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

Consultation

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Overview:

The December 2010 Energy Bill requires Ofgem to produce a report with an assessment of different electricity capacity margins and the risk to security of supply associated with each alternative. In this document we consult on the approach to measuring and modelling the electricity capacity margin and the risk of supply shortfalls in Great Britain.

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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 December 2010 Energy Bill will amend the Electricity Act 1989 (Electricity Act) to insert a new section which will oblige Ofgem to provide the Secretary of State with a report assessing different electricity capacity margins and the risk to security of supply associated with each alternative. Ofgem's capacity assessment report is to be delivered to the Secretary of State every September, starting in 2012. The report is intended to be used as an input into the design of a potential capacity mechanism under the Electricity Market Reform.

Fulfilling the new Electricity Act will require the conduct of a one-off exercise to develop a model which assesses the security of supply risks associated with the different electricity capacity margin levels. This model will then be updated on an annual basis 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 we intend to delegate the construction and updating of the model to National Grid Electricity Transmission plc.

This document consults on a proposed approach to measuring and modelling the risk of supply shortfalls in Great Britain.

Associated documents

- Energy Bill (HC Bill 206)
- 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".

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

Contents

Executive Summary

In the next decade the electricity market in Great Britain (GB) will go through significant changes. GB will lose around 25 percent of its generation capacity due to ageing plants and environmental regulations. In addition, GB is expected to experience a significant rise in intermittent generation (for instance from wind). The Department of Energy and Climate Change (DECC) under the Electricity Market Reform (EMR) has indicated that in its view a Capacity Mechanism is necessary and has run a consultation on the design of that mechanism, which closed on 4 October 2011.

Under some forms of Capacity Mechanisms, the Secretary of State will need to form a view on the level of electricity supply capacity required for the purpose of meeting the demands of existing and future consumers in GB. Ofgem will produce estimates of the risk to security of supply associated with different levels of the capacity margin. The Secretary of State may use these alongside other factors, including the value consumers attach to not having energy supply interruptions ('value of lost load') and the costs of different capacity margin levels, to determine the required level of capacity on the system.

Any decision on the required capacity level will have significant consequences for consumers and other market participants. If the level is set too high, it may result in unnecessarily high prices to pay for the excess capacity. Conversely, if set too low, it could result in supply issues if the capacity level is not sufficient to cope with demand.

In order for DECC to make a decision on the required level of capacity, DECC will amend the Electricity Act 1989 and will place a new obligation on Ofgem. To fulfil the obligation, the Authority will need to prepare a report for the Secretary of State every September, starting in 2012 that will include:

(i) a range of plausible forecasts of demand and installed capacity for the next four years;

(ii) the resulting range of plausible forecasts of the capacity margin; and

(iii) the associated risk of supply shortfalls.

A clear conceptual approach is needed to produce this report, as well as a new modelling tool. The report will include an assessment of the de-rated capacity margin, which is the expected excess of available generation capacity[2] to demand. The report will also show the risk of supply shortfalls associated with the de-rated capacity margin. We propose to measure this risk using two measures: Loss of Load Expectation (LOLE) and Expected Energy Unserved (EEU). LOLE is defined as the

[2] Available generation takes into account any expected intermittency of the generation fleet and the fact that plants at times may not generate because of faults or maintenance.

probability of demand being higher than available capacity during the year. EEU is the expected volume of demand that cannot be met over a year.

A base case scenario will be developed primarily based on available data from NGET. Recognising long term uncertainty in key inputs, for example retirement decisions and installed generation capacity, a small set of alternative scenarios around the base case will be presented. For the base case scenario and the alternative scenarios the model will produce a range of plausible forecasts of the de-rated capacity margin and the associated LOLEs and EEUs for the next four years. To capture short term variability in demand and generation, for example due to weather conditions and plant faults, the model will use stochastics (probability distributions) based on historical data. Our methodology is similar to the approaches followed by capacity adequacy studies conducted by transmission system operators in Europe and in the US.

We are of the view that National Grid Electricity Transmission plc (NGET) is best placed to carry out the modelling that will inform Ofgem's annual report to the Secretary of State. This will ensure consistency with other existing reports where appropriate. It will also make use of NGET's knowledge of the market, data and modelling capabilities. This consultation document has been developed in close collaboration with NGET.

In order to develop the most appropriate approach, we are keen to get views on our proposals from key stakeholders and industry experts. In particular, we would like to receive comments on our approach and which of our specific modelling and data proposals would be most appropriate for producing an assessment of the risk of supply shortfalls in Great Britain.

We are seeking responses to the consultation questions set out in this document by 7 December 2011. We intend to publish the final decision document at the turn of the year. The model development will begin in early 2012 with the first submission of the final report to the Secretary of State by 1 September 2012.

1. Introduction

Chapter Summary

In this chapter we describe the background that led to the obligation on the Authority to provide the Secretary of State with an annual report on the plausible forecasts of the capacity margin and associated risk of supply shortfalls. We also briefly describe existing security of supply reports and explain the reasoning for a new modelling approach. Finally, we set out the structure of the document.

Background

1.1. Historically Great Britain (GB) has benefited from robust security of supply from its fleet of generation plants. However, over the coming years the electricity system will experience changes that raise concerns over security of supply. GB will lose around 25 percent of its generation capacity due to ageing plants and environmental regulations. In addition, GB is expected to experience a significant rise in intermittent generation, for instance from wind.

1.2. In this context, the Department of Energy and Climate Change (DECC) under the Electricity Market Reform (EMR) has indicated its desire to introduce a Capacity Mechanism in GB and has run a consultation on the design of that mechanism, which closed on 4 October 2011.[3] Under some forms of Capacity Mechanisms, the Secretary of State will need to form a view on what electricity supply capacity is required to provide the level of supply security appropriate for GB consumers.

1.3. Any decision on the required capacity level will have significant consequences for consumers and other market participants. If the capacity level is set too high, it may result in unnecessarily high prices to pay for the excess capacity. Conversely, if set too low it could result in supply issues if the capacity level is not sufficient to cope with demand.

