



Summer Outlook Report

2018

nationalgrid



How to use this interactive document

To help you find the information you need quickly and easily we have published the *Summer Outlook Report* as an interactive document.

Home

This will take you to the contents page. You can click on the titles to navigate to a section.



A to Z

You will find a link to the glossary on each page.



Arrows

Click on the arrows to move backwards or forwards a page.



Hyperlinks

Hyperlinks are highlighted in bold throughout the report. You can click on them to access further information.

Welcome to the 2018 *Summer Outlook Report*. The report draws together analysis and feedback from across the industry to present a view of supply and demand for the summer ahead.



We had a great response to our recent readership survey and I'd like to thank you for taking the time to share your views.

Acting on your feedback we have:

- strengthened the information we have included on the markets we are connected to
- provided more commentary and background on the factors affecting these markets
- provided more in-depth analysis of the recent changes to the electricity generation capacity profiles of a number of major European countries
- concentrated on the impact of transit gas and the changing profile of LNG supplies to GB.

The *Summer Outlook Report* is just one in a suite of documents from the System Operator exploring the future of energy. I encourage you to read our other publications including:

- *Response and Reserve Roadmap* – explores the complexity of balancing supply and demand in a changing energy landscape
- *Future Energy Scenarios* – will explore the longer term trends in the industry and how that may impact the energy mix from today to 2050. Look out for the FES 2018, which we'll be publishing on 12 July 2018.

- *Winter Review and Consultation* – explores the actual energy demand and supply patterns and how they compare with our forecasts. This year it will include an analysis of the recent cold weather spell on both the gas and electricity systems. We'll be publishing this in early June.

In them you can find out more about the evolution of the energy landscape, and how we're working with our stakeholders to build and operate the gas and electricity systems of the future. Thank you for taking the time to read this year's *Summer Outlook Report*.

To find out more, and register for email updates, go to our website. We want to make sure our publications are as useful to you as possible, so please let us know what you think. You can email your feedback to us at marketoutlook@nationalgrid.com, join the debate on Twitter using #FutureofEnergy

Fintan Slye
Director UK System Operator

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Executive summary

The *Summer Outlook Report* is an annual publication delivered by National Grid each spring. It presents our view of the gas and electricity systems for the summer ahead (April to September). The report is designed to inform the energy industry and support their preparations for this summer and beyond.

Overview: Electricity summer 2018

Both peak and minimum transmission system demands this summer are expected to be lower than the 2017 weather corrected outturn. Minimum transmission system demand is expected to be 17 GW, this equates to 21.1 GW of underlying demand, only marginally lower than last summer's minimum. Peak transmission system demand is anticipated to be 33.7 GW between the high summer months of June to August. We expect there to be sufficient generation and interconnector imports to meet demand throughout the summer period.

The increase in distribution connected generation, for example wind and solar PV, has contributed to this downward trend in demands. Solar PV continues to impact the daily demand profile because

the daytime demands we see on the transmission system are suppressed by it, which can make forecasting difficult. Solar PV and wind generation connected to the distribution networks have increased to 12.9 GW and 5.7 GW respectively. Increased supply and demand variability caused by these periods of low demand and high levels of renewable generation can create operability challenges. As a result, we may need to take more actions to curtail generation and possibly instruct inflexible generators to reduce their output in order to balance the system.

In our operational outlook chapter we explore these challenges and we continue to work with industry participants to develop the tools and services needed to manage them.

Executive summary

Overview: Gas summer 2018

Gas from the UK and Norwegian Continental Shelf, or 'beach' gas, is expected to be the dominant component of gas supplies into GB this summer. We anticipate that gas from the more flexible, 'non-beach' supplies, particularly interconnector imports and LNG will remain low. However, base LNG volumes are expected to be higher than we have seen during winter periods. Our analysis informs us that the total gas supply will be in excess of what is required to meet GB demand. As a result, we expect to see GB sourced gas to be routed to where the gas price is more attractive. Therefore we anticipate transit gas demand on the network during the summer period.

The increase in renewable electricity generation not only has an impact on the operability of the electricity system, it also affects demand on the gas system. Lower overall electricity demand, along with increased renewable generation, means there is less of a requirement for gas fired electricity generation. As a result, we expect overall gas demand to be 35.7 bcm this year, slightly lower compared to summer 2017.

In the gas demand chapter, we explore how much of an impact the effect of weather has on gas demand. The difference between a day with high wind and solar generation and a day with low wind and solar generation can amount to 20 per cent of demand on a summer's day. The change in demand patterns can introduce significantly more within day and day to day changes in flows on the gas transmission system, and reinforces the need for a more agile network.

This summer we expect to see one of the highest volumes of maintenance on the gas transmission system to date. Summer can be a challenging time to manage supply and demand variability as well as providing access to the network even though GB demand is lower.

We continue to work closely with our customers to minimise the impact of maintenance during this busy period. As we continue to see our customers using the network in different ways, we will continue to develop the operational tools to manage the within day variations of supply and demand on the network.

National Grid's role

National Grid plays a vital role in connecting millions of people to the energy they use, safely, reliably and efficiently.

We own and manage the high voltage electricity transmission network in England and Wales. We are also the System Operator of the high voltage electricity transmission network for the whole of Great Britain, balancing the flows of electricity to homes and businesses in real time.

We don't generate electricity and we don't sell it to consumers. It is the role of energy suppliers to buy enough electricity to meet their customer's needs from the power stations and other electricity producers. Once that electricity enters our network, our job is to plan and operate the system to make sure supply and demand are balanced on a second-by-second basis.

On the gas side, we own and operate the high pressure gas transmission network for the whole of Great Britain. We are responsible for managing the flow of gas to our connected customers and businesses; working with other companies to make sure that gas is available where and when it is needed.

We do not own the gas we transport and neither do we sell it to consumers. That is the responsibility of the energy suppliers and shippers.

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

Accessing further information

The *Summer Outlook Report* is just one of the ways we provide information to and engage with the industry. In this chapter, we've brought

together some of the other ways you can stay up-to-date throughout the year.

Key publications from the System Operator

System Operator publications The *Summer Outlook Report* is just one of the documents within our System Operator suite of publications on the future of energy. Each of these documents aims to inform the energy debate and is shaped by engagement with the industry.

The starting point for our analysis is the *Future Energy Scenarios (FES)*. This document considers the potential changes to the demand and supply of energy from today out to 2050.

The network and operability changes that might be required to operate the electricity system in the future are explored in the *Electricity Ten Year Statement*, *System Operability Framework* and *Network Options Assessment*.

For gas, these issues are considered in the *Gas Ten Year Statement and Future Operability Planning* publications. We share aspects of our analysis with the industry during the development of these documents to make sure that the proposed solutions meet the needs of our stakeholders.

You can find out more about any of these publications, and how they incorporate insight from our stakeholders, by clicking on the document front covers on the next page or by visiting our [Future of Energy webpage](#).

Figure 0.1
Key publications from the System Operator 2017/18



Network Options Assessment
January 2018

The options available to meet reinforcement requirements on the electricity system.



Winter Outlook Report
October 2018

Our view of the gas and electricity systems for the winter ahead.



Summer Outlook Report
April 2018

Our view of the gas and electricity systems for the summer ahead.



Electricity Ten Year Statement
November 2018

The likely future transmission requirements on the electricity system.



System Needs and Product Strategy
April 2018

Our view of future electricity system needs and potential improvements to balancing services markets.

Accessing further information

Latest operational information

The information provided in our Outlook reports is based on the best data currently available to us. This outlook will change as we progress through the summer. There are a number of sources of information you can access for the most up-to-date view, both for electricity and gas.

Electricity

Much of our electricity analysis is based on generation availability data provided to us by generators. This is known as Operational Code 2 (OC2) data. As generators update their plans each week, the picture of supply and demand will change. You can access the latest OC2 data, which is published each Friday, on the [BM Reports website](#).

Our demand forecasts are regularly updated throughout the year. The demands published in this report are based on forecasts from March 2018. For the most up-to-date information, we encourage the industry to view our latest forecasts on the [BM Reports website](#).

The System Operator Notification Reporting system (SONAR) provides real time operational information for market participants and members of the public. The system informs the market about certain changes that generators have made to their operational parameters, or instructions the Control Room may have issued to start up power stations. You can view these notifications and sign up for email alerts via the [SONAR website](#).

Gas

To support market participants and other interested parties, we publish a range of data on the operation of the gas transmission network. The Market Information Provision Initiative (*MPI*) publishes information required under UNC and EU obligations, as well as additional information we feel is useful for the market.

Events

We host industry events throughout the year to discuss the operation of the gas and electricity systems, and debate important industry

changes. You can find out more about our [gas](#) and [electricity](#) operational forums on our website.

Please tell us what you think

We want to make sure that we continue to provide you with the right information to support your business planning. To do this, we'd like to know what you think about this

publication. You can share your feedback by emailing us at marketoutlook@nationalgrid.com.

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Electricity

Summer demand

This section presents our current view of demand for summer 2018. All demand figures in this chapter are transmission system demands. These demands are based on national demand plus a station load of 500MW. Further information on the demand assumptions can be found at the end of this chapter.

Key messages

- Overall transmission demands will be lower than 2017.
- Distribution connected generation will continue to grow.
- Peak demand for the high summer period is expected to be 33.7 GW.
- Daytime minimum demand is estimated to be 1.1 GW lower than 2017 at 20.1 GW.
- Minimum summer demand is expected to be 0.6GW lower than 2017 at 17 GW.

Key terms

- **Distribution connected generation:** any generation that is connected to the local distribution network, rather than to the transmission network. It also includes combined heat and power schemes of any scale. Generation that is connected to the distribution system is not directly visible to National Grid and therefore acts to reduce demand on the transmission system. You can access our latest daily distribution connected generation forecasts up to 7 days ahead on our website.
- **High summer period:** the period between 1 June and 31 August, or weeks 23 to 35. It is when we expect the greatest number of planned generator outages. At the same time, this is when we normally experience higher demand, predominantly driven by the increased use of cooling systems.
- **Transmission system demand (TSD):** demand that National Grid, as the System Operator, sees at grid supply points, which are the connections to the distribution networks. It includes demand from the power stations generating electricity (the station load) at 500MW.
- **Underlying demand:** demand varies from day-to-day, depending on the weather and the day of week. Underlying demand is a measure of how much demand there is once the effects of the weather and the day of the week have been removed.
- **Weather corrected demand:** is the demand seen on the transmission system, with the effect of the actual weather removed and the impact of normal weather added.
- **Network Innovation Allowance (NIA):** is a set allowance each RIIO network licensee receives as part of their price control allowance. Its aim is to fund projects directly related to the Licensees network that have the potential to deliver financial benefits.
- **Normalised demand:** is the forecasted demand using long term trends to estimate underlying demand with a 30 year average (on a weekly resolution) for the weather component added.

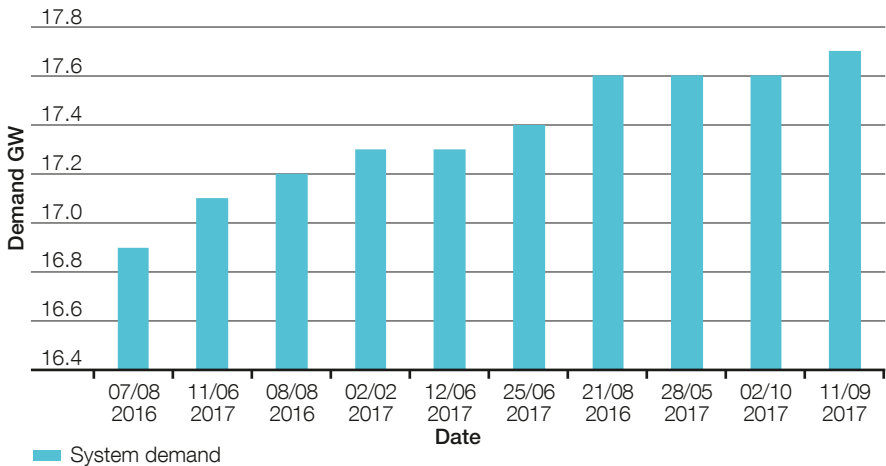
Electricity

Overview

The key characteristics of the summer period is low demands and variability day to day. Periods of low demand have an impact on how we operate the transmission system. As a result, it is important that we understand the minimum levels of demand along with the peak demand that we can expect to see during the summer months. During summer 2017, we saw the second lowest system

demand on record (actual demand based on actual weather including station load). In figure 1.1, we see that out of the 10 lowest system demands, seven occurred in 2017 alone. This downward trend in demand is largely due to an increase in distribution connected generation (both renewables and non-weather generations) connected to the distribution networks.

Figure 1.1
Ten lowest demands



Summer system demand

Our analysis suggests transmission demands for the coming summer are likely to be lower than last year's weather corrected outturn. This is mainly because of the increase in distributed energy sources combined with an anticipated drop in the underlying demand. Distributed energy sources refer to the generation connected to the distribution

network. Because it is connected to the distribution system and is therefore not directly visible to us, it acts to reduce demand on the transmission system. Table 1.1 illustrates the gradual reduction in demands year on year along with our forecast demands for summer 2018.

Table 1.1

Weather corrected summer system demands for the last 3 years and the forecast for 2018

Year	Summer minimum (GW)	Day time minimum (GW)	High summer peak (GW)
2015	18.4	25.8	37.5
2016	17.8	22.7	36.3
2017	17.6	21.2	34.4
2018 (forecast)	17.0	20.1	33.7

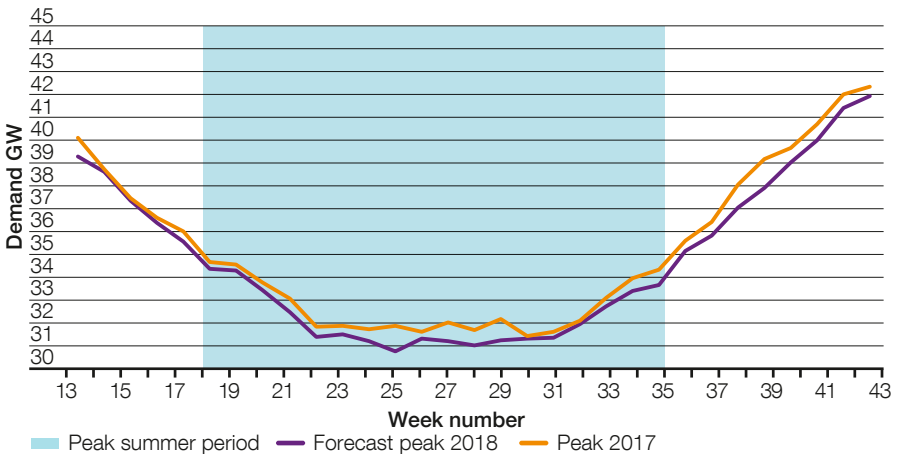
Electricity

Weekly peak demand

Figure 1.2 shows the weather corrected weekly peak demand for summer 2017, along with our forecast for 2018. Our peak demand forecast for the high summer period (between June and the end of August) is 33.7GW.

