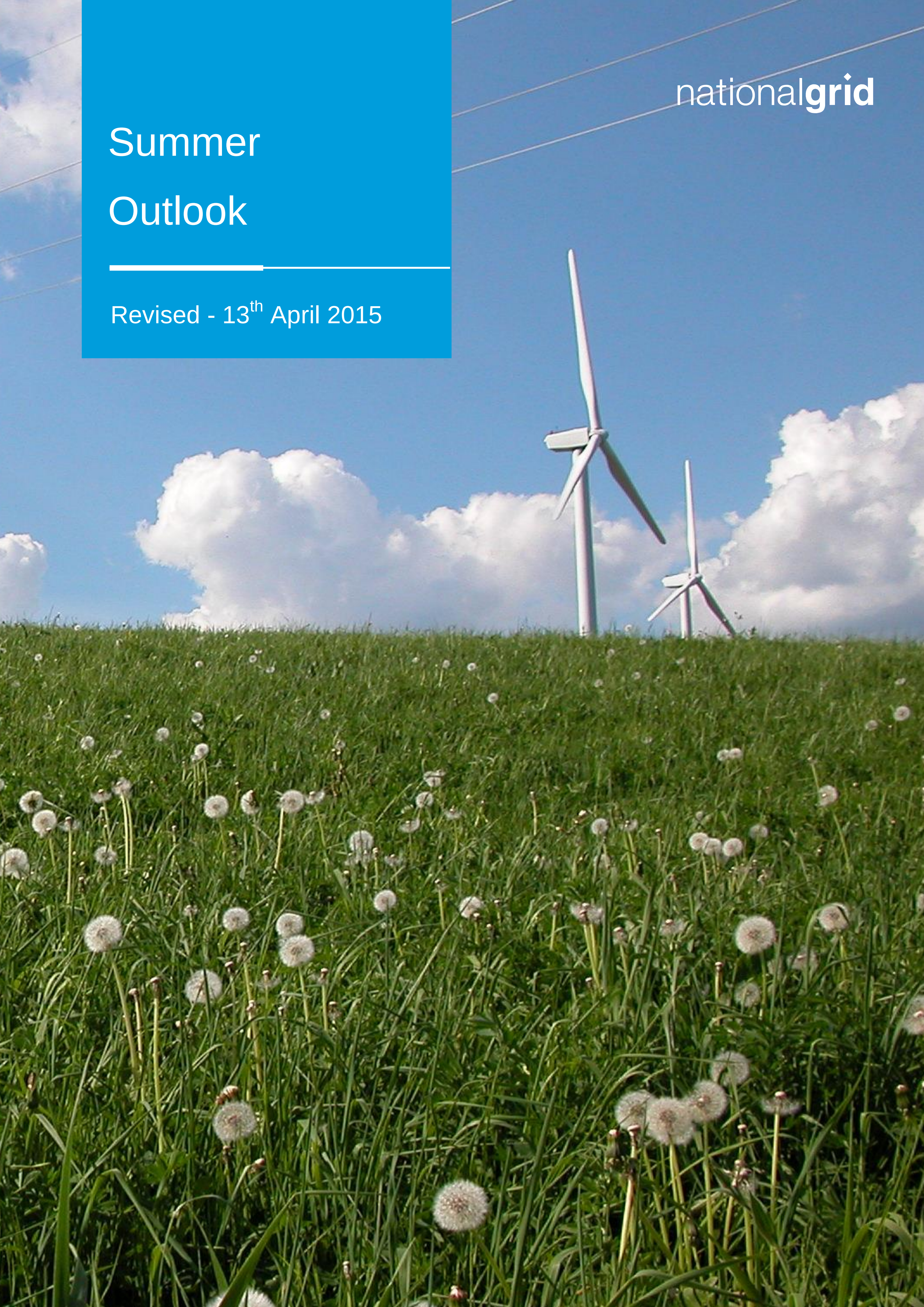
Summer Outlook

Revised - 13th April 2015



nationalgrid

Roles and Responsibilities

National Grid owns the high-voltage electricity transmission network in England and Wales and is the System Operator of the high-voltage electricity transmission network – the country's power motorways - for the whole of Great Britain. We are responsible for managing the flows of electricity to homes and businesses on a real time basis.

We don't generate the power - neither do we sell it to consumers. We all pay our bills to energy suppliers, who buy enough electricity to meet their customers' needs from the power stations and other electricity producers.

Once that electricity enters our network, our job is to 'fine tune' the system to make sure supply and demand match second by second.

On the gas side, we are the system owner and operator of the gas transmission network for the whole of Great Britain, responsible for managing the flow of gas to homes and businesses.

Like electricity, we do not own the gas we transport and neither do we sell it to consumers, that again is the responsibility of energy suppliers and shippers.

Together, these networks connect people to the energy they use.

Introduction

Welcome to our 2015 Summer Outlook Report. It presents our view of the gas and electricity systems for the summer, which can help the energy industry plan ahead for the coming months. As the country's System Operator for the gas and electricity transmission networks we work alongside power generators, energy suppliers, gas shippers, analysts and others in the energy industry to meet the challenges we will face.

I am pleased to say that supplies of both gas and electricity look to be adequate for the summer period and our networks are in good shape to meet the operational challenges of the coming months. Despite periods of low demand, summers are challenging as many of the winter hurdles we face as the System Operator are replaced with new ones.

The complexity of operating the gas network is increasing, with two main issues. We have an increase in the variety of supply sources and it's not easy to predict where the gas will be coming from. We also have gas and electricity interactions, with gas fired power generation currently marginal plant, and a growing amount of intermittent electricity generation adding to the unpredictability of flows.

Turning to electricity, our greatest challenges come from the continuing trend of falling peak energy demand and lower minimum demand levels, and the associated system operability issues. As such it is this challenge where we will focus our efforts through the summer.

With this in mind, we've taken a fresh approach to this year's report. We've acted on feedback from our stakeholders and we're making the report more useful and relevant. As well as improving our explanation of the key system operability issues, we have expanded the scope of the report to include case studies on current issues affecting the industry. These include the negative prices experienced in August 2014, and how we manage surges in demand caused by major summer television events.

The views of our stakeholders are crucial as we enter a period where the energy industry has to meet the challenge of providing secure, affordable and sustainable energy. To facilitate that change, we are trying to provide better quality information to the market in a more usable format. We value your opinion and to this end, we have made a step change in our engagement with stakeholders on the suite of annual Market Outlook Reports. We have been reviewing what stakeholders want from them. We are collating this feedback and will make those changes to the reports throughout 2015, ensuring that they better meet the needs of the growing audience.

Thank you for taking the time to read this year's report. I hope you find it helpful and encourage you to let us have any comments or feedback at marketoutlook@nationalgrid.com.

Cordi O'Hara
Director, Market Operation
National Grid

Executive Summary

Fuel Prices

Fuel prices suggest that coal will be favoured over gas for power generation by a small margin…

For summer 2015 the forward prices suggest that coal will still be the favoured fuel for generation, even after the increase in the carbon price on April 1st is taken into consideration. However, the effective price of the two fuels is very close and it would only take a small change in either to increase competition between the two.

The prices of gas in the European and Asian markets suggest that LNG deliveries to Europe may be favoured over East Asia.

For the summer ahead the two most important issues to consider in fuel pricing are:

- the relative price of gas in the GB spot market (NBP gas) and the East Asia markets, which is likely to influence the destination of liquefied natural gas (LNG) cargoes.
- the relative price of gas and coal in the UK power generation market, which is likely to influence the choice of fuel for base load and marginal generation through the summer.

Gas

Demand is forecast to be met by a range of supplies with some margin…

There is a wide range of possible sources of gas supply to GB, with total supply capacity well in excess of expected summer demand.

Supplies from the UK Continental Shelf and Norway are expected to be similar to last year and make up the majority of the total. Flows from continental Europe may be lower than last year due to production restrictions at the Groningen field in the Netherlands.

LNG supplies have, as mentioned in previous Summer Outlook and Winter Outlook Reports, been difficult to predict. There are a number of influences affecting availability. Demand in East Asia is one; for summer 2015 the demand may be affected by changes to the generation mix from Japan. This includes the timing of any re-introduction of nuclear generation and the relative price of oil affecting the mix of oil and gas powered generation.

Although balance of continental supplies and LNG is hard to predict, we expect that the combined supply will be enough to ensure that summer demand is met.

Capacity at the Rough storage site has recently been reduced, and there has been a corresponding change to the injection regime. Despite this, net injection over the summer is expected to be higher than last year as stock levels were lower than last year at the end of the winter.

Executive Summary

Further demand variability with increasingly diverse supply patterns continues to increase network operability challenges…

Supply diversity in the UK, and the available margin of supply above demand helps support demand security throughout the year but the uncertainty over which sources of supply will be utilised on any given day, particularly LNG, storage and European interconnection, leads to greater operational unpredictability. This is further exacerbated by the variability of demand due to the increasing interaction between marginal gas fired power generation and renewable generation, as well as increased medium range storage injection and withdrawal operations.

Unpredictability makes all aspects of system operability more challenging and requires greater network flexibility during the summer period to accommodate the range of daily and within day supply and demand scenarios that we may see. Historically the flexibility of the network and the effectiveness of current operational tools have enabled the majority of customer requirements to be met with minimum SO intervention. However as these demands for more agile flow profile characteristics continue, the burden on system dynamic need becomes increasingly challenging without more direct SO intervention being likely.

Electricity

System operability is the main focus for the System Operator in the summer…

The level of generation availability is expected to be adequate to meet demand over the summer; system operability will be our main focus during this period.

During low demand periods, we may be required to curtail or buy off flexible generators or increase demand through demand-side response to keep the system secure. Flexible generators are electricity generation units that can quickly adapt their output, such as gas fired generation.

Flexible generators[1] will be required to maintain:

- sufficient frequency response by reducing the impact of the largest generation or demand losses;
- positive and negative regulating reserve levels to cater for forecasting errors in generation (principally wind) and energy demand;
- voltage profiles across all areas of the network;
- sufficient system inertia.

The minimum level of demand expected on the system this summer is 18.6 GW, which is 1.1 GW higher than the expected level of inflexible generation to be running at that time. This means there may be a requirement for inflexible generators to reduce their output over the summer minimums.

[1] One generator can help to balance more than one of the four issues detailed above.

Executive Summary

Generators, including most large wind farms, and demand-side response providers will be called on to provide balancing and ancillary services where required. We will take these actions in economic order to operate the system securely and efficiently at all times. As System Operator, we actively procure these ancillary services. See page for links to our ancillary services.

We are taking action to manage increasingly challenging transmission system issues…

High voltage issues have grown year on year as reactive power demand has fallen. Factors likely to be contributing to this falling reactive power demand include the growth of embedded generation and energy efficiency measures, as well as the increasing use of cables in the distribution and transmission networks.

As the summer minimum demand requirements continue to fall, periods of low demand and lightly loaded cables increase the likelihood of high voltage occurrences. The high relative proportion of embedded generation at low demand levels, where supply forecasting is significantly more complex and less predictable, further exacerbates the management of high voltage issues. In response, National Grid has put a number of actions in place to manage the occurrences in the short and medium term, including a significant capital investment programme. A similar investment programme is ongoing by the Scottish Transmission Owners, SPT and SHETL.

System inertia is the measure of how resilient the system is to changes due to disturbances in the system, for example a sudden drop in generation or demand that causes a mismatch between demand and supply. Non-synchronous generators do not contribute to system inertia.

Active management will involve a range of actions through the Balancing Mechanism, or contracts and trades done ahead of time. The System Operability Framework (SOF)[2], published annually by National Grid has been developed to study in-depth, year-round impact of Future Energy Scenarios (FES) on system operability. This document provides more detailed information on the impacts and management tools we have adopted, as well as others that are being developed.

Negative System Sell Prices (SSP), caused by a combination of low demands and inflexible generation may occur. Incidences of negative SSPs have been increasing in line with the rising percentage of renewable technologies in the generation mix. A case study on page 37 explores the conditions that led to this in August 2014. This case highlights to industry what type of conditions may lead to negative prices in the future.

[2] http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/System-Operability-Framework/

Executive Summary

Generation margins are forecast to be at a comfortable level over the summer…

Our peak weather corrected summer demand for the high summer period is our lowest ever forecast at 37.5 GW. This forecast reflects the increase in embedded solar photovoltaic (PV) installations and the peaks in generation capacity from these installations coinciding with peak energy demands.

It is likely that embedded solar generation will lead to a permanent reduction in summer peak demands. Embedded solar PV are small generation units connected to the distribution network; the capacity of these units has nearly doubled from 2.4 GW (Feb 2014) to 4.4 GW (Feb 2015) and we are expecting this capacity to increase further, with installed capacity estimated to reach 5.5 GW by Feb 2016.

The System Operator does not receive live metered data from embedded PV. It is a major contributor to the trend of decreasing demand and we now publish seven day forecasts of embedded generation every day. See page 22 for further information on this service.

Generation margins are currently forecast to be adequate over the summer, with a possibility of providing maximum export on the interconnectors without eroding the reserve requirement.

Executive Summary

Key Statistics

Gas	
Minimum demand forecast	100 mcm
Average demand forecast	182 mcm
Maximum demand forecast	350 mcm
Summer supplies *Forecasts assume similar UKCS to last year, lower LNG and potentially higher imports from Norway.*	33 bcm

Electricity	
Current generator capacity	73.5 GW
De-rated generation capacity; the amount of generation expected to be available when demand is forecast to be at its highest this summer	42.4 GW
Maximum forecast demand level	37.5 GW
Forecast margin when demand is expected to be at its highest this summer	4.9 GW
Lowest demand level forecast for this summer	18.6 GW
The difference between the lowest demand forecast and lowest level of inflexible generation expected to be running at that time	1.1 GW

Stakeholder Engagement

The energy sector is in a period of flux. As an industry, we have to meet the challenge of providing secure, affordable and sustainable energy. National Grid as System Operator sits at the heart of the energy industry and is responsible for operating both the gas and electricity networks.

The challenges of operating the systems are increasing, as is demonstrated through this Summer Outlook Report (SOR) and other National Grid reports, such as the Future Energy Scenarios report[3] and the System Operability Framework[4].

To understand the possibilities that these changes may bring, it is more important than it has ever been that we consult with our stakeholders. We have made a step change recently in our engagement with stakeholders on the suite of annual Market Outlook Reports.

We have been conducting a review into what stakeholders want from them. We are developing a strategy based on this feedback and will be implementing positive changes to the reports throughout 2015. This will ensure that they better meet the needs of their growing and broadening audience.

This SOR is the first in the suite of Market Outlook Reports for 2015. Stakeholders told us that they want the SOR to be interesting, relevant and informative. In this issue, we are focussing on operability of both the gas and electricity networks. On electricity, we include case studies on operability that bring the issues to life, with one on TV pickups and the other on negative imbalance prices.

We would like to hear your feedback on this report. Please contact us with your thoughts and comments by email at marketoutlook@nationalgrid.com.