1.4. To that end, the December 2010 Energy Bill will amend the Electricity Act 1989 (Electricity Act)[4] to place an obligation on the Authority to prepare a report for the Secretary of State assessing different electricity capacity margins and the risk to security of supply associated with each alternative.

[3] Department of Energy and Climate Change, Electricity Market Reform White Paper 2011, http://www.decc.gov.uk/assets/decc/11/policy-legislation/EMR/2176-emr-white-paper.pdf
[4] The proposed new draft section of the Electricity Act is set out in Appendix 2.

Existing security of supply reports

1.5. There are several existing reports on security of supply for GB. DECC and Ofgem jointly publish the Statutory Security of Supply Report (SSSR) in accordance with their obligation under section 172 of the Energy Act 2004.[5] The SSSR provides forward looking energy market information relating to security of supply, including the identification of risks and drivers.

1.6. In addition, National Grid Electricity Transmission plc (NGET) publishes the National Electricity Transmission System (NETS) Seven Year Statement (NETS SYS) in accordance with Standard Licence Condition C11 of NGET's Electricity Transmission Licence.[6] The aim of the NETS SYS is to assist existing and prospective users of the NETS in assessing opportunities available to them for making new or further use of the NETS in the competitive electricity market in GB. NGET also publishes the Winter Outlook Report and the Summer Outlook Report which look at supply and demand for the seasons ahead.[7]

1.7. Although the above reports relate to security of supply in the electricity sector, they fall short of providing an estimate of the risk of supply shortfalls in a form that can be used as an input into a potential capacity mechanism. Therefore, Ofgem believes that in order to fulfil its obligation, which it is anticipated to have following amendments to the Electricity Act, the report to the Secretary of State will have to estimate the future electricity capacity margin and quantify the associated risk to security of supply. To do so, a new approach is needed as well as a new modelling tool for GB.

Document structure

1.8. In this document we set out our proposed approach to fulfilling Ofgem's anticipated, new obligation. In particular, we are consulting on our general approach for assessing the capacity margin and the associated risks to security of supply. In addition, we welcome industry's views on modelling and specific data that our approach may require.

1.9. This document is structured as follows:

- In Chapter 2, we set out the requirements of the Energy Bill (which will amend the Electricity Act).

[5] Available from http://www.decc.gov.uk/assets/decc/What%20we%20do/UK%20energy%20supply/resilience/803-security-of-supply-report.pdf
[6] Available from http://www.nationalgrid.com/uk/Electricity/SYS/
[7] There are also independent reports regarding security of supply, an example is the Poyry report on the impact on wind intermittency (http://www.poyry.com/linked/group/study).

- Chapter 3 presents the measures of risk and capacity margin we propose to use. It also sets out our approach to dealing with the short term variation and the long term uncertainty of input variables.

- Chapter 4 presents the proposed modelling approach and data requirements. These relate to more complex aspects of the modelling, in particular building the demand and supply profiles of the GB electricity market and how to take account of the effects of wind intermittency, plant outages and transmission constraints.

- Chapter 5 sets out our next steps.

2. Legislative requirement

Chapter Summary

This chapter sets out Ofgem's obligation under the December 2010 Energy Bill, which will amend the Electricity Act 1989 (Electricity Act).

2.1. This section summarises Ofgem's new obligation which is set out in the Energy Bill 2010. The Energy Bill will amend the Electricity Act, by inserting a new section 47ZA into the Electricity Act. Appendix 2 includes the relevant draft clauses. Under the new draft section 47ZA of the Electricity Act the Authority must, before 1 September 2012, and before that date in every subsequent calendar year, prepare a report for the Secretary of State with:

- a forecast of the peak demand for the supply of electricity to consumers in GB, and;
- an assessment of different possible electricity 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.

2.2. The draft section 47ZA of the Electricity Act states that the report should produce a forecast for the above for each of the four calendar years immediately following the year of the report or any other periods that the Secretary of State specifies by order. For example, the 2012 report will include forecasts up to the end of 2016, under the current reporting requirement. We note that there is flexibility in the draft section 47ZA for the time horizon to be modified by the Secretary of State. However, we are not consulting on the time horizon for the capacity assessment as it is determined by the Secretary of State.

2.3. In particular, the draft section 47ZA of the Electricity Act states that the capacity margin assessment must take into account:

- the generation of electricity;
- the operation of electricity interconnectors;
- the storage of electricity;
- 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;
- demand side response.

2.4. The draft section 47ZA of the Electricity Act allows Ofgem to delegate the forecast of the peak demand and the capacity assessment to another party, which can be a transmission licence holder.

3. Measuring the risk of supply shortfalls

Chapter Summary

This chapter describes the reasons for choosing the de-rated capacity margin as our proposed capacity margin measure and sets out the measures of risk we propose to use. It also maps out our approach to dealing with short term variation and long term uncertainty of the model input variables.

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

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

3.1. The Electricity Act will require Ofgem to produce an assessment of different possible capacity margins and an assessment of the risk of supply shortfalls. There are various definitions for the capacity margin as well as measures for the risk of supply shortfalls. This chapter first presents the capacity margin and the two measures of risk we propose to include in our report alongside the reasoning for these proposals. We also set out our proposed approach to dealing with short term variability and long term uncertainty of key model input variables.

De-rated capacity margin

3.2. The Energy Bill requires Ofgem to provide estimates of the capacity margin. There are two main capacity margin measures:

- The **capacity margin or reserve margin** is defined as the excess of installed generation over demand.

- The **de-rated capacity margin** is defined as the expected excess of available generation capacity over demand. Available generation capacity is the part of the installed capacity that is expected to be accessible in reasonable operational timelines, ie it is not decommissioned[8] or offline due to maintenance or forced outage. The available generation capacity will also take into account any expected intermittency of the generation fleet.

3.3. We propose to use the de-rated capacity margin rather than the simple capacity margin in our report. The latter becomes a less and less reliable indicator of system security when more and more intermittent plant is added to the system. This is because intermittent plants' generation, like wind farms, depends on weather

[8] Decommissioned plants are sometimes referred to as "mothballed".

conditions and thus these types of plants provide uncertain levels of generation capacity.

