Promoting choice and value
for all gas and electricity customers

Electricity Capacity Assessment 2013: consultation on methodology

Consultation

Reference:	154/12	**Contact:**	Patricia Ochoa, Christos Kolokathis
Publication date:	23 November 2012	**Team:**	Energy Market Research & Economics
Response deadline:	21 December 2012	**Tel:**	020 7901 7153 020 7901 3156
		Email:	patricia.ochoa@ofgem.gov.uk christos.kolokathis@ofgem.gov.uk

Overview:

The Electricity Act 1989 (as amended by the Energy Act 2011) requires Ofgem to provide the Secretary of State with an Electricity Capacity Assessment report by every September. The first report was submitted in August 2012. The next report is due by 1st September 2013.

A model was developed by Ofgem and National Grid to support the analysis in the 2012 Electricity Capacity Assessment report. The methodology used for this analysis was consulted upon with industry, and was validated by academics and consultants.

The purpose of this consultation is to get views on the validity of the general approach for assessing the risks to electricity security of supply for the 2013 Electricity Capacity Assessment report. We are also consulting on proposed amendments to specific aspects of the methodology.

Context

Ofgem's[1] principal objective is to protect the interests of existing and future consumers. The interests of consumers are their interests taken as a whole, including their interests in the reduction of greenhouse gases and in the security of the supply of electricity to them.

In this context, the Energy Act 2011 amended the Electricity Act 1989 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 Electricity Capacity Assessment report has to be delivered to the Secretary of State by every September. The report is intended to inform decisions on the Electricity Market Reform and in particular the Capacity Market.

Fulfilling the obligation set out in the Electricity Act required a one-off exercise to develop a model which assesses the risks to electricity security of supply. This model was developed in 2012 and our proposal is to update this model to fulfil the Authority's obligation for annual reporting.

The Electricity Act allows for the modelling to be delegated to a transmission licence holder and last year we delegated the construction of the model to National Grid Electricity Transmission plc.

The purpose of this consultation is to get views on the validity of the general approach for assessing the risks to electricity security of supply for the 2013 Electricity Capacity Assessment report. We are also consulting on proposed amendments to specific aspects of the methodology.

Associated documents

- 2012 Electricity Capacity Assessment Report:

  http://www.ofgem.gov.uk/Markets/WhlMkts/monitoring-energy-security/elec-capacity-assessment/Pages/index.aspx

- Department of Energy and Climate Change, *Electricity Market Reform White Paper 2011* "Planning our Electric Future: A White Paper for Secure, Affordable, and Low-Carbon Electricity".:

  http://www.decc.gov.uk/assets/decc/11/policy-legislation/EMR/2176-emr-white-paper.pdf

[1] In this document the Gas and Electricity Markets Authority is referred to as "the Authority" or as "Ofgem".

Contents

Executive Summary

The 2012 Electricity Capacity Assessment model was designed by Ofgem and National Grid and developed by National Grid in close collaboration with Ofgem. DECC provided comments during the process. The methodology was consulted upon with industry and academics. It was also validated by a panel of academic advisors and LCP Consulting.

We believe the general methodology used last year remains fit for purpose and valid for the period of analysis the 2013 report will cover (i.e. five winters from 2013/14 to 2017/18).

Purpose of this consultation

The purpose of this consultation is to get views on the general approach for assessing the risks to electricity security of supply for the 2013 Electricity Capacity Assessment report. We are also seeking opinions on the following specific aspects of the methodology:

- The approach to assess the impact of interconnector flows on security of supply at periods of high demand and more specifically on the risk metrics: LOLE, EEU and the frequency and duration of expected outages:

  We are minded to use a similar approach to the one used in 2012 with further analysis of the security of supply outlook in GB and its interconnected countries and the likelihood of having concurrent periods where the risk of available supply not meeting demand in each country is high. This analysis will help us to understand the potential and likely direction of interconnector flows.

- The availability of data and information to analyse the potential impact of Demand Side Response (DSR) on electricity security of supply in the next five winters:

  The lack of reliable data sources is the main difficulty to estimate the evolution of DSR in the coming future. We are looking for suggestions on appropriate data that may be used for our analysis.

- The approach to the estimation and the sensitivity analysis of available wind power at times of high demand:

  Given that there is insufficient data for direct estimation of a relationship, if any, between wind availability and high demand, we are minded to maintain the assumption of no relationship between these variables. We propose to analyse this issue further by using different data sources and carry out additional sensitivity analysis.

We welcome views on modelling and any specific data that our approach may require. A decision document describing the methodology to be implemented, taking into account the responses to this consultation will be published in January 2013.

1. Introduction

1.1. The Electricity Act 1989[2] obliges Ofgem to provide the Secretary of State with an Electricity Capacity Assessment report by 1st September every year. The 2012 report was submitted to DECC in August 2012[3]. The report sets out our assessment of the risks to security of supply over the next five winters.

1.2. The 2012 Electricity Capacity Assessment model used for this analysis was designed by Ofgem and National Grid and developed by National Grid [4] in close collaboration with Ofgem[5]. The methodology was consulted upon with industry and academics. It was also validated by a panel of academic advisors[6] and LCP Consulting.

1.3. The report was well received by DECC, industry and other stakeholders, and it has focused attention on the mid decade risks to electricity security of supply. The next report is due by 1st September 2013.

1.4. The analysis in the report is based on the results of a probabilistic model combined with sensitivity analysis to account for the uncertainty related to the expected levels of supply and demand. The model calculates the probability of demand exceeding supply during a typical period in the winter season.

1.5. The risk and the impact of supply shortfalls are evaluated using well-established probabilistic measures: Loss of Load Expectation (LOLE) and Expected Energy Unserved (EEU). We also estimate the possible frequency and duration of potential shortfalls, and the de-rated margin.

1.6. Details on the current methodology can be found in the 2012 Electricity Capacity Assessment report[7] and the technical description in Appendix 3 of this consultation. We believe the methodology used last year remains fit for purpose and valid for the period of analysis of the 2013 report (five winters from 2013/14 to 2017/18).

1.7. However, doing the first report has made us aware of possible amendments to the modelling assumptions and data inputs. In this document we set out our proposed changes to the existing methodology.

[2] Section 47ZA as inserted by the Energy Act 2011 can be found in Appendix 2.
[3] The report was made public on the 5th October 2012.
[4] National Grid developed the model in collaboration with Chris Dent (Durham University) and Stan Zachary (Heriot-Watt University).
[5] In collaboration with Redpoint Energy.
[6] Professors Derek Bunn (London Business School), Goran Strbac (Imperial College) and Michael Grubb (Cambridge University and Ofgem).
[7] http://www.ofgem.gov.uk/Markets/WhlMkts/monitoring-energy-security/elec-capacity-assessment/Pages/index.aspx.

1.8. This document is structured as follows: Chapter 2 presents a brief description of the general methodology and modelling approach used in the 2012 report; Chapter 3 explains our proposed amendments to the methodology, and Chapter 4 presents the next steps. Appendix 1 presents the consultation response form and a summary of the questions; the legislative requirement can be found in Appendix 2; a more detailed technical description of the methodology used for the 2012 report is available in Appendix 3; the glossary is in Appendix 4, and a feedback questionnaire in Appendix 5.

2. Ofgem's electricity capacity assessment report: general methodology

Chapter Summary

In this chapter, we present a brief description of the general methodology used for the 2012 Electricity Capacity Assessment report which combines probabilistic modelling with scenario analysis. A detailed description of the methodology can be found in the 2012 report itself[8] and a technical description is provided in Appendix 3 of this consultation.

We also explain why we consider the general approach used last year remains appropriate for assessing capacity adequacy in the GB market for the period of analysis in the 2013 report (five winters from 2013/14 to 2017/18).

Question box

Question 1: Do you agree that the general methodology used for Ofgem's 2012 electricity capacity assessment is still valid to analyse GB's generation adequacy in the next five winters from 2013/14 to 2017/18? Please justify and provide alternative methodological suggestions and their comparative advantages if you disagree.

Question 2: In how many years do you think the effect of time-linked variables will be significant enough to require a fully chronological model to calculate generation adequacy? Please justify and provide data or references to back up your views.

Question 3: Do you agree that our proposed sensitivities around interconnector flows, generation capacity (de-rating factors, new builds, closures, and mothballing), and demand are sufficient to capture the uncertainties that have the most significant impact on the calculation of LOLE and EEU? Please justify the rationale behind any new sensitivity proposed.

Question 4: Are there any alternative measures of capacity adequacy other than the ones used in the 2012 report (LOLE, EEU, 1 in n probability of controlled disconnections, frequency and duration of expected outages and de-rated capacity margins) that we should report? Please provide a justification for suggested measures and explain what their comparative advantages are.

[8] http://www.ofgem.gov.uk/Markets/WhlMkts/monitoring-energy-security/elec-capacity-assessment/Pages/index.aspx

2.1. For the 2012 Electricity Capacity Assessment report we used a combination of a probabilistic approach with sensitivity analysis to assess the uncertainty related to intermittent wind generation, interconnector flows, investment and plant retirement decisions, and overall electricity demand.

2.2. The probabilistic model was designed by Ofgem and National Grid and developed by National Grid in close collaboration with Ofgem. The methodology was consulted upon with industry and academics. It was also validated by a panel of academic advisors and LCP Consulting.

2.3. We believe the general methodology used last year remains fit for purpose and valid for the period of analysis of the 2013 report (five winters from 2013/14 to 2017/18). This chapter presents a brief description of the overall modelling approach used in 2012 and proposed for 2013. In the following chapter we detail the proposed amendments to this approach for the 2013 report.

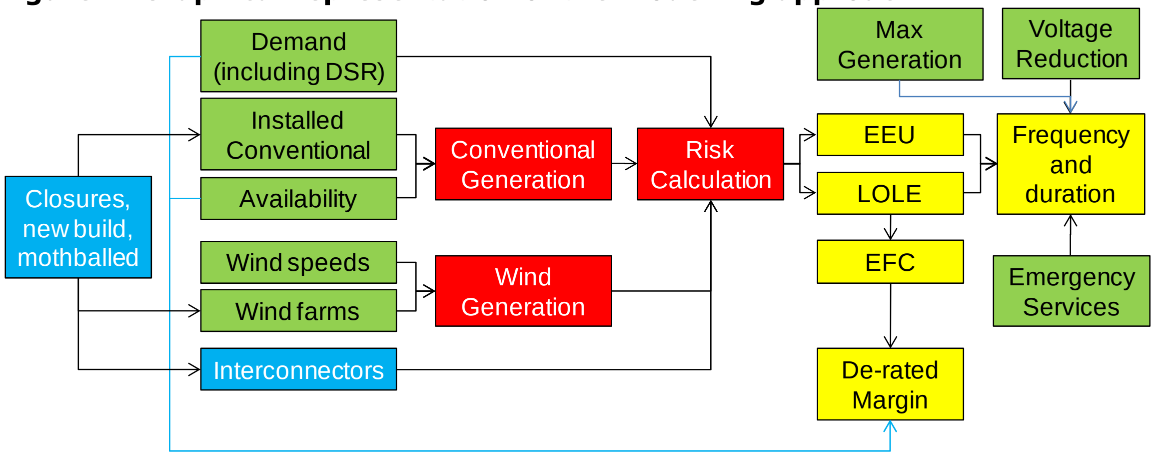
Modelling Approach

2.4. The capacity assessment model is a probabilistic model that analyses capacity adequacy during the winter period[9]. It is a time-collapsed model; this means it calculates the probability of demand exceeding available supply at a randomly chosen half-hour from the winter period[10]. We also estimate the possible frequency and duration of any shortfalls.