[3] www.nationalgrid.com/fes

[4] http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/System-Operability-Framework/

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1. Fuel Prices

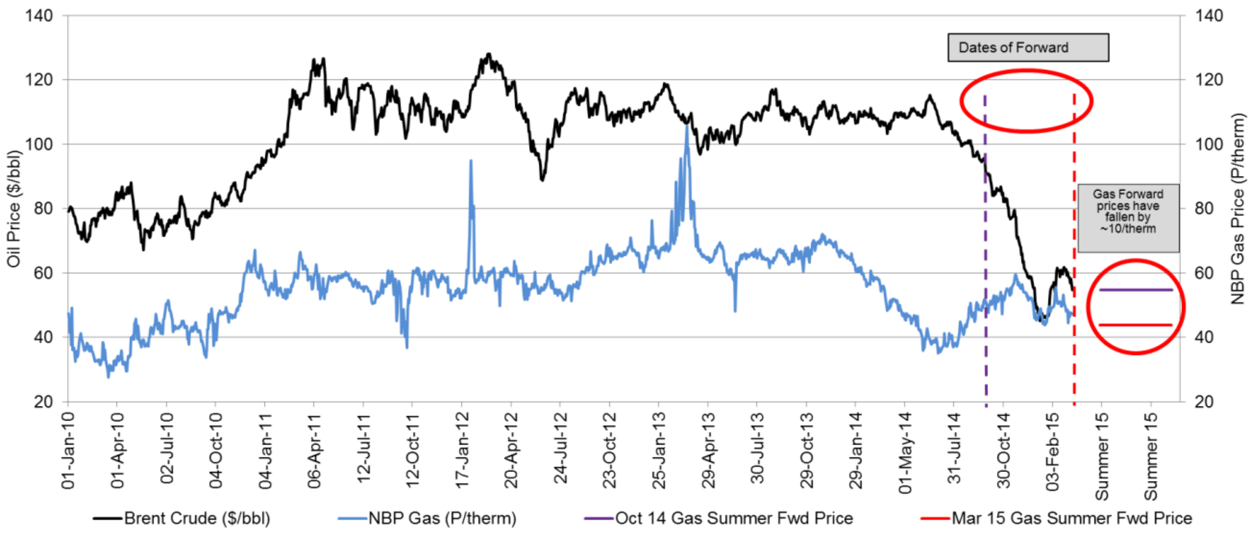
Expected coal and gas prices suggest that coal will be the preferred fuel for power generation by small margin this summer.

The prices of gas in the European and Asian markets suggest that LNG deliveries to Europe may be favoured over East Asia.

The fall in the oil price since the summer of 2014 has had a significant effect on the world energy market, and future movements in the oil price will have consequences for development of new oil and gas reserves, as well as the continuing operation of existing fields. These medium and long term effects are however largely outside the scope of our Summer Outlook document and will instead be considered in our Future Energy Scenarios document to be published in in July 2015.

While there are linkages between oil and gas prices due to the effect of associated fields and the impact of oil indexed gas imports to continental markets there are often occasions where gas market specific events will see prices trend in opposite directions. As shown in **Figure 1**, NBP prices fell in early 2014, responding to low demand and plentiful supply while the oil price remained high, but rose later in the year despite a fall in the oil price. Prices fluctuated through the winter and by mid-March the NBP price was around 3 p/th cheaper than the start of October, with the forward price for summer 2015 around 10p/th lower than the summer 2015 price recorded at the start of the winter.

Figure 1 - Brent crude oil and NBP gas prices



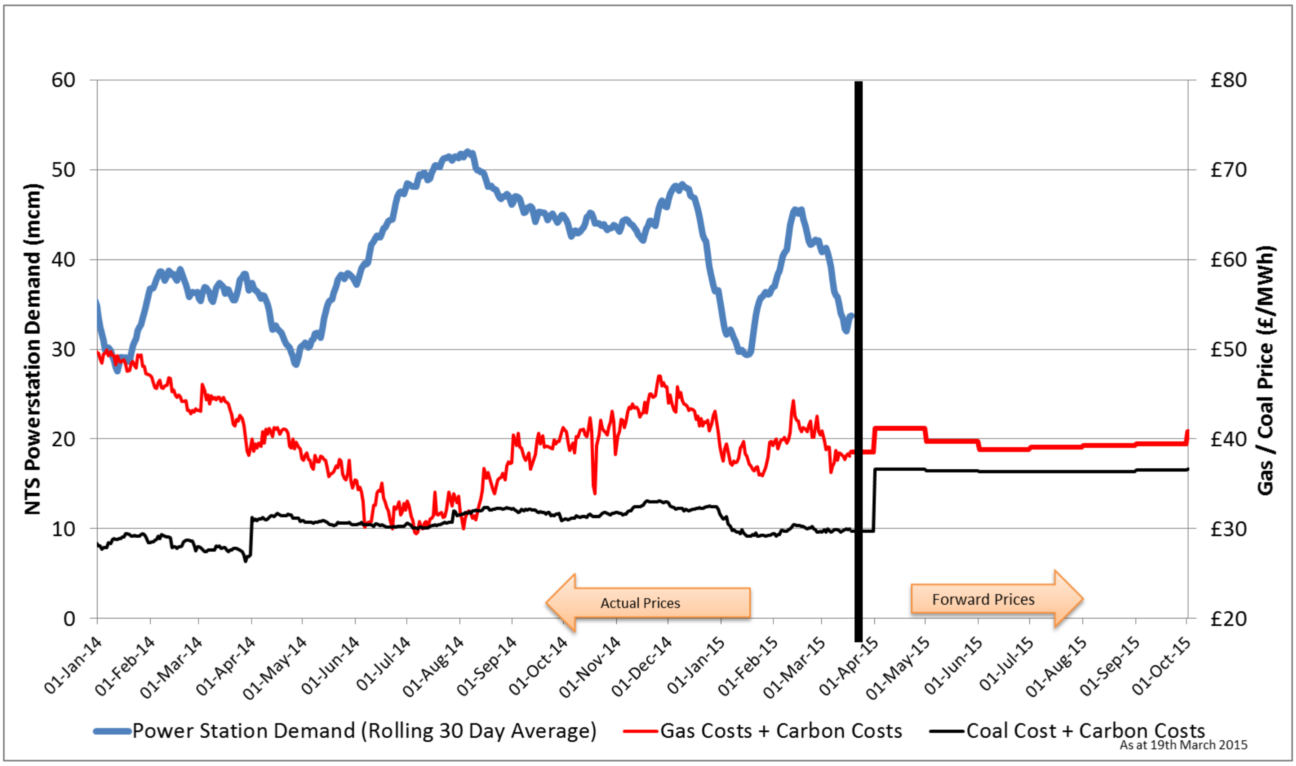
For the summer ahead the two most important issues to consider in fuel pricing are:

- the relative price of gas in the GB spot market (NBP gas) and the East Asia markets, which will influence the destination of liquefied natural gas (LNG) cargoes. Prices in the two markets this summer are expected to be closer than for some years. LNG flows are discussed in section 2;

- the relative price of gas and coal in the UK power generation market. This will determine which fuel will provide baseload generation through the summer and which fuel will provide marginal generation. See page 7 for the impact on gas demand of power generation changes due to sensitivities of gas prices.

Our analysis of the response of the power generation market to fuel prices is shown in **Figure 2**. The chart shows the gas and coal price for power generation, including the effect of the carbon price and the different efficiencies of the coal and gas fired plant. Through last summer the gas price dipped below the coal price and there was a clear, though temporary increase in gas fired generation. For summer 2015 the forward prices suggest that coal will still be the favoured fuel for generation, even after the increase in the carbon price on April 1st. However, the prices of the two fuels are very close and it would only take a small change in either to increase the level of competition between them.

Figure 2 - Coal and gas prices and power generation



2. Gas Demand

Gas demand for power generation is forecast to be lower than last summer based on an assumption that fuel prices continue to favour coal over gas. Demand in all other sectors is anticipated to be in line with last summer's demand profile.

This chapter covers the gas demand outlook for the forthcoming summer. Despite storage injection and continental exports, demands during mid-summer are about half the demands experienced in the winter. Supply availability during the summer is generally high but at times is reduced due to periods of maintenance. This can result in relatively high flow ranges in terms of supply source and entry terminals.

2.1. Weather

Figure 3 shows the historical Composite Weather Variable (CWV, essentially a proxy for temperature), seasonal normal conditions and actual conditions for summer 2014. The CWV is capped at 16°C as there is little or no influence of temperature sensitive gas demand above this. This means that in the warmer months (June, July and August) there is very little variation in CWVs.

Figure 3 - Summer composite weather

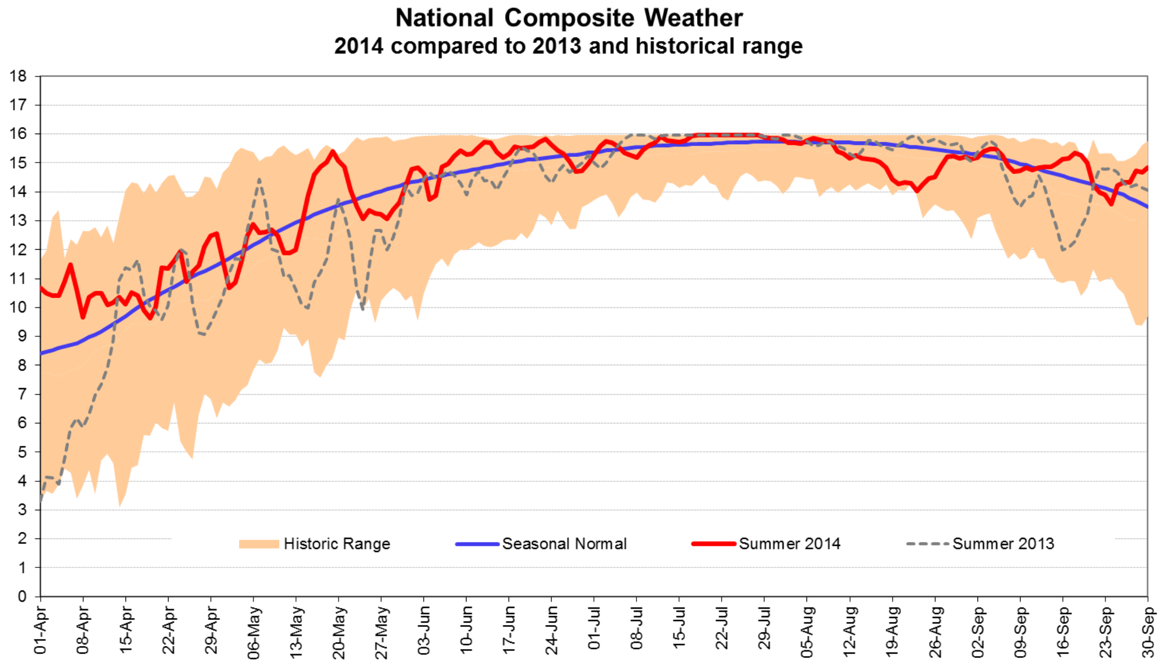


Figure 3 shows that colder conditions are essentially restricted to April, May and, to a lesser extent, September. Hence only in these months are the weather sensitive gas demands (non-daily metered i.e. domestic) noticeably influenced by the weather.

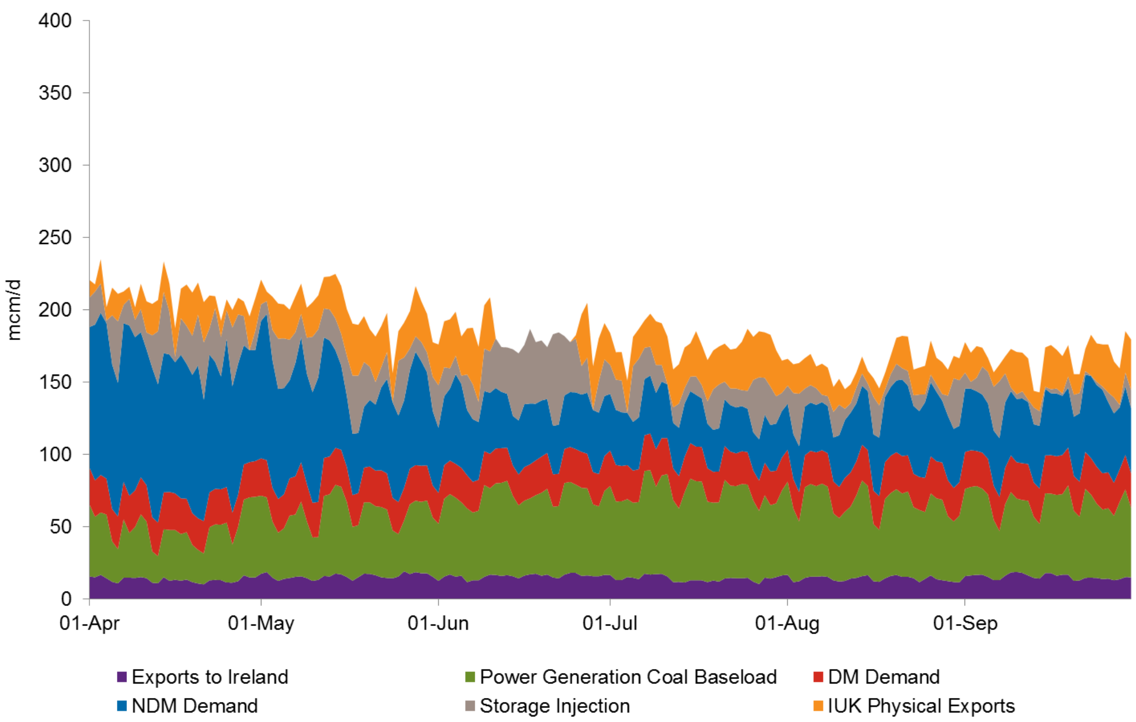
For summer 2014, April was warmer than seasonal normal conditions with seasonal normal conditions returning throughout the remainder of the summer.

2.2. Demand Forecast

Figure 4 shows the actual demands in summer 2014. Interesting features are:

- Ireland exports and daily metered (DM) demands remained largely flat over the summer and in line with projections.
- Storage injection and IUK were at higher levels throughout summer. Storage injection increased further during June and coincided with an outage at IUK.
- Non-daily metred (NDM) demand was lower than seasonal normal levels particularly during April, consistent with the warmer weather shown in **Figure 3**. This was in contrast to the previous summer period that experienced very cold April and May leading to higher demands in the summer of 2013.
- Gas for power generation was higher than forecast due to a number of factors; these included marginal price differences between coal and gas power generation. There are also increased levels of planned and un-planned outages on the coal and nuclear fleets, leading to a higher reliance on gas power generation.

Figure 4 – Actual summer gas demand 2014



Gas

Figure 5 and **Table 1** show the forecast for summer 2015. Power loads are based on coal remaining the lower cost fuel for generation.