This is 700MW lower than last year's weather corrected outturn as a result of the increase in distributed generation and a reduction in underlying demand.

Figure 1.2
Weekly peak demand outturn for 2017 against our 2018 forecast



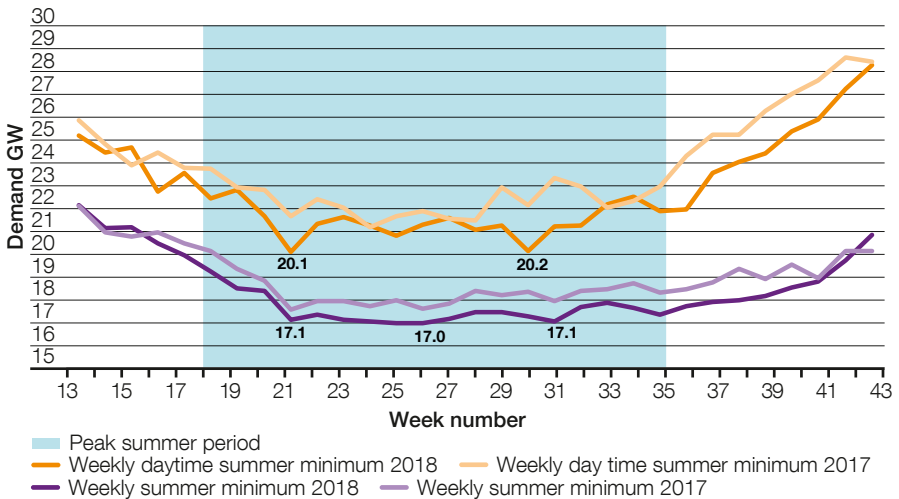
Summer minimum demands

In order to support the operation of the system during the summer months, it is important to consider both the summer minimum demand and the daytime summer minimum demands. Historically, the lowest demand occurred overnight; however, with the growth in renewable generation, wind and solar PV, the lowest demand can now occur during the day. Minimum demands are becoming increasingly more significant when balancing supply and demand on the

transmission system because the availability of flexible plant during these periods is reduced. The daytime summer minimum demand for 2018 is expected to be approximately 20.1 GW, 1.1 GW lower than last year's weather-corrected outturn.

The summer minimum demand for 2018 is also forecast to be 17 GW, 0.6GW lower than last year's weather corrected outturn.

Figure 1.3
Weekly minimum demand outturns for 2017 and our forecast for 2018



In accordance with Grid Code, we publish our most recent forecasts on the BM reports website¹. Demands published in this report are based on demand forecasts conducted

in February 2018. For the latest forecasts, please visit our [BM reports website](https://www2.bmreports.com/bmrs/?q=demand/2-52-weekahead).

¹ <https://www2.bmreports.com/bmrs/?q=demand/2-52-weekahead>

Electricity

Daytime minimum demand

In summer 2017, we experienced something we hadn't experienced before on the electricity transmission system; we saw the day time minimum demand fall lower than the overnight minimum.

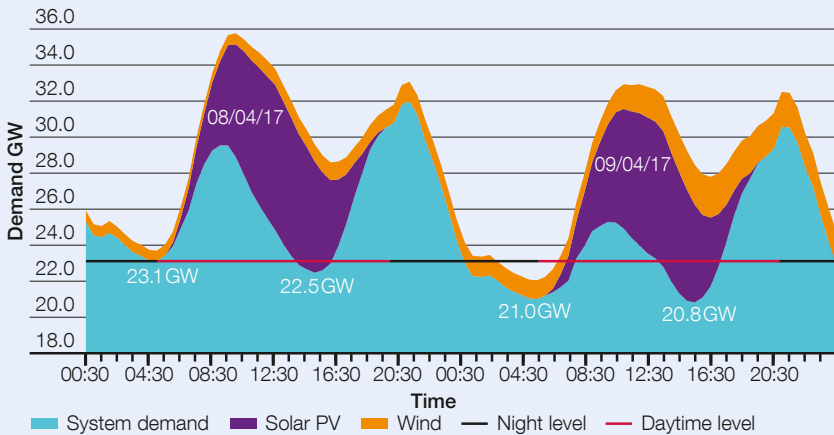
This happened on two occasions, on the 08 and 09 April and was caused by very high distribution connected generation. solar PV and wind output, coupled with high temperatures during the day reduced the demand on the transmission system.

PV generation for the 08 April was 8GW and wind was approximately 900MW, giving a total of 8.9GW. Similarly, on the

9 April, whilst the PV outturn had dropped to 7.5GW compared to the previous day, wind had increased to 1.9GW, giving a total of 9.4GW of distribution connected generation. Accurate forecasts on the day meant the Control Room were well equipped ahead of time to manage both periods of low demand.

We see in figure 1.4 the effect that distribution connected generation had on the transmission demand for both dates. We are likely to see this repeated if we get high PV days with wind and high temperatures.

Figure 1.4
Daytime minimum demand vs overnight demand



Daily demand profile

In the daily half hourly demand profile in figure 1.5, demand ranges from a minimum of 16.5 GW and a maximum peak of 35.4 GW (please note this excludes the 500 MW station load). The orange bars represent the times when there is the highest amount of solar

generation. The purple bars represent when solar begins to generate and/or when generation begins to reduce. The red bars represent the times when there is no solar generation.

Figure 1.5
Daily half hourly demand profile from the high summer period 2017

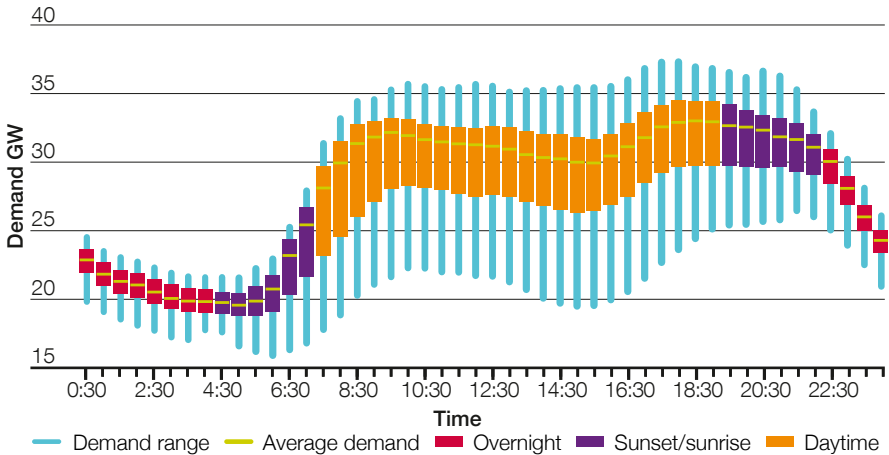


Figure 1.5 suggests the daily minimum demand is likely to occur between 5am and 6am. Demand then increases until 8am, where it remains relatively flat until 4pm and then begins to pick up for the evening peak. Daily peak demand is largely influenced by the amount of solar radiation, for example, if it is a bright and sunny day, the peak demand is likely to occur either in the morning between 8am and 9am, or after sunset. The daytime demands between 9am and sunset are suppressed by distribution connected solar generation.

During the summer months, demand profiles can change from day to day depending on the levels of renewable generation on the system, in particular, solar PV. Variability on the system has increased as the amount of renewable generation has grown which ultimately creates challenges when managing system operability. Maximum solar generation output usually coincides with the demand reduction after lunchtime.

Electricity

Summer peak demand

Figure 1.6
Estimated summer peak demand timings

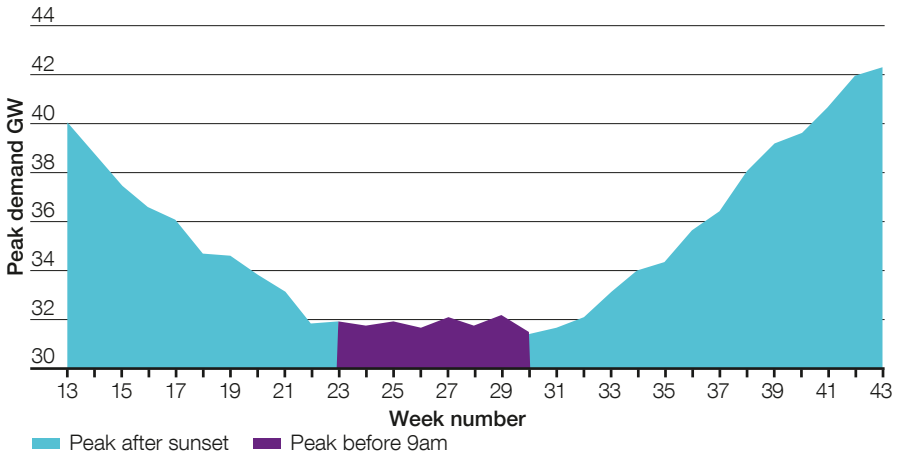


Figure 1.6 shows our estimated timings for the peak demand based on seasonal normal weather. Our analysis suggests daily summer peak demand is likely to occur between 8am and 9am during weeks 23 to 30 due to late sunset times and the amount of solar

generation. The daily peak demand is significantly impacted by the amount of solar PV generation.

Distribution connected solar generation

Figure 1.7
Historic and forecast PV capacity and daily maximum output

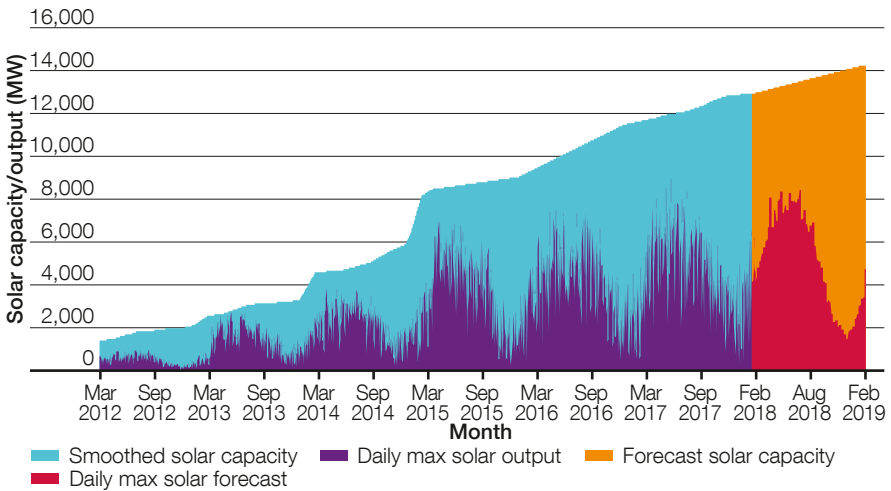


Figure 1.7 shows historic solar PV capacity growth and daily maximum generation output. It also includes our year ahead (March 2018 to February 2019) forecast for both installed capacity and maximum daily output.

Distribution connected solar capacity had increased to 12.9GW by February 2018.

Electricity

Assumptions

All demand figures in this chapter are transmission system demands. These demands are based on national demand plus a station load of 500MW.

1. Underlying demand is corrected for the impact of weather and day of week. This is likely to be 500MW lower in 2018 compared with summer 2017. Our 500MW assumption is based on the analysis of the underlying demand levels over the last 12 months.
2. Distribution connected solar PV capacity in February 2018 was 12.9GW. Currently our 2-52 weeks ahead forecast assumes a 110MW increase in the capacity per month. Our long range forecast models assumes around 14.7GW of solar capacity by the end of March 2019.
3. Distribution connected wind capacity has increased from 4.8GW in 2017 to 5.7GW, and we anticipate it will be broadly flat this summer.



Spotlight:

Forecasting solar generation and Network Innovation Allowance (NIA) projects

National Grid is involved in a number of projects with external partners to improve the monitoring and forecasting of solar PV generation.

Because all solar is connected to the distribution networks, historically National Grid, as the System Operator, has no visibility of live metering from solar generation. This has meant that accurately forecasting demand has proved challenging. With installed solar PV capacity increasing since 2011, it has become an important component in our demand forecast. To improve the accuracy of our demand forecasts, we have launched a number of projects to help us to tackle this directly. The result of this work has meant that by summer 2017, we had seen a marked improvement in our daytime demand forecasting accuracy. As a result, our average midday demand error has reduced.

Our NIA partnership with Sheffield Solar continues to provide near-real time estimates of national solar power output. Together we have developed a system to produce localised outturns at each of the 327 Grid Supply Points in the UK. These datasets are invaluable for live monitoring and network planning, as well as providing the framework to build solar power forecasting models. We are now in discussion to continue this collaboration to provide high frequency data which will supply 5 minute solar outturn data, rather than the current 30 minute outturn data, as well as improving and validating further outturn values. Real time solar PV generation output can be accessed here <https://www.solar.sheffield.ac.uk/pv/live>

We are also involved in a number of other projects which address the accuracy of our

solar PV forecasts. All solar power forecasts rely on an accurate prediction of the weather, in this case solar radiance; this has proven to be a dominant source of PV forecasting error. Our NIA partnership with the Met Office has led to a new post-processing technique, which had an immediate impact during summer 2017 and we expect to see further improvements during 2018. From summer 2018, we will be joined by a Natural Environment Research Council (NERC) sponsored meteorologist from the University of Reading. The project will focus on whether extra meteorological information and data can be used to guide and adjust our solar forecasts.

Another NIA project we are a part of focuses on the methods used to translate forecast solar radiance values into solar power generation. Our collaboration with the University of Reading proposed a new model incorporating seasonal and time of day effects, which is currently being assessed.

We are also involved in a three month venture with the Alan Turing Institute for Data Science. This has resulted in a new artificial intelligence based solar power forecasting model, which has shown accuracy improvements at 7 days ahead. We are also in the process of evaluating this as a future forecasting model.

These projects are serving to improve solar PV forecasting and monitoring and ultimately to improve our demand forecasts. We are also continuing to explore further opportunities to enhance the improvements we have already seen, all of which help us to balance supply and demand more accurately and economically.