2.5. Figure 1 below presents the structure of the model. The inputs for new build, closures, mothballed plant and interconnector flows are based on Ofgem's assumptions while expected demand, available conventional capacity, and the characteristics of wind farms are primarily based on historical data and analysis from National Grid. The wind speeds are based on the Modern Era Retrospective-analysis for Research and Applications (MERRA) dataset produced by NASA.

[9] The model focuses on normal winter demand. Times of extremely high demand that may cause emergency situations are represented in the tails of the demand distribution but are not the main focus of the analysis.
[10] The Base Case in the 2012 Electricity Capacity Assessment Report is based on the winter period and the analysis of the summer period is included as a complementary analysis.

Figure 1: Graphical representation of the modelling approach



Note: The green boxes represent inputs based on historical/factual data, the blue boxes represent inputs based on Ofgem's assumptions, the red boxes represent calculation modules and the yellow boxes are the results of the model.

2.6. The analysis presented in the 2012 Electricity Capacity Assessment report presents a Base Case as well as a range of sensitivities around interconnector flows, generation capacity (new build, closures and mothballed plant), and demand. We are planning to use a similar set of sensitivities in the 2013 Electricity Capacity Assessment report, but we are seeking views on whether other sensitivities should be included.

2.7. There are four key outputs from our modelling: two probabilistic measures of security of supply, LOLE and EEU; the frequency and duration of expected outages and the de-rated capacity margin:

- *Loss of Load Expectation* (LOLE) - the mean number of periods per year in which supply does not meet demand.
- *Expected Energy Unserved* (EEU) - the mean amount of electricity demand that is not met in a year. EEU combines both the likelihood and the potential size of any supply shortfall.
- *Frequency and duration of expected outages* – a translation of the results of the probabilistic risk measures into tangible impacts for electricity customers, based on judgements around how the electricity system would operate at the time when supply does not meet demand, and the order and size of mitigation actions taken by the System Operator.
- *De-rated capacity margin* –the excess of available generation capacity over demand. Available generation capacity is the part of the installed capacity that can in principle be accessible in reasonable operational timelines, i.e. it is not decommissioned or offline due to maintenance or forced outage.

2.8. To calculate the LOLE and EEU, in the four year modelling period, the model constructs probability distributions of winter demand[11], wind power and available conventional generation.

2.9. The distribution of winter demand is based on appropriately rescaled historical demand data and demand growth forecasts provided by National Grid[12]. The distribution of wind power is based on wind speed data which is used to estimate the corresponding levels of wind generation appropriate to the projected wind fleet. The distribution of available conventional generation is derived from installed capacities combined with a de-rating factor[13].

2.10. The evolution of installed capacity over the four year period is one of the most difficult issues to form a firm view on and one of the most significant assumptions for analysing generation adequacy. The Electricity Capacity Assessment report includes different sensitivities to account for different possible views regarding this issue.

2.11. We also estimate the frequency and duration of outages of a given severity when mitigation actions available to the System Operator have been exhausted (covering demand reduction and potential supply increases). The frequency and duration estimates help us to illustrate possible impacts on customers of supply shortfalls (i.e. the average frequency of controlled disconnections of customers given the volume of demand).

2.12. Finally, we calculate the de-rated capacity margin for each winter. The de-rated margin represents the excess of 'typical' available generation capacity over winter demand and can be expressed in percentage terms. This 'typical' available capacity is the sum of the average available conventional capacity and the Equivalent Firm Capacity (EFC[14]) of the wind generation. The EFC is the quantity of firm capacity that can be replaced by a certain volume of wind generation to give the same level of security of supply, as measured by LOLE or EEU[15].

2.13. As noted in our 2012 report, the de-rated margin is not a direct measure of the risk to security of supply. This is because different markets, with different generation technologies, might exhibit the same de-rated margin but have very different risk levels (LOLE, EEU, and 1 in n frequency of outage). However, the de-rated margin remains an accessible and widely used indicator of trends in electricity

[11] Winter demand is based on Average Cold Spell (ACS) demand. This reflects the combination of weather elements (i.e. temperature, illumination and wind) that give rise to a level of peak demand within a financial year that has a 50% chance of being exceeded as a result of weather variations alone.
[12] These take into account economic growth and energy efficiency measures.
[13] The de-rating factors are derived from the analysis of the historical availability performance of the different generating technologies.
[14] For a detailed explanation of the calculation of EFC and justifications for using this measure to find the de-rated capacity of wind power see Appendix 4 of the 2012 Electricity Capacity Assessment report: http://www.ofgem.gov.uk/Markets/WhlMkts/monitoring-energy-security/elec-capacity-assessment/Pages/index.aspx
[15] It would be possible to assign a de-rated capacity based on wind in comparison with conventional plant instead of *firm* capacity; this would make little difference to the calculation result at the expense of non-negligible additional complexity of the calculation.

security of supply. It is also understood by industry and stakeholders. For these reasons we include the de-rated margin as one of the outputs of our modelling.

Time-collapsed model

2.14. The capacity assessment model is a time-collapsed model, i.e. it investigates the probability distribution of the margin of available supply over demand at a randomly chosen point in time. A fully chronological model is not required for the calculation of LOLE and EEU under the current characteristics of the GB electricity market and the expected evolution of the market during the next five winters.

2.15. Estimates of the frequency and duration of outages are created by combining the outputs of the model with estimates for the duration of outages based on operational experience. We believe that this approach is still valid for the 2013 report (five winters from 2013/14 to 2017/18).

2.16. There are a number of explicit time linkages in the GB system, where the value of variables, at a specific period, is linked to the value of the same variable in preceding periods: e.g. the availability of pumped storage, demand side response, and the impact of intermittent generation on system stability. However, we believe that the use of a non-chronological model is still justified by the fact that these variables do not have a significant impact on the risk of supply shortfalls. We explain our reasoning in more detail below:

1. **Pumped storage:** In 2012 we assumed there were no energy constraints imposed by the capacity of storage. Supporting analysis by National Grid demonstrated that the pumped storage generators have sufficient storage capacity to operate throughout the peak period (around 4 hours).We therefore treated pumped storage as conventional plant with its availability depending on outages (planned and unplanned). In 2013, we propose to treat pumped storage in the same way.

2. **Demand Side Response (DSR):** DSR refers to changes in energy use by end-user customers in response to a signal. The potential for DSR in a specific period is linked to the realised DSR in the periods before as customers have limited capacity and incentives to reduce their demand. A chronological model is required to fully capture this behaviour.

   In the 2012 Electricity Capacity Assessment report, DSR was reflected in National Grid's demand data, i.e. the demand data was net of DSR, and following National Grid analysis, we assumed that DSR continued at current levels for the period of the analysis.

   In addition, according to National Grid, there was no reliable data available[16] to develop an explicit model for DSR. We explore whether this assumption stands in the following chapter.

[16] National Grid and Ofgem carried out two Industry workshops to discuss the methodology for the 2012 Electricity Capacity Assessment. The question of whether a reliable DSR dataset was available was raised but neither National Grid nor Ofgem received appropriate datasets

3. **Intermittent generation:** A fully chronological model is necessary in order to consider the impact of wind generation on short term (e.g. intraday) system operation; however, our analysis focuses on capacity adequacy in the medium to long term (next five winters).

   A fully chronological model would be appropriate to represent a system with high penetration of intermittent sources as such a system would require a minimum level of flexible generation to balance intermittent flows and ensure system stability. National Grid expects intermittent generation to reach about 17%[17] in energy terms by 2017/18. We believe the time-collapsed model remains valid to represent this level of intermittent generation.

following these workshops.

[17] http://www.nationalgrid.com/NR/rdonlyres/C7B6B544-3E76-4773-AE79-9124DDBE5CBB/56766/UKFutureEnergyScenarios2012.pdf

3. Amendments to the methodology

Chapter Summary

We set out our proposed amendments to the methodology for the 2013 Electricity Capacity Assessment report. We only discuss the elements of our methodology where changes are proposed: interconnectors, demand side response, and the correlation between wind and demand. All other elements not included in this chapter will be treated in the same way as for the 2012 report.

Question box

Question 5: Do you agree with using a qualitative model to assess the impact of interconnector flows on LOLE and EEU in our Base Case and sensitivities? Please justify and provide suggestions for alternative approaches and comparative advantages if you disagree.

Question 6: Do you know of any reliable sources of half hourly demand side response data that cover a time period starting before the last recession (ideally at least 10 years) that could be used by Ofgem to produce the 2013 Electricity Capacity Assessment report? Please provide references.

Question 7: Do you know of any existing analysis or figures on the potential for demand side response during the next five winters that could be used by Ofgem to produce the 2013 Electricity Capacity Assessment report? Please provide references and explain clearly how any suggested analysis can be used to calculate LOLE and EEU.

Question 8: Do you agree that the proposed options for longer historic time series of wind and winter demand in GB are relevant for investigating the relationship between these two variables? Please justify and provide suggestions for alternative options and their comparative advantages.

Question 9: Do you agree with the proposed methodology to estimate the distribution of demand net-of-wind? Please justify and provide suggestions for alternative options and their comparative advantages.

Interconnectors

3.1. Interconnection capacity between GB and the Continent and Ireland is currently 4GW. The direction and size of interconnector flows therefore has a significant impact on the calculation of the risks to electricity security of supply. It is also important to balance the impact of different assumptions on security of supply against the impact on the cost to consumers, –e.g. if we believe that GB will import electricity at times of high demand then less generation capacity may be needed in

GB compared to the case where there are no imports, but GB may be more reliant on imported electricity to meet high demand.

3.2. We believe that interconnectors are beneficial for security of supply in general. We recognise that interconnectors may provide services such as trading balancing energy, trading balancing reserves, frequency response and black start. However, from an electricity capacity assessment perspective we need to form a view on the specific contribution of interconnector flows to GB security of supply during the winter season.

3.3. For the 2012 Electricity Capacity Assessment report we used informed assumptions for the level of interconnector flows in our Base Case and sensitivities. In the Base Case we set flows with the Continent at float (i.e. no imports or exports), while assuming full exports to Ireland. We noted this was a 'cautious approach', justified by the uncertainties surrounding the future of electricity supply and demand in Europe, and the fact that we have been traditionally exporting to Ireland during winter. This approach is consistent with National Grid's assumptions in their Gone Green 2012 scenario.

3.4. For the 2013 report we have considered two different approaches to assess the contribution of interconnectors to GB's capacity margin and security of supply risk. Below we present a brief description of the two approaches and their advantages and disadvantages for assessing the contribution of interconnector flows to our security of supply measures (LOLE and EEU):

1. *Developing a quantitative (e.g. econometrics) model to predict interconnector flows* - a quantitative model uses mathematical techniques to calculate numerical values. The main advantage of these models is that they may provide a precise numerical result; however, the result is subject to how accurately the relationships among the variables in the system can be represented. The result will also depend heavily on the precision of the numerical parameters used in the model as inputs.

   Assumptions are often used in quantitative models where numerical parameters are difficult to estimate. For our analysis these include electricity prices and generation costs during the next five winters. The results of such a model may be misleading as they could be interpreted as robust when they are only as reliable as the assumptions that feed into the model.

2. *Developing a qualitative model to assess the likely direction and level of flows* – a qualitative model is 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).

