-rated capacity margin will be calculated. Two respondents suggested reporting seasonal de-rated capacity margins (ie four per year). One respondent suggested that the de-rated capacity, being a mean, could be misleading in conveying security of supply risk and proposed including information on distributions of capacity margins.

Reflecting respondents' views, we will be reporting the de-rated capacity margin through the year focusing on times of system stress.[8] We will also consider presenting information on the distribution of the de-rated capacity margin so as to show the impact of short-term uncertainty on the de-rated capacity margin.

Chapter 3 – Question 2: Are there any measures of risk other than LOLE and EEU that we should report and what are their comparative advantages?

We proposed the use of the Loss of Load Expectation (LOLE) and Expected Energy Unserved (EEU) to assess the risk of supply shortfalls in the GB electricity sector. LOLE is the probability of the capacity margin being negative (ie demand being higher than generation capacity in at least one period during the year). EEU is a statistical measure of the expected volume of firm demand that cannot be met over a year because generation is lower than required.

There was general support for LOLE and EEU as effective measures of electricity security of supply risk. Three respondents also suggested additional measures (eg frequency and duration of unserved events) that they believe should be added to the modelling. Four respondents raised the point that flexibility as well capacity adequacy should be captured in responding to this question. As with the de-rated capacity margin calculation, the need for transparency was a common theme.

We have discussed the issues of flexibility and transparency in the main section of the decision document. Having carefully considered respondents' views, we maintain our intention to report LOLE and EEU as the main risk metrics in our final report as both measures are internationally accepted criteria for assessing system adequacy.[9] We are going to report LOLE and EEU for the calendar years and at times of system stress separately.

We are also considering looking at additional metrics, ie:

[8] This may involve reporting at a seasonal level, ie at peak demand for each of the seasons.
[9] One respondent argued that voltage reduction incidences should be included when calculating the risk metrics. We agree that when calculating LOLE and EEU the model should include actions that the system operators may take for security of supply purposes (eg voltage reduction, disconnections).

The Office of Gas and Electricity Markets
9 Millbank London SW1P 3GE **Tel** 020 7901 7000 **Fax** 020 7901 7066 **www.ofgem.gov.uk**

- equivalent firm capacity from wind and imports via the interconnectors required to achieve a given level of demand security;
- the variability of the de-rated capacity margin, LOLE and EEU; and
- frequency and duration of unserved events.

.

Chapter 4 – Question 3: Are there any additional key input assumptions that we should consider in the modelling?

In general respondents believed that the key input assumptions had been captured. Four respondents suggested that weather rather than just wind speeds should be simulated in order to capture changing consumer responses to temperature as a result of energy efficiency, and the variation in thermal plant output at different temperatures. Two respondents stressed the importance of considering gas supply, although most would be content to include it as a stress test rather than an additional stochastic variable. One respondent suggested that embedded solar should be included, whereas another said it could be ignored for now. Two respondents believed that the Value of Lost Load (VoLL) should be included as a variable. Finally, various other suggestions were made regarding among others, the inclusion of electricity storage, emissions limits and biomass availability in the model.

We agree that including a temperature variable in the model would allow us to capture changes in demand for electricity more explicitly. However, the model will capture the effects of temperature through the inclusion of the distribution of electricity demand. We also plan to take into consideration the effect of improved energy efficiency as per NGET UK Future Energy Scenarios.[10]

The availability of gas supply, as discussed in the consultation document, has important implications for the electricity system. We believe that the stress test of gas availability will be a key stress test in our final report.

With regard to VoLL and the analysis of the costs of energy unserved events, we remain of the view that they are beyond the scope of this analysis. The objective of the capacity assessment report to the Secretary of State is to assess the risks of supply shortfall. We believe that the remit stops short of assessing what the costs might be in case of supply shortfalls, or how best to address these risks.

Energy storage capacity will be included under the generation portfolio.[11] With regards to the other suggestions for inclusion in the model (eg biomass availability, embedded solar, emissions limits etc), we currently believe that to include these elements explicitly in the modelling would add significant complexity without the equivalent improvements in model accuracy. Should they become more significant in the coming years, we would look to include them.

