Electricity Capacity Assessment Report 2013

Report to the Secretary of State

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Overview:

This document is Ofgem's annual report to the Secretary of State assessing the outlook for electricity security of supply.

Based on advice from National Grid, our assessment suggests that the risks to electricity security of supply over the next six winters have increased since our last report in October 2012. This is due in particular to deterioration in the supply-side outlook. There is also uncertainty over projected reductions in demand. We continue to expect that margins will decrease to potentially historically low levels in the middle of the decade and that the risk of electricity customer disconnections will appreciably increase, albeit from near-zero levels.

Although it is clear that the risks to security of supply are increasing, it is very difficult to accurately estimate the level of security of supply that will be provided by the market. In particular, this is because of uncertainties regarding the level of demand, commercial decisions about generating plant and interconnector flows. We have undertaken sensitivity analysis to highlight the potential effects of these uncertainties.

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Context

Ofgem's 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.

Our Project Discovery report in 2009 highlighted that Britain's energy industry faces an unprecedented challenge to secure supplies due to the global financial crisis, tough environmental targets, increasing gas import dependency and the closure of ageing power stations. We have since undertaken further analysis to inform thinking on how to help maintain security of supply.

The Energy Act 2011 introduced an obligation on Ofgem to provide the Secretary of State with a report assessing plausible electricity capacity margins and the risk to security of supply associated with each alternative. This report is to be delivered to the Secretary of State by 1 September every year.

Ofgem's first Electricity Capacity Assessment report was delivered to the Secretary of State in August 2012 and published in October 2012. This required a one-off exercise to develop a model that assesses the risks to electricity security of supply. This model will be updated on an annual basis, as necessary, to fulfil the Authority's reporting obligation. The legislation allows for the modelling to be delegated to a transmission licence holder and we have delegated the construction and updating of the model to National Grid Electricity Transmission plc.

Associated documents

Electricity Capacity Assessment 2013: decision on methodology

Electricity Capacity Assessment 2013: consultation on methodology

Electricity Capacity Assessment Report 2012

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

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

Contents

Executive summary

This report sets out an updated assessment of the risks to electricity security of supply in Great Britain. We present the de-rated capacity margins (the average excess of available supply over winter peak demand) that could be delivered by the market over the next six winters under normal operation of the system – and the risks associated with them. Even during this relatively short time horizon, the uncertainties are large.

The analysis is based on National Grid's forthcoming 2013 Gone Green scenario, adjusted to reflect our own views on interconnector flows and supply-side developments under current policy arrangements.

We published our first Electricity Capacity Assessment report in October 2012. This showed that the risks to security of supply were expected to increase appreciably in the coming years from near-zero levels. This was mainly due to a significant reduction in electricity supplies from coal and oil generation plant, coupled with limited investment in new plant.

Since last year, the outlook for the supply side has deteriorated and industry has announced the withdrawal of more than 2GW of installed generation capacity in the near future. Further withdrawals are still likely. Uncertainty around policy and future prices continues to limit investment in conventional generation and no new plant is expected before 2016. We estimate that around 1GW of new gas plant will come online before the end of the decade and the installed capacity of wind power will more than double over the same period.

Peak demand has fallen by around 5GW over the last seven years due mainly to the economic downturn and improvements in energy efficiency. National Grid in their 2013 Gone Green scenario project peak demand to fall a further 3-4GW by 2018/19, in part due to higher levels of demand-side response expected in the coming years. A drop in demand of this magnitude may in time compensate for the deterioration in the supply side. However, this is a material change from National Grid's previous projection, which partly reflects a more pessimistic economic outlook but also changes in methodology and assumptions. The magnitude of this change highlights the uncertainty that exists around future demand.

We present a Reference Scenario that provides a view of the outlook for security of supply, based on the information currently available to us. It is difficult to provide a firm view given the significant uncertainties around both supply and demand. Therefore, the Reference Scenario alone should not be relied upon to assess the risks to security of supply in the coming years. We also present different views illustrating some of the key uncertainties.

The Reference Scenario shows de-rated capacity margins decreasing faster in the next few years than expected in our 2012 report but still bottoming out in 2015/16 at around 4 per cent, before recovering thereafter. This view uses National Grid's Gone Green 2013 scenario demand projection. If we look at National Grid's overall Gone Green 2013 scenario, the trends are the same but the margins are consistently around 2 percentage points higher as we make less optimistic assumptions than National Grid with regards to plant investment and retirement and the contribution of interconnectors.

Small reductions in margins from current levels would result in a significant increase in the risks to security of supply. To illustrate the impact of the projected demand reductions not materialising, we present a 'high demand' sensitivity that uses National Grid's broadly flat demand projection from last year. We also present a 'low supply' sensitivity with pessimistic assumptions on the supply side. These sensitivities only illustrate changes in one variable at a time and so do not capture potential mitigating effects, for example of the supply side reacting to higher demand projections.

De-rated capacity margins
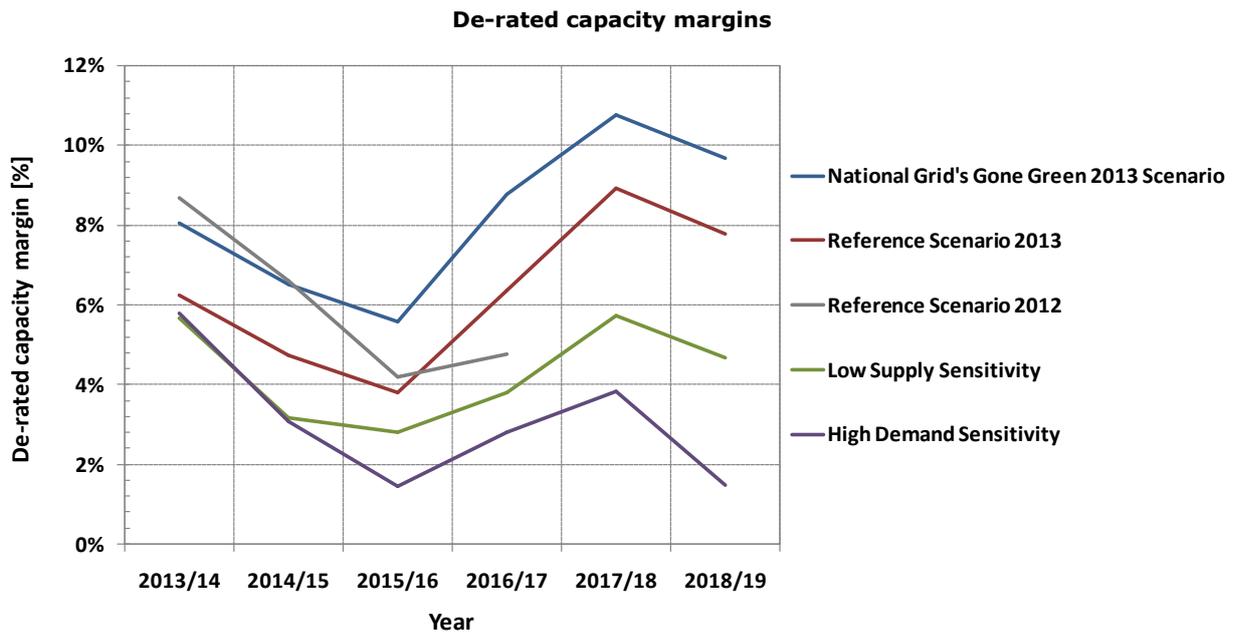
While de-rated margins illustrate trends in the market, they are not a measure of the risk to security of supply. Instead, we present risk using the "Loss of Load Expectation". This represents the number of hours per year in which supply is expected to be lower than demand under normal operation of the system. Importantly, this is before any intervention by the System Operator, so does not represent the likelihood of customer disconnections.

In the Reference Scenario, we estimate an increase in Loss of Load Expectation from less than 1 hour per year in winter 2013/14 to just under 3 hours per year in 2015/16 as de-rated margins decrease. This is within the maximum level of risk accepted by other European countries, including France, Ireland and Belgium. However, if demand were to remain broadly flat then the risks to security of supply would be markedly higher than in the Reference Scenario, reaching up to 9 hours in 2015/16. The risks are also higher in the low supply sensitivity.

Loss of load expectation
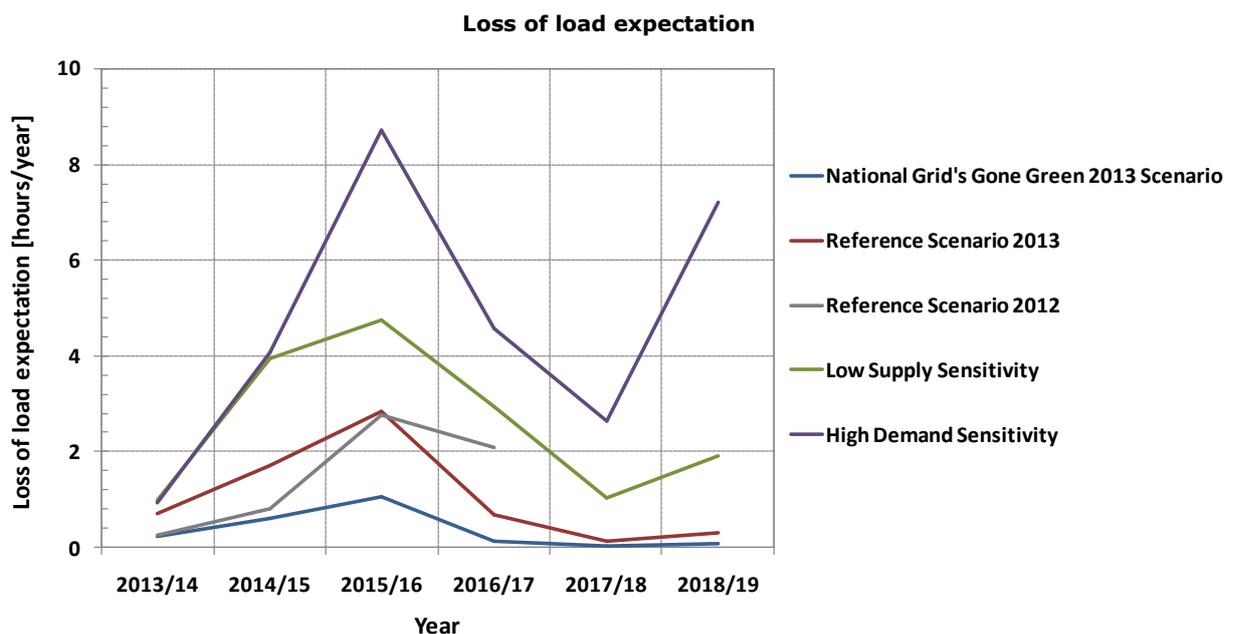
The expected volume of demand that may not be met because of electricity shortfalls in the Reference Scenario reaches around 3GWh in 2015/16 compared to 1GWh this winter. If demand were to remain broadly flat, this figure would be higher - peaking at around 11GWh. Controlled disconnections of customers - involving industrial and commercial sites before households - would only take place if a large deficit were to occur. This is because the System Operator is usually able to manage supply shortfalls up to a certain level with little or no impact on customers, such as by making use of emergency interconnector services that involve increasing imports and reducing exports where possible. These services are not taken into account in the de-rated margins and risk measures.

To illustrate the potential impact on customers, we estimate in the Reference Scenario that the probability of a large shortfall requiring the controlled disconnection of customers increases from around 1 in 47 years in winter 2013/14 to 1 in 12 years in 2015/16. This increases significantly to around 1 in 4 years if the demand reductions fail to materialise. Aside from the potential for controlled disconnections, any tightening in de-rated margins could impact customers through an increase in wholesale prices.

The assessment of risk is therefore highly sensitive to assumptions in the Reference Scenario. In addition to demand projections and decisions on plant investment and retirement, we have analysed sensitivities to represent the upside and downside risks associated with uncertainties over the availability of conventional and wind generation and the contribution of interconnector flows.

Ofgem and National Grid have consulted widely on the methodology used for this analysis. The modelling and data analysis was delegated to National Grid given their modelling capabilities and data availability.

1. Security of supply outlook

1.1. This report fulfils the Authority's obligation[1] to provide the Secretary of State with an annual report assessing the risks to electricity security of supply in Great Britain (GB) in the next four years. The main aim of this report is to inform Government's decisions with regards to the Electricity Market Reform (EMR) and, in particular, the Capacity Market. We have therefore decided to extend our analysis this year to cover the period up to winter 2018/19. This is when the first delivery year of a Capacity Market could be expected if the Government decides to run an auction in 2014, as proposed in the Draft Energy Bill in November 2012[2].

1.2. We presented our first Capacity Assessment report in October 2012. This document represents our second such report. As in our 2012 report, we estimate a set of plausible de-rated capacity margins that could be delivered by the market during normal winter conditions and the risks associated with them.

1.3. Our assessment is based upon expectations of how the supply and demand sides of the market are likely to evolve under current policies (eg in the absence of a firm decision to implement a Capacity Market). The assumptions are based on National Grid's forthcoming 2013 Future Energy Scenarios[3], adjusted to reflect Ofgem's views on the outlook for the supply side with respect to future investment and retirement of plant and the contribution of interconnector flows.

1.4. This assessment is not a traditional "P95" risk analysis[4], a "20% margin" analysis[5], nor an assessment of what would happen if policies change (eg a Capacity Market or cash-out reforms are implemented). We estimate plausible de-rated capacity margins that represent the average excess of available supply over demand during periods of high demand (ie winter) as opposed to periods with extremely high demand and/or extremely low supply[6]. These extreme periods are accounted for in the calculation of probabilistic risk measures. The available supply takes into account the fact that generation plant are sometimes offline due to maintenance or outages by "de-rating" the installed capacity based on historical rates of availability.

1.5. The Department of Energy and Climate Change (DECC) are expected to publish their views on de-rated capacity margins and the risks associated with them in their EMR Draft Delivery Plan consultation this summer and in the Secretary of State's electricity Capacity Assessment report by the end of the year. National Grid are due to publish their Future Energy Scenarios in July and their Winter Outlook in the autumn. How their results compare with the ones presented in this report will depend mainly on any differences in assumptions. The main differences between DECC and Ofgem analyses in 2012 were in relation to the assumptions on demand and interconnector flows.

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[1] As set out in section 47ZA of the Electricity Act 1989.

[2] http://services.parliament.uk/bills/2013-14/energy.html

[3] http://www.nationalgrid.com/uk/Gas/OperationalInfo/TBE/

[4] A "P95" risk analysis provides a value for a variable (eg de-rated margin) where there is only a 5% chance of it being exceeded.

[5] National Grid's Seven Year Statement (SYS) used to report a "20% margin" based on the electricity transmission system Security and Quality of Supply Standard (SQSS) definition of plant margin: "the amount by which the total installed capacity of directly connected power stations and embedded large power stations (with wind de-rated) and imports across directly connected external interconnections exceeds the ACS Peak Demand. This is often expressed as a percentage (eg 20%) or as a decimal fraction (eg 0.2) of the ACS Peak Demand."

[6] Commonly referred to as "stress periods".

1.6. We expect DECC to define a reliability standard for the GB market through their EMR Delivery Plan. A reliability standard indicates the accepted level of risk in the market. It represents a trade-off between the level of security of supply and the investment required to achieve that level. This reliability standard may serve as a benchmark to qualify the estimated levels of risks presented in this report.

Methodology

1.7. The methodology we use to calculate the risks to security of supply combines a probabilistic approach with sensitivity analysis. The probabilistic approach captures the uncertainty due to variable generation, plant faults and the effect of weather on demand. Uncertainties related to future economic growth and policy development and their potential impacts on future demand, interconnector flows and investment and retirement decisions cannot be given credible probabilities. We have therefore developed a Reference Scenario and we undertake sensitivity analysis to account for these uncertainties.

1.8. De-rated capacity margins do not reflect the amount of variability associated with them, which can differ significantly depending on the generation mix, the characteristics of the demand-side and the arrangements over interconnectors. By way of illustration, two systems with the same de-rated capacity margin may have significantly different levels of risks depending on the proportion of variable generation capacity (eg wind power) in each system[7].

1.9. The proportion of wind power in the GB system has increased considerably in recent years and is expected to continue doing so. This, combined with other factors such as the smart meter rollout and the potential expansion of the interconnector network, make de-rated margins a less relevant indicator of security of supply. Therefore, comparing de-rated capacity margins over time does not give an accurate picture in terms of risks. Nonetheless, de-rated margins are a familiar and intuitive indication of trends in the short to medium term so we continue to present them here.

1.10. To illustrate the risks to security of supply we use two well-established statistical measures:

- Loss of Load Expectation (LOLE): the expected number of hours per year in which supply is expected to be lower than demand under normal operation of the system. By normal operation of the system we mean in the absence of intervention (eg voltage reduction) by the System Operator.

- Expected Energy Un-served (EEU): the amount of electricity demand in MWh that may not be served in a given year. EEU combines both the likelihood and the potential size of any supply shortfalls.

1.11. LOLE, as interpreted in this report[8], is not a measure of the expected number of hours per year in which customers may be disconnected. For a given level of LOLE and EEU, results may come from a large number of small events where demand exceeds supply in principle but that can be managed by National Grid through a set of mitigation actions

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[7] Although the average availability of wind power is taken into account by de-rating the capacity, there is a much wider variation around this average (depending on wind conditions) than there is for conventional generation.

[8] LOLE is often interpreted in the academic literature as representing the probability of disconnections after all mitigation actions available to the System Operator have been exhausted. We consider that a well functioning market should avoid using mitigation actions in regular basis and as such we interpret LOLE as the probability of having to implement mitigation actions.

available to them as System Operator[9]. The results may also come from a small number of large events (eg the supply deficit is more than 2-3GW[10]) where controlled disconnections cannot be avoided. Given the characteristics of the GB system, any shortfall is more likely to take the form of a large number of small events that would not have a direct impact on customers.

1.12. To illustrate the potential impact on customers of the risks, we estimate the likely frequency and size of events. This includes the probability of large events resulting in controlled disconnections of customers. It accounts for the probability of disconnecting any type of demand, including both industrial and domestic customers. The probability of household disconnections would be lower than this given that industrial and commercial customers would be disconnected first. We are not able to calculate the probability of household disconnections as this would vary depending on the level of industrial consumption at the exact time of an outage.

1.13. It would not be appropriate to use the probability of controlled disconnections of customers as the main measure of the risk to security of supply. This would imply that it is acceptable to use mitigation actions on a regular basis, therefore reducing the quality of the service provided to electricity customers[11]. In addition, regular use of maximum generation could increase the probability of plant outages in the longer term as generation plant are not designed to run frequently at maximum output.

1.14. In this chapter, we present the general outlook for supply, demand, and interconnector flows. We also present the key results of our assessment in terms of de-rated margins and measures of risks for the Reference Scenario and the main sensitivities analysed. The structure of the report is summarised at the end of this chapter.

Outlook for supply, demand and interconnectors

Supply

1.15. Since last year, market participants have announced their intention to withdraw more than 2GW of installed capacity in the near future. In the 2013 Reference Scenario we estimate that a further 1GW of installed capacity will mothball by 2015/16. This is in addition to what has already been announced, mainly due to high levels of uncertainty about future market conditions, and low levels of profitability for gas-fired plant.

1.16. Figure 1 shows the evolution of installed capacity by generation type in the Reference Scenario. It also presents the installed capacity from last year's Reference Scenario for comparison.

1.17. Large Combustion Plant Directive[12] (LCPD) opted-out coal plant have been using their hours[13] faster than expected due to higher than expected profitability in the last year[14].

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[9] The System Operator can implement mitigation actions to maintain the system when available supply is not high enough to meet demand. These include voltage control, maximum generation instructions and the provision of emergency services from the interconnectors. For further information refer to Chapter 2.

[10] The exact amount varies with the specific conditions of the market at the time of the outage, including the flows over the interconnectors at the time.

[11] For example, variations in voltage may result in lights dimming and may damage domestic appliances.

[12] 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 plant.

[13] Under the LCPD directive, fossil-fuelled generating plants must choose to either opt-in (ie reduce their emissions) or opt-out of the Directive. Opted-out LCPD oil plant are restricted to 10,000 hours of operation in the same period.

[14] Coal plant profitability has increased in the last year due to higher gas prices resulting in less gas-fired generation and higher electricity prices.

Such plant have therefore been closing earlier than expected, with only 1GW currently operating (out of the original 9GW of opted-out coal plant in 2008), half of which should close by 2014/15. Opted-out oil plant are also closing earlier than expected, before using up their hours, due to low profitability as they are currently not competitive. Only 1GW of oil plant is currently in operation.

Figure 1: Installed capacity by generation technology type in the Reference Scenario
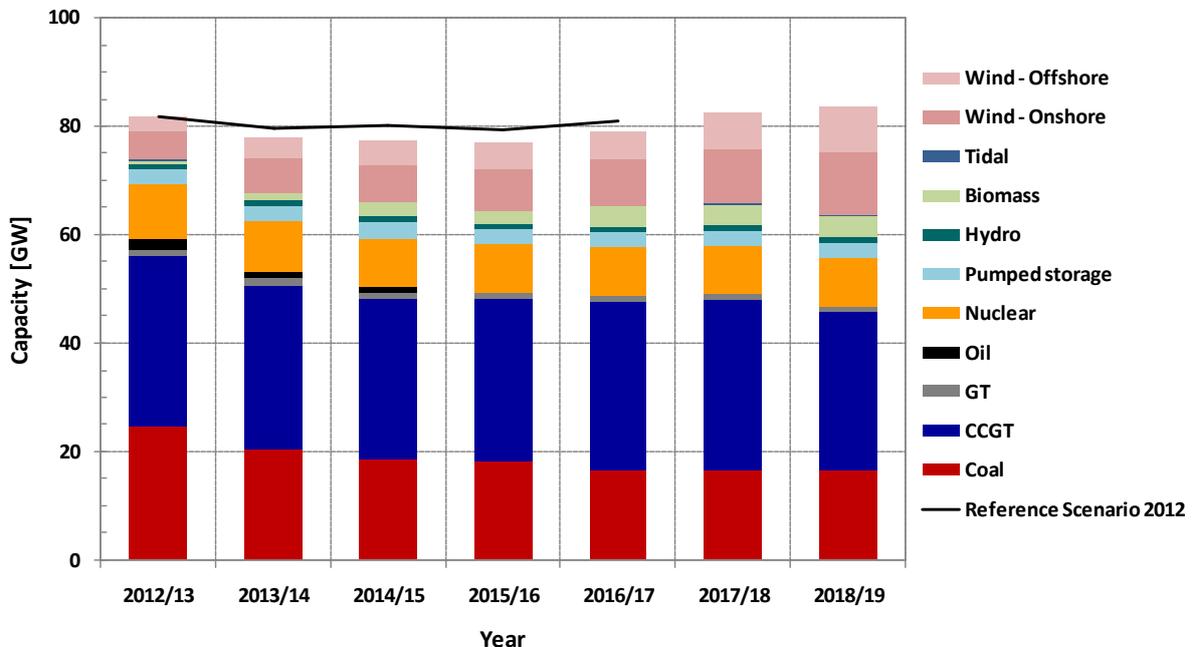
1.18. More than 2GW of LCPD opted-in plant have also closed or converted to biomass since October 2012, resulting in less pollutant plant but with reduced capacity. Around 0.5GW of nuclear capacity is reaching the end of its technical life and is expected to close by 2014/15, though potential extensions are being considered. Around 2GW of CCGT plant should be retired by 2018/19 for the same reasons.

1.19. Wind generation, onshore and offshore, is expected to grow rapidly in the period of analysis and especially after 2015/16, rising from around 9GW of installed capacity now to more than 20GW by 2018/19. Given the variability of wind speeds, we estimate that only 17% of this capacity can be counted as firm (ie always available) for security of supply purposes by 2018/19[15].

1.20. No new conventional plant is expected before winter 2016/17. Around 0.5GW is expected to start operating in winter 2016/17 and an extra 0.5GW by winter 2017/18, when 0.1GW of biomass is also expected.

1.21. As installed capacity falls in the next few years, all else being equal, prices can be expected to rise and it is possible that this will lead plant that is currently mothballed to come back online. This is captured in the Reference Scenario though we also assume that the uncertainties surrounding the implementation of the EMR and other market reforms are having as much impact on plant investment and retirement decisions as expectations around how prices will evolve.

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[15] The Equivalent Firm Capacity (EFC) measures the quantity of firm capacity (ie always available) that can be replaced by a certain volume of wind generation to give the same level of security of supply, as measured by LOLE.

Demand

1.22. Average Cold Spell (ACS)[16] peak demand has fallen over the last seven years as shown in Figure 2, mainly due to the economic downturn and improvements in energy efficiency. The Reference Scenario uses National Grid's 2013 Gone Green demand projection, which expects further reductions, with demand falling by 0.8% on average per annum, such that it is more than 3GW lower in 2018/19.

1.23. A drop in demand of this magnitude may compensate for the expected net supply-side reductions, resulting in lower risks to security of supply. However, demand forecasting is a particularly complex exercise, especially during an economic downturn and with uncertain weather patterns. Figure 2 also presents National Grid's 2012 final and provisional[17] Gone Green scenarios and 2013 Gone Green and Slow Progression scenarios to illustrate the uncertainty and potential ranges of variation around the evolution of demand.

Figure 2: National Grid's historic and projected ACS peak demand
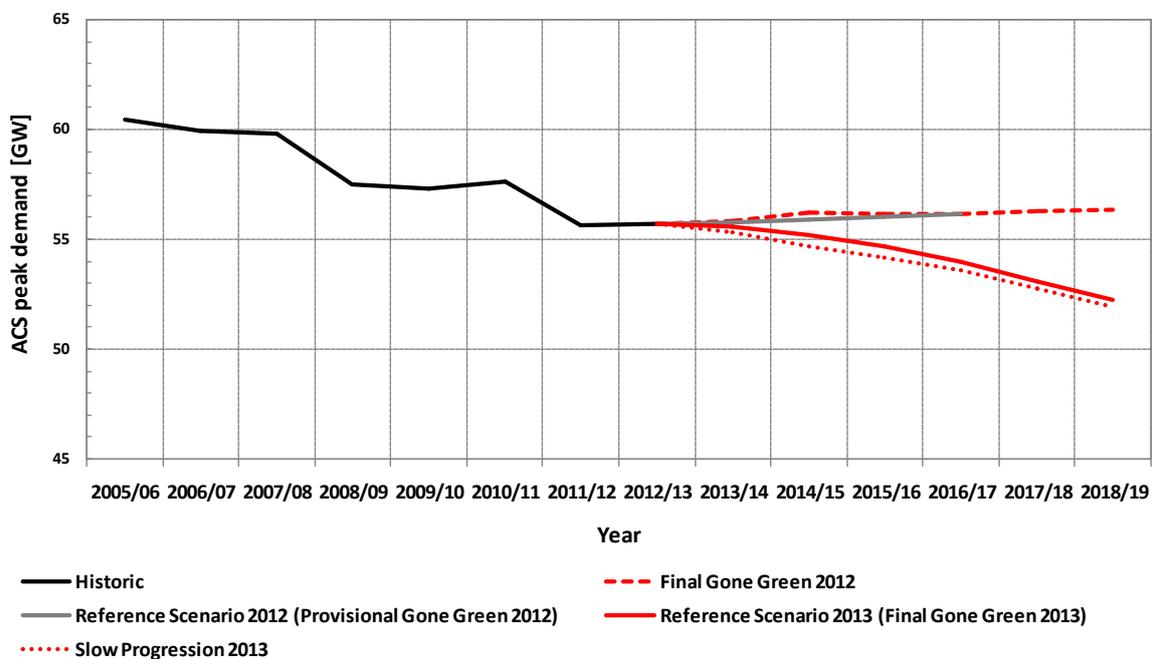
1.24. According to National Grid, the expected drop in peak demand is mostly due to increased energy efficiency in the domestic sector and increased Demand-Side Response (DSR)[18]. National Grid projects an increase in DSR from about 1.2GW in 2013/14 to around 2GW in 2018/19. Smart metering, through the effects of time-of use tariffs[19], is expected to lead to greater levels of DSR in the later part of the decade.

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[16] Average Cold Spell (ACS) peak demand is the demand level resulting from a particular combination of weather elements that give rise to a level of peak demand within a financial year (1 April to 31 March) that has a 50% chance of being exceeded as a result of weather variations alone. The Annual ACS Conditions are defined in the Grid Code.

[17] A provisional 2012 Gone Green scenario was produced by National Grid for Ofgem's 2012 Electricity Capacity Assessment. For this year we use National Grid's final 2013 Gone Green and Slow Progression scenarios. These are due to be published by National Grid in their Future Energy Scenarios in July 2013.

[18] DSR refers to customers responding to a signal to change the amount of energy they consume from the grid at a particular time.

[19] Time of use tariffs refers to the variable pricing of electricity consumption based on varying costs of generation.

1.25. Detailed information on the differences in the inputs and assumptions with regards to the 2012 and 2013 Gone Green demand projections is not yet available from National Grid.

Interconnector flows

1.26. Interconnection capacity between GB and mainland Europe and Ireland is currently 3.8GW. Assumptions about the likely direction and size of interconnector flows therefore have a significant impact on the calculation of the risks to GB security of supply.

1.27. The contribution of interconnector flows to de-rated capacity margins has been variable in the past with some years mostly importing and some others mostly exporting during the winter period. According to National Grid, in the last year GB has been mainly importing electricity from mainland Europe and exporting to Ireland, resulting in no overall net flows. We have also observed a series of outages due to physical problems with the cables. In particular, the capacity with Northern Ireland (Moyle) has been reduced from 450MW to 250MW. This issue is not expected to be corrected in for some time[20].

1.28. We consider that interconnectors are beneficial for security of supply in general. Interconnectors give the GB market options that would not be there without them, providing services such as energy and reserves balancing trading, frequency response and 'black start'. They may also help reduce the cost of electricity throughout the year. However, from a 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. Ideally, we would also assess their responsiveness under tight conditions when de-rated margins are close to zero and short-term prices in GB could in principle attract imports. However, this is extremely difficult to quantify as it depends on the supply and demand conditions in other markets as well as in GB, which are all highly uncertain.

1.29. In the Reference Scenario and all sensitivities we assume that interconnectors can help to reduce the probability of large events resulting in controlled disconnections of customers. This is because the mitigation actions available to National Grid to manage supply deficits include increasing the level of imports and/or reducing the level of exports. Therefore, disconnections would only take place after any assistance from the interconnectors. However, this type of assistance is not reflected in the LOLE calculation as this provides a measure of the risk of needing the System Operator to intervene to manage supply and/or demand.

1.30. As in 2012, we take a cautious view on interconnector flows in the Reference Scenario by assuming full exports to Ireland and no net flows to mainland Europe under normal operation of the market. This is based on:

- The assumption that interconnector flows will mainly respond to price differentials after the implementation of Market Coupling[21] in 2013.

- Our recent analysis[22] of the structure of the GB and surrounding markets and the similarities and complementarities between these systems. From this analysis we

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[20] For further information refer to:
http://www.eirgrid.com/media/All-Island_GCS_2013-2022.pdf

[21] ENTSO-E defines Market Coupling as "the method by which Day Ahead energy prices and volumes for each local market are calculated by gathering all Day Ahead bids and offers (collectively termed orders in the network code) in the different local markets in order to match them at European level on a marginal pricing basis". For further information refer to:
https://www.entsoe.eu/fileadmin/user_upload/_library/consultations/Network_Code_CACM/120323_NetworkCodeConsultation_FINAL.pdf

conclude that we cannot anticipate future price differentials between GB and relevant markets in mainland Europe with a sufficient degree of certainty, while prices in Ireland are likely to continue to be higher than those in GB.

1.31. We would expect that, in a situation of tight margins, ahead of mitigation actions being implemented, prices would rise resulting in higher interconnector flows into GB. However, GB is not the only European country expecting de-rated margins to fall in the next six winters. France, Ireland, Germany and Belgium are also facing security of supply challenges. Our analysis also suggests that, at the moment, there are no evident complementarities between GB and its interconnected markets as we have very similar patterns of demand and supply availability.

1.32. Historically, the evolution of de-rated capacity margins in these interconnected markets has been positively correlated, which means that when de-rated capacity margins are low in one market they also tend to be low in other markets. This does not mean that markets experience large deficits resulting in controlled disconnections of customers at the same time[23] but, if we assume that prices reflect margins at some level, then it is likely that prices are high at the same time. We do not have enough information to be able to anticipate with sufficient certainty whether or not GB is expected to have the higher price ensuring imports.

1.33. The relationship between GB and its interconnected markets is likely to change in the future as reforms (eg 'Market Coupling') are implemented making interconnectors more responsive to our market needs. The relationship may also change if demand and supply patterns diverge. The rapid growth of renewable generation in Germany and Southern Europe and the expansion of the interconnector network should impact the future relationship and help improve the outlook for security of supply in Europe in the coming years. The uncertainty resulting from all these changes justifies our cautious approach.

Key results

De-rated capacity margins and measures of risk

1.34. In the Reference Scenario we use National Grid's 2013 Gone Green demand scenario and our views on the potential evolution of the supply side and the contribution of interconnector flows. With this information we estimate the risks to security of supply to increase faster in the short term than expected in our 2012 report before improving from 2016/17 as lower demand more than compensates for net supply reductions.

1.35. Figure 3 presents our estimates of de-rated capacity margins, and Figure 4 presents our key risk measure, the Loss of Load Expectation (LOLE). The dashed lines in the figures illustrate what the de-rated margins and risks may look like if demand is higher or lower than projected in the Reference Scenario. The high demand sensitivity illustrates the effect of demand remaining broadly flat as projected in National Grid's Gone Green 2012 demand scenario. The low demand sensitivity uses the 2013 Slow Progression demand projection.

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[22] For further information refer to the work carried out by Pöyry Management Consulting for Ofgem available in: http://www.ofgem.gov.uk/Markets/WhlMkts/monitoring-energy-security/elec-capacity-assessment/Pages/index.aspx

[23] In fact, we assume that, under current conditions, is unlikely to experience large outages resulting in controlled disconnections at the same time and this is reflected in our calculation of the probability of controlled disconnections of customers.

Figure 3: De-rated capacity margins for the Reference Scenario and demand sensitivities
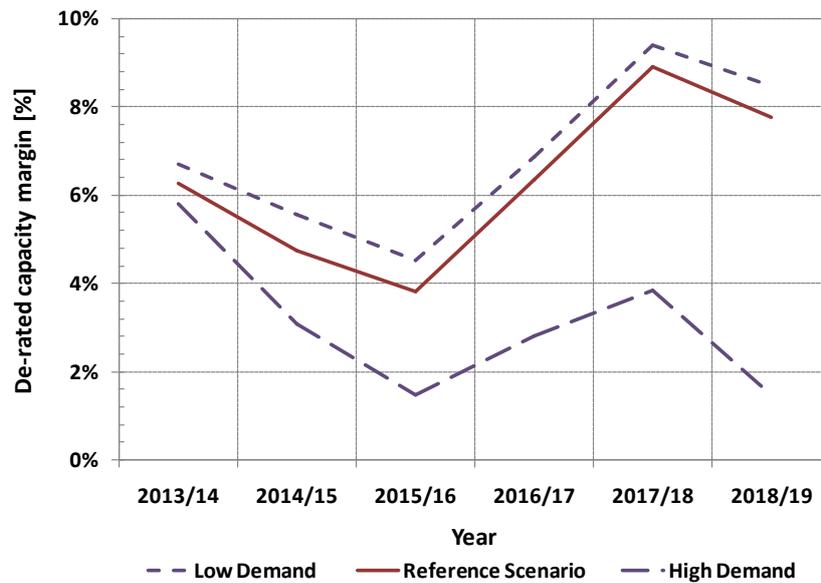

Figure 4: Risk to security of supply (LOLE) for the Reference Scenario and demand sensitivities
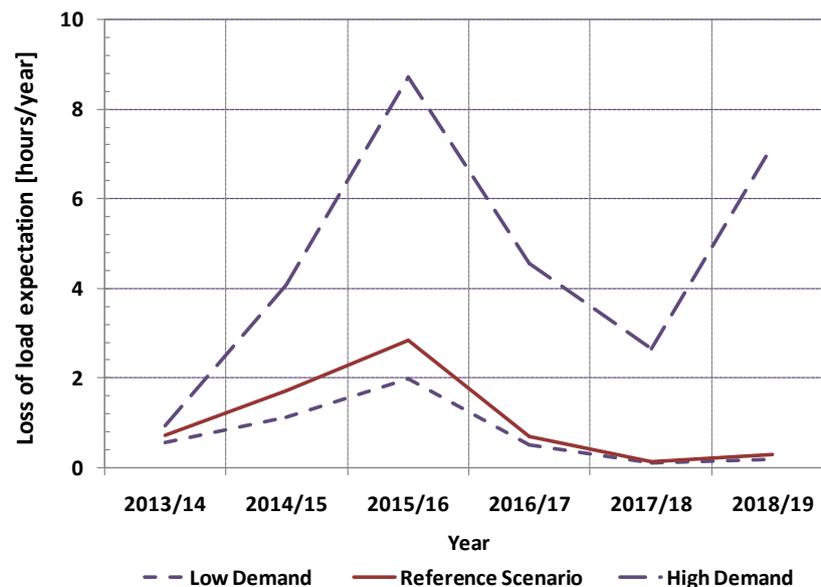
1.36. In the Reference Scenario, we estimate LOLE, ie the average number of hours per year where available supply is not expected to be sufficient to meet demand in the absence of intervention from the System Operator (as opposed to the expected number of hours of controlled disconnections of customers), to increase from less than 1 hour in 2013/14 to around 3 hours in 2015/16. We also estimate that LOLE may vary from around 2 to 9 hours per year in 2015/16 as a consequence of the uncertainty in the demand outcome, other things being equal.

1.37. The risks to security of supply increase as the de-rated margins decrease and vice versa. However, the effects are not symmetrical. Importantly, a change in the de-rated margins when they are low has a larger impact on the risks (LOLE) than a change in the de-rated margins of the same magnitude when they are high. This explains the significant peak in the risks in 2015/16 in the high demand sensitivity. It also emphasises the importance of

exploring plausible lower de-rated margins through sensitivities to get a better sense of the risks to security of supply in GB in the coming years.

Sensitivity analysis

1.38. Figure 3 and Figure 4 illustrate the potential range of variation around the Reference Scenario due to uncertainty in the demand projections. The Reference Scenario results are also sensitive to assumptions on other variables, including the evolution of supply side factors (eg investment and retirement of plant), interconnector flows, de-rating factors and the contribution of wind power at times of very high demand.

Supply sensitivities

1.39. Decisions on whether power stations are built, mothball, return to service or close depend on companies' specific commercial and financial positions, the outlook for energy prices as well as the energy policy environment. It is therefore very difficult to form a firm view on these specific commercial decisions. Figure 5 and Figure 6 present de-rated capacity margins and LOLE for the high and low supply sensitivities.

1.40. In the low supply sensitivity we explore the possibility that, compared to the Reference Scenario, more plant mothball in the next couple of years and no plant come back from mothballing or are built in the second half of the period due to uncertainty and low profitability expectations. This results in lower de-rated margins and higher risks. The high supply sensitivity assumes that companies are less cautious so keep generating or come back online in response to higher prices. This sensitivity also assumes more conventional plant are built by the end of the decade. This results in higher de-rated margins and lower risks.

1.41. De-rated capacity margins in the low supply sensitivity move from around 6% in 2013/14 to around 2% in 2015/16. They then increase up to 2017/18 to reach similar levels to 2013/14, with a slight decrease in 2018/19 when older plant reach the limit of their technical life. The high supply sensitivity shows margins consistently staying higher than 6%, but maintaining the trend of falling margins up to 2015/16 and then recovering to reach about 12% in 2018/19 due to new plant coming online.