3.4. Traditionally, the de-rated capacity margin is measured relative to peak demand. However, the electricity system could also be under stress at non-peak demand times, when maintenance outages are scheduled, ie in summer. Ofgem's report will therefore estimate the annual profile of the de-rated capacity margin in addition to the de-rated capacity margin at peak demand.

Capacity adequacy vs. capacity flexibility

3.5. In general, the capacity adequacy of a power system is defined as the ability of generation to match demand at all times. In the long term, capacity adequacy is delivered through investment in generation and other infrastructure to cover peak demand. In the short term, capacity adequacy is guaranteed by the availability of enough flexible capacity to cover for demand fluctuations, loss of generation units due to forced outages as well as variability in wind generation. Flexible capacity refers to plant types that can increase generation output quickly ("ramp-up"). As greater amounts of wind generation are added to the system the need for flexible generation will increase.

3.6. DECC's Capacity Mechanism aims to address a potential lack of capacity to meet demand during periods of high demand and low wind generation. The aim of the mechanism is not to address the potential lack of short term flexibility, ie look at plants that can increase generation output quickly.[9] In addition, the Energy Bill requires Ofgem to assess the risk of supply shortfalls associated with peak demand conditions and not with a potential lack of flexible generation capacity. Our approach does not take into account the different flexibility characteristics of the plants to arrive at the de-rated capacity margin and the measures of risk.

Transmission

3.7. When transmission constraints exist, a situation could arise where nationally there is enough available generation capacity, but demand in an area of the country still cannot be met. The model will have to make allowances for transmission constraints. We propose the development of a two region model: with one being England and Wales and the other Scotland to identify possible security of supply risks at a regional level. This issue is discussed in more detail in chapter four.

[9] The White Paper specifically states "We propose that the Capacity Mechanism addresses the third problem [resource adequacy], though interactions between a Capacity Mechanism and short-term balancing actions would need to be carefully considered". Resource adequacy in the White Paper is defined as "how to ensure there is sufficient reliable and diverse capacity to meet demand, for example during winter anti-cyclonic conditions where demand is high and wind generation low for a number of days" (2011, pp62). Department of Energy and Climate Change, Electricity Market Reform White Paper 2011, http://www.decc.gov.uk/assets/decc/11/policy-legislation/EMR/2176-emr-white-paper.pdf

Gas availability

3.8. Currently there is approximately 35GW of installed gas generation capacity in GB. Therefore, availability of gas supplies has important implications for the electricity system. Although we are not proposing to explicitly model gas fuel availability, we plan to include a specific stress test on the availability of gas in our report.

Short term variation

3.9. There are several key inputs that are needed for the estimation of the de-rated capacity margin, for example demand growth, wind build rates, maintenance outages, interconnection flows, etc. Some of the key input variables may experience short term variation. For example, available generation may vary in the short term due to random plant faults and demand due to changes in the weather conditions.[10]

3.10. This short term variation results in some uncertainty around the short term outcomes of the de-rated capacity margin. Therefore, there is some uncertainty about the degree of protection the de-rated capacity margin offers against supply shortfalls. We propose to also report measures that quantify the risk of supply shortfalls associated with the different capacity margins.

Measures of risk

3.11. There are two main measures that are used in the electricity sector to assess the risk of supply shortfalls, the Loss of Load Expectation and the Expected Energy Unserved.[11]

Loss of Load Expectation (LOLE)

3.12. LOLE is the probability of the capacity margin being negative or of demand being higher than generation capacity in the year.[12] It can be expressed as a simple percentage probability (eg an x% probability of an outage during the year) or as a 1-in-x year chance event.

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[10] Chapter 4 provides more details on the properties of key input variables and how we propose to treat them.
[11] Another much less frequently reported measure of risk is the expected distribution of outages, which is a more detailed statistical output and shows the distribution of outages of different sizes. This measure is based on the same estimation principles as LOLE and EEU.
[12] Demand is defined as net-of-wind demand. Generation is defined as the available generation, which is the part of the installed capacity that can in principle be accessible in reasonable operational timelines, ie it is not decommissioned or offline due to maintenance or forced outage. Available generation capacity will also take into account any expected intermittency of the generation fleet. Generation includes interconnection. We explain the reasons for using these definitions in chapter 4.

3.13. The use of LOLE is an internationally accepted criterion in capacity adequacy reports (eg EirGrid in Ireland, Pennsylvania–New Jersey-Maryland Interconnection (PJM), Mid-West Independent System Operator (MISO)). These reports may also provide international standards for illustrative purposes. For instance, the current capacity adequacy report for the US PJM supports a generation LOLE of 1 in 10 years.[13] However, we appreciate that different power systems face different circumstances and therefore international standards may not be directly applicable to the GB system.

Expected Energy Unserved (EEU)

3.14. This is a statistical measure of the expected volume of firm demand (ie net of interruptible contracts) that cannot be met over a year because generation is lower than required. The measure has been used by the DECC in assessing electricity security of supply and when evaluating policy options under the EMR.

3.15. Similar to LOLE calculations, to calculate EEU, the model will estimate the probability of demand being higher than generation capacity. In addition, an estimate of the supply shortfall will be attached to these probabilities. Finally, it will aggregate the product of the individual probabilities with the estimated shortfall for the whole year, producing an estimate of EEU.

3.16. We therefore consider Ofgem's capacity assessment report should also include EEU as it measures the magnitude of possible supply shortages.

Long term uncertainty

3.17. In addition to the short term variation in some key input variables, we recognise that predicting the outcome of some variables in the long term is also uncertain. For example, retirement decisions, installed generation capacity, and demand growth can affect the de-rated capacity margin and the associated risk measures.