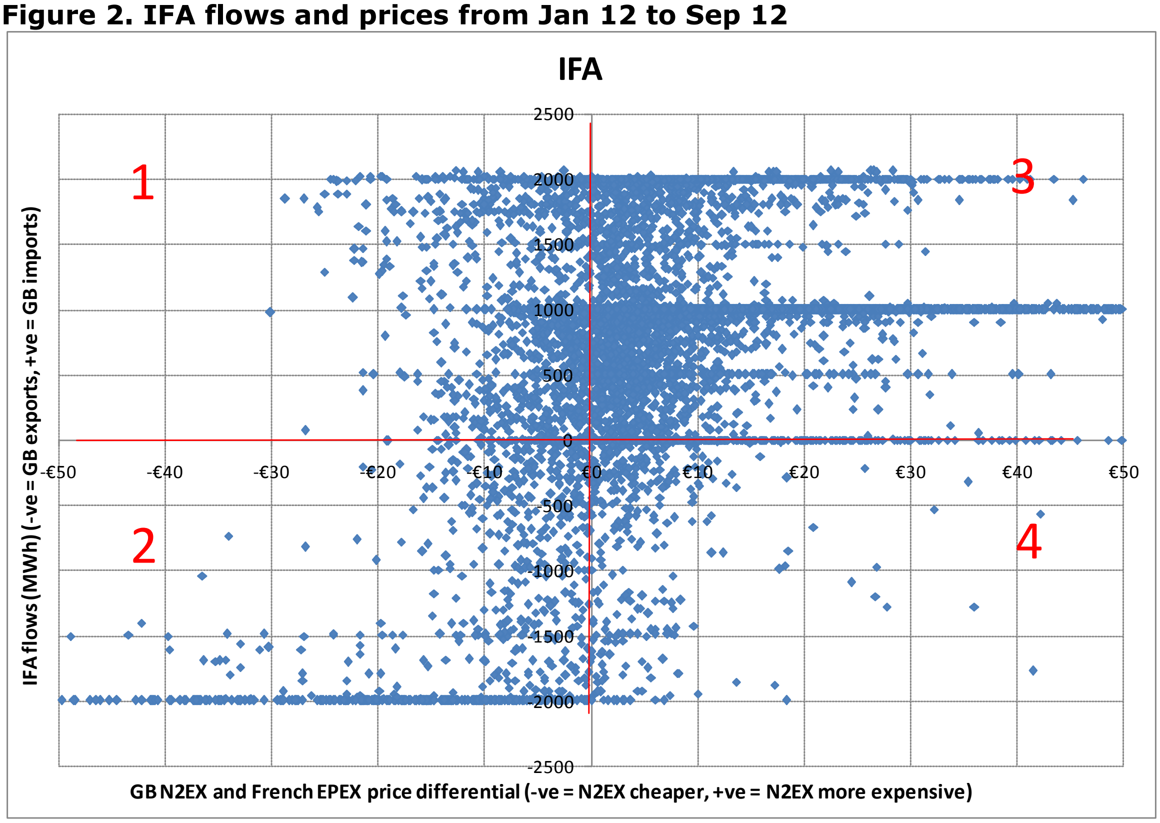
   The main disadvantage of a qualitative model is that it does not provide a precise numerical answer, but the main advantage is that the results are taken as indicators of possible outcomes instead of precise forecasts.

In the absence of a precise numerical answer, a qualitative model should be complemented with plausible sensitivities to illustrate the impact of interconnector flows on the risk measures.

3.5. We have analysed two types of quantitative models to estimate interconnector flows during winter: a regression model based on historical flows, and a price differential model. We discuss them in more detail below.

3.6. We believe that a quantitative model based on historical flows would not be robust or fit-for-purpose for our period of analysis. Market coupling should be implemented in North West Europe in 2013 dramatically changing the current market arrangements in the IFA interconnector and increasing price responsiveness, which has been limited in the past (see Figure 2).

Figure 2. IFA flows and prices from Jan 12 to Sep 12

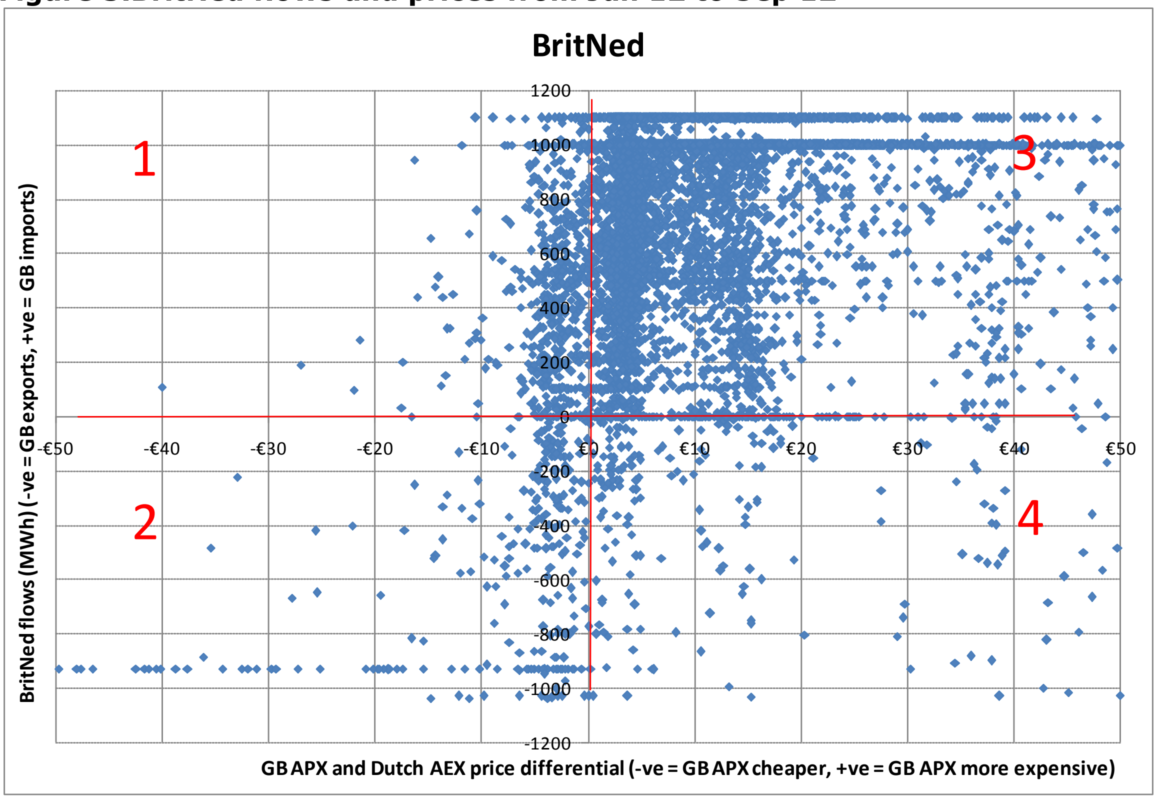


Note: The points represent the amount of imports to (positive values in the vertical axis) and exports from GB, and the relative spot price at the time of the flows. In a fully price responsive system we would only have points in sectors 2 and 3 in the graph. The points in sector 1 represent imports to GB when the price in GB is lower than the price in France. Similarly, the points in section 4 represent exports from GB when the price in GB is higher than the price in France.
Sources: Ofgem and Bloomberg

3.7. Market coupling is already implemented in BritNet; however, this interconnector has only been in operation since April 2011 and the market arrangements are being adjusted to increase price responsiveness in the flows, which has been limited during the period of operation (see Figure 3).

3.8. This means that historical flows are not good indicators of future flows. Following the implementation of Market coupling, and as more data becomes available, a quantitative model based on historical flows may be a good option to estimate interconnector flows in the future.

Figure 3.BritNed flows and prices from Jan 12 to Sep 12



See the note under Figure 2 for an explanation of the graph.
Sources: Ofgem and Bloomberg

3.9. Another approach is to recognise that market coupling should bring increased price responsiveness and flows in the direction of the country with the higher price. Therefore, we have considered how a quantitative model based on price differentials could be used to predict the direction of flows. The question this model would need to answer is whether the price is higher in GB compared to its interconnected countries during normal winter demand (as opposed to emergency times where demand is extremely high or supply is extremely low).

3.10. There is a high level of uncertainty surrounding the key input assumptions of such a model, in particular demand[18] and supply[19], on either side of the

[18] Some sources of uncertainty around the evolution of demand include the expected rate of economic recovery and the impact of energy efficiency measures.
[19] Sources of supply uncertainty in Europe include the type of technology that will be used to

interconnector. Significant amounts of price data from across Europe would also be required, and much of this in not available on a consistent and reliable basis. Therefore, given these uncertainties, forecasting the relative prices between interconnected countries is largely a speculative activity and is highly unlikely to provide an accurate representation of reality.

3.11. Therefore, we are considering the option of developing a qualitative model to assess the level and direction of future flows for our Base Case and sensitivities. For such a model we will need to analyse the general security of supply outlook in Europe and, in particular, in the countries interconnected with GB.

3.12. A key question would be to understand the likelihood of having concurrent periods of system stress (i.e. where the risk of available supply not meeting demand is high) which may limit the potential for interconnector flows.

3.13. Given the characteristics of the generation fleets in GB, Ireland, France and the Netherlands, we do not believe that plant outages are currently correlated[20]. However, with further penetration of wind generation this assumption may not be valid at the end of our period of analysis (winter 2017/18). We will analyse both the potential penetration of wind generation in GB and its interconnected countries and the relationship of wind availability among these countries to estimate the potential impact on interconnector flows.

3.14. We also need to evaluate the correlation of high demand between GB and the interconnected countries. If high demand is concurrent at both sides of the interconnector, this means that electricity may only flow in the direction of the country with the lower margin (implying higher price). For this to be the case, the price will also have to be able to reflect the level of margin, which is another element that has to be analysed to get more insights on the likely direction and level of interconnector flows.

3.15. On balance, and given the high level of uncertainty around the expected supply and demand in GB and the interconnected countries in the coming years, a qualitative model presents a good alternative to assess the contribution of interconnector flows to security of supply in GB at peak times, but we are seeking views on this. We have described above some of the elements that should be considered for this kind of analysis but our list is not exhaustive and we will consider other elements if we decide to use this approach.

---

replace plant closures under LCPD, and the impact on nuclear phase-out in Germany. In GB we have uncertainty surrounding the consequences of the implementation of EMR and other reforms such as the Electricity Balancing Significant Code Review which are not yet fully developed.

[20] There is no reason to believe that fossil fuel or nuclear plants will experience technical issues at the same time in GB and the interconnected countries.

Demand Side Response (DSR)

3.16. DSR involves changes in energy use by end-use customers in response to a signal[21]. From a capacity assessment perspective we are interested in the level of electricity DSR during periods of high demand. During these periods, DSR may result in demand reduction; however, DSR may result in an increase in demand at non-peak times when a temporary peak reduction is compensated for. It may also increase net demand in response to low prices.

3.17. Demand reductions during high demand periods may come either from a genuine reduction in consumption or by generating electricity on site. Also, while energy efficiency measures generally would not facilitate DSR, some DSR might have spill over energy efficiency benefits.

3.18. In the longer term, we expect DSR to play an important role in maintaining secure and sustainable energy supplies. But, presently, only a small proportion of domestic and industrial customers vary their demand in response to signals. In the 2012 Electricity Capacity Assessment report, DSR was reflected in National Grid's demand data, i.e. the demand data was net of DSR, and following National Grid analysis, we assumed that DSR continued at current levels for the period of the analysis.