Operational view including generation/supply

Our operational view is based on historic performance and data provided to us by generators. We use this data to present a picture of operational surplus for each week of summer and to determine the actions we may ask generators to take during periods of low demand.

Key messages

- We are able to meet normalised demand and our reserve requirement in all weeks throughout summer including the shoulder months of April and September under all interconnector scenarios.
- There is a possibility that we may have to instruct inflexible generators to reduce their output, in order to balance supply and demand.

Key terms

- **Operational Code 2 (OC2):** data: information provided to National Grid by generators. It includes their current generation availability and planned maintenance outages.
- **Operational surplus:** the difference between the level of demand and generation expected to be available, modelled on a week-by-week basis. It includes both notified planned outages and assumed breakdown rates for each power station type.
- **Flexible generation:** types of generation that can respond quickly to requests to change their output, such as interconnectors, some coal and gas units, pumped storage and most large wind farms.
- **Inflexible generation:** types of generation that require long notice periods to step down or ramp up their output, do not participate in the Balancing Mechanism or have obligations that influence when they can generate. Examples of inflexible generation include nuclear, combined heat and power (CHP) stations, and some hydro generators and wind farms.
- **Shoulder months:** are those months that are not technically heat driven months, nor are they cooling driven months. Yet, they can cause demand for either heating or cooling or both in the same month.

Operational view

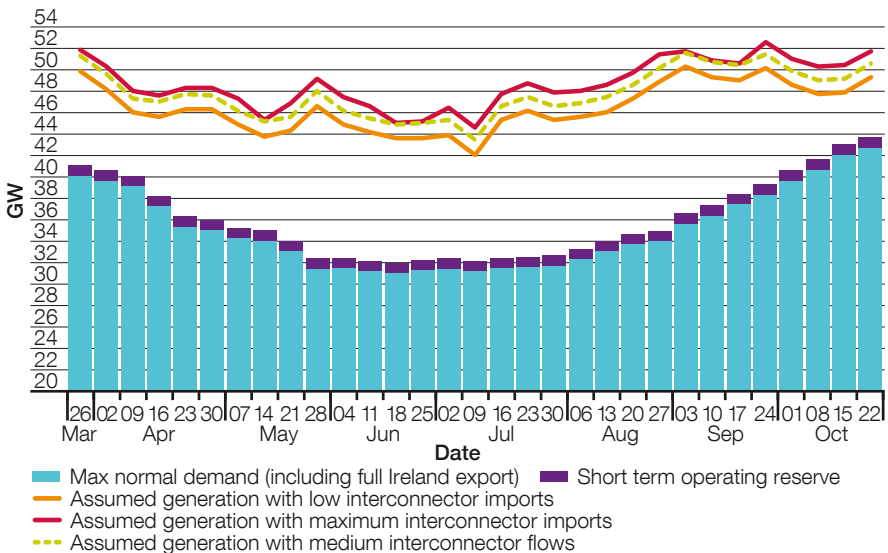
Our operational view is based on current generation availability data called Operational Code 2 (OC2) data. This is submitted weekly by generators. In our analysis we have used data provided to us on 15 March 2018.

The OC2 data includes generators' planned maintenance outages. To account for unexpected generator breakdowns, restrictions or losses close to real time, we apply a breakdown rate to the OC2 data. The breakdown rate is based on the units availability, maximum export limit (MEL), during the highest demand days over summer or winter excluding units we know are on planned outage. This is done by unit but grouped and applied by fuel type. The data is then modelled against forecast normalised transmission system demand, plus a reserve

requirement of 900MW and a range of interconnector flows, to provide a week-by-week view of the operational surplus.

The operational view does not consider any market response by generators to high demand or tighter conditions. The availability includes those with capacity market contracts that are only incentivised to run during a system stress event. We know that generators have greater flexibility in planning summer outages and, as market prices change to reflect the level of operational surplus, generators may take a commercial decision to move their planned maintenance programme. For the most up-to-date information, we encourage the industry to regularly view the latest OC2 data, which is published each Friday on the [BM Reports website](#).

Figure 1.8
Operational view summer 2018



Operational view including generation/supply

Figure 1.8 compares the expected weekly generation and differing levels of interconnector flows, against the weekly normalised demand forecast for the summer period. It is based on the OC2 data provided to us by generators on 15 March.

In the summer months, maintenance outages reduce the available generation capacity from power stations. This is because power stations use this period to carry out maintenance to ensure their availability over the winter months when there is higher demand and stronger market prices. Based on current economic conditions, we expect some coal power stations to be temporarily mothballed during summer 2018. We would expect them to become available if there was an obligation to fulfil their Capacity Market contracts, if they have them, or if the price increased to a level to make it profitable to generate. These units can require a few days' notice to run. As a result of these factors, the lowest levels of generation are typically seen during the high summer period, between June and August.

Based on current operational data, the minimum available generation is expected to be 42.1 GW in the week commencing 9 July (under the low interconnector scenario). We are able to meet normalised demand and our reserve requirement in this week, and throughout the summer period, into the shoulder month of September, even with low interconnector imports. Our operational view is based on the best data currently available to us. Changes to the notified generation and forecast demand will alter this outlook, potentially increasing or decreasing the level of operational surplus. For the most current information, we encourage the industry to regularly view the latest OC2 data, published each Friday on the [BM Reports website](#).

Unlike the operational view presented here, the data presented on the BM Reports website is largely unadjusted which means that it does not include derating for breakdowns; with the exception of wind, which is included at an assumed load factor for each month. The forecast peak demand for the week and a level of reserve are then compared to this to calculate the operational surplus. Data on BM Reports does not include interconnector imports or exports.

Assumptions

1. Demand

The demand used in our operational view is normalised transmission system demand (TSD) as mentioned in the 'demand' chapter. This takes in to account the rise in output from the increase in distribution connected generation which acts as a reduction in demand. The demand also includes the power used by generating stations when producing electricity (the station load at 500MW) and interconnector exports. We have assumed 1000MW of export to Ireland across the Moyle and EWIC interconnectors during the peak demand period. The IFA and BritNed interconnectors are treated as a source of generation.

2. Reserve

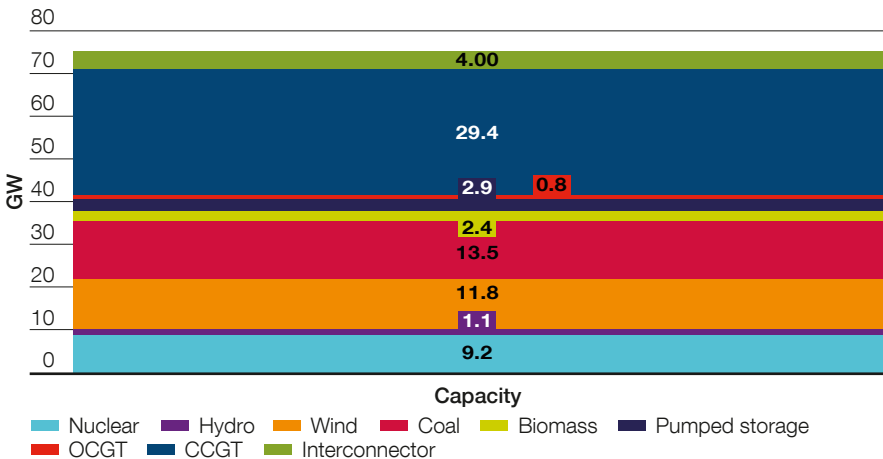
To be able to manage the second-by-second regulation of system frequency and respond to sudden changes in demand and supply, National Grid is required to maintain a level of reserve. In reality, this level of reserve varies daily depending on system conditions. A high

wind or solar forecast will increase the level. However, we have assumed a real time reserve requirement of 0.9GW for each week of our analysis. This is shown in figure 1.8 as a purple bar above the maximum normal demand.

3. Available generation capacity during summer 2018

Figure 1.9 shows the generation capacity expected to be available during summer 2018. This is from the maximum declared availability from the OC2 data, per unit, by fuel type, for the summer period. Later on we will apply a de-rating factor to account for breakdowns and restrictions and include planned outages which will result in plant having decreased ability to generate at its normal level for a particular week. The capacity includes only the generation that is connected to the transmission system and submits data to OC2. This is higher than last year due to the increase in installed wind capacity and some coal and gas plants that were expected to close in 2018 remaining open.

Figure 1.9
Available generation capacity for summer 2018



Operational view including generation/supply

4. Generator breakdown

The operational data provided to us by generators only includes their planned maintenance outages. As mentioned earlier, closer to real time, there may be unexpected generator breakdowns or availability reductions. To account for this in our analysis, we assume a breakdown rate for each generation type. These rates are shown in table 1.2.

They are based on the following:

- historic summer breakdown rates over the last 3 years
- they are taken from a units output against its capacity, on demand peaks higher than the 80th percentile
- it excludes zeroes if the outage was notified to us, and was therefore planned.

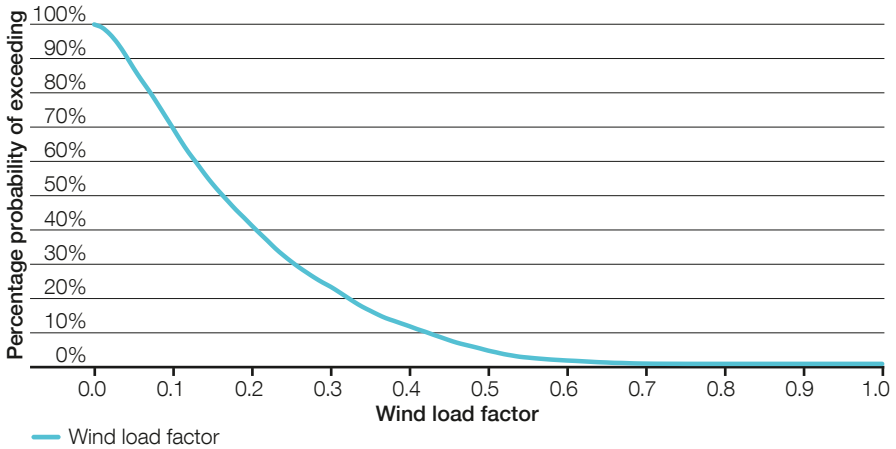
Table 1.2
Assumed breakdown rates for summer 2017

Power station type	Assumed breakdown rate
Nuclear	8%
Interconnectors	0%
Hydro generation	5%
Wind generation	84%
Coal & Biomass	13%
Pumped storage	3%
OCGT	8%
CCGT	12%

To determine how much weekly output we could reasonably expect from wind generation this summer, we use a load factor as a realistic scenario. This is calculated from the historic wind farm load factor distribution

for summer daytimes and is shown in figure 1.10. We use the median wind load factor of 16 per cent in our analysis as a scenario. This means there is a 50 per cent chance of the wind being either higher or lower than this.

Figure 1.10
Summer daytime wind load factors



Interconnectors

Our analysis is based on three possible interconnector scenarios for periods of peak demand, shown by the graph in figure 1.8. Each scenario includes a varying level of import from Continental Europe. Further details on interconnectors can be found in the 'Europe and interconnected markets' chapter.

The three interconnector scenarios listed below, assume full export to Ireland, which adds 1,000MW to expected demand:

- Low imports of 500MW, resulting in a net export of 500MW.
- Medium base case of 1,800MW, resulting in a net import of 800MW.
- Full interconnector imports of 3,000MW, resulting in a net import of 2,000MW.

Operational view including generation/supply

System operability during periods of low demand

In the summer, there is a significant reduction in the demand we see on the transmission system. This is because there is less of a requirement for heating and lighting compared with winter and a higher output from distribution connected solar generation. As a result, there are fewer generation units needed on the system to meet demand.

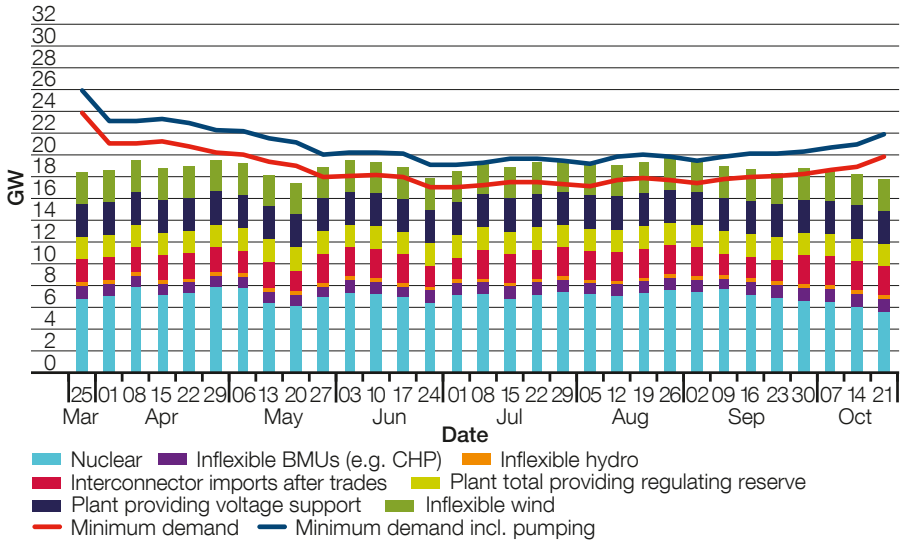
However, the system still needs to respond to the largest generation or demand loss. It is also necessary to maintain positive and negative regulating reserve levels. This is to account for forecasting errors and reductions in generator availability closer to real time.

As a result, we need to make sure that there is sufficient flexible generation on the system to be able to reduce their output low enough to meet that level of demand, and still have the ability to increase or reduce further to maintain sufficient frequency response.

To help us to understand the actions that we may need to take this summer to respond to periods of low demand, we model levels of inflexible generation against current expected minimum demands for each week. These forecasts are updated weekly throughout the summer and can be found on our [website](#).

To understand potential operability issues we need to stack de-rated inflexible generation against the forecast minimum demand. Ideally we want to keep this inflexible generation producing electricity, plus volumes for response and reserve which are required to be maintained. This is shown in figure 1.11 as a weekly resolution. Pumped storage demand is included at an assumed load factor of 70 percent; this is a method of increasing demand and is a routine action.

Figure 1.11
Weekly minimum demand and generation profiles



Based on current data, we can see that inflexible generation is expected to exceed minimum demand (blue line) during periods of the summer. As a consequence, we anticipate that we will be asking pumped storage units to increase demand by more than the assumed level by moving water back to their top lakes, and trading further to reduce the level of interconnector imports.