[10] NGET, UK Future Energy Scenarios, November 2011. http://www.nationalgrid.com/NR/rdonlyres/86C815F5-0EAD-46B5-A580-A0A516562B3E/50819/10312_1_NG_Futureenergyscenarios_WEB1.pdf
[11] In particular, we will consider the charging and pumping aspects of pumped hydro storage. The details of how this will be done are still to be developed.

The Office of Gas and Electricity Markets
9 Millbank London SW1P 3GE **Tel** 020 7901 7000 **Fax** 020 7901 7066 **www.ofgem.gov.uk**

Chapter 4 – 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?

We suggested using stochastics for input variables which are characterised by short term variation (eg wind, demand, generation availability) and to use scenarios and stress tests to assess the impact of variables which exhibit long term uncertainty (eg interconnection flows).

Most respondents seemed comfortable with the proposed split of stochastics, scenarios and stress tests. One respondent suggested that only scenarios and stress tests should be used and one respondent suggested that only stochastics should be used as they believed scenarios were not sophisticated enough. The range of stress tests and scenarios favoured by respondents was wide.

We favour the combination of stochastics, scenarios and stress tests to model different types of input variable uncertainties. We intend to use stochastics for measuring uncertainty in wind output, short term demand variability, and forced outages.

With regards to scenarios and stress tests, we can understand the interest in having a wide range of options presented. However, we believe it is necessary to focus on a relatively small number of options which are applied consistently in each capacity assessment annual report. We intend to use scenarios for:

- interconnection flows;[12]
- commissioning/decommissioning dates; and
- a gas supply stress test.

How these scenarios are presented in the final report will depend on their effect on the results. As some of these variables will affect the de-rated capacity margin in a similar way we may consider combining some of these scenarios into downward or upward scenarios. Furthermore, we will be running several other sensitivity tests with regard to variables such as generation reliability, maintenance outages, demand growth, etc. Should any of those other aspects of the modelling have a significant impact on margins we will also report them.

Chapter 4 – Question 5: Do you agree with the proposed approach to modelling wind availability?

Our methodology is based on historic sampling of wind speeds. In our consultation, we suggested two options to convert wind speeds to wind availability:

- Option 1: look at the correlation of wind speeds and wind generation availability based on data from existing wind farms.
- Option 2: convert wind speeds to wind generation availability by looking at the technical specifications of wind turbines.

We were minded to use the second option given that wind technology has developed significantly in recent years. Once the data has been converted to wind availability

[12] We are minded to include 4 different scenarios for interconnection, ie full import/export (± 3GW) and half capacity import/export (± 1.5GW) from/to Europe.

The Office of Gas and Electricity Markets
9 Millbank London SW1P 3GE **Tel** 020 7901 7000 **Fax** 020 7901 7066 **www.ofgem.gov.uk**

distributions, these would be matched to the demand data from the same period. The statistical method used to capture geographic wind correlations would be determined once statistical analysis of relevant data had been undertaken.

There was a range of different views regarding the best approach to modelling wind. Some advocated simulating weather rather than just wind (four respondents). Two respondents favoured option 1 while six respondents favoured converting wind speeds to wind generation availability using the technical specifications of turbines. Four respondents recommended using a hybrid approach consisting of both options.

We are currently planning to extract data from NASA's MERRA reanalysis. The MERRA dataset uses physical atmospheric models to reconstruct physical atmospheric conditions based on available measurements from met stations. The use of this dataset has two main advantages. First, we can extract data for any location required. Second, as it is based on a publicly available dataset it will allow us to be more transparent.

The distribution of available wind output would then be based on the full wind resource dataset. We will also look at a representative subset of data at times of high demand. This is to capture the relationship of demand and wind generation at times that contribute more to the risk of supply shortfalls.