3.19. To build an explicit model to predict future levels of DSR during periods of high demand we need half-hourly data over at least ten years - a long enough period to cover pre-recession times. Also, in order to avoid double counting, it is important to ensure that it is genuine DSR (i.e. demand reduction in response to changes in price) instead of a reduction in demand that may have occurred independent of price levels. We are also interested in understanding the level of DSR due to the wholesale price (triad avoidance), and what level of wholesale price triggers this reduction in demand. Ofgem and National Grid do not know of any reliable data source to build an explicit model to predict DSR at peak periods.

3.20. Even so, we will investigate further the potential for DSR development in the next five winters. Understanding the potential for DSR development will enable us to decide on whether or not we should include sensitivities around DSR in the 2013 Electricity Capacity Assessment report.

Wind – demand correlation

3.21. To assess generation adequacy in GB we need to estimate the distribution of wind availability over winter. In 2012, data for wind availability during winter in GB was not sufficient to enable us to understand the relationship, if any, between wind availability and high demand. Therefore, we made the assumption of there being no relationship between these variables[22]. This means that the distribution of wind power and winter demand were estimated separately, though the distribution of wind

[21] Signals could include prices, incentives, information, contracts, laws or regulations.
[22] The alternative was to assume that there is a relationship between the two variables but this requires a second assumption on the nature of the relationship.

was based on historical wind speeds over winter. We then combined these distributions with the distribution of conventional generation to create the distribution of margin during winter.

3.22. However, there is a widespread belief that the wind stops blowing when there is a severe cold spell, resulting in lower wind generation at the time of extreme demand for electricity. For example, this could be caused by a region of high pressure sitting over Britain, bringing cold temperature but very little wind. As severe cold spells only occur occasionally, there is very little data for these extreme periods. Consequently, it is difficult to find sufficient statistical evidence to support or challenge this belief.

3.23. If this widespread belief is true, then our assumption of independence of the distributions of wind availability and winter demand may result in an underestimation of the risks to security of supply at times of extremely high demand, as less wind may then be available than assumed in our model. To account for this possibility in the 2012 Electricity Capacity Assessment report we presented a sensitivity where the distribution of wind output is scaled down to test the effect of having less wind available at peak times.

3.24. For the 2013 Electricity Capacity Assessment report we propose to maintain the assumption of independence. However, we will investigate whether it is necessary to adjust the distribution of wind availability so that it corresponds more closely to the availability of wind at times of high demand. Thus, we propose to explore further whether evidence exists for a relevant wind-demand relationship. For this we need long historic time series of wind and demand.

3.25. Long time series of wind speeds are available from the MERRA data base but long enough time series of consistent aggregated demand in GB are not available[23]. We are exploring options for a longer historic series of demand, including:

- Using England and Wales demand which is available from National Grid back to 1985, or
- Using temperature records as a proxy for demand which are available from National Grid back to the mid-1980s[24].

3.26. A longer historic time series of demand combined with the MERRA wind data will provide a greater number of examples of wind power output at times of extremely high demand – either England and Wales demand or GB temperatures would be sufficient to identify truly extreme historic periods.

3.27. The proposed analysis will enable us to get a better understanding of the relationship between wind and demand in extreme periods and will provide information that will help us decide on the appropriate distributions and/or

[23] Completely consistent data for GB is only available from 2005.
[24] In a ready-processed format.

sensitivities to include in the report to account for plausible scenarios of wind availability at periods of extremely high demand.

4. Next Steps

Chapter Summary

This chapter sets out the process so far and next steps.

4.1. In preparation for this formal consultation we informally consulted with the members of our Academic Advisory Group and held a workshop with the UK Energy Research Centre (UKERC) to discuss the validity of the current methodology and possible amendments for the 2013 Electricity Capacity Assessment report. We have been working closely with National Grid and their consultants in the preparation of this document. DECC have also provided comments. National Grid, as developers of the original model, are in charge of the implementation of the amendments to the model. They are also responsible for the data provision.

4.2. This consultation document briefly describes the Electricity Capacity Assessment model that was used for the 2012 report in Chapter 2 and outlines a proposal for modelling amendments in Chapter 3. We are seeking views on the proposed amendments and the validity of the general methodology. To this end, we have posed a number of specific questions to stakeholders.

4.3. The consultation period will run for four weeks and will close on 21 December 2012. During the consultation period, Ofgem and National Grid may informally seek views from experts regarding specific and technical modelling.

4.4. We will then publish a final decision document in January 2013, based on the consideration of views arising from this consultation.

4.5. The model amendments will be implemented in early 2013 in order to deliver the final report to the Secretary of State by 1st September 2013.

Appendices

Index

Appendix 1 - Consultation Response and Questions

1.1. Ofgem would like to hear the views of interested parties in relation to any of the issues set out in this document.

1.2. We would especially welcome responses to the specific questions which we have set out at the beginning of each chapter heading and which are replicated below.

1.3. Responses should be received by 21 December 2012 and should be sent to:

Patricia Ochoa
Energy Markets Research and Economics
9 Millbank
London
SW1P 3GE
0207 7901 7153
Patricia.ochoa@ofgem.gov.uk

1.4. Unless marked confidential, all responses will be published by placing them in Ofgem's library and on its website www.ofgem.gov.uk. Respondents may request that their response is kept confidential. Ofgem shall respect this request, subject to any obligations to disclose information, for example, under the Freedom of Information Act 2000 or the Environmental Information Regulations 2004.

1.5. Respondents who wish to have their responses remain confidential should clearly mark the document/s to that effect and include the reasons for confidentiality. It would be helpful if responses could be submitted both electronically and in writing. Respondents are asked to put any confidential material in the appendices to their responses.

1.6. Next steps: Having considered the responses to this consultation, we intend to publish a final decision document in January 2013 outlining the final details for the amendments to the methodology. Any questions on this document should, in the first instance, be directed to:

Christos Kolokathis
Energy Markets Research and Economics
9 Millbank
London
SW1P 3GE
0207 7901 3156
Christos.kolokathis@ofgem.gov.uk

CHAPTER TWO

Question 1: Do you agree that the general methodology used for Ofgem's 2012 electricity capacity assessment is still valid to analyse GB's generation adequacy in the next five winters from 2013/14 to 2017/18? Please justify and provide alternative methodological suggestions and their comparative advantages if you disagree.

Question 2: In how many years do you think the effect of time-linked variables will be significant enough to require a fully chronological model to calculate generation adequacy? Please justify and provide data or references to back up your views.

Question 3: Do you agree that our proposed sensitivities around interconnector flows, generation capacity (de-rating factors, new builds, closures, and mothballing), and demand are sufficient to capture the uncertainties that have the most significant impact on the calculation of LOLE and EEU? Please justify the rationale behind any new sensitivity proposed.

Question 4: Are there any alternative measures of capacity adequacy other than the ones used in the 2012 report (LOLE, EEU, 1 in n probability of controlled disconnections, frequency and duration of expected outages and de-rated capacity margins) that we should report? Please provide a justification for suggested measures and explain what their comparative advantages are.

CHAPTER THREE

Question 5: Do you agree with using a qualitative model to assess the impact of interconnector flows on LOLE and EEU in our Base Case and sensitivities? Please justify and provide suggestions for alternative approaches and comparative advantages if you disagree.

Question 6: Do you know of any reliable sources of half hourly demand side response data that cover a time period starting before the last recession (ideally at least 10 years) that could be used by Ofgem to produce the 2013 Electricity Capacity Assessment report? Please provide references.

Question 7: Do you know of any existing analysis or figures on the potential for demand side response during the next five winters that could be used by Ofgem to produce the 2013 Electricity Capacity Assessment report? Please provide references and explain clearly how any suggested analysis can be used to calculate LOLE and EEU.

Question 8: Do you agree that the proposed options for longer historic time series of wind and winter demand in GB are relevant for investigating the relationship between these two variables? Please justify and provide suggestions for alternative options and their comparative advantages.

Question 9: Do you agree with the proposed methodology to estimate the distribution of demand net-of-wind? Please justify and provide suggestions for alternative options and their comparative advantages.

Appendix 2 – Section 47ZA of the Electricity Act 1989 as inserted by the Energy Act 2011.

"**47ZAAnnual report by Authority on security of electricity supply**

(1) The Authority must, before 1 September 2012, and before that date in every subsequent calendar year—

(a) prepare a report on the future demand for, and supply of, electricity in Great Britain, in accordance with subsection (2), and

(b) send the report to the Secretary of State.

(2) A report under subsection (1) must include, as regards each forecast period—

(a) a forecast of the peak demand for the supply of electricity to consumers in Great Britain;

(b) an assessment of different possible capacity margins for that supply, and of the degree of protection that each would provide against the risk of shortfalls in supply due to unexpected demand or unexpected loss of capacity.

(3) The forecast periods in relation to a report under subsection (1) are—

(a) each of the four calendar years immediately following the year of the report; or

(b) any other periods that the Secretary of State specifies by order.

(4) A forecast by virtue of subsection (2)(a) must be expressed as a single figure in megawatts rounded to the nearest 100 megawatts, unless the Secretary of State directs otherwise.

(5) An assessment by virtue of subsection (2)(b) must take into account, in particular—

(a) the generation of electricity;

(b) the operation of electricity interconnectors;

(c) the storage of electricity;

(d) the extent to which the available capacity of a generating station is likely to be lower than its maximum possible capacity due to routine maintenance, weather conditions or any other expected limitation on its operation;

(e) demand side response.

(6) A forecast or assessment by virtue of subsection (2) may to any extent be made by, or based on information provided by—

(a) the holder of a transmission licence;

(b) any other person.

(7) The Secretary of State may give the Authority directions regarding—

(a) the form of a report under subsection (1);

(b) the manner in which such a report must be prepared or sent;

(c) the manner in which a forecast or assessment by virtue of subsection (2) must be made or expressed (including, in particular, the method of calculation of any of the things mentioned in subsection (2)(a) or (b)).

(8) In this section—

- "capacity margin" means the amount by which the peak demand for the supply of electricity is exceeded by the capacity likely to be available to meet that demand;
- "consumers" includes both existing and future consumers;
- "demand side response" means the cessation of, or a reduction in, the provision of electricity to a person at times of high demand, by agreement with the person."

Appendix 3 – Technical description of the 2012 Electricity Capacity Assessment model

1.1. In this document we describe the modelling approach used for the 2012 Electricity Capacity Assessment report. We first give an overview of the modelling, and then give a description of the model design and structure, including the source of key assumptions.

Aims and overview of modelling

1.2. The aim of the study is to produce a range of scenarios for given seasons, and for each scenario estimate the risk that there is insufficient capacity to meet electricity demand. The seasons modelled are those in which the system is considered to be at risk, usually the winter season in each year.

1.3. The primary outputs of each estimate are:

- loss-of-load expectation (LOLE), defined as the mean number of periods per year in which supply does not meet demand;
- expected energy unserved (EEU), defined as the mean amount of electricity demand that is not met in a year. EEU combines both the likelihood and the potential size of any supply shortfall.

Further outputs are:

- estimates of de-rated capacity margins, defined as the excess of available generation capacity over demand;
- the likely frequency and duration of outages, i.e. periods in which supply fails to meet demand.

Sensitivity development

1.4. A key part of this study has been to develop a Base Case view of the future electricity demand and supply background over the next five winters. This Base Case covers assumptions on:

- Electricity demand at ACS peak;
- Installed generation capacity, including new builds, retirements and mothballing;
- Interconnector capacity and imports/exports at peak;
- Generator availabilities.