Figure 5: De-rated capacity margins for the Reference Scenario and supply sensitivities
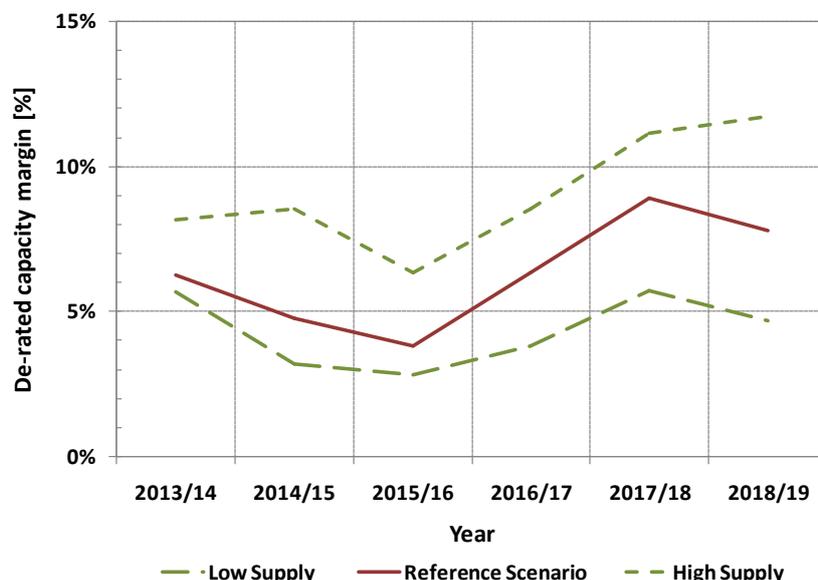
Figure 6: Risk to security of supply (LOLE) for the Reference Scenario and supply sensitivities
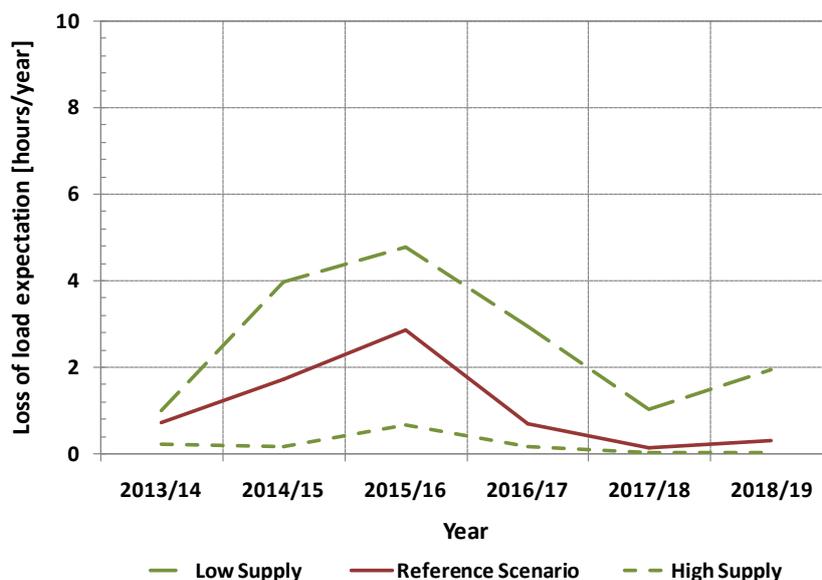
1.42. In the low supply sensitivity LOLE increases to around 5 hours per year in 2015/16 then decreases to about 2 hours per year at the end of the decade, while in the high supply sensitivity it remains at less than 1 hour per year for the whole period.

Interconnector flow sensitivities

1.43. We present sensitivities around interconnector flows to illustrate the impact of these assumptions in the risk measures and de-rated capacity margins[24]. The assumption of full exports to Ireland is maintained in all sensitivities with the exception of the no-net-flows case where net interconnector flows are set at zero. In the high imports and high exports sensitivities we assume flows of 1.5GW from and to mainland Europe (ie half capacity). The full imports sensitivity assumes 3GW imports from mainland Europe.

1.44. We do not present a full exports sensitivity as we consider GB is unlikely to export at full capacity during peak demand in the coming years given that this would result in negative de-rated margins in GB. We expect prices to reflect this and, as explained above, we expect interconnectors to react to price differentials more in the future (with Market Coupling). The implementation of Ofgem's proposed reform of cash-out arrangements may also contribute to improving the contribution of interconnectors by sharpening the price signals, though this is not reflected in our analysis.

1.45. As shown in Figure 7, half imports (1.5GW) from mainland Europe increase the de-rated margins up to around 9% in 2013/14 (12% with full imports) but the trend observed in the Reference Scenario is maintained with de-rated margins falling until 2015/16 and then increasing again in the second half of the decade. The half exports to mainland Europe sensitivity results in de-rated margins lower than 2% in 2015/16 with a peak of 6.5% in 2017/18. Figure 8 presents the risks trends for these sensitivities.

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[24] As with all other sensitivities, we do not assign probabilities to the occurrence of these sensitivities.

Figure 7: De-rated capacity margins for the Reference Scenario and interconnector flows sensitivities
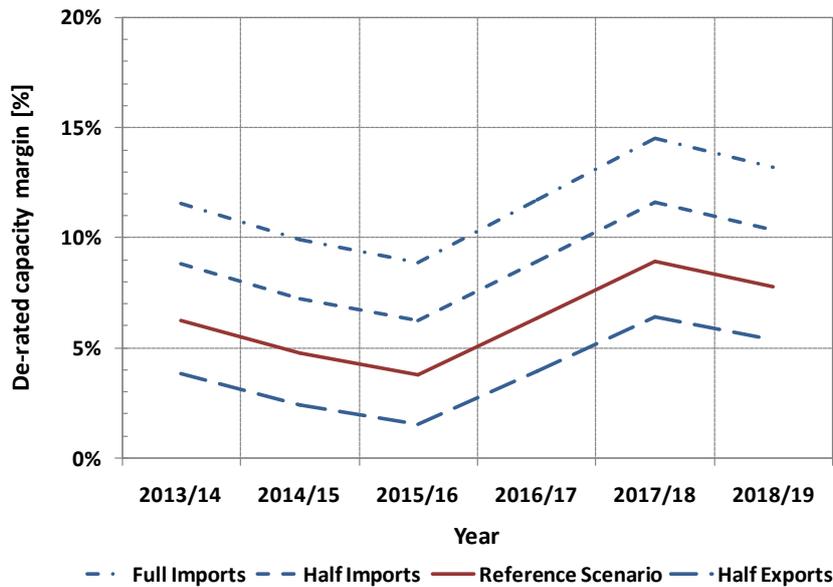
Figure 8: Risk to security of supply (LOLE) for the Reference Scenario and interconnector flows sensitivities
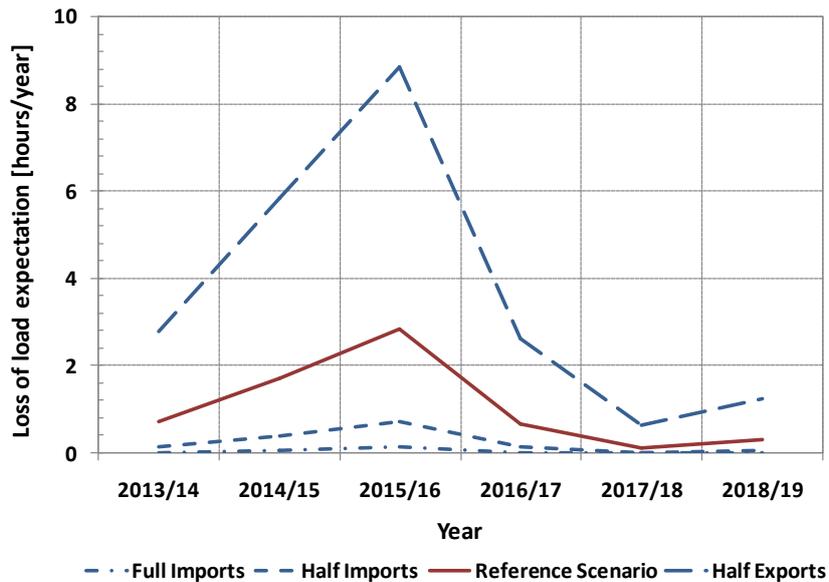
1.46. We also present a sensitivity where interconnector flows are excluded (ie no net flows from mainland Europe or Ireland). This sensitivity may be useful when making decisions to procure extra capacity through policy intervention (eg a Capacity Market) due to the high levels of uncertainty surrounding the assessment of future interconnector flows. In addition, including exports in the demand projections when calculating how much capacity to procure through policy interventions would mean supporting investment to secure demand abroad as well as demand in GB.

1.47. De-rated margins in the no-net-flows sensitivity are higher than in the Reference Scenario, reaching 5% in 2015/16, and the corresponding risks measures are lower with LOLE around 1-2 hours in the same year.

Conventional generation availability sensitivities

1.48. For the purposes of this analysis, when we refer to conventional generation capacity we mean the non-wind[25] plant connected to the GB transmission system. Wind generation capacity is analysed separately given that its outcome in terms of generation availability is much more variable and difficult to predict.

1.49. Estimating de-rating factors is a complex task given that historical plant availability combines the effects of technical (unexpected) outages as well as capacity withdrawals as a result of market conditions (strategic outages). These are difficult to differentiate in the historical data and could potentially bias the results. In the Reference Scenario, we use de-rating factors by technology to represent the average availability of each type of plant. These are based on historical winter availabilities in the last seven years.

1.50. A small variation in the de-rating factors may have a significant impact on the de-rated margins and risk measures. With the low conventional availability sensitivity we illustrate the case where the de-rating factors are on average 4% lower[26]. This could be the result of different factors, including ageing of the fleet. More variable patterns of utilisation of conventional plant to balance a system with more variable wind generation could also result in more outages. The high conventional availability sensitivity illustrates the case where generators increase their availability by around 4% at times of peak demand to, for example, profit from higher prices[27].

1.51. Figure 9 and Figure 10 present the de-rated capacity margins and risks measures for these sensitivities. As shown in the figures, the de-rated margin for the low availability sensitivity is less than 1% in 2015/16 with a LOLE of around 16 hours per year, while in the high availability sensitivity the de-rated margin is about 7% and the LOLE is close to zero for the same year.

Figure 9: De-rated capacity margins for the Reference Scenario and conventional generation availability sensitivities

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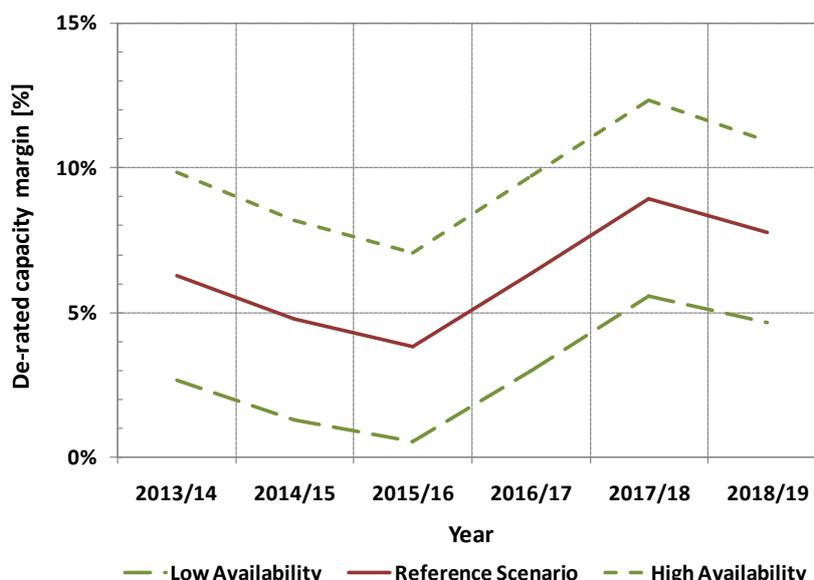
[25] The proportion of other variable sources of generation such as solar is very limited in the current GB market.

[26] We use the mean plus and minus one standard deviation to find the variations for these sensitivities.

[27] We do not use this assumption in the Reference Scenario as we do not have evidence in this sense.

Figure 10: Risk to security of supply (LOLE) for the Reference Scenario and conventional generation availability sensitivities
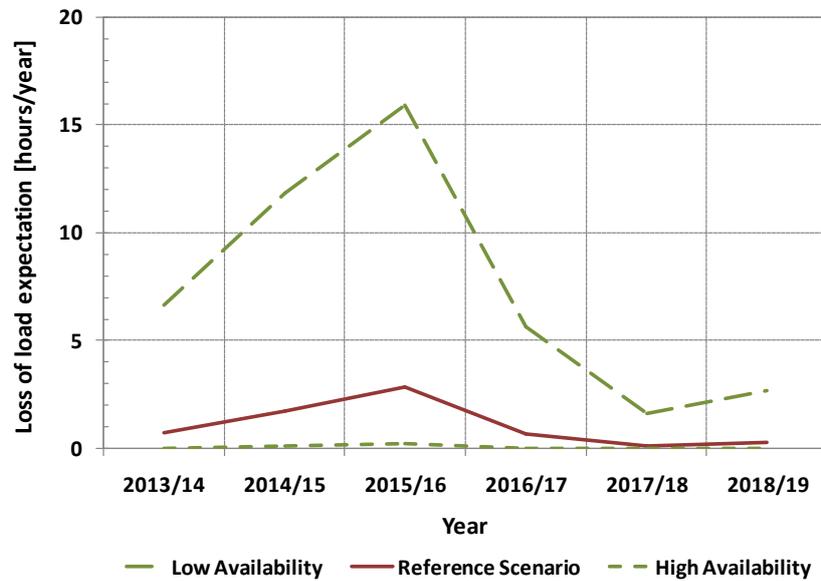

Wind power availability sensitivity

1.52. In the Reference Scenario we assume that demand and wind power availability are independent in the winter season. In other words, we assume that wind power availability does not vary in line with demand variations within the winter season[28]. It is important to note that we do not assert that there is no relevant statistical relationship between demand and available wind power. Rather, we assume independence between these variables because the required data to support a more complex model structure including explicit wind-demand dependence does not exist.

1.53. With the sensitivity on wind availability we illustrate the outcomes if the availability of wind decreases by up to 50%[29] at times of extremely high demand (ie demand that is above the winter average). The de-rated margin drops to about 2% and the LOLE rises to more than 6 hours in 2015/16, as shown in Figure 11 and Figure 12.

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[28] In annual terms wind availability tends to be lower in summer when demand is lower than in winter.

[29] For further information refer to Appendix 5.

Figure 11: De-rated capacity margins for the Reference Scenario and wind generation availability sensitivities
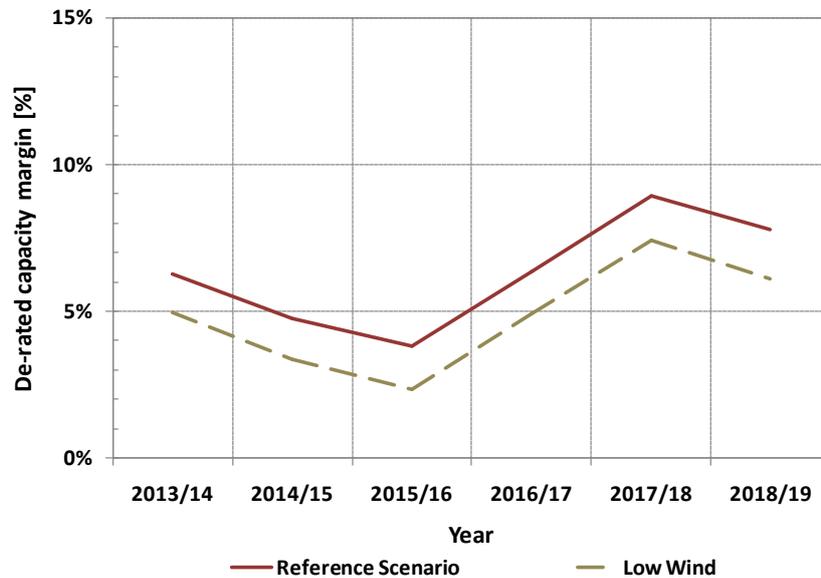
Figure 12: Risk to security of supply (LOLE) for the Reference Scenario and wind generation availability sensitivities
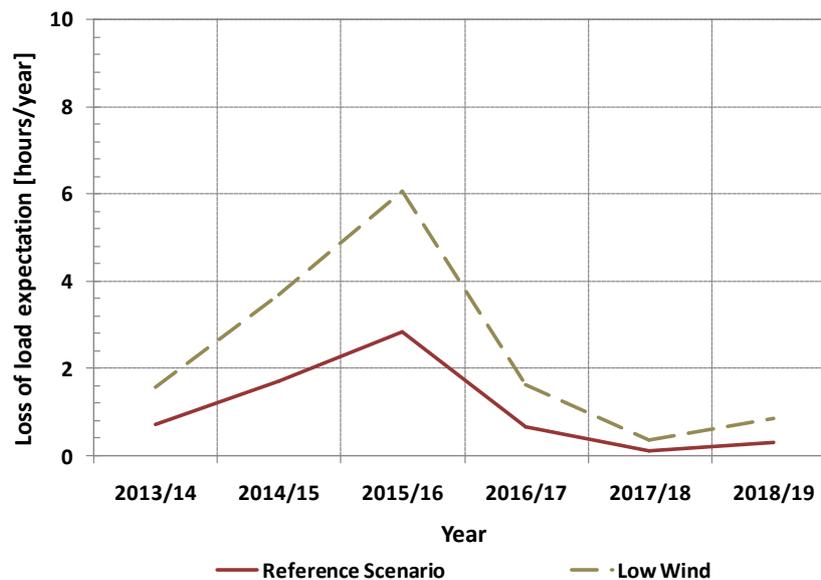
Potential impacts on customers

1.54. As noted earlier, most supply deficits in the GB market are not noticeable for customers as the System Operator can manage small events using a range of mitigation actions. These include voltage control, requesting maximum generation from plant or requesting emergency services from the interconnectors.

1.55. If all mitigation actions were exhausted and demand was still not met, the System Operator would proceed with the controlled disconnection of customers by asking the Distribution Network Operators (DNOs) to disconnect load. The DNOs would start shedding the largest loads first, which would likely be industrial users and then go down the list of electricity consumers at the time. In addition, information would be provided to

the market to reduce demand (rather than disconnect). This would most likely start by appealing for industrial and commercial customers to reduce demand then moving to the next stage by asking customers in general to reduce demand and to avoid turning on appliances at peak times. This process is covered by stages of emergency actions which are detailed in the Grid Code[30].

1.56. We estimate the probability of controlled disconnections of customers, including both non-domestic and domestic, to increase from around 1 in 47 years in 2013/14 to around 1 in 12 years in 2015/16 before falling to 1 in 112 years in 2018/19.

1.57. The probability of controlled disconnections of customers follows the same trend as the LOLE, though it is by definition smaller as only some shortfalls would lead to controlled disconnections. The sensitivity presenting the highest probability of controlled disconnections is the low conventional generation availability sensitivity, which peaks at around 1 in 2 years in 2015/16.

Structure of the report

1.58. The Electricity Capacity Assessment Report 2013 is structured as follows:

- Chapter 2 presents a brief description of the methodology used for our analysis.

- Chapter 3 describes the assumptions for the Reference Scenario and sensitivities.

- Chapter 4 presents the results in terms of de-rated margins and risk measures and potential implications for customers.

- Appendix 1 further expands our analyses introducing specific studies and sensitivities. Appendix 2 compares our estimations of the risk measures from last year's Electricity Capacity Assessment report with those from this report. Appendix 3 lays out a detailed description of the model. Appendix 4 introduces an analysis of the contribution of interconnector flows to security of supply. Appendix 5 details the numerical results behind the figures presented throughout this report in table format. Appendix 6 provides a glossary of terms used.

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[30] Note that the explanation presented in this document is for illustration purposes only and it is not intended to provide precise information. This process is accurately documented in the appropriate provisions of the Grid Code, as described in OC6 (Demand Control), OC7 (Operational Liaison) and BC1 (Balancing Code).

2. Methodology

2.1. This chapter describes the methodology used for this report. In particular, we explain the modelling approach and indicators used to assess the risk to electricity security of supply in GB. A detailed description of the modelling approach can be found in Appendix 3.

2.2. Like the 2012 report, the 2013 report uses a combination of a probabilistic approach and sensitivity analysis. We use a probabilistic approach to assess the uncertainty related to short-term variations in demand and available conventional generation due to outages and wind generation. This is combined with sensitivity analysis to assess the uncertainty related to the evolution of electricity demand and supply due to investment and retirement decisions (ie mothballing, closures) and interconnector flows, among others.

2.3. The Reference Scenario represents a view of the future outlook for security of supply based on the information currently available to us. It is presented to facilitate comparison with the various sensitivities. Our analysis sets out an updated assessment of the risks to electricity security of supply in Great Britain over the next six winters (ie from 2013/14 to 2018/19).

2.4. The methodology was designed by Ofgem and National Grid and the probabilistic model was developed by National Grid in close collaboration with Ofgem. The methodology was consulted upon with industry[31] and academics. The probabilistic model was validated by LCP Consulting.

Modelling Approach

High level approach and outputs

2.5. The Capacity Assessment model is a probabilistic model that analyses capacity adequacy in GB. Under the current characteristics of the GB market, any problems related to generation adequacy are likely to materialise during the winter season[32]. Therefore, our model uses a distribution of demand during winter season. Times of extremely high demand that may cause emergency situations are represented in the tails of the demand distribution.

2.6. Our model is a time-collapsed model; this means that it calculates the probability of demand exceeding available supply (supply deficit) at a randomly chosen half-hour from the winter period. Due to the physical characteristics of electricity systems, a supply deficit does not necessarily mean that customers will be disconnected but it means that the SO will need to intervene to try and avoid disconnections. Only large supply deficits lead to disconnections in the GB system. We estimate the possible frequency and duration of any shortfalls to provide an indication of the risk of controlled disconnections of customers.

2.7. Figure 13 below presents a schematic representation of the model. The inputs for investment and retirement decisions (new build, closures, mothballing) are based on National Grid's Future Energy Scenarios[33] amended to reflect Ofgem's views, mainly with

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[31] The methodology was consulted with industry and academics in 2011 and 2012. The consultation documents, corresponding responses and decision documents can be found in http://www.ofgem.gov.uk.

[32] This has been demonstrated with the analysis of the summer period included in Appendix 1.

[33] The Future Energy Scenarios are developed annually by National Grid to illustrate potential scenarios of the future development of the GB electricity and gas sectors. For further information refer to:
http://www.nationalgrid.com/uk/Gas/OperationalInfo/TBE/Future+Energy+Scenarios

regards to the impact of policy uncertainty. The inputs on interconnector flows are based on Ofgem's assumptions while expected demand, available conventional capacity (de-rating factors), and the characteristics of wind farms are 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 the National Aeronautics and Space Administration (NASA).

Figure 13: Schematic representation of the modelling approach[34]

Demand (including DSR) | Installed Conventional | Availability | Wind speeds | Wind farms | Interconnectors | Closures, new build, mothballed | Conventional Generation | Wind Generation | Risk Calculation | Max Generation | Voltage Reduction | EEU | LOLE | EFC | Frequency and duration | Emergency Services | De-rated Margin
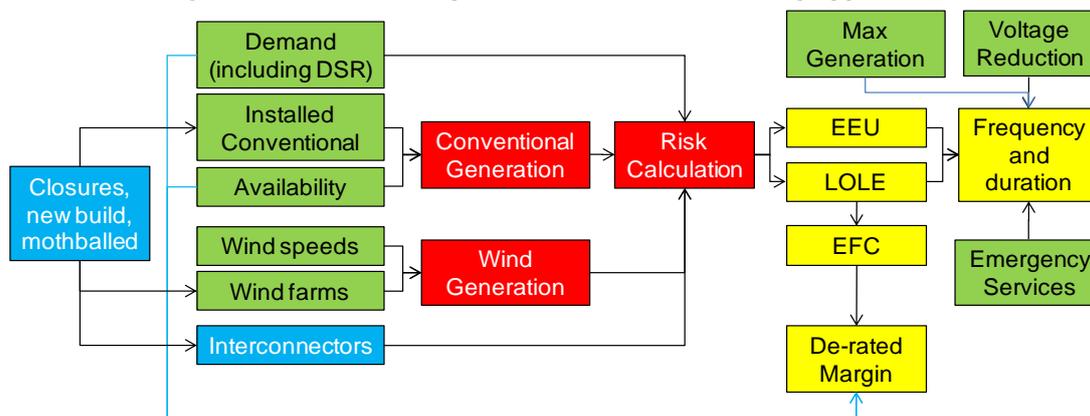
2.8.   There are five key outputs from our modelling: two probabilistic measures of security of supply, Loss of Load Expectation (LOLE) and Expected Energy Unserved (EEU); the frequency and duration of expected outages, the Equivalent Firm Capacity (EFC) of wind power and the de-rated capacity margin:

- **LOLE:** the mean number of hours per year in which supply does not meet demand in the absence of intervention from the System Operator.

- **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:** an illustration of the results of the probabilistic risk measures in terms of tangible impacts for electricity customers. This is based on judgements around how the electricity system would operate at a time when supply does not meet demand, and the order and size of mitigation actions taken by the System Operator. It is therefore not as accurate as the LOLE and EEU but it allows us to provide a view of the probability of experiencing controlled disconnections of customers.

- **EFC:** the quantity of firm capacity (ie always available) that can be replaced by a certain volume of wind generation to give the same level of security of supply, as measured by LOLE. This measure is used to calculate the average contribution of wind power to the de-rated margin. It varies with the proportion of wind power in the system.

- **De-rated capacity margin:** the average excess of available generation capacity over peak demand, expressed in percentage terms. Available generation capacity takes into account the contribution of installed capacity at peak demand by

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[34] 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 outputs of the modelling.

adjusting it by the appropriate de-rating (or availability) factors which take into account the fact that plant are sometimes unavailable due to outages.

2.9. LOLE is not a measure of the expected number of hours per year in which customers may be disconnected. We define LOLE to indicate the number of hours in which the system may need to respond to tight conditions.

2.10. For a given level of LOLE and EEU, results may come from a large number of small events where demand exceeds supply in principle but it can be managed by National Grid through a set of mitigation actions available to them as System Operator[35]. The results may also come from a small number of large events (eg the supply deficit is more than 2 to 3GW[36]) where controlled disconnections cannot be avoided. Conversely, given the characteristics of the GB system, any shortfall is more likely to take the form of a large number of small events that would not have a direct impact on customers.

2.11. LOLE serves to take account of the impact of rising levels of variable generation. However, it may not reflect any potential improvements[37] in the capacity of the system to cope with more variability before any disconnections. We do not expect these improvements to have a significant impact in the market in the next six winters.

Quantifying LOLE and EEU

2.12. To calculate the LOLE and EEU, in the six winter modelling period, the model constructs probability distributions of winter demand[38], wind power and available conventional generation. The LOLE and EEU are calculated by combining (ie through convolution[39]) the three distributions; this represents the main risk calculation. The outcome of the convolution is a distribution of margins (ie the difference between supply and demand) for each winter in the modelling period. The LOLE and EEU are then estimated from the part of the distribution for which supply is lower than demand.

2.13. The distribution of winter demand is based on rescaled historical demand data and demand growth projections provided by National Grid. The distribution of wind power is based on wind speed data which is used to estimate the corresponding levels of wind generation associated with the projected installed wind capacity.

2.14. The distribution of available conventional generation is derived from installed capacities combined with a de-rating factor. The de-rating factors are derived from the analysis of the historical availability performance of the different generating technologies, at times of winter peak period. The winter peak period is defined here as the days in winter where

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[35] The System Operator can implement mitigation actions to maintain the system when available supply is insufficient to meet demand. These include voltage control, maximum generation instruction and emergency services from the interconnectors.

[36] This varies with the specific conditions of the market at the time of the outage, including the flows over the interconnectors at the time.

[37] One potential improvement would be for example further penetration of frequency management through automated appliances. For further information refer to:

http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?file=20130430_Creating%20the%20right%20environment%20for%20demand-side%20response.pdf&refer=Markets/sm/strategy/dsr

[38] Winter demand is based on Average Cold Spell (ACS) demand. This reflects the combination of weather elements (ie 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.

[39] Convolution is the mathematical operation of obtaining the distribution of the sum of two independent random variables from their individual distributions.

demand is greater than the median[40] of daily demands from October to March, in every year[41].

2.15. We assume that interconnectors will respond to price differentials in the future after the implementation of Market Coupling in 2013. However, we cannot model future price differentials between GB and interconnected markets with sufficient precision due to all the uncertainty surrounding the evolution of the North-Western European electricity markets. Consequently, we use informed assumptions based on the analysis presented in Appendix 4 where we considered the structure of the GB and interconnected markets, historical price differentials and the security of supply outlook in these markets.

2.16. The uncertainties surrounding the evolution of both supply and demand are significant. Hence, our report includes sensitivity analysis to account for a range of possible views[42]. Each sensitivity assumes a change in one variable[43] from the Reference Scenario, with all other assumptions being held constant. The purpose of this is to assess the impact of the uncertainty related to each variable in isolation, on the risk measures. Our report is not using scenarios (ie a combination of changes in several variables to reflect alternative worlds or different futures), as this would not allow us to isolate the impact of each variable on the risk measures.

Frequency and duration of outages

2.17. LOLE is not a measure of the expected number of hours per year in which customers may be disconnected. To illustrate the potential impact on customers, we also estimate the frequency and duration of outages of a given severity when mitigation actions available to the System Operator have been exhausted. These actions cover demand reduction (eg voltage control) and potential supply increases. The frequency and duration estimates help us to illustrate possible impacts on customers of supply shortfalls (ie the average frequency of controlled disconnections of customers given the volume of demand). The tools available to the System Operator are discussed below.

- **Voltage reduction:** For small events, both in terms of energy and duration, the SO can manage the system by instructing voltage control. This is subsequently applied by the DNOs. This action involves reducing the voltage level and hence the level of consumption. The SO estimates the maximum level of demand reduction that can be achieved through this measure to be 500MW[44].

- **Maximum generation:** The maximum generation action is a service where the SO instructs generators to generate at the maximum possible output. This involves operating a generator above 100% of its rated output[45]. The amount of available extra capacity through the maximum generation is estimated at around 250MW by the SO.

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[40] The median is the value that separates the higher half of the data set from the lower half. By using only periods where demand is higher than the median we are ensuring that we only use the higher half of the data set which represent periods of high demand during the winter.

[41] For further information refer to Chapter 3.

[42] For further information refer to Chapter 3.

[43] For example, in the demand sensitivities we have developed, the only variable changing is demand.

[44] This is based on National Grid's operational experience. Section OC6.5.3. of the Grid Code outlines the obligations for demand control for the DNOs.

[45] This mode of operation causes significant wear and tear to the generator and as a result this measure can only be applied rarely.

- **Emergency services from interconnectors[46]:** Emergency services from interconnectors are used as a last resort solution before initiating controlled disconnections of GB customers. In the event of a supply shortfall, after all other measures have been exhausted, the SO can request assistance from the SOs of the interconnected markets. Specifically, the SO-SO agreements in place enable the SO to request the reduction of exports from GB or the increase of imports from the neighbouring markets . The available volume through emergency services from interconnectors depends on the level of imports and exports prior to requesting emergency services.

2.18. Figure 14 illustrates the mitigation actions available to the SO and their potential sequence.

Figure 14: Schematic representation of mitigation actions
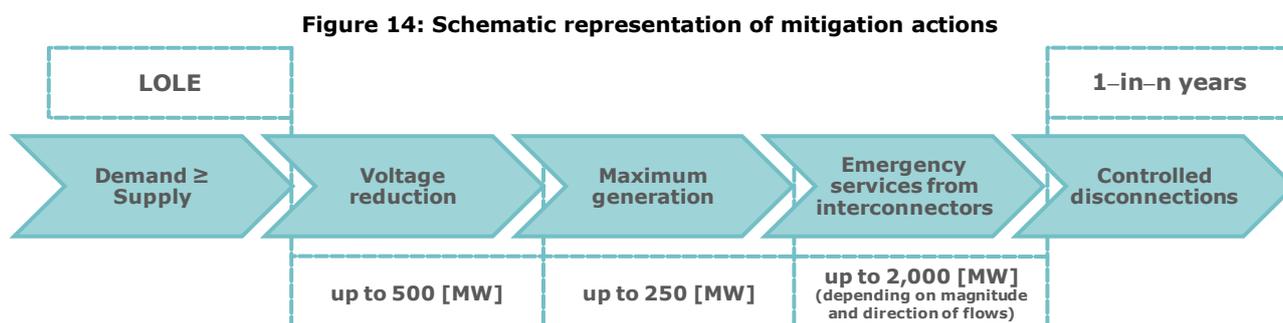
Interpreting risks to security of supply

2.19. The probabilistic measures of security of supply presented in this report are often misinterpreted. LOLE is the expected number of hours per year in which supply does not meet demand. This does not however mean that customers will be disconnected or that there will be blackouts for that number of hours a year. Most of the time, when available supply is not high enough to meet demand, National Grid may implement mitigation actions to solve the problem without disconnecting any customers. However, the system should be planned to avoid the use of mitigation actions and that is why we measure LOLE ahead of any mitigation actions being used.

2.20. LOLE does not necessarily mean disconnections but they do remain a possibility. If the difference between available supply and demand is so large that the mitigation actions are not enough to meet demand then some customers have to be disconnected – this is the controlled disconnections step in Figure 14 above. In this case the SO will disconnect industrial demand before household demand.

2.21. The model output numbers presented here refer to a loss of load of any kind. This could be the sum of several small events (controlled through mitigation actions) or a single large event. As a consequence of the mitigation actions available, the total period of disconnections for a customer will be lower than the value of LOLE. Even when a single large event occurs, part of the problem is solved with mitigation actions.

2.22. As an illustration of the impacts on customers, we also present in the report the 1-in-n years probability of controlled disconnections metric. This illustrates the (noticeable) consequences of the reported LOLE and EEU on customers specifically (ie after the mitigation actions have been used). The 1-in-n years estimate is an approximation only as it is very difficult to perform a precise calculation. We present it in order to help

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[46] For further information refer to:
http://www.nationalgrid.com/uk/Electricity/Balancing/services/balanceserv/systemsecurity/sotoso/

understand the potential situations that could arise but it should not be used for planning purposes.

2.23. The 1-in-n figure refers to the controlled disconnection of both industrial and household demand. The process to implement controlled disconnection of customers is as follows. If all mitigation actions were exhausted and the required System Margin was still not met, the System Operator would ask the Distribution Network Operators and Non-Embedded Customers and Suppliers to proceed with controlled demand reduction. National Grid will endeavour to achieve demand reduction in a manner that is equitable to all users, in order to avoid or reduce unacceptable operating conditions on any part of the GB Transmission System.

2.24. Each DNO ensures it can provide a 20% reduction of its total system demand in four incremental stages (between 4% and 6%), which can be achieved at all times, with or without prior warning, and within 5 minutes of receipt of an instruction from the System Operator. The reduction of a further 20% (40% in total) can be achieved following issue of the appropriate GB System Warning by National Grid within agreed timescales[47].

2.25. We are not able to calculate how many households (if any) would be disconnected in the event of a large outage – as this will depend on a number of factors, including the level of industrial demand at the time.

2.26. The LOLE and EEU estimates are just an indication of risk. There is considerable uncertainty around the main variables in the calculation (eg demand, the behaviour of interconnectors etc.). Therefore, we run sensitivities to show the range of possible outcomes depending on these uncertainties. For example, the Reference Scenario and sensitivities make different assumptions on the level and direction of interconnector flows with Ireland and mainland Europe.

2.27. The impact of interconnectors on LOLE is different from their impact on the 1-in-n probability of controlled disconnections. Our assumption is that, regardless of the assumptions on the level and direction of flows during normal winter conditions in the Reference Scenario and sensitivities (which have a direct impact on LOLE), we can almost always count on interconnectors to reduce the probability of controlled disconnections. For illustration, the probability of requiring voltage control would be higher if GB were exporting electricity to France compared to a situation where GB were importing electricity from France. However, the GB System Operator will be able to request assistance from the interconnectors by reducing exports before disconnecting any GB customers.

2.28. The inclusion of exports to Ireland and/or mainland Europe in the Reference Scenario or sensitivities does not mean that GB would be exporting electricity abroad while disconnecting customers in GB. As explained above, the SO makes use of mitigation actions before resorting to controlled disconnections. One of these actions is the provision of emergency services from interconnectors. Depending on the agreements in place (and the sensitivity assumptions) this would mean that exports could be reduced in an emergency situation and/or that imports from other markets could be called upon to alleviate any gap between supply and demand. As such, none of the sensitivities in our report calculate the probability of disconnection estimates while GB is a net exporter.

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[47] This process is covered in the appropriate provisions of the Grid Code, as described in OC6 (Demand Control), OC7 (Operational Liaison) and BC1 (Balancing Code).

Quantifying and interpreting de-rated capacity margins

2.29. Finally, we calculate the de-rated capacity margins for each winter. The de-rated margin represents the average excess of generation capacity over peak demand and is expressed in percentage terms. This "typical" available capacity is the sum of the average available conventional capacity and the Equivalent Firm Capacity (EFC[48]) of wind generation. The EFC is the quantity of firm capacity (ie always available) that can be replaced by a certain volume of wind generation to give the same level of security of supply, as measured by LOLE.

2.30. De-rated margins are not good indicators of security of supply because they do not reflect the amount of variability associated with them, which can differ significantly depending on the generation mix. By way of illustration, two systems with the same de-rated margin may have significantly different levels of risks depending on the proportion of variable generation capacity (eg wind power) in each system. Although the average availability of wind power is taken into account by de-rating the capacity, there is a much wider variation around this average (depending on wind conditions) than there is for conventional generation.

2.31. Comparing de-rated margins over time does not give an accurate picture in terms of risks as the proportion of wind power in the GB system has increased considerably in recent years and is expected to continue doing so. All else remaining equal, de-rated margins will need to increase steadily over time in order to achieve the same level of security of supply. Nonetheless, de-rated margins are a familiar and intuitive indication of trends in the short to medium term.

2.32. Generally, when the variations in the generation mix are not extensive (as is the case during the period evaluated in this report) the LOLE and EEU tend to increase when the de-rated margins decrease and vice versa. However, the effects are not symmetrical. Importantly, a change in the de-rated margins when they are low has a larger impact on the risks (eg LOLE and EEU) than a change of the same magnitude in the de-rated margins when they are high. This emphasises the importance of exploring plausible lower de-rated margins through sensitivities to get a better sense of the risks to security of supply in GB in the coming years.

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[48] For further information on the calculation of EFC and the rationale for using this measure to find the de-rated capacity of wind power refer to Appendix 3.

3. Assumptions

3.1. This chapter describes the model input assumptions. It is split into three sections. We first present the assumptions on the supply side, followed by the assumptions on the demand-side. Finally we present the assumptions around interconnector flows. Each section describes the assumptions for the Reference Scenario and relevant sensitivities.

3.2. The Reference Scenario builds on National Grid's Gone Green 2013 scenario from its forthcoming Future Energy Scenarios. We have made adjustments to National Grid's supply-side assumptions to reflect our own views on the closure, mothballing and new build decisions of generators, and on interconnector flows. Each sensitivity is designed to vary only one variable and hold all other variables constant. The purpose of this is to assess the uncertainty related to an individual variable, and its impact on the risks to security of supply.