Finally, as suggested by respondents, we are minded to use a hybrid between options 1 and 2 in order to translate wind speeds into wind generation. In particular, we will primarily use option 2, but at the same time check for the validity of its predictions by using historical correlation of wind speeds and wind generation at existing sites. Embedded wind generation will be analysed in a similar fashion.

The exact statistical methodology applied to the data will be pinned down once the dataset has been put together. NGET will present the details of the methodology at the proposed industry workshop (see Section 3 for details).

Chapter 4 - 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?

We proposed to use NGET's existing methodology and assumptions for:

- Demand growth
- Non-wind embedded generation
- New generation
- Decommissioning and retirement dates

We suggested using informed decisions to make any changes to the National Electricity Transmission System (NETS) Seven Year Statement (SYS) data relating to commissioning dates. We also suggested that the Transmission Entry Capacity (TEC) register would be a good guide for existing plants' operational maximum export limit but proposed to reduce the TEC register values to reflect maximum historical real time availabilities for these plants.

There were some divergent views on the reliability of the TEC and NETS SYS for the purposes of forecasting capacity, although a general view that they would be a reasonable starting point was expressed. Two respondents expressed concerns about using informed

The Office of Gas and Electricity Markets
9 Millbank London SW1P 3GE **Tel** 020 7901 7000 **Fax** 020 7901 7066 **www.ofgem.gov.uk**

decisions to deviate from these sources. One respondent argued that the capacity assessment should only look at transmission connected capacity, given the lack of information on embedded capacity. However, six respondents argued that the DNOs should be obliged to provide this information through a licence condition.

We believe that using NGET's existing methodology and assumptions for the above aspects of the model increases transparency. We had initially proposed to use the scenarios and assumptions in NETS SYS. However, since our consultation was published, NGET has issued a more recent and up-to-date set of scenarios and assumptions in the "UK Future Energy Scenarios" document. We now plan on using these scenarios and assumptions which have been consulted on extensively with industry and stakeholders. We believe that these are a good starting point for the analysis.

The use of "informed decisions" to alter these assumptions or databases will only occur if new information has become available since the database was constructed. For instance, if it is officially announced that a plant will be fully converted to biomass or that a new build generation plant is experiencing delays in construction, this information will be added to the database so that the most relevant and up-to-date information is being used for the capacity assessment. Any such changes to the UK Future Energy Scenarios assumptions will be clearly stated in the final report.

With regards to embedded generation, wind embedded generation capacity will be treated similarly to transmission connected generation capacity. With regards to non-wind embedded generation due to lack of data at non-peak times, it will have to be taken into account on the demand side of the model. That is, demand used for the model's calculations will be net of non-wind embedded generation. In the future, we will look into what industry processes (e.g. licence conditions) should be initiated in order to improve the quality of the embedded generation data.

Chapter 4 – 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 sought views on requesting information from generators on likely commissioning and decommissioning dates as well as achievable output levels for mothballed plants. We also asked industry whether such information would be of value and how to ensure confidential information is not made available to the market.

There were divergent views on this issue. Some argued that there was considerable uncertainty on the timing of plant closures, and decisions can be made at quite short notice, which means that confidential information is not necessarily more reliable. Some respondents felt that as commercial considerations could change, they should not be held to information provided in their confidential submissions. However, one respondent suggested that there should be penalties for providing inaccurate information. Four respondents suggested that the capacity assessment should only be based on information freely available to the market.

Given the responses we believe that requesting data from industry stakeholders on a confidential basis would not guarantee any better accuracy as decisions can change rapidly in such a commercial sphere. Consequently, we do not intend to request additional

The Office of Gas and Electricity Markets
9 Millbank London SW1P 3GE **Tel** 020 7901 7000 **Fax** 020 7901 7066 **www.ofgem.gov.uk**

confidential information from industry stakeholders, but will continue to involve industry informally through workshops.

Chapter 4 – Question 8: What are your views on how best to model LCPD opted-out plants' restricted running regimes?