1.5. A set of sensitivities has also been developed to test the impact on capacity adequacy of key uncertainties in the Base Case assumptions.

1.6. Each sensitivity is used as an input to the probabilistic model, described below.

Probabilistic model

1.7. In normal circumstances there is a margin of generation capacity over electricity demand. The risks of supply shortfalls due to inadequate capacity occur at the extremes of high demand and/or low availability of generation capacity. We therefore take a probabilistic approach, using recent history to estimate the possible ranges of electricity supply and demand, and hence the distribution, at any time, of the excess of supply over demand. This distribution forms the basis of the estimation of the primary outputs of each forecast, i.e. LOLE and EEU. We further test the sensitivity of these outputs to variation in input assumptions. The latter include varying views of future capacity and electricity demand, together with assumptions about their statistical relationship as they vary over time.

1.8. The constructed model is a probabilistic model of capacity adequacy in the GB electricity market, and corresponds in turn to each of the five winter seasons ahead. It is a *time-collapsed* model, that is, it models the joint distribution of available conventional generation capacity X, wind generation capacity W and electricity demand D at a typical, or randomly chosen, half-hourly time period during the season studied. This time-collapsed model is sufficient to calculate the distribution of the surplus $Z = X + W - D$ at such a randomly chosen time, together with the primary outputs LOLE and EEU.

1.9. The model is indifferent as to the serial variation through time of the distributions of the variables involved, that is, it takes no account of the chronological ordering of the half-hourly time periods into which the studied season is decomposed. However, both the expected frequency and duration of outages depend on this ordering. Thus, in order to provide estimates of the latter quantities, it is necessary to combine the model with further information.

1.10. The distribution of demand is based on recent historical half hourly demand for electricity on the system, for the winters 2005/06 to the preceding winter. This distribution is adjusted for the scenario assumption on peak demand in each winter.

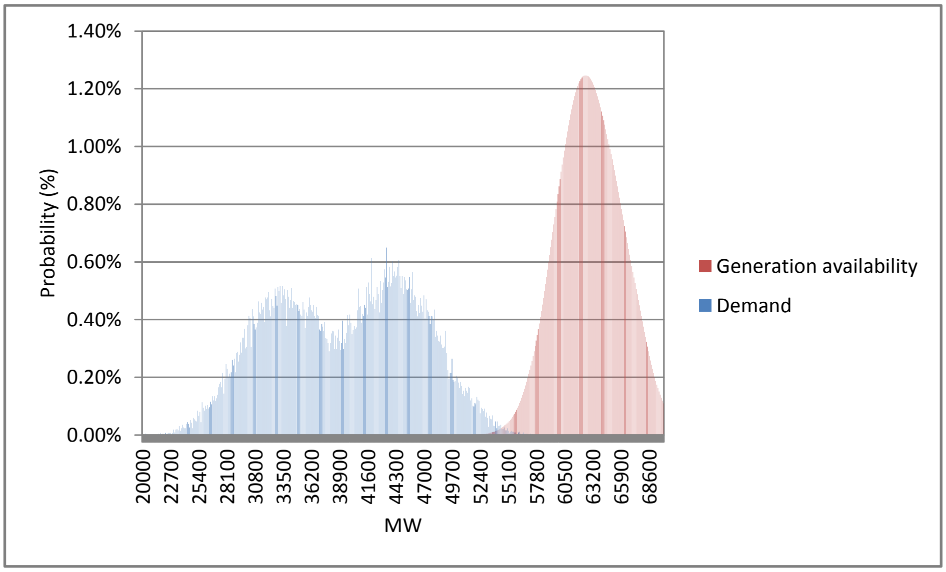
1.11. The distribution of future generation capacity availability is built up from two distributions with distinctly different characteristics. The conventional (non-wind) capacity distribution is calculated using the installed capacity and the mean winter availability of each generating unit. The mean availability has been estimated from historical data, covering the period from 2005/06 to the preceding winter. The distribution of wind output availability is calculated from historical wind speed data covering the period from 1979 to the preceding winter for current and future GB wind farm locations.

1.12. The random variables X, W *and* D are assumed to be independent. However, in order to take account of possible statistical association between wind generation W

and demand *D*, the distribution of *W* is estimated from wind data corresponding to those times when demand was observed to be high, and thus the system was most likely to be under stress. The distribution of *Z* is then obtained by the convolution[25] of the distributions of *X, W and -D.*

1.13. Figure A3.1 shows a schematic representation of the combination of distributions of supply and demand. The mean of the generation capacity availability distribution is higher than the mean of the demand distribution. There is a high, but not 100%, probability that supply exceeds demand.

Figure A3.1 Schematic diagram of electricity demand and capacity distributions



1.14. The model calculates two well-established metrics of security of supply, the Loss of Load Expectation (LOLE) and the Expected Energy Unserved (EEU). The LOLE is the mean number of periods per year in which supply does not meet demand. The EEU is the corresponding volume of demand that is expected not to be met during the year. The LOLE and EEU are derived from the Loss of Load Probability (LOLP) and Expected Power Unserved (EPU). The LOLP is the probability of demand exceeding supply, and the EPU is the corresponding volume of demand that is expected not to be met, during a randomly chosen half-hourly period. LOLP and EPU are formally defined as,

$$[\mathrm{LOLP}] = \mathbf{P}(Z \leq 0) \qquad (1)$$

$$[\mathrm{EPU}] = \mathbf{E}(\max(-Z,0)) = \int_{-\infty}^{0} \mathrm{d}z\mathbf{P}(Z \leq z) \qquad (2)$$

[25] Convolution is the mathematical operation of obtaining the distribution of the sum of two independent random variables from their individual distributions. See for example, R. Durrett, Probability: Theory and Examples, 4th ed. Cambridge University Press, 2010.

where *P* and *E* denote probability and expectation respectively. The LOLE is then defined as the LOLP multiplied by the number of hours in the studied season, while the EEU is defined as the EPU multiplied by the length of the studied season. Thus, EEU combines both the likelihood and potential size of any supply shortfall.

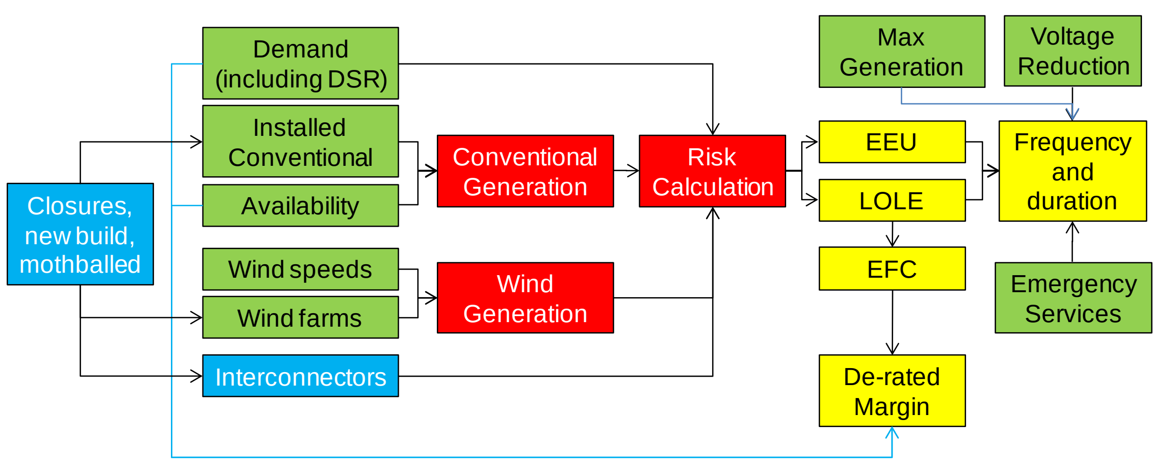
1.15. There are other reasons why electricity consumers might experience disruptions to supply, which are out of the scope of this assessment and thus not captured by this model, such as:

- **Flexibility**. The ability of generators to ramp up in response to rapid increases in demand or decreases in the output of other generators.
- **Insufficient reserve**. Unexpected increases in demand or decreases in available capacity in real time which must be managed by the System Operator through procurement and use of reserve capacity.
- **Network outages**. Failures on the electricity transmission or distribution networks
- **Fuel availability**. The availability of the fuel used by generators. In particular the security of supplies of natural gas at times of peak electricity demand.

Model design and structure

1.16. A bespoke model has been designed and built for this study, based on the principles described above. Figure A3.2 is a schematic representation of the model structure, showing inputs, calculations, and outputs. We give a brief description here, with each component described in more detail in the following sections.

Figure A3.2 Model structure



1.17. The model inputs consist of the scenario views of different future supply and demand assumptions. This includes future demand distributions and levels, the capacities of generators and interconnectors, conventional generator availabilities, and the historical wind speed data.

1.18. There are two major calculation modules. The first deals with the construction of the wind distribution, and the second does the calculations of the security of supply metrics. These are covered in more detail in the relevant sections below.

1.19. The outputs are the LOLE and EEU results and the additional metrics of the frequency and duration of outages.

1.20. In addition, we calculate a commonly used indicator of security of supply: the de-rated capacity margin. The de-rated margin represents the excess of available generation capacity to Average Cold Spell (ACS) peak demand and is expressed in percentage terms. Available generation takes into account the contribution of installed capacity at peak demand by adjusting it by the appropriate de-rating factors.

Assumptions

Figure A3.3 Summary of common assumptions and data sources

Assumption	Source
Demand distribution	Historical Indicative Demand Outturn (INDO) data for 2005/06 to preceding winter for the period in which GB is on Greenwich Mean Time. INDO data has been available since the formation of the GB BETTA[26] market in 2005. Defines the demand profile.
ACS Peak demand	Sensitivity variable. For Base Case, source is NGET provisional work for Future Energy Scenarios. Defines the overall level of demand growth.
Installed capacity	Sensitivity variable. For Base Case, the primary source is NGET provisional work for Future Energy Scenarios with some changes in assumptions. This provides the full portfolio of installed capacity for the next 5 winters.
Embedded wind capacity	NGET provisional work for Future Energy Scenarios.
Conventional plant availability	Analysis of historical Maximum Export Limit (MEL) data and planned outage data.
Wind speed data	MERRA re-analysis data set.
Wind turbine power curves	Manufacturer data. Taken from publically available specifications.
Wind farm locations	NGET internal research.
Interconnector capacities	NGET provisional work for Future Energy Scenarios.
Interconnector peak flow	Sensitivity variable.
Demand Side Response	Current levels of DSR. DSR already exists in historical demand distribution data.

Demand

1.21. The starting point for the distribution of demand is the historical half hourly demand of the winters since winter 2005/06. This data is the Indicative Demand Outturn (INDO) data, available for GB as a whole since the introduction of the British Electricity Trading Arrangements (BETTA) in 2005.