3.3. An important factor for our supply, demand and interconnector flows assumptions is the energy policy in place. We have only modelled policies that are already in place or for which a decision has been taken. Therefore our assumptions do not reflect the impact of the potential implementation of a Capacity Market or cash-out reform. No additional Energy Market Reform (EMR) policies are taken into account in our analysis. We assume that Market Coupling[49] is implemented from the winter of 2013/14.

Supply

3.4. This section presents assumptions on the supply side. We have followed a similar approach to the 2012 report. More specifically, the assumptions for the Reference Scenario build on National Grid's Gone Green 2013 scenario, amended for the latest public information on recent and future capacity changes. The assumptions are also amended to reflect Ofgem's views regarding the evolution of installed capacity due to the uncertainty in future market conditions and policy.

3.5. Decisions on whether power stations close, return to service or are built depend on companies' specific commercial and financial position, the outlook for energy prices as well as the energy policy environment. It is very difficult to form a firm view on these decisions. We have therefore developed sensitivities to explore the effect of these key uncertainties on our risk measures.

3.6. We use the most up-to-date market information at the time of publication relating to the capacities of generators. The assumptions for the Reference Scenario and sensitivities are presented in the next section.

Reference Scenario

3.7. Since the publication of Ofgem's 2012 report, a number of plant have announced their permanent closure or mothballing. Some of these plant closures and mothballing decisions were expected while others were not anticipated. Total installed capacity is

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[49] "Market Coupling is the method by which Day Ahead energy prices and volumes for each local market are calculated by gathering all Day Ahead bids and offers (collectively termed orders in the network code) in the different local markets in order to match them at European level on a marginal pricing basis", ENTSO-E, Network code on Capacity Allocation & Congestion Management (CACM). This definition could be extended to other electricity products (eg intra-day prices). For further information refer to:
https://www.entsoe.eu/fileadmin/user_upload/_library/consultations/Network_Code_CACM/120323_NetworkCodeConsultation_FINAL.pdf

expected to be around 77.9GW in the winter of 2013/14 (down from 79.5GW in our 2012 report), falling steadily to 76.8GW by 2015/16 (down from 79.3GW in our 2012 report), before increasing to 83.6GW in 2018/19. Figure 15 presents the installed capacity by technology in GB over the next six winters.

Figure 15: Installed capacity by generation technology type in the Reference Scenario
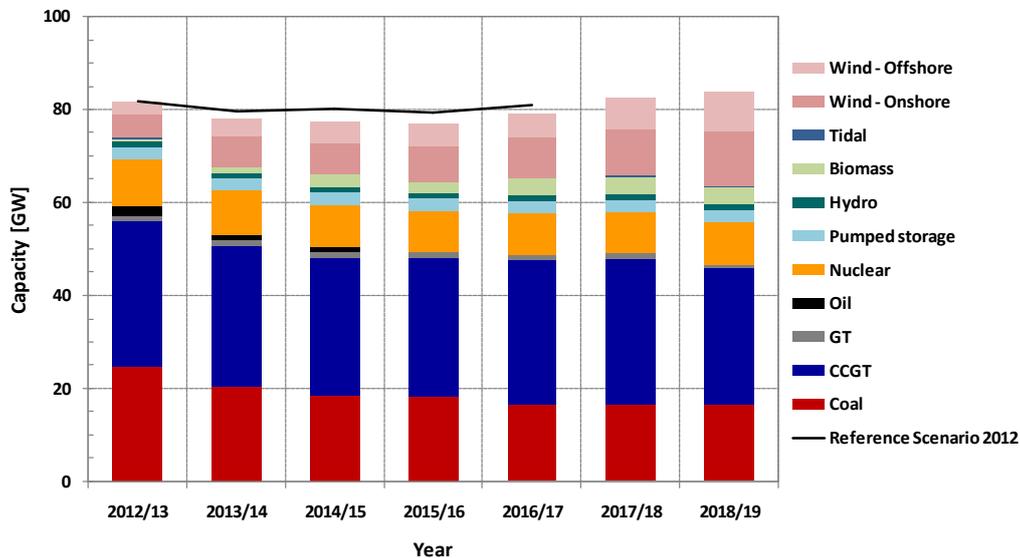
3.8. The generation mix changes over time. Fossil fuel capacity (around 6.3GW) is expected to be replaced by new variable wind generation and biomass plant (around 12.4GW) in the timeframe of our analysis. In particular, older coal and oil plant will close due to the requirements of European environmental legislation, while some coal plant are expected to convert to biomass. Some nuclear capacity is also expected to retire over the period. CCGT capacity is expected to vary during the period of analysis.

3.9. Figure 16 presents the change in installed capacity for each technology type in each winter of analysis.

Figure 16: Changes in installed capacity by generation technology type in the Reference Scenario
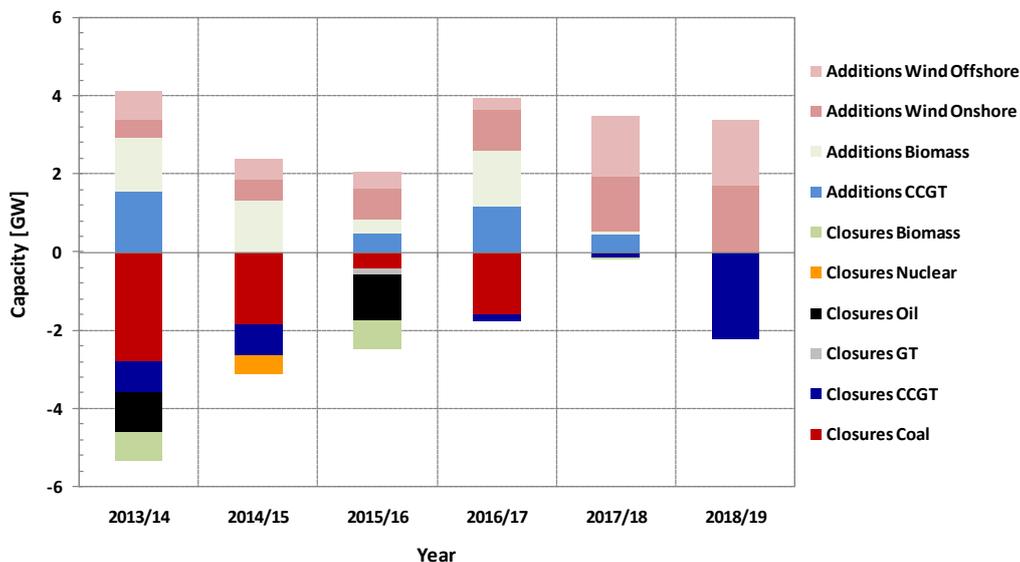
3.10. The changes in the installed capacity due to closures, mothballs and new-builds, by technology type are discussed in turn below.

Closures

3.11. A number of plant are expected to close over the analysis period. These closures are mainly driven by the Large Combustion Plant Directive (LCPD) that restricts the operation of coal and oil plant, and plant reaching the end of their technical lifetime.

3.12. Under the LCPD directive, fossil-fuelled generating plant must choose to either reduce their emissions or opt-out of the Directive[50]. Coal plant that opt-out are restricted to operating for 20,000 hours[51] between 1 January 2008 and 31 December 2015, by which time they must close[52]. A total of 12GW of coal and oil plant in GB opted-out of the Directive will have to close by the end of December 2015. Two coal plant, with a combined capacity of 2GW, have also opted-out of the LCPD, but have converted to generate from biomass. This would result in a reduction of their available capacity of around 0.5GW[53].

3.13. The bulk of LCPD closures have already been realised, with over 7GW having shut down permanently by the end of winter 2012/13 and an extra 0.7GW of biomass plant expected to close before winter 2013/14. Additionally, we expect 1GW of coal plant to close at the end of 2013/14 and 0.7GW of biomass plant to close at the end of 2014/15. Only 1.1GW of oil plant are expected to remain operational until the end of 2015.

3.14. Opted-in LCPD coal capacity is expected to decrease over the course of the period, mainly due to plant conversions from coal to biomass. In particular, around 2.5GW of opted-in coal plant are expected to convert to biomass by 2016/17. This is due to the profitability of coal generation decreasing with the implementation of the Carbon Floor Price (CPF)[54], while biomass conversion is supported by governmental policy through the Renewable Obligation[55]. In addition 0.3GW of opted-in LCPD coal capacity is scheduled to close permanently by 2014/15.

3.15. The Industrial Emissions Directive (IED)[56] will place restrictions on the operation of some existing coal and older CCGT stations post 2016/2017[57]. This creates uncertainty in the market as generators have until January 2014 to decide whether to opt-in or opt-out of the Directive. We assume that the IED does not affect the supply situation in the timeframe of our analysis.

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[50] The LCPD aims to reduce the emission levels of sulphur dioxide (SO_2) and nitrogen oxides (NO_x) from large combustion plants, including power plants, across Europe. For more information see:
http://www.defra.gov.uk/industrial-emissions/eu-international/lcpd

[51] Opted-out LCPD oil plant are restricted to 10,000 hours of operation in the same period.

[52] The LCPD required coal and oil plant to fit pollution abatement equipment to comply with the emission limits set by the Directive. However, it gave coal and oil plant the option to opt-out of this provision, thus restricting their operation times.

[53] As plant convert from coal to biomass their capacity is reduced due to the lower heat content of biomass compared to coal.

[54] For further information refer to:
http://www.hmrc.gov.uk/climate-change-levy/carbon-pf.htm

[55] For further information refer to:
https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/42842/3235-consultation-ro-banding.pdf

[56] For further information refer to:
http://www.defra.gov.uk/industrial-emissions/eu-international/industrial-emissions-directive

[57] Under the IED, coal and old CCGT plants can either fit emission reduction equipment to comply with the requirements, or take one of two derogations available. The hours based restriction (Limited Lifetime Obligation, LLO) and emissions based restriction (Transitional National Plan) will both limit the load factors of these stations.

3.16. Approximately 500MW of nuclear capacity is scheduled to close before winter 2014/15. The two nuclear plant that were due to reach the end of their technical lifetimes within the period of analysis have been granted lifetime extensions that put their closures beyond 2018/19[58]. No further nuclear plant closures are assumed in the Reference Scenario.

3.17. It is expected that some older CCGT plant will come offline after the mid-decade, as they reach the end of their technical lifetime. We assume that 0.3GW of CCGT plant will close permanently in 2016/17 and 2017/18 combined, with another 2.2GW closing in 2018/19.

Mothballing of plant

3.18. One of the most difficult issues to form a firm view on relates to mothballing of plant. Since the publication of our 2012 report, the number of CCGT plant mothballed has increased in the GB system. Generators have cited low profitability for gas generation as the main driver for recent mothballing decisions.

3.19. We assume around 1.5GW of mothballed plant in winter 2013/14. An additional 0.8GW of gas plant are expected to mothball before winter 2014/15. We assume that around 0.5GW of mothballed plant will be brought back on the system in 2015/16 and an additional 0.7GW in 2016/17 as margins get tighter.

New-builds

3.20. Decisions on whether power stations are built depend on companies' specific commercial and financial decisions. During the analysis period, we expect the installed capacity of wind and biomass to increase, mainly driven by Government support policies and some new CCGT plant becoming operational.

3.21. Installed capacity of wind has been growing for more than a decade[59]. It is expected that wind capacity will continue to grow over the next six winters, driven mainly by support policies and decreasing costs for the technology. Wind capacity is assumed to increase from 10.2GW in 2013/14 to 20.1GW in 2018/19 with the installation of Round 2 to 3 offshore wind farms, and the further deployment of onshore wind, both transmission connected and embedded.

3.22. Our assumptions on CCGT capacity include just under 1GW of new build, which is due to start construction. We assume that half of it will come online in winter 2016/17 and the rest in 2017/18.

3.23. As coal plant convert to biomass, we expect the installed capacity of biomass to increase, with a simultaneous decrease in coal capacity. While plant conversions are expected to lead to an additional 2.4GW of biomass plant between 2014/15 and 2016/17, this represents a net reduction in total capacity as the capacity of the converted plant is lower than the coal plant it replaces.

3.24. In addition, we assume that 0.7GW of biomass plant (converted LCPD opt-out plant) is relicensed and becomes operational from 2014/15. A further 0.1GW of dedicated biomass plant are assumed to come online in 2017/18.

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[58] Two of the Advanced Gas Cooled Reactors that were scheduled to retire in 2016 have received a seven year lifetime extension.

[59] For further information refer to: "Wind: State of the Industry 2012", by renewableUK (information relevant to the entire UK, ie GB and Northern Ireland).

Conventional and wind generation availabilities

3.25. In order to estimate the available generation capacity we need to de-rate the installed capacity by the corresponding de-rating factors that represent the availability of different generation technology types.

3.26. Estimating de-rating factors is a complex task given that it is difficult to differentiate between technical (unexpected) outages, and capacity withdrawals as a result of market conditions (strategic outages) from the historical data, creating potential bias in the results.

3.27. Conventional generation availabilities are derived from the analysis of the historical availability performance of the different generating technologies during the winter peak period. We defined winter peak period as the days in winter where demand is greater than the median of daily demands from October to March, in every year (2005 to 2012).

3.28. By considering the winter peak period, we are reflecting in our de-rating factors the potential for plant to increase their availability at times of high demand, and hence increase prices,. In the Reference Scenario the de-rating factors per technology type are estimated as their average availability over the past seven winter estimates (ie from 2005 to 2012).

3.29. An important input assumption on the supply side is the contribution of wind generators to security of supply. Wind power availability is more variable than the availability of conventional generation due to the variable nature of wind speeds. Therefore, we use a different approach to calculate the contribution of wind to security of supply by calculating the Equivalent Firm Capacity (EFC)[60] for each winter and sensitivity. The EFC shows the contribution of wind generation to security of supply by taking into account the margin changes in the GB system. The EFC values are in the range of 17% – 24% of the installed wind capacity for the Reference Scenario; depending on the winter under study (the lower values correspond to the later winters of the analysis period where the proportion of wind power in the generation mix is larger). Appendix 3 presents a detailed description of the calculation method for EFC.

3.30. Table 1 shows the availability (ie de-rating factors) of generators per technology type for the Reference Scenario.

Table 1: Generator de-rating factors per technology type

Fuel type	Availability [%]
Coal / Biomass	88%
Gas CCGT / Gas CHP	85%
OCGT	92%
Oil	82%
Nuclear	81%
Hydro	84%
Pumped Storage	96%
Wind (EFC)	17% – 24%

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[60] The EFC is the quantity of firm capacity (ie always available) that can be replaced by a certain volume of wind generation to give the same level of security of supply, as measured by LOLE.

Sensitivities

3.31. We have used sensitivities to explore the effects of uncertainties in the key assumptions on the supply side. Below we present sensitivities around the Reference Scenario relating to the potential evolution of supply, the available wind resource at times of extreme demand, and the de-rating factors of conventional generators.

Supply

3.32. **High supply sensitivity:** we assume that market signals for CCGT plant improve and their profitability increases. In addition, there is an upside risk that generators will invest in new plant or not mothball existing plant despite uncertainty in the market. Therefore we assume that no additional CCGT is mothballed, some is brought back on the system, and the construction of new CCGT plant accelerates.

3.33. In the high supply sensitivity we assume that an additional 1.4GW of CCGT is available in 2013/14 increasing to 2.3GW in 2014/15. The amount of additional CCGT plant assumed to be available on the system decreases from 2014/15, to reflect the decrease in the availability of mothballed plant in that year. It is also assumed that 0.5GW of new CCGT becomes operational a winter earlier than in the Reference Scenario, in 2016/17, and an additional 2GW of new CCGT comes online for winter 2018/19. In the winter of 2014/15, 0.5GW of additional nuclear plant is assumed to be granted extension of its period of operation and therefore we consider it being available.

3.34. **Low supply sensitivity:** we assume the profitability of gas and oil plant remains unfavourable, leading to additional plant being mothballed or shutting down. In addition, there is a risk that uncertainty and lack of confidence around energy policies results in a lack of investment in new plant and additional plant being mothballed.

3.35. In low supply sensitivity, we assume that no new CCGT gets built within the timeframe of the analysis, reducing CCGT capacity by around 0.9GW from winter 2017/18 with respect to the Reference Scenario. We assume an additional 0.7GW of CCGT is mothballed in 2016/17. In addition, we assume approximately 0.4GW of oil plant shut down in 2013/14 and an additional 0.7GW of biomass plant are unavailable from 2014/15.

3.36. Figure 17 presents the changes in installed capacity by generation technology type for the high and low supply sensitivities compared to the Reference Scenario.

Figure 17: Installed capacity changes for the high and low supply sensitivities with respect to the Reference Scenario
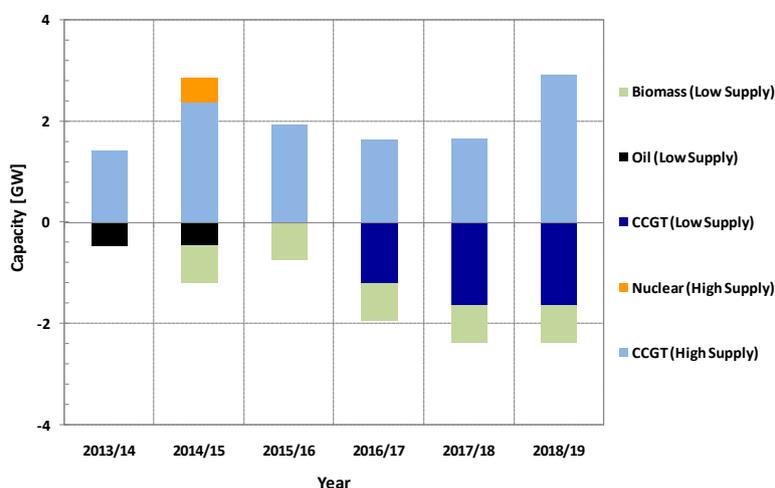
Conventional generation availability

3.37. De-rating factors are derived from the analysis of the historical availability performance of the different conventional technologies at times of winter peak demand, from 2005 to 2012. In the Reference Scenario the availability per technology type is defined as the mean availability over the past seven winter estimates.

3.38. As the availability of conventional power plants shows a significant amount of variation on a year-to-year basis, we have developed two sensitivities to account for potentially higher or lower availability per technology type than in the Reference Scenario. The low conventional availability sensitivity reflects the potential of reduced plant availability, eg due to the ageing of the generation fleet or more variable patterns of utilisation of conventional plant[61]. The high conventional availability sensitivity illustrates the case where generators increase their availability at times of peak demand to profit from higher prices. The low and high bounds are estimated by statistical analysis of the plant availability over the past seven winters[62].

3.39. Table 2 details the availability of the generators per technology type for the low and high conventional availability sensitivities.

Table 2: Generator availability per technology type

| Fuel type	Availability [%]	
	Low	**High**
Coal / Biomass	86%	90%
Gas CCGT / Gas CHP	81%	89%
OCGT	87%	97%
Oil	75%	89%
Nuclear	76%	86%
Hydro	78%	90%
Pumped Storage	93%	99%

Wind generation availability

3.40. There is not yet sufficient data for wind generation during winter in GB to enable us to understand the relationship, if any, between wind availability and high demand[63]. Therefore, in the Reference Scenario we make the assumption that there is no relationship between these variables at the time of high demand. This means that the distribution of wind power and winter demand are estimated separately, although the distribution of wind is based on historical wind speeds over winter.

3.41. However, there is a widespread belief that the wind stops blowing when there is a severe cold spell, resulting in lower wind availability at the time of high demand for electricity. Figure 18 presents the relationship between the wind load factor and daily peak demand observed from 2005 to 2012. Figure 18 illustrates that the available wind appears to decrease as daily peak demand increases. However, there is insufficient data to find this trend statistically significant and so we have taken the possibility into account via the wind-demand sensitivity.

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[61] This could be driven by the need to operate plant flexibly as more variable wind generation becomes operational.

[62] The low and high bounds are estimated as the mean availability ± one standard deviation, based on the annual availabilities per technology type over the past seven winters.

[63] From the security of supply perspective, we are mainly interested in the available wind resource at times of high demand.

Figure 18: Wind load factor at times of daily peak demand
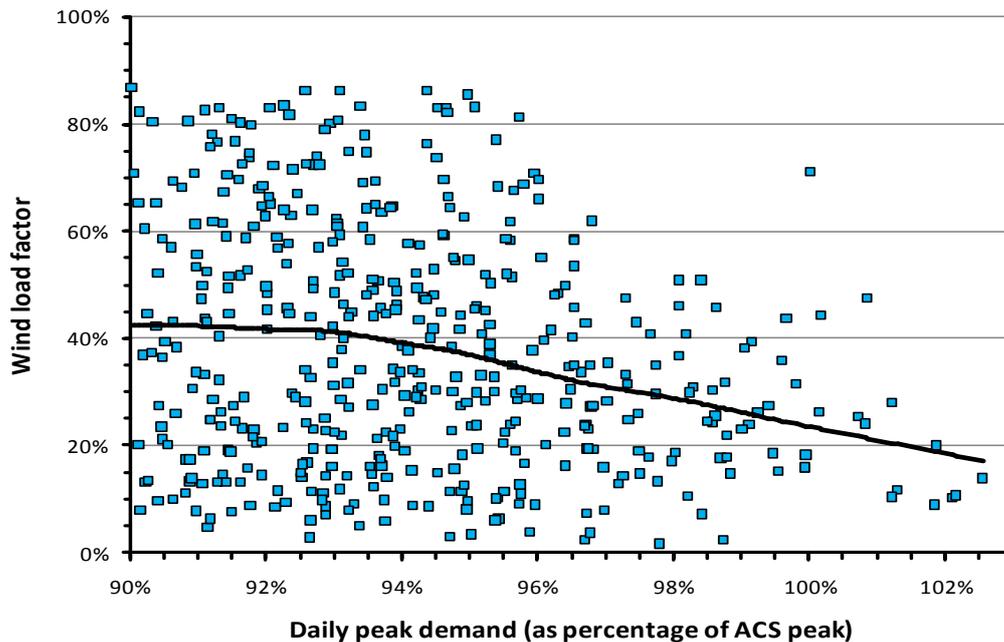
3.42. For the wind generation availability sensitivity we assume that wind availability decreases at time of high demand. In particular this sensitivity assumes a reduction in the available wind resource for demand levels higher than 92% of the ACS peak demand. The maximum reduction is assumed to be 50% for demand levels higher than 102% of ACS peak demand[64].

Demand

3.43. Electricity demand assumptions for the Reference Scenario are taken from the Gone Green 2013 scenario assumptions produced by National Grid for its Future Energy Scenarios. National Grid expect economic growth, energy efficiency and demand management to be the main variables driving changes in demand over the period of our analysis.

3.44. Demand is very difficult to predict, especially during an economic downturn and with uncertain weather patterns. For example, demand could be significantly higher than expected due to severe winter conditions. In addition, it is also very difficult to anticipate the impact of energy efficiency policies on energy use. We have thus developed sensitivities around the potential evolution of electricity demand.

3.45. The demand used in our analysis is the ACS peak demand, which is demand adjusted for the effect of weather variations. It reflects demand at winter peak under average weather conditions. The basis for this is the demand as seen by National Grid on the transmission network net of embedded generation[65] and demand-side response[66] to which the contribution of embedded wind at peak[67] is added.

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[64] For further information refer to Appendix 3.

[65] Embedded generation is generation connected to the distribution network. This consists of a range of technologies including for example small scale Combined Heat and Power, generation from landfill gas, and biomass. The electricity generated by such schemes is typically used in the local system rather than being transported across the UK, and hence manifests as a reduction in demand as seen by National Grid.

Reference Scenario

3.46. Demand for electricity has been declining since 2008, primarily as a result of the economic downturn and the implementation of energy efficiency measures. Figure 19 depicts the evolution of the historical ACS peak demand from 2005 together with the National Grid's Gone Green 2013 projected ACS peak demand up to the winter of 2018/19 inclusive.

Figure 19: Historic and projected ACS peak demand
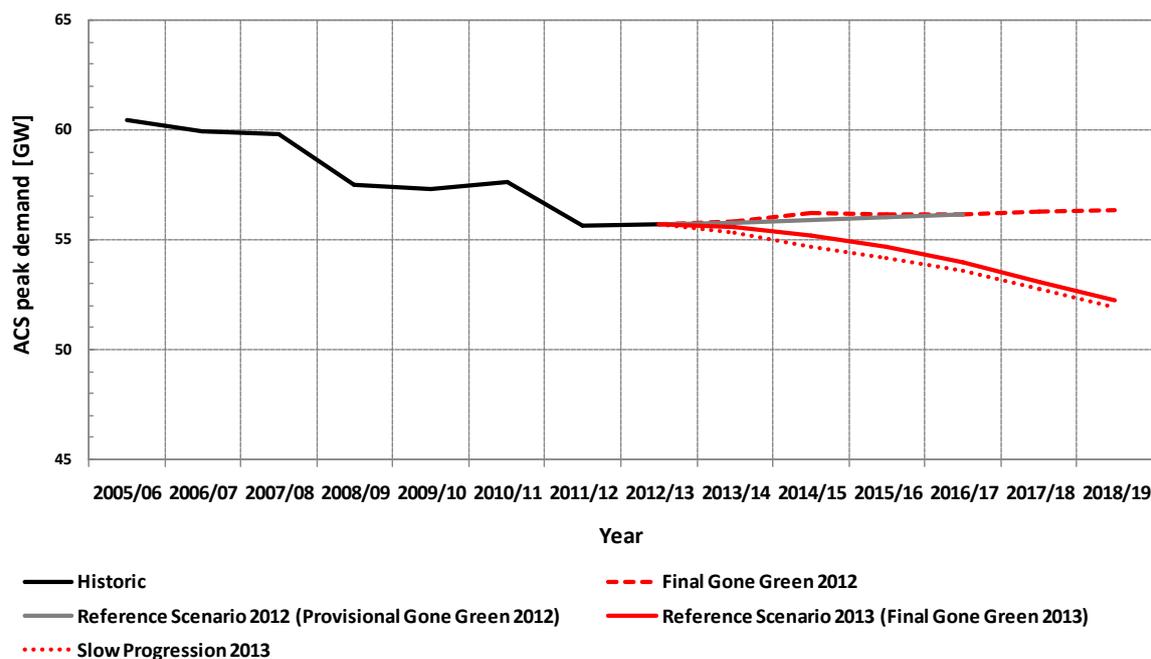
Economic growth

3.47. National Grid's Gone Green scenario is based on an axiom of moderate economic growth, benchmarked against external economic forecasts[68]. The Gone Green 2013 scenario assumes that the economy will rebound slowly and GDP growth rates will reach 2.3% by the end of the analysis period[69]. This growth is expected to drive demand higher in the industrial sector, where the contribution of the sector at ACS peak demand grows by 0.5GW between 2013/14 and 2018/19. This is partly offset by a reduction in demand from the commercial sector. National Grid in their Gone Green 2013 scenario project demand in the commercial sector to drop by 0.4GW in the same period, driven mainly by a reduction in non-manufacturing productivity.

3.48. Table 3 presents the forecast for GDP growth assumed in National Grid's Gone Green 2013 scenario.

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[66] Demand-side response refers to an active, short term reduction in electricity consumption as seen by National Grid either through shifting it to another period or replacing transmission connected generation with embedded generation, or simply not using electricity at that time.

[67] The contribution of wind is added back to demand as we are modelling wind, transmission connected and embedded generation, explicitly in our model. The contribution of embedded wind at peak is based on National Grid's assessment.

[68] GDP growth forecasts are provided to National Grid by Experian Business Strategies.

[69] The OBR expects a similar GDP growth in the first couple of winters (eg 1.8% in winter 2014/15) and higher rates in the later winters (eg 2.8% in 2017/18). For further information refer to:
http://cdn.hm-treasury.gov.uk/budget2013_complete.pdf

Table 3: Forecast of GDP growth

GDP growth	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
GDP used for Reference Scenario (2011/12 = 100)	100	99.9	100.7	102.3	104.2	106.3	108.6	111.1
% change year-on-year	n/a	-0.1%	+0.8%	+1.6%	+1.9%	+2.0%	+2.2%	+2.3%

Note: (+) Increase; (-) Decrease.

Energy efficiency

3.49. Energy efficiency has been a flagship policy area across the European Union over recent years. The GB government is implementing a series of policies to drive higher energy efficiency in both the domestic and non-domestic sectors[70].

3.50. National Grid, in their Gone Green 2013 scenario, project energy efficiency measures to drive demand down across all sectors and particularly in the domestic sector. They project the increased penetration of energy efficient appliances and lighting technologies to result in a reduction of overall energy demand, and subsequently ACS peak demand, in the domestic sector. Table 4 shows the variation in ACS peak demand due to energy efficiency measures in the domestic sector with respect to the winter of 2013/14. National Grid project energy efficiency policies to have a minimal impact on demand in the industrial and commercial sectors.

Table 4: Variation in ACS peak demand due to energy efficiency measures in the domestic sector

Variable [GW]	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
Variation in ACS peak demand	0	-0.4	-0.7	-1.3	-1.9	-2.4

Note: (+) Increase; (-) Decrease.

Demand-side response (DSR)

3.51. DSR refers to customers responding to a signal by changing the amount of energy they consume from the grid at a particular time[71]. These signals could include prices, incentives, information or contracts. 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.

3.52. Demand in our analysis is treated net of demand reduction due to DSR. National Grid currently estimates that around 1GW of DSR is available from the non-domestic sector

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[70] For example, the Green Deal and Energy Company Obligation (ECO) target mainly energy efficiency in the domestic sector, and the Carbon Reduction Commitment (CRC) Energy Efficiency Scheme targets energy efficiency in the non-domestic sector.

[71] For further information refer to the Ofgem consultation "Creating the right environment for demand-side response".
http://www.ofgem.gov.uk/Markets/sm/strategy/dsr/Documents1/20130430_Creating%20the%20right%20environment%20for%20demand-side%20response.pdf

through triad avoidance[72]. National Grid project DSR in the non-domestic sector to grow over the course of the analysis period from 1.2GW in 2013/14 to 2GW in 2018/19.

3.53. In the domestic sector, it is expected that smart metering, through the effects of time-of use tariffs[73], will lead to greater amounts of DSR. In National Grid's Gone Green 2013 scenario, DSR in the domestic sector grows from negligible levels in 2013/14 to 0.4GW in 2018/19.

3.54. Table 5 summarises the assumed impact of DSR participation on ACS peak demand over the next six winters.

Table 5: Variation in ACS peak demand due to DSR programmes

Variation in ACS peak demand [GW]	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
Non-domestic sector (triad avoidance)	-0.2	-0.3	-0.5	-0.7	-0.8	-1
Domestic sector (smart metering)	0	-0.1	-0.1	-0.2	-0.3	-0.4

Note: (+) Increase; (-) Decrease.

Other drivers

3.55. National Grid project the penetration of new technologies to result in an increase in ACS peak demand. However, ACS peak demand decreases due to the net effect of all drivers. Specifically, heat pumps[74] and electric vehicles are assumed to contribute an additional 0.7GW at ACS peak demand by 2018/19.

3.56. In addition, National Grid project further deployment of embedded generation technologies to have a downward effect on ACS peak demand. These technologies, and especially small-scale CHP generation, are assumed to reduce ACS peak demand by 0.5GW by 2018/19.

Largest infeed loss reserve

3.57. National Grid reserves power to maintain the integrity of the network in the event of the loss of the largest generator (the largest infeed loss)[75]. Its importance is such that National Grid would curtail demand before using this reserve. We therefore consider it on the demand-side in our analysis.

3.58. National Grid currently holds around 0.7GW of capacity to meet the largest infeed loss requirements and expects that no projects are likely to have a higher requirement before

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[72] Triad refers to the three half-hourly periods of highest demand during a winter season. National Grid determines the charges to suppliers, and subsequently customers, for the use of the transmission network based on average of their triad demand. Hence, customers have an incentive to reduce their demand during the triad periods. Demand reduction at the time of triad is called triad avoidance.

[73] Time of use tariffs refers to the variable pricing of electricity consumption based on varying costs of generation.

[74] Heat pumps are assumed to replace economy 7 electric storage heating, which is generally not operating at times of peak demand. As a result, heat pumps result in a net increase of demand at times of peak demand.

[75] Currently the National Electricity Transmission System Security Quality of Supply Standards, which is approved by Ofgem, limits the largest infeed loss reserve to approximately 1.3GW. The limit is scheduled to increase to 1.8GW in April 2014. For further information refer to:
http://www.nationalgrid.com/uk/Electricity/Codes/gbsqsscode/. National Grid is currently working with the DNOs to better understand the risk of a large infeed loss causing the consequential loss of distributed generation. The findings of this work should inform further analysis of the reserve to secure the system against the largest infeed loss.

2020. We therefore assume that the reserve requirement for the largest infeed loss is 0.7GW and remains constant throughout our analysis period.

3.59. In 2012, we assumed an increase in the reserve requirement from approximately 0.7GW to 1.6GW from 2014/15 onward. This was based on National Grid's preliminary analysis that suggested that a higher reserve requirement was needed to account for a forecasted increase in the largest infeed loss[76]. For this year's analysis, National Grid have undertaken a full assessment and have concluded that the likelihood of a situation arising which would require a higher reserve for the largest infeed loss is very low. Hence an increase in the reserve requirement is not necessary against such levels of risk.

Sensitivities

3.60. We have developed sensitivities to capture the main uncertainties regarding demand. Below we present key sensitivities around the potential evolution of demand due to economic growth and energy efficiency, and the future participation of DSR in the market.

Demand

3.61. Demand evolution is highly dependent on future economic growth and the success of energy efficiency policies. We have thus run a high-demand and low-demand sensitivity to account for uncertainties around these drivers. Table 6 illustrates the changes in ACS peak demand (in GW) for the high and low demand sensitivities compared to the Reference Scenario.

Table 6: Variation in ACS peak demand for the high and low demand sensitivities

Variation in ACS peak demand [GW]	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
High demand	+0.3	+1.1	+1.5	+2.3	+3.2	+4.0
Low demand	-0.3	-0.5	-0.4	-0.3	-0.3	-0.4

Note: (+) Increase; (-) Decrease.

3.62. In the high demand sensitivity we use the National Grid Gone Green 2012 demand projection. This is broadly flat across the analysis period, assuming that the demand increase due to economic growth is compensated by demand reductions due to the effects of energy efficiency improvements.

3.63. In the low-demand sensitivity we use the National Grid Slow Progression 2013 demand projection. This shows a similar trend to the Gone Green 2013 demand projection, albeit with higher demand reduction throughout the analysis period. This is primarily due to slower economic growth assumptions compared to Gone Green 2013.

Demand-side response

3.64. Recognising there is high uncertainty around the potential evolution of DSR, we have developed a sensitivity to evaluate the potential effect of lower DSR participation in the future on security of supply. This sensitivity assumes that DSR continues at current levels, which results in an increase of ACS peak demand from the Reference Scenario.

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[76] For example, National Grid considered that some wind farms which planned to connect behind existing plants, would have a combined output in excess of 1.3GW but only in situations where the wind farm was generating at 90% of its maximum capacity.

Table 7 depicts the variation in ACS peak demand in the DSR sensitivity with respect to the Reference Scenario.

Table 7: Variation in ACS peak demand for the DSR sensitivity

Year	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
Variation in ACS peak demand [GW]	+0.2	+0.4	+0.6	+0.9	+1.1	+1.4

Note: (+) Increase; (-) Decrease.

Interconnectors

3.65. This section describes our assumptions around interconnector flows for the Reference Scenario and sensitivities.

3.66. Interconnection capacity between GB and Mainland Europe and Ireland is currently 3.8GW[77]. The installed interconnected capacity of GB has decreased since our 2012 report, due to a failure on a cable of the Moyle interconnector[78]. This has reduced our interconnector capacity by 250MW. Preliminary reports suggest it is highly uncertain whether and when the full Moyle capacity will become available.

3.67. We consider that interconnectors are beneficial for security of supply in general. Interconnectors give the GB market options that would not be there without them, providing services such as energy and reserves balancing trading, frequency response and "black start". They may also help reduce the cost of electricity throughout the year. However, from a 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.

3.68. With the implementation of Market Coupling, interconnection flows in the future are expected to be driven by price differentials between GB and the relevant markets, including the directly interconnected markets but not only. Forecasting future prices in GB and its interconnected markets is a difficult exercise, due to the uncertainties related to the evolution of demand and supply in the different markets, especially at a time of significant market reforms and uncertainty across the European markets (eg Capacity Market in France)[79].

3.69. In last year's report we used informed assumptions for the level of interconnector flows in the Reference Scenario and sensitivities. We assumed flows with mainland Europe at float (ie no imports or exports on average) and 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 and are expected to continue exporting. This approach was consistent with National Grid's assumptions in their Gone Green 2012 scenario.

3.70. For this year's report we have conducted a qualitative analysis[80] to assess the likely direction and level of flows in the future[81]. Specifically we have carried out a formal

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[77] Currently, a number of projects are at various stage of development and could complete in the timeframe of our analysis. However, there is high uncertainty on whether and when these projects might become operational (eg this will depend on them receiving the necessary application agreements) and hence, we assume no increase in our interconnected capacity.

[78] This is consistent with the assumption made by the Irish TSOs in their Generation Adequacy report. http://www.eirgrid.com/media/All-Island_GCS_2013-2022.pdf

For further information refer to the operator's website:

http://www.mutual-energy.com/Media/Press_Archive/decision_on_repair.php

[79] We do not consider a quantitative model to predict interconnector flows fit-for purpose. This was validated by the responses to our 2013 consultation.

[80] Further information on our qualitative analysis can be found on Appendix 4.

analysis of the structure of and interactions between GB and its interconnected markets to identify possible outcomes. Actual interconnector flows will be determined by price differentials in the future. Hence, these results should be taken as indicators of possible outcomes instead of precise forecasts and are complemented with plausible sensitivities.

3.71. We conclude that we can only anticipate with a significant degree of certainty that GB will export electricity to Ireland in the next six winters, as we expect prices in Ireland to be higher than in GB. This is supported by the current level of price differentials between the two markets, their similarities and market outlook. With regards to the interconnectors with mainland Europe at periods of low margins, on average:

- We may or may not import electricity from the Netherlands depending, among others, on the situation in the German and Belgium markets, and potential mothballing and closure decisions across Europe;

- We may or may not import from or export to France depending on the evolution of the market in France and its interconnected markets, including Germany and Belgium[82].

3.72. The qualitative analysis consists of two elements: structural analysis and historical analysis. Both are described below.

Structural analysis

3.73. GB is not the only European Market expecting decreasing capacity margins in the next six winters. France and Ireland are facing similar challenges. The situation in the Netherlands is different as the Dutch power sector is going through a period of important investment in new plant. This means, the Netherlands is expected to be a net exporter of electricity over the course of the analysis period. However, the Netherlands is interconnected with Germany and Belgium and the direction of their export flows will be determined by the price differentials between Germany, Belgium, and GB.

3.74. In addition, there are no evident complementarities[83] between GB and its interconnected markets as we have very similar patterns of demand and supply availability. Historically, the evolution of margins in these interconnected markets has been positively correlated[84] which means that when margins are low in one market they tend to be low in other markets.

3.75. Furthermore, demand, which is the main driver for changes in the level of margins, is also correlated between GB and its interconnected markets. Therefore, it is possible to experience periods of tight margins at the same time at both ends of all GB interconnectors.

3.76. We do not expect the availability of conventional generation to be correlated between GB and its interconnected markets in the future. As the penetration of wind increases in GB and the relevant markets the correlation of available generation might change in the

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[81] A qualitative analysis was supported by the response to our 2013 Capacity Assessment consultation.

[82] France, Germany and Belgium are considering the implementation of Capacity Markets to ensure security of supply in the future.

[83] For example, in hydro-based South American markets the rainy season in the Northern hemisphere coincides with the dry season in the Southern hemisphere resulting in opposite cycles of generation availability which are the main drivers of margins in these interconnected markets.