Figure 5 - Forecast gas demand summer 2015

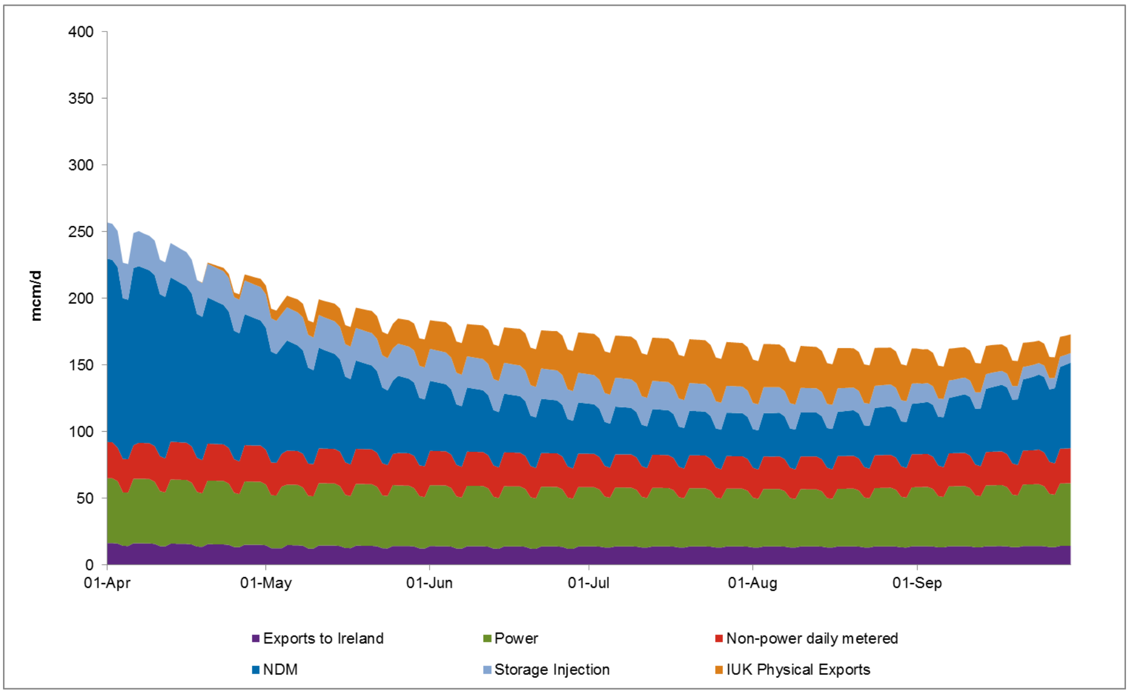


Table 1 - Forecast average daily gas demand for summer 2015 (mcm/d)

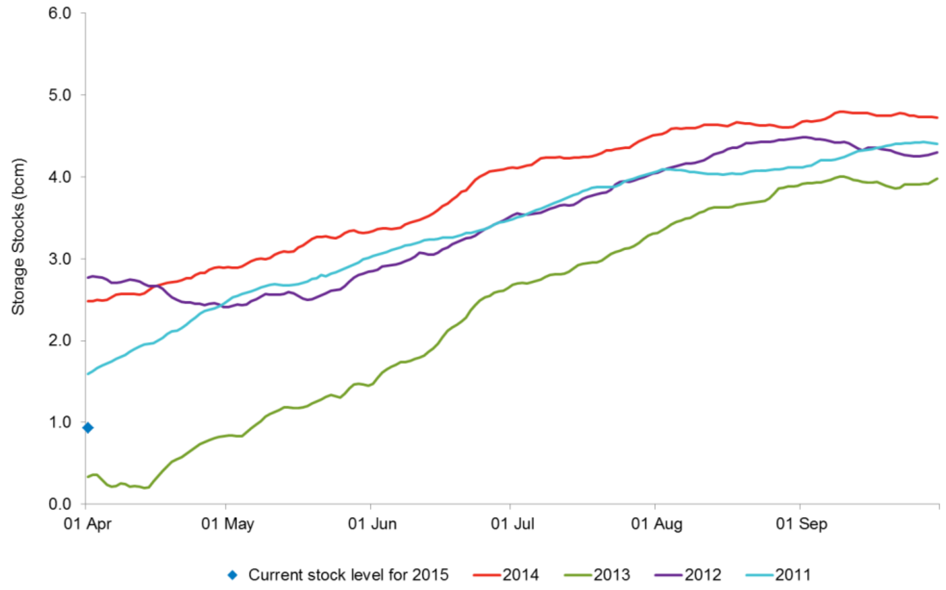
April to September	Daily average			Actual range		Forecast range	
mcm/d	2014 actual	2014 weather corrected	2015 forecast	2014 low	2014 high	2015 low	2015 High
NDM	54	57	57	26	118	20	225
DM + Industrial	24	23	25	20	27	15	35
Ireland Exports	15	15	14	10	19	10	25
Total Power	50	50	43	19	72	20	100
Total demand	144	147	141	104	200	85	350
IUK export	21	21	26	0	43	0	60
Storage injection	20	20	16	0	64	0	85
GB Total	185	168	182	142	237	100	350

Table 1 shows the daily average and forecast range in demand compared with the actual values in 2014. The 2015 forecast average values are derived using seasonal normal conditions.

For NDM daily demand we have used the previous 30 year weather history to identify the possible range of demand for 2015. We note that the range can vary considerably with very cold April, May and September conditions influencing NDM high ranges, and low storage injection and IUK export demands combining with warm mid-summer conditions influence the lower range. As an example of the wide spread, during 2013 the range reached 348 mcm during April and aligned with colder than seasonal normal conditions, and during the middle of summer levels fell to a low of 91 mcm.

IUK exports were higher in summer 2014 than in summer 2013, possibly associated with increased LNG supplies into the GB market. LNG availability is expected to be high again in summer 2015 and we are expecting correspondingly high IUK exports.

Figure 6 - Summer storage stocks 2010 – 2014



The storage stock level at the end of winter was lower than in most recent years, though still significantly higher than in 2013 when the Rough storage facility was almost empty by the end of winter. Capacity at Rough has recently[5] been reduced from 3.3 bcm to between 2.6 and 2.9 bcm, for up to 6 months, but even taking this into account the net injection over the summer is expected to be higher than last year. There have been changes to the injection regime at Rough, but these should be compatible with filling the reservoir to the new, reduced, capacity by the end of the summer.

We will report on the implications for winter gas supplies in the Winter Outlook Report in October. Note that the historical storage injection shown in **Table 1** and **Table 2** is for the total injection over the summer, including fast cycle mid-range storage sites that might be expected to inject and withdraw many times throughout the summer.

Exports to Ireland remain consistent with last summer levels. We have assumed that flows from Moffat will reduce from 1st October 2015 with the introduction of supplies into the Republic of Ireland from the Corrib gas field.

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5 http://www.centrica-sl.co.uk/index.asp?pageid=578

Gas

Power generation is projected on an assumption that fuel prices continue to favour coal over gas during summer 2015. We have a lower forecast compared with actual levels over the summer 2014. We have not made any assumptions concerning unplanned outages at specific sites and at specific periods in time. Our approach considers standard annual plant availability assumptions.

Table 2 - Total volume of summer demand for 2014 and forecast for 2015 (bcm)

bcm	2014 actual	Summer total 2014 weather corrected	2015 forecast
NDM	9.9	10.4	10.4
DM + Industrial	4.4	4.4	4.5
Ireland Exports	2.7	2.8	2.6
Total Power	9.2	9.2	7.9
GB Total	26.4	26.9	25.7
IUK Export	3.8	3.8	4.7
Storage Injection*	3.6	3.6*	2.9*
Total	33.8	34.4	33.3

*Forecast storage injection is for net injection over the summer. The 2014 actual injection is the gross position, reflecting repeated withdrawal and injection at mid-range storage sites through the season. Net injection for 2014 was 2.2 bcm

Table 2 shows a similar forecast for the total volume of summer gas demand in 2014 for NDM, DM, IUK and exports to Ireland. Power demand reflects the base levels for gas generation operating as marginal plant.

Sensitivity Analysis

The analysis has been based on our fuel price projections as shown in **Figure 2** (coal and gas prices and power generation). There remains considerable uncertainty over the outturn level of the gas price over the summer with the potential for lower prices either as a result of the fall in oil prices feeding into long term contracts or due to additional supplies of LNG being available in the market.

Given these uncertainties we have assessed the impact of gas prices falling by 30% in the July – September period as sensitivity to our analysis. Under such conditions gas generation would increase sharply in the later summer months and increases the total demand from 33.3 bcm to 35.5 bcm (**Table 2**, increasing by circa 2.2 bcm).

The impact of increased demand for gas in power generation remains within our low-high range (**Table 1**) and the increase would be expected to be met through increased supplies of LNG and/or imports of gas from Norway or the continent.

3. Supply Forecast

The gas market is expected to be supplied with some margin this summer. Supplies from the UKCS and Norway similar to last year.

The balance of LNG and continental supply is, as usual, difficult to predict, but we expect that there will be enough gas available to meet requirements.

Supplies of gas through the summer for the last five years and our forecast for 2015 are shown in **Figure 7** and **Table 3**.

Figure 7 - Historic and forecast summer gas supplies

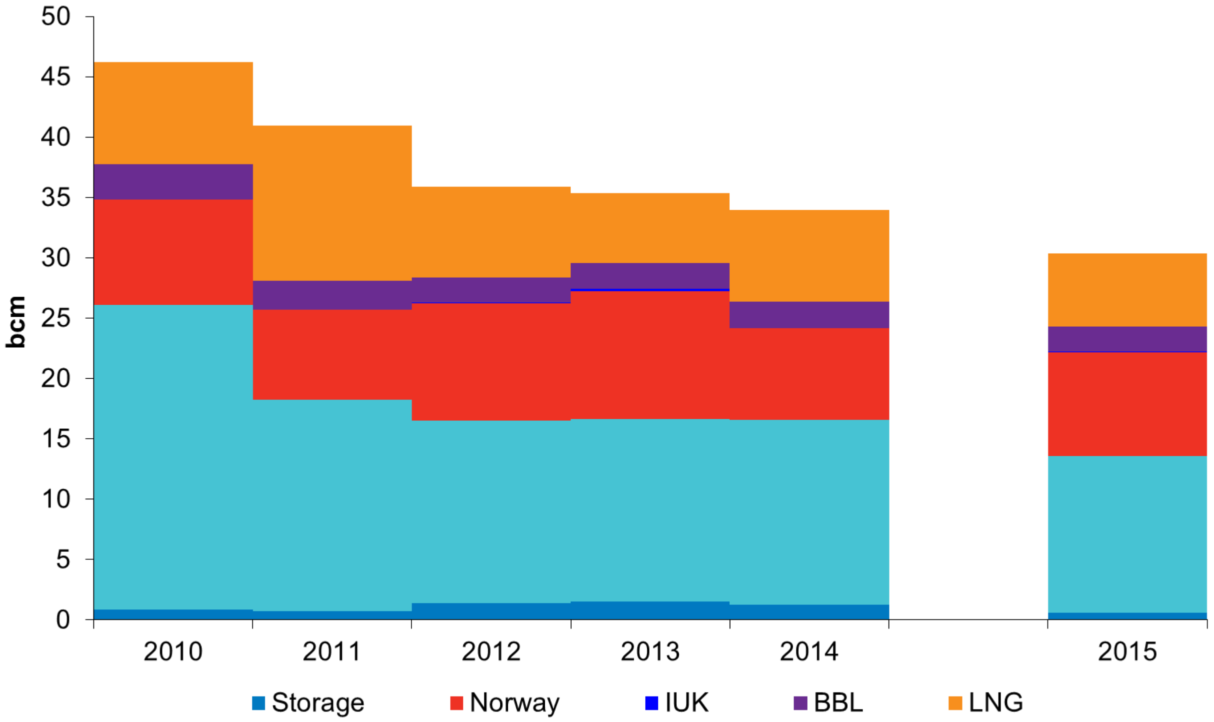


Table 3 - Historic and forecast summer gas supplies

(bcm)	UKCS	Norway	LNG	Continent	Storage	Total
2010	25	9	8	3	1	46
2011	18	7	13	2	1	41
2012	15	10	8	2	1	36
2013	15	11	6	2	2	35
2014	15	8	8	2	1	34
Average	**18**	**9**	**9**	**2**	**1**	**40**
2015	15	8	8	1	<1	33

Supplies from the UK Continental shelf (UKCS) and Norway have been reasonably predictable over this period, in line with total annual production.

The IUK interconnector between Bacton and Zeebrugge in Belgium generally transports gas from GB to continental Europe in the summer; we are expecting this to be the case in summer 2015 as well, though there may also be occasional imports.

Flows through the BBL pipeline from Balgzand in the Netherlands to Bacton have been consistent over many years, driven largely by long term contracts.

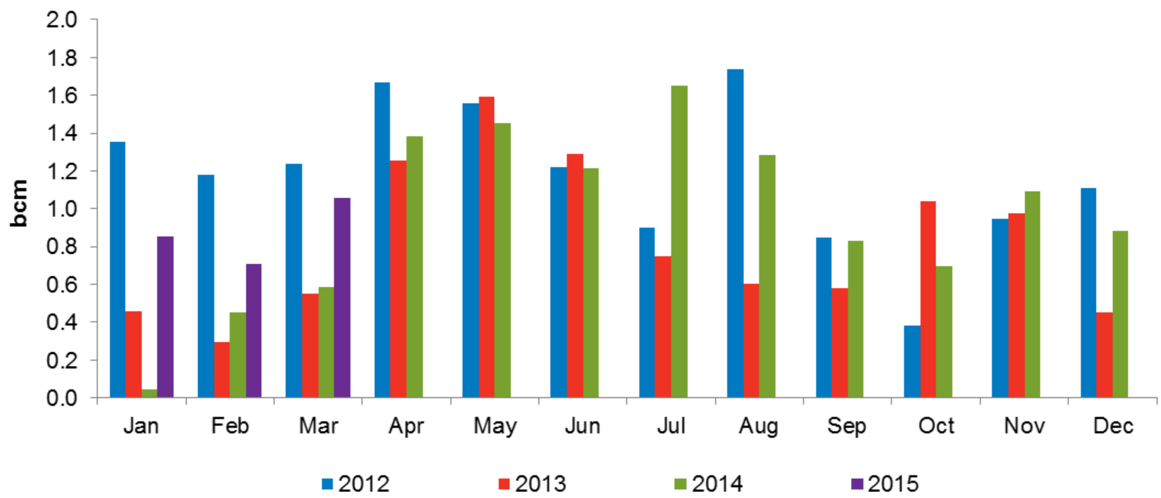
In December 2014 the Dutch government imposed a cap on production from the Groningen field in the North East of the Netherlands in response to fears of seismic events. The cap for the first half of the year was tightened in February 2015 and since then BBL flows from the Netherlands to GB have been reduced by around 10 mcm/day on average. It is not yet known whether the total production permitted for the year will be reduced or kept at the current level but as a precautionary measure we have reduced the expectation of gas from the continent in our forecast.

In recent years there has been considerable uncertainty in predictions of LNG supplies over both the summer and winter. LNG availability depends on a number of factors the most important of which recently have been the price and demand in East Asia. We have written about this in previous Summer and Winter Outlook Reports, and in our Future Energy Scenarios documents.

Typically over the last few years there has been a peak in LNG deliveries in the early summer as more Middle Eastern cargoes become available due to declining demand in East Asia at the end of the winter. In some years this has been followed by a dip in the mid-summer, thought to be due in part to increased electricity demand in East Asia in response to the air conditioning load. This is however by no means universal, as shown by **Figure 8**.

In 2014 a combination of lower demand in East Asia and steadily increasing supply in the Pacific basin from Papua New Guinea meant that more LNG was available for export to Europe.

Figure 8 - Monthly LNG imports



Gas

For summer 2015 the prices of gas delivered to the East Asia market and to North West Europe are likely to be closer than in recent years. Demand in Japan is currently stronger than previously expected, though demand in Korea has declined. Restarting nuclear reactors in Japan will reduce demand for gas in the power generation market, and a continuing low oil price will make oil fired generation more competitive with gas fired generation.