We recognised the importance of incorporating LCPD opted-out plants in the modelling in a different manner to conventional generation. We sought views on how best to model available generation going forward of plants that have opted-out of the LCPD.

Seven respondents suggested ways of included LCPD opted-out plants in the modelling. Three respondents argued that economic considerations should be explicitly modelled. Of the non-economic based approaches, the most favoured was an extrapolation of historic running hours (four respondents). One respondent made the valid point that with the introduction of Carbon Price Support in 2013, this may encourage coal plant to use up their hours earlier. One respondent noted different historic availabilities for opted-in and opted-out plant.

Since the methodology excludes price modelling, including LCPD opted-out plants running regimes based on economic considerations would represent a significantly more complex and less transparent approach. Our favoured approach is an extrapolation of historic running hours. We plan to include LCPD opted-out plants in the model based on their historical patterns of use and their remaining operating hours. As part of the scenarios regarding decommissioning dates (see Question 4) we will also investigate the impact of early or late closures by LCPD opted-out plants (in case they use up their remaining operating hours faster than expected).

Chapter 4 – 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?

We proposed two options for modelling interconnection flows:

- Option 1: Use NETS SYS interconnection assumption flows[13] for the base case scenario and additional scenarios could be run regarding other flows.
- Option 2: Build a specific model for the interconnection flows based on prices. This would entail modelling GB and interconnected countries' electricity systems to come up with prevailing electricity prices and interconnector flows.

Eight respondents favoured option 1 and three respondents favoured option 2. A number of respondents noted that to model interconnectors properly would require full analysis of the surrounding markets. This would be too complex and could diminish the transparency of the capacity assessment. Others suggested that the scenario approach assumed in the SYS would be appropriate and suggested scenarios that could be run (such as full import and full export to the Continent).

Interconnection flows depend on several drivers such as electricity prices in GB and in Continental Europe, contractual arrangements, etc. Given the high degree of uncertainty regarding the drivers, the complexity of modelling the drivers, and in the interest of

[13] These assumptions match the ones for interconnection flows in NGET's "UK Future Energy Scenarios" document.

The Office of Gas and Electricity Markets
9 Millbank London SW1P 3GE **Tel** 020 7901 7000 **Fax** 020 7901 7066 **www.ofgem.gov.uk**

transparency, we have decided to favour option 1. The Gone Green base case assumes that GB fully exports to Ireland and neither imports nor exports to France and the Netherlands. We are also minded to include 4 different scenarios for interconnection, ie full import/export (± 3GW) and half capacity import/export (± 1.5GW) from/to Europe.

Chapter 4 – 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?

In principle we would like to include Demand Side Response (DSR) in the model. Due to a lack of data and its currently insignificant role in the market, forecasting future behaviour will be difficult. We sought views from stakeholders on how to model DSR and whether it is worth Ofgem requesting additional data from DNOs on DSR.

Most respondents highlighted the difficulty in estimating volumes of DSR. There was a general view that DNOs would not be best placed to provide this information. Nine respondents noted the impact of smart metering, time of use tariffs, and other technology changes, on the availability of demand side response in the future. Three respondents suggested assumptions on demand side response should be derived via industry consultation, although it is not clear what form that would take. One respondent did not think DSR would be worth modelling.

We remain of the view that DSR should be included in the model as it is likely to have a more significant role in maintaining system adequacy in the future. We intend to use data currently held by NGET on DSR for the first report,[14] while acknowledging that this data is limited and only accurate around peak demand periods. Ofgem will also look into ways to improve data provision with regard to DSR for future reports.

Chapter 4 – Question 11: Is historical data of scheduled outages a good indicator of future patterns of scheduled maintenance timings?

We proposed two options to model maintenance:

- Option 1: Build a model that optimises maintenance outages throughout the year based on electricity prices.
- Option 2: Use historical data about maintenance outages to arrive at a statistical distribution of the available capacity.