As we approach real time, these requirements may change depending upon the weather, wind conditions and the generation available on the day. We will continue to update this forecast during the summer. We will inform and engage with inflexible generators where actions have been exhausted on flexible generation and further balancing is required (please see appendix).

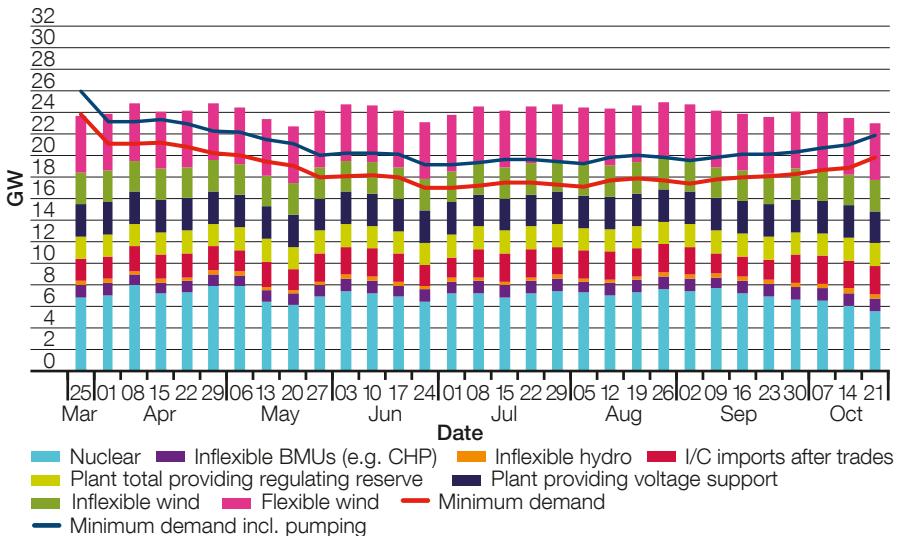
Operational view including generation/supply

Modelling flexible wind generation

As the amount of installed wind capacity continues to increase, it has become economic to carry a proportion of regulating reserve on large wind farms in times of high wind. Regulating reserve is the amount of generation that National Grid holds back on units, to manage the second-by-second regulation of system frequency to respond to sudden changes in demand and supply. The flexibility of wind farms allows us to issue curtailment instructions if necessary, asking them to reduce their output for a short period. The number of instructions we issue to wind farms is likely to increase in the future, as we continue to see reduced demand at the summer minimum (with more distribution connected solar capacity) and fewer flexible generators running overnight and in the afternoon.

In figure 1.12, flexible wind farm output has been added to the cumulative minimum output (the pink bars at the top), assuming the same wind load factor of 51 per cent. It shows that if flexible wind does not contribute to meeting the frequency response and regulating reserve requirements, it will need to be curtailed this summer to ensure that supply does not exceed demand. This curtailment will either be carried out via the Balancing Mechanism or by direct trades. There is a possibility of curtailment across the summer period, depending on wind conditions. This action will be carried out in economic order, along with increased pumping, and trades conducted to reduce import on the interconnectors.

Figure 1.12
Weekly minimum demand and generation profiles including flexible wind output



In our analysis, we have only considered possible wind curtailment at a national level. It is also possible that we may need to curtail wind at a local level this summer. Local issues are likely to be caused by constraints on the system resulting from faults, maintenance or network design. They may result in a higher level of generation in a geographical area than is needed or that can be safely exported to other areas of the electricity network. You can find out more about constraints in the appendix, or by accessing the latest forecasts for potential wind curtailment on our [website](#).

Operational view including generation/supply

Modelling inflexible generation

Assumptions

1. Load factors

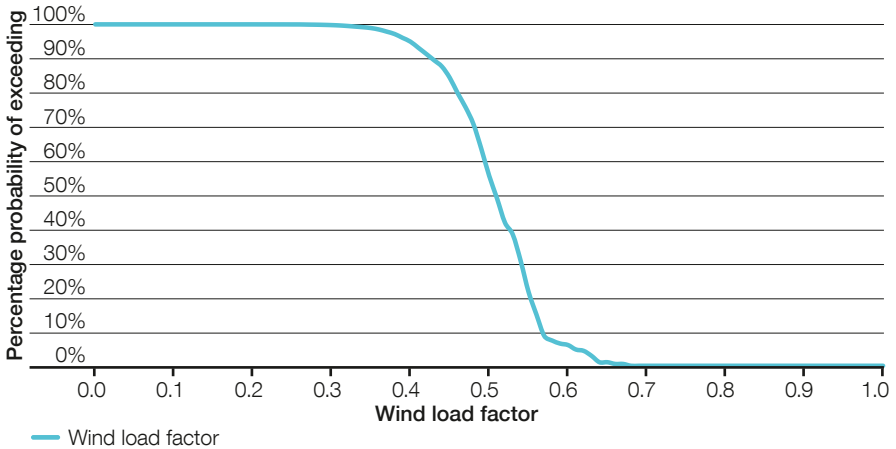
In order to determine how much inflexible generation is likely to be available during periods of low demand either early morning or during the afternoon, we apply a load factor to each generation type. These load factors, which are shown in table 1.3, are based on historic availability over previous minimum demand periods. We also apply a load factor to interconnectors. This is based on the price differential between Continental Europe and GB plus a reasonable number of trades it would take to resolve rate of change of frequency (RoCoF) issues by limiting the size of the interconnector loss. You can find out more about expected interconnector flows

this summer in the 'Europe and interconnected markets' chapter. More information about RoCoF can be found in the appendix. The load factor for flexible and inflexible wind is determined from figure 1.13. This shows that on at least one of the days where we might reasonably expect the lowest demand to occur, we can assume a wind load factor of 51 per cent. Again, there is a 50 per cent chance of the wind being higher or lower than this. The other load factors are chosen to represent a realistic low demand scenario. The interconnector flows are after trade action which we would aim to do in advance of an issue.

*Table 1.3
Inflexible load factor assumptions at minimum demand*

Generator type	Load factor
Nuclear	0.9
Inflexible Balancing Mechanism units (CHP)	0.5
Inflexible hydro	0.5
Flexible and inflexible wind	0.51
Moyle interconnector	0.5
East West interconnector	0.5
BritNed	0.70
Interconnexion France-Angleterre	0.70

Figure 1.13
Wind load factors at minimum demand



Generation merit order

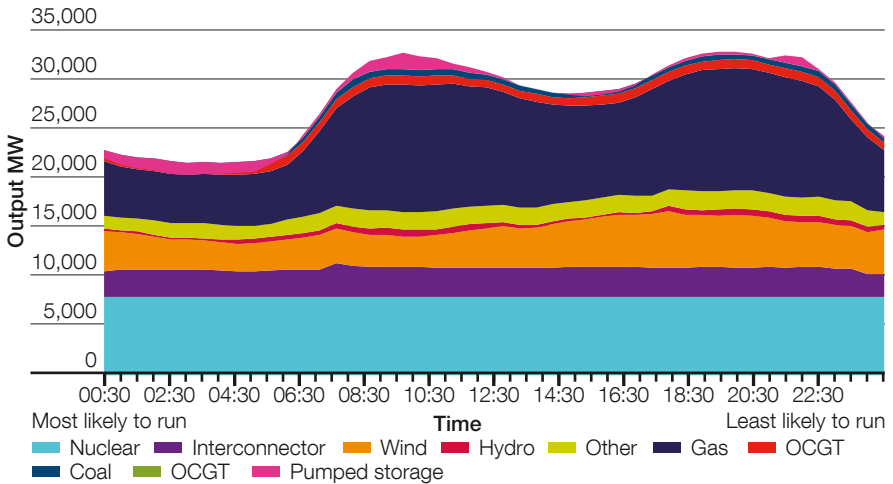
A generation merit order describes the sequence in which generators provide energy to the market at any given time. It is predominantly based on the cost of producing it, for each type of generator. The price at which energy can be sold varies throughout the day, depending on the levels of demand and generation capacity on the transmission system.

The most cost-efficient power stations feature first in the merit order, providing continuous output across the day, known as baseload. Less cost-efficient generators may respond to peaks in demand, when the price at which electricity can be sold is higher.

As an example, figure 1.14 shows the output of different types of generators over the course of a typical mid-summer day. It is based on data from 17 August 2017. It does not include solar or embedded wind because these are embedded and therefore do not make up the transmission connected demand or generation which is illustrated in figure 1.14. We expect generator output to follow a similar pattern in summer 2018.

Operational view including generation/supply

Figure 1.14
Generator output for a typical mid-summer day



Nuclear power stations, as shown in figure 1.14, typically provide a large proportion of the baseload in the summer. Wind generation also features early in the merit order as it has no fuel costs. However, it can only run when the wind is blowing. As a result of their input costs and efficiency, the most variable generator output is typically from gas and coal-fired power

stations. These power stations are called the marginal plant and are able to adjust their output in response to price signals as demand varies throughout the day. Based on analysis of current prices, gas-fired units are likely to feature ahead of coal in the generation merit order, as they will be more economical to dispatch.

Europe and interconnected markets

Our Europe and interconnected markets chapter explores interconnector behaviour and provides market insights into the impact to GB, of pricing and renewable generation in neighbouring countries.

Key messages

- GB forward prices for summer 2018 are expected to remain higher than markets in Continental Europe.
- Based on historical views and forward prices we expect there to be net imports of electricity on the interconnectors from Continental Europe. We also expect net exports of electricity on interconnectors to Ireland during peak, switching to imports overnight and during periods of high wind.
- Further nuclear outages in France are not likely to impact margins, even during the shoulder months.

Key terms

- **Operational Code Section 2 (OC2) data:** information provided to National Grid by generators. It includes their future generation availability and planned maintenance outages.
- **Operational surplus:** the difference between the level of demand and generation expected to be available, modelled on a week-by-week basis. It includes both planned outages and assumed breakdown rates for each power station type.
- **Flexible generation:** types of generation that can respond quickly to requests to change their output, such as interconnectors, some coal and gas units and most large wind farms.
- **Inflexible generation:** types of generation that require long notice periods to step down or ramp up their output, do not participate in the Balancing Mechanism or have obligations that influence when they can generate. Examples of inflexible generation include nuclear, combined heat and power (CHP) stations, and some hydro generators and wind farms.

Overview

The direction which interconnectors flow is determined by price, which in turn is influenced by the weather, and the amount of renewable generation available. This chapter looks at

interconnector availability for summer 2018 based on outages, forward pricing and activity in Continental Europe. All of these factors may affect interconnector flows into or out of GB.

Europe and interconnected markets

Interconnectors

The weather impacts price because of the influence on demand and distributed energy sources. This is as a result of the increase in renewable generation and demand fluctuations caused by changes in temperature. As a result, we expect occasional variations to interconnector flow patterns.

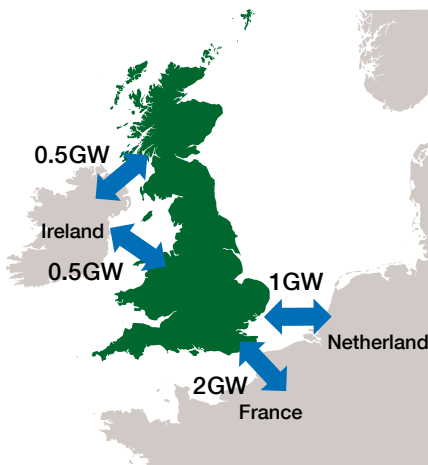
The forward seasonal prices between the GB, French and Dutch markets for summer 2018 indicate positive price spreads in favour of the GB market. We expect to export to Ireland during peak times on both the Moyle and East West interconnector (EWIC) interconnectors, turning to imports during the night and periods of high wind.

The Netherlands and France

Interconnexion France-Angleterre (IFA), the interconnector between France and GB, is currently under a fault outage with a reduced capability of 1.5 GW until the end of April. It is then expected to be at its full 2 GW capability this summer apart from two planned outages for essential maintenance. These outages are scheduled for 18 June to 29 June and 03 September through until 14 September inclusive. During these periods the capability will reduce to 1 GW.

The BritNed interconnector has a 1 GW capability between GB and the Netherlands. There are two planned outages this summer scheduled for 14 May to 18 May and 17 September through until 21 September inclusive. The capability will reduce to 0 GW during both of these outages.

We note that the start of the second BritNed outage is within a few days of the completion of IFA's September outage. Any delay to the return of IFA may impact the planned start of BritNed or result in both IFA and BritNed being on outage at the same time. At present, this would not adversely impact security of supply or operability; however, we will keep this under review.



Ireland

The East West Interconnector (EWIC) is currently under a fault outage with zero capability until 29 March. It will be on a planned outage for 9 days starting 01 May through until 09 May inclusive. During this time its capability will reduce from 0.5GW to 0GW. The 0.5GW

Moyle interconnector to Northern Ireland is expected to be at full capability throughout summer 2018, however, the maximum flow is subject to Transmission Entry Capacity (TEC) values.

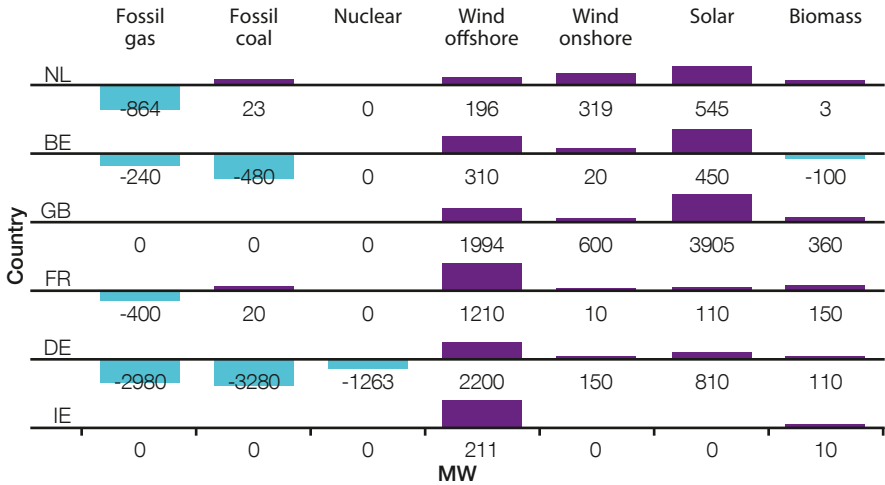
Increase in renewable generation since summer 2017

Renewable generation capacity including wind, solar and biomass also continues to grow in Continental Europe and GB. These generation types now contribute towards a larger proportion of the generation mix. Figure 1.16 shows the increases in the generation components in GB and neighbouring countries from 2017 to 2018 (negative values are shown in blue). The chart shows that onshore wind capacities have increased in each country,

while solar capacities have increased significantly in the Netherlands, Belgium and GB. Gas and coal capacities are generally decreasing. Nuclear capacity has reduced in Germany since last summer and although the increase in its renewable capacity is not as great as other countries, the total renewable capacity has reached a new record of 94GW which equates to 47 per cent of total capacity.