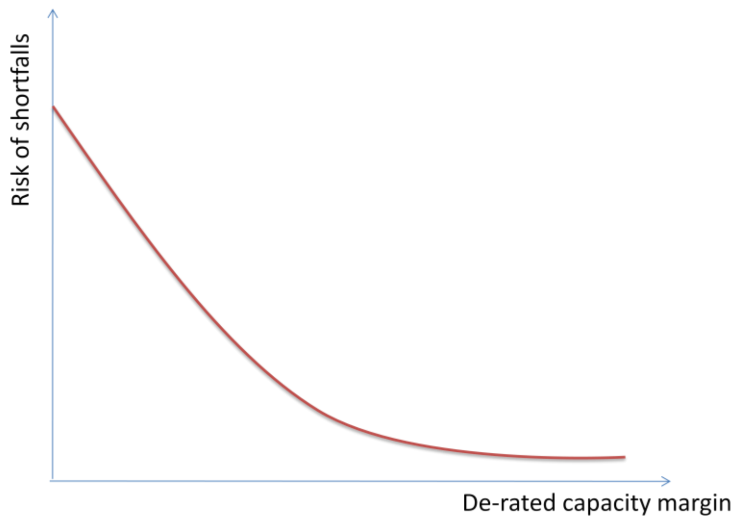
3.18. In order to address this long term uncertainty, we propose to use a small set of alternative scenarios around a base case scenario, as well as a stress test.[14] For the base case scenario, the alternative scenarios and the stress test, the model will produce a range of plausible forecasts of the de-rated capacity margin and the associated LOLEs and EEUs for the next four years.

3.19. Figure 1 illustrates the relationship between the de-rated capacity margin and the risk of supply shortfalls. As the de-rated capacity margin rises, the level of LOLE

[13] We are not consulting on the appropriate level of capacity as it will not be determined by Ofgem.
[14] Chapter 4 sets out which variables we propose to treat under different scenarios as well as the stress test.

and EEU falls. Above a certain de-rated capacity margin the risk of shortfalls becomes very low.

Figure 1. Illustrative relationship between de-rated capacity margin and risk of shortfalls (the level of LOLE and EEU).



4. Modelling and data requirements

Chapter Summary

This chapter sets out our high level modelling approach and how we propose to model input variables.

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

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

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

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

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

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

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

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

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

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

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

4.1. In chapter 3 we presented two measures of risk, LOLE and EEU, as well as the de-rated capacity margin. The de-rated capacity margin needs several input variables to be modelled for both demand and generation capacity. This chapter provides a high level overview of our modelling approach. It also presents our proposals for how to model the relevant components of demand and generation capacity.

Modelling approach

4.2. Figure 2 below illustrates the modelling approach to arrive at the de-rated capacity margin and the proposed measures of risk, (ie LOLE and EEU) for any given year. LOLE and EEU are closely related to the de-rated capacity margin.

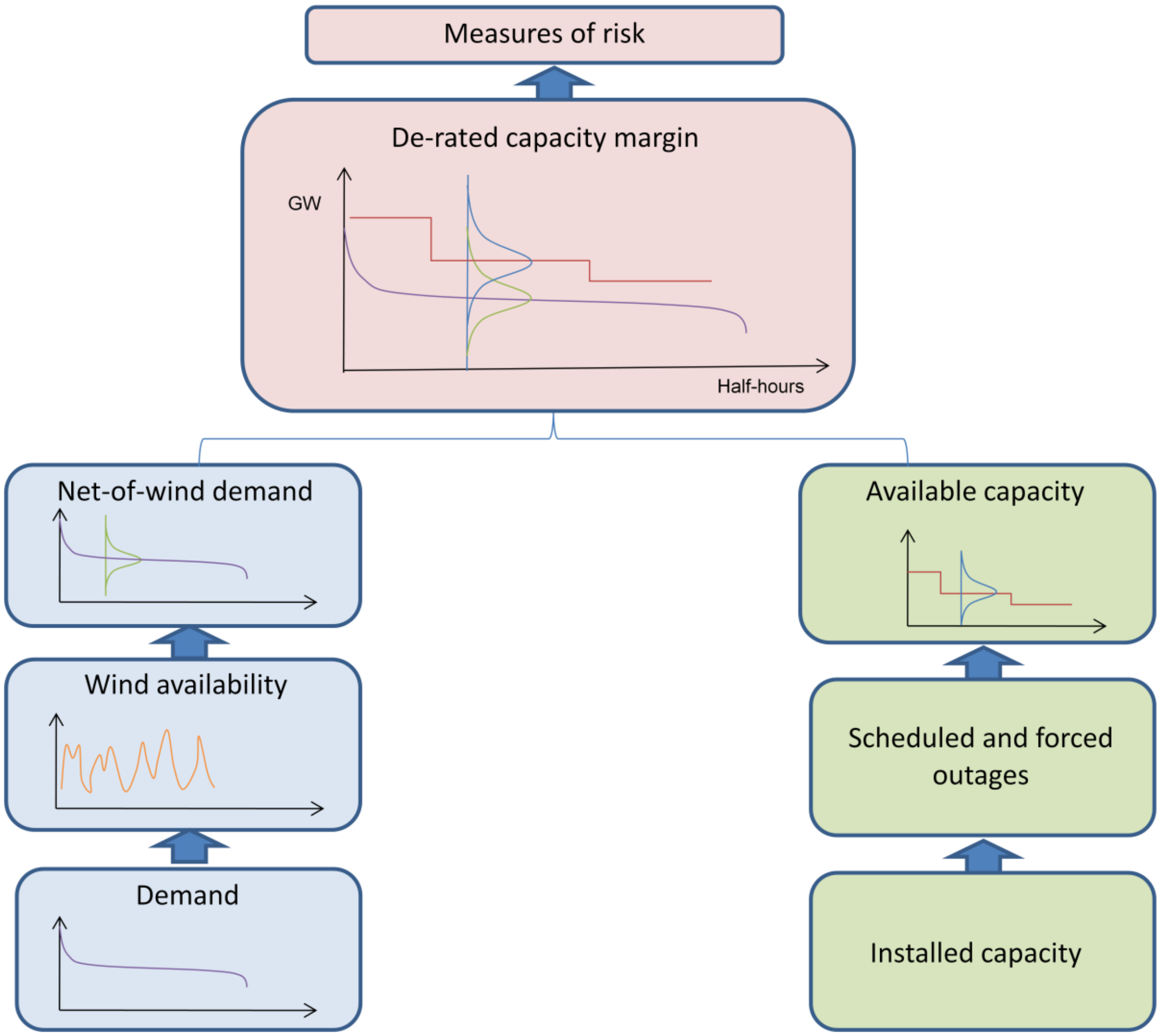
4.3. Net-of-wind demand and available generation exhibit short term variation due to the uncertainty around key inputs. Therefore, both net-of-wind demand and available generation should be represented by distributions around a mean value. The de-rated capacity margin is estimated by the combination of these distributions. To compute this combination requires sophisticated statistical methods such as Monte Carlo simulations or direct convolution. The exact statistical method to be used is a model technical specification issue and will be determined at a later stage.