Views on this issue were divided amongst respondents with six saying that historical patterns should be sufficient and with four suggesting optimising maintenance outages. Six respondents emphasised that maintenance patterns are likely to change with the changing capacity mix. Some respondents suggested modelling forward prices to estimate maintenance planning. Another option would be to optimise maintenance so as to minimise EEU. This would avoid the need to model prices explicitly but would make the methodology more complex and may lead to underestimation of EEU and LOLE by introducing perfect foresight.

[14] Current estimates of DSR from NGET include triad avoidance (approximately 500MW) and SO contracts (approximately 700-750MW for the current season).

The Office of Gas and Electricity Markets
9 Millbank London SW1P 3GE **Tel** 020 7901 7000 **Fax** 020 7901 7066 **www.ofgem.gov.uk**

Although both proposed options are valid, the option 2 would be fit for purpose in the next few years. We will assume that no plant plans to be unavailable at the time of system stress and consequently that maintenance patterns will follow their historical patterns of occurrence, ie during the extended summer period. This assumption and methodology will be kept under review and the methodology enhanced if experience demonstrates that companies are changing their maintenance strategies.

Chapter 4 – Question 12: Will treating half-hour periods independently have significant effects on our estimates of the de-rated capacity margin and risks of supply shortfalls and how should the model take into account half-hourly cross-correlations?

The suggested modelling approach treats half-hourly periods independently from each other. We appreciate that this does not always hold true and sought views as to whether the assumption of independence would have significant effects on our results.

A number of respondents expressed concerns about treating each half-hour independently. Three respondents suggested that full time series modelling is required. In particular, two respondents mentioned the need for time series modelling in relation to system flexibility issues and three with regards to accurately capturing electricity storage and DSR in the framework. On the other hand, two respondents expressed a view that there is currently too much uncertainty in the frequency and distribution of events to make full time series modelling meaningful.

If the capacity assessment report was to address the issue of capacity flexibility explicitly, then we appreciate that modelling cross-correlations of half-hourly periods would have been essential.

It is our view that pumped hydro storage plants are likely to run daily business cycles in order to take advantage of the within day variation in demand and prices. That is, they dispatch during the day when demand is high and pump overnight when demand is low in order to start the next day with similar levels of water stocks. That means that different days can in approximation be treated independently as levels of water stocks will be similar. In addition, we can also assume that energy storage will be available for the high demand periods of the day.

We will treat DSR as demand reduction during the high demand periods as per question 10. However, we believe that currently it is not significant enough to merit modelling of half-hour cross correlations.

In light of the above we believe that modelling half-hourly correlations is not essential.

Chapter 4 - Question 13: Are there any boundaries other than Cheviot that may significantly affect the risk of supply shortfalls?

Currently there are a number of boundaries where constraints can occur even in the absence of transmission outages. We proposed that in a first instance a two region model be developed: with one region being England and Wales and the other Scotland, ie taking into account the Cheviot boundary.

The Office of Gas and Electricity Markets
9 Millbank London SW1P 3GE **Tel** 020 7901 7000 **Fax** 020 7901 7066 **www.ofgem.gov.uk**

Five respondents deferred to the transmission owners to respond to this question. One respondent proposed other boundaries which they believe should be included in the modelling (eg B9 Midlands South, B14 London, B15 Thames Estuary), one respondent signalled other boundaries that might become important in future years (eg South West England) and one respondent indicated that a regional model was not necessary.

For the first year of the report we have decided to build a two region model taking into account the Cheviot (B6) boundary constraint. This boundary is essential to model as it is responsible for a large part of the transmission constraints in GB.[15] We acknowledge that over time other boundaries may become important for assessing the risk of supply shortfalls. The decision to add additional boundaries in future reports will be based on information about how significant their impact is on the volume of constraints, potential derogations associated with new connections, the background generation capacity and demand in the adjacent areas, etc.

[15] According to NGET the boundary accounts for two thirds of all constraint payments.

The Office of Gas and Electricity Markets
9 Millbank London SW1P 3GE **Tel** 020 7901 7000 **Fax** 020 7901 7066 **www.ofgem.gov.uk**