Europe and interconnected markets

Figure 1.15
Changes in generation mix in GB and neighbouring countries²



The increase in wind and solar generation capacity can put downward pressure on wholesale electricity prices. There is a clear correlation between price and periods when the weather has exceeded the seasonal norm in respect of increased wind and sunshine hours. Excess generation during these periods

is likely to transfer to the higher-price markets via the interconnectors between Continental European countries. However, as a result of the potential variation in outputs from renewable energy sources, we may see an increase in price fluctuations on the intraday market and other near term markets.

² Source of data: <https://transparency.entsoe.eu/generation/r2/installedGenerationCapacityAggregation/show>

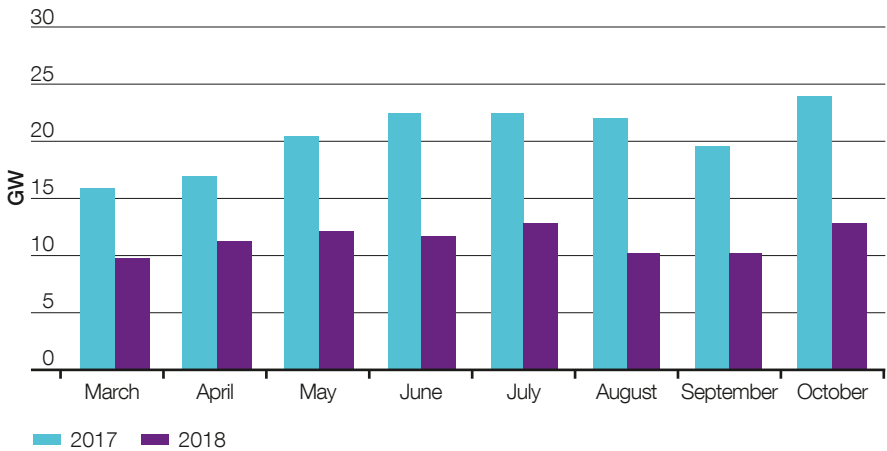
Nuclear availability in France

France has 63GW of nuclear generation, the highest among GB’s neighbouring countries; this represents almost 62 per cent of its total generation capacity. The availability of these nuclear plants significantly impacts the total generation in France, which in turn can influence flows across IFA. For example, in winter 2016/17, 12 reactors were shut down for extra safety inspections due to an anomaly in the carbon concentration of steel in the steam generator. As a result, 20 nuclear reactors were taken out of service for repair work on pumping station pipes. These unexpected outages reduced the total

output from the French nuclear fleet and tightened supply margins in France. This led to notable increases in French forward electricity prices. As a result, GB witnessed full exports to France across IFA regularly during the periods of reduced availability.

Figure 1.16 shows the capacity expected to be affected by French nuclear outages for summer 2018. The capacity on outage this summer is much lower compared to summer 2017 and therefore is not expected to significantly impact IFA flows between GB and France.

Figure 1.16
French nuclear plants outage



Europe and interconnected markets

Northern Ireland plant closures and Moyle interconnector

Three units in Northern Ireland failed to win capacity contracts in the Ireland T-1 Capacity Market auction held by the Single Electricity Market Operator (SEMO) on 15 December 2017. This included two coal-fired units at Kilroot (de-rated 439MW) and one gas-fired unit at Ballylumford (de-rated 128MW). The T-1 auction was a part of the new wholesale electricity market arrangement in Ireland and Northern Ireland and became live at the end of 2017 under the Integrated Single Electricity Market (I-SEM).

The owner of the three units has announced that it is likely to close the two units at Kilroot and the unit at Ballylumford on 23 May and 31 December 2018 respectively. This is because they were unsuccessful in securing capacity market payment to cover fixed costs. This might encourage strong imports from the UK via the Moyle Interconnector to meet demand in Northern Ireland given that Ireland's North-South Interconnector will not be operational before 2021.

Historical views of interconnector flows and forward price spreads

The actual flows last summer via the four interconnectors is summarised in table 1.4.

Table 1.4
Interconnector flows overnight

Overnight (7pm-7am)	IFA	Moyle	BritNed	EWIC	EWIC (outage corrected) ³
Import	95%	86%	95%	70%	90%
Floating	0%	0%	2%	21%	1%
Export	5%	14%	3%	9%	9%

We see that overnight, the IFA and BritNed interconnectors were importing into GB over 95 per cent of the time in summer 2017 while the

interconnectors to Ireland, Moyle and EWIC, were importing into GB over 86 per cent of the time.

Table 1.5
Interconnector flows at peak

Peak Times (7am-7pm)	IFA	Moyle	BritNed	EWIC	EWIC (outage corrected)
Import	90%	44%	96%	38%	58%
Floating	0%	0%	3%	21%	1%
Export	10%	56%	1%	41%	41%

We also see high imports from the IFA and BritNed interconnectors during the day. Both were importing into GB over 90 per cent of the time in summer 2017. The Moyle and EWIC

interconnectors were exporting to Ireland on average 49 to 50 per cent of the time last summer. This information is summarised in table 1.5.

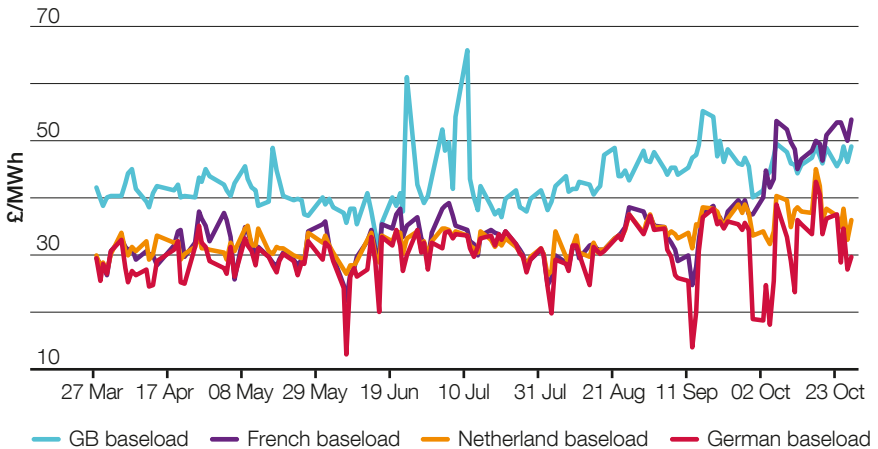
³The last column is for outage-time corrected EWIC flows as there was an outage on EWIC between 18/4-26/5 2017.

Europe and interconnected markets

Figure 1.17 shows the day-ahead baseload electricity price curves in GB and neighbouring countries indicating that most of the time during summer 2017, GB prices were higher than in

France and the Netherlands and hence why we saw consistent imports to GB via the IFA and BritNed interconnectors.

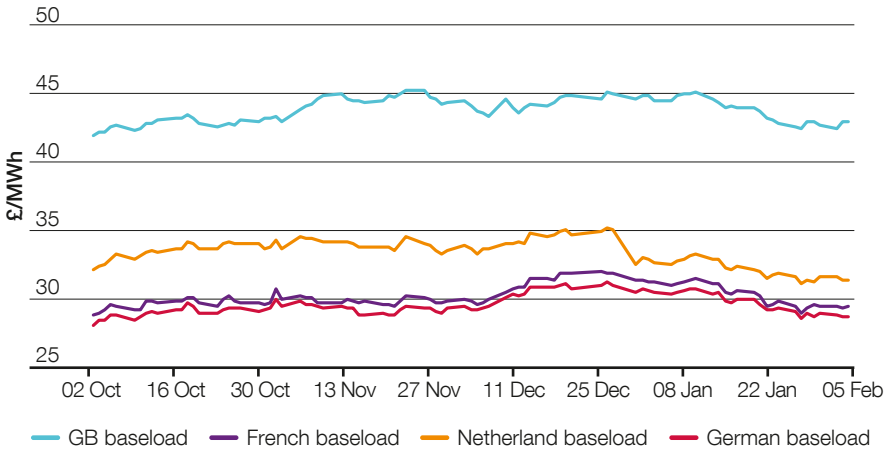
Figure 1.17
Day ahead baseload price in summer 2017



The current forward price spreads between GB and Continental European markets for summer 2018 are similar to previous years. Figure 1.18 shows that the forward baseload

prices for summer 2018 in GB are higher than the prices in the French and the Dutch markets and therefore we would expect to see similar imports from IFA and BritNed as last summer.

Figure 1.18
Forward prices for summer 2018



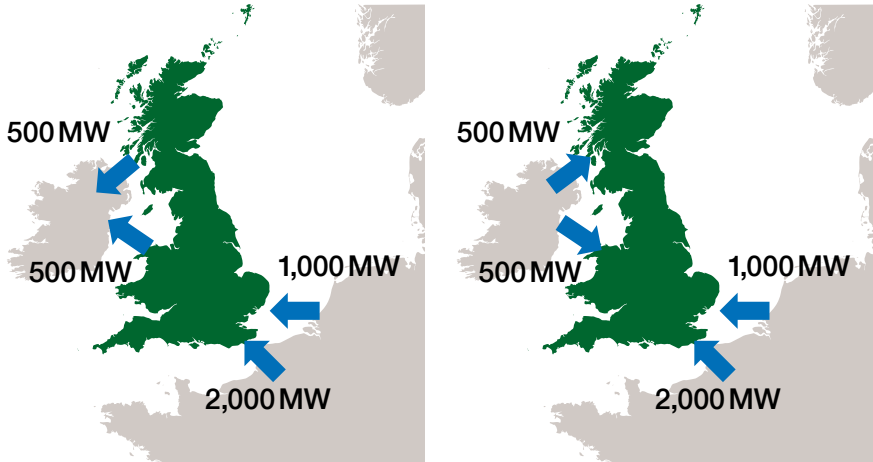
Assumptions on interconnector flows summer 2018

- GB forward prices for summer 2018 are expected to remain higher than in the French, Dutch and German markets.
- Forward prices remain lower in Continental European markets than forward prices in GB due to the increase in renewable energy installed capacities, and a gradual transition from old coal-fired plants.
- Renewable generation is weather dependent and this may increase price fluctuations on the intraday market and other near term markets.
- Based on historical analysis and current forward price spreads, it is expected that full imports into GB via both the BritNed and IFA interconnectors is more likely throughout summer 2018, although there may be some fluctuating flows during peak times.
- Based on historical analysis, current forward price spreads and possible plant closures, we expect GB to export to Ireland during peak times on both the Moyle and EWIC interconnectors, whilst importing during off-peak. We would also expect imports into GB during periods of high wind output in Ireland.

Europe and interconnected markets

Figure 1.19

Forecast flows on the interconnectors during peak and off-peak times



Forecast flows on the interconnectors during peak times (7am to 7pm)

Forecast flows on the interconnectors during off peak times (7pm to 7am)

Interconnector net flows summer 2018

The following scenarios assume full export (1000MW) to Ireland via EWIC and Moyle interconnectors during peak times. Each scenario includes a varying level of imports via IFA and BritNed interconnectors:

- Low imports of 500MW, resulting in a net export of 500MW to GB market.
- Medium base case of 1,800MW, resulting in a net import of 800MW to GB market.
- Full interconnector imports of 3,000MW, resulting in a net import of 2,000MW to GB market.

Electricity operational outlook

In our role as System Operator, National Grid must manage a number of operability issues during periods of low demand. This chapter outlines some of these issues, and the tools and services that are available to us to make sure that we can continue to operate the system securely and effectively.

Key messages

- More actions to manage rate of change of frequency (RoCoF) are expected due to anticipated low demand.
- Cash-out prices may be more volatile.

Key terms

- **Head room and foot room:** the ability of generation plant to alter its output. Head room is the operation of plant below its maximum to allow output to increase if necessary. Foot room describes the ability of plant to decrease its output without going below minimum output levels.
- **System inertia:** a measure of how resilient system frequency is to change. These changes may be caused by disturbances such as a sudden drop in generation or demand, leading to an underlying imbalance or 'mismatch' between demand and supply.
- **Reactive power:** describes the movement of energy across the network. It is measured in MVAR (mega volt amps reactive). Assets forming part of and connecting to the transmission system naturally generate or absorb reactive power depending on their own and the systems' characteristics at the time. Flows of reactive power have a direct impact on the voltage levels seen across the network, which must be closely monitored and managed.
- **System Operator Flagging⁴ (SO-Flagging):** is the process that identifies Bid Offer Acceptances (BOAs) and Balancing Services Adjustment actions that are potentially taken for system balancing reasons. The SO-Flagging process is documented in the System Management Action Flagging Methodology Statement which is required under National Grid's Transmission Licence.

⁴https://www.elixon.co.uk/wp-content/uploads/2016/10/Imbalance_Pricing_guidance_v11.0.pdf
The System Management Action Flagging Methodology Statement is here:
<https://www.nationalgrid.com/sites/default/files/documents/APPENDIX%20D-SMAF.pdf>

Operational outlook

Overview

As we mentioned in previous chapters, the key factors driving the operational challenges during the summer period are low demand and high proportions of low inertia generation on the system. Both of these factors are heavily influenced by the weather as it affects the output of renewable generation.

This weather dependency makes it difficult to forecast the services needed to balance

the system. This means there can be large variations in the use of services and in the number of actions taken on a day-by-day and week-by-week basis.

The probability of different weather conditions is considered when procuring the right type of service, and to strike a balance between the cost and risk to the electricity industry and end consumers.

Balancing services

There are a number of balancing services that can be employed to balance supply and demand on the electricity system. Most of these can be found in the appendix.

Footroom services

To manage periods when negative reserve on the system is extremely low, there are a selection of footroom services and actions that can be called upon. These services might include the following:

- De-synchronise units in the Balancing Mechanism
- Interconnector trading
- Contracts for decreased Stable Export Limit (SEL) on conventional generators
- Flexibility from nuclear power stations
- Demand turn-up.