4.4. In order to estimate net-of-wind demand, we first estimate the annual demand profile based on historical demand profiles, applying demand growth forecasts. We then subtract the corresponding estimated wind availability to arrive at the net-of-wind demand. We treat wind on the demand side because it is weather driven, unlike other forms of generation.

4.5. On the generation side, we start from the installed capacity, (eg existing plant capacity, interconnectors). We take into account scheduled and forced outages to arrive at available capacity.

4.6. The above process is carried out for each half-hour of each year modelled. We propose to use half-hourly data as it will allow us to capture variation in the short term due to changes in daily demand and generation capacity and thus adequately capture the risks to security of supply.

Figure 2. Graphical representation of the modelling approach



Approaches to modelling input variables

4.7. In each period, the de-rated capacity margin is influenced by a set of drivers (such as weather conditions, economic growth, fuel prices, etc). The influence of these drivers' on the de-rated capacity margin needs to be estimated by modelling a number of input variables (eg demand profile, wind availability, interconnection flows). The input variables are then used to calculate the de-rated capacity margin.

4.8. For forecasting reasons we separate input variables into two types:

- **Type 1**: input variables which are characterised by short term variation but do not experience fundamental change over time. For these variables, historical data can be used to project likely future distributions.

- **Type 2**: input variables that may experience a fundamental change over time or are too difficult to model.

4.9. This classification has implications on the modelling of the input variables. Table 1 shows how we propose to model the primary input variables:

Table 1. Modelling approach for input variables

Input types	**Modelling approach**	**List of variables**
Type 1	Stochastics[15] (probability distributions)	Forced outages, wind availability, demand profile
Type 2	Forward looking assumptions	Demand side response, transmission investment, embedded generation
	Scenarios about future	Demand growth; generation plant decommissioning, retirement and new build dates; wind build rates, interconnection capacity
	Stress tests	Gas availability

4.10. **Stochastics**: One example of a Type 1 variable is the demand profile, ie the total power customers require over the course of a year. The demand profile primarily depends on weather conditions within the year. Although weather conditions will vary, we do not expect a fundamental change to the annual temperature profile. Therefore, we aim to capture the effect of weather conditions on the demand profile by looking at long enough historical data. Historical data will be used to model the short term variability by defining the mean and variance of a probability distribution.[16]

[15] In a stochastic approach there is some uncertainty around the future evolution of a variable which is described by probability distributions. This means that there are many expected outcomes, but some outcomes may be more probable than others.
[16] The stochastic approach has been designed based on our knowledge of available data and

4.11. In order to forecast the type 2 input variables we need to make informed decisions. The informed decisions can take the form of:

- **Forward looking assumptions**: For some input variables we can predict their future evolution with a firm degree of certainty, eg the capacity of existing generation plants with no plans to decommission. For other input variables we can assume that their influence on the capacity margin is relatively minor. An example of this is demand side response, which is not expected to increase in importance significantly in the next 4 years. This assumption may change in future years. In addition, historical evidence may be used in the background to forecast some input variables.

- **Scenarios**: When the evolution of important input variables is highly uncertain we may use a base case scenario along with variations around the base case scenario. For example, decommissioning old plants and building new capacity can significantly influence the capacity margin. We appreciate that new build plants are sometimes delivered later than first anticipated and that plants that are to be decommissioned, (eg nuclear) may get an extension.

4.12. In addition, **stress tests** should be run to assess the risk to security of supply of extreme events. An example of this is a shortage of gas supplies. We are not proposing to explicitly model fuel availability. However, we do believe that gas supplies are an important component of electricity security of supply, so we plan to include a specific stress test on this in our report.

4.13. The following sections of this chapter present how we propose to model the primary input variables. First, we present the inputs needed to model net-of-wind demand and then those required for the modelling of available capacity.

Net-of-wind demand

4.14. In order to estimate net-of-wind demand we need to estimate demand and wind generation availability separately. The estimate of demand requires an estimation of the demand profile and demand growth.

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methodology. The methodologies proposed may have to be amended should the required data not be available or prove unsatisfactory for our purposes.

Demand profile

4.15. The annual demand profile should be based on historical data over a sufficiently long time series.[17] The process for building the demand profile from the historical data series is as follows:

- First, for each year we order the half-hourly demand data from highest to lowest, ie create a load duration curve. To make the profile comparable across years, the effect of demand growth is removed.

- Second, the half-hourly demand data is averaged across the available years based on the above ordering. The data points collected for each half-hour will define the mean and standard deviation of the demand profile for that particular half-hour.[18]

Demand growth

4.16. NGET's current methodology for estimating demand growth in the NETS SYS is primarily based on econometric analysis.

4.17. Annual demand growth is estimated using econometric models that take into account growth in economic activity, household numbers and industrial output, as well as, embedded generation development, energy efficiency measures, etc. As no definitive data exists on the impact of energy efficiency measures, assumptions are made on their significance and impact.

4.18. We are proposing to use NGET's existing methodology and assumptions for demand growth.[19] This will ensure consistency across Ofgem's report, the Winter and Summer Outlooks and NETS SYS. We are also proposing to run 'high' and 'low' demand growth scenarios.