[84] Correlation is a measure of dependence between two variables. A positive correlation indicates that as one variable increase so too does the other, whilst a negative correlation indicates that as one increases the other decreases. A correlation of zero means there is no dependence between the variables.

future. This will depend on the levels and proportion of installed wind in the different markets and the location of the installed wind. Subsequently, any correlation of the wind resource in GB and the relevant markets could have an impact on the correlation of available generation.

Historical Analysis

3.77. We analysed how interconnector flows have responded in the past to changes in the main GB system parameters: demand, capacity margins, availability of conventional generation, availability of wind power, and prices. No consistent pattern of response has been identified to any of these parameters. This increases the difficulty in assessing future interconnector flows.

3.78. With the implementation of Market Coupling from winter 2013/14 we can broadly expect flows to follow the direction of higher prices[85]. Our analysis of historical price differentials demonstrates that only Ireland and GB have shown a consistent pattern, with GB prices being consistently and significantly lower than prices in Ireland in the past. The differences with other markets are variable in direction and magnitude and are expected to change in the future given market changes and reforms currently under development in the different markets (eg EMR in Great Britain, Capacity Market in France, nuclear phase-out in Germany and Switzerland, and the implementation of Market Coupling for North-West Europe).

Reference Scenario

3.79. Based on these two analyses, the Reference Scenario takes a cautious approach to interconnector flows similarly to the 2012 analysis. In particular, we assume:

- Full exports to Ireland (750MW), based on historical flows and expected price differentials between GB and Ireland;

- Interconnector flows with mainland Europe are at float, ie not importing or exporting on average, due to high levels of uncertainty with regards to future price differentials between GB and the markets of mainland Europe.

3.80. Table 8 details our assumptions for the interconnector flows (in MW) during winter peak periods in the Reference Scenario.

Table 8: Interconnector flow assumptions (in MW) at winter peak periods for the Reference Scenario

Name	To	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
Moyle	SEM (NW)	-250	-250	-250	-250	-250	-250
East-West	SEM (RoI)	-500	-500	-500	-500	-500	-500
IFA	France	0	0	0	0	0	0
BritNed	Netherlands	0	0	0	0	0	0

Note: (+) Great Britain Imports; (-) Great Britain Exports.

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[85] Market Coupling is expected to be implemented across North-West Europe in 2013. The implementation will initially be across the day-ahead markets. The target is to extend Market Coupling in the intra-day markets. It is uncertain when the implementation of Market Coupling across intra-day markets will be in place.

Sensitivities

3.81. To assess the uncertainty surrounding the interconnector flows we complement the analysis with sensitivities to illustrate what would happen if flows were higher or lower than expected.

3.82. Therefore, we have developed a range of interconnector sensitivities which make different assumptions on imports/exports with mainland Europe at peak times. These are described below and presented in Table 9.

- The full imports sensitivity assumes 3GW interconnection imports with France and the Netherlands across the entire analysis period compared to the Reference Scenario (full exports of 750MW to Ireland assumed). We do not present a full exports sensitivity as we consider the possibility to export at full capacity during peak demand highly unlikely given this would result in negative de-rated margins in GB. We expect prices to reflect this and improved interconnector responsiveness, as a result of the implementation of Market Coupling in the future;

- Half import/export sensitivities assume ± 1.5GW interconnection flows with France and the Netherlands compared to the Reference Scenario (full exports of 750MW to Ireland assumed).

Table 9: Interconnector flow assumptions (in GW) at winter peak periods for sensitivities

Sensitivity	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
Full imports	+3.0	+3.0	+3.0	+3.0	+3.0	+3.0
Half imports	+1.5	+1.5	+1.5	+1.5	+1.5	+1.5
Half exports	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5

Note: (+) Great Britain Imports; (-) Great Britain Exports.

No net interconnector flows

3.83. We also include a sensitivity which excludes interconnector flows. In this sensitivity the de-rated margins and risk measures are estimated based only on domestic demand and the availability of domestic generation. This approach may be helpful to DECC when making decisions to procure extra capacity through a Capacity Market due to the high levels of uncertainty surrounding the assessment of future interconnector flows. In addition, including exports in the demand projections when calculating how much capacity to procure through policy interventions would mean supporting investment to secure demand abroad as well as demand in GB.

3.84. The Energy-only Market will continue to operate in parallel to any policy intervention to procure extra capacity. Therefore, excluding exports to Ireland from the calculations of how much capacity to procure on top of what would be delivered by the energy only market alone does not imply that exports will not take place. Exports will continue to respond to the energy-only market rules and will take place under regular conditions if prices in GB are lower than those in Ireland.

4. Results

4.1. In this chapter we present the results of our assessment on the levels of risk to security of supply and of the associated de-rated capacity margins for the GB electricity sector over the next six winters.

4.2. We use two well established probabilistic measures to quantify the risks to security of supply:

- Loss of Load Expectation (LOLE): is the mean number of hours per year in which supply does not meet demand in the absence of intervention from the System Operator.

- Expected Energy Unserved (EEU): is 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.

4.3. Moreover, to illustrate the impacts on customers of the risk measures in our assessment (LOLE and EEU) we have also calculated the frequency of occurrence of supply shortfall events large enough that they might lead to controlled customer disconnections. We do this by calculating the frequency of a range of supply shortfall events that vary in magnitude from 0-10MW to 2,750MW+. We explain that only in the case of supply shortfalls greater in magnitude than 2,750MW is there a risk of controlled customer disconnections.

4.4. This chapter is structured as follows. We start with a description of the risks to security of supply (LOLE, EEU and the risk of customer disconnections) in the Reference Scenario. We follow this with an examination of the results in each of our major sensitivities (demand, supply, interconnector flows and both conventional plant and wind power availabilities). The chapter concludes by looking at the associated de-rated capacity margins in the Reference Scenario and each of our major sensitivities.

Measures of risk and impact on customers

Reference Scenario

4.5. Figure 20 and Figure 21 present the estimated LOLE and EEU for the GB electricity sector from winter 2013/14 to winter 2018/19 for the Reference Scenario.

4.6. Figure 20 shows that the LOLE for next winter 2013/14 is estimated at 0.7 hours per year. Broadly this means that we estimate the expected number of hours that electricity demand is higher than available supply (a supply shortfall) in winter 2013/14 to be around 0.7 hours per year. Note that this is from a total of 8,760 hours in a one year period[86]. The LOLE is then expected to increase towards winter 2015/16 when it reaches a level of 2.9 hours per year. This is largely driven by the closure of power plant over this period[87]. The LOLE is then estimated to decrease to 0.1 hours per year in winter 2017/18. This improvement is driven by the entry of new capacity, (mostly wind and gas CCGTs) and a decline in electricity demand. At the end of our period of analysis, we

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[86] While our analysis is carried out over the six month period that includes winter, we present the LOLE in hours per year as we have analysed the summer months in our summer sensitivity (see Appendix 1) and observe that they do not present a security of supply risk in GB and so do not contribute to our assessment of LOLE.

[87] For comparison a LOLE of 2.9 hours per year is within the reliability standards used by France, Ireland and Belgium.

observe the estimated LOLE rising marginally in winter 2018/19, when it is expected to be 0.3 hours per year.

**Figure 20: Loss of load expectation for the Reference Scenario**
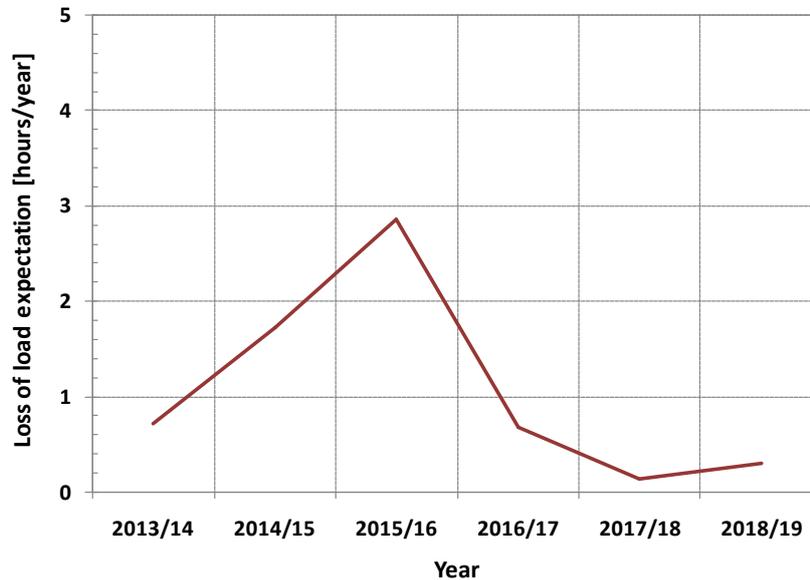
Figure 21: Expected energy unserved for the Reference Scenario
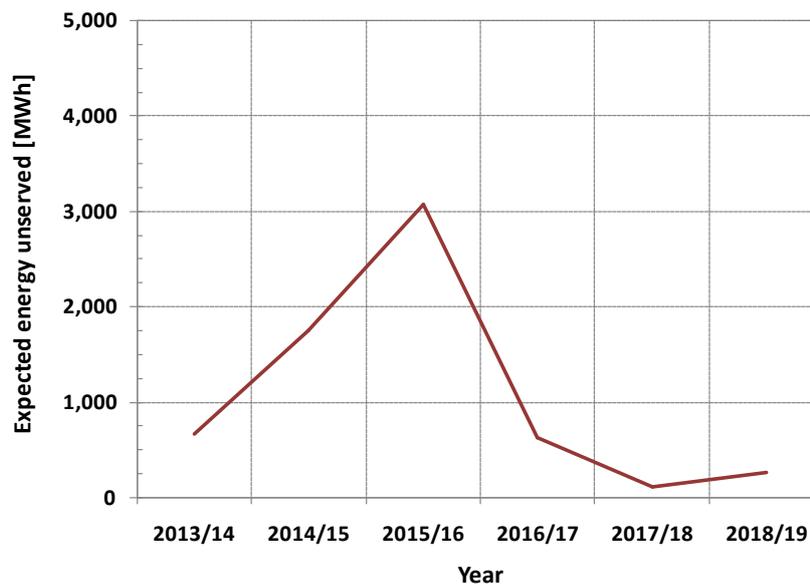
4.7. The EEU in Figure 21 follows a similar trend to the LOLE over the next six winters. For winter 2013/14, the EEU is expected to be 659MWh. This means that we estimate the total volume of electricity demand that cannot be met by available supply during winter 2013/14 to be 659MWh. The estimated EEU then rises in the following two winters to reach approximately 3,070MWh by 2015/16. As with the LOLE, the estimated EEU falls in the following two winters to reach a low of 106MWh in 2017/18. It increases again slightly in the final year of our analysis.

Impact on customers

4.8. As discussed in Chapter 2, a positive value for the risk measures of LOLE and EEU does not necessarily mean disconnections for customers, although they do remain a possibility. This is because for a reasonably wide range of supply shortfalls, the GB SO can employ mitigation actions that prevent the immediate disconnection of supply to customers. Only after the SO has exhausted its available actions will customers be at risk of disconnection. Specifically, the range of mitigation actions available to the SO are: (i) voltage reduction; (ii) maximum generation; and (iii) emergency services from interconnectors. A detailed description of mitigations actions is provided in Chapter 2.

4.9. The impacts of these actions are generally not perceptible to electricity customers and they can be used in parallel. Nevertheless, the SO is likely to use mitigation actions as a last resort measure as it results in the economically inefficient operation of the electricity system and costs to the SO.

4.10. Table 10 presents supply shortfall events of increasing magnitude and aligns them with the mitigating strategy that the SO may employ in response to them. The table shows that the SO can manage a volume of supply shortfall in the range of 0 – 2,750MW through a combination of voltage reduction, maximum generation and emergency services. However, events larger than 2,750MW would probably exceed the mitigation actions available and could result in controlled disconnections of electricity customers. We stress that controlled disconnections would involve the largest industrial customers first and would ensure that domestic households are protected for as long as possible as described in Chapter 2.

Table 10: Mitigation actions

Supply shortfall event [MW]	Mitigation action
0 – 10	No impact
10 – 500	Voltage reduction
500 – 750	Voltage reduction and maximum generation
750 – 2,750	Voltage reduction, maximum generation and emergency services
2,750 +	Controlled disconnections

4.11. We use the information above to illustrate the potential impacts on customers of the risk measures in our assessment (LOLE and EEU). To do this we estimate the frequency of occurrence of supply shortfall events large enough that they might lead to controlled customer disconnections. Table 11 presents our estimates for illustration purposes. It shows the frequency of occurrence of increasingly large supply shortfall events for the Reference Scenario. We would expect only those supply shortfalls on the bottom row of the table (corresponding to 2,750MW+) to risk customer disconnections.

Table 11: Frequency of supply shortfalls

Supply shortfall event [MW]	Frequency [1 in n years]					
	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
0 – 10	1-in-0.10	1-in-0.04	1-in-0.03	1-in-0.1	1-in-0.5	1-in-0.2
10 – 500	1-in-0.5	1-in-0.2	1-in-0.1	1-in-0.5	1-in-3	1-in-1
500 – 750	1-in-23	1-in-10	1-in-6	1-in-24	1-in-126	1-in-55
750 – 2,750	1-in-12	1-in-5	1-in-3	1-in-12	1-in-65	1-in-28
2,750 +	1-in-47	1-in-19	1-in-12	1-in-49	1-in-256	1-in-112

4.12. Table 11 shows that the estimated frequency of supply shortfalls events of all sizes increases over the period of analysis from winter 2013/14 to winter 2015/16. This is consistent with the significant increases observed in LOLE and EEU for the same period. We note, however, that the estimated frequency of the largest supply shortfalls (ie those large enough to risk customer disconnections at 2,750MW+) is very low in winter 2013/14 at approximately 1-in-47 years, but rises to 1-in-12 years in winter 2015/16. In the following winter, the estimated frequency of 2,750MW+ supply shortfalls declines significantly to 1-in-49 years and further again in winter 2017/18 to 1-in-256 years. As with the LOLE and EEU, there is a small increase in the estimated frequency of the largest supply shortfall events in winter 2018/19.

Sensitivities

4.13. We use sensitivities to investigate the impact on our risk measures of uncertainty in key input assumptions. We have run sensitivities on our assumptions on demand, supply, interconnector flows and both conventional plant and wind power availabilities. Each sensitivity is designed to vary only one variable and hold all other variables constant. A detailed description behind the development of the sensitivities is presented in Chapter 3.

Supply

4.14. The level of future GB electricity supply is driven by the decisions of private companies to close, mothball or invest in new power plants. The supply sensitivities explore the impact on our risk measures of uncertainties surrounding these decisions.

4.15. As set out in Chapter 3, the low supply sensitivity assumes that no new plant are built over the period of the analysis. In addition, we assume that approximately 1,200MW of biomass and LCPD opted-out oil plant will be unavailable in winter 2014/15. An additional 700MW of CCGT is assumed mothballed from winter 2016/17 onwards. In contrast, the high supply sensitivity assumes that some mothballed CCGT plant return to the market and new CCGT plant are built towards the end of the analysis period. This means that in the high supply sensitivity an additional 1,400MW of CCGT is available throughout the period of the analysis compared to the Reference Scenario. This figure is higher (2,300MW) in winter 2014/15 and (2,500MW) in winter 2018/19. The first rise is due to more mothballed CCGT being available for suppliers to bring back on line and the second rise is due to new CCGT build. The high supply sensitivity also assumes 500MW of additional available nuclear plant in winter 2014/15.

4.16. Figure 22 and Figure 23 show the estimated LOLE and EEU for the low and high supply sensitivities over the next six winters, together with the Reference Scenario.

4.17. The figures show that the trend of the low and high sensitivities remains broadly similar to the Reference Scenario throughout the period of analysis. It also shows that the high supply sensitivity results in a far lower LOLE and EEU than the low demand sensitivity. This is because the supply sensitivities are more symmetric around the Reference Scenario than the demand sensitivities. Even so, the results indicate that with around 1,500 to 2,500MW of additional capacity available throughout the period of the analysis, the estimated measures of risk fall to very low levels. For example, in winter 2015/16 the LOLE is estimated to be 0.7 hours per year and the EEU is 620MWh.

4.18. In contrast, the low supply sensitivity highlights the impact on the risks to security of supply of having around 500 to 2,500MW less capacity available throughout the period of the analysis. In the low supply sensitivity, the maximum values of the estimated LOLE and EEU rise to 4.8 hours and to 5,480MWh, respectively, both in winter 2015/16.

Figure 22: Loss of load expectation for the Reference Scenario and supply sensitivities
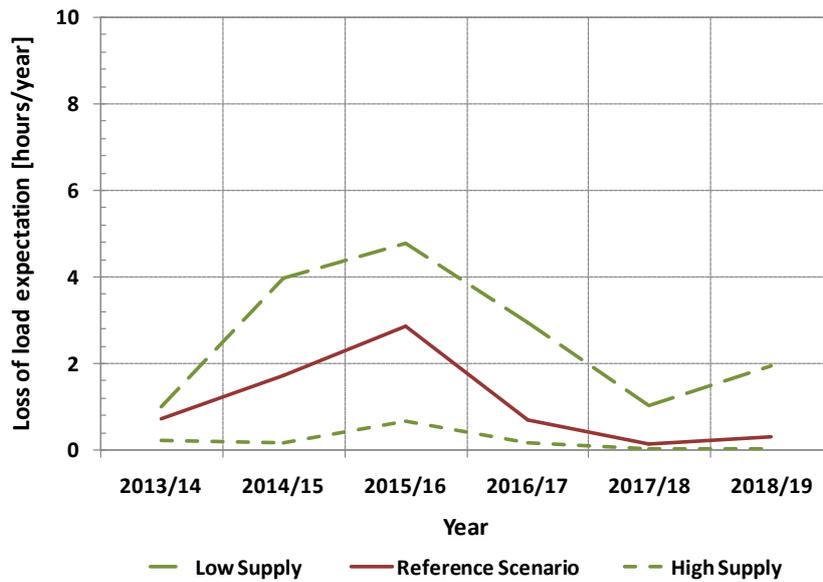

Figure 23: Expected energy unserved for the Reference Scenario and supply sensitivities
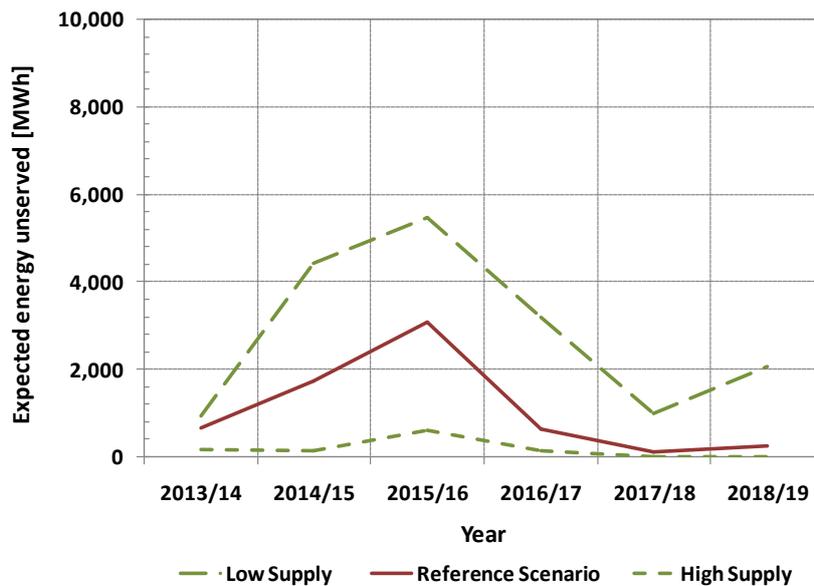
Conventional generation availability

4.19. In the Reference Scenario, we derive the availability of conventional power plants from their average availabilities observed over the seven year period 2005 to 2012. As the availability of conventional power plants shows a significant amount of variation on a year-to-year basis, we have developed two sensitivities to explore the impact on our risk measures of lower and higher availabilities per technology than those used in the Reference Scenario. The availability assumptions considered for the two sensitivities are presented in Chapter 3 and are based on a reasonable level of variation around the Reference Scenario values[88].

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[88] The low and high sensitivity are estimated as the average availability ± one standard deviation based on the annual availabilities per technology type over the past seven winters.

4.20. Figure 24 and Figure 25 show the estimated LOLE and EEU for the low and high conventional generation availability sensitivities over the next six winters, together with the Reference Scenario.

4.21. The figures indicate that reasonably small changes in conventional generation availability have a material impact on the risk of supply shortfalls. This is most notable in 2015/16, where the estimated LOLE ranges from 0.2 hours per year in the high availability sensitivity to 16 hours per year in the low availability sensitivity, for the Reference Scenario is 2.9 hours per year. The EEU also varies significantly in this year from 178MWh to 22,702MWh, in the high and low supply availability sensitivities, respectively.

**Figure 24: Loss of load expectation for the Reference Scenario and conventional generation availability sensitivities**
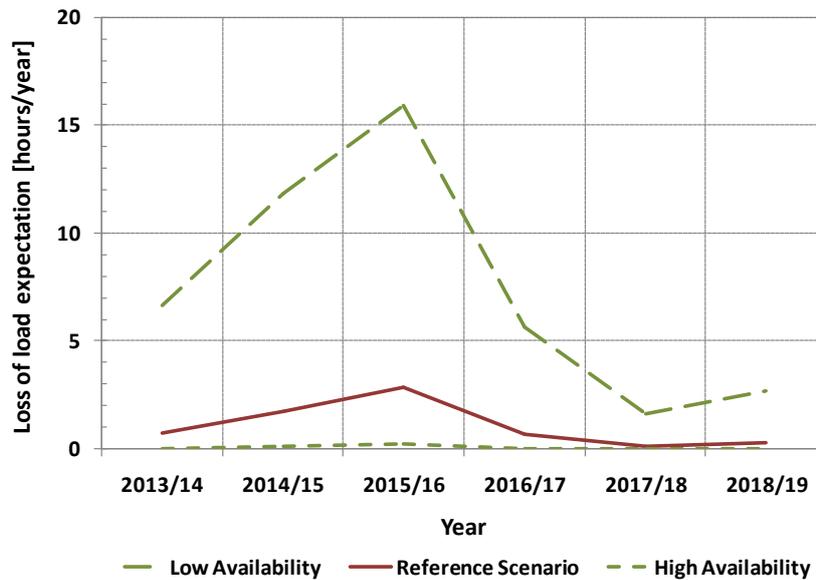
Figure 25: Expected energy unserved for the Reference Scenario and conventional generation availability sensitivities
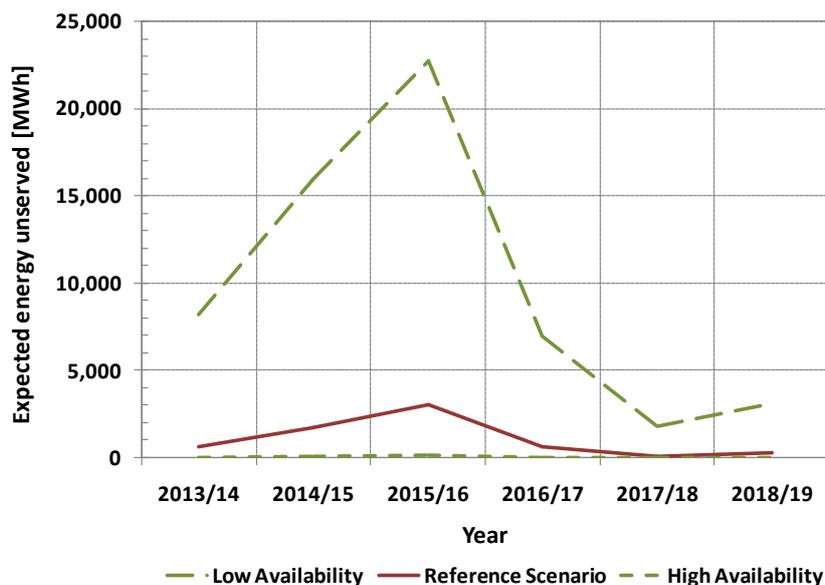
Wind generation availability

4.22. In the Reference Scenario we assume that wind output and demand are independent variables, hence wind output is the same irrespective of the demand level. However, there is some evidence that wind output falls during periods of severe cold weather and consequently very high demand. To test the impact of this relationship on our risk measures, we have performed a sensitivity analysis.

4.23. In this sensitivity the quantity of wind output starts to fall when demand rises above 92% of the ACS peak demand. As demand rises further the quantity of wind generation output declines, at a broadly constant rate, until it reaches 50% of its value in the Reference Scenario at 102% of the ACS peak value. Appendix 3 provides further details of the approach.

4.24. Figure 26 and Figure 27 show the estimated LOLE and EEU for the lower wind generation sensitivity over the next six winters, together with the Reference Scenario.

4.25. The figures show that lowering wind generation during periods of peak demand leads to a significant increase in estimated LOLE and EEU, particularly in the second and third years of our analysis. For example, in winter 2015/16, lower wind generation contributes to a doubling in the values of the estimated risk measures: LOLE grows from 2.9 hours per year in the Reference Scenario to 6 hours per year in the low wind generation sensitivity and EEU is approximately 6,907MWh in the low wind generation sensitivity compared with 3,070MW in the Reference Scenario.

Figure 26: Loss of load expectation for the Reference Scenario and wind generation availability sensitivity
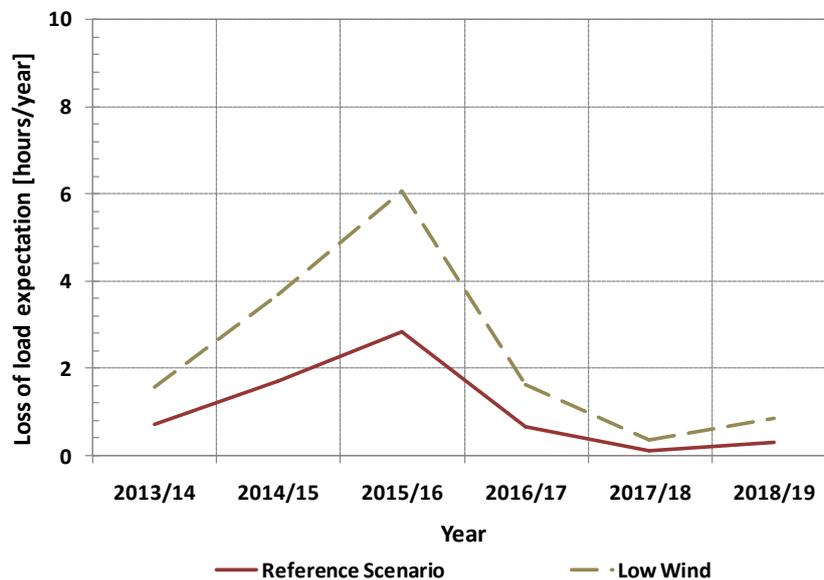
Figure 27: Expected energy unserved for the Reference Scenario and wind generation availability sensitivity
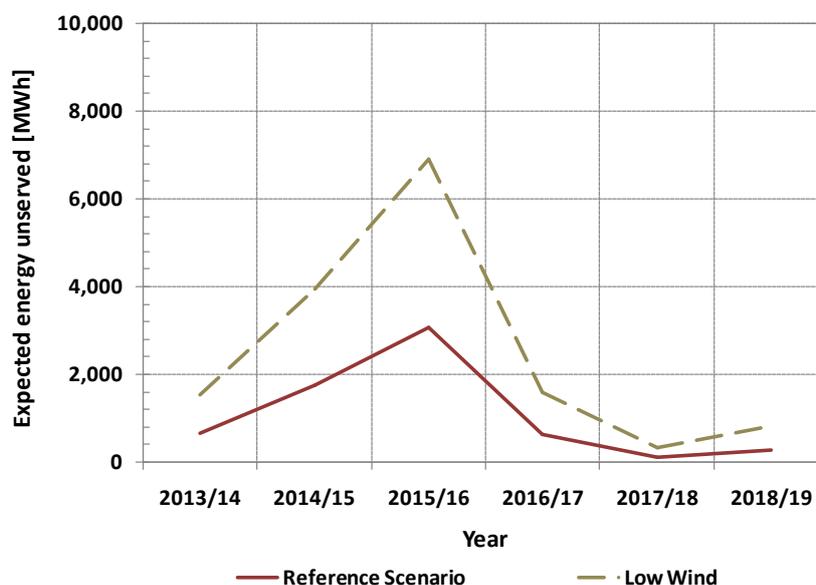
Demand

4.26. As set out in Chapter 3, future levels of electricity demand will depend on a range of factors that include the speed of economic growth, the severity of the weather and the success of energy efficiency programmes. To investigate the effects on our risk measures of uncertainty around future levels of electricity demand, we have developed a low and a high demand sensitivity.

4.27. In our high demand sensitivity we assume higher economic growth than in the Reference Scenario but its impact on demand is balanced by energy efficiency programmes. As a result, the level of demand remains broadly flat across the analysis period. In the low demand sensitivity we assume lower economic growth than in the Reference Scenario. This reduces demand slightly with respect to the Reference Scenario levels. Importantly, the low and high demand sensitivities are not symmetrical around the Reference Scenario. By the end of the analysis period, the high demand sensitivity results in a demand figure of 7.6% above the Reference Scenario, while in the low demand sensitivity we estimate demand at -0.8% below the Reference Scenario by winter 2018/19.

4.28. Figure 28 and Figure 29 present the estimated LOLE and EEU in the high and low demand sensitivities, for the next six winters, together with the Reference Scenario.

4.29. The estimated results for the low demand sensitivity are similar to those in the Reference Scenario, albeit with risks to security of supply being slightly lower overall. As in the Reference Scenario, the low demand sensitivity reaches its peak in winter 2015/16. In this winter the estimated LOLE is 2 hours per year and EEU is 2,028MWh, which compare with Reference Scenario figures for LOLE and EEU of 2.9 hours per year and 3,070MWh, respectively. By the end of the period the LOLE converges with the Reference Scenario figure.

4.30. The results of the high demand sensitivity are more striking. Here, the flat demand profile over the period results in far higher results for LOLE and EEU. By winter 2015/16, the LOLE is estimated to be 8.7 hours per year and the EEU is 11,130MWh, both around three times higher than in the Reference Scenario. The high demand sensitivity highlights

the importance of the level of demand to GB security of supply. It shows that if demand does not fall over the coming years, other things being equal, the magnitude of expected supply shortfalls (the EEU) could be over three times more severe by winter 2015/16. In practice, a flat demand profile might result in higher electricity prices over this period and could prompt generators to bring back mothballed or invest in new plant.

Figure 28: Loss of load expectation for the Reference Scenario and demand sensitivities
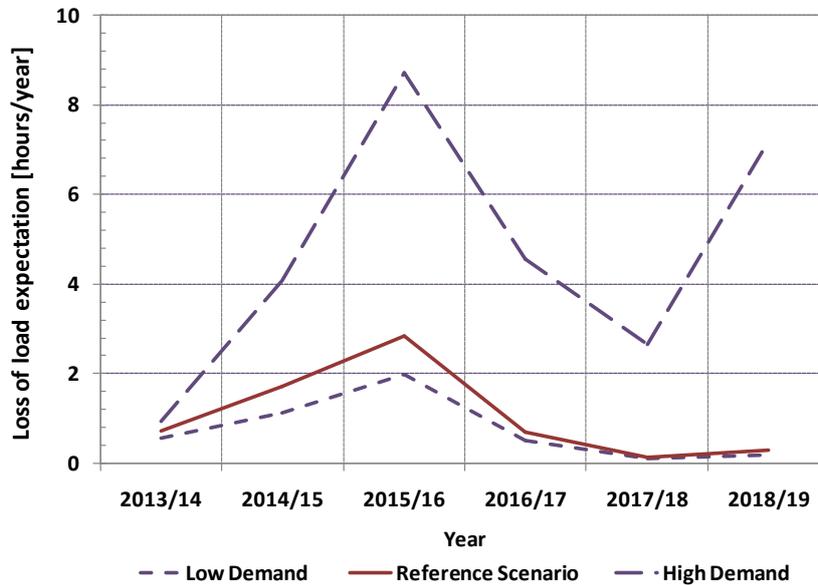
Figure 29: Expected energy unserved for the Reference Scenario and demand sensitivities
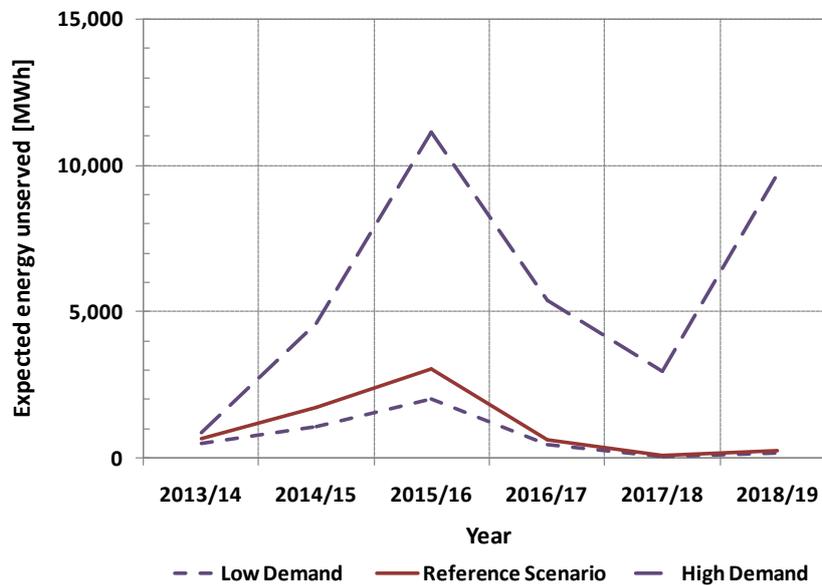
Interconnectors

4.31. As discussed in Chapter 3, we have taken a cautious approach in the Reference Scenario on the contribution of interconnectors to security of supply during periods of peak demand. In the Reference Scenario, we assume interconnectors with mainland Europe are at float (no import or export) and interconnectors to Ireland export 750MW throughout the period of the analysis. The detailed description and rationale of the assumptions are presented in Chapter 3.

4.32. The actual direction of interconnector flows in the future will be determined by the price differential between the interconnected markets. This differential will depend on supply and demand conditions in the interconnected markets and is likely to lead to outturn interconnector flows that are lower or higher than those assumed in the Reference Scenario. Our interconnector sensitivities explore the impact on our risk measures of uncertainty around the direction and quantity of interconnector flows. We have developed three sensitivities using different imports/exports on interconnectors with mainland Europe with respect to the Reference Scenario. In all three we maintain the assumption of full exports to Ireland (750MW):

- **Full-import sensitivity:** assumes an additional 3GW of imports from mainland Europe across the entire analysis period compared to the Reference Scenario.

- **Half-import/export sensitivities:** two sensitivities that assume ±1.5GW interconnector flows with mainland Europe compared to the Reference Scenario over the next six winters.

4.33. Figure 30 and Figure 31 show the estimated LOLE and EEU for the three interconnector sensitivities over the next six winters, together with the Reference Scenario.

4.34. Figure 30 highlights the importance of interconnectors to GB security of supply. In both the full and half-imports sensitivities, the values of LOLE and EEU significantly improve compared to the Reference Scenario. For example, in winter 2015/16, the estimated LOLE in the full imports sensitivity is 0.2 hours per year and the EEU is 117MWh. This compares to a LOLE of 2.9 hours per year and an EEU of 3,070MWh in the Reference Scenario.

4.35. On the other hand, the half-exports sensitivity results in far higher risks to security of supply. In the half-exports sensitivity, GB is exporting an additional 1,500MW to mainland Europe. The impact of this is most stark in winter 2015/16, where the LOLE is estimated to be 8.8 hours per year and the EEU is 11,139MWh. By 2018/19, the LOLE and EEU in the half-exports case are significantly lower, but still well above the equivalent Reference Scenario figures.

Figure 30: Loss of load expectation for the Reference Scenario and interconnector flows sensitivities
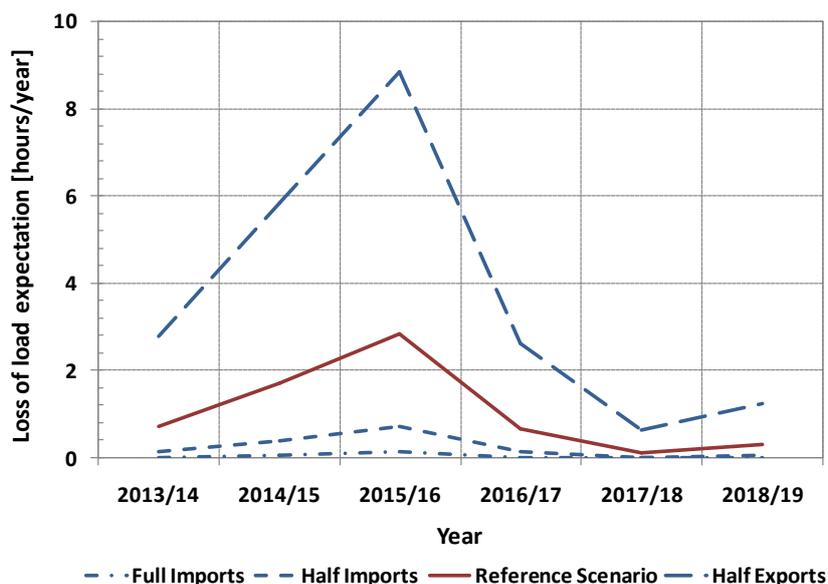
Figure 31: Expected energy unserved for the Reference Scenario and interconnector flows sensitivities
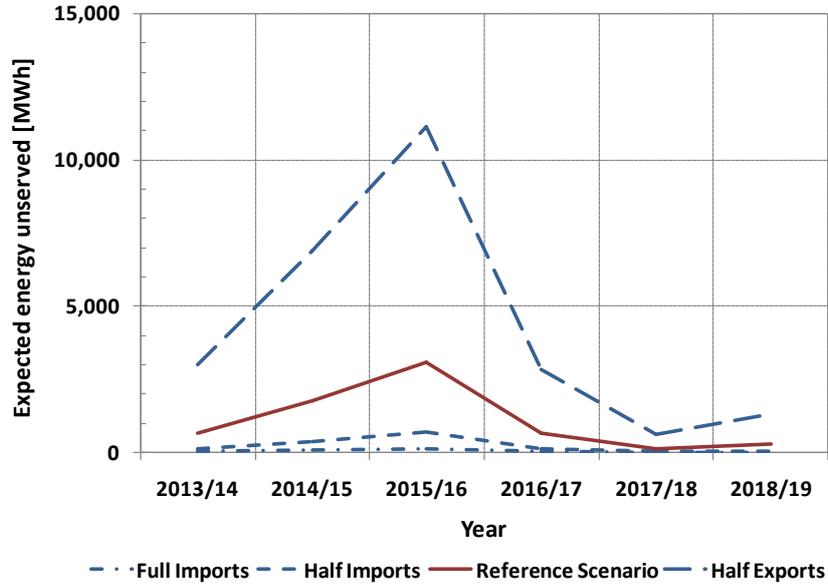
No net interconnector flows

4.36. We also analyse the risks to security of supply in a case where interconnector flows are excluded (ie no net flow from mainland Europe or Ireland). The rationale for this analysis is explained in Chapter 3.

4.37. Figure 32 and Figure 33 show the estimated LOLE and the EEU for the Reference Scenario together with the respective levels of risk for the no-net-flows sensitivity over the next six winters.