Loss of mains protection

Historically, balancing actions were taken on the transmission system to avoid accidentally tripping off distributed generators because of how their loss of mains protection⁵ was configured. As system conditions have evolved to accommodate the increase in renewable generation and the closure of conventional generation, historic loss of mains protection techniques such as rate of change of frequency (RoCoF) and vector shift have become less suitable. This is because of their sensitivity to events that happen on the wider transmission system, rather than their local distribution system.

Decreasing levels of system inertia will continue to require active management of the RoCoF this summer. Actions may need to be taken to reduce the risk of the largest in-feed losses such as interconnectors and large Balancing Mechanism Units (BMUs). Actions may also need to be taken to increase inertia by increasing the number of synchronous plant on the system.

Services to manage vector shift continue to evolve. In order to reduce the risk of accidental tripping on the distribution networks, more targeted actions are being pursued, along with modifications to the Distribution Network Code. National Grid has been working closely with the industry to find long-term solutions to the operational challenges created by the inadvertent tripping of distributed generators.

Ofgem has approved Distribution Code modification DC0079⁵, to align the RoCoF limit constraint for generators below 5MW;

this became effective from February 2018. It has been modified so that distribution connected sites are able to withstand frequency changes between 0.5 and 1.0Hz/s, depending on the capacity. Almost all distribution connected sites over 5MW have had their protection equipment adjusted. When the three year implementation period is successfully completed, the need to manage RoCoF will be relaxed. The modification also takes the first steps to removing vector shift as a suitable form of loss of mains protection. This applies to all new connections.

Voltage

Reactive power describes the movement of energy across the network. The flows of reactive power on the system will affect voltage levels. Unlike system frequency, which is constant across the network, the 'voltage profile' varies by location based on prevailing real and reactive supply and demand. The growth of embedded generation and energy efficiency measures, coupled with the physical properties of the distribution and transmission networks, have all contributed to the falling reactive power demand. As transmission system demand continues to fall, the likelihood of high voltage occurrences increases. System Operator actions to manage high voltage have therefore increased significantly over recent years, intensified by the running patterns of generation during low demand periods. In the short term, a number of tools exist that enable the running of specific generators to access their MVar (units of reactive power) capability, where forward indications of plant

running indicate it is prudent and cost-effective to do so. These actions include:

1. Contracting with generators in advance for longer periods to manage uncertainty and risk. These contracts seek to reflect the generation economics of conventional plant and ensure a minimum guaranteed profitability to run during periods where the generator would otherwise be uneconomic.
2. Trading actions within-day, when running patterns are more volatile.
3. Bid Offer Acceptances in the Balancing Mechanism.

We anticipate that in the future there will be an increase in the number of actions needed to manage voltage. This is because weak market prices for the critical low demand periods leads to less flexible plant being temporarily shut down or 'mothballed', and flexible plant avoiding running overnight.

⁵For loss of mains protection, see appendix

Operational outlook

Distributed energy sources

Managing local constraints

The Connect and Manage programme allows new electricity generators to connect to the network once all enabling works have been completed, but before the wider transmission system reinforcements have been made. The swift growth in renewable generation under the Connect and Manage programme⁶ has resulted in areas of the network requiring actions to manage constraints, both from transmission connected and distribution connected generation. This will continue

until the system is reinforced, or until market arrangements are in place to manage them. Examples include the Caithness and Dumfries & Galloway areas.

To increase the number of parties that can help manage these areas, we continue to develop the number of trading arrangements and contracts available in order to decrease generation or increase demand in the affected areas.

New connections

Western HVDC link

In late 2017 power began to flow through the Western HVDC link, providing relief to the constraints on the transmission networks between Scotland and England, known as the B6 boundary. This allows greater access to renewable generation in Scotland and results in a reduction in balancing costs arising from the use of constraint management.

At times of low demand, it is likely that this renewable generation will provide

the footroom and flexibility on the system. As the system congestion eases, these actions are less likely to be SO-flagged. They will feed in to the calculation of system prices (energy imbalance prices). It is worth noting, that whilst overall balancing costs will reduce with the commissioning of the Western HVDC link, there is also likely to be an increase in the volatility of system prices and an increase in the number of occasions where system prices are negative.

⁶https://www.ofgem.gov.uk/sites/default/files/docs/2007/11/connect-and-manage_phil_0.pdf

Chapter two

Gas demand	52
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Gas demand

In this chapter we look at the projected demand for gas for heating, for industry, for export and for electricity generation.

Key messages

- Gas demand is expected to be slightly lower in summer 2018 than it was in summer 2017.
- The weather can have an effect on gas demand for heating that is much bigger than any forecast increase or decrease in demand. A 5 per cent increase or decrease due solely to the weather has been common in recent years.
- The weather also affects gas demand for electricity generation. The difference between a day with high wind and solar generation and a day with low wind and solar can amount to 20 per cent of demand on a summer's day.

Key terms

- **National balancing point (NBP) gas price:** the wholesale gas market in Britain has one price for gas, irrespective of where it has come from. This is called the national balancing point of gas. It is usually quoted in pence per therm.
- **Non-daily metered (NDM) demand:** a classification of customers where gas meters are read monthly or at longer intervals. These are typically residential, commercial or smaller industrial consumers.
- **Daily metered (DM) demand:** a classification of customers where gas meters are read daily. These are typically large-scale consumers.

Overview

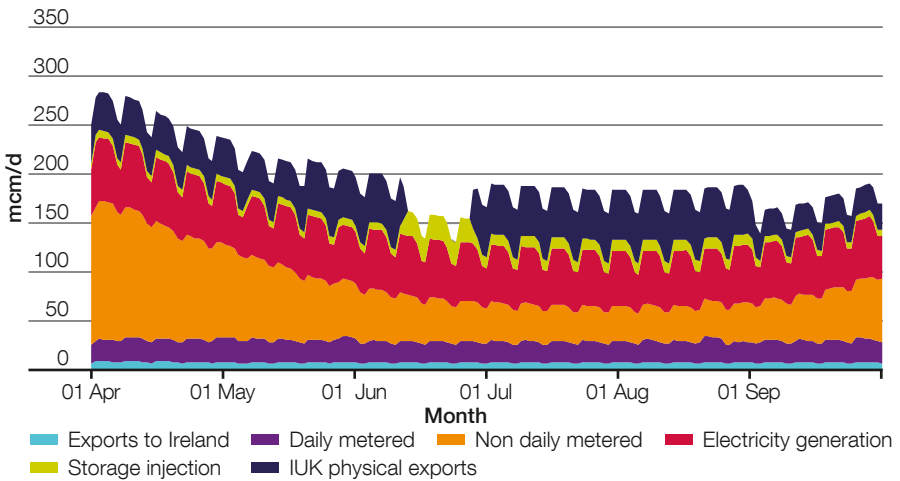
Gas demand for summer 2018 is expected to be slightly lower than summer 2017. In this chapter we will look at the forecast demand in different sectors and examine some of the factors affecting them.

Total gas demand

Our forecast gas demand for summer 2018, displayed as daily values, is shown in figure 2.1. In table 2.1 we summarise demand as an aggregate value for the summer. Both the chart and table show the demand forecast under seasonal normal weather conditions.

Seasonal normal weather conditions assume that the weather is neither hotter nor colder than the historical average. In table 2.1, we show summer 2017 demand as both an actual measured value and corrected for seasonal normal weather conditions.

Figure 2.1
Forecast gas demand profiles for summer 2018



Gas demand

Table 2.1¹

Forecast total gas demand for summer 2018 and history for previous summers

bcm	2013	2014	2015	2016	2017 actual	2017 weather corrected	2018 forecast
Non -daily metered (NDM)	12.3	9.9	11.3	11.1	10.4	10.8	11.0
Daily metered (DM) + industrial	4.5	4.4	4.2	4.1	4.4	4.4	4.0
Ireland	2.7	2.7	2.8	1.7	1.6	1.6	1.5
Electricity generation	7.7	9.2	8.3	11.6	10.5	10.5	9.9
Export to Europe	2.6	3.8	5.0	5.2	7.0	7.0	7.2
Storage injection	5.3	3.6	3.4	2.6	2.5	2.5	1.8
Total	35.0	33.8	35.2	36.4	36.6	36.9	35.7

As we see from table 2.1, there is no clear pattern emerging of total demand levels when we compare previous years.

Gas demand for heating

Gas used for space heating is sensitive to the effects of the weather. Temperature is the most important factor, but wind speed is also important. Gas used for heating is mostly in the non-daily metered (NDM) sector. This category includes residential properties, commercial properties and some small industrial customers. In figure 2.1 you can see that NDM demand ranges from 142 mcm on a weekday in April, to 32 mcm on a weekend day in July and August.

The trend in gas demand for heating is a balance between the reduction in demand due to increased appliance efficiency and insulation, and an increase in demand as more houses are built. Over the next few years we expect the increased efficiency of new build insulation to be the dominant factor which will lead to NDM demand reductions.

However, for summer 2018, the forecast is more finely balanced with the increase in new connections outweighing the reductions in demand from improved energy efficiency. As a result, we expect NDM demand to be slightly higher than last summer's weather corrected demand at 11 bcm.

When we analyse historical gas demand we create a weather corrected value. This illustrates what the demand would have been under seasonal normal weather conditions. Table 2.1 shows that the actual measured demand for summer 2017 was 0.4 bcm lower than the weather corrected value, indicating that the weather was slightly warmer than normal.

¹ All totals include shrinkage and will therefore not tally.

In some years the effect of the weather is much greater than this. In figure 2.2 you can see the effect that the weather has had on the NDM demand during summer since 2011.

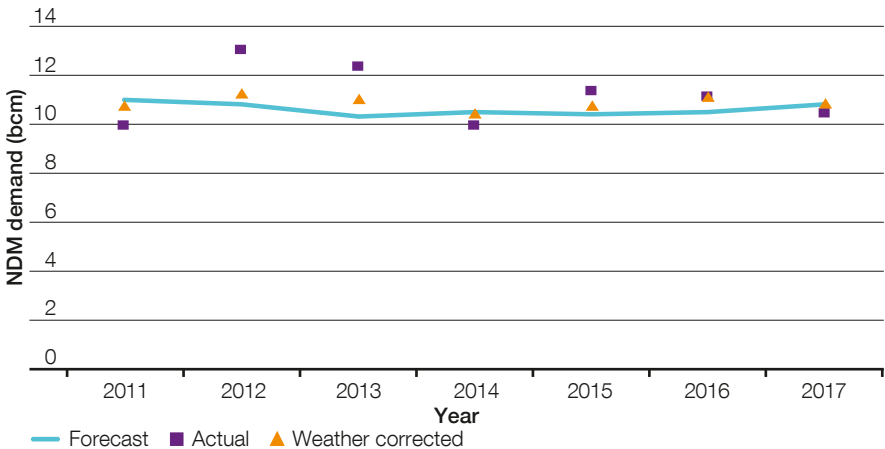
We have shown the forecast demand, the actual, observed demand, and the weather corrected demand. You can see that in the cold wet summer of 2012, the NDM demand was around 1.8 bcm higher than we would have expected under seasonal normal conditions. On the other hand, in the warmer summers of 2011, 2014 and 2017 the demand was lower than would have been expected under seasonal normal conditions.

The chart also shows how the weather affects the accuracy of our forecasts for the summer.

In most years the weather corrected demand for the summer as a whole has turned out reasonably close to our forecast, though the actual, observed weather has shown a much greater spread. Over the years 2011 to 2017 the average difference between the weather corrected demand and our forecast for the summer was 0.3 bcm. For the actual demand the average difference from the forecast was much larger, at 1.1 bcm.

The uncertainty introduced by the weather can mask any underlying change in the gas demand. If we had seasonal normal weather in summer 2017 and summer 2018 we would expect a growth in NDM demand of 0.2 bcm, much smaller than the 1.1 bcm uncertainty due to the weather.

Figure 2.2
The effect of weather on NDM demand



Gas demand

Other gas demand

Electricity generation

Gas for electricity generation is expected to be lower than last summer. This is the result of lower overall electricity demand and an increase in renewable generation. Gas for electricity generation is also influenced by spark spreads between coal and gas and the price differential across interconnected markets. You can find out more about the types of power stations that are more likely to run this summer in the generation merit order on page 35.

If the wind is not blowing or the sun is not shining the lost wind or solar generation can be replaced with gas fired generation. During summer 2017 we saw a good correlation between renewable generation and gas fired generation; for every extra unit of renewable generation, one unit of gas fired generation was lost.

To understand how much solar PV and wind influences gas demand for generation, we examined days from summer 2017 with similar total electricity demand but different patterns of generation. Gas demand for electricity generation differed by around 30 mcm, which represents around 20 per cent of the total gas demand on a day in the middle of summer.

Daily metered demand and industrial load

The daily metered (DM) sector is mostly made up of large industrial and commercial customers. Although some gas is used for space heating, the majority is used for heat in industrial processes. Some gas is also used as a feedstock, an ingredient for chemical manufacturing processes. Feedstock and process heating show little or no dependence on the weather. Demand for the sector as a whole, shown by the purple area in figure 2.1, is essentially flat across the summer.

Demand in the DM sector has been declining year on year, mirroring the decline in energy intensive industries. There is also a continuing drive towards greater energy efficiency. As a result, we expect DM demand to be slightly lower in summer 2018 than it was in summer 2017.

Exports to Ireland

Gas is exported to both Northern Ireland and the Republic of Ireland, and the Isle of Man via the Moffat interconnector. The high dependency of gas for electricity generation in these markets means that there is little weather sensitivity in the export flow. The pale blue area in figure 2.1 shows flat demand across the summer.

More than half of the gas in Ireland is provided by the Corrib field, with a small supply from the Kinsale field. Exports from GB through Moffat make up around 40 per cent of the total supply. Production from the Corrib field is more or less at its peak and beginning to decline. Consequently, we expect this decrease to be replaced by slightly higher daily flows from GB via Moffat during summer 2018. Exports in summer 2017 were higher because of an outage at the Corrib field. Overall this summer we expect the total exports aggregated over the summer period to be slightly lower than last summer.

Exports to Europe

The GB gas market is connected to Belgium by the IUK interconnector, connecting Bacton on the Norfolk coast to Zeebrugge. Flows through the IUK interconnector respond well to the difference between the NBP gas price in GB and the Zeebrugge price in Belgium. In recent years, gas has tended to flow from GB to Belgium for most of the summer and from Belgium to GB during the winter months. In summer 2017 the flow was all towards Belgium with no days of reverse flow.