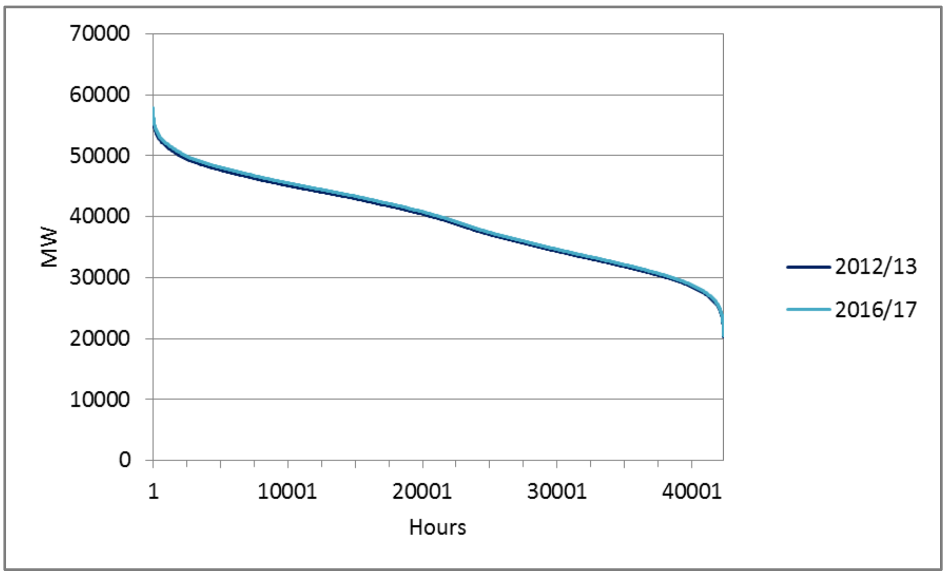
[26] British Electricity Trading Transmission Arrangements.

1.22. The distribution of each historical winter is rebased against the ACS peak demand value for that historical year.

1.23. For each historical year, the generation from embedded wind has been estimated using the wind model and added onto demand. The purpose of this is to allow all wind (both embedded and transmission connected) to be modelled explicitly on a consistent basis in the model.

1.24. To account for overall growth in demand, the distribution is scaled by the forward looking assumptions for ACS peak. Figure A3.4 shows the demand distribution for Base Case 2012/2013 and 2016/2017[27], as a Load Duration Curve.

Figure A3.4 Demand distribution Base Case 2012/2013 and 2016/17



1.25. For each of the five future years, the highest demand in the distribution is higher than the quoted ACS peak demand, by about 1.8 GW. The difference exists for two reasons. Firstly, ACS peak does not represent the outturn peak in any one year. ACS peak demand is a value that is calculated to remove the effects of weather fluctuations on peak demand. To calculate the ACS demand, the actual peak value is adjusted to the demand that would have been expected in an average cold spell. If the peak day is colder than the average cold spell, then the outturn peak will be higher than the reported ACS value.

1.26. Secondly, the demand distribution used in the model includes demand met by embedded wind, and so is higher than the ACS peak which does not include embedded wind.

1.27. The demand distribution for each of the future years is a direct input to the risk assessment calculation.

[27] The highest value in the demand distribution is higher than the assumed ACS peak.

Conventional capacity

1.28. For the purposes of this study, when we refer to conventional generation capacity we mean the non-wind generators connected to the GB transmission system.

1.29. A standard approach to modelling the availability of conventional generators is to treat each generator as being either fully available or completely unavailable. Each generator is assigned a probability of being available, estimated from historical data.

1.30. The exception is for CCGTs which contain multiple Gas Turbine (GT) units. In this case, the failure of each GT unit has been modelled individually.

1.31. The availability assumptions for each generator type are estimated from analysis of historical availability as submitted by generators to National Grid. The data used is the Maximum Export Limit (MEL) submitted by generators for the winters from 2005/06 to the preceding winter.

1.32. The MEL data submitted by generators is commercial and a generator may declare itself unavailable for a number of reasons. There may be a planned maintenance outage, or a forced (unplanned) outage, or commercial reasons not directly related to technical availability. We assume that at times of system stress generators will only declare themselves unavailable if they are in fact technically unavailable.

1.33. The proportion of this unavailability that is due to planned maintenance was identified. On the assumption that under current market conditions this planned maintenance would not be scheduled for times of system stress, we exclude planned outages from our unavailability assumptions.

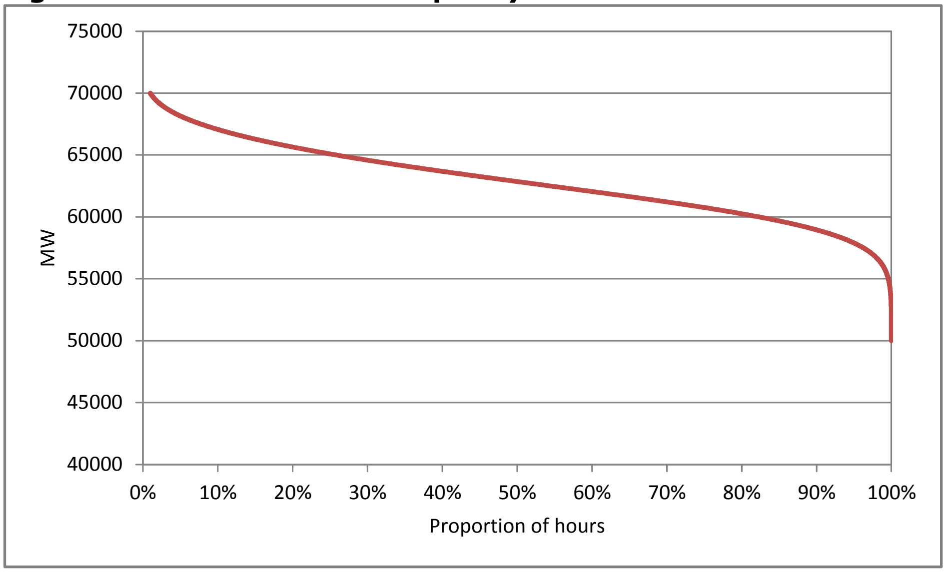
1.34. The final mean availability assumptions used in the Base Case are shown in Figure A3.5.

Figure A3.5 Generator availability assumptions

Fuel Type	Winter Availability
Coal (and Biomass)	87%
Gas CCGT	86%
OCGT	77%
Gas CHP	86%
Hydro	92%
Pumped Storage	95%
Nuclear	83%
Oil	81%

1.35. The availability and capacities of individual generators are combined into a single capacity outage table, which is a distribution of the aggregate available capacity. The distribution is shown as a Capacity Duration Curve in Figure A3.6. For example, there is close to a 100% probability that there will be at least 50GW of available capacity.

Figure A3.6 Conventional capacity distribution



Wind data source and modelling approach

1.36. The source for wind speed data is NASA's Modern Era Retrospective-analysis for Research and Applications (MERRA) reanalysis dataset.[28] This is a long term (1979-preceding winter) dataset built up from analysis of remote sensor (satellite) data. The full dataset is global in coverage and contains information on all aspects of climate.

1.37. For the purposes of this study, a subset of the MERRA data has been downloaded. The subset contains wind speeds at 2m, 10m and 50m height, for a grid covering the British Isles. The grid is at 0.5 degree longitude by 0.75 degree latitude which corresponds to approximately 50 km spacing over GB.

1.38. The model uses this data in combination with the capacity, hub height and coordinates of all transmission connected and embedded wind in GB.

1.39. The time series of wind speed is converted into a load factor series using either onshore or offshore turbine power curves, as appropriate.

1.40. For the capacity assessment model, wind output distributions are generated for each of the five winters for which the capacity assessment is performed. The

[28] MERRA data used in this project have been provided by the Global Modelling and Assimilation Office (GMAO) at NASA Goddard Space Flight Center through the NASA GES DISC online archive. https://gmao.gsfc.nasa.gov/merra/

distributions are calculated from the sensitivity capacity mix, combined with the full set of wind speed data (1979-preceding winter).

1.41. A single aggregate distribution of wind generation is created for each year. A large range of wind output levels can occur, with varying probabilities. It is useful to be able to translate this into an equivalent amount of firm capacity which provides the same contribution to security of supply, where the contribution to security of supply is measured in terms of LOLE or EEU.

1.42. We therefore use a standard measure known as Equivalent Firm Capacity (EFC). This is the amount of capacity that is required to replace the wind capacity to achieve the same level of LOLE. It is specific to a particular capacity and demand background.

1.43. EFC is a measure of the capacity adequacy provided by wind. A key use of the EFC is in the calculation of de-rated capacity margins, where the aim is to reflect the contribution of each generation type to capacity adequacy. It does not provide any insight on operational issues such as errors in wind forecasting.

Treatment of special cases

1.44. Here we discuss the treatment of special cases covering interconnectors, Demand Side Response (DSR), pumped storage and embedded generation.

1.45. Imports or exports on interconnectors to Ireland or Continental Europe are modelled as a decrease or increase in demand respectively. The assumptions on imports or exports over the interconnectors at peak vary between sensitivities. Exports are added directly to the demand distribution, and imports are subtracted from the distribution.

1.46. The availability of generation from pumped storage is modelled as conventional generation. The model does not take account of any constraints that may be imposed by the capacity of the storage, which could potentially limit the availability of generation from pumped storage across the peak period. Supporting analysis in National Grid's report suggests that the pumped storage generators have sufficient storage to operate across the peak period. This suggests that this limitation of the modelling is not significant for the five winters modelled.

1.47. Demand Side Response is assumed to continue at current levels. The model makes use of the actual historical demand data which already includes any demand reduction due to DSR. Using the historical data directly means that the impact of the current level of DSR is included in the model. We assume that there is no growth in DSR over the five year modelling period. This is consistent with National Grid's Future Energy Scenarios work.

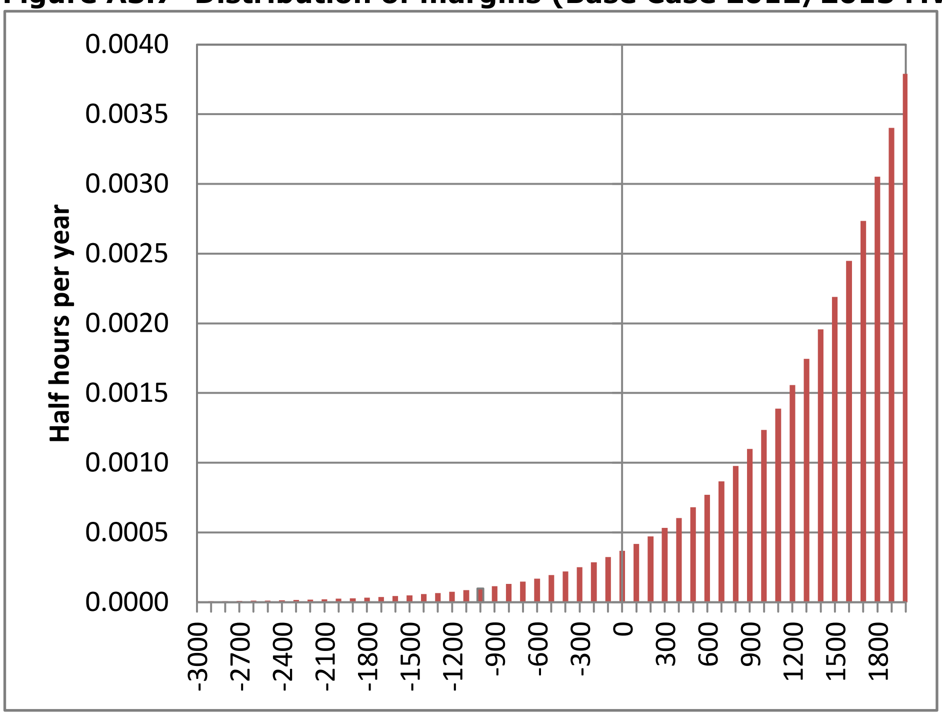
1.48. The historical demand data used is for demand met on the transmission system. Generation from embedded generators manifests as a decrease in demand on the transmission system. In this study, embedded wind generation is modelled explicitly as generation, and therefore the historical demand distribution is increased by an estimate of the demand met by embedded wind historically in each half hour. All other embedded generation (consisting of a range of technologies including for example small scale Combined Heat & Power, generation from landfill gas, and biomass) is implicitly modelled in the demand data. We assume that the growth in non-wind embedded generation is the same as the growth in demand.