Figure 32: Loss of load expectation for the Reference Scenario and no-net-flows sensitivity
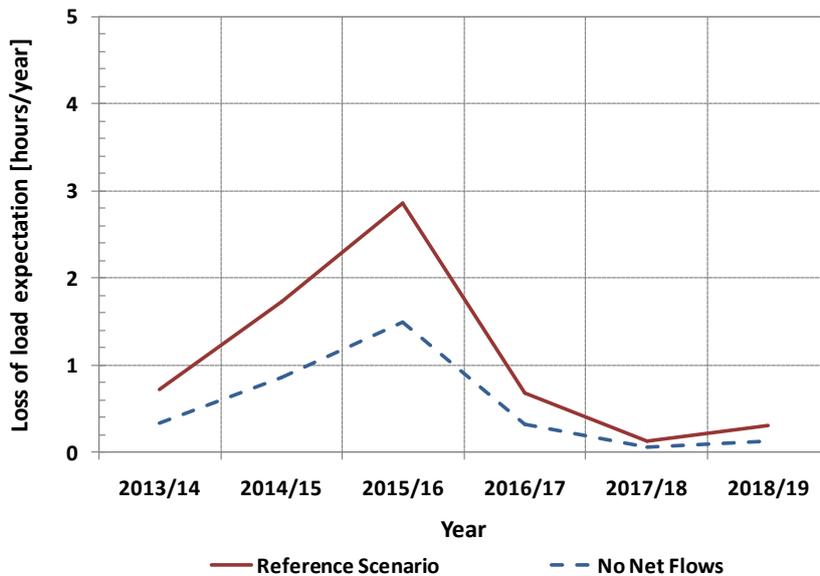
**Figure 33: Expected energy unserved for the Reference Scenario and no-net-flows sensitivity**
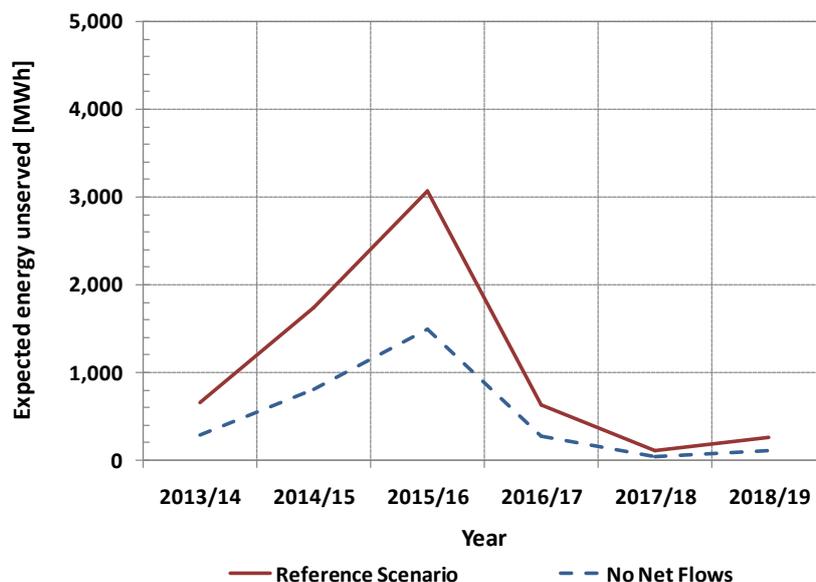
4.38. We observe that having no net flows at peak demand periods has a significant impact on our risk measures which are lower compared to the Reference Scenario where 750MW are exported to Ireland. With no net flows, the GB electricity system will have a higher capacity surplus to mitigate potential risks. The impact on the risk measures is most notable in 2015/16, where the estimated LOLE declines from 2.9 hours per year in the Reference Scenario to 1.5 hours per year in the no-net-flows sensitivity. Similarly, the estimated EEU decreases approximately 50% with respect to the Reference Scenario.

De-rated capacity margin

4.39. The de-rated capacity margin is commonly used by industry as an indicator of security of supply. We note however, that the de-rated margin is not a measure of the risk of supply shortfalls or the potential impact of those on electricity customers. As a result, it is advised that de-rated capacity margins should not be compared across different markets or over time in the same country if there have been significant changes in the generation portfolio.

4.40. In this section we present the estimated de-rated capacity margins in the Reference Scenario and each one of our major sensitivities (demand, supply, interconnector flows and both conventional plant and wind power availabilities).

Reference Scenario

4.41. Figure 34 shows the estimated de-rated capacity margin for the Reference Scenario over the next six winters.

4.42. The figure shows that the estimated de-rated capacity margin declines from 6.3% in winter 2013/14, to 3.8% in winter 2015/16 (its lowest point). This fall is driven by the exit of power plants, in particular coal and oil plant over this period. Beyond winter 2015/16, the de-rated margin rises to a peak of 8.9% in winter 2017/18. This is driven by National Grid's projected demand reductions in its Gone Green 2013 scenario and the entry of new capacity such gas, wind power and some biomass.

Figure 34: De-rated capacity margin for the Reference Scenario
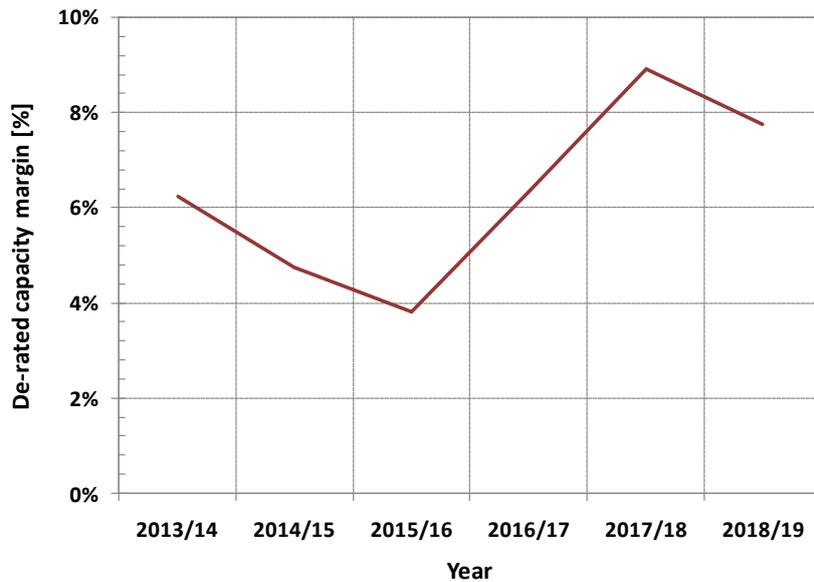
4.43. Figure 35 compares the Reference Scenario de-rated capacity margin with the LOLE for the next six winters.

4.44. The figure indicates a strong relationship between the de-rated capacity margin and LOLE. Thus we observe in Figure 35 the LOLE tends to increase when the de-rated margins decrease and vice versa. However, the effects are not symmetrical. Importantly, a change in the de-rated margins when they are low has a larger impact on the risks (eg LOLE and EEU) than a change of the same magnitude in the de-rated margins when they are high. This emphasises the importance of exploring plausible lower de-rated margins through sensitivities to get a better sense of the risks to security of supply in GB in the coming years.

Figure 35: Reference Scenario de-rated capacity margin and LOLE
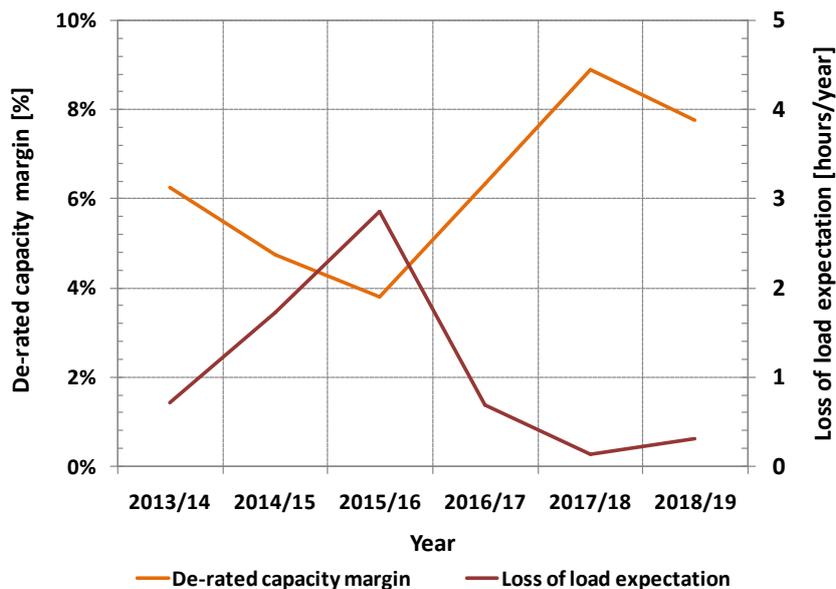
Sensitivities

Supply

4.45. Figure 36 presents the estimated de-rated capacity margins for the high and low supply sensitivities over the next six winters, together with the Reference Scenario.

Figure 36: De-rated capacity margin for the Reference Scenario and supply sensitivities
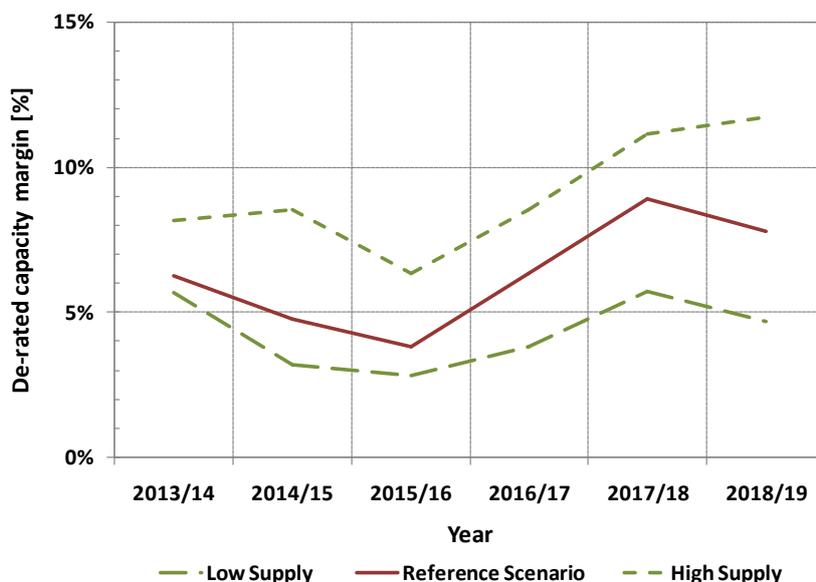
4.46. The figure illustrates the impact on de-rated capacity margins of having higher or lower levels of supply. In winter 2015/16, with around 700MW less capacity in the low supply sensitivity compared with the Reference Scenario, the de-rated margin falls to 2.8%. In contrast, in the same year, the high supply sensitivity gives a figure of 6.3%. The high supply sensitivity peaks at 11.7% in winter 2018/19.

Conventional generation availability

4.47. Figure 37 presents the estimated levels of de-rated capacity margins for the low and high conventional generation availability sensitivities over the next six winters, together with the Reference Scenario.

4.48. The figure highlights the impact on the de-rated capacity margins of varying conventional generation availability. Notably, the estimated de-rated margin varies between 0.5% and 7% in the low and high availability cases, respectively, for winter 2015/16. This compares with 3.8% in the Reference Scenario.

Figure 37: De-rated capacity margin for the Reference Scenario and conventional generation availability sensitivities
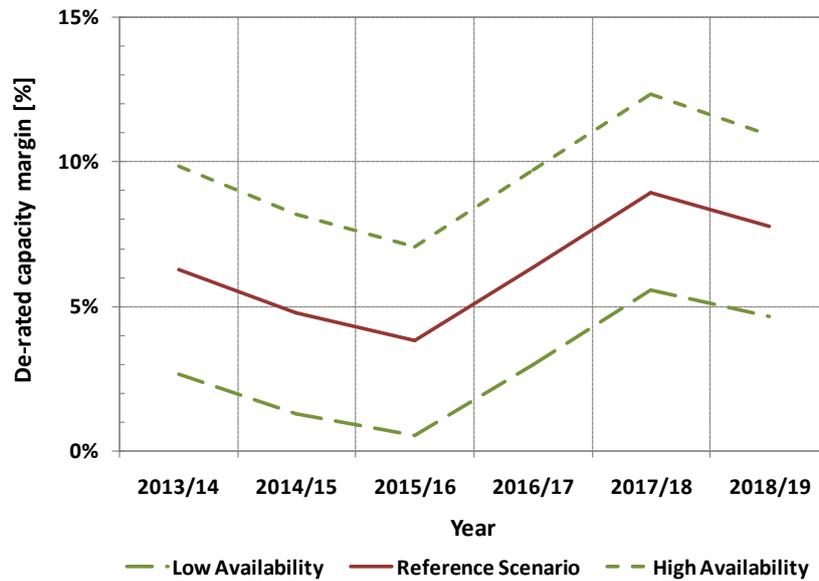
Wind generation availability

4.49. Figure 38 presents the estimated de-rated capacity margins for the wind availability sensitivity over the next six winters, together with the Reference Scenario.

4.50. The figure shows that a fall in the contribution of wind supply at very high levels of demand, results in a decrease in de-rated margins. The lowest level of estimated de-rated capacity margin is observed in 2015/16 at 2.4%, nearly half the value in the Reference Scenario.

**Figure 38: De-rated capacity margin for the Reference Scenario and wind availability sensitivity**
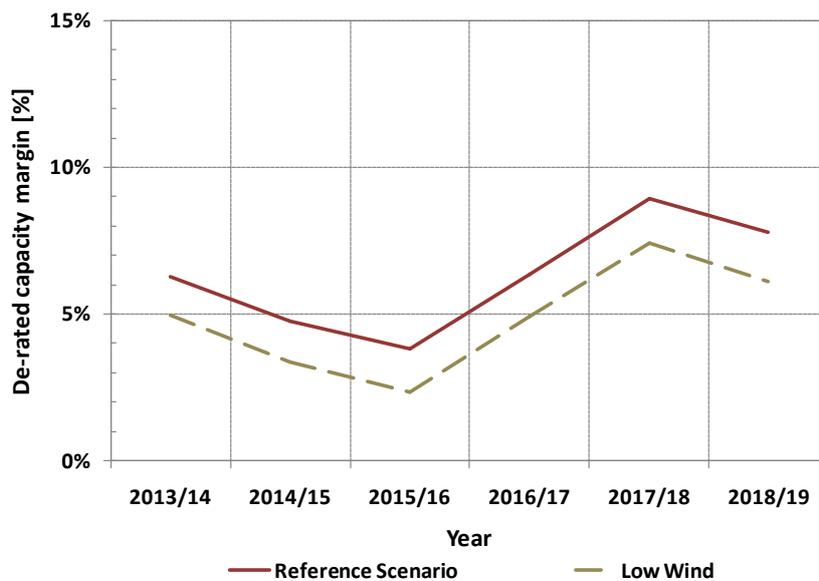
Demand

4.51. Figure 39 presents the estimated de-rated capacity margins for the high and low demand sensitivities over the next six winters, together with the Reference Scenario.

Figure 39: De-rated capacity margin for the Reference Scenario and demand sensitivities
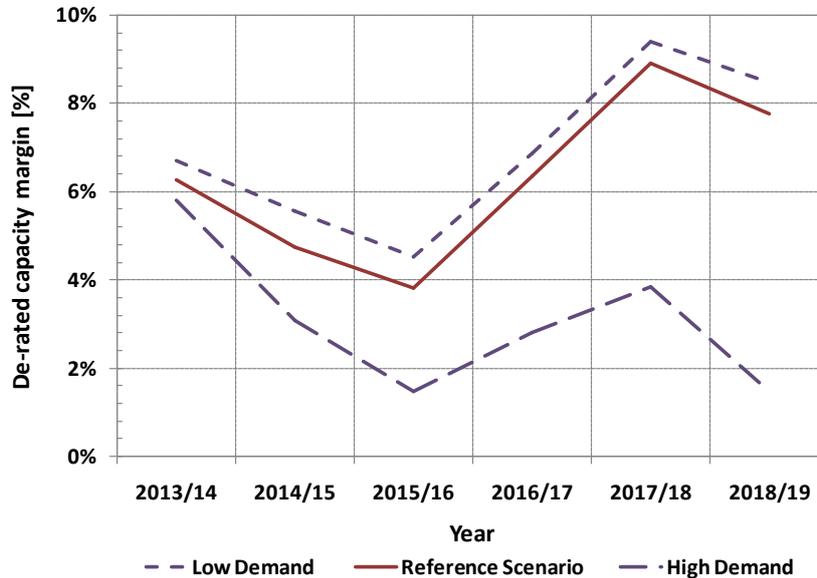

4.52. The figure shows that the low demand sensitivity only has a small effect on the de-rated capacity margin with respect to the Reference Scenario. This is expected, given how close the demand figures of the Reference Scenario and low demand sensitivities are. However, the impact of the high demand sensitivity is greater. Here, the high demand sensitivity results in de-rated margins at a lower level than in the Reference Scenario. Notably, the estimated de-rated margin falls below 2% in winters 2015/16 and 2018/19.

Interconnectors

Figure 40: De-rated capacity margin for the Reference Scenario and interconnector flows sensitivities
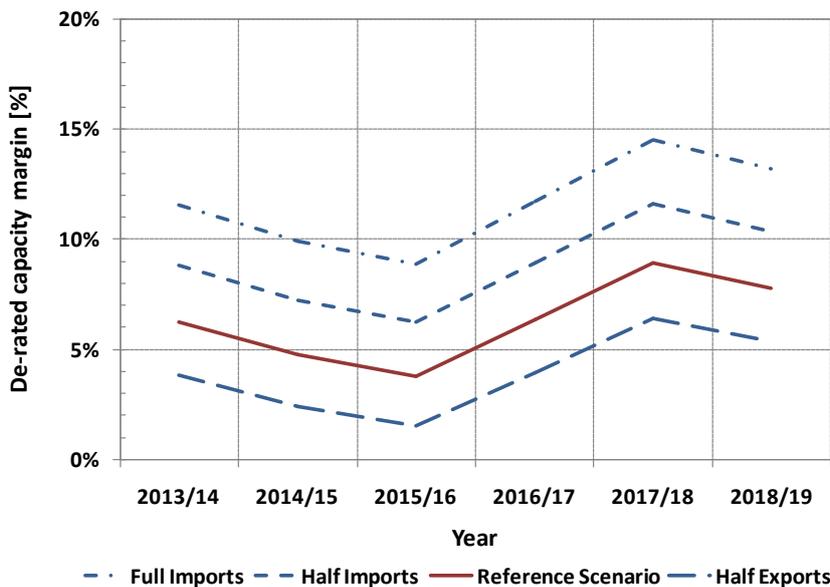
4.53. Figure 40 presents the estimated de-rated capacity margins for the three interconnector flow sensitivities over the next six winters, together with the Reference Scenario.

4.54. The figure highlights the impact that the direction of interconnector flows can have on the estimated level of the de-rated capacity margins in GB. With full imports, in winter 2015/16, the estimated de-rated capacity margin rises to 8.9%, which is about a third higher than the de-rated capacity margin in our high supply sensitivity (see Figure 36). This also compares, in the same year, with 6.3% in the half-imports case and 3.8% in the Reference Scenario. In the half-exports case the estimated de-rated capacity margin is 1.5% in 2015/16. For all the sensitivities, the de-rated capacity margins peak in 2017/18. Where the de-rated margin for the full-imports sensitivity, is 14.5%, almost double the value in the Reference Scenario.

No net interconnector flows

4.55. Figure 41 compares the size of the de-rated capacity margins attained under the no-net-flows sensitivity and the Reference Scenario throughout the period of analysis.

4.56. The figure shows that having no net flows (ie no net flow from mainland Europe or Ireland) improves the de-rated capacity margin throughout the period. For the winter of 2015/16, no net flows in GB increases the estimated de-rated margin from by 3.8% in the Reference Scenario to 5% in the no-net-flows sensitivity.

Figure 41: De-rated capacity margin for the no-net-flows sensitivity
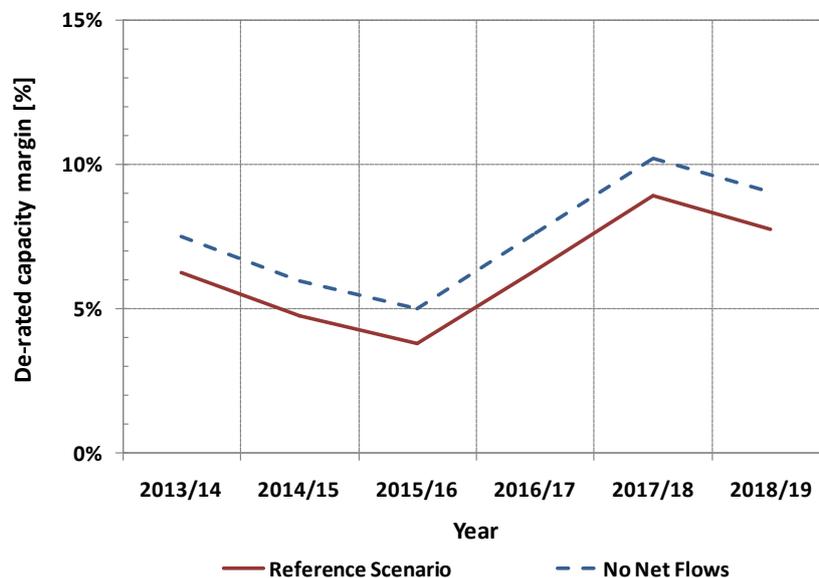
Appendices

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Appendix 1 – Detailed results

1.1. This appendix contains details for additional sensitivities which are not covered in the main part of the report. The sensitivities undertaken in the appendix are as follows:

- Transmission boundary constraint

- Summer season

- Demand and wind confidence intervals

- Demand-side response

- Gas stress test

- National Grid Gone Green scenario 2013

Transmission boundary constraint

1.2. Another possible cause of system risk can arise from physical limitations in certain areas on the GB transmission network. For instance, a situation could arise where nationally there is enough generation to supply overall demand, but in a particular region demand cannot be met. This is because there may be insufficient transmission capacity to transfer power from the area with surplus generation to that with a generation shortfall.

1.3. According to National Grid, the Cheviot boundary, between Scotland and England, is expected to be the most constrained transmission network link in GB over the period of analysis. Table 12 summaries the generation and demand assumptions on either side of the Cheviot boundary for the Reference Scenario. We represent this by the MW surplus in ACS peak demand over installed capacity in all of England & Wales (EW) and Scotland (SC) separately. We also include the Cheviot transmission boundary capacity in MW.

Table 12: Surplus capacity in EW and SC and Cheviot boundary capacity

Variable [MW]	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
Surplus capacity in EW over ACS peak demand	15,418	15,553	15,080	17,133	19,834	19,693
Surplus capacity in SC over ACS peak demand	6,980	6,525	7,156	7,992	9,480	11,521
Transmission capacity	3,300	3,300	4,300	6,400	6,400	6,400

1.4. Table 12 shows that the surplus capacities in EW and SC both follow an increasing trend over the period. This increase is notably higher in percentage terms in Scotland than in England and Wales, largely due to the volumes of wind generation that are estimated to be built in Scotland. The table also indicates that the capacity of the Cheviot boundary is due to almost double from 2016/17 onwards.

1.5. Despite Table 12 showing that the surplus capacity in both EW and SC is always positive, the physical limitations (eg limited transfer capability and availability) of the Cheviot boundary could potentially impact our risk measures of security of supply. To test the impact of the presence of the boundary, we have run a sensitivity that treats the GB system as two interconnected regions, ie EW and SC. We summarise in Table 13 the

impact of the Cheviot boundary on our risk metrics LOLE and EEU. In each case, we have also presented the change in LOLE and EEU with respect to the Reference Scenario.

Table 13: Impact of the Cheviot boundary in the risk metrics

Risk metric	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
GB LOLE [hours/year]	0.7	1.7	2.9	0.7	0.1	0.3
Additional GB LOLE [hours/year]	0.0032	0.0015	0.0002	0.0000	0.0000	0.0000
GB EEU [MWh]	659	1,746	3,070	628	106	265
Additional GB EEU [MWh]	2.1016	0.9875	0.1246	0.0000	0.0000	0.0002

1.6. Table 13 shows that before the planned capacity upgrade of the Cheviot boundary in 2015/16, there would be only very small increases in our risk measures resulting from the presence of the limited transfer capability of the Cheviot boundary. This suggests that the Cheviot boundary is unlikely to act as a significant constraint when electricity generated in SC is required to meet demand in EW or vice versa. Following the capacity upgrade in 2015/16, our results suggest that the presence of the Cheviot boundary would have no discernable impact on our risk measures. This implies that at no time during these years the new upgraded capacity on the boundary would act as a constraint to the flow of electricity between Scotland and England.

Summer season

1.7. The summer season in GB differs from the winter period in two key ways. The first is that peak demand is considerably lower in summer than in winter and the second is that planned maintenance outages historically occur more often in the summer.

1.8. Table 14 compares the assumptions for the ACS winter peak demand with summer peak demand over the next six winters in the Reference Scenario.

Table 14: ACS peak demand and summer peak demand for the Reference Scenario

Peak demand [MW]	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
Winter	55,550	55,150	54,590	53,900	53,040	52,340
Summer	40,300	40,010	39,604	39,103	38,479	37,971

1.9. Table 14 shows that the trend in summer peak demand is similar to that for ACS winter peak demand. Table 14 also highlights the marked differential between the two. Because demand is so much lower in summer, there is very little historical data on generators' behaviour during periods of tight margins in the summer season. We have therefore conducted the summer analysis via a deterministic stress test approach as opposed to the probabilistic modelling used for the winter analysis.

1.10. To account for the higher levels of maintenance that occur in the summer, we have based our assumptions in this sensitivity on historical average summer maintenance by generator type. In doing so, we have also recognised that a portion of this planned maintenance may have the flexibility to be rescheduled in response to short term indications of low capacity margins. National Grid estimate this to be 2,350MW. This capacity is then added back on to the supply side in the calculation of the de-rated capacity margin.

1.11. We further assume that the contribution of wind generation is lower during the summer season than in the winter season. We take a conservative view on the EFC of wind

generation based on mean availabilities from National Grid's Winter Outlook Report. We then use an EFC of approximately 10% in summer compared to 24% in winter.

1.12. Table 15 presents the estimated winter and summer de-rated capacity margins for the next six winters.

Table 15: Winter and summer de-rated capacity margins for the Reference Scenario

De-rated capacity margin [MW]	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
Winter	3,561	2,686	2,133	3,511	4,854	4,176
Summer	7,799	6,989	6,553	7,808	8,995	8,326

1.13. The estimated summer de-rated capacity margin is on average 4,260MW higher than the winter de-rated margin over the period of the analysis. Both de-rated margins follow a similar trend, being lowest in winter 2015/16 and highest in winter 2017/18. The differential between the de-rated margins remains broadly constant throughout the period.

1.14. Figure 42 illustrates the estimated winter and summer de-rated capacity margins for the next six winters expressed in percentage terms.

Figure 42: Winter and summer de-rated capacity margins for the Reference Scenario
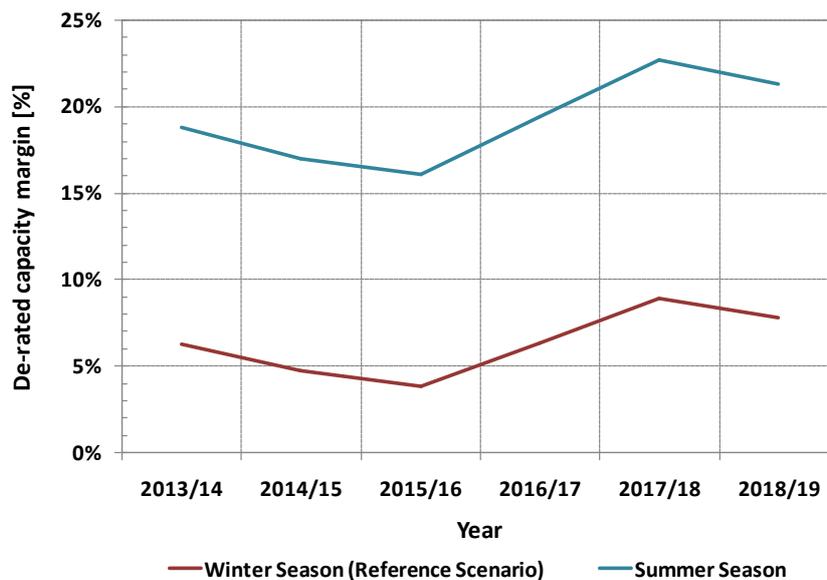
1.15. Figure 42 shows that when calculated in percentage terms, the summer margins are almost three times the size of the winter margins. The figure also highlights the trends in the two profiles observed above.

Demand and wind confidence intervals

1.16. To estimate the risk measures LOLE and EEU, we combine input data assumptions with stochastic distributions (eg electricity demand, wind power output). We have examined the impact of uncertainty in the input data assumptions using sensitivity analysis. To do the same for the distributions of demand and wind, we use a standard statistical technique known as bootstrapping. We explain this technique in more detail in Appendix 3.

1.17. Figure 43 and Figure 44 present the estimated LOLE and the EEU for the Reference Scenario together with the 95% confidence intervals for this risk measures over the next six winters.

Figure 43: Loss of load expectation for the Reference Scenario and associated confidence intervals
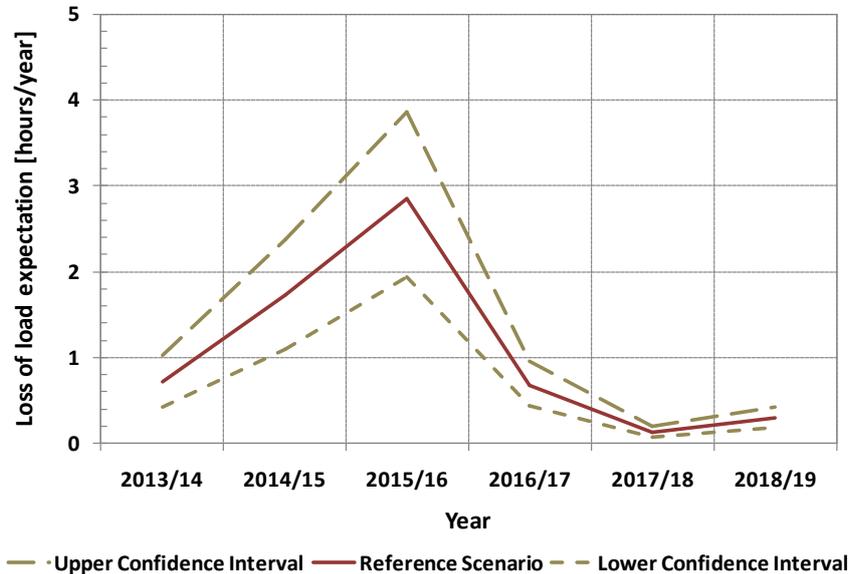
Figure 44: Expected energy unserved for the Reference Scenario and associated confidence intervals
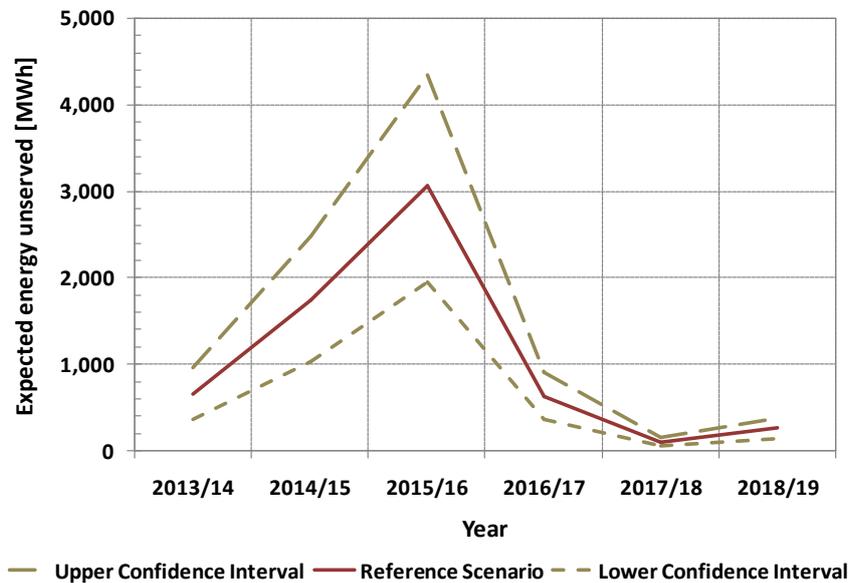
1.18. The figures show the range of the LOLE and EEU estimates around the Reference Scenario due to uncertainty in the distribution of demand. The estimates suggest that in winter 2015/16, the LOLE in the Reference Scenario could range between 1.9 hours per year and 3.9 hours per year. The estimated EEU in the same year could range between 1,956MWh and 4,351MWh.

1.19. Importantly, the test carried out above investigates the uncertainty around the historical distributions used in the analysis. These distributions may well change during the period of the analysis in ways unknown to us now. This introduces further uncertainty around the Reference Scenario risk estimates.

1.20. Figure 45 depicts the range of uncertainty around wind power output due to the distribution of wind in the Reference Scenario over the period of analysis.

Figure 45: Mean estimate for wind power output and associated confidence intervals
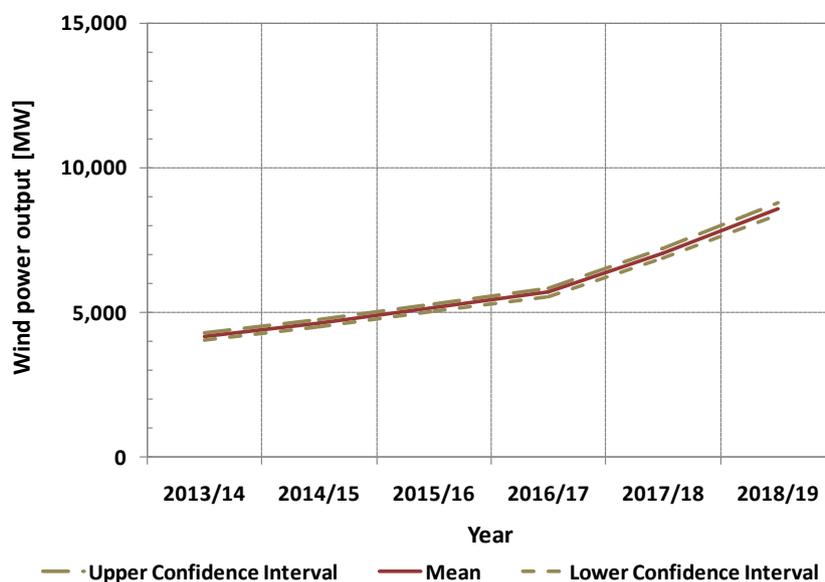
1.21. The figure shows a growth of the mean value of wind power output over the next six winters consistent with the increase in the levels of installed wind capacity. We observe that the intervals are around 3% above and below the mean value.

1.22. We have not translated the uncertainty in the wind power output into ranges for our risk measures[89] because of the small range around the wind output.

Demand-side response

1.23. The demand-side response (DSR) sensitivity recognises that there is high uncertainty around the potential future evolution of DSR. The sensitivity considers the effect on our risk measures of lower DSR participation. Specifically, we assume that DSR remains at levels registered in 2012/13 throughout the next six winters, leading to an increase of ACS peak demand compared to the Reference Scenario. We present the details of this assumption in Chapter 3.

1.24. Figure 46 and Figure 47 present the estimated magnitude of the risk to security of supply under the Reference Scenario and DSR sensitivity for the period of analysis.

1.25. We can see from the figures that a lower level of DSR increases the risks to security of supply in GB. This is represented by higher levels of LOLE and EEU in the DSR sensitivity in contrast to the Reference Scenario. For example, we note that in 2015/16, the DSR sensitivity contributes to an estimated 60% and 70% increase in LOLE and EEU respectively.

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[89] Uncertainty may also arise due to errors in the wind speed data used and the transformation from wind speeds to wind power output. However, we do not envisage this to materially affect the LOLE and EEU ranges presented.

Figure 46: Loss of load expectation for the Reference Scenario and demand-side response
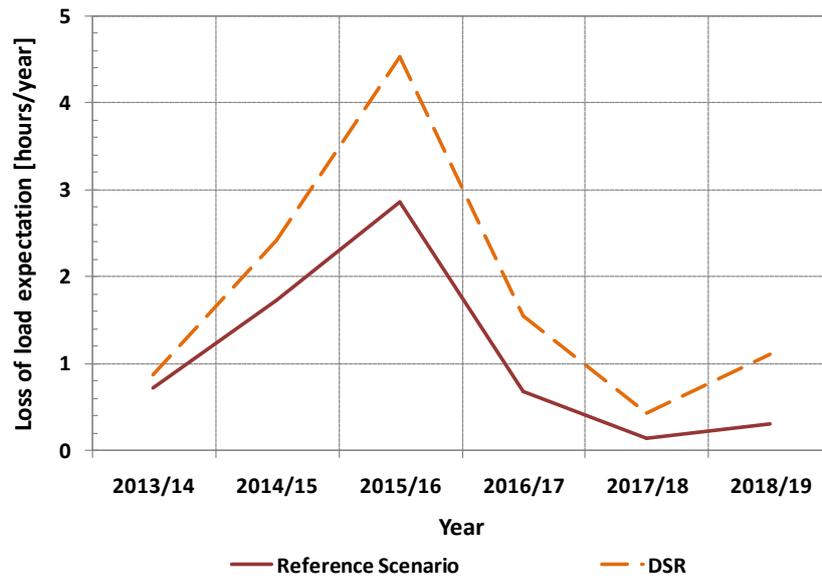
Figure 47: Expected energy unserved for the Reference Scenario and demand-side response
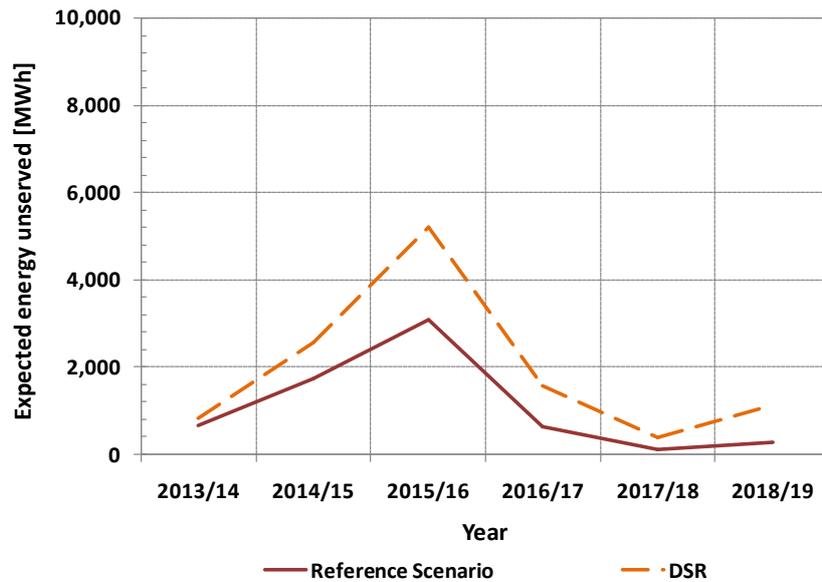
1.26. Figure 48 shows the estimated de-rated capacity margins for the Reference Scenario and DSR sensitivity during the next six winters.

1.27. The figure shows that lower levels of DSR lead to a tighter outlook for de-rated capacity margins. For instance, in the winter of 2015/16, characterised by the minimum estimated de-rated margin in the Reference Scenario (ie 3.8%), the DSR sensitivity presents a lower estimated de-rated capacity margin of 2.9%.