We discuss exports to Europe in more detail in the 'Europe and interconnected markets' section.

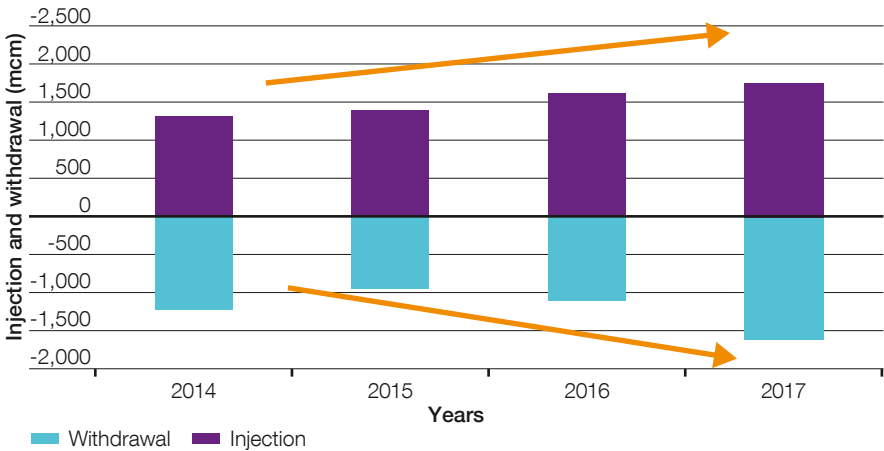
Looking at the forecast in table 2.1 you will see we expect summer 2018 to be very similar to summer 2017.

Storage injection

With the closure of Rough as a seasonal facility and its subsequent reclassification as a production field; the remaining storage in GB is mid-range storage (MRS). This has increased in total volume over recent years and is able to offer both seasonal and day to day cycling. This provides a valuable balancing option to the market close to real time.

The total requirement for gas injection into MRS during the summer will depend on the level of stock at the end of the winter. Over the last three summers, the stock level at the beginning of April has ranged from 0.3 bcm in April 2014 to 0.6 bcm in April 2017. The available space in MRS in 2017 was 1.4 bcm; therefore there was a need for 0.8 bcm to be injected to fill the sites to capacity. In recent years there has been a trend for more injections and withdrawals to be made from MRS during the summer period, as you can see in figure 2.3. Total injection in summer 2017 was 1,800 mcm more than twice as much as was needed to fill the sites to capacity.

*Figure 2.3
Injection and withdrawal from mid-range storage summer 2014 to 2017*

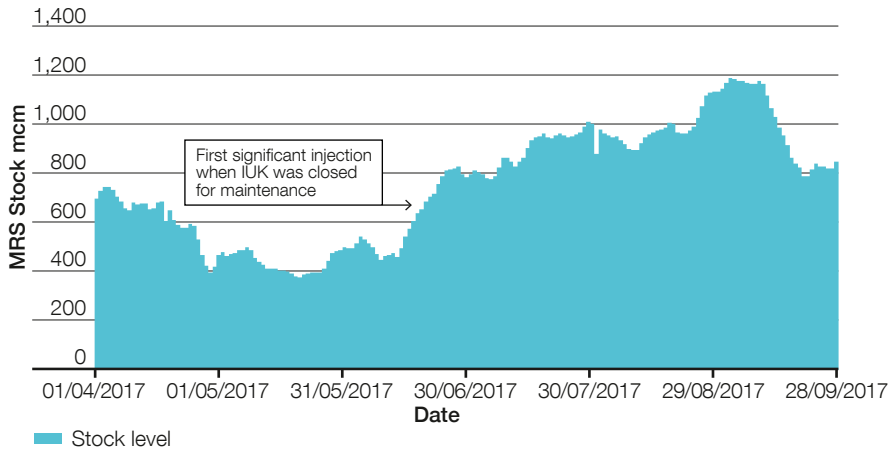


Gas demand

In figure 2.4, you can see the total MRS stock level through summer 2017. This shows that the first significant and sustained injection was made when IUK was closed for annual maintenance. Gas that had been flowing to Europe became available for MRS injection.

The interconnector outage effectively presented greater opportunity to the market for MRS cycling together with increasing MRS stock volume. With comparable market conditions expected in summer 2018 we expect MRS to behave in a similar way to summer 2017.

Figure 2.4
MRS stock level – summer 2017



Gas supply

GB continues to benefit from a wide range of supply sources; here we look at the supplies of gas we expect to see during summer 2018.

Key messages

- We expect that there will be sufficient gas to meet demand in summer 2018.
- Supplies from the UKCS and Norway are expected to be the dominant components this summer.

Key terms

- **UK Continental Shelf (UKCS):** made up of the areas of the sea bed and subsoil beyond the territorial sea over which the UK exercises sovereign rights of exploration and exploitation of natural resources.
- **BBL:** a gas pipeline running from Balgzand in the Netherlands to Bacton in the UK.
- **IUK:** the Interconnector (UK) Limited is a bi-directional gas pipeline connecting Bacton in the UK and Zeebrugge in Belgium.
- **Liquefied natural gas (LNG):** natural gas that has been converted to liquid form for ease of storage or transport. It is formed by chilling gas to -161°C so that it occupies 600 times less space than in its gaseous form.

Overview

We refer to gas from UKCS and Norway as 'beach' supplies. The amount of beach supply in summer is determined mainly by maintenance on the transmission system. The more flexible supplies, referred to as non-beach supplies including storage, liquefied natural gas (LNG) and gas

imported through the interconnectors are more responsive to gas prices, in both the GB and global gas markets.

Our supply forecast from all sources is shown in figure 2.5 with five years of history provided for comparison.

Gas supply

Table 2.2
Forecast and historic gas supply by source

(bcm)	2013	2014	2015	2016	2017	2018
UKCS	15.1	15.3	15.9	16.1	17.3	17.9
Norway	10.6	7.6	11.3	12.3	13.3	13.2
LNG	5.8	7.6	6.2	5.3	3.3	2.9
Continent	2.3	2.2	0.3	0.5	0.1	0.1
Storage	1.5	1.3	1.1	1.2	1.9	1.6
Total	35.9	35.4	34.0	34.8	35.8	35.7

Beach Supply

UKCS

Production from the UKCS in 2017 was higher than 2016. The Edradour and Glenlivet fields in the West of Shetland came on-line, and production increased at some other fields, offsetting the declines elsewhere for example, Rough. We are expecting aggregate supply in summer 2018 to be similar to summer 2017, with the exception of Rough.

In June 2017 Centrica Storage announced that the Rough long-range storage site would close. At the time they estimated that there was more than 5 bcm of gas still in the facility. In January 2018 Centrica started to operate Rough as a production field rather than a storage site. We have included 0.7 bcm for production from Rough in our UKCS projection, in line with indicative data published by Centrica Storage.

Norway

Norway supplies gas through pipelines to Germany, Belgium and France as well as to GB. Gas production on the Norwegian Continental Shelf reached record levels² in 2017 and flows to GB were particularly high. We are expecting flows to GB in summer 2018 to remain high, similar to summer 2017.

²<http://www.npd.no/en/news/News/2018/The-Shelf-2017/>

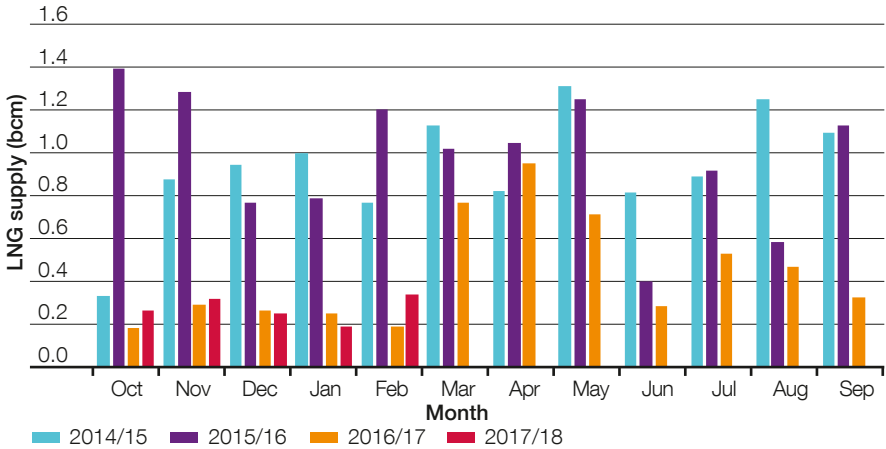
Non-Beach supply

LNG

Supplies of LNG to the GB market were notably less in October 2016 and since then have been lower than in previous years as shown in figure 2.5. LNG has been flowing instead to Asian markets, where it attracts a higher price. Historically, we generally see

a peak in LNG delivery to GB in the early summer as winter heating demand in the Asian markets declines, but before Asian electricity load for air conditioning reaches its peak. We are expecting a similar flow characteristic this summer.

Figure 2.5
LNG supply



Interconnectors

In summer 2017 the IUK and BBL interconnectors contributed little gas to the GB market. Gas flowed from GB to Europe via IUK throughout the summer. We are expecting similar behaviour this summer. However, flows through IUK respond very well to the difference in gas price at the GB NBP hub and the Belgian Zeebrugge hub, so occasional days of import to GB might be expected if prices on the two hubs dictate.

Storage

We have discussed the expected behaviour of storage in the gas demand chapter. In summary, we are expecting gas to be supplied from storage in response to short term market conditions, with frequent switching between injection and withdrawal.

Europe and interconnected markets

This chapter explores the impact of global markets on LNG flows while also exploring what happens to surplus gas during the summer months.

Key messages

- We expect to see GB sourced gas routed to where the gas price is more attractive in Europe. Therefore, we expect to experience transit gas demand on the network during the summer period.
- Interconnector imports and LNG will remain low, albeit base LNG volumes are expected to be higher than seen during winter periods.

Key terms

- **UK Continental Shelf (UKCS):** made up of the areas of the sea bed and subsoil beyond the territorial sea over which the UK exercises sovereign rights of exploration and exploitation of natural resources.
- **BBL:** a gas pipeline running from Balgzand in the Netherlands to Bacton in the UK.
- **IUK:** the Interconnector (UK) Limited is a bi-directional gas pipeline connecting Bacton in the UK and Zeebrugge in Belgium.
- **Liquefied natural gas (LNG):** natural gas that has been converted to liquid form for ease of storage or transport. It is formed by chilling gas to -161°C so that it occupies 600 times less space than in its gaseous form.
- **Transit gas:** gas that enters and exits the national transmission system without being consumed in GB.
- **National balancing point (NBP):** is Britain's wholesale gas market. It has one price regardless of where the gas is sourced and is usually quoted in pence per therm.

Overview

While we expect there to be sufficient gas supply to meet demand for summer 2018, we expect there to be more gas than is needed. Our analysis indicates that any excess gas will be exported to Europe.

LNG supply was briefly covered in the supply chapter; here we explore the changing LNG landscape.

LNG

LNG delivery to GB and to all of North West Europe is very dependent on conditions elsewhere in the world market. New LNG export facilities have come on line over the last 12 months, including new or expanded terminals in the US, Russia, Australia and recently Bangladesh. But at the same time global demand for LNG has risen sharply. Imports to China, Japan and Pakistan reached record levels in 2017. China is making a concerted effort to replace coal with gas to improve air quality and we expect that demand for LNG there will continue to grow.

With such a dynamic global market it is hard to predict how much LNG will be available for GB. Forward prices suggest that Asian markets this summer will attract a higher price than GB so we are not expecting very high LNG deliveries. Nevertheless, based on historical patterns, we would expect higher deliveries in the early summer than the very low levels that we saw during winter 2017/18.

Interconnectors

Flows through IUK respond very well to the difference in gas price at the GB NBP hub and the Belgian Zeebrugge hub. Demand in Europe for gas for injection into storage will be high this summer as storage was heavily used to support high demand in the cold weather during February and March. This has contributed to forward prices that suggest that flows through IUK this summer will mostly be from GB to Belgium.

BBL has provided little gas during the summer since 2014. Production at the Groningen field in the Netherlands was restricted in 2015 in an attempt to limit seismic activity in the Groningen area. The production restrictions have been tightened every year and as a result we are not expecting any significant supply through BBL this summer.

Transit

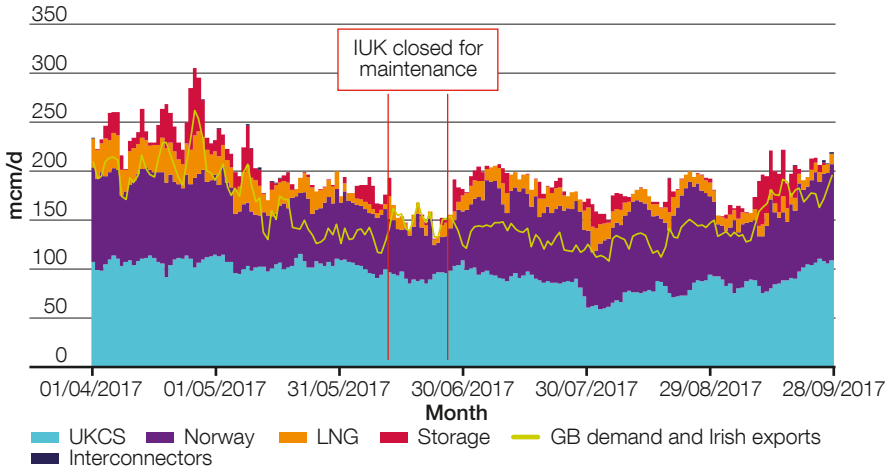
In the gas supply and gas demand sections we discuss supply meeting demand, including exports. It is not always obvious that some of the gas that is imported to GB is not used to supply demand in GB. It is used to provide gas for onward export, using the GB gas transmission network for transit. We show in figure 2.6 the daily supplies to GB for summer 2017. The chart also shows aggregate demand for GB markets and Irish exports, shown as the yellow line. For almost the entire summer, more gas was being supplied than was needed to satisfy GB demand and Irish exports. The surplus of supply was exported through IUK to Europe. From mid-May through to the end of August, supplies from UKCS and Norway alone were greater than the demand; Norwegian gas was using GB for onward transit to the rest of Europe. The only time that supply and demand were aligned was in June when IUK was closed for annual maintenance.

We see how well the market responds to differing operating characteristics from season to season. With beach supplies expected to be slightly higher in summer 2018 than in summer 2017, and demand expected to be slightly lower, we expect to see GB being used for transit again throughout summer 2018.