Calculation of outputs

1.49. The distributions of conventional capacity and wind are combined to form a single distribution of generation capacity. The demand distribution is then subtracted to form a distribution of margins of supply over demand.

1.50. There is a small portion of the distribution for which demand exceeds supply and margins are negative. This is the left hand side of the distribution shown in Figure A3.7. Each bar represents the expectation of the number of half hours per year that the margin will be in that 100 MW tranche.

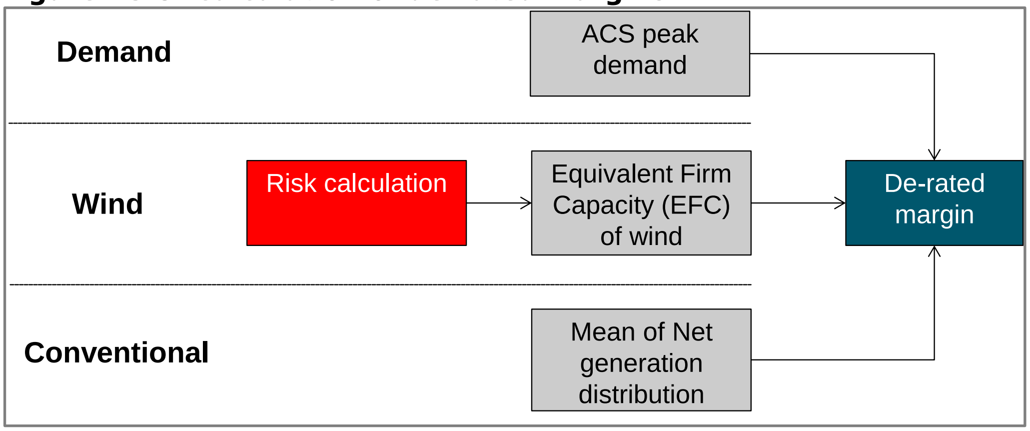
Figure A3.7 Distribution of margins (Base Case 2012/2013 MW)



1.51. The distribution of margins is used to calculate the risk and the impact of supply shortfalls by including two well-established probabilistic measures of security of supply analysis: LOLE and EEU. In addition, we calculate a commonly used indicator of security of supply: the de-rated capacity margin.

1.52. The calculation of the de-rated margin is shown schematically in Figure A3.8 below. There are three components: demand, wind generation and conventional generation. The de-rated margin can be stated in percentage terms as the excess of generator availability, divided by demand.

Figure A3.8 Calculation of de-rated margins



1.53. For demand, we use the ACS peak demand. As described above, it is possible for outturn demand to exceed this level. We also adjust at this point for the amount of generation that must be held as reserve against the largest loss on the system. Net exports over the interconnectors (which vary by sensitivity) are added to demand.

1.54. For conventional generation, the installed capacity of each generation type is multiplied by the mean availability of that type. The assumed availabilities are shown in Figure A3.5.

1.55. For wind capacity, the average availability of wind is not suitable as this would overstate the contribution of wind to security of supply. A more suitable value is the Equivalent Firm Capacity (EFC), estimated from the probabilistic model as described above. The model calculates the amount of firm capacity that would be needed to replace the wind capacity to give the same LOLE. This is lower than the mean winter load factor because of the chance that wind output will be very low.

1.56. The EFC is specific to any one sensitivity and year because it is dependent on the overall generation mix. The Capacity Assessment 2012 Base Case produces EFC values that are typically in the range of 20 -22%.

1.57. The de-rated capacity margin also includes an adjustment for assumed flows on the interconnectors and the reserve held by the System Operator (SO) for single largest infeed loss. This type of reserve is required in order to maintain the stability of the system, and therefore disconnection of demand would occur in preference to use of this reserve (whereas other forms of reserve would be used to prevent supply shortfalls).[29] As it is a form of reserve that must be maintained, we therefore include it as "demand" in the analysis.

1.58. The interconnection and reserve adjustment are applied as increases to GB demand. The assumptions for the Base Case are shown in Figure A3.9 below.

[29] This reserve is a sub-set of the full reserve requirement that the SO holds in order to manage the system on operational timescales.

Figure A3.9 Adjustments to ACS peak demand for interconnection and reserve

	2012/13 (MW)	2013/14 (MW)	2014/15 (MW)	2015/16 (MW)	2016/17 (MW)
Winter peak demand (ACS)	55614	55734	55873	55985	56173
Exports to Ireland	950	950	950	950	760
Reserve for largest infeed loss	700	700	1572[30]	1572	1572
Winter demand (ACS) – adjusted	57264	57384	58395	58507	58505
Summer peak demand - adjusted	40200	40279	41242	41314	41441

Estimation of impact on customers - Frequency and duration analysis

1.59. We have translated the risk metrics, LOLE and EEU, into the possible effects on electricity customers. We estimate the likely frequency and duration of shortfalls in supply and categorise these outages by severity. The categories are defined by the potential mitigating measures which may be available to the System Operator. These measures can be seen on Figure A3.10.

Figure A3.10 Mitigation measures

Action	Comments	Assumed effect in MW
Voltage reduction	Reduce demand by instructing distribution network owners (DNOs) to reduce voltage	500
Maximum generation	Increase in supply by instructing generating plants to increase generation to maximum	250
Provision of emergency services through interconnection	Increase in supply through interconnection services with neighbouring countries (various services available, eg Emergency Instruction, Emergency Assistance and Cross-Border Balancing)	2000

1.60. We define a set of outage categories to match the possible mitigation measures shown in Figure A3.10. The duration and energy unserved calculated for each of these categories is shown in Figure A3.11 for the Capacity Assessment 2012 Base Case. The mitigation measures are assumed to be always available and always taken in the order shown in this figure.

[30] Practically, National Grid will only hold enough response to cater for events that can happen on any individual day – so one needs to check when the largest loss actually increases. At the moment National Grid uses about 700MW of capacity to meet the response requirement. From winter 2014/2015 this number will increase by 872MW to 1572MW.

Figure A3.11 Outage categories with typical duration and typical size of outage

Event	Typical size	Typical Duration	Mitigation
	MWh	(mins)	(options)
0 - 10MW	0.04	1.00	No impact
10 - 500MW	32.66	8.76	Voltage reduction
500 - 750MW	1,347.62	100.85	Voltage reduction and max gen
750 - 2750MW	4,621.57	136.17	Voltage reduction, max gen and emergency services from interconnection
2750+ MW	22,346.22	310.75	Controlled disconnections

1.61. The probabilistic model does not produce the frequency and duration of outages directly as it does not account for the chronological ordering of the time periods during which the variable under study are measured. We can estimate the frequency and duration of outages using the following additional assumptions:

- We assume that outages occur on a typical peak demand day (a weekday in January).
- We assume that the conventional plant availability is constant over the duration of an outage. This is reasonable given that typical repair times are longer than the peak period.
- We assume that the wind availability does not change over the duration of an outage. This is an approximation that is reasonable given the level of wind generation in the time horizon of the modelling, but which will become less valid in future years.

1.62. Using the minute by minute demand profile for the typical peak demand day, the total duration of an outage may be defined as the length of continuous time for which demand exceeds supply. The maximum severity of this outage (GW) is the maximum value of the excess of demand over supply, and it is possible to estimate the mean length of time, during the outage, at which the shortfall is at this maximum value. For each level of shortfall which is lower than the maximum, it is similarly possible to estimate the mean length of time, during the outage, at which the shortfall is at this lower level.

1.63. Controlled disconnections occur after voltage reduction, maximum generation services and emergency services from interconnectors have been exhausted. For the Capacity Assessment 2012 Base Case, the modelling suggests that a shortfall in demand of 2.75GW or greater will typically last 5 hours and the total energy unserved would be 22GWh.

1.64. Given this set of outage types, typically characterised by their maximum levels of severity, for each year and sensitivity we need to find the frequency of each outage type. These frequencies need to be consistent with the outputs of the earlier probabilistic model. To describe the analysis, for each outage type k, let f_k denote the annual frequency of outages of this type, and, for each loss of load of j GW, let $\mu_{k,j}$ denote the mean length of time (hours) that such an outage lasts. Then, for each j

$$N_j = \sum_{k=1}^{K} f_k \mu_{k,j} \qquad (3)$$

where N_j is the expected number of hours per year at which the loss of load is j. The N_j, which are illustrated in Figure A3.7, are the fundamental outputs of the earlier probabilistic model; indeed we have

$$[\text{LOLE}] = \sum_{j=1}^{J} N_j \qquad (4)$$

$$[\text{EEU}] = \sum_{j=1}^{J} jN_j \qquad (5)$$

where J is the maximum loss of load with a non-negligible probability. Given the earlier estimates of the $\mu_{k,j}$, the equations (3) (which are J equations in K unknowns) may now be solved for the required frequencies f_k. For example, if outage type k corresponds to a maximum loss of load during the outage of k GW, so that $K = J$ and, for each k we have $\mu_{k,j} = 0$ for $j > k$, then the equations (3) may be solved recursively, starting with $j = J$, to determine uniquely all the f_k[31].

1.65. The final values are thus a set of frequencies (1 in n years) for each shortfall category. The results should be considered approximate only, due to the additional assumptions required. There is also a risk that each of the mitigation measures may not be fully available to the System Operator when required.

Uncertainty analysis

1.66. In this section we describe the approach to quantifying the uncertainty inherent in this analysis.

1.67. The uncertainty can be characterised into three types:

---

[31] As a simple numerical example, which is intended for illustration only, suppose that the daily demand curves suggest that there are just two shortfall types: type 1 shortfalls correspond to an outage of 1 GW and have a mean duration of $\mu_{1,1}$ = 1hr, while type 2 shortfalls correspond to an outage of 2 GW with a mean duration of $\mu_{2,2}$ = 2hrs, coupled with an outage of 1 GW with a further mean duration of $\mu_{2,1}$ = 3 hrs. The equations (3) then become

$$N_1 = f_1 + 3f_2$$
$$N_2 = 2f_2$$

giving $f_2 = N_2/2$ and then $f_1 = N_1 - 3N_2/2$. If the expected number of hours in the year at which the loss of load is 1 GW is given by $N_1 = 0.13$, while the expected number of hours in the year at which the loss of load is 2 GW is given by $N_2 = 0.02$, then we have $f_1 = 0.1$ and $f_2 = 0.01$. Thus type 1 shortfalls occur on average 1 year in 10, while type 2 shortfalls occur on average 1 year in 100.

- Statistical (internal) uncertainty
- Uncertainty due to independence assumptions within the model
- Uncertainty due to non-statistical modelling assumptions

1.68. We describe the approach to each of these in turn below.

1.69. Statistical (internal) uncertainty is the uncertainty in the probability distributions derived from historical data, in this case the probability distributions of demand and wind. It arises from the natural randomness in the finite sample of data used in the analysis.

1.70. Uncertainty in the probability distributions derived from historical data can be estimated through a resampling technique known as *bootstrapping*. This technique uses sampling with replacement from within the dataset to produce *bootstrap* samples. Each of these bootstrap samples is then used to re-estimate the output quantity of interest, e.g. LOLE or EEU. The resampling of the data is done in blocks sufficiently large as to be considered independent of each other. The variability in the re-estimated quantities then provides a reasonable measure of the uncertainty due to the finiteness of the input data.