Figure 48: De-rated capacity margin for the Reference Scenario and demand-side response sensitivity
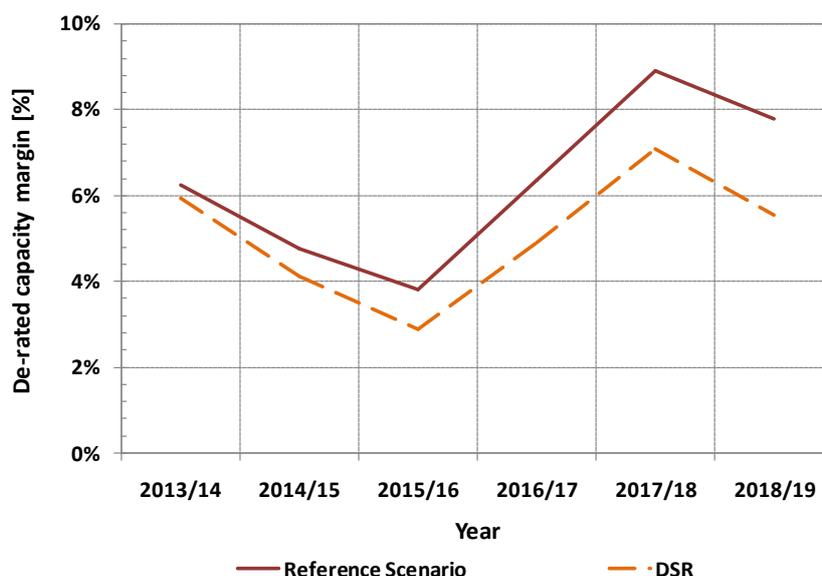
Gas stress test

1.28. The aim of the gas stress test is to analyse the impact of a drop in gas supplies to GB on generating capacity margins. Two tests are considered: (i) the potential impact on margins during an "N-1" event; and (ii) how much gas could be lost from peak day deliverability before margins are impacted.

1.29. To complete this test we compare demand for gas from the power and non-power sectors with peak day gas deliverability. If potential demand for gas is higher than peak day deliverability, then capacity margins may be affected. This is because, such a result would suggest that some gas plant could not be utilised if called upon.

1.30. To undertake both stress tests, we have produced an estimate for total potential gas demand from the power sector. Based on data from National Grid and Mott MacDonald, we consider that new CCGT plant is 52% efficient and that plants are running at a consistent load throughout the day. The results are presented in Table 16 together with an assumption on the total gas demand from the non-power sector.

Table 16: Potential demand for gas

Gas demand [MCM/day]	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
Potential gas demand from power (Reference Scenario 2013)	120.9	118.0	118.8	122.8	123.9	115.1
Total gas demand from non-power (National Grid Gas Ten Year Statement 2012[90])	422.6	417.5	400.2	396.6	389.8	384.5
Total potential gas demand (potential power plus non-power)	543.5	535.5	519.0	519.4	513.6	499.6

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[90] National Grid Gas Ten Year Statement 2012. http://www.nationalgrid.com/NR/rdonlyres/E60C7955-5495-4A8A-8E80-8BB4002F602F/58097/GasTenYearStatement2013.pdf

Test 1: Effect of "N–1" event on capacity margins

1.31. In this test we compare the total potential gas demand against total peak supply availability during an N-1 event. An n-1 event is equivalent to the loss of the largest import facility in GB. In this test we assume the loss of Milford Haven[91] (86 mcm per day). The second row in Table 17 shows the impact of an N-1 event on peak supply availability (shown in row 1). The third row repeats the total potential gas demand figures from Table 16 and the final row presents the surplus supply figures.

Table 17: Gas supply surplus (n-1) and total potential gas demand

Variable [MCM/day]	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
Peak supply availability	713.2	723.5	719.1	701.5	685.3	679.6
Peak supply availability ("n-1" event)	627.2	637.5	633.1	615.5	599.3	593.6
Total potential gas demand	543.5	535.5	519.0	519.4	513.6	499.6
Supply surplus ("n-1" event)	83.7	102.1	114.1	96.1	85.6	94.0

1.32. Table 17 shows that under an N-1 outage event, there is still a large surplus of gas supplies throughout the period of the analysis. Therefore, an N-1 outage event is not likely to impact our calculated de-rated capacity margins.

Test 2: Potential gas losses before de-rated capacity margins are affected

1.33. We extend the analysis to assess how much peak supply availability could be lost before the potential demand for gas from power could not be served. Table 18 presents the surplus supply by subtracting total potential demand for gas from peak supply availability.

Table 18: Gas supply surplus and total potential gas demand

Variable [MCM/day]	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
Peak supply availability	713.2	723.5	719.1	701.5	685.3	679.6
Supply surplus	169.7	188.1	200.1	182.1	171.6	180.0

1.34. Table 18 shows that under our assumptions, and depending on the year, between 170 and 200mcm per day of supply availability would have to be lost before de-rated capacity margins were impacted. This is between 24% and 28% of total gas supply. This range represents a very significant loss in gas supply availability. Therefore, the likelihood of occurrence is low.

1.35. In addition, it should be highlighted that we have assumed maximum CCGT output for 24 hours and as such the analysis provides an hypothetical maximum demand from CCGT generation (eg if it were required to run as a baseload source). We would normally expect gas-fired generators to run for only the peak 6 hours of the day[92].

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[91] DECC 2011, "Risk assessment for the purpose of EU Regulation 994/2010 on security of gas supply – An addendum to the Statutory Security of Supply report 2011", November 2011.
https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/48224/3428-risk-assessment-eu-reg-sec-supply.pdf

[92] For further information refer to Ofgem's Gas Security of Supply Report:
http://www.ofgem.gov.uk/Markets/WhlMkts/monitoring-energy-security/gas-security-of-supply-report/Documents1/Gas%20SoS%20Report.pdf

National Grid Gone Green scenario 2013

1.36. Here we present the levels of risk to security of supply and of the associated de-rated capacity margins for National Grid's Gone Green 2013 scenario over the next six winters.

1.37. In this respect, Figure 46 and Figure 47 illustrate the estimated LOLE and EEU in National Grid's Gone Green 2013 scenario, for the next six winters, together with the Reference Scenario.

Figure 49: Loss of load expectation for the Gone Green 2013 and Reference Scenario
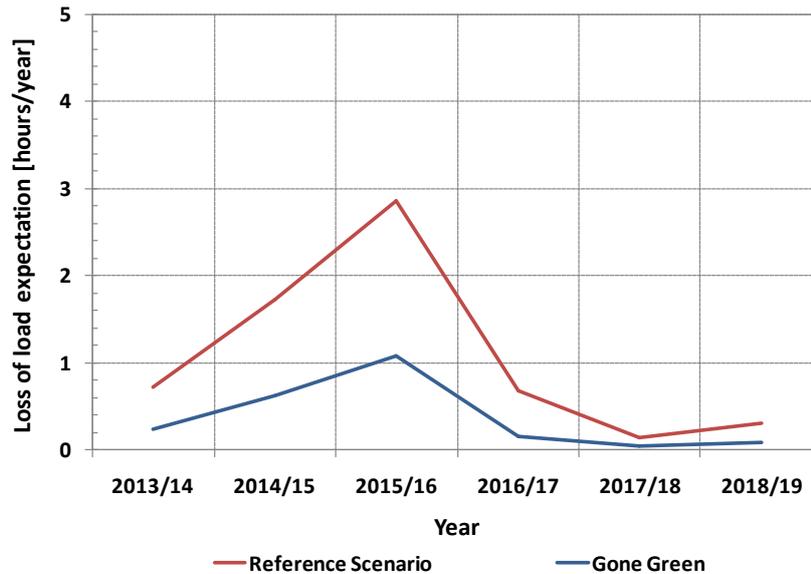
Figure 50: Expected energy unserved for the Gone Green 2013 and Reference Scenario
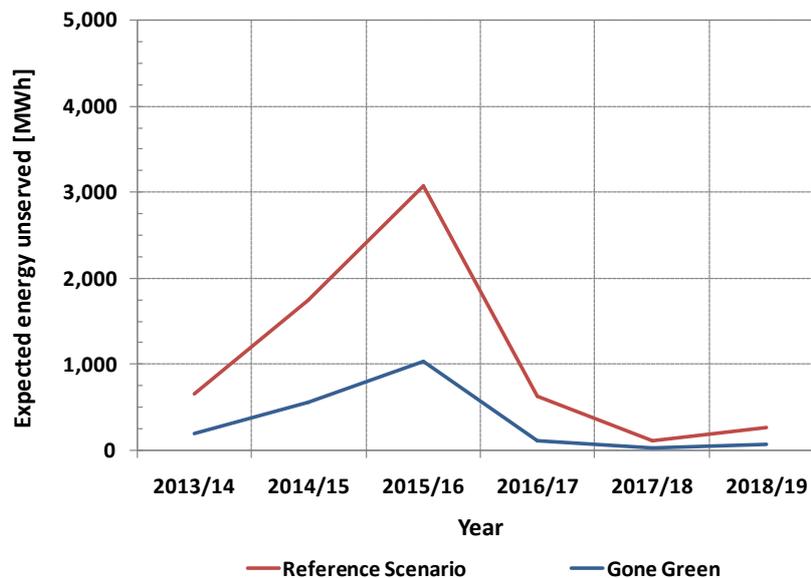
1.38. Figure 49 shows that the LOLE for next winter 2013/14 is estimated at 0.2 hours per year in the Gone Green scenario. The LOLE is then expected to increase towards winter 2015/16 when it reaches a level of 1 hour per year. This is largely driven by the closures of power plant over this period. The LOLE is then estimated to decrease to 0.1 hours per

year in winter 2018/19. This improvement is mainly driven by a decline in electricity demand.

1.39. Figure 47 shows that EEU follows a similar trend to the LOLE over the next six winters in the Gone Green scenario. For winter 2013/14, the EEU is estimated to be 190MWh. The estimated EEU then rises in the following two winters to reach approximately 1,031MWh by 2015/16. As with the LOLE, the estimated EEU falls in the following two winters to reach a low of 69MWh in 2018/19.

1.40. Figure 51 shows the estimated de-rated capacity margins for National Grid's Gone Green 2013 scenario and the Reference Scenario over the period of analysis.

Figure 51: De-rated capacity margin for the Gone Green 2013 and the Reference Scenario
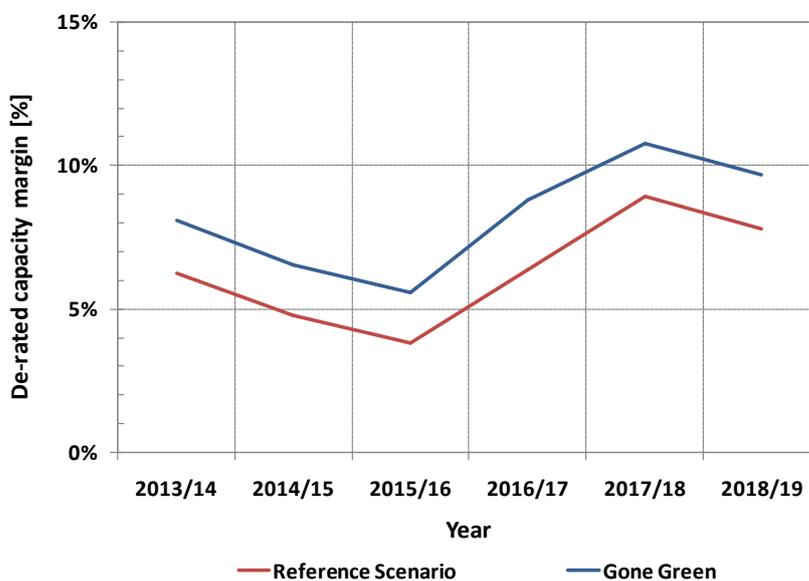
1.41. Figure 51 shows that the estimated de-rated capacity margin under National Grid Gone Green 2013 declines from 8.0% in winter 2013/14, to 5.6% in winter 2015/16 (its lowest point). This fall is driven by the closure of power plants. Beyond winter 2015/16, the de-rated margin under Gone Green 2013 rises to a peak of 10.8% in winter 2017/18. This is mainly driven by a decline in electricity demand.

Appendix 2 – Comparing the 2012 and 2013 reports

2.1. In this chapter we compare the headline results of last year's Electricity Capacity Assessment report with those from this report. We first highlight the major differences in assumptions between the 2012 and 2013 reports. We then present a comparison of the LOLE and EEU estimates, followed by the de-rated capacity margins. We note that the Electricity Capacity Assessment report 2012 only estimates risks out to winter 2016/17, while the results in this report run a further two years to 2018/19[93].

2.2. Both reports are structured in a similar way presenting a reference line with sensitivities to illustrate the impact of variations in the input variables on the results. We refer to the reference line as Base Case in the 2012 report. In this year's report we have decided to refer to it as Reference Scenario to highlight the fact that it is not intended to be a best view forecast of future risks but rather a plausible outcome under a particular scenario defined by a set of assumptions with regards to the main inputs to the analysis (ie expected supply availability, demand and interconnector flows). The change in the name does not reflect any changes in the methodology.

Assumptions

2.3. Table 19 illustrates the key differences in Reference Scenario assumptions between the 2012 and 2013 Electricity Capacity Assessment reports.

Table 19: Key Reference Scenario assumption differences between the 2013 and 2012 reports

Year	Variable [MW]	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
2013	Installed wind capacity	10,208	11,286	12,490	13,802	16,720	20,113
	Installed conventional capacity	67,739	65,941	64,336	65,224	65,634	63,441
	ACS peak demand	55,550	55,150	54,590	53,900	53,040	52,340
	Largest infeed loss	700	700	700	700	700	700
	Net interconnector flows	-750	-750	-750	-750	-750	-750
2012	Installed wind capacity	9,485	10,468	11,778	12,981	–	–
	Installed conventional capacity	70,025	69,557	67,568	67,761	–	–
	ACS peak demand	55,734	55,873	55,985	56,173	–	–
	Largest infeed loss	700	1,572	1,572	1,572	–	–
	Net interconnector flows	-950	-950	-950	-760	–	–

Note: (+) Great Britain Imports; (-) Great Britain Exports.

2.4. Table 19 shows that the estimates on the quantity of wind capacity have increased in this year's report. This is in line with updated assumptions from National Grid. On the other hand our estimates on conventional generation are lower this year. This reflects the increase in the number of plant that have permanently closed or mothballed since last year and the announcements that some new build will be further delayed.

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[93] For the capacity assessment report 2013 we have chosen to extend the analysis by one year to capture winter 2018/19 in our analysis, the first year of the Government's planned capacity market auctions.

Electricity Capacity Assessment Report 2013

2.5. Both reports use similar estimates for ACS peak demand in 2013/14 and 2014/15, but from 2015/16, ACS winter peak is estimated to fall in this year's report. This reflects the difference in demand assumptions between National Grid's Gone Green 2012 and 2013 scenarios.

2.6. On estimating interconnector flows, while our methodology has not changed in this year's report, the estimated quantities have. This is due to the failure on a cable of the Moyle interconnector, which has reduced its capacity by 250MW. Finally, the table shows the change in National Grid's estimate for the reserve requirement of the largest infeed loss.

Measures of risk

2.7. Figure 52 and Figure 53 compares the Reference Scenario results for the LOLE and EEU estimates in the Capacity Assessment report 2012 and 2013 over the next six winters.

Figure 52: Loss of load expectation for the Reference Scenario 2012 and 2013

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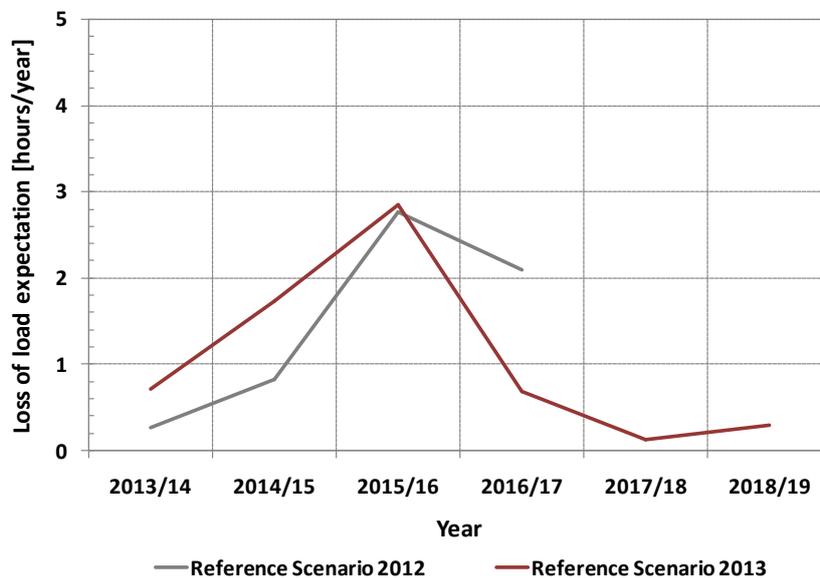
Figure 53: Expected energy unserved for the Reference Scenario 2012 and 2013
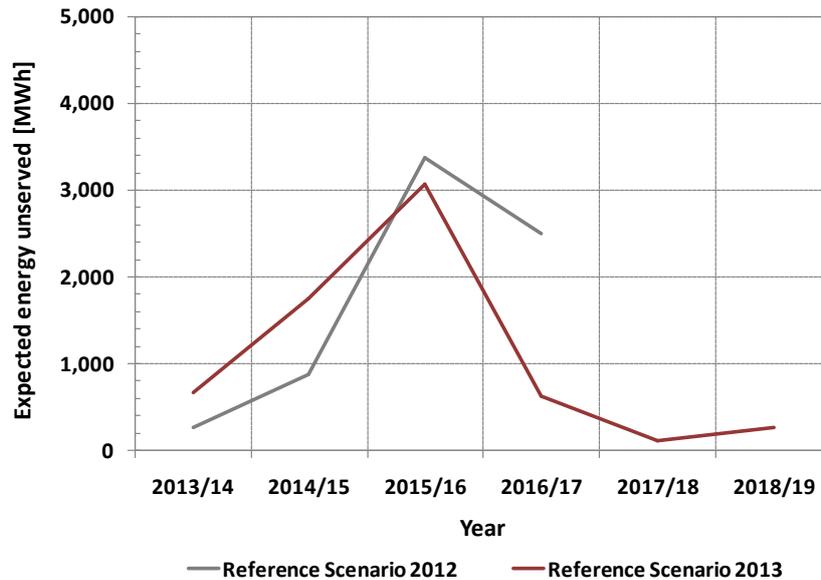
2.8. Figure 52 and Figure 53 show that, up to winter 2015/16, the risk of supply shortfalls measured through LOLE and EEU is higher in this year's Capacity Assessment report (red line) than in last year's report (grey line) in the first three years of the analysis. The increase in the risk levels is largely driven by lower levels of installed capacity compared with last year's report combined with relatively similar levels of electricity demand in the first three winters of the analysis.

2.9. The results in both reports converge to similar levels in 2015/16. This is because the factors increasing our risk measures in this year's report are almost completely balanced by lower estimated levels of ACS peak demand and increases in estimated installed wind capacity.

2.10. In winter 2016/17, the results diverge significantly, with the estimated LOLE and EEU for winter 2016/17 considerably lower in the 2013 report. This is driven by the difference in the electricity demand assumptions in the two reports, with National Grid assuming lower electricity consumption in this year's analysis. In this year's report the LOLE in winter 2016/17 is estimated at 0.7 hours per year (compared with 2.1 hours per year in the 2012 report) and the EEU is estimated at 628MWh (compared with 2,494MWh in the 2012 report).

De-rated capacity margin

2.11. Figure 54 compares the Reference Scenario results for the de-rated capacity margins in both Capacity Assessment reports for the next six winters.

Figure 54: De-rated capacity margin for the Reference Scenario 2012 and 2013
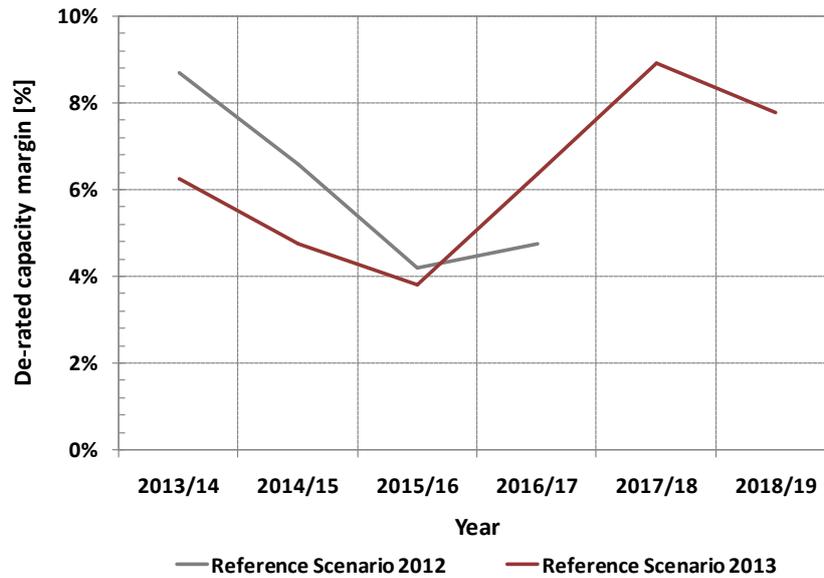
2.12. As expected from the LOLE and EEU results, Figure 54 shows that in the first three years of our analysis the de-rated capacity margins are lower in the 2013 report than in last year's. In winter 2013/14, the estimated de-rated capacity margin is 6.3%, compared with the 8.7% de-rated margin expected last year. In winter 2015/16, the two de-rated capacity margins converge to around 4%. In the following year, the de-rated margins are now expected to be higher (6.3%) in this year's report compared to those estimate last year (4.8%). This is driven by the lower assumptions on demand that National Grid have provided for this year's analysis.

Appendix 3 – Modelling approach

3.1. In this appendix we describe the modelling approach used for the 2013 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.

Overview of the modelling approach

3.2. The primary outputs of the Electricity Capacity Assessment model are:

- **LOLE:** the mean number of hours per year in which supply does not meet demand in the absence of intervention from the System Operator.

- **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:** an illustration of the results of the probabilistic risk measures in terms of tangible impacts for electricity customers. This is based on judgements around how the electricity system would operate at a time when supply does not meet demand, and the order and size of mitigation actions taken by the System Operator. It is therefore not as accurate as the LOLE and EEU but it allows us to provide a view of the probability of experiencing controlled disconnections of customers.

- **EFC:** the quantity of firm capacity (ie always available) that can be replaced by a certain volume of wind generation to give the same level of security of supply, as measured by LOLE. This measure is used to calculate the average contribution of wind power to the de-rated margin. It varies with the proportion of wind power in the system.

- **De-rated capacity margin:** the average excess of available generation capacity over peak demand, expressed in percentage terms. Available generation capacity takes into account the contribution of installed capacity at peak demand by adjusting it by the appropriate de-rating (or availability) factors which take into account the fact that plant are sometimes unavailable due to outages.

3.3. LOLE is not a measure of the expected number of hours per year in which customers may be disconnected. We define LOLE to indicate the number of hours in which the system may need to respond to tight conditions.

3.4. For a given level of LOLE and EEU, results may come from a large number of small events where demand exceeds supply in principle but it can be managed by National Grid through a set of mitigation actions available to them as System Operator[94]. The results may also come from a small number of large events (eg the supply deficit is more than 2 to 3GWh[95]) where controlled disconnections cannot be avoided. Conversely, given the characteristics of the GB system, any shortfall is more likely to take the form of a large number of small events that would not have a direct impact on customers.

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[94] The System Operator can implement mitigation actions to maintain the system when available supply is insufficient to meet demand. These include voltage control, maximum generation instruction and emergency services from the interconnectors.

[95] This varies with the specific conditions of the market at the time of the outage, including the flows over the interconnectors at the time.

3.5. LOLE serves to take account of the impact of rising levels of variable generation. However, it may not reflect any potential improvements[96] in the capacity of the system to cope with more variability before any disconnections. We do not expect these improvements to have a significant impact in the market in the next six winters.

Sensitivity development

3.6. A key part of this study has been to develop a Reference Scenario for the future electricity demand and supply background over the next six winters. This Reference Scenario 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.

3.7. A set of sensitivities has also been developed to test the impact on capacity adequacy of key uncertainties in the Reference Scenario assumptions.

Probabilistic model

3.8. Under 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 demand and supply, 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 assessment, ie LOLE and EEU. We further test the sensitivity of these outputs to variation in input assumptions. The latter include, among other, varying views of future capacity and electricity demand, together with assumptions about their statistical relationship as they vary over time.

3.9. The constructed model is a probabilistic model of capacity adequacy in the GB electricity market, and corresponds in turn to each of the next six winters. It is a time-collapsed model; 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 period of the winter under study. 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.

3.10. The model takes no account of the chronological ordering of the half-hourly time periods of the winter under study. 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.

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[96] One potential improvement would be for example further penetration of frequency management through automated appliances. For further information refer to:
http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?file=20130430_Creating%20the%20right%20environment%20for%20demand-side%20response.pdf&refer=Markets/sm/strategy/dsr

3.11. The distribution of demand is based on recent historical half hourly demand for electricity on the system, for the winters 2005/06 to 2012/13. This distribution is adjusted for the scenario assumption on peak demand in each winter.

3.12. 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 2011/12. The distribution of wind output availability is calculated from historical wind speed data covering the period from 1979 to 2012 for current and future GB wind farm locations.

3.13. The random variables X, W and D are assumed to be independent. 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 the winter season. The distribution of Z is then obtained by the convolution[97] of the distributions of X, W and $-D$.

3.14. Figure 55 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 55: Schematic diagram of electricity demand and capacity distributions
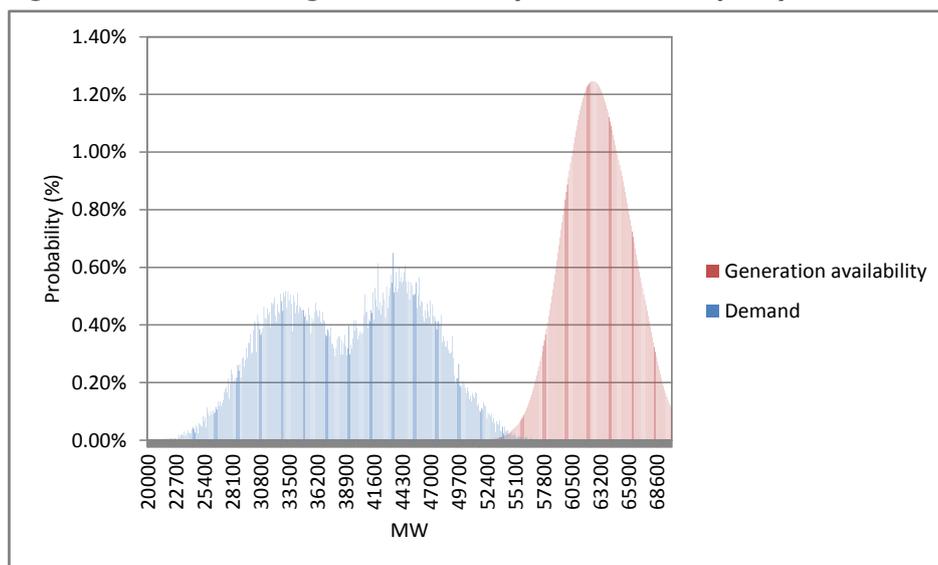
3.15. The model calculates two well-established metrics of security of supply, the Loss of Load Expectation (LOLE) and the Expected Energy Unserved (EEU). The LOLE is the mean number of periods per year in which supply does not meet demand, in the absence of intervention from the System Operator. The 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 follows:

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[97] 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.

$$[\text{LOLP}] = \mathbf{P}(Z \le 0) \tag{1}$$

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

3.16. 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 winter, while the EEU is defined as the EPU multiplied by the length of the studied winter. Thus, EEU combines both the likelihood and potential size of any supply shortfall.

3.17. 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

3.18. A bespoke model has been designed and built for this study, based on the principles described above. Figure 56 is a schematic representation of the modelling approach, showing inputs, calculations, and outputs. We give a brief description here, with each component described in more detail in the following sections.

Figure 56: Schematic representation of the modelling approach
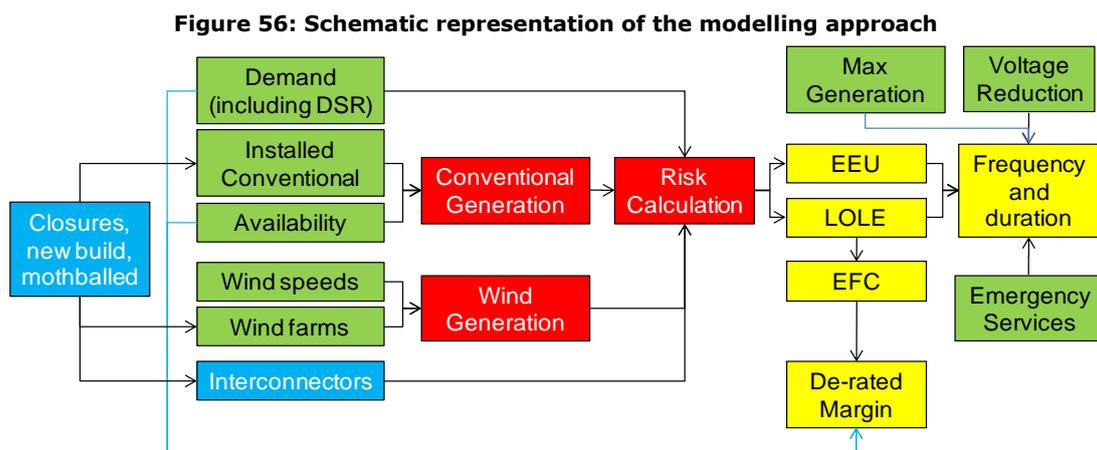
3.19. The model inputs consist of the scenario views of different future supply and demand assumptions. This includes future demand distributions and levels, the capacities of generators and interconnectors, conventional generator availabilities, and the historical wind speed data.

3.20. 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.

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

3.22. In addition, we calculate a commonly used indicator of security of supply: the de-rated capacity margin. The de-rated margin represents the average excess of available generation capacity over 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

3.23. Table 1 provides a summary of the sources used to derive the assumptions for the main inputs of the model.

Table 20: Summary of common assumptions and data sources

Assumption	Source
Demand distribution	Historical Indicative Demand Outturn (INDO) data for 2005/06 to 2012/13 for the period in which GB is on Greenwich Mean Time. INDO data has been available since the formation of the GB BETTA[98] market in 2005. Defines the demand profile
ACS Peak demand	Sensitivity variable. For Reference Scenario, source is National Grid's Gone Green 2013 scenario for the Future Energy Scenarios. Defines the overall level of demand growth.
Installed capacity	Sensitivity variable. For Reference Scenario, the primary source is National Grid's Gone Green 2013 scenario for the Future Energy Scenarios with amendments to reflect Ofgem's views. This provides the full portfolio of installed capacity for the next six winters.
Embedded wind capacity	National Grid's assumptions for Gone Green 2013.
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 adjusted for actual operation of wind turbines.
Wind farm locations	National Grid internal research.
Interconnector capacities	Based on Ofgem's assumptions.
Interconnector peak flow	Sensitivity variable. For Reference Scenario, the primary source is Ofgem's and Pöyry's analysis.
Demand-side Response	Sensitivity variable. For the Reference Scenario, the primary source is National Grid Gone Green 2013 scenario

Demand

3.24. 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.

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[98] British Electricity Trading Transmission Arrangements.

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

3.26. 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.

3.27. To account for overall growth in demand, the distribution is scaled by the forward looking assumptions for ACS peak.

3.28. For each of the next six winters, the highest demand in the distribution is higher than the quoted ACS peak demand, by about 1.8GW. 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 peak 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.

3.29. 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.

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

Conventional generation

3.31. 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.

3.32. 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.

3.33. 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.

3.34. 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 2011/12. 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.

3.35. We estimate the availability of each generator type at times of high winter demand for every winter. In particular, we are considering days with a demand level higher than the 50th percentile of winter peak demand. By considering periods of high winter demand the calculated availability represents a realistic estimate of what the generator is capable of generating at times of high demand, including rescheduling of any planned maintenance.

3.36. The Reference Scenario availability is defined as the mean availability of the seven winter estimates. The availability values used for the low (high) availability sensitivities are defined as the mean minus (plus) one standard deviation of the seven winter estimates.

3.37. The final mean availability assumptions used in the Reference Scenario and sensitivities are shown in Table 21.

Table 21: Generator availability per technology type

Fuel type	Availability [%]		
	Low	Reference Scenario	High
Coal / Biomass	86%	88%	90%
Gas CCGT / Gas CHP	81%	85%	89%
OCGT	87%	92%	97%
Oil	75%	82%	89%
Nuclear	76%	81%	86%
Hydro	78%	84%	90%
Pumped Storage	93%	96%	99%

3.38. The availability and capacities of individual generators are combined into a single capacity outage table, which is a distribution of the aggregate available capacity.

Wind generation

3.39. The source for wind speed data is NASA's Modern Era Retrospective-analysis for Research and Applications (MERRA) reanalysis dataset[99]. This is a long term (1979-2012) 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.

3.40. 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 50km spacing over GB. The model uses this data in combination with the capacity, hub height and coordinates of all transmission connected and embedded wind in GB.

3.41. To access the raw data, University of Reading were contracted to build an extraction tool. The tool is written in FORTRAN90 and compiled into a form which can be run on a standard Windows PC. The detailed description of this tool is online[100]. The tool can be run stand alone to extract the wind speed data for an individual wind farm location over a specified period of time (1979-2012). The tool interpolates between local grid points to derive the wind speed for the specified location. It also adjusts for hub height using a logarithmic relationship.

Conversion from wind speed to wind power output

3.42. The wind output is estimated for each wind farm under consideration in GB. For a specific wind farm the latitude, longitude and hub height are input into the wind tool to generate a wind speed time series. The wind speed time series is converted into a wind load factor time series using a wind power (load factor) curve. Finally the wind load factor time

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[99] 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/

[100] University of Reading Wind profile program documentation: http://www.met.reading.ac.uk/~marc/it/wind/

series is multiplied by the installed capacity of the respective wind farm to produce the wind output from this wind farm.

3.43. The process for constructing the wind power curve is detailed below. This is a different approach from the 2012 analysis in which we used typical wind power curves from manufacturers to convert wind speeds to wind power output.

3.44. The wind power curve was constructed by using actual output data from 9, randomly chosen, wind farms that are currently generating, and is applied on both onshore and offshore wind[101]. Specifically, the actual output time series of the 9 wind farms was converted into a load factor time series by dividing with the installed capacity of the respective wind farm. An *S*-curve[102] was subsequently fitted to the load factor data using a non-linear squares method[103]. A cut-out speed of 25 m/sec was chosen with a standard deviation of 1.5 m/sec, as this is typically given by wind farm manufacturers as a cut-out speed.

3.45. Figure 57 presents the wind power curve used in the 2013 and 2012 analysis. The 2013 approach has two advantages over the 2012 approach:

- The 2013 methodology intrinsically accounts for any wind turbine unavailability, based on historical data;

- It models the behaviour of a group of turbines rather than the behaviour of an individual turbine. This accounts for the geographic dispersion of wind turbines in a wind farm, as the wind speed varies from turbine to turbine in a wind farm.

Figure 57: Wind power curve in the 2013 and 2012 analysis[104]

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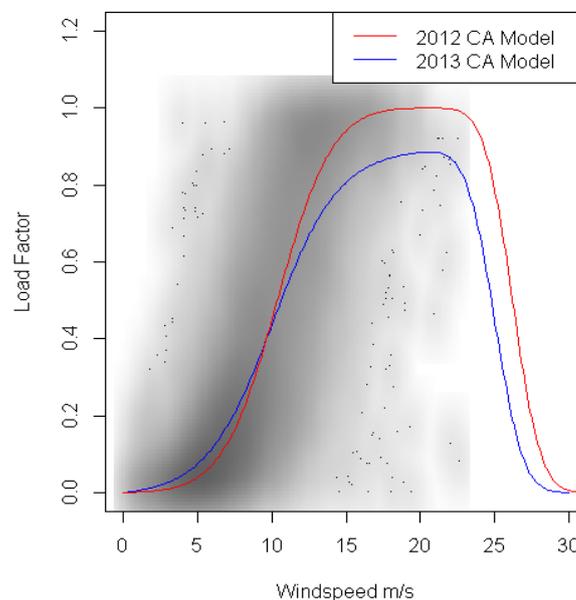
[101] We use the same wind power curve for both onshore and offshore turbines as the main difference in output is due to wind speeds being higher offshore.

[102] The S-curve is given by the following formula: $Load\ Factor = \frac{1}{1+Be^{-C \cdot w/s}} - \frac{A}{1+B}$, where w/s is the MERRA wind speed and A, B and C are the parameters which characterise the fit.

[103] As there is very few data at high wind speeds to fit a cut-out S-curve using a non-linear least squares method, one was fitted by inspection.

[104] The grey shaded area indicates the actual MW metered data used to calibrate the 2013 model. Darker areas indicate a higher density of data points.

Wind data validation

3.46. To assess the accuracy of the wind output methodology we have made a comparison with the metered output of all 97 wind farms that are currently submitting output data to National Grid. For each site we have used the wind output methodology described above and subsequently calculated the errors in these wind output estimates, compared with the metered data. We have repeated this calculation over the 2012 calendar year for:

- The 9 wind farms which were used to derive the wind power curve;

- The 50 wind farms that submitted high quality wind output data to National Grid over 2012;

- All 97 wind that submitted metering data to National Grid over 2012.

3.47. Figure 58 shows the location of the wind farms used for each of the three calculations[105].

Figure 58: Location of wind farms for wind data validation
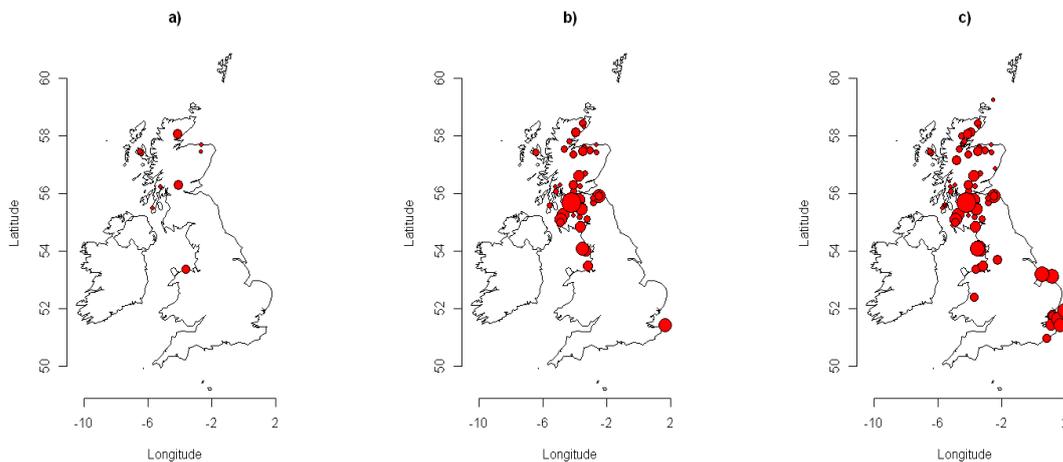
3.48. In addition, we have repeated this calculation using the 2012 wind power curves and estimated the respective errors. Figure 59 shows the errors for the 2013 and 2012 methodologies with regards to the metered wind output data.