This combination of factors supports the expectation that supplies of LNG to Europe will be more plentiful this summer than for some years. Our forecast for LNG supply over the summer is line with last year with the potential for even higher supplies available should demand increase.

In the Summer Outlook Report, gas storage is principally considered as gas demand rather than gas supply as the majority of flows will be injecting gas into storage rather than withdrawing. Some withdrawal is expected from the fast cycle mid-range storage facilities, and this is captured in **Table 3**. The rate of withdrawal at the Hornsea facility has recently been reduced from 18 mcm/d to 12 mcm/d but we do not expect this to have a significant effect on the totals shown in the table.

4. Summer System Operation

4.1. National Transmission System Operability

The overall gas supply situation over the summer is expected to be adequate given the diversity of options available. This diversity supports security of supply throughout the year, but the supply options that exist combined with the variability of demand lead to greater unpredictability, particularly during summer periods. This unpredictability makes all aspects of system operability more challenging. This section provides a brief overview of some of the key issues.

4.1.1. Supply and Demand

A key operational challenge is predicting the disposition of supply on any specific day to allow the network to be configured. This year, global supply and pricing factors have resulted in LNG supply uncertainty. Over the summer period LNG has a credible supply range broadly between 5% and 50% of daily demand, and may vary greatly from day to day with boat schedules and commercial priorities.

The trend of increasing demand variation is generally more noticeable during summer. Stable domestic, industrial and commercial consumption interacts with more variable sources (power generation, storage and interconnectors), together these increase the variation of demand over the summer period.

The demand variation from marginal gas power stations is anticipated to result in operational challenges due to the uncertainty of usage from each site. More intermittent renewable generation capacity is likely to add to the volatility, with wind in particular increasing by around 10% since last summer.

4.1.2. Storage

This summer period has a greater potential for storage injection than last year due to the increased number of sites in operation and having lower stocks at the start of the period. This leads to more difficulty in accurately forecasting demand as it is harder to predict which sites will inject and when. However, improvements have been made in recent years with gas demand forecasting which helps mitigate against this issue.

As well as the impact on overall demand forecasting, there is an associated impact on network operation due to the specific location of many of these sites. There are some clusters of storage sites on the Yorkshire coast and around Cheshire, meaning that there is a potential for large demand swings in these areas. This requires more flexible operational strategies to meet local pressure commitments, particularly when coupled with maintenance or local construction activities being carried out on the NTS.

Increases in supply capability, particularly due to LNG deliveries can drive additional demand from storage sites and through the interconnectors effectively resulting in a UK transit scenario.

4.1.3. Linepack

The last few years have seen increasing levels of within day imbalance of supply and demand. This has culminated in unprecedented levels of linepack depletion through this winter. If this continues into the summer it will have an impact on operation of the system, how we use the network, and meeting customer output requirements. This would potentially increase the need for commercial actions to manage the situation.

4.1.4. Balancing

A trend for network balancing later in the day is being experienced, as shippers are using flexible storage sites and interconnectors to balance. This is leading to more frequent balancing and a greater predominance of "buy" actions by the system operator. Over the last 6 months around 80% of actions have been "buy" actions, whereas a few years ago the opposite was true.

The challenges outlined increase the complexity of managing maintenance and construction activities on the NTS as operating conditions are far less predictable than they were previously.

4.2. National Transmission System Maintenance Programme & Network Expansion

To ensure a high level of safety and reliability in operation, it is essential that a system of inspection and maintenance exists for assets associated with the transmission of natural gas. Effective maintenance is essential to minimise the safety and environmental risks caused by failure of pipelines and plant.

In accordance with National Grid's Gas Transporter Safety Case, maintenance activities shall comply at all times with any statutory or legislative requirements, in order to meet legal obligations. These practices are robustly designed and seek to minimise overall operating cost by increasing the useful life of pipelines and plant, reducing the risk of failure and emergency repairs.

There are no major capacity expansions planned for 2015/16 on the NTS. However projects to upgrade the gas quality monitoring and communications systems on the network shall continue through 2015/16.

Following last years in-line inspection results the pipeline feature inspection programme continues to investigate any results which are deemed to require a visual inspection in line with National Grid's pipeline integrity policies. The planned programme of in line inspection operations continues for 2015/16 with a total of 11 inspections planned.

National Grid's maintenance plan includes the impact of network reinforcement, the annual maintenance programme and any ASEP impacts due to maintenance. Published documents can be found on the National Grid website at: http://www2.nationalgrid.com/uk/industry-information/gas-transmission-system-operations/maintenance/

The documents detail Aggregated System Entry Points (ASEP) capability for each month, based on Seasonal Normal Demand conditions for the period where scheduled maintenance has most impact on capability. The figure has been generated by National Grid and assumes the particular ASEP is favoured at the expense of other terminals. Where no volume has been given, this indicates that the maintenance scheduled has no adverse effects on the ASEP capability.

5. Generator Adequacy

5.1. Demand levels

Our peak weather corrected summer demand for the high summer period is 37.5 GW and the summer minimum demand forecast is 18.6 GW. These forecasts are based on long term average summer weather conditions.

Our peak weather corrected summer demand for the high summer period is 37.5 GW. This is the lowest ever forecast and is due in large part to increases in embedded photovoltaic (PV) solar generation.

Table 4 - Peak Summer Demand & Installed Embedded PV Capacity – SOR 2014 Vs SOR 2015

	SOR – 2014	SOR – 2015
Peak Demand Forecast	38.4	37.5
PV (Solar) Capacity	2.4	4.4

Peak weather corrected demand forecast for summer 2015 has dropped by 900 MW since 2014, primarily due to a 2 GW increase in embedded solar photovoltaic (PV) generation. During high summer period the demand peak occurs from mid-day to afternoon; therefore with increasing embedded solar generation, summer peak demands are likely to drop in the coming years. There is more detail on embedded PV below on page 22.

Figure 9 - Half hourly demand profiles based on the actual average half hourly GB demand during 2014 British summer time (BST) period

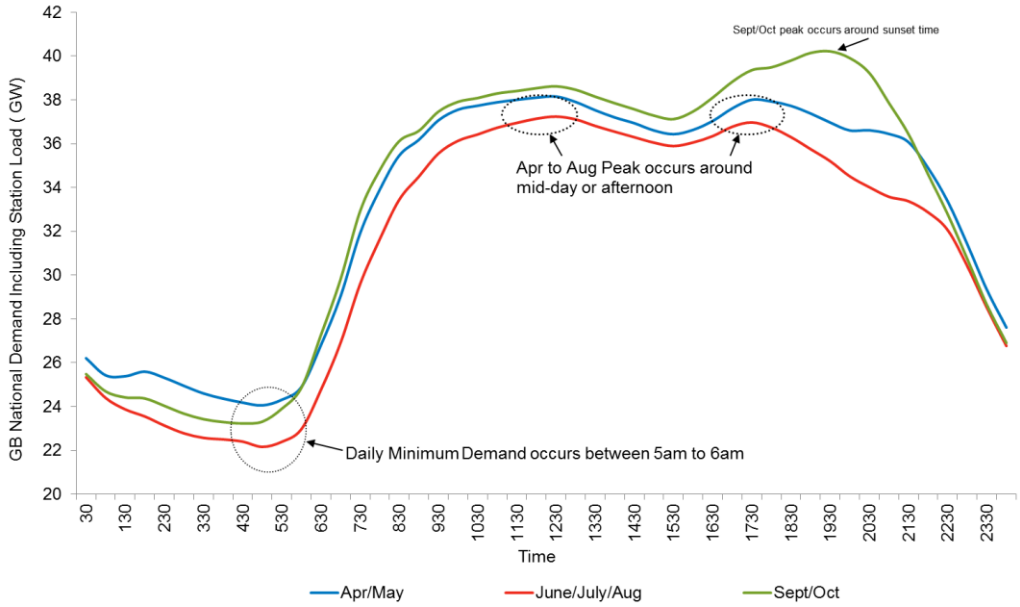


Figure 9 shows the average daily half hourly demand profile of summer months of 2014.

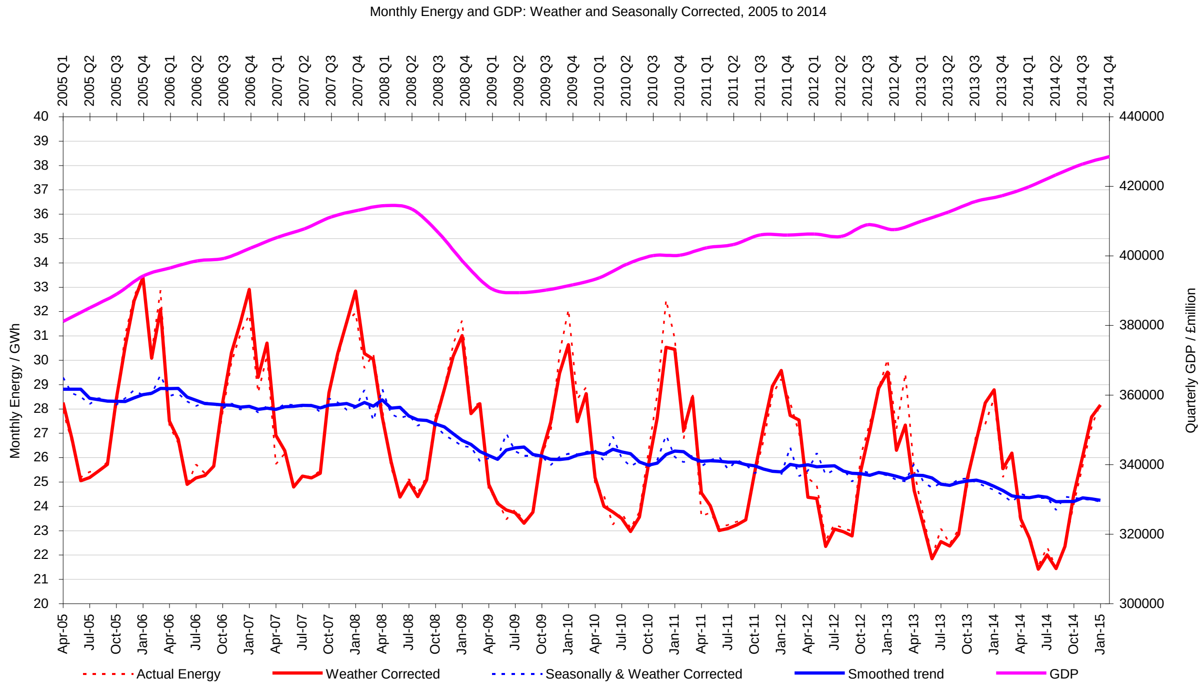
The figure shows that the daily peak figure that is used throughout the rest of the report does not necessarily occur at the same time of the day throughout the summer.

Between April and August demand is reasonably flat across the working day, and most likely to peak at the mid-day or late afternoon, depending upon weather conditions.

During September and October the daily peak occurs in the evening, due to the change in sunset times.

The daily minimum occurs around 05:00 - 06:00 throughout the summer.

Figure 10 - Monthly energy and GDP: weather and seasonally corrected (2005 to present)



Source Data for GDP/ABMI: http://www.ons.gov.uk/ons/site-information/using-the-website/time-series/index.html

Since 2005 both demand and energy use has fallen steadily. **Figure 10** shows there is no simple direct relationship between GDP and demand for energy. Demand has been falling consistently since 2006.

The financial crisis did have an impact on demand. The step change in demand levels is clearly visible in Q4 of year 2008, as shown in **Figure 10**. However after this one-off event demand continued to fall, despite a prolonged period of economic growth. Even the recent increase in GDP numbers has had no substantial effect on demand for energy.

The fall in the underlying demand level is partly due to increases in renewable embedded generation such as wind and solar and smaller scale conventional sources of generation. Furthermore, there has also been a real reduction in energy usage. This is likely to be due to energy efficiency measures and behavioural change, with the shift towards decarbonisation. The fall in the level of demand is sustained and expected to continue. This effect has been incorporated into the 2015 forecast. Details for embedded PV generation capacity are included on page 22.

Figure 11 - Weather corrected weekly peak demand for the past 3 summers and forecast demand for summer 2015

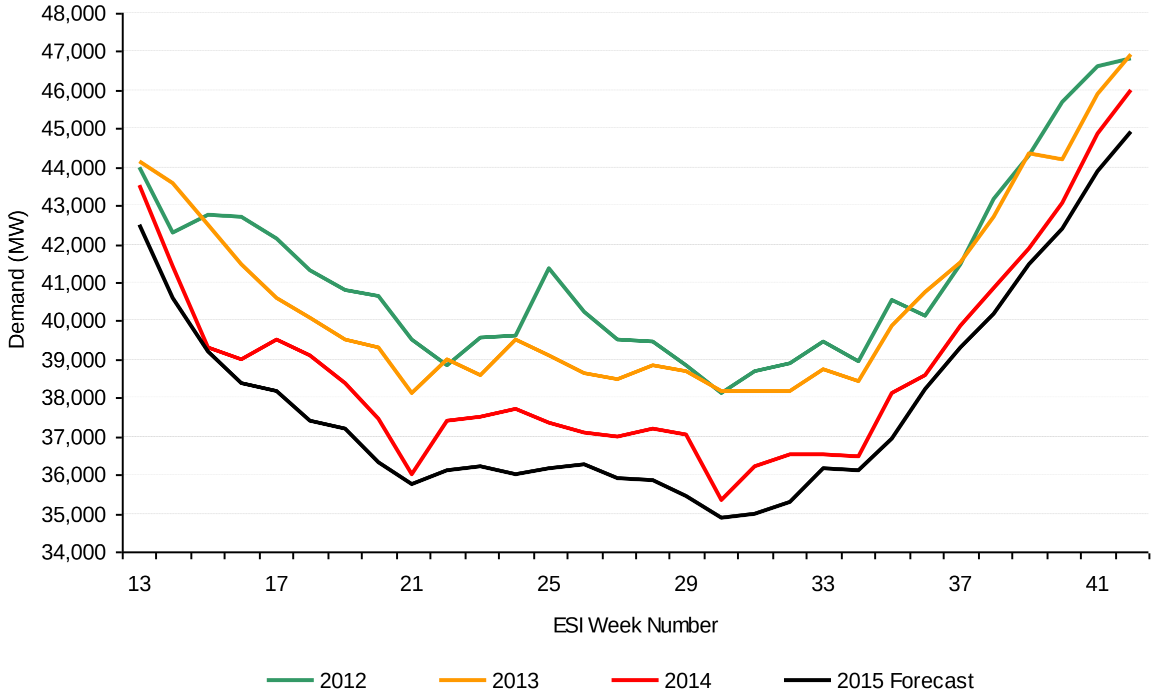
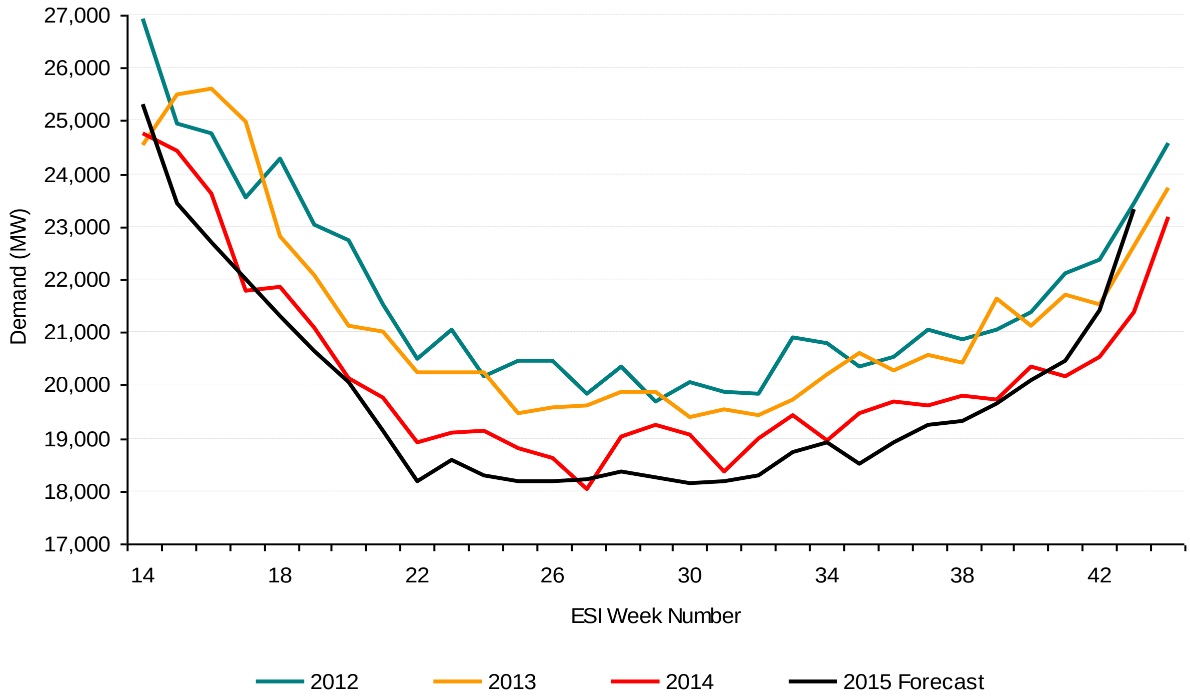


Figure 11 depicts the actual weekly weather corrected peak demands for the last 3 summer periods and the forecast for 2015.