Wind availability

4.19. In our modelling approach, wind generation availability is subtracted from demand, to produce the net-of-wind demand. It is our understanding that data on wind speeds is readily available and of a longer time series than data on wind

[17] NGET holds more than ten years of demand data. This should ensure a sufficient number of data points to define the demand profile distribution.

[18] We do not endorse a "calendar-ordering" approach, eg the first half-hour of the first year combined with the first half-hour of the second year, etc., because it tends to flatten out the demand shape and results in estimated demand profiles that do not reflect a realistic annual demand profile.

[19] NGET's existing methodology includes embedded generation (wind and non-wind) in the assumptions for demand growth. Under our approach, embedded wind generation will be treated under wind availability and non-wind embedded generation under available capacity.

generation. We are aware of two main options to convert wind speeds to wind generation availability:

- Under the first option, we would look at the correlation of wind speeds and wind generation availability based on data from existing wind farms.

- Under the second option, we would convert wind speeds to wind generation availability by looking at the technical specifications of wind turbines.

4.20. Given that wind technology has developed significantly in recent years, historic correlations of wind speeds and wind generation availability under the first option may no longer be valid. Therefore, we are minded to use the second option, but are inviting views on whether it is appropriate.

4.21. Once the correlation between wind speed and generation availability has been established it will be applied going forward to new and existing sites. Subsequently, this correlation will be used to convert wind speed distributions into wind generation availability distributions. Wind availability and demand are correlated, and therefore, it is important that the methodology captures this correlation. Wind generation availability will be matched with the demand data from the same time periods.

4.22. Moreover, we recognise the existence of geographic wind correlations. Our chosen modelling approach should take these into account. The method that captures these correlations will be determined once statistical analysis of relevant data has been undertaken.

4.23. We appreciate that data for wind generation may be scarce with regard to extreme weather conditions, ie very cold snaps such as the winters of 2009 and 2010. Therefore, the statistical distribution of wind availability and its correlation with demand at extreme weather conditions may not be as robust as at other times. However, we believe that our suggested approach is making best use of available information.

4.24. In addition, we propose to treat wind embedded generation (ie connected directly to the local distribution network) using the same approach, as both embedded and transmission connected wind should have the same wind profile characteristics all else being equal. Finally, we are also proposing to run different scenarios for wind build rates going forward.

4.25. The next section of this chapter presents the “other side” of the model as described in Figure 2, ie the components required to estimate available capacity.

Available capacity

4.26. As with demand, an annual profile will also be estimated for generation availability. Although some generation input variables may not vary within a year (eg generation capacity of existing plants, interconnection capacity) others may have a significant variation, which may be correlated with demand, eg maintenance outages. The approaches to modelling different input variables are presented in turn below. The two final sections discuss cross-correlations between individual half-hours and how we propose to handle transmission constraints.

Installed capacity

4.27. The first step to establish installed capacity is to determine the maximum generation capacity of the installed infrastructure. The installed infrastructure should include existing plants, new builds, decommissionings and retirements, non-wind embedded generation, interconnection, demand side response and pumped storage.

4.28. National Grid currently has a database of all transmission-connected existing plants by plant name, type and location, as well as commissioning, decommissioning and retirement dates. This is provided by the Transmission Entry Capacity (TEC) register and also includes pumped storage generation and decommissioned plant.

4.29. However, the TEC register may overestimate the maximum operational capacity before outages for some plants. For example, plants that have opted out from the Large Combustion Plant Directive (LCPD)[20] may be running in reduced regimes and may elect not to serve demand throughout the year. In addition, the TEC register may not be a good guide of how much interconnectors may contribute towards available capacity or when a new plant may become operational. We explore these issues below.

Existing generation, degradation, decommissioning and retirements

4.30. We believe that the TEC register should in general be a good guide for existing plants' operational maximum export limit (MEL). However, it is not a good guide for ageing gas, coal and nuclear plants which may not be able to reach the register's value. Therefore, we are proposing to reduce the TEC register values to reflect the maximum historical real time availabilities for these plants.

4.31. A generator may wish to retire a plant or decommission a plant for a relatively long period. At a later stage the generator may wish to recommission that plant. Appreciating that decommissionings and retirements are commercial decisions, we propose to use NGET's approach as per NETS SYS[21] with informed decisions to determine the decommissioning and retirement dates for the base case scenario. We will also run alternative scenarios around these dates. In addition, plants that have opted-out of the LCPD have restricted operating hours. Available capacity of these

[20] Directive 2001/80/EC of the European Parliament and of the Council of 23 October 2001 on the limitation of emissions of certain pollutants into the air from large combustion plants.
[21] Under NETS SYS, a plant is removed from the TEC register in cases where NGET has been notified.

plants will have to be amended to account for this limit in operation. We are seeking views on how to model available generation going forward of plants' that have opted out of the LCPD.

4.32. Another approach to help make informed decisions on the likely dates for decommissioning and achievable output levels for mothballed plants is to request that generators provide Ofgem and NGET with more information on a confidential basis. We are asking the industry whether such information would be of value and how to ensure confidential information is not made available to the market.

New generation

4.33. In the TEC register the commissioning dates of new plants will normally correspond to both the 'contract' date and to the actual start of commercial output from the plants in question. However, sometimes commercial output starting dates may slip significantly. Therefore, we are proposing to use NETS SYS with informed decisions relating to commissioning dates for the base case scenario. We will also run alternative scenarios around the commissioning dates. We are considering asking generators to provide confidential information on their plans for new builds to complement this data.

Interconnection

4.34. The GB market is becoming more interconnected with Europe. Currently, there is a total of 3.5GW of installed interconnection capacity with France, Ireland and the Netherlands. Another 500MW of interconnection will become operational with Ireland in 2012. In addition, there are several other interconnection projects at various phases of planning.

4.35. Interconnection can directly impact on the size of the capacity margin depending on the direction of flows. Although historical interconnection flow data exists, it does not necessarily provide an accurate picture of how flows will act in the future. This is because interconnection flows should in principle be driven by the price differential between the interconnected countries and price differentials going forward may be very different to in the past. There are two options for integrating interconnection flows into the model:

- One option would be to use NETS SYS interconnection flow assumptions for our base case scenario. Under this scenario links with France and the Netherlands are assumed to neither import nor export and GB is assumed to be fully exporting to Ireland. Additional scenarios could then be run regarding flows.