1.71. In the case of demand, bootstrapping is used to estimate 95% confidence intervals for LOLE and EEU based on the uncertainty in the demand distribution. The demand is divided into weekly blocks which are assumed to be independent, then resampled many times to produce a large number of bootstrap samples. Each sample produces a different estimate for LOLE and EEU. We thus find 95% confidence intervals for LOLE and EEU.

1.72. A similar technique may in principle be used to assess the uncertainty due to the finiteness of the wind data. However the feasibility of this approach depends on managing the large computational overhead in the processing of this data. Further, uncertainty in the distribution of wind generation may well be dominated by the uncertainty in the assumption that wind generation is independent of demand. Assessment of this latter uncertainty is discussed below.

1.73. The distribution of conventional plant availability is derived from historical analysis of outage rates, and the uncertainty in this distribution is best characterised through sensitivity analysis on the outage rates used.

1.74. The assumption of independence of distributions is a source of uncertainty. The assumption that wind and demand are independent at times of system peak is a reasonable assumption given that there is no well characterised statistical relationship between the two. This assumption is an uncertainty which is tested to some extent through the "Lower wind at peak" sensitivity. This sensitivity assumes wind is lower at peak times, ie 75% of the Base Case value.

1.75. Figure A3.12 summarises the approach to the uncertainties on various parameters in the modelling.

Figure A3.12 Summary of approach to treatment of uncertainties

Uncertainty source	Uncertainty type	Approach
Demand	Statistical (internal)	Bootstrapping &sensitivity analysis
Wind	Statistical (internal) and data source, but dominated by independence assumption	Bootstrapping
Distribution of conventional capacity	Dominated by modelling assumptions about plant availability probabilities	Sensitivity analysis
Assumption of independence of demand and wind at time of system peak	Independence assumption in model	Sensitivity analysis, based on varying wind distribution at times of peak demand
Installed generating capacity	Modelling assumption	Sensitivity analysis
Forced outage rates	Modelling assumption	Sensitivity analysis: variation of forced outage rates by +-5%
Availability of capacity over interconnector	Modelling assumption	Sensitivity analysis

Transmission constraint model

1.76. This section describes the model used to estimate the impact of the Cheviot constraint on LOLE and EEU. The model outputs the *additional* LOLE and EEU due to this constraint, and this must be added to the LOLE and EEU already present in the unconstrained model.

1.77. The basis of the analysis is a two-area model which uses separate distributions of demand, wind and conventional generation availability for England and Wales and for Scotland, and imposes a constraint on the transfer of capacity across the Cheviot boundary. However, the model does not define separate values of LOLE and EEU for each of the above two regions. To attempt to do so would require additional assumptions about how the system is operated at times of peak (in which the flow across the Cheviot boundary is almost invariably from Scotland to England). However, since the system is operated on a GB-wide basis, any such assumptions are unlikely to correspond to what happens in practice.

1.78. To describe the model, let the random variables Z_{EW} and Z_S represent the respective surpluses at any random time instant in England and Wales and in Scotland. Let c be the capacity of the transmission link between the two regions. Then the additional LOLE and EEU due to the transmission constraint are calculated via the corresponding additional LOLP and EPU given by

$$[\text{Additional LOLP}] = \mathbf{P}(Z_{\text{EW}} + Z_{\text{S}} > 0, Z_{\text{EW}} \leq -c) + \mathbf{P}(Z_{\text{S}} + Z_{\text{EW}} > 0, Z_{\text{S}} \leq -c) \qquad (6)$$

$$[\text{Additional EPU}] = \mathbf{E}((\min(-Z_{\text{EW}}, Z_{\text{S}}) - c)^{+}) + \mathbf{E}((\min(-Z_{\text{S}}, Z_{\text{EW}}) - c)^{+}) \qquad (7)$$

where for any random variable Y we define Y^{+} = *max (Y,0)* and where, in each of the above two expressions, the first term on the right side corresponds to the transmission link being insufficient to transfer power from Scotland to England and

Wales and the second term on the right side corresponds to the transmission link being insufficient to transfer power from England and Wales to Scotland[32].

1.79. The distributions of the random variables Z_{EW} and Z_S are calculated as that of the random variable Z in the single-area model. These two random variables cannot be treated as independent, as neither wind generation nor demand may be treated as independent between the two regions. However, on the assumption that conventional generation availability *may* be treated as independent between the two regions, Z_{EW} and Z_S are conditionally independent for any given combination of wind and demand values in the two regions. Evaluation of the above expressions for the additional LOLP and EPU is then achieved by conditioning on the allowed values of wind and demand combinations. As in the single area unconstrained model wind and demand continue to be treated as independent of each other.

1.80. The additional complexity of the required two-area analysis is such that an exact calculation of outputs (based on a complete enumeration of all possible wind and demand combinations over the two regions) is computationally infeasible, and therefore the model uses an approach known as Importance Sampling to find a reduced sample which can be used to estimate the additional LOLE and EEU in a two-area system. The additional uncertainty introduced by this approach is small and is reported as the standard error of the importance sample.

[32] The above expression for the additional LOLP due to the transmission constraint is straightforward. To understand the expression for the additional EPU, note that whenever, for example, $Z_{EW} < -c$ and $Z_S > c$ the transmission constraint has the effect of reducing the power transferred from Scotland to England and Wales from $min(-Z_{EW}, Z_S)$ to c.

Appendix 4 - Glossary

C

Capacity margin

The capacity margin is defined as the excess of installed generation over demand. It is sometimes referred to as reserve margin.

Capacity mechanism

Policy instrument designed to help ensure security of supply by providing a more secure capacity margin than that which would be determined by the market without intervention.

Combined Heat and Power (CHP)

The simultaneous generation of usable heat and power (usually electricity) in a single process, thereby leading to reductions in the amount of wasted heat.

Constraints (also known as congestion)

A constraint occurs when the capacity of transmission assets is exceeded so that not all of the required generation can be transmitted to other parts of the network, or an area of demand cannot be supplied with all of the required generation.

Consumer

In considering consumers in the regulatory framework we consider users of network services (for example generators, shippers) as well as domestic and business end consumers, and their representatives.

D

DECC

Department of Energy and Climate Change.

Demand profile

The rate at which energy is required, expressed in kilowatts (kW) or megawatts (MW). It is usually related to a time period, typically half an hour, e.g. 1 kWh used over half an hour is a demand rate of 2 kW. A graph of demand rate over a typical day, for example, is the demand profile.

Demand Side Response (DSR)

An active, short term reduction in electricity consumption either through shifting it to another period, using another type of generation, or simply not using electricity at that time.

De-rated capacity margin

The de-rated capacity margin is defined as the excess of available generation capacity over demand. Available generation capacity is the part of the installed capacity that can in principle be accessible in reasonable operational timelines, i.e. it is not decommissioned or offline due to maintenance or forced outage.

Distribution Network Operators (DNO)

DNOs came into existence on 1 October 2001 when the ex-Public Electricity Suppliers were separated into supply and distribution businesses. There are 14 DNOs covering discrete geographical regions of Britain. They take electricity off the high voltage transmission system and distribute this over low voltage networks to industrial complexes, offices and homes. DNOs must hold a licence and comply with all distribution licence conditions for networks which they own and operate within their own distribution services area. DNOs are obliged to provide electricity meters at the request of a supplier.

E

Embedded generation

Any generation which is connected directly to the local distribution network, as opposed to the transmission network, as well as combined heat and power schemes of any scale. The electricity generated by such schemes is typically used in the local system rather than being transported across the UK.

EMR

Electricity Market Reform.

Energy efficiency

A change in the use of energy to reduce waste and lower energy use. For example, insulation in buildings, reducing demand from heat, or increasing the efficiency of appliances so they use less energy.

Expected energy unserved

This is a statistical measure of the expected volume of demand that cannot be met over a year because generation is lower than required.

F

Forced outages

The shutdown of a generating unit, transmission line, or other facility for emergency reasons or a condition in which the generating equipment is unavailable for load due to unanticipated breakdown.

I

Interconnector

Electricity interconnectors are electric lines or other electrical plants based within the jurisdiction of Great Britain which convey electricity (whether in both directions or in only one) between Great Britain and another country or territory.

Intermittent generation

Electricity generation technology that produces electricity at irregular and, to an extent, unpredictable intervals, eg wind turbines.

L

Large Combustion Plant Directive (LCPD)

An EU Directive placing restrictions on the levels of sulphur dioxide, nitrogen oxides and dust particulates which can be produced by combustion plants with a thermal output greater than 50MW. The implementation of the LCPD in the UK requires coal and oil plant to fit flue gas de-sulphurisation (FGD) equipment or have their total running hours restricted to 20,000 between 1 January 2008 and 31 December 2015 before closing prior to the end of that period.

Loss of Load Expectation (LOLE)

LOLE is the probability of the capacity margin being negative or of demand being higher than generation capacity in the year.

M

Maximum Export Limit (MEL)

MEL is the maximum power export level of a particular BM Unit at a particular time.

Mothballed

A term often used for long term storage of Generating Units. Such plant is sometimes also referred to as ‘decommissioned’.

N

National Electricity Transmission System (NETS) System Operator (SO)

The entity responsible for operating the GB electricity transmission system and for entering into contracts with those who want to connect to and/or use the electricity transmission system. National Grid is the GB electricity transmission system operator.

National Grid Electricity Transmission plc (NGET)

NGET is the Transmission System Operator for Great Britain. As part of this role it is responsible for procuring balancing services to balance demand and supply and to ensure the security and quality of electricity supply across the Great Britain Transmission System.

P

Peak demand, peak load

These two terms are used interchangeably to denote the maximum power requirement of a system at a given time, or the amount of power required to supply customers at times when need is greatest. They can refer either to the load at a given moment (eg a specific time of day) or to averaged load over a given period of time (eg a specific day or hour of the day).

Pumped storage

Process, also known as hydroelectric storage, for converting large quantities of electrical energy to potential energy by pumping water to a higher elevation, where it can be stored indefinitely and then released to pass through hydraulic turbines and generate electrical energy.

S

Scheduled outage

The shutdown of a generating unit, transmission line, or other facility for inspection or maintenance, in accordance with an advance schedule.

Sensitivity

This is a test whereby a single factor is changed (eg interconnector flows) keeping all other factors fixed to their base case value to see the effect the single factor produces on the model output (eg LOLE)

T

Transmission System

The system of high voltage electric lines providing for the bulk transfer of electricity across GB.

The Authority/Ofgem

Ofgem is the Office of Gas and Electricity Markets, which supports the Gas and Electricity Markets Authority ("the Authority"), the regulator of the gas and electricity industries in Great Britain.

U

UKERC

UK Energy Research Centre.

W

WOR

Winter Outlook Report.

Appendix 5 - Feedback Questionnaire

1.1. Ofgem considers that consultation is at the heart of good policy development. We are keen to consider any comments or complaints about the manner in which this consultation has been conducted. In any case we would be keen to get your answers to the following questions:

1. Do you have any comments about the overall process, which was adopted for this consultation?
2. Do you have any comments about the overall tone and content of the report?
3. Was the report easy to read and understand, could it have been better written?
4. To what extent did the report's conclusions provide a balanced view?
5. To what extent did the report make reasoned recommendations for improvement?
6. Please add any further comments?

1.2. Please send your comments to:

Andrew MacFaul
Consultation Co-ordinator
Ofgem
9 Millbank
London
SW1P 3GE
andrew.macfaul@ofgem.gov.uk