For the high summer period[6] *(ESI Week 23 to ESI Week 36)*, the peak weather corrected demand forecast for 2015 is 37.5 GW, compared to actual weather corrected outturn of 38.6 GW for 2014.

6 1^{st} June – 31^{st} August

Figure 12 - Weather corrected weekly minimum demand for the past 3 summers, and forecast demand for summer 2015



The summer minimum demand is expected to occur around 05:00 to 06:00 on a Sunday in late July.

The minimum normalised weather demand forecast for the summer of 2015 is 18.6 GW. This compares with an actual outturn minimum demand of 18.6 GW for summer 2014, corrected for the impact of the weather on demand.

In addition to the weather and school holidays, embedded wind generation is a key factor affecting minimum demand levels. We currently assume a total of 4.1 GW of installed capacity for embedded wind generation.

We assume no increase in the embedded wind generation capacity during the summer of 2015.

5.2. Interconnector flows

National Grid's GB transmission system is linked by interconnectors to the transmission systems of France, Ireland and the Netherlands.

The interconnector to France is called IFA and has a capacity of 2GW.

The interconnector to the Netherlands is called BritNed and has a capacity of 1GW. The interconnectors to Ireland are called Moyle and the East West interconnector(EWIC), each have a capacity of 500MW.

Full availability is expected on BritNed throughout 2015, EWIC has a planned short outage in mid-September and IFA is reduced to 1 bipole (+/-1000MW) for 11 days in March/April, and again for 11 days in October. Currently the Moyle interconnector is reduced to 1 pole (+/-250MW) due to a cable fault, the earliest expected return date is 2016.

The current spreads between GB and EU, for summer 2015 are slightly wider than at this time last year (in EU to GB direction), with GB prices at a similar level, and EU prices lower. This indicates that full imports are expected on IFA and BritNed. 26% of weekdays saw net import to GB reduce below 1500MW during the morning hours (generally 05:00-07:00); this is expected to remain similar for summer 2015.

Flows on EWIC and Moyle are expected to continue to flow from GB to Ireland the majority of the time. During times of high wind in Ireland (particularly overnight) we would expect the flow to change to an import to GB.

5.3. Generator capacity

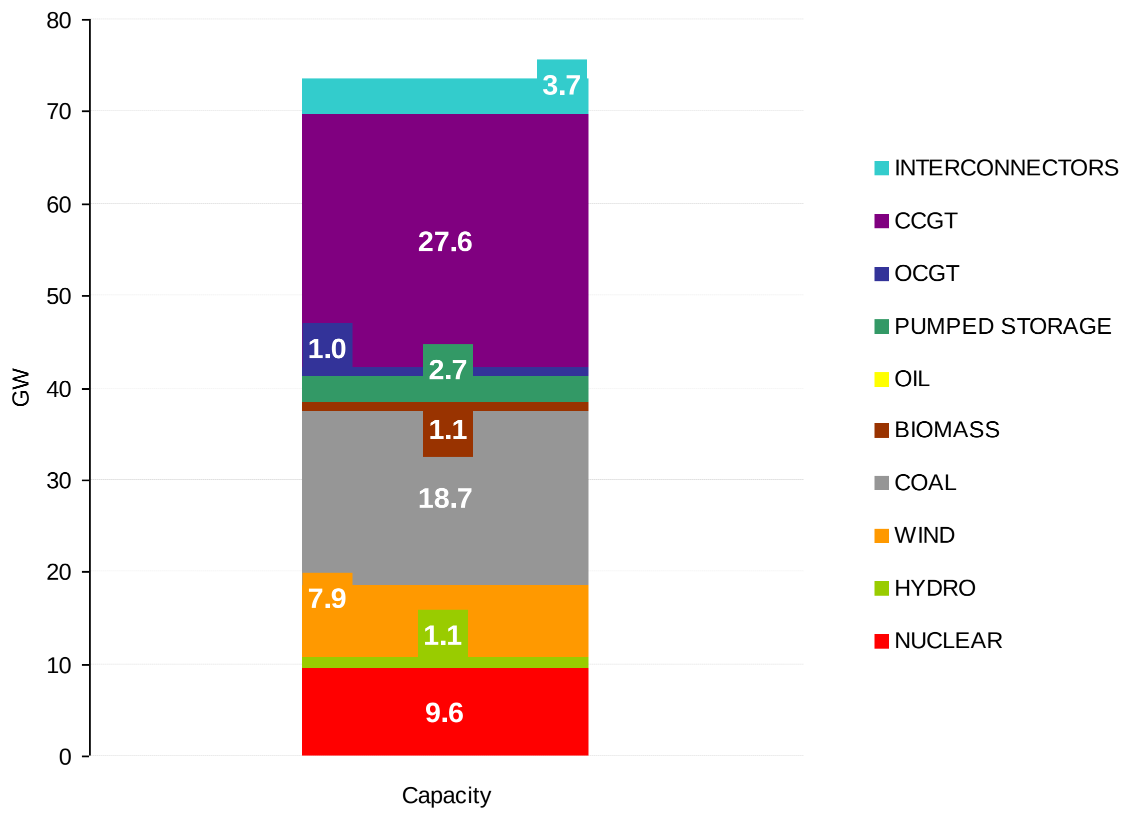
Margins are currently forecast to be at a comfortable level over the summer. It would be possible to provide maximum export on the interconnectors most weeks without eroding the reserve requirement.

Figure 13 shows the expected generation capacity at the start of the summer. This has dropped by 1.6 GW to 73.5 GW (including interconnectors) since the Winter Outlook Report, published in October 2014. This is due to the closure of Barking, Littlebrook and EON's Killinghomei. These decreases have been partially offset by the inclusion of further wind generation added to the system.

The capacity could fall further as there is a risk of more gas stations having reduced TEC, being mothballed, or facing closure, during the summer. Two such stations at risk are Centrica's Brigg and Killingholme power stations, the latter of which has submitted zero availability to us going forward from the end of March. This means that they are included in **Figure 13** as overall capacity in the market. However, Killingholme is not included in overall margin analysis, in **Figure 18** below, for this summer.

Even with this uncertainties and recent closures, there is more than enough generation capacity available in the market to meet forecast demand for the summer.

Figure 13 - Generation capacity – summer 2015

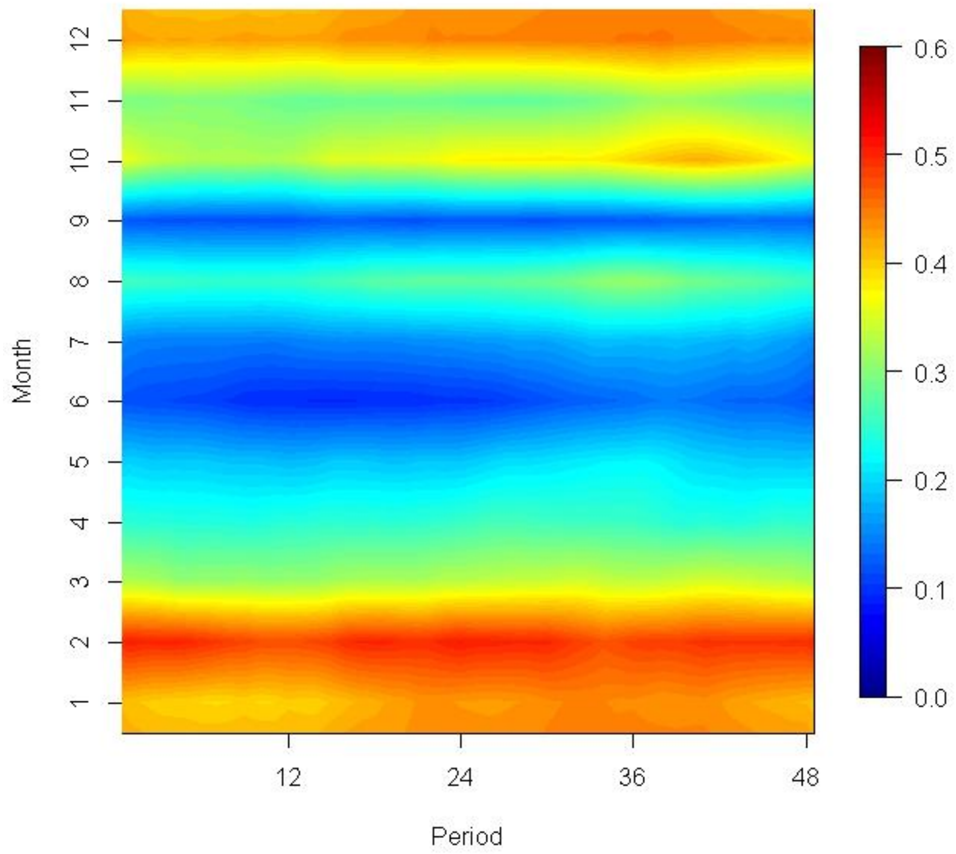


5.4. Wind power

There is an increasing amount of wind powered generation connected to both the transmission system and embedded within distribution networks. This section shows how we account for the contribution of transmission connected wind power in our adequacy analysis.

Figure 14 shows the mean load factor of wind generation by month and trading period (per half hour of the day) throughout 2014. A load factor is the expected proportion of output for a given capacity. The figure shows the seasonal variability across the year with the winter months being more windy and small increased effect during day light hours in summer.

Figure 14 - Average wind power by settlement period and month in 2014



The data is taken from wind farms with directly connected operational metering. The month of the year is plotted on the vertical axis and trading period on the horizontal axis, with Period 24 corresponding to the half hour ending at noon. The mean annual load factor for 2014 was 29%.

Table 5 - Comparison of seasonal wind load factors from 2011-13 and 2014

Year/Mean Load Factor	Winter	Spring	Summer	Autumn
2011-2013	**30%**	**23%**	**16%**	**28%**
2014	**45%**	**26%**	**18%**	**28%**

In **Table 5** the seasonal mean load factors for 2014 are compared to mean load factors for 2011 to 2013.The increase could be due to one or a number of potential reasons. One potential reason is that 2014 was a particularly windy year and that there is now greater geographic dispersion of wind farms.

Figure 15 - Wind load factor summer daytime: probability of exceeding a given wind load factor

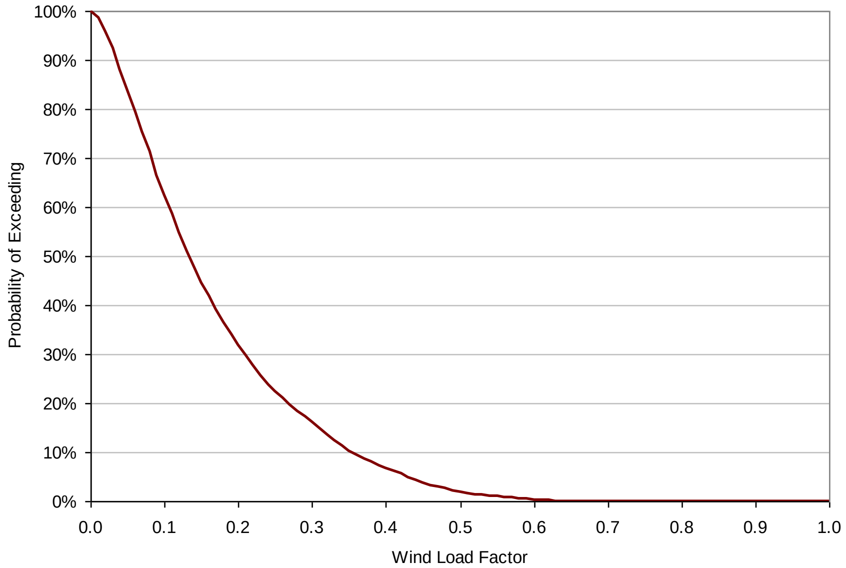
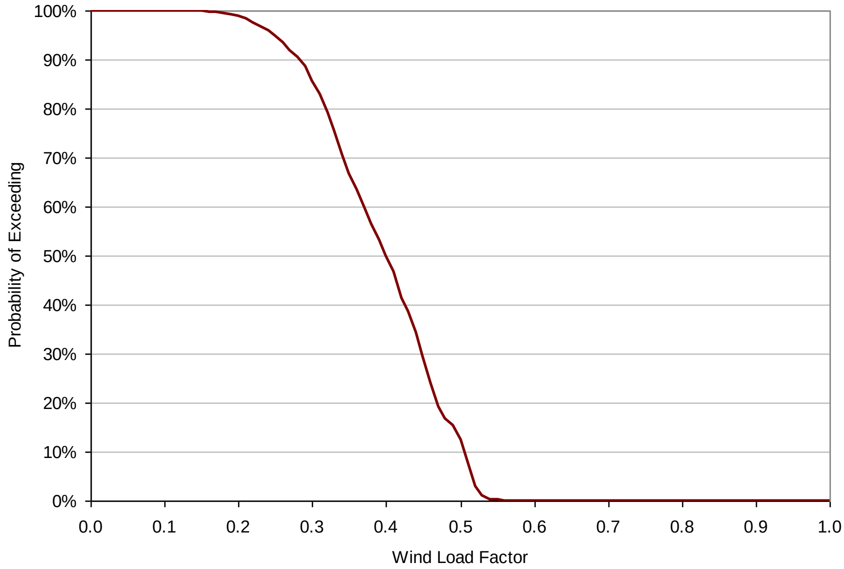


Figure 15 shows historic wind farm load factor distribution during the daytime in high summer months (June to August). The median wind load factor is 14%; based on this it is reasonable to assume that half of the time the load factor will be less than 14% during the day.