3.49. Figure 59 illustrates that the 2012 methodology overestimates the wind output at low wind speeds, which are the most relevant for our probabilistic model, as the LOLE and EEU reflect the time periods that there is insufficient supply to meet demand. Further analysis showed that this was due to the unavailability of wind turbines during these periods[106]. The 2013 methodology shows an improved performance for low wind speeds.

3.50. Figure 60 presents the probability density plots of the aggregated wind power output using the 2013 and 2012 wind power output methodology and the 2012 metered generation.

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[105] The three graphs present the locations for: a) the 9 wind farms which were used to derive the wind power curve; b) the 50 wind farms that submitted high quality wind output data to National Grid over 2012 and c) all 97 wind that submitted metering data to National Grid over 2012.

[106] The 2012 analysis assumed that all wind turbines are available when the wind blows. The 2013 uses a more realistic approach with regards to the unavailability of wind turbines, based on the historical performance of a sample of wind farms and by considering the behaviour of a group of wind turbines.

Figure 59: Distribution of errors for 2013 and 2012 wind power output methodologies – with regards to 2012 metered data
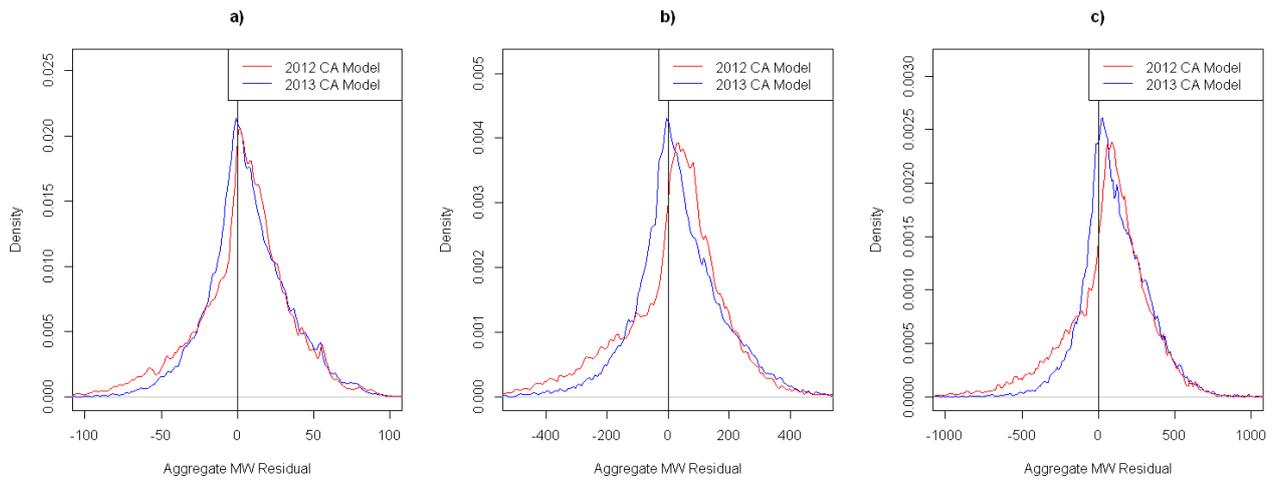
Figure 60: Probability density plots of the aggregate wind power output of the wind farms over 2012
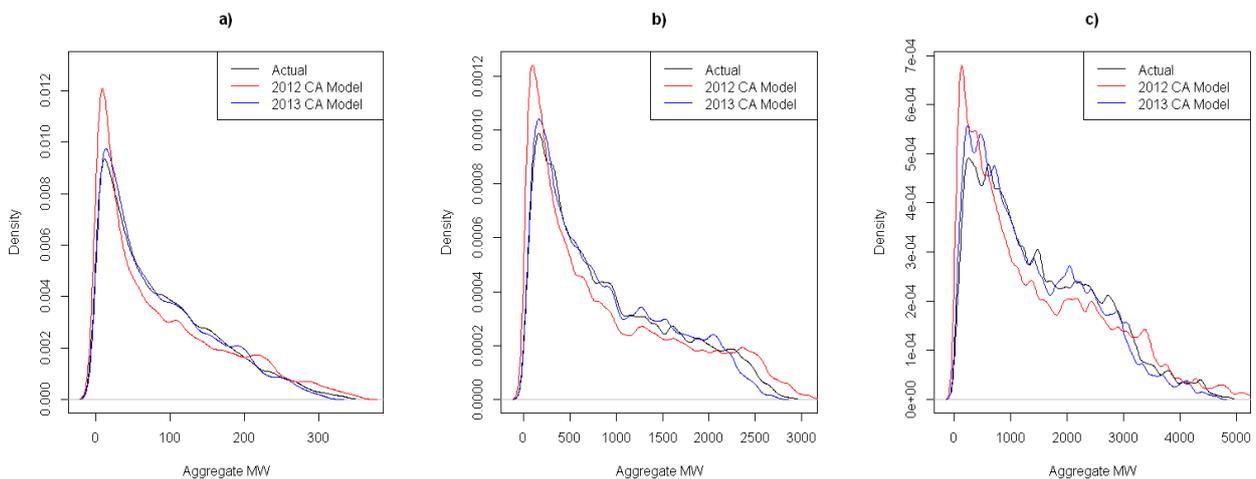
Wind output distributions

3.51. For the capacity assessment model, wind output distributions are generated for each of the six winters for which the capacity assessment is performed. The distributions are calculated from the scenario capacity mix, combined with the full set of wind speed data (1979-2012).

3.52. A single aggregate distribution of wind generation is created for each year. The installed wind capacity in 2013/2014 is 10.2GW, and by 2018/2019 this has increased to 20.1GW. There is nearly a zero probability of there being no output at all from wind.

3.53. The wind distribution for each capacity year is convolved with the distributions of conventional generation and demand to create a distribution of the margin of supply over demand. The key metrics of LOLE and EEU are calculated from this distribution.

Equivalent Firm Capacity

3.54. The wind distributions above show that 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.

3.55. 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.

3.56. EFC is a measure of the capacity adequacy provided by wind and it varies with the proportion of wind in the generation mix. 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.

3.57. For illustration, Figure 61 shows, for a given wind distribution, the average winter load factor and the EFC. At very small installed capacity of wind, the EFC is close to the mean availability of wind. As the installed capacity of wind and the proportion of wind in the system increases, the value of EFC drops as the possibility of near zero wind output, GB-wide, becomes increasingly important in determining wind's contribution within the risk calculation.

Figure 61: Comparison of wind distribution, average winter load factor and EFC
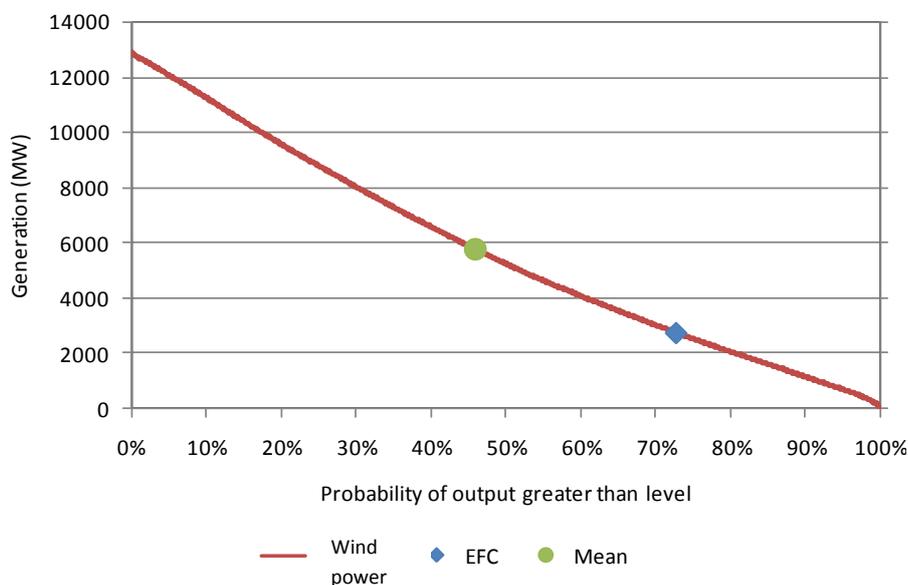
3.58. The EFCs calculated in this study are higher than other values that have been quoted for the contribution of wind to security of supply. For example, National Grid have previously used a value of 8% in the Winter Outlook 2011/12. Also, the value of EFC varies year on year in our analysis while similar report may assume a constant figure over the period of analysis.

3.59. The large difference in these numbers reflects two very different approaches. The Winter Outlook approach is based on observations of the output of wind at peak times. By its nature this is a small number of observations, and it is therefore possible that the wind output at the time of observation could have been very different.

3.60. We do not consider this approach appropriate for a capacity adequacy analysis, as it represents a pessimistic estimate of the availability of wind in isolation from the rest of the system.

3.61. In contrast, EFC is a statistical approach which takes account of the change in risk to security of supply due to the intermittent nature of wind output. The EFC value depends on both the system background scenario (ie generation and demand scenario) and the variability of wind. It recognises that the system already has some non-zero risk, and aims to calculate the level to which wind can be relied on so as to not increase this risk[107].

Treatment of special cases

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

3.63. Imports or exports on interconnectors to Ireland or mainland 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.

3.64. 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 by National Grid 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.

3.65. Demand-side Response is assumed to grow in the Reference Scenario over the course of the analysis period. 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 DSR participation grows over the six winter modelling period, both in the domestic and non-domestic sector. This follows National Grid's Gone Green 2013 work.

3.66. 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. Growth in embedded generation is reflected in the projected ACS peak demand.

Calculation of outputs

3.67. 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.

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[107] For further information refer to: S. Zachary and C. J. Dent, "Probability theory of capacity value of additional generation," J. Risk and Reliability, vol. 226, no. 1, pp. 33-43, 2012.

3.68. 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 illustrated in Figure 62. Each bar represents the expectation of the number of half hours per year that the margin will be in that 100 MW tranche.

Figure 62: Illustration of a distribution of de-rated margins
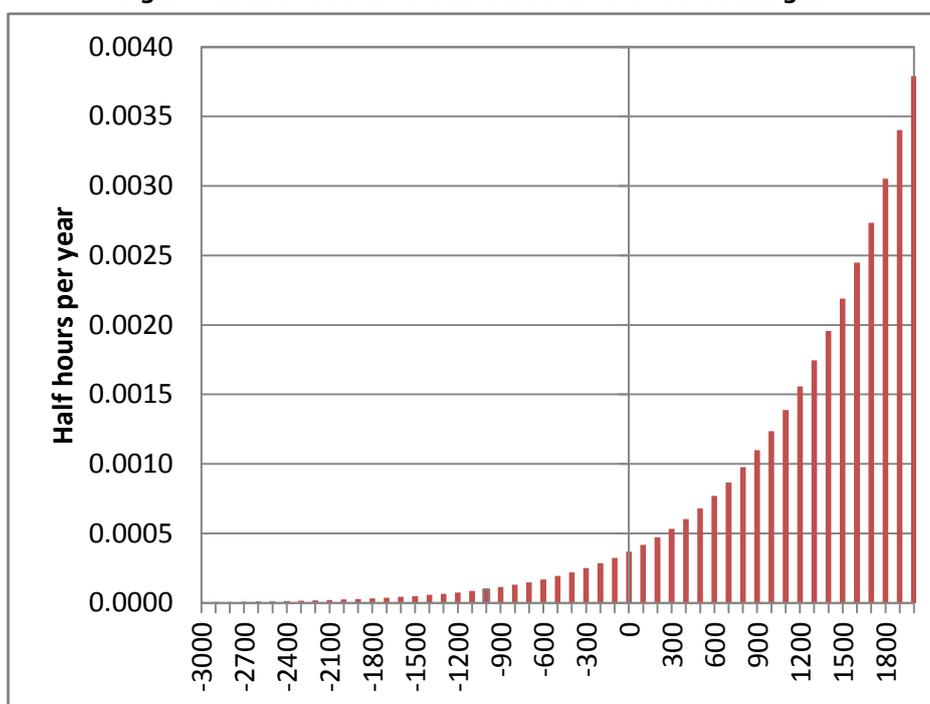
3.69. The distribution of margins is used to calculate the risk and the impact of supply shortfalls by including two well-established probabilistic measures of security of supply analysis: LOLE and EEU. In addition, we calculate a commonly used indicator of security of supply: the de-rated capacity margin.

3.70. The calculation of the de-rated margin is shown schematically in Figure 63 below. There are three components: demand, wind generation and conventional generation availability. The de-rated margin can be stated in percentage terms as the average excess of generator availability, divided by peak demand. The de-rated margin is defined as follows:

$$\text{De} - \text{rated margin} \; = \; \frac{\text{Average Available Supply} - (\text{ACS Peak Demand} + \text{Net Exports} + \text{LIF})}{(\text{ACS Peak Demand} + \text{Net Exports} + \text{LIF})} \qquad (3)$$

3.71. Where net exports are added to (subtracted from) the ACS peak demand if GB is a net exporter (importer) and LIF represents the largest infeed loss reserve requirement.

Figure 63: Calculation of de-rated capacity margin
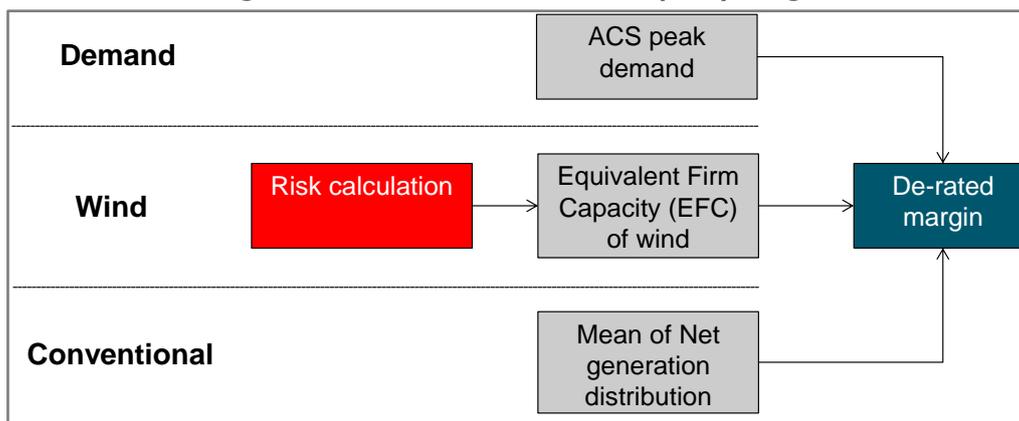
3.72. For demand, we use the ACS peak demand. As described above, it is possible for outturn demand to exceed this level. We also adjust at this point for the amount of generation that must be held as reserve to protect the integrity of the system against the largest infeed loss. Net exports (imports) over the interconnectors (which vary by sensitivity) are added to (subtracted from) demand.

3.73. 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 Table 21.

3.74. 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 could be very low.

3.75. The EFC is specific to any one sensitivity and year because it is dependent on the proportion of wind power in the overall generation mix. The Reference Scenario produces EFC values that are typically in the range of around 17 – 23%. At very small capacity of installed wind, the EFC is close to the mean winter load factor for wind. As the installed capacity of wind increases, the EFC value decreases, as the possibility of near-zero wind production, system-wide, becomes increasingly important in determining the contribution of wind to the risk calculation.

3.76. The de-rated capacity margin also includes an adjustment for assumed flows on the interconnectors and the reserve held by the System Operator for single largest infeed loss. This type of reserve is required in order to maintain the stability and integrity of the system, and therefore disconnection of demand would occur ahead of using this reserve (whereas other forms of reserve would be used to prevent supply shortfalls[108]). As it is a form of reserve that must be maintained, we therefore include it as "demand" in the analysis.

3.77. The interconnection and reserve adjustment are applied as increases to GB demand. The assumptions for the Reference Scenario are shown in Table 22 below.

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

Table 22: Interconnector flow assumptions (in GW) at winter peak periods for sensitivities

Variable [MW]	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
ACS Peak Demand	55,550	55,150	54,590	53,900	53,040	52,340
Exports to Ireland	750	750	750	750	750	750
Reserve for Largest Infeed Loss	700	700	700	700	700	700
Adjusted ACS peak demand	57,000	56,600	56,040	55,350	54,490	53,790

Frequency and duration of outages

3.78. For illustration, 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 in Table 23.

Table 23: Mitigation measures

Action	Comments	Assumed effect [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 markets (various services available, eg Emergency Instruction, Emergency Assistance and Cross-Border Balancing)	2,000

3.79. 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. 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 winters.

3.80. 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. Controlled disconnections occur after voltage reduction, maximum generation services and emergency services from interconnectors have been exhausted.

3.81. 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 μ_{kj} denote the mean length of time (hours) that such an outage lasts. Then, for each j

$$N_j = \sum_{k=1}^{K} f_k \mu_{k,j} \tag{4}$$

3.82. Where N_j is the expected number of hours per year at which the loss of load is j. The N_j are the fundamental outputs of the earlier probabilistic model; indeed we have:

$$[\text{LOLE}] = \sum_{j=1}^{J} N_j \tag{5}$$

$$[\text{EEU}] = \sum_{j=1}^{J} j N_j \tag{6}$$

3.83. Where J is the maximum loss of load with a non-negligible probability. Given the earlier estimates of the $\mu_{k,j}$, the equations (4) (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 (4) may be solved recursively, starting with $j = J$, to determine uniquely all the f_k[109].

3.84. 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

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

3.86. The uncertainty can be characterised into three types:

- Statistical (internal) uncertainty

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[109] 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 1GW and have a mean duration of $\mu_{1,1} = $ 1hr, while type 2 shortfalls correspond to an outage of 2GW with a mean duration of $\mu2,2 = $ 2hrs, coupled with an outage of 1GW with a further mean duration of $\mu_{2,1} = $ 3 hrs. The equations (5 and 6) 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 1GW is given by $N_1 = 0.13$, while the expected number of hours in the year at which the loss of load is 2GW 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.

- Uncertainty due to independence assumptions within the model

- Uncertainty due to non-statistical modelling assumptions

3.87. 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.

3.88. 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, eg 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.

3.89. In the case of demand, bootstrapping has been 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.

3.90. 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. Due to the computational overhead of processing the wind data, it has not been possible to estimate the confidence intervals on LOLE and EEU. However, it has been possible to examine the confidence intervals in the wind distribution itself, which gives some insight into the scale of this uncertainty. In addition, uncertainty in the distribution of wind generation may well be dominated by the uncertainty in the assumption that wind generation is independent of demand. The latter uncertainty is discussed below.

3.91. 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 of the outage rates.

3.92. 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 low wind generation sensitivity.

3.93. Table 24 summarises the approach to the uncertainties on various parameters in the modelling.

Table 24: 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 & sensitivity analysis
Distribution of conventional capacity	Dominated by modelling assumptions about plant availability probabilities	Sensitivity analysis
Assumption of independence of demand and wind at time of extreme demand	Independence assumption in model	Sensitivity analysis, based on varying wind distribution at times of extreme demand
Installed generating capacity	Modelling assumption	Sensitivity analysis
Availability of capacity over interconnector	Modelling assumption	Sensitivity analysis

Low wind generation sensitivity

3.94. The Capacity Assessment model requires as one of its inputs a specification of the joint distribution of demand D and available wind generation W. While the marginal distributions of these two quantities can be estimated from the available data, this is insufficient to reliably assess the joint distribution in the region of extreme demand which is most important for determining the model outputs. For the Reference Scenario, we assume that wind and demand are independent at times of extreme demand. This is a reasonable assumption given that there is no well characterised statistical relationship between the two.

3.95. However, there is a widespread belief that the wind stops blowing when there is a severe cold spell, resulting in lower wind availability at the time of extreme demand for electricity. The underlying rationale is that meteorological conditions that lead to extreme demand may be also associated with lower wind availability than under normal conditions.

3.96. 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 extreme demand, as less wind may be available than assumed in our model. We have developed a sensitivity to assess the impact of an inverse relation between wind availability and extreme demand.

3.97. Figure 64 shows data for available wind generation[110] and daily peak demand, at the time of extreme demand. The data correspond to modelled wind load factors and demand data for half-hourly periods from 2005-12, for which daily peak demand exceeded 90% of ACS peak demand. The plotted line shows an estimate of the mean wind load factor conditional on the daily peak demand. This is fitted using a locally weighted least squares smoothing technique (LOWESS)[111].

3.98. For the wind-demand sensitivity we assume that wind availability decreases at the time of extreme demand. In particular this sensitivity assumes a reduction in the available wind resource for demand levels higher than 92% of ACS peak demand. The maximum reduction is assumed to be 50% for demand levels higher than 102% of ACS peak demand. Wind availability is assumed to fall linearly between demand levels of 92% and 102% of ACS peak demand. Figure 64 depicts the relation between the available wind resource and demand at the times of extreme demand.

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[110] Based on a 2013-14 installed capacity scenario and expressed as a load factor.

[111] The fit has been tested against varying choices of the width of the smoothing window.

Figure 64: Wind load factor at times of daily peak demand (2005 – 2012)
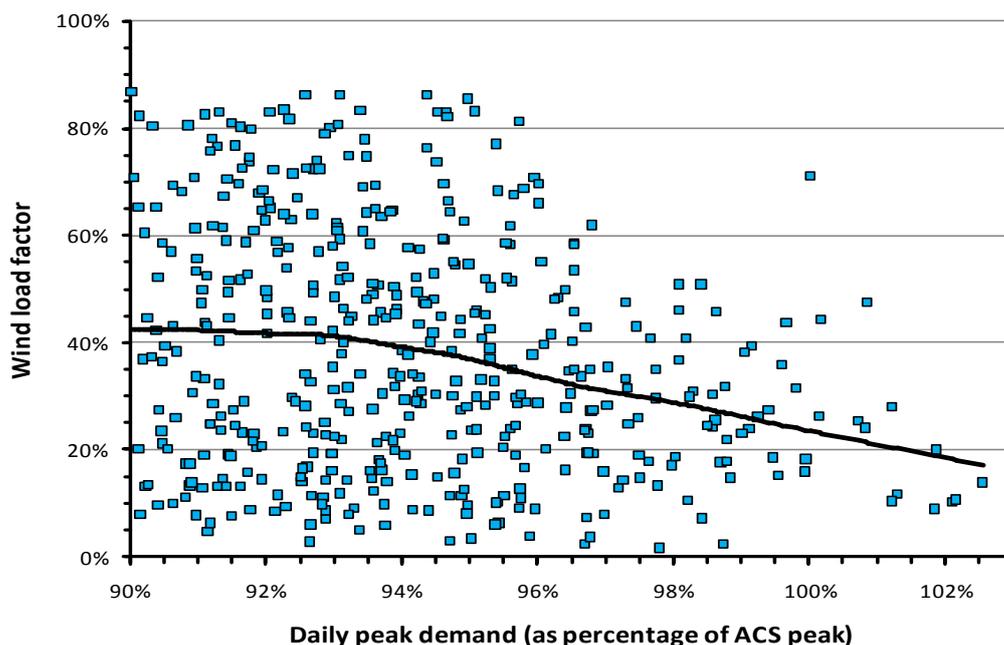
Transmission constraint model

3.99. 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 single-area model.

3.100. 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. The model does not define separate values of LOLE and EEU for each of the above two regions. This 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.

3.101. 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:

$$[\text{Additional LOLP}] = \mathbf{P}(Z_{EW} + Z_S > 0, Z_{EW} \leq -c) + \mathbf{P}(Z_S + Z_{EW} > 0, Z_S \leq -c) \qquad (7)$$

$$[\text{Additional EPU}] = \mathbf{E}((\min(-Z_{EW}, Z_S) - c)^+) + \mathbf{E}((\min(-Z_S, Z_{EW}) - c)^+) \qquad (8)$$

3.102. 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[112].

3.103. 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.

3.104. 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.

Winter severity analysis

3.105. For the 2013 report we have undertaken a complementary analysis to account for the uncertainty due to the use of limited demand history. Our analysis is based on demand data from 2005 onward, for which National Grid possesses information in a consistent manner. The purpose of this analysis is to answer the following two questions:

- What is the effect of using a longer time-series of demand data on risks to security of supply?

- How does the severity of a winter impact the risks to security of supply?

Effect of a longer time series on risk calculations

3.106. The probabilistic model uses demand data from the winter of 2005/06 to 2012/13. This provides limited information around the extremes of demand, which dominate the risk calculation outcomes, due to these occurring rarely and the limited history of demand data we possess. This analysis assesses the effect of using a longer history of demand data on the risk calculation.

3.107. As demand data are not available on a consistent manner for years prior to 2005, we are using historical daily temperature data as a proxy for demand. We recognise however that demand is dependent on various parameters (eg brightness) including temperature. For this analysis we use historical temperature data from 1990 – 2012.

3.108. The historical temperature data are converted[113] into daily peak demand estimates based on present demand patterns[114]. For each historical year of data we estimate the

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[112] 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.

[113] For this conversion we use info on: i) the temperature variable, ii) sunrise and sunset times and iii) the day of week to estimate the daily peak demand.

LOLE for a given future year[115]. The results of this calculation are scaled according to the results of the full risk calculation[116]. Finally, we estimate the LOLE for a future year, as the mean of the LOLEs calculated for each of the 22 years of history used in this analysis. Figure 65 shows the LOLE results for future years based on this analysis and the main risk calculation, for a test case.

3.109. The difference in the LOLEs calculated with the two methods varies between around 23 – 38%, depending on the level of LOLE[117]. Figure 65 illustrates that the seven years of history considered in the main risk calculation are sufficiently representative of the longer 22 year profile.

Figure 65: Winter severity analysis
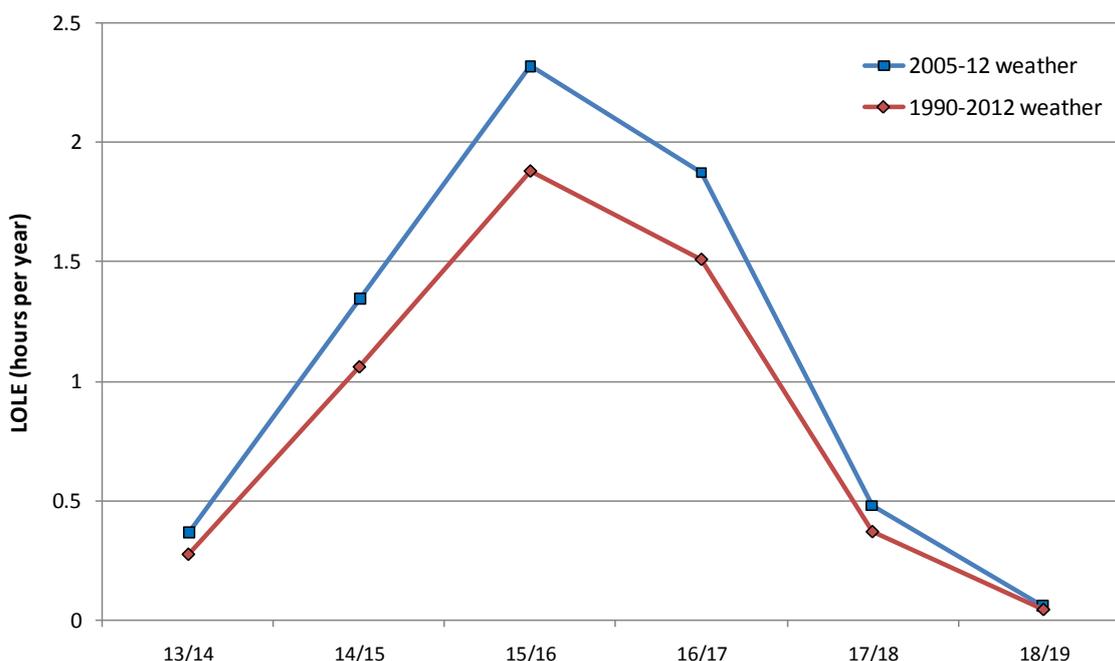
LOLE conditional of winter severity

3.110. We have analysed how the LOLE results vary based on the severity of historical data considered. We have undertaken the risk calculation based only on one winter of historical data at a time. Figure 66 shows the LOLEs for the winters of 2013/14 and 2015/16 if only one historic winter, from the seven winters we are using in the main risk calculation, is considered.

3.111. The LOLE figures presented here highlight how the LOLE results can vary significantly depending on the history considered. Specifically we can see that for a relatively cold winter, such as winter 2010/11, the LOLE result is around ten times higher than for a

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[114] This in turn is a simplifying assumption as demand patterns can change within such a timeframe.

[115] This is a different calculation than our main risk calculation. Our main risk calculation uses historical half hourly demand data, while this analysis uses a time series of daily peak demands, based on historical temperatures, to derive the demand distribution and subsequently the LOLE.

[116] Specifically, by comparing the outcomes of this analysis and the main risk calculation for the seven winters that we possess half hourly demand data, we form a relationship between the LOLEs produced by the two calculations. This relationship is then applied to scale the LOLE results for all years considered in this analysis.

[117] The higher the LOLE value of the main risk calculation is, the smaller the percentage difference between the two estimates. On the contrary the absolute difference between the two estimates is greater for higher values of LOLE.

relatively warm winter, such as winter 2006/07. This demonstrates that the risks to security of supply will greatly depend on the severity of a future winter.

3.112. The LOLE figures presented in this report are simple averages of the seven LOLE estimates, one for each winter of history considered. This approach is reasonable, considering the variability of risk levels as a function of the severity of a winter and the fact that it is not possible to predict the severity of a future winter with any confidence.

Figure 66: LOLE conditional on winter demand profile
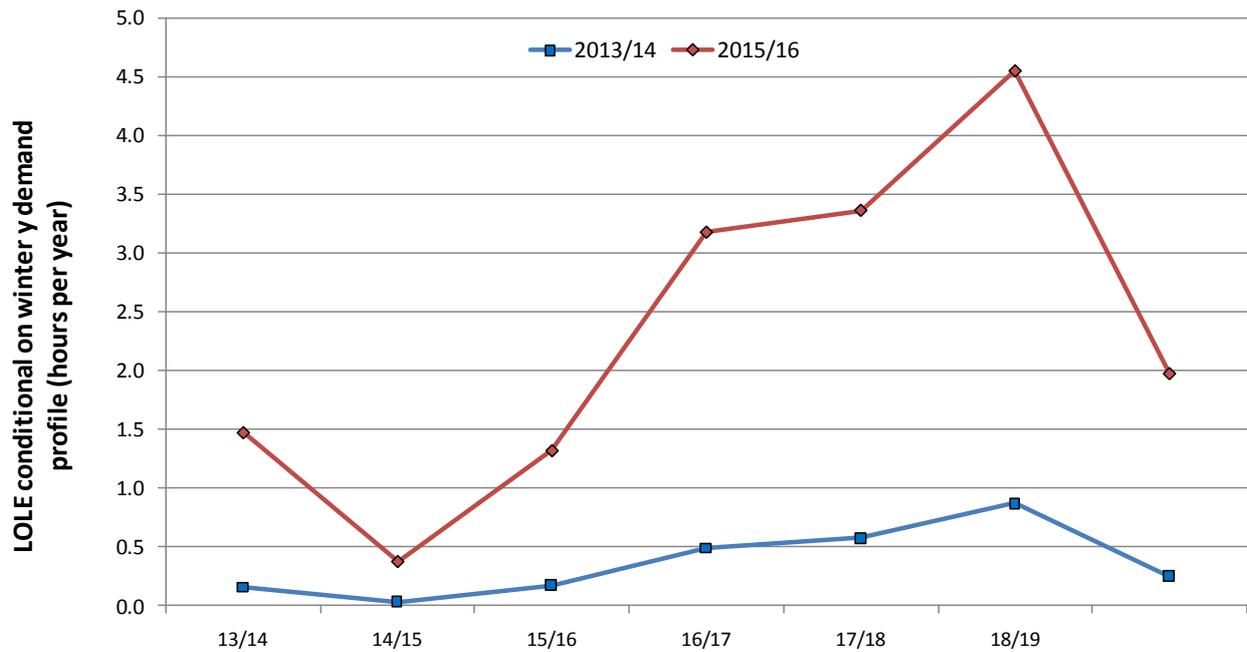
Appendix 4 – Analysis of the contribution of interconnector flows

Introduction

4.1. We consider that interconnectors are beneficial for electricity security of supply in general. Interconnectors give the GB market options that would not be there without them, providing services such as energy and reserves balancing trading, frequency response and 'black start'. They may also help reduce the cost of electricity throughout the year. Interconnectors might help reduce the probability of large events resulting in controlled disconnections of customers. Indeed, the mitigation actions available to National Grid to manage supply deficits consist of voltage control, maximum generation request and reducing the level of exports and/or increasing the level of imports before disconnecting GB customers.

4.2. From a capacity assessment perspective we need to form a view on the specific contribution of interconnector flows to the probability of having to implement mitigation actions in the GB system.

4.3. With the implementation of market coupling from winter 2013/14, interconnection flows in the future are expected to be mostly driven by price differentials between GB and the relevant markets, including, but not only, the directly interconnected markets. However, forecasting future prices in GB and its interconnected markets is a very difficult exercise, due to the uncertainties related to the evolution of demand and supply in the different markets, especially at a time of significant market reforms and uncertainty across the relevant markets (eg Capacity Market in France, Nuclear phase-out in Germany).

4.4. For this year's report we have conducted a qualitative[118] analysis to assess the likely direction and level of interconnector flows in the next six winters. This has been done by formally analysing the structure of and interactions between GB and its interconnected markets to identify possible outcomes. As part of this analysis, Pöyry Management Consulting has undertaken a statistical analysis on behalf of Ofgem. We reproduce part of their analysis here and the full report is published alongside this report in Ofgem's webpage[119].

4.5. This appendix describes the analysis which is composed of the following two elements:

- Structural Analysis: can we find any elements in the fundamental structure of the interconnected markets to enable us to anticipate the level and direction of interconnector flows?

- Historical Analysis: how have the interconnected markets interacted in the past, how might these dynamics change in the coming years, and what does this imply for the likely direction and level of future flows?

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[118] We consider a quantitative analysis not fit for our purpose given the expected changes in the market arrangements in Europe with the implementation of Market Coupling and the uncertainties surrounding the assumptions required by such a model. This view has been confirmed by the respondents to our consultation on the methodology for this assessment.

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

4.6. The results of this analysis confirm our 2012 report views that there is a significant level of uncertainty with regards to potential flows on the GB interconnectors with mainland Europe. With regards to Ireland, we can anticipate with a significant degree of certainty that GB will export electricity to Ireland in the next six winters, based on historical price differentials and historical flows between the two markets. These results should be taken as indicators of possible outcomes instead of precise forecasts and are complemented with plausible sensitivities.

Structural analysis

4.7. The purpose of the structural analysis is to identify whether GB and its interconnected markets are characterised by any elements that can enable us to anticipate the direction and level of interconnector flows in the future. The key elements of the structural analysis are:

- Market outlook for our interconnected markets and other relevant markets; and

- Similarities and complementarities between these markets and the GB market.

Market outlook in relevant markets

4.8. This section presents the market outlook for our directly interconnected markets, ie Ireland, France and the Netherlands, and other relevant markets that may indirectly impact interconnector flows between GB and its directly interconnected markets: Belgium and Germany[120].

4.9. Governments in Ireland, France, the Netherlands and Belgium have indicated their acceptable levels of risks to security of supply by deciding on a reliability standard[121]. A reliability standard is generally defined in LOLE terms, ie the maximum number of hours of LOLE per year[122]. It represents a trade-off between the level of security of supply and the investment required to achieve that level.

Table 25: Reliability standard in interconnected markets

Reliability standard	LOLE [hours/year]
Northern Ireland	4.9
Republic of Ireland	8.0
France	3.0
Netherlands	4.0
Belgium	18.0

4.10. From our analysis we conclude that generation adequacy is expected to get tighter in the markets surrounding GB with the exception of the Netherlands. Below we present the market outlook for the relevant markets.

4.11. **Ireland**: GB has historically been an exporter to Ireland. The Transmission System Operators for Northern Ireland (NI) and the Republic of Ireland (ROI) publish a joint capacity assessment report[123] where they present the outlook for security of supply in

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[120] Belgium and Germany are not directly interconnected with GB but are interconnected with France and the Netherlands.

[121] A reliability standard can also be called generation adequacy standard (NI & RoI) or adequacy criterion (FR), among others.

[122] DECC is planning to consult on a reliability standard in the summer.

[123] "All-island Generation Capacity Statement – 2013-2022" by SONI and EirGrid available at:

the all-island market for the next 10 years. They are expecting the risks to remain below their reliability standard of 8 hours of LOLE per year. In addition to the all-island, each jurisdiction has defined their own reliability standard; this is 4.9 hours of LOLE per year for NI, and 8 hours of LOLE per year for the ROI. The report also includes individual analysis for the Northern Ireland and Republic of Ireland. Northern Ireland is facing a tighter situation than the Republic of Ireland up to 2016. Their Base Case assumes full exports from GB to Ireland through the East-West and Moyle interconnectors. However, in a scenario with the interconnectors between GB and Ireland being unavailable, the Irish TSOs expect NI to face a deficit of supply[124] in 2015 and 2016 and the jurisdiction fails to meet its reliability standard. The tightness in the Northern Irish market is alleviated from 2017 with the expected commissioning of the second North-South link that allows for higher capacity transfers between NI and ROI.

4.12. **France**: The French TSO publishes a capacity assessment report where they present the outlook for the market for the medium and long term[125]. France is expected to experience a period of tight margins, where the level of risks is higher than their reliability standard, after the mid-decade[126]. This is mainly driven by the retirement of opted-out LCPD plant and the scheduled closure of two nuclear reactors at Fessenheim in 2017. These are expected to be partly replaced by new CCGT and wind. In addition, the outlook on the supply side has deteriorated recently with the mothballing of CCGT plant. The French TSO, in their 2012 report, expected a capacity deficit of 1.2GW in 2016 and 2.5GW in 2017 and assessed an LOLE of 5 and 6.5 hours per year in the two years respectively. This is higher than the reliability standard of 3 hours per year set by the French government. They expect the situation to deteriorate if imports from neighbouring markets are not available, with France facing a capacity deficit of 7.5GW in 2016 and 8.6GW in 2017 in the scenario excluding interconnector flows.

4.13. **Netherlands**: The Dutch TSO produces a capacity assessment report that covers the next 16 years[127]. The Netherlands is experiencing a period of increasing investment in power generation. The Dutch TSO, in their 2010 report, expect around 14GW of new plant of large-scale generation to come online from 2012 to 2018[128]. As a result, the Netherlands is expected to experience high levels of security of supply during the next six winters, accompanied by negligible levels of LOLE, well below their reliability standard of 4 hours of LOLE per year. Consequently, the Dutch TSO expects the Netherlands to be an exporter of electricity in this period[129]. The Netherlands currently has 5.5GW of interconnected capacity, including 1GW with GB.

4.14. **Belgium**: Belgium is expected[130] to face tight margins for the rest of the decade, and the country could be reliant on imports to meet domestic demand[131]. In particular, Belgium is

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http://www.eirgrid.com/media/All-Island_GCS_2013-2022.pdf

[124] A generation deficit/surplus represents the lack/excess of (firm) capacity for a market to exactly meet its reliability standard.

[125] For more information see:

http://www.rtefrance.com/uploads/Mediatheque_docs/vie_systeme/annuelles/bilan_previsionnel/an/generation_adequacy_report_2012.pdf

[126] The French government have decided to contract for capacity reserve in 2015 as a transitional measure to maintain the risks at the accepted levels before the initiation of the capacity market in 2016. For more information see article 26 of the decree 2012-1405, available here (in French):

http://www.legifrance.gouv.fr/affichTexte.do?cidTexte=JORFTEXT000026786328&dateTexte=&categorieLien=id

[127] For more information see:

http://www.tennet.eu/nl/about-tennet/news-press-publications/publications/technical-publications/report-on-monitoring-of-reliability-of-supply-2010-2026.html

[128] Ibid.