- Another option would be to build a specific model for the interconnection flows based on prices. This would entail modelling the GB and interconnected countries electricity systems to come up with the prevailing electricity prices and the interconnector flows.

4.36. We are seeking views on which of the two aforementioned options is most appropriate. Should the first option be preferred, we are also seeking views on what the alternative scenarios for interconnection flows should be. NETS SYS will be used as a base case scenario with regards to interconnection capacity. We will also be considering possible scenarios around interconnection capacity installed.

Non-wind embedded generation

4.37. Wind embedded generation is treated under wind generation on the demand side. Non-wind embedded generation is usually generation of a smaller scale than transmission connected generation. Most international studies do not include embedded generation in their capacity assessment modelling. However, we believe we should take it into consideration as there is currently a total of 9GW of installed embedded generation on the system, a high proportion of which is non-wind.[22]

4.38. NGET currently has some data on existing embedded generation in the NETS SYS which is submitted by Distribution Network Operators (DNOs). We propose to use NGET's existing data and assumptions on non-wind embedded generation as per the NETS SYS. We are also asking industry whether it is worth Ofgem requesting additional data from DNOs on embedded generation.

Demand side response

4.39. Demand side response (DSR), (eg self-interruption, interruptible contracts), can be used to balance the electricity system during periods of high demand. To date, DSR has not had a significant role in the market but its role in balancing the market is likely to increase.

4.40. NGET has some data on demand side response contracts. It will be difficult to forecast future behaviour as such contracts have rarely been used.

4.41. In principle, we would like to include DSR in the model.[23] We are seeking views from industry stakeholders on how to model DSR and whether it is worth Ofgem requesting additional data from DNOs on DSR.

Scheduled outages

4.42. We will need to take account of scheduled outages in order to have an estimate of available generation capacity. Plant scheduled maintenance timing has been mostly driven by commercial decisions and by and large occurred at times of

[22] NGET, Seven Year Statement, http://www.nationalgrid.com/uk/Electricity/SYS/.
[23] Smart meters may affect the level of consumer demand at peak times. Although smart meters are not a form of demand side response, we are proposing to model the effects of smart meters under this category.

low electricity prices, ie over the summer months. We are aware of two options to model scheduled outages:

- The first option is to build a model that optimises maintenance outages throughout the year based on electricity prices. This involves modelling GB's electricity system to derive an annual profile of electricity prices. Generating plants then optimise their maintenance by organising maintenance outages at times when prices are low. However, this method does not take into account other factors that influence scheduled outages such as contractor availability and contractor prices. This method has been used by some US transmission operators, eg PJM, MISO.

- The second option is to use historical data about maintenance outages to arrive at a statistical distribution of the available capacity. This entails a statistical analysis of historical maintenance probabilities at the plant-type level.[24] Given the correlation of demand levels and scheduled outages, the plant availability data should be matched with the demand data from the same time periods.

4.43. The first option would require a significant modelling effort to construct a fully optimising model. We believe this method will be more suited to the energy market when significantly more wind is on the system resulting in far wider shifts in maintenance patterns. However, as we do not see maintenance patterns shifting in the short term, we believe the second option is also valid, at least for the initial reports. We are inviting views from the industry on the best approach to tackle this issue.

Forced outages

4.44. Forced unscheduled outages can be a risk to short term security of supply. For the purpose of the modelling, we propose using historic data on the annual distribution of forced outages to calculate the probability of plant forced outages.

Half-hourly cross-correlations

4.45. The modelling approach treats half-hourly periods independently from each other, ie the availability of generation in one half-hour is not impacted by what has happened in the previous one. We appreciate that this does not always hold true, ie there may be important half-hourly cross-correlations within a day and across days.

4.46. For example, anti-cyclonic weather conditions may result in very cold spells for several days. Under such conditions, the availability of DSR in any half-hour may

[24] It is important in this context to take into account any plant correlations in maintenance patterns. Plant type averaging is valid if outages of plants within the same plant types are uncorrelated.

be negatively impacted by the high demand periods of the previous days. Under some DSR interruptible contracts there is a limit on the hours of interruption allowed. Similarly during very cold days pumped storage generation may be negatively impacted by the high demand periods of the previous half-hours due to lower availability of water reserves. Although DSR is not currently significant in the market, there is approximately 2.6GW of pumped storage capacity. Another example would be extended periods of low or high wind, ie high wind availability half-hours are likely to be followed by similarly strong wind availability. We are seeking views as to whether such effects may have significant effects on the capacity margin and the risk of supply shortfalls and on how they should be modelled.

Transmission

Transmission constraints and a regional model

4.47. In order to assess the risk to security of supply we need to understand how energy flows from generators to consumers. When transmission constraints exist, a situation could arise where there is enough available generation capacity nationally, but demand in one area of the country still cannot be met.

4.48. Currently, there are a number of boundaries where constraints can occur even in the absence of transmission outages. The Cheviot boundary, between Scotland and England, is arguably the most constrained boundary in GB.

4.49. For this reason, in the first instance, we propose the development of a two region model: with one being England and Wales, and the other Scotland to identify possible security of supply risks at a regional level. In particular, the model should report the de-rated capacity margin, LOLE and EEU in GB in aggregate, as well as in both regions. Regional LOLEs and EEU will have to take into account the direction and level of flows through the Cheviot boundary at peak and non-peak conditions.

4.50. Our proposal is to take into account only the most significant constraints at this point. We recognise that the model may therefore not take full account of the impact of all transmission constraints on security of supply. NGET will advise us if boundaries other than Scotland/England should be assessed. We are also seeking views from the industry on whether there are other boundaries that should be taken into account.

4.51. In terms of data requirements, there is a need for locational data on both the demand and generation side, as well as data for the Cheviot transmission transfer limits. We are aware that NGET compiles this data.