Similarly there is a 20% chance that the load factor will be below 6% and a 10% chance that the load factor will be below 4% during the day. We can therefore use this 14% value in the margins analysis below as a reasonable expectation of wind for the demand peak of a summer day.

Figure 16 - Wind load factor at minimum demand level: probability of exceeding a given wind load factor on at least one the 2015 minimum summer demands



The lowest average load factors occur overnight in the summer period. During 2014 the lowest summer overnight load factor was 0.001 (0.1%). However, high winds do occur during periods of low overnight demand during summer. The lowest demands usually occur early on Sunday morning between mid-June and mid-August.

Figure 16 shows the chance of the wind load exceeding a given value during at least one of these low demand periods. The median load factor is 40%. This shows the typical maximum wind load factor (40%) expected during one of the low demand periods in any year and is used for the low demand scenario forecasts for the year 2015.

We can therefore use this 40% value in analysis for margins, as it is a reasonable expectation of contribution from wind for a summer day at the minimum demand level.

5.5. Embedded solar generation

Embedded generation describes small generation units that are connected to the distribution network, such as solar photovoltaic (PV) and wind and the System Operator does not receive live metering for this generation. Embedded PV capacity has increased substantially from 2.4 GW in February 2014 to 4.4 GW in February 2015.

Figure 17 - Total photovoltaic (PV) capacity & estimated generation (historic and forecast) April 2011 – February 2016

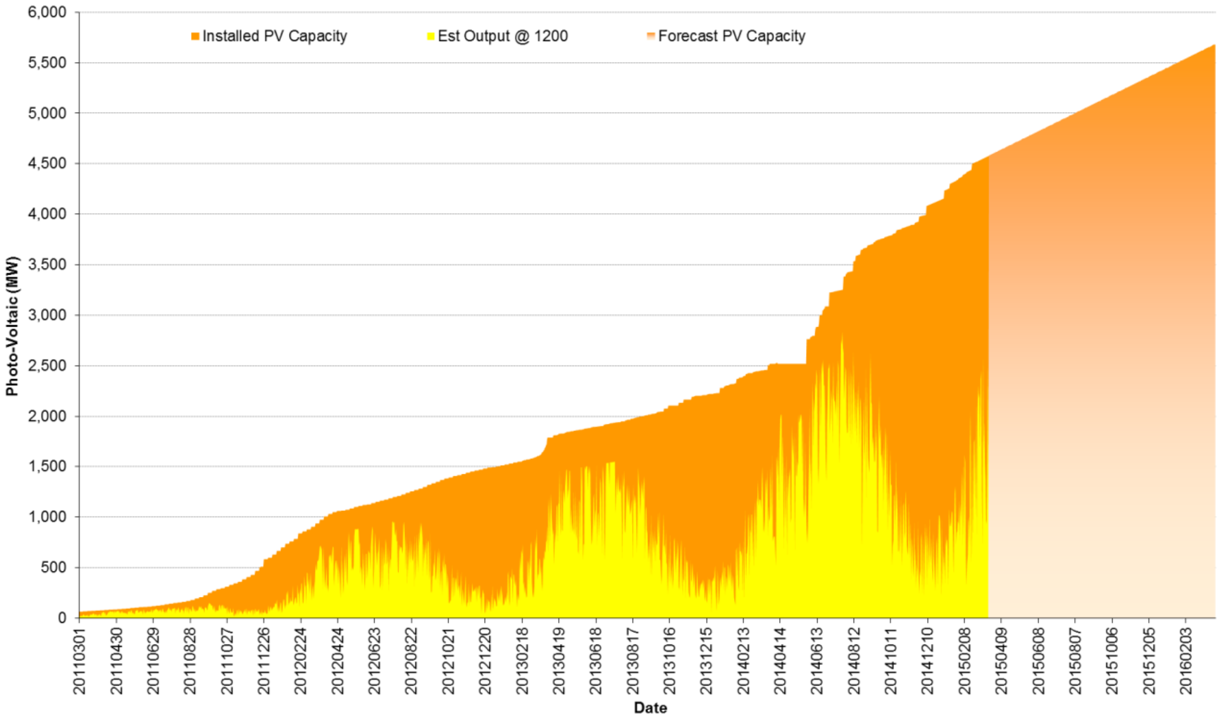


Figure 17 shows the actual growth in the installed capacity during 2011 to 2014 and the forecast growth in the capacity for the year 2015. **Figure 17** shows the estimated actual PV generation based on the actual weather, and forecast PV generation for the year 2015 based on the normal weather. Normal weather is based on average radiation over the last 30 years.

Embedded PV generation is a major contributor to the trend of decreasing demand. This means that we now include estimates of PV generation in our demand forecasts. We are assuming a 90 MW linear increase of installed capacity per month for the next 12 months. This increase has been factored into our summer demand forecasts for 2015. At the time of publishing this Summer Outlook Report, our PV capacity forecast for Feb 2016 is 5.5 GW.

In addition to this seasonal forecast, we now publish a daily forecast of embedded generation for the next seven days. For more information, please visit our website for access to this (see DemandData_Update file):

http://www2.nationalgrid.com/UK/Industry-information/Electricity-transmission-operational-data/Data-explorer/.

5.6. Generation availability

As usual over the summer period, there will be a significant generation outage programme that will reduce the amount of available generation plant. Generation margin, which is the excess of generation availability over demand and reserve requirements, is published on the BM Reports website[7]. **Table 6** shows the assumed de-rating factors. De-rating factors are the expected proportion of the sum of availability of each fuel type based on historic summer average breakdown rates. These are then applied to the weekly availability submissions from the generators, which contain planned outages.

For wind farms, the assumed losses are based on load factors as shown in **Figure 15**. This shows the median wind farm load factor for summer daytimes to be 14% and this load factor has been used in the analysis.

Table 6 - Assumed losses of generation availability for summer 2015

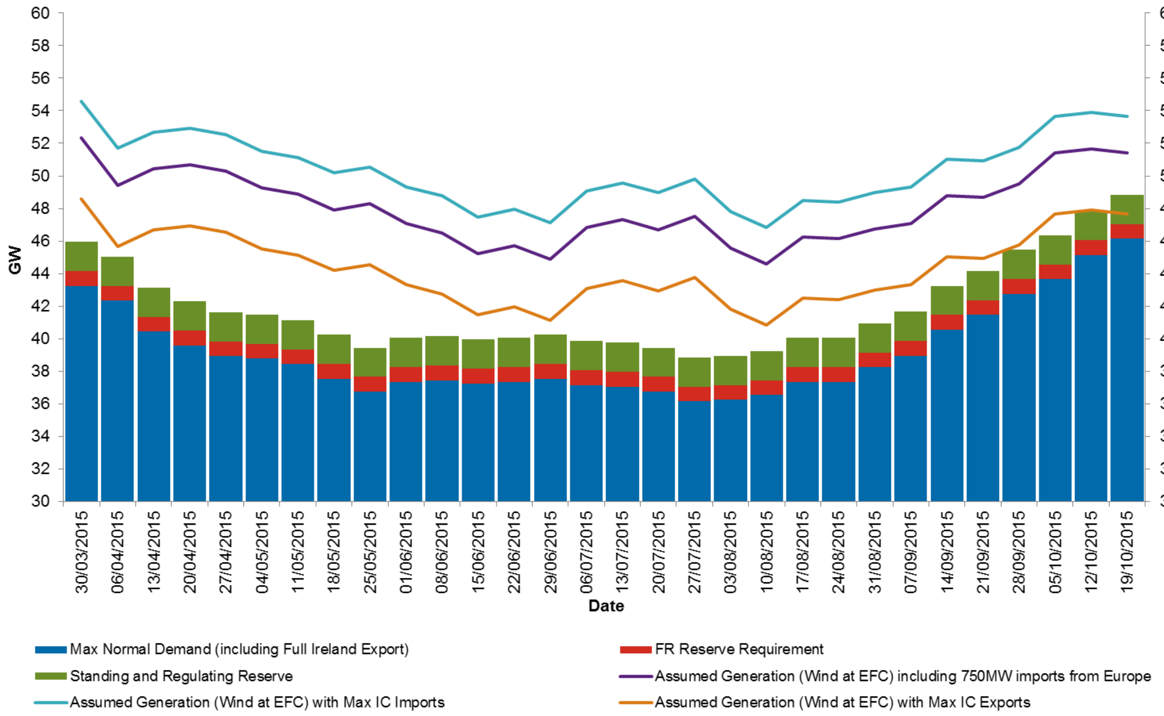
Power station type	Assumed de-rating factors
Nuclear	91%
Interconnectors	100%
Hydro generation	77%
Wind generation	86%
Coal & biomass	87%
Pumped storage	98%
OCGT	90%
CCGT	83%

The demand used for margin analysis is Transmission System Demand (TSD), as per the Grid Code, so includes assumed exports on the interconnectors. Our assumed exports are 750MW to Ireland. So the demand used is National Demand plus this 750MW. In the analysis we also assume 750MW imports from the continent which is added to the generation side, creating a virtual float scenario on the interconnectors as our base case.

The assumed losses in **Table 6** are applied to the notified availabilities declared to National Grid by generators. Generators submit information on their expected availability to National Grid as System Operator under Grid Code Operating Code 2 (OC2). This information is used to calculate the assumed generation availability shown in **Figure 18**. The chart also looks at the best and worst case with interconnectors at both maximum import and export.

[7] http://www.bmreports.com/bsp/BMRSSystemData.php?pT=WEEKFC

Figure 18 - Assumed generation availability



The short term operating reserve (STOR) is included in **Figure 18** as basic and frequency response reserve.

The minimum generation availability over the summer is 41.7 GW in the week commencing 10th August. The margin in this week is forecast to be 4.9 GW, assuming the interconnectors are at net float (0 GW flow in each direction). The margin for the highest demand of the high summer period is 5.4GW. The minimum margin is 2.2 GW and this occurs in the very last week of the British Summer Time (BST) period, week commencing 19th October.

The chart shows that over the summer it is possible to provide maximum export on the interconnectors without eroding the reserve requirement in all but the last two weeks before clock change. **Figure 18** shows margins are forecast to be adequate throughout the summer.

If it looked likely that there would be an erosion of reserve due to high interconnector export flow, trading on the interconnectors would be considered as a way to reduce exports. If the position could not be rectified by trading, a Notification of Insufficient System Margin (NISM) warning would be issued. This notification is used to inform the market and to encourage an increase in available generation, or reduction in demand.

6. System Operability

Summer operability of the transmission system is becoming increasingly more challenging, with the increasing levels of intermittent power sources. This section focusses on those challenges and how we manage them through our role as System Operator.

6.1. System operation during low demand periods

The smallest weekly minimum margin is 1.1 GW. This means there may be a requirement for inflexible generators to reduce their output over the summer minimums.

Demands during the summer are around two thirds of winter demands. There tends to be a lower level of generator availability during the summer months due to planned maintenance and lower prices available. During periods of low demand, such as in summer, a number of flexible generators are required to:

- maintain sufficient frequency response[8] to ensure that the system can withstand the largest generation or demand loss.
- maintain positive and negative regulating reserve levels to cater for demand forecast error, wind forecast error, generation and demand losses.

In addition, during periods of low demand, two other factors may affect generator balancing decisions, in that we have to:

- maintain the voltage profile across the country within specified limits.
- maintain sufficient system inertia. See page 32 for more details.

The impact of these four issues in the coming summer is that it is likely that we will need to take a number of actions during low demand periods on conventional and wind generators to keep the system secure. These issues are discussed in more detail below.

Ancillary Services

National Grid procures Ancillary Services in order to balance demand and supply and to ensure the security and quality of electricity supply across the GB Transmission System.

These services can be grouped into two areas:

1. Related to the second by second management of energy:
   - Firm Frequency Response (FFR)
   - Fast Reserve (FR)
   - Short Term Operating Reserve (STOR).
2. To ensure system security:
   - Black Start
   - Commercial Intertrips
   - Reactive Power.

These services are procured through tenders or bilaterally, depending on the available market, with commercial information being published on our website. For more information on Ancillary Services and how you may participate, visit the following page:

http://www2.nationalgrid.com/UK/Services/Balancing-services/Service-Guides/

[8] Frequency response requirements increase as the demand falls due to the relative size of the largest loss increasing, and due to demand itself being slightly frequency sensitive.

Inflexible plant that must run are:

- nuclear generation;
- combined heat and power (CHP) stations;
- some hydro generators which either have water level management obligations or have BELLA[9] connection agreements;
- wind farms that have BELLA connection agreements or are not large[10].

Interconnectors provide a variety of frequency response services and, in some cases, System Operator to System Operator trading.

The remaining generators are more flexible, including most large wind farms. All large wind farms that are obliged to do so are now participating in the Balancing Mechanism, and some are submitting prices for the Ancillary Services required by the Grid Code (frequency response and reactive power). We call on these services when more economic options have been used up.

We have modelled the amount of inflexible generation that we can reasonably expect to be running at the time of the weekly minimum demand. This allows us to quantify the likelihood of us needing to ask less flexible generators to alter their output during these periods.

Our assumptions on the load factors for the different categories of generator and interconnectors during low demand periods are shown **Table 7**. A load factor is the multiplier by with we can use against availability to get the predicted level based on historic data.

Our assumed load factor for inflexible wind farms is based on **Figure 19**. This shows that for the days where we might reasonably expect the lowest demand to occur, we can expect the wind load factor to be 40% on at least one of these days.

Table 7 - Inflexible load factor assumptions at minimum demand

Power station type	Load factor
Nuclear	0.91
Inflexible BM units (CHP)	0.90
Inflexible hydro	0.10
Inflexible wind	0.40
Irish Interconnectors	-1.0
BritNed	0.70
Interconnector France Angleterre	0.50

Figure 19 shows the cumulative minimum output profile from less flexible generators. This is based on the load factors in **Table 7** and the generators' OC2 availability submissions.