[129] TenneT expects the supply surplus to increase from 3.8GW in 2011 to 12.9GW in 2018.

[130] For more information on the market outlook in Belgium, see the "Scenario outlook and adequacy forecast" by ENTSO-E:

expected to experience a deficit of supply in the period under both a "best-view" scenario and a pessimistic scenario[132]. The situation could worsen in the future if they experience more problems with the nuclear plant that have recently been out of service (2GW) due to cracks in the reactor vessels. In any scenario, Belgium would be dependent on electricity imports to meet domestic demand. Belgium is not directly interconnected with GB, but it is interconnected with the Netherlands.

4.15. **Germany**: The generation adequacy situation is expected to get tighter in Germany. The German government has decided to phase-out all nuclear plant by 2022[133], from which around 8.5GW have already shut down[134]. An additional 6 GW of conventional generation is expected to close permanently by 2014. At the same time, some CCGT plant have been taken offline, due to the negative or low profitability of gas-fired generation. On the other hand, 5GW of conventional generation are expected to come online by 2015, alongside the continuous deployment of wind and solar power. The IEA[135] expects Germany to face tighter margins from the mid-decade, as the phase-out of nuclear capacity continues. The IEA assesses that an additional 6GW of new conventional capacity will be required for the market to maintain a 10% reserve margin. Germany is not directly interconnected to GB, but it is interconnected with the Netherlands and France.

4.16. Table 26 summarises the security of supply outlook for the markets under study. In brief, it is expected that security of supply will get tighter in the markets surrounding GB, with the exception of the Netherlands.

Table 26: Generation adequacy outlook in markets surrounding GB

Market	Security of Supply outlook
Ireland	In the central scenario, which assumes full imports from GB, risks to security of supply are below the markets' reliability standard. In a scenario where interconnectors with GB are unavailable, Northern Ireland faces a deficit of supply in 2015 and 2016, before the scheduled commissioning of the second North-South interconnector.
France	France is expected to face tight margins after the mid-decade resulting in a level of risk above their reliability standard. The situation is expected to worsen in a scenario excluding imports.
Netherlands	The Netherlands is expected to experience high levels of security of supply and be a net exporter of electricity during our analysis period.
Belgium	Belgium is expected to face tight margins for the rest of the decade, and rely on imports to meet domestic demand.
Germany	Germany is expected to face tighter margins after the mid-decade, primarily due to the phase-out of nuclear capacity.

Similarities and complementarities between GB and relevant markets

4.17. Even if both sides of the interconnector expect tight margins, there may be an evident direction of flows if markets are highly complementary. For example, if the peak of demand in one market occurs during summer due to air conditioning while demand in the

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https://www.entsoe.eu/about-entso-e/working-committees/system-development/system-adequacy-and-market-modeling/soaf-2012-2030/

[131] The Belgian TSO assessed that one of the conditions for fulfilling system adequacy in winter 2012/13 is the availability of 3.5GW of import interconnection capacity into the Belgian grid, assuming that excess generation is available in other Central Western European countries.

[132] Ibid

[133] Of the 21GW of operational nuclear power, when the German government announced the moratorium on nuclear power, 10GW were taken out of service with immediate effect. The remaining nuclear capacity is scheduled to shut down by 2021 and 2022, depending on the plant's age.

[134] For more information see: "Energy Policies in IEA countries: Germany – 2013 Review", by IEA:

http://www.iea.org/Textbase/npsum/germany2013SUM.pdf

[135] Ibid.

other market peaks in winter due to heating requirements, then we could expect with significant confidence each market to have inflows through the interconnector at peak demand, even if they are both experiencing tight margins at peak demand.

4.18. We have analysed the historical behaviour of the following key elements of the electricity markets: demand, availability of conventional generation, wind availability, and de-rated margins in GB and our directly interconnected markets (Ireland, France, Netherlands) and other relevant markets (Germany, Spain)[136] to try and identify the degree of correlation between them.

4.19. Based on this analysis we conclude that currently there are no apparent complementarities between GB and its interconnected markets, as we have very similar patterns of margins and demand and supply availability. Historically, the evolution of de-rated capacity margins in these interconnected markets has been positively correlated. This means that when margins are low in one market they also tend to be low in the other market.

Statistical analysis

4.20. The statistical analysis was undertaken by Pöyry Management Consulting on behalf of Ofgem. We reproduce part of the analysis here. The full report is available is available in Ofgem's webpage[137].

4.21. The relationship between the key elements of the markets is estimated using correlation coefficients. The correlation coefficient can vary between -1 and 1. The sign of the coefficient indicates whether the two variables analysed are moving in the same (+) or opposite (-) direction. The magnitude of the coefficient indicates the strength of the correlation, ie a value close to 1 (absolute) indicates that the two variables are changing with the same proportions. On the contrary, a value closer to 0 indicates that the two variables change with a different order of magnitude (weak or no correlation).

4.22. For example, correlation between gas and electricity prices is normally positive as an increase in gas prices would result in an increase in the electricity prices. Table 27 shows our interpretation of the strength of a relation for this report, as this is estimated by the correlation coefficient.

Table 27: Interpretation of the magnitude (absolute value) of a correlation coefficient

Correlation level	Range of the coefficient of correlation
Weak	0.0 – 0.2
Medium	0.2 – 0.5
High	0.5 – 0.8
Very high	0.8 – 1.0

4.23. Below we describe the data used for this analysis.

- Demand: hourly demand data over the period 2005-2012 are used for this analysis. The demand data for this analysis are sourced by ENTSO-E and the respective national TSOs[138].

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[136] We have included Germany and Spain in our analysis due to the large growth of renewables in these systems and their potential impact on interconnector flows between GB and France.

[137] http://www.ofgem.gov.uk/Markets/WhlMkts/monitoring-energy-security/Pages/index.aspx

[138] All demand data have been converted to refer to GMT time.

- Conventional Generation availability: half-hourly (converted to hourly) plant availability as reported by Elexon is used for GB. For other markets, historical margins have been estimated using monthly availability profiles at the individual market level per technology.

- Wind: hourly wind load factor data has been produced based on wind speed data (from the Anemos[139] wind atlas) and the characteristics of the wind farms in the respective market (eg wind farm location). The hourly wind load factors have been converted to wind power output based on the installed capacity of wind[140].

Demand

4.24. We have analysed the historical relationship between demand in GB and relevant markets. The correlation analysis shows that demand between GB and relevant markets has been highly correlated. Specifically, demand between GB and Ireland is estimated to be very highly correlated, and for all other markets highly correlated[141]. This means that when demand is high in GB, it is also high in the other markets, and vice versa.

Supply

4.25. Plant outages, ie scheduled maintenance and unplanned outages, are generally affected by elements unique to the individual plants (eg age of plant, part failures). Hence, we do not expect the availability of conventional generation to be correlated in GB and its interconnected markets in the past or future. This is consistent with the approach followed in the probabilistic model, where conventional generation availability per plant is considered an independent variable.

Historical GB margins

4.26. Historical margins refer to realised margins in the past as opposed to expected de-rated margins as projected in the Capacity Assessment report. The analysis is based on actual demand and generation availability[142].

4.27. This section describes the relation of margins in GB and the market's own parameters ie demand, conventional generation availability and wind generation. In addition, it describes the correlation of historical margins between GB and the relevant markets. Margins discussed in this section exclude interconnector flows.

4.28. We have estimated the correlation between GB margins, and the market's own parameters. GB margins show a high degree of negative correlation with demand. This implies that changes in demand have been the main driver of changes in margins in GB. In addition, the correlation of GB margins and availability of conventional generation is variable and predominantly positive. Available conventional generation has been the second most important driver of GB margins. This variability could be explained by plant investment cycles in GB.

4.29. We have also analysed the correlation of GB margins with the market's own parameters, at times of margins below 20%. This analysis shows that periods of margins below 20%

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[139] For further information on the Anemos wind atlas refer to: http://www.anemos.de
[140] We have used average quarterly installed capacities of wind for each market.
[141] All correlation coefficients for all years were found to be statistically significant.
[142] Historical margins have been estimated as the difference between the actual available generation (conventional and wind) and demand outturn in every hour.

are produced by different parameters in different years. For example low margins can be driven by plant outages in one year and high demand in another year.

Correlation of margins between GB and relevant markets

4.30. The results show a high degree of correlation between the availability margins in GB and those in Ireland, a medium level of positive correlation between GB and France, and a positive but highly variable correlation between GB and the Netherlands. These suggest that margins move broadly in same direction in GB and the directly interconnected markets.

Conclusions

4.31. From the above analysis of the structural characteristics of the GB and relevant markets, we conclude that these markets featured similar structures with similar behaviours in the past. There are no evident complementarities between the markets and therefore the likely level and direction of flows is not evident.

4.32. In particular, our analysis shows that the evolution of available margins has been primarily driven by the evolution of demand in all markets and that demand patterns have been highly correlated between markets. We broadly expect the relation between demand in GB and relevant markets to be maintained in the next six winters. This could lead to concurrent periods of high and tight margins in GB and its interconnected markets.

4.33. On the supply side, the availability of conventional generation plant between the different markets has not been correlated is the past. In addition, investment patterns can vary significantly between GB and the relevant markets therefore resulting in different patterns of conventional generation availability. These patterns are expected to be driven, among others, by market reforms that are due to take be implemented in the coming years (eg capacity mechanism in France) and the characteristics of the markets (eg the Netherlands is a favourable location for new investment due to its geographical location and high interconnection capacity with its neighbouring countries). This could lead to periods of tight margins in one market while margins are high in another market.

4.34. It is therefore not possible to conclude on which direction flows will travel. Even though we expect demand in GB and its interconnected markets to continue to move in similar patterns, in the future, GB and its interconnected markets may or may not face concurrent periods of tight supply, depending on the evolution of supply in all markets.

Historical analysis

4.35. GB and its interconnected markets have all experienced high levels of security of supply in the last decade. It is therefore not possible to analyse how they have behaved during periods of very tight or negative margins[143].

4.36. We have evaluated the number of periods in which available capacity margins were lower than 15% in GB and France in the recent past. We observed that the occurrence of historical margins below 15% in GB varies significantly from year to year, although it is largely concentrated in the winter season. In addition, the coincidence of low margins in both GB and France also varies significantly year on year.

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[143]We refer here to realised margins in the past as opposed to expected de-rated margins as projected in the Capacity Assessment report.

4.37. The analysis showed that, for margins below 15%, which is low compared to the normal level of margins experienced in recent years, interconnector flows have not consistently improved or worsened the margins in GB. For margins below 30% the interconnector flows have generally contributed to improve the security of supply outlook in GB.

4.38. We have also analysed how interconnector flows have responded in the past to changes on the main GB market parameters: demand, de-rated margins, availability of conventional generation, availability of wind power, and prices. The purpose of this analysis was to try and identify the main drivers of GB interconnector flows. However, no significant drivers could be identified. The statistical part of this analysis was also undertaken by Pöyry on behalf of Ofgem.

Drivers of GB interconnector flows

4.39. This section presents the analysis of the correlation between GB net interconnector flows and key market parameters in GB (eg de-rated margins. demand and available supply) during winter peak hours. In addition, we discuss the correlation between GB net flows and the key parameters of the relevant markets.

4.40. The results of this analysis show that the correlations between historical GB net flows and the GB demand and supply availability are low and variable. Historical GB interconnector flows have not been responding only to the situation in the GB market.

4.41. In addition we have estimated the correlation of GB imports with margins in GB. These correlations are predominantly negative. This could indicate that there have been more hours where low GB margins were associated with imports to GB, and vice versa. However, the correlations are weak and variable and therefore we cannot draw strong conclusions based on them.

4.42. We have undertaken a correlation analysis of the net flows for GB with the market parameters of our directly interconnected markets. We observe that historical GB margins have a weak correlation with the market parameters in the relevant markets. This means that GB interconnector flows have not been strictly responding to the market conditions in our interconnected markets.

Historical analysis of price differentials[144]

4.43. In this section we present a price differential analysis between GB and its interconnected markets. This analysis considers day-ahead prices from 2008 to 2012.

4.44. The results of this analysis demonstrate that only Ireland and GB have shown a consistent pattern, with GB prices being consistently and significantly lower than prices in Ireland. The differences with other markets are variable in direction and magnitude. In addition price differentials are expected to change in the future given market changes and reforms currently under development in the different markets, for example: EMR in GB, Capacity Mechanism in France, nuclear phase-out in Germany and Switzerland, and the implementation of market coupling.

Historical flows

4.45. In this section we discuss historical flows on the GB interconnectors with Ireland, France and the Netherlands. In particular, we have analysed the flows patterns with our

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[144] This analysis was undertaken by Pöyry Management Consulting on behalf of Ofgem.

interconnected markets and the responsiveness of the interconnectors to prices. It is not possible to identify a consistent pattern of interconnector flows with mainland Europe. On the contrary, GB has consistently exported to Ireland during winter time.

4.46. In addition, analysis of historical flows with France indicates that the IFA[145] interconnector has shown limited responsiveness to prices in the past, as is shown on Figure 67. Market coupling is expected to be implemented in North-west Europe in 2013, dramatically changing the current market arrangements on the IFA interconnector and increasing price responsiveness.

Figure 67: IFA flows and prices from January 2012 to September 2012[146]
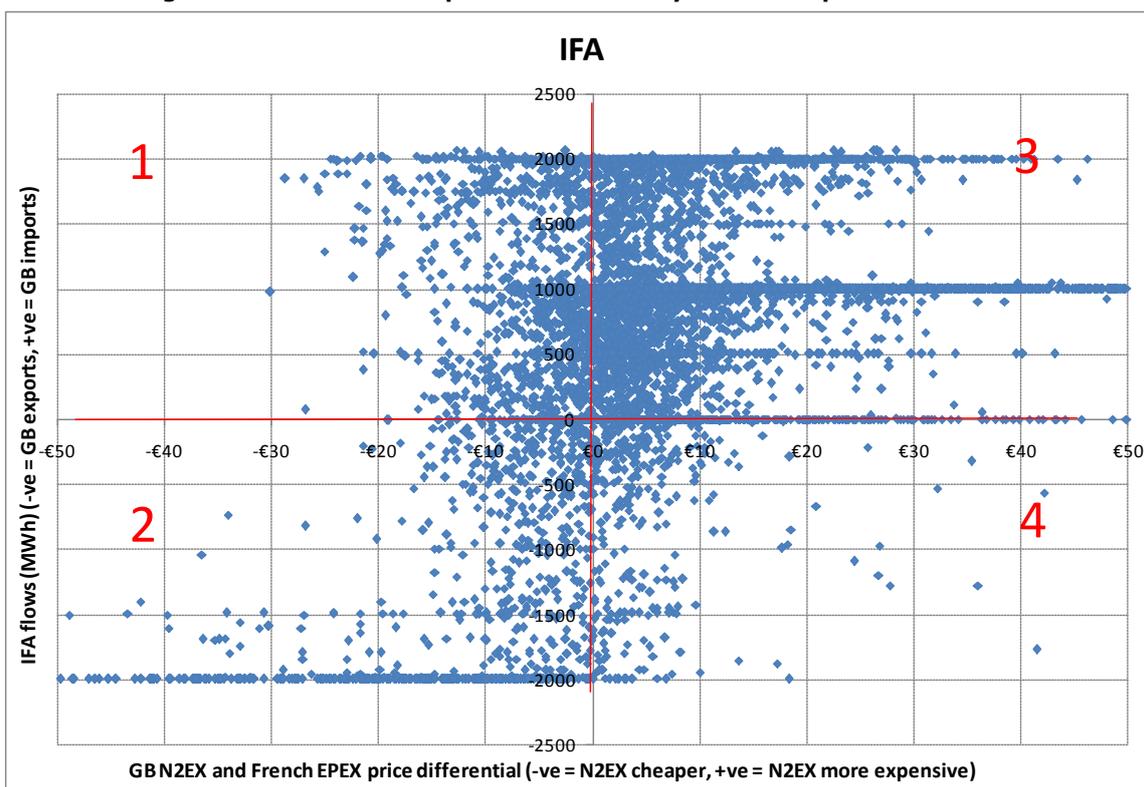
4.47. Market coupling is already implemented in BritNed[147]; however, market arrangements are being adjusted to increase price responsiveness in the flows, which has been limited during the period of operation. This is illustrated on Figure 68.

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[145] Interconnexion France Angleterre: the England-France interconnector

[146] 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 sector 4 represent exports from GB when the price in GB is higher than the price in France (sources: Ofgem and Bloomberg).

[147] BritNed is a joint venture of Dutch TSO TenneT and British National Grid and operates the electricity link between Great Britain and The Netherlands which was commissioned in 2011.

Figure 68: BritNed flows and prices from January 2012 to September 2012
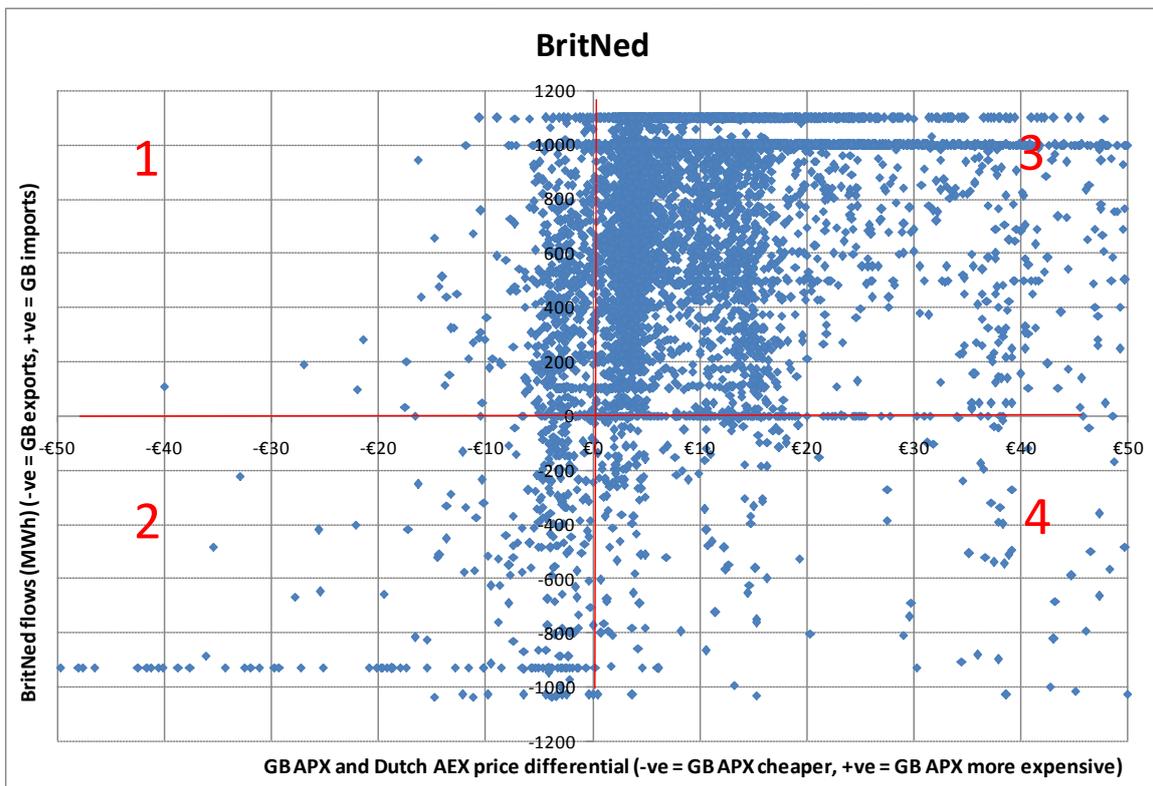
Conclusions

4.48. Based on this analysis, we conclude that historical GB interconnector flows have not been strictly dependent on conditions in GB or its interconnected markets. This suggests that GB interconnector flows have been influenced by a combination of factors.

4.49. In addition, price responsiveness has been limited on the interconnectors with mainland Europe. There is no consistent pattern of flows with the markets in mainland Europe and price differentials between these markets have been variable in direction and magnitude. With the implementation of market coupling from winter 2013/14 we can broadly expect flows to follow the direction of higher prices in the future. However, it is very difficult to assess the level of prices in GB and its interconnected markets in the next six winters to be able to determine price differentials and flow directions.

4.50. On the other hand, our analysis of historical price differentials demonstrates that Ireland and GB have shown a consistent pattern, with GB prices being consistently and significantly lower than prices in Ireland in the past. GB has been historically a net exporter of electricity to Ireland.

Reference Scenario assumptions

4.51. From the above two analyses, we conclude that we can only anticipate with a significant degree of certainty that GB will export electricity to Ireland in the next six winters, based on historical price differentials and flows between the two markets. With regards to the interconnectors with mainland Europe at periods of low margins, on average:

- We may or may not import electricity from the Netherlands depending, among others, on the situation in the German and Belgian markets, and potential mothballing decisions around Europe.

- We may or may not import from or export to France depending on the evolution of the market in France and its interconnected markets , including Germany and Belgium.

Appendix 5– Detailed results tables

Table 28: Adjusted (ie largest infeed loss and net-flows) ACS peak demand by study and sensitivity

Adjusted ACS peak demand [MW]	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
Reference Scenario 2013	57,000	56,600	56,040	55,350	54,490	53,790
Low Supply	57,000	56,600	56,040	55,350	54,490	53,790
High Supply	57,000	56,600	56,040	55,350	54,490	53,790
Conventional Generation Low Availability	57,000	56,600	56,040	55,350	54,490	53,790
Conventional Generation High Availability	57,000	56,600	56,040	55,350	54,490	53,790
Wind Generation Availability	57,000	56,600	56,040	55,350	54,490	53,790
Low Demand	56,733	56,110	55,596	55,040	54,205	53,369
High Demand	57,273	57,658	57,586	57,623	57,700	57,772
Full Imports	54,000	53,600	53,040	52,350	51,490	50,790
Half Imports	55,500	55,100	54,540	53,850	52,990	52,290
Half Exports	58,500	58,100	57,540	56,850	55,990	55,290
No Net Interconnector Flows	56,250	55,850	55,290	54,600	53,740	53,040
Demand-side response	57,200	57,000	56,640	56,250	55,590	55,190
National Grid Gone Green 2013	56,250	55,850	55,290	54,600	53,740	53,040

Table 29: ACS peak demand by study and sensitivity

ACS peak demand [MW]	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
Reference Scenario 2013	55,550	55,150	54,590	53,900	53,040	52,340
Low Supply	55,550	55,150	54,590	53,900	53,040	52,340
High Supply	55,550	55,150	54,590	53,900	53,040	52,340
Conventional Generation Low Availability	55,550	55,150	54,590	53,900	53,040	52,340
Conventional Generation High Availability	55,550	55,150	54,590	53,900	53,040	52,340
Wind Generation Availability	55,550	55,150	54,590	53,900	53,040	52,340
Low Demand	55,283	54,660	54,146	53,590	52,755	51,919
High Demand	55,823	56,208	56,136	56,173	56,250	56,322
Full Imports	55,550	55,150	54,590	53,900	53,040	52,340
Half Imports	55,550	55,150	54,590	53,900	53,040	52,340
Half Exports	55,550	55,150	54,590	53,900	53,040	52,340
No Net Interconnector Flows	55,550	55,150	54,590	53,900	53,040	52,340
Demand-side response	55,550	55,150	54,590	53,900	53,040	52,340
National Grid Gone Green 2013	55,550	55,150	54,590	53,900	53,040	52,340

Table 30: Loss of load expectation by study and sensitivity

LOLE [hours/year]	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
Reference Scenario 2013	0.72	1.73	2.85	0.68	0.13	0.30
Low Supply	1.00	3.96	4.76	2.95	1.03	1.93
High Supply	0.21	0.16	0.67	0.16	0.03	0.02
Conventional Generation Low Availability	6.65	11.83	15.94	5.67	1.65	2.68
Conventional Generation High Availability	0.02	0.10	0.23	0.03	0.00	0.01
Wind Generation Availability	1.58	3.70	6.06	1.63	0.37	0.87
Low Demand	0.55	1.11	1.98	0.50	0.09	0.19
High Demand	0.93	4.06	8.73	4.57	2.64	7.20
Full Imports	0.02	0.07	0.15	0.02	0.00	0.01
Half Imports	0.14	0.40	0.74	0.14	0.02	0.06
Half Exports	2.80	5.84	8.84	2.63	0.64	1.25
No Net Interconnector Flows	0.33	0.86	1.49	0.32	0.05	0.13
Demand-side response	0.87	2.42	4.53	1.55	0.42	1.11
National Grid Gone Green 2013	0.23	0.62	1.07	0.14	0.04	0.09

Table 31: Expected energy unserved by study and sensitivity

EEU [MWh]	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
Reference Scenario 2013	659	1,746	3,070	628	106	265
Low Supply	944	4,416	5,480	3,203	1,007	2,076
High Supply	175	132	620	133	18	14
Conventional Generation Low Availability	8,226	15,989	22,702	6,972	1,773	3,119
Conventional Generation High Availability	16	71	178	19	2	8
Wind Generation Availability	1,516	3,931	6,907	1,579	313	816
Low Demand	493	1,069	2,028	448	75	164
High Demand	881	4,605	11,130	5,380	2,989	9,714
Full Imports	15	55	117	14	1	5
Half Imports	114	352	680	109	15	43
Half Exports	2,995	6,895	11,139	2,834	597	1,283
No Net Interconnector Flows	283	808	1,487	270	41	110
Demand-side response	816	2,554	5,203	1,571	381	1,134
National Grid Gone Green 2013	190	562	1,031	115	26	69

Table 32: De-rated capacity margin by study and sensitivity in MW

De-rated capacity margin [MW]	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
Reference Scenario 2013	3,561	2,686	2,133	3,511	4,854	4,176
Low Supply	3,228	1,794	1,578	2,093	3,113	2,507
High Supply	4,644	4,826	3,543	4,726	6,079	6,294
Conventional Generation Low Availability	1,503	728	295	1,653	3,017	2,500
Conventional Generation High Availability	5,615	4,634	3,963	5,378	6,710	5,873
Wind Generation Availability	2,821	1,902	1,315	2,715	4,046	3,286
Low Demand	3,798	3,110	2,507	3,775	5,095	4,519
High Demand	3,322	1,778	841	1,614	2,213	855
Full Imports	6,257	5,328	4,721	6,123	7,462	6,698
Half Imports	4,901	3,996	3,415	4,805	6,144	5,420
Half Exports	2,239	1,392	871	2,243	3,590	2,966
No Net Interconnector Flows	4,229	3,338	2,771	4,155	5,494	4,794
Demand-side response	3,385	2,342	1,629	2,753	3,932	3,058
National Grid Gone Green 2013	4,535	3,638	3,084	4,790	5,790	5,134

Table 33: De-rated capacity margin by study and sensitivity in %

De-rated capacity margin [%]	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
Reference Scenario 2013	6.25%	4.75%	3.81%	6.34%	8.91%	7.76%
Low Supply	5.66%	3.17%	2.82%	3.78%	5.71%	4.66%
High Supply	8.15%	8.53%	6.32%	8.54%	11.16%	11.70%
Conventional Generation Low Availability	2.64%	1.29%	0.53%	2.99%	5.54%	4.65%
Conventional Generation High Availability	9.85%	8.19%	7.07%	9.72%	12.31%	10.92%
Wind Generation Availability	4.95%	3.36%	2.35%	4.91%	7.42%	6.11%
Low Demand	6.69%	5.54%	4.51%	6.86%	9.40%	8.47%
High Demand	5.80%	3.08%	1.46%	2.80%	3.84%	1.48%
Full Imports	11.59%	9.94%	8.90%	11.70%	14.49%	13.19%
Half Imports	8.83%	7.25%	6.26%	8.92%	11.59%	10.37%
Half Exports	3.83%	2.40%	1.51%	3.95%	6.41%	5.36%
No Net Interconnector Flows	7.52%	5.98%	5.01%	7.61%	10.22%	9.04%
Demand-side response	5.92%	4.11%	2.88%	4.90%	7.07%	5.54%
National Grid Gone Green 2013	8.06%	6.51%	5.58%	8.77%	10.77%	9.68%

Table 34: Wind equivalent firm capacity by study and sensitivity in MW

EFC [MW]	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
Reference Scenario 2013	2,364	2,612	2,864	2,800	2,940	3,436
Low Supply	2,400	2,742	2,962	3,048	3,252	3,820
High Supply	2,244	2,340	2,642	2,622	2,760	3,076
Conventional Generation Low Availability	2,714	2,996	3,284	3,238	3,414	3,982
Conventional Generation High Availability	2,010	2,218	2,436	2,370	2,486	2,910
Wind Generation Availability	1,624	1,828	2,046	2,004	2,132	2,546
Low Demand	2,334	2,546	2,794	2,754	2,896	3,358
High Demand	2,398	2,762	3,118	3,176	3,510	4,096
Full Imports	2,060	2,254	2,452	2,412	2,548	2,958
Half Imports	2,204	2,422	2,646	2,594	2,730	3,180
Half Exports	2,542	2,818	3,102	3,032	3,176	3,726
No Net Interconnector Flows	2,282	2,514	2,752	2,694	2,830	3,304
Demand-side response	2,388	2,668	2,960	2,942	3,118	3,718
National Grid Gone Green 2013	2,248	2,474	2,702	2,602	2,786	3,244

Table 35: Wind equivalent firm capacity by study and sensitivity in %

EFC [%]	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
Reference Scenario 2013	23.16%	23.14%	22.93%	20.29%	17.58%	17.08%
Low Supply	23.51%	24.29%	23.72%	22.08%	19.45%	18.99%
High Supply	21.98%	20.73%	21.15%	19.00%	16.51%	15.29%
Conventional Generation Low Availability	26.59%	26.55%	26.29%	23.46%	20.42%	19.80%
Conventional Generation High Availability	19.69%	19.65%	19.50%	17.17%	14.87%	14.47%
Wind Generation Availability	15.91%	16.20%	16.38%	14.52%	12.75%	12.66%
Low Demand	22.86%	22.56%	22.37%	19.95%	17.32%	16.70%
High Demand	23.49%	24.47%	24.96%	23.01%	20.99%	20.37%
Full Imports	20.18%	19.97%	19.63%	17.48%	15.24%	14.71%
Half Imports	21.59%	21.46%	21.19%	18.80%	16.33%	15.81%
Half Exports	24.90%	24.97%	24.84%	21.97%	19.00%	18.53%
No Net Interconnector Flows	22.35%	22.27%	22.03%	19.52%	16.93%	16.43%
Demand-side response	23.39%	23.64%	23.70%	21.32%	18.65%	18.49%
National Grid Gone Green 2013	22.02%	21.92%	21.63%	18.85%	16.66%	16.13%

Table 36: Total installed conventional capacity by study and sensitivity in MW

Installed Conventional capacity [MW]	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
Reference Scenario 2013	67,739	65,941	64,336	65,224	65,634	63,441
Low Supply	67,289	64,749	63,594	63,292	63,247	61,054
High Supply	69,151	68,799	66,254	66,862	67,287	66,357
Conventional Generation Low Availability	67,739	65,941	64,336	65,224	65,634	63,441
Conventional Generation High Availability	67,739	65,941	64,336	65,224	65,634	63,441
Wind Generation Availability	67,739	65,941	64,336	65,224	65,634	63,441
Low Demand	67,739	65,941	64,336	65,224	65,634	63,441
High Demand	67,739	65,941	64,336	65,224	65,634	63,441
Full Imports	67,739	65,941	64,336	65,224	65,634	63,441
Half Imports	67,739	65,941	64,336	65,224	65,634	63,441
Half Exports	67,739	65,941	64,336	65,224	65,634	63,441
No Net Interconnector Flows	67,739	65,941	64,336	65,224	65,634	63,441
Demand-side response	67,739	65,941	64,336	65,224	65,634	63,441
National Grid Gone Green 2013	68,140	66,342	64,762	66,080	66,035	63,911

Table 37: Installed capacity per generation type for the Reference Scenario in MW

| Installed capacity per generation type [MW]	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
Biomass	1,410	2,730	2,355	3,800	3,895	3,895
Coal - LCPD Opted-In	19,465	18,600	18,180	16,575	16,575	16,575
Coal - LCPD Opted-Out	975	0	0	0	0	0
Gas - CCGT	28,530	27,750	28,240	29,265	29,565	27,360
Gas - CHP	1,700	1,700	1,700	1,700	1,700	1,700
Gas - GT	755	755	595	620	620	620
Hydro	1,115	1,115	1,115	1,115	1,115	1,115
Nuclear	9,470	8,980	8,980	8,980	8,980	8,980
OCGT	430	430	430	430	430	430
Oil	1,140	1,140	0	0	0	0
Pumped Storage	2,745	2,745	2,745	2,745	2,745	2,745
Tidal	0	0	0	0	10	20
Wind - Offshore	3,970	4,500	4,925	5,200	6,725	8,405
Wind - Onshore	6,235	6,790	7,565	8,600	9,995	11,705

Table 38: Installed capacity changes by generation type for the Reference Scenario in MW

Installed capacity changes by generation type [MW]	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
Closures Nuclear	0	-490	0	0	0	0
Closures Coal	-2,780	-1,845	-420	-1,605	0	0
Closures CCGT	-800	-780	0	-140	-155	-2,205
Closures GT	0	0	-165	0	0	0
Closures Oil	-1,000	0	-1,140	0	0	0
Closures Biomass	-740	0	-740	0	0	0
Additions CCGT	1,555	0	490	1,165	455	0
Additions Biomass	1,365	1,315	365	1,445	100	0
Additions Wind Onshore	455	550	780	1,035	1,390	1,715
Additions Wind Offshore	740	525	425	275	1,525	1,680

Table 39: Installed capacity changes per generation technology type in the low and high supply sensitivities

Installed capacity changes per generation technology type [MW]	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
Biomass (Low Supply)	0	-740	-740	-740	-740	-740
Oil (Low Supply)	-450	-450	0	0	0	0
CCGT (Low Supply)	0	0	0	-1,190	-1,645	-1,645
Nuclear (High Supply)	0	490	0	0	0	0
CCGT (High Supply)	1,400	2,370	1,920	1,640	1,655	2,915

Figure 69: GB Reference Scenario LOLE and Reliability standards set by other markets
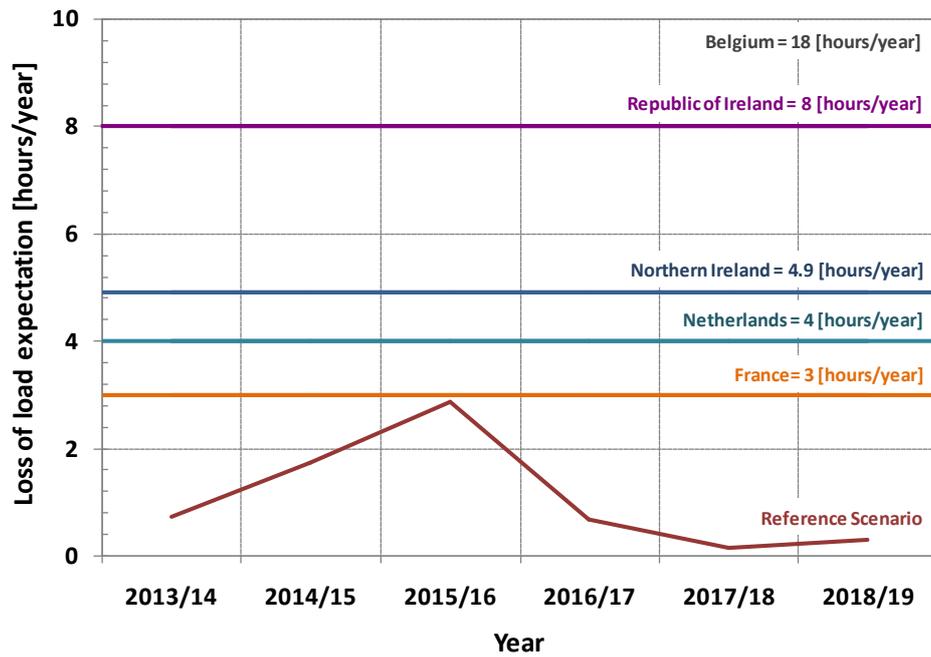
Appendix 6 – Glossary

A

ACS

Average Cold Spell.

B

BETTA

British Electricity Trading Transmission Arrangements.

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 market (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.

Capacity sterilisation

Capacity sterilisation refers to a situation where generation capacity is effectively not accessible to the system operator due to specific circumstances (eg located behind transmission constraints).

Carbon Price Floor

The carbon price floor is a tax on fossil fuels used in the generation of electricity. This is achieved through changes to the existing Climate Change Levy (CCL) regime in the case of gas, solid fuels and liquefied petroleum gas (LPG) used in electricity generation. These changes include the setting up of new carbon price support (CPS) rates of CCL.

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, eg 1kWh used over half an hour is a demand rate of 2kW. 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 average excess of available generation capacity over peak demand, expressed in percentage terms. Available generation capacity takes into account the contribution of installed capacity at peak demand by adjusting it by the appropriate de-rating (or availability) factors which take into account the fact that plant are sometimes unavailable due to outages.

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.

Equivalent firm capacity (EFC)

It is the quantity of firm capacity (ie always available) that can be replaced by a certain volume of wind generation to give the same level of security of supply, as measured by LOLE. This measure is used to calculate the average contribution of wind power to the de-rated margin. It varies with the proportion of wind power in the system.

Expected energy unserved

It is 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.

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.

G

GB

Great Britain.

Gigawatt (GW)

The gigawatt is equal to one billion watts (ie 1 gigawatt = 1,000,000,000 watts). The watt symbol: W) is a derived unit of power in the International System of Units. Power is the rate at which energy is generated or consumed and hence is measured in units (eg watts) that represent "energy transfered per unit time".

I

IFA

Interconnexion France Angleterre. The England-France Interconnector is a 2,000MW high voltage direct current (HVDC) link between the French and British transmission systems with ownership shared between National Grid and Réseau de Transport d'Electricité (RTE).

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.
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)

It is the mean number of hours per year in which supply does not meet demand in the absence of intervention from the System Operator.

M

Maximum Export Limit (MEL)

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

Megawatt (MW)

The megawatt is equal to one million watts (ie 1 megawatt = 1,000,000 watts). The watt symbol: W) is a derived unit of power in the International System of Units. Power is the rate at which energy is generated or consumed and hence is measured in units (eg watts) that represent "energy transferred per unit 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 or National Grid Electricity Transmission plc (NGET)

National Grid 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.

NETS SQSS

National Electricity Transmission System Security and Quality of Supply Standard.

NETS SYS

National Electricity Transmission System Seven Year Statement.

NI

Northern Ireland.

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.

R

ROI

Republic of Ireland.

RTE

Réseau de transport d'électricité. RTE, an independent subsidiary of EDF, is the French electricity transmission system operator. It is a public service company responsible for operating, maintaining and developing the high and extra high voltage network. It guarantees the reliability and proper operation of the power network.

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

SEM

The Single Electricity Market. SEM is the wholesale electricity market operating in the Republic of Ireland and Northern Ireland. As a gross mandatory pool market operating with dual currencies and in multiple jurisdictions the SEM represents the first market of its kind in the world.

SEMO

Single Electricity Market Operator. SEMO is the single electricity market operator for the Republic of Ireland and Northern Ireland.

Sensitivity

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

SONI

System Operator for Northern Ireland. SONI is the licensed independent electricity Transmission System Operator (TSO). It is responsible for the safe, secure, efficient and reliable operation of the high voltage electricity system in Northern Ireland.

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 ("the Authority"), the regulator of the gas and electricity industries in Great Britain.

U

UKERC

UK Energy Research Centre.

W

WOR

Winter Outlook Report.