Transmission Losses

4.52. Transmission losses depend on demand levels, weather conditions such as temperature and humidity and location of generation and demand amongst other things. Currently, NGET forecasts for total transmission losses are of approximately

2% of demand at peak demand conditions.[25] We propose to use NGET's INDO demand data[26] which includes transmission losses.

[25] NGET, Seven Year Statement, http://www.nationalgrid.com/uk/Electricity/SYS/.
[26] This is the published Balancing Mechanism Reporting Agent (BMRA) Initial Demand Outturn based on National Grid operational generation metering.

5. Next steps

Chapter Summary

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

5.1. In preparation for this formal consultation we held an informal consultation during August and September. In particular, we organised an industry workshop to seek views on our preliminary thoughts on the approach and modelling options. In addition, we held a workshop with the UK Energy Research Centre (UKERC). We have been working closely with DECC and NGET during this pre-consultation stage.

5.2. We have also appointed an academic advisory body, which consists of Prof. Goran Strbac, Imperial College London, Prof. Derek Bunn, London Business School, and Prof. Michael Grubb, University of Cambridge and Ofgem. The academic advisory body has been providing ongoing support from the beginning of the project.

5.3. While Ofgem is responsible for delivering the report, we believe it is appropriate to ask NGET to undertake the modelling as this will utilise NGET's existing knowledge of the market, data and modelling capabilities. We intend to direct a modification to NGET's licence in order to put an obligation on NGET to develop the models required for the capacity assessment under the methodological specifications set out in this consultation and in the final decision document on modelling and methodology. Delegating the modelling of the capacity assessment to the system operator is consistent with current international practice in Ireland, Australia, and some parts of the US.

5.4. This consultation document outlines Ofgem's views on the assessment of the capacity margin and the risks to security of supply (Chapter 3) as well as the modelling approach (Chapter 4). We are seeking stakeholder views on the proposed approach. To this end, we have posed a number of specific questions to industry stakeholders.

5.5. The consultation period will run for eight weeks and will close on 7 December 2011. During this period Ofgem and NGET may informally seek views from industry experts regarding specific and technical modelling issues in parallel to this consultation.

5.6. We will then publish a final decision document around the turn of the year based on the consideration of views arising from this consultation.

5.7. The model development will begin in early 2012 in order to deliver the first submission of the final report to the Secretary of State by September 2012.

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 7 December 2011 and should be sent to:

Socrates Mokkas
Energy Market Research and Economics
Ofgem, 9 Millbank
London SW1P 3GE
020 7901 7304
socrates.mokkas@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 at the turn of the year outlining the final model details. Any questions on this document should, in the first instance, be directed to:

Karen Mayor
Energy Market Research and Economics
Ofgem, 9 Millbank
London SW1P 3GE
020 7901 3089
karen.mayor@ofgem.gov.uk

CHAPTER: Three

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

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

CHAPTER: Four

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

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

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

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

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

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

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

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

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

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

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

Appendix 2 – The Energy Bill Clauses 77 and 78

PART 2

SECURITY OF ENERGY SUPPLIES

CHAPTER 1

ELECTRICITY SUPPLY

77 Annual report by Gas and Electricity Markets Authority on security of electricity supply

Before section 47 of the Electricity Act 1989 (and after the cross-heading immediately preceding that section) insert—

"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."

78 Annual report by Secretary of State on security of energy supplies

(1) Section 172 of the Energy Act 2004 (annual report by Secretary of State on security of energy supplies) is amended as follows.

(2) After subsection (2) insert—

"(2A) In 2012 and in every subsequent calendar year the report must also include, in particular, as regards each of the assessment periods, an assessment by the Secretary of State of what electricity supply capacity is required.
(2B) For the purposes of subsection (2A) the electricity supply capacity required is the capacity required for the purpose of meeting the demands of consumers for the supply of electricity in Great Britain, including spare capacity to allow for unexpected demands or unexpected loss of capacity.
(2C) The assessment 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.
(2D) An assessment by virtue of subsection (2A) 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."

(3) In subsection (3), after "report" insert ", other than the assessment by virtue of subsection (2A),".

(4) After subsection (3) insert—
"(3A) An order under this section is subject to the negative resolution procedure."

(5) In subsection (4)—
(a) after the definition of "consumers" insert—

““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;”;

(b) after “distribution system,” insert ““electricity interconnector”, “generating station”, “generation”, “supply,””.

Appendix 3 – 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 Cycle Gas Turbine (CCGT)

A power station that generates electricity by means of a number of gas turbines whose exhaust is used to make steam to generate additional electricity via a steam turbine, thereby increasing the efficiency of the plant above open cycle gas turbines.

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.

Decommissioning

A term often used for long term storage of Generating Units. Such plant is sometimes referred to as 'mothballed'.

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, ie 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 firm demand (ie net of interruptible contracts) 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 and 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.

Load curve

The relationship of power supplied to the time of occurrence. Illustrates the varying magnitude of the load during the period covered.

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. It can be expressed as a straight percentage probability (eg an x% probability of an outage during the year) or as a 1-in-x year chance event.

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 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.

NETS SQSS

National Electricity Transmission System Security and Quality of Supply Standard.

NETS SYS

National Electricity Transmission System Seven Year Statement.

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 (e.g. a specific time of day) or to averaged load over a given period of time (e.g. 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.

SSSR

Statutory Security of Supply Report.

T

Transmission Entry Capacity (TEC)

The Transmission Entry Capacity of a power station is the maximum amount of active power deliverable by the Power Station at the Grid Entry Point (or in the case of an Embedded Power Station at the User System Entry Point), as declared by the Generator, expressed in whole MW. The maximum active power deliverable is the maximum amount deliverable simultaneously by the Generating Units and/or CCGT Modules less the MW consumed by the Generating Units and/or CCGT Modules in producing that active power and less any auxiliary demand supplied through the station transformers.

Transmission Losses

Electricity lost on the Great Britain transmission system through the physical process of transporting electricity across the network.

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 (GEMA), the body established by section 1 of the Utilities Act 2000 to regulate the gas and electricity markets in Great Britain.

U

UKERC

UK Energy Research Centre.

Appendix 4 - 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:

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