9 **Bilateral Embedded License Exemptible Large Power Station Agreement - held by large embedded power stations that do not participate in the Balancing Mechanism**
http://www.nationalgrid.com/uk/Electricity/_OLDGettingConnected/dnoConnected/agreements/

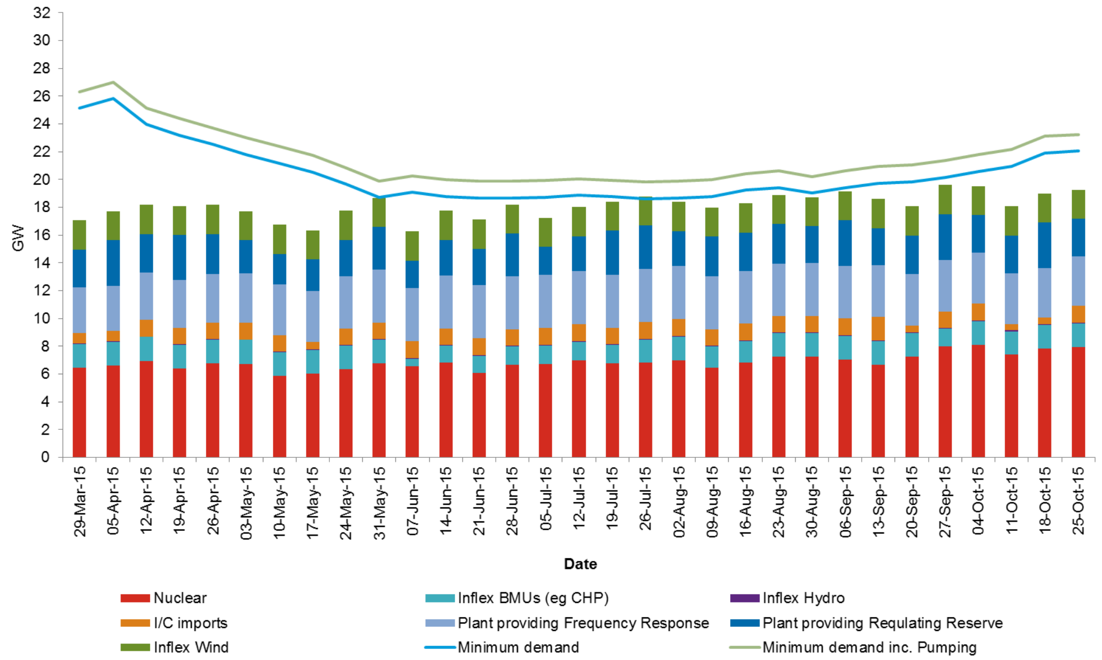
10 As defined by the Grid Code. Virtually all generators which are not large do not have a connection agreement (relationship) with National Grid. Small embedded generators meet local demand, reducing the amount of demand seen by the transmission system. Small wind farms are modelled explicitly as their output is not related to demand.

This profile includes the synchronised plant required to meet our frequency response and reserve requirements. The weekly minimum demand profile is also shown, together with pumping demand at an assumed load factor of 50%.

Figure 19 shows that there is a risk that inflexible generators may be instructed to reduce their output this summer, assuming 1.2 GW of pumping. For several weeks the margins are small, with the smallest margin being 1.1 GW in the week containing 26th July. Actual margins will depend on conditions and plant running on the day.

We will keep these margins and assumptions under review during the summer and will inform and engage with inflexible generators if necessary. The margins are smaller than last year, and we expect this trend to continue in future years.

Figure 19 - Weekly minimum demand and generation profiles



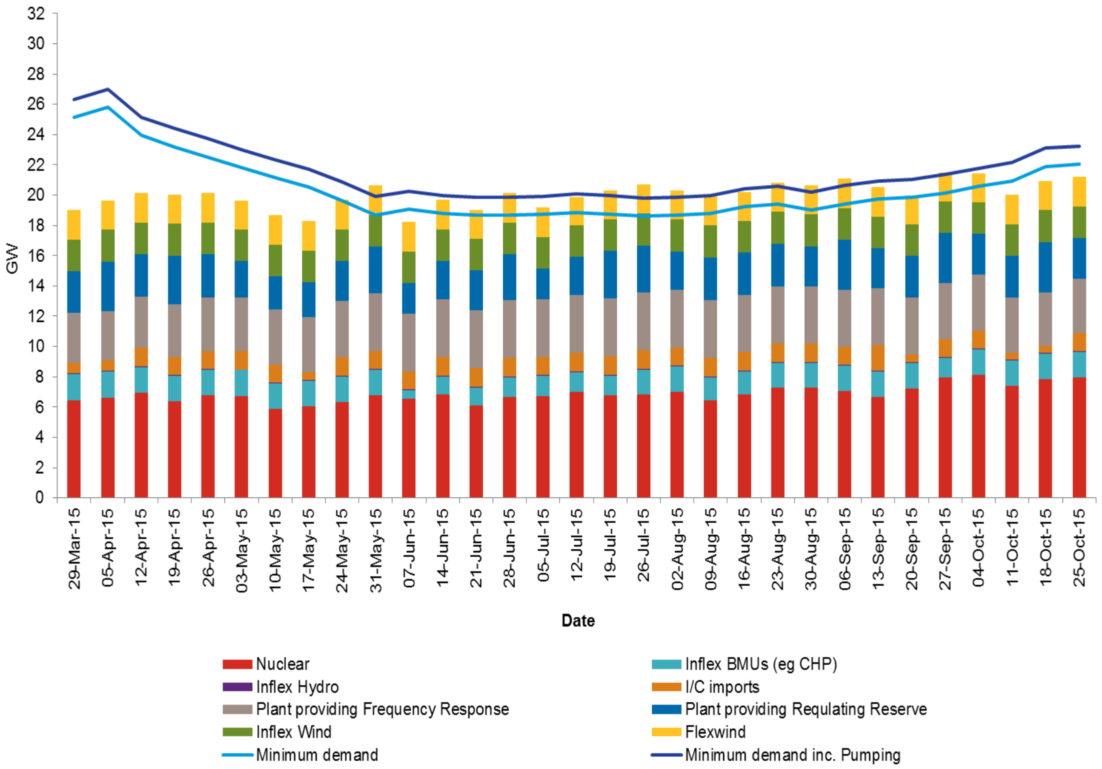
With increasing installed wind capacity, it is now becoming economic to carry a proportion of regulating reserve on large wind farms when it is windy. This has resulted in the occasional short curtailment instruction being issued to wind farms. The number of these short curtailment instructions is likely to increase as the demand drops towards the summer minimums and fewer flexible generators run overnight. Historically the principal reason for curtailing wind output has been for transmission constraints – see chapter on Transmission System Issues from page 30. The inherent flexibility of wind farms allows short instructions to be given to alter output, thus maintaining the supply and demand balance as an alternative to synchronising fossil fuelled generation overnight.

In **Figure 20** flexible wind farm output has been added, assuming the same load factor of 40%. It shows that if flexible wind did not contribute to meeting the frequency response requirement and the regulating reserve requirement it will need to be curtailed this summer. This would be for energy reasons so that supply does not exceed demand.

If wind did contribute to meeting the frequency response and regulating reserve requirement then the effect on this chart would be a reduction in the size of the flexible wind block, with the wind farms displacing some of the conventional generation providing these services. Initially high frequency response and negative regulating reserve are likely to be the most economic services for wind farms to provide as they do not involve pre-emptively de-loading the generator. Provision of low frequency response and positive regulating reserve would involve de-loading the wind farm in preparation for providing the service.

We encourage the wind farms and generators to submit cost reflective prices to provide frequency response as it will help us manage these low demand periods more efficiently and economically, and reduce wider wind curtailment events. On an hourly basis, currently it is cheaper to shut down some generators and wind farms completely, rather than to carry frequency response on them. We are developing mechanisms to minimise the risk associated with participation, and will engage generators further on this.

Figure 20 - Weekly minimum demand and generation profiles (including flexible wind output)



Most wind farms and interconnectors do not contribute to system inertia, due to electronic decoupling. Synchronous generators do contribute towards system inertia explained on page 32; their contribution reflects the physical design of the machine. Inertia acts to slow down the rate of change of frequency when there is an instantaneous demand or infeed loss in the timescales before frequency response takes effect.

A Grid Code Working Group[11] has been addressing this issue. During low demand periods when there are high levels of interconnector imports and high levels of wind farm output, there will be fewer conventional machines synchronised to the system.

Should there be insufficient system inertia during these periods, additional synchronous machines will need to be synchronised and rotating to ensure the system remains secure.

During low demand periods it may also be that actions on one generator solves more than one of the issues discussed above, for example: synchronising a generator in a particular region to support the local voltage profile may contribute to ensuring there are sufficient machines synchronised to meet the system inertia requirements.

It may also be that actions are not taken on some generators for the same reason. For example, if a number of conventional generators had notified us that they planned to run overnight and are left running, then a wind farm may be curtailed to resolve an energy imbalance because the conventional generators were carrying frequency response and the wind farm in question could not carry frequency response. We will take actions in economic order to operate the system securely and efficiently at all times.

[11] http://www.nationalgrid.com/uk/Electricity/Codes/gridcode/workinggroups/freqresp/, http://www.nationalgrid.com/uk/Electricity/Codes/gridcode/workinggroups/freqrespTSG/

6.2. Transmission system issues

As System Operator for GB, we are taking action to manage increasing transmission system issues.

As well as balancing supply and demand on the system second by second, managing transmission system constraints and facilitating equipment maintenance and construction, the following section describes the background of some of the other issues that National Grid need to address when making balancing actions. The case study on page 37 shows how these can occur on the system at the same time and how the control room manage a complex situation.

6.2.1. Transmission Voltage

Under the conditions of the Transmission Licence, National Grid work to a set of codes, which define the criteria and methodologies used in planning and operation of the national electricity transmission system. The Security and Quality of Supply Standards sets out the steady state and post fault voltage limits in operational and planning timescales, which are designed to ensure that equipment on both the transmission and distribution networks are operated safely and reliably.

High voltage issues are a common problem and can occur for a number of reasons including lightly loaded transmission lines and cables, low reactive demand, compensation equipment outages and lack of other forms of voltage support such as synchronous generation.

Typically high voltages have occurred during the minimum demand periods over the summer months at the extremities of the network, due to long lightly loaded transmission lines. This is caused by a phenomenon known as the Ferranti Effect, where the voltage at the receiving end of a lightly loaded transmission line can exceed the voltage at the sending end. National Grid Control Room routinely switch out certain circuits to reduce the problem, and in the past this has been easily predicted and managed. The issue of high voltage has grown year on year, with the period and area of the network increasing, and is no longer confined to the summer minimum demand periods but is affecting overnight periods throughout the year. A much wider area of the network is now affected, with voltage issues occurring in areas that have never experienced issues before.

High voltages are observed on the system during periods of low reactive power demand; the issue has spread alongside a reduction of reactive demand seen at the Grid Supply Points (GSPs) over recent years. The chart below **Figure 21** shows the year on year decline in reactive power demand and the reduction in the ratio between reactive demand and active power demand. Showing that reactive power demand is decreasing quicker than active power demand, Q is the reactive demand and P in the active demand. Low reactive demands are now being seen over summer and winter minimum periods.

Figure 21 - Long Term Active and Reactive Power Trend

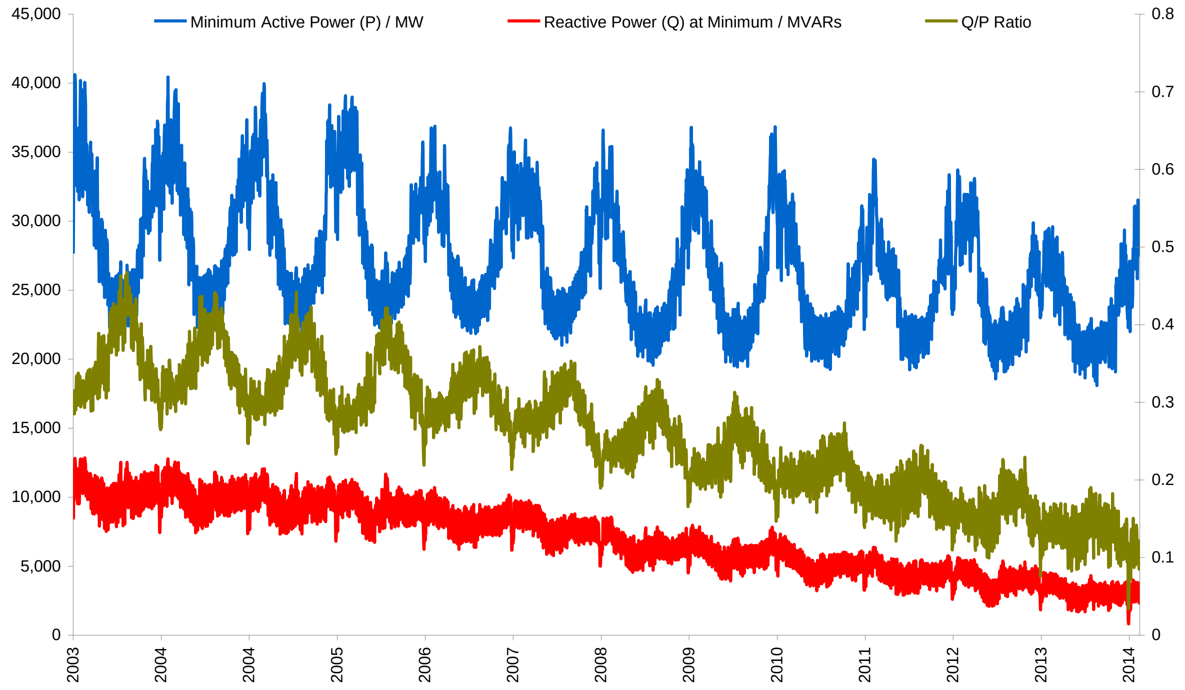


Figure 21 above shows actual active MW (P), reactive MVAR (Q), and the ratio of P/Q Mvar's/MW.

There has been a decline in the summer minimum demand since 2006. This is shown in **Figure 21**. The chart shows actual active MW (P), reactive MVAR (Q), and the ratio of Mvar's/MW (P/Q). This has steadily declined over the period and this trend is expected to continue through 2015.

There are a number of factors that could be contributing to the reduction in reactive power demand, including: growth of embedded generation, increased use of cables on the distribution and transmission networks, energy efficiency measures and changes in demand behaviours.

High voltages occurs when demand is low and lines and cables are lightly loaded, so forecasting demand accurately is also important when identifying voltage issues on the network. The increasing levels of embedded generation has made demand forecasting more complex and less predictable, particularly at low demand levels, where total volume of embedded generation is relatively large in proportion to demand.

Short term actions

The System Operator has a number of tools available to manage high voltages on the transmission network.

- National Grid will contract with synchronous generators, that are located close to the area of the network experiencing the high voltages, to absorb reactive power overnight. This is done in the competitive tender rounds where more than one generator can mitigate the voltage issues.
- National Grid will contract with wind farms to provide reactive support

- The Electricity Control Room will keep system voltage close to the lower limit during the day to allow larger headroom for the rising voltage overnight.
- The Control Room will switch out lightly loaded lines over minimum periods to remove the voltage gain that is produced in certain areas.
- The Control room will optimise the use of reactive compensation equipment on the system.

Medium term actions

- National Grid are working closely with the DNOs to understand the decline in reactive power demand and identify mitigating actions.
- There are investigations ongoing that suggest modifications to the Grid Code that would cap the levels of reactive power being transferred between the distribution and transmission networks. This is ongoing in conjunction with a similar draft European Code proposal.
- Network planning teams are looking at better ways of working with the Distribution Network Operators to coordinate system planning, including fuller utilisation of reactive capability from distributed generation
- Since 2011 new reactive power compensation equipment has been in delivery, with 4 shunt reactors commissioned and another 7 planned by the end of 2015.
- A further 8 reactors across 2015 and 2016 were sanctioned as part of a programme of actions to address the deficit in reactive power absorption identified by the end of 2016.
- A similar investment programme is ongoing by the Scottish Transmission Owners, to be delivered by 2017.

6.2.2. Lack of system inertia

Synchronous machines are characterised by a large mass rotating with the electrical system frequency. It is the sum total of the stored energy in the rotating machines, generators and motors, that make up what is referred to as system inertia. System inertia is a measure of the resilience of the transmission system, showing how resistant the system is to changes in frequency due to disturbances such as sudden losses of demand or generation. In situations where the electrical frequency is decreasing, due to a mismatch in demand and generation, the mechanical energy stored in the rotating machines is released into the electrical system, which slows the rate at which the electrical system is changing.

In the case of increasing electrical frequency, energy is stored in the rotating machines, which again slows the rate of change of electrical frequency.

Non-synchronous generators (like wind farms) which are on the increase are not directly coupled to the electrical system frequency, the majority of which use power electronics to converts DC power into AC power aligned with the system frequency.

Because of this, non-synchronous generators do not contribute to system inertia. Low system inertia can occur when non-synchronous generation displace synchronous generation, which increases the risk of rapid changes in system frequency.

6.2.3. Rate of change of frequency relays (RoCoF relays)

RoCoF relays are used to protect the embedded generator connected at the distribution level in case of islanding a section of the network. Following a system fault part of the network can become split from the rest of the national system. From a safety prospective, it is required that no generation is running in the islanded part. The way to detect islanding and disconnect the embedded generators, it is though the RoCoF relays which will detect the imbalance between generation and demand in the islanded part, and will disconnect the embedded generators. This will also ensure that no embedded generator is running when the islanded part is being energised.

The rate of change of frequency following a loss of generation or demand is determined by the size of the loss and the system inertia at the time. At times of low system inertia, as described in the section above, the size of the loss must be managed so that RoCoF relays on embedded generators are not triggered and cause further increases in the imbalance between generation and demand.

In periods of large volumes of non-synchronous generation and low system inertia, the System Operator will plan to use the most economic combination of increasing system inertia by bringing on synchronous plant and reducing the largest loss on the system. Both of these will require action through the Balancing Mechanism, or contracts and trades done ahead of real time.

The joint Distribution and Grid Code working group are progressing to change the RoCoF settings, to avoid them being triggered due to low inertia. The group was formed to assess and facilitate an adjustment to the relays for all generators above 5MW, that is expected to be fully implemented in August 2016. The working group is also examining requirements for smaller generators and is seeking engagement from this sector.

6.2.4. Long term planning to address transmission system issues

The System Operability Framework (SOF) has been developed to study in-depth, year-round impact of our Future Energy Scenarios on system operability in the years to come. The topics such as inertia, system strength, system stability and voltage control are discussed in detail as part of SOF.

The process begins by assessing existing network performance, identifying the root causes of incidents and constraints observed on the system in recent years, and highlighting potential new changes in system dynamics in future years based on system studies. National Grid is committed to stakeholder engagement and action on the feedback we receive.

For access to the System Operability Framework, please see the following page:

http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/System-Operability-Framework/

6.3. Summer system operation case study: Wimbledon 2013 men's singles final

Electricity usage varies over the course of a day, week, and year. This variation in demand is due to a number of factors such as temperature, light levels, and business activity. Using historical and forecast data the demand profile for any given day of the year can be predicted. One interesting challenge for National Grid is forecasting the effect of major televised events, and how they can distort a predictable pattern of demand over the course of the day.

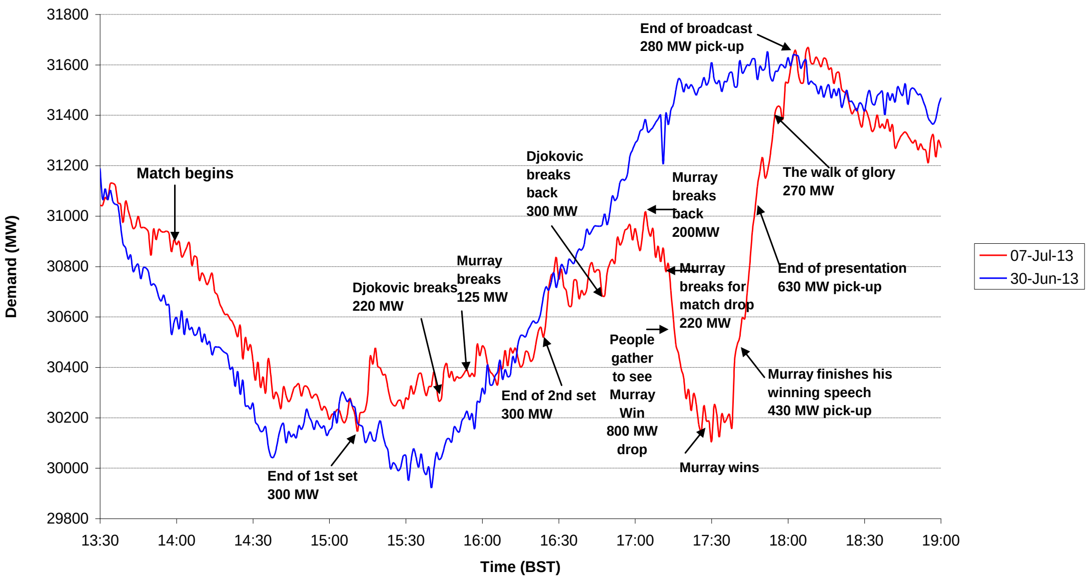
The 127th Wimbledon final was won by Andy Murray on the 7th July 2013, becoming the first Briton to win the men's singles title since Fred Perry in 1936. BBC1's coverage had a five minute peak audience of 17.3 million from 5:30pm as Murray celebrated his win. It was the highest peak UK audience of any televised programme in 2013, and the highest audience for a Wimbledon final since at least 1990. With such high viewing figures, a television programme can affect the behaviour and energy use of a relatively large proportion of the population. Over the course of such an important match electricity demand can swing in sympathy with the unfolding events.

What happened on the system

Figure 22 below shows demand in MW over the course of the Wimbledon men's final, the red line showing the match day demand and blue showing the demand curve for the Sunday before.

It is worth bearing in mind that different days of the week have different demand profiles, for example, Sundays and Mondays look quite different, and a Sunday in August would look different to a Sunday in December.

Figure 22 - Wimbledon Men's Final 7th July 2013, Murray Vs Djokovic



As the match begins at 14:00, there are no unusual changes, only the normal gradual afternoon decline, until the end of the first set at around 15:15 when a sizable 300MW increase occurs. As both Djokovic and Murray trade breaks of serve over the next 2 hours, the electricity demand jumps up in steps as the audience boil kettles, flush toilets and switch on lights as their attention is momentarily averted from television screens. As the tension builds with Murray breaking serve, an audience of 17.3 million gather around TV sets, the electricity demand drops 220MW, and then a further 800MW. Murray wins, and following his acceptance speech, demand jumps 430MW, then 630MW at the end of the trophy presentation, 270MW after the ‘walk of glory’ and a final 280MW as the BBC coverage comes to an end. In total an increase of 1610MW in demand over a 25 min period. This is in stark contrast to the steady increase in demand seen over the same period on the previous Sunday.

Managing TV pickups

Many popular television programmes have a similar effect on electricity demands; sporting events, soap operas and royal weddings. National Grid work to forecast these events and have contingency measures in place to manage the swings in demand in real time. In order to maintain system frequency at close to 50Hz, changes in demand need to be met by equal changes in generation. This means the National Grid Control Room will plan to hold additional levels of generator reserve over these periods so that they can be called upon at short notice when required. These reserve services and other types of balancing service are provided by a competitive market known as the Balancing Mechanism, National Grid are incentivised by Ofgem to procure these services in the most efficient and economical way. One common option is to run competitive tender rounds to contract balancing services in advance, which can often be more economical than relying on the Balancing Mechanism at closer to real time.

Table 8 - Top 10 TV pickups since 2010

Programme	Channel	TV Pickup (MW)	Date
Royal Wedding - Bride's Carriage Procession returns to Buckingham Palace	BBC1	1600	29/04/2011
Eastenders	BBC1	1245	02/04/2013
Military Driving School	ITV1	1240	19/04/2011
The True Price of a Pint: Tonight	ITV1	1210	07/04/2011
The Chase	ITV1	1210	04/03/2011
Coronation Street	ITV1	1197	09/04/2014
Eastenders	BBC1	1165	06/09/2012
Coronation Street	ITV1	1158	01/04/2013
Coronation Street	ITV1	1150	03/04/2013
Euro 2012 England v Ukraine	ITV1	1110	19/06/2012

Table 9 - Top 10 TV pickups of all time

Programme	Channel	TV Pickup (MW)	Date
World Cup Semi: West Germany v England	BBC1	2800	04/07/1990
World Cup: England v Brazil - half time	BBC1 and ITV	2570	21/06/2002
World Cup: Nigeria v England - half time	BBC1	2340	12/06/2002
Eastenders: Who Shot Phil Episode	BBC1	2290	05/04/2001
The Darling Buds of May	ITV	2200	28/04/1991
The Darling Buds of May	ITV	2200	12/05/1991
Rugby World Cup Final: England v Australia - half time	ITV	2110	22/11/2003
Coronation Street	ITV	2100	18/04/1994
World Cup: England v Argentina -half time	ITV	2100	30/06/1998
Coronation Street	ITV	2070	01/04/2007

6.4. Balancing the system on difficult days

Negative System Sell Prices can be caused by a combination of the summer transmission system issues.

This section describes some of the challenges that National Grid face during the day to day balancing of the system. These situations add complexity to the operation of the transmission system and can have an impact on system imbalance prices, in some cases causing System Sell prices to turn negative.

6.4.1. Case study: low demand and high wind

On the 11th of August 2014, GB was hit by the tail end of hurricane Bertha. The hurricane tracked further north across GB than forecast resulting in a large number of wind farms, particularly in Scotland, being exposed to higher wind speeds than expected. At the day ahead stage the total transmission and embedded GB wind output was forecast to peak at 7.9GW, with the wind output in Scotland alone expected to peak at 2.9GW. At the time, the power transfer limit between Scotland and England and Wales was 2.4GW, taking into account the synchronous generation and low demand in Scotland overnight, the ENCC needed to take actions to prevent the export limit from being exceeded.

Planning actions

With such large volumes of non-synchronous generation predicted, commercial trades were enacted at day ahead on both European Interconnectors, BritNed and IFA, to limit the size of the largest infeed to GB, and remove the exposure to a Rate of Change of Frequency risk. Less inertia on the system due to high levels of non-synchronous generation, means that the transmission system cannot tolerate such a large infeed loss, and the risk needs to be managed by pulling back the largest loss, buying additional response, or by increasing inertia. Key wind farms in Scotland that are not accessible in the Balancing Mechanism, were traded off in advance of the forecast conditions. At the same time high system voltage was expected to affect the South of England, and Didcot and Medway units were required to run to absorb reactive power over the minimum periods to maintain system voltage standards.

Events on the day

On the day GB wind output was 1GW higher than expected, and embedded wind generation in Scotland suppressed demand further than forecast, meaning that additional actions would be required to manage the Scotland to England transfer. Lower outturn demands also caused the system reserve and response requirements to increase, which led the ENCC to take further actions in the Balancing Mechanism to ensure these reserve and response requirements could be met.

In ENCC timescales, Emergency Actions were taken on both European Interconnectors to manage the size of the GB infeed loss and remove the exposure to Rate of Change of Frequency risk, in line with previous energy trades in the planning timescales. The ENCC took bid offer actions in the Balancing Mechanism to take off approximately 2.2GW of wind generation. These actions were primarily:

- To manage the power flow across the Scotland to England boundary, down to the transfer limit.

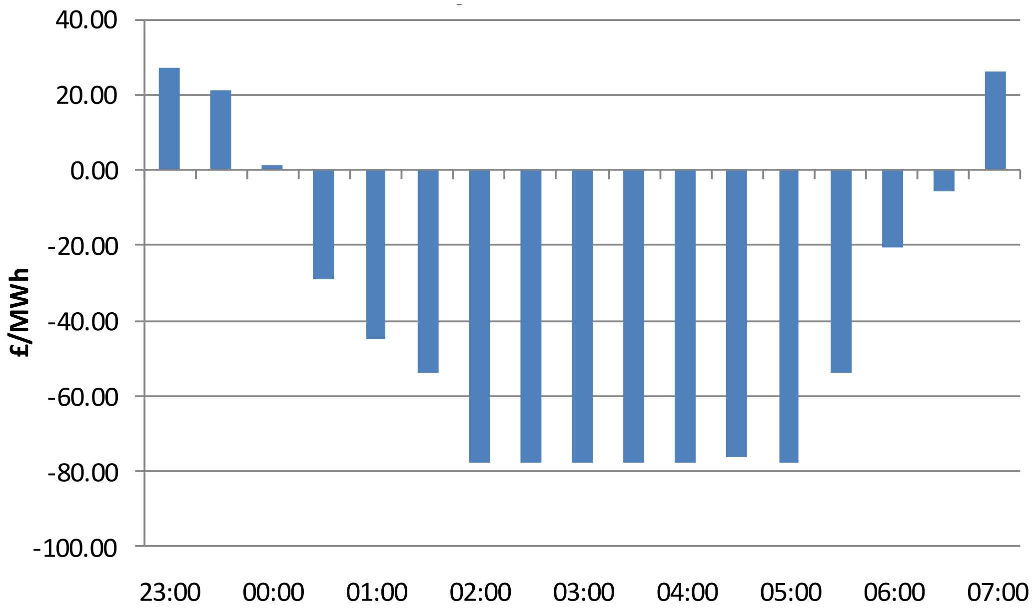
- To manage downward regulation – this is to ensure that at low demand levels, there is sufficient downward flexibility on generators to allow changes in demand to be met whilst maintaining system frequency standards.
- To manage system inertia – high volumes of non-synchronous generation with low inertia displace synchronous generators with typically high levels of inertia. This decreases the size of the allowable largest infeed loss, which will need to be managed to avoid being exposed to a Rate of Change of Frequency risk. The ENCC need to constrain synchronous plant into service in order to increase the level of inertia present on the system.

On the 11th of August between 23:00 and 07:00, the ENCC issued over 600 instructions to market participants in order to manage constraints and maintain system frequency within operational limits. **Figure 23** below shows how System Sell Price dropped to minus £78/MWh between 03:30 and 05:00.

Imbalance settlement

When supply and demand does not balance after all bilateral trading activity is complete in the electricity market, National Grid will issue instructions to generators or Bid Offer acceptances to ensure that supply matches demand in real time. To incentivise market participants to balance their position, an imbalance settlement mechanism is used where participants pay, or are paid system imbalance prices depending on their position in relation to the rest of the transmission system. The System Sell Price is the imbalance price that is used to settle the difference between contracted generation or consumption and the amount that was actually generated or consumed. It is paid to parties who have a net surplus of imbalance energy. The System Buy Price is paid by parties who have a net deficit of imbalance energy. Imbalance prices are calculated for each half hour settlement period, based on the balancing actions and Bid/Offer prices that National Grid needed to take to match demand and generation.

Figure 23 - System Sell Price on the 11th of August



Negative system sell prices

Negative imbalance prices can occur when many balancing actions are required and the Bid prices accepted, to reduce generation to balance the system are negative. Participants will submit negative Bid prices when they prefer not to be taken as a balancing action to reduce generation; a negative Bid price would mean a generator would be paid to produce less energy. If the weighted average of all accepted Bids is negative, then the System Sell Price will also be negative which, in the imbalance settlement, would result in parties being charged for producing more energy than required.

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