Providing the GB network for the purpose of transiting gas serves to underpin security of supply. Our role and challenge is to ensure the availability and capability of the existing transmission network remains. We need to continue to work with our customers to help us to inform our risk decisions for balancing the gas transmission system.

Europe and interconnected markets

Figure 2.6
Gas supply to GB with GB demand and exports to Ireland



Gas operational outlook

This section looks at the operational challenges facing us over the coming summer. These challenges influence how we are adapting the way we operate the network, at a time when access requirements increase to carry out key maintenance work. This is set against the back-drop of significant changes in the way the network is being used year on year.

Key messages

- We expect to see similar supply and demand patterns to summer 2017, with demand only approximately 30% lower than the winter peak.
- This summer we expect to see one of the highest volumes of maintenance on the gas transmission system to date.
- We continue to see our customers using the gas network in different ways. In response, we continue to evolve the operational tools we have available to manage the within day variations of flow on the network.

Key terms

- **Gas day:** the gas day starts at 05:00 and ends at 04:59. Users of the transmission system are incentivised to balance supply into, and demand from, the network by the end of the gas day.
- **National transmission system (NTS):** a high pressure gas transportation system consisting of compressor stations, pipelines, multijunction sites and offtakes. Pipelines transport gas from terminals to offtakes. The system is designed to operate at pressures up to 94 barg.
- **Transit gas:** gas that enters and exits the national transmission system without being consumed in GB.

Gas operational outlook

Overview

GB's gas supply and demand patterns continue to change. Not only do we see within day changes, but we also see changes in the location of supply and demand. Clear trends from season to season are not yet apparent. This variability has an

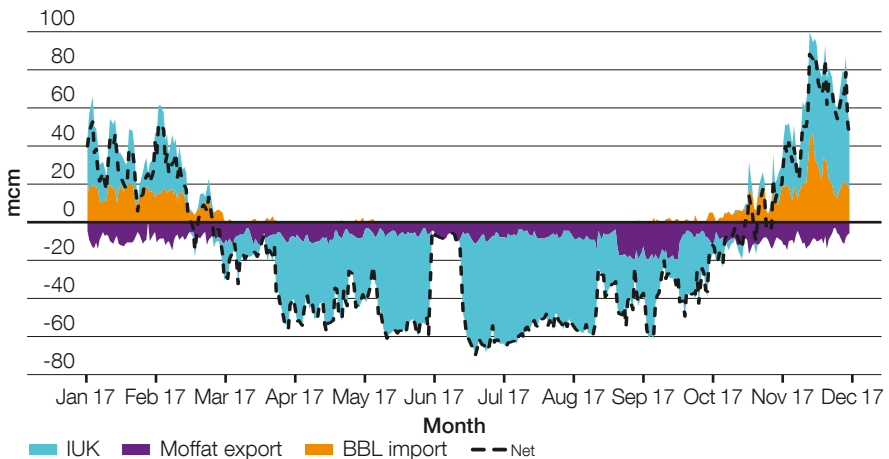
impact on how we configure and operate the National Transmission System (NTS) which is becoming increasingly challenging to predict. The impact of these variations is the increased use of the compressor fleet which in turn leads to an increase in required maintenance.

Supply and demand

Although gas demand is lower during the summer months, the total GB demand is only approximately 30 per cent lower than the winter peak. During the summer months, export flows via the IUK interconnector offsets the reduction in GB demand, this is illustrated in figure 2.7. Focusing on interconnector

flows last year, we can see that IUK imports gas during the winter period and as winter ends, they turn to export for the duration of the summer. This characteristic of summer demand we believe will continue, using the GB network for onward gas transit.

Figure 2.7
Historical interconnector flows during 2017

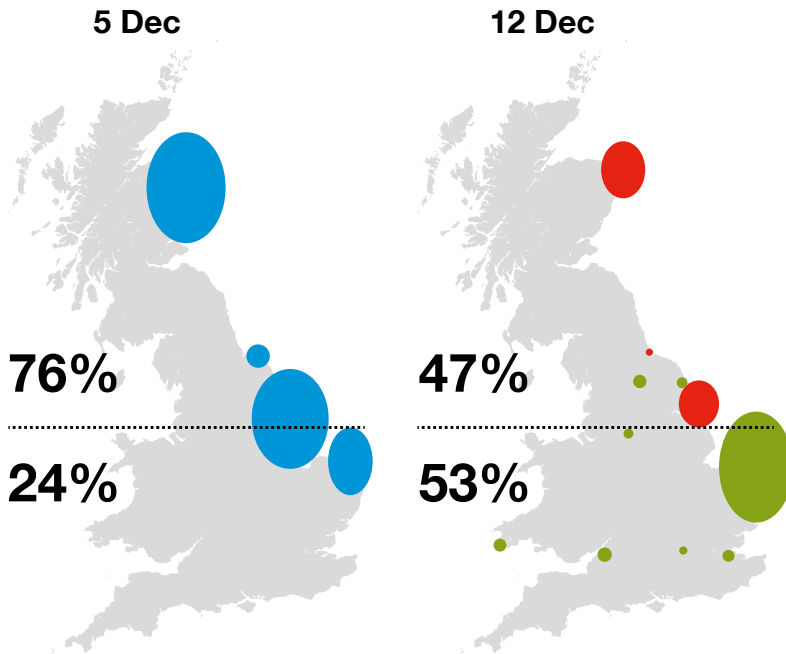


There are two further characteristics of the supply and demand patterns that we expect will continue into the summer months. Firstly, the short term locational changes in supply and demand patterns which influence linepack fluctuations and therefore pressures on the network. Figure 2.8 provides an example of how these changes can occur from one week to the next. Secondly, market participants are balancing their portfolios closer to real

time in response to commercial opportunities in the market. This makes it harder to predict the ideal network configuration to meet our customers' requirements.

These characteristics not only impact our role as Residual Balancer but also impacts our role as provider of safe control of operations with regards to system pressures for the DNs and other customers.

Figure 2.8
Variations in supply and demand patterns one week apart

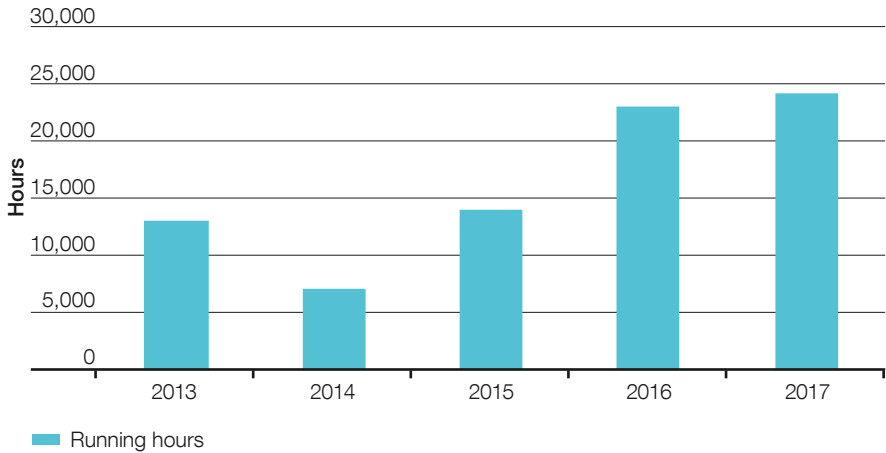


In response to these challenges we continue to use our compressor fleet more than we have done in previous years. Figure 2.8

highlights how the compressor fleet usage has doubled compared to previous years.

Gas operational outlook

Figure 2.9
Compressor fleet running hours



How we're responding

The volume of maintenance on the system continues to increase year on year. This summer we expect to see one of the highest volumes of maintenance on the gas transmission system to date. This will impact supply and demand patterns and compressor fleet usage. We continue to engage closely with the industry to ensure that outages are coordinated and we will always aim to facilitate maintenance on the network with minimal disruption to our customers. You can find more details on our website. The final [Maintenance Plan](#) will be published at the end of March.

Increasing demand variation is more noticeable in the summer as commercially sensitive sites respond to fluctuating market prices. Variable supply and demand requirements means the flexibility required on the network within day continues to increase along with the need to better predict the requirements of our customers. Our thoughts on the longer term impacts of this are now being shared in the [Gas Future Operability Planning](#) document.

Chapter three

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Appendix

Product	Energy	Description
Black Start	E	National Grid has an obligation to ensure that, in the unlikely event of total or partial shutdown of the transmission system, contingency arrangements are in place to enable a timely and orderly restoration of electricity supplies. Black Start is the procedure to recover from such a shutdown. It involves isolated power stations being started individually and gradually being reconnected to the transmission system. In order to maintain this Black Start capability and ensure restoration timescales can be met, some warning of units is required.
BM Start-Up	E	<p>The BM Start-Up service gives National Grid access to additional generation Balancing Mechanism Units (BMU's) that would not otherwise be available in operational timescales due to their technical characteristics and associated lead times. If a BMU has a long lead time then it cannot be issued with a Bid Offer Action (BOA) prior to its synchronisation. BM Start-Up contracts are enacted to allow the electricity Control Room access to such BMUs, enabling the units to be run at short notice.</p> <p>BM Start-Up is used by National Grid in our role as residual balancer to assist in ensuring sufficient plant availability on the day to meet demand plus reserve requirements.</p>
Capacity Market Notice (CMN)	E	<p>The Capacity Market has been introduced by the UK Government as part of the Electricity Market Reform programme. It aims to ensure the future security of our electricity supply by providing a payment for reliable sources of capacity, alongside electricity revenues, to ensure the delivery of energy when needed. This aims to encourage the investment we need to replace older power stations and provide backup for more intermittent and inflexible low carbon generation sources. The Capacity Market delivery year runs from 1 October to 30 September.</p> <p>A decision to issue a Capacity Market Notice (CMN) is based on available data provided by industry participants. It calculates the predicted shortfall between the forecast volume of demand on the electricity transmission system (plus the volume of operating margin held in reserve by National Grid) and the availability declared by generators. Four hours ahead of real time, if there is a heightened risk of a national shortage of generation (500MW or less) which is considered a period of system stress, the automated notice is generated by National Grid. The market is expected to respond to this notice by adjusting its position, with providers either delivering energy or reducing demand against their agreement.</p> <p>Capacity providers are required to deliver in accordance with their capacity obligations. Failure to do so will result in financial penalties. Capacity providers that over-deliver may be eligible for additional payments.</p> <p>It should be noted that there is no formal dispatch mechanism in the Capacity Market. In the event of a CMN being activated it is recommended that industry participants make themselves aware of other operational information available to the industry closer to the time the notice is active from. These include, for example, the BM Reports website.</p> <p>A CMN will be issued by National Grid via a dedicated website (www.gbcpm.nationalgrid.co.uk/). All industry participants and stakeholders can view this website. They can also subscribe for automated email and SMS alerts. The Capacity Market Notice can be cancelled if the situation improves, based on data being updated in real time.</p> <p>More information can be found at: https://www.emrdeliverybody.com/SitePages/Home.aspx https://www.ofgem.gov.uk/electricity/wholesale-market/market-efficiency-review-and-reform/electricity-market-reform-emr https://www.elxox.co.uk/new-balancing-mechanism-reporting-service-bmrs/</p>
Connect and Manage		<p>The underlying principle is that generators can acquire firm access rights from a particular date and be allowed to generate or receive compensation from that date, subject to:</p> <ol style="list-style-type: none"> 1) local works complete 2) plant commissioned and available

Product	Energy	Description
Constraints and power flows	E	<p>Transmission constraint management is required where the electricity transmission system is unable to transmit power to the location of demand due to congestion at one or more parts of the transmission network. To manage this, National Grid has to take actions to re-balance the generation and demand on each side of the constraint. Actions may include buying and selling power through bids and offers in the Balancing Mechanism, trading or contracting.</p> <p>There are some areas of the network where the rapid growth in connected generation has resulted in significant constraint volumes. One example of this is the transfer of power from Scotland to England under windy conditions. In some areas, the majority of this generation is embedded within the distribution network and as a result, does not have a mandatory services agreement with National Grid. This means that this generation is exempt from the Balancing and Settlement Code and is not required to provide certain services.</p> <p>Where there is insufficient controllable demand and generation in a specific area to manage power flows, National Grid may issue a localised negative reserve active power management (localised NRAPM) system warning to the industry. This notification is designed to encourage all generators to reduce their output where possible to reduce power flows, or allow National Grid to issue instructions to control flows of power.</p>
Demand Control Imminent (DCI)	E	<p>Demand Control Imminent (DCI) warning may be issued to provide short-term notice when a demand control instruction is expected in the following 30 minutes. It must be cancelled or re-issued within the next two hours. The warning is sent only to the DNOs and transmission connected demand that will receive a demand control instruction and is published on the BMRS without reference to the affected parties.</p>
Demand Control Instruction	E	<p>Demand control can be spread nationally to manage system margin shortfall or concentrated locally for other system operation challenges to limit the consequences on the wider network. For system margin shortfall, National Grid would employ demand control as a last resort and would instruct sufficient demand reduction to remove the margin shortfall over the high demand period. With prior notice via an HRDR warning the day before, National Grid may issue a Demand Control Instruction to the DNOs and transmission connected demand in the event of system margin shortfall. The instruction will contain the level of reduction required to avoid the shortfall and specifies the demand control stages required. The instruction can relate to up to 40% of the recipients total demand and is split into stages of voltage reduction and demand disconnection. The DNO can reduce the voltage on its network, which reduces demand without affecting customer supplies and in subsequent stages disconnect portions of demand up to the maximum demand reduction. Without prior notice, the maximum reduction available is 20%. Each year DNOs notify National Grid of their demand control plan, which contains the anticipated demand reduction from voltage reduction and demand disconnection.</p>
Demand turn-up	E	<p>The service encourages large energy users and small generators to either increase demand or reduce generations when there is excess energy on the system. This typically occurs overnight and during weekend afternoons in the summer.</p> <p>Fixed demand turn-up is procured for the whole of British Summer Time via a tender process.</p> <p>Flexible demand turn-up is where parties can bid their availability and prices on a weekly basis throughout summer.</p>

Appendix

Product	Energy	Description
Electricity Margin notice (EMN)	E	<p>The Electricity Margin Notice (EMN) is the first of the hierarchy of notifications issued by National Grid to manage security of supply.</p> <p>An EMN is part of the first level of operational notifications issued by National Grid at times of system stress. An EMN can be issued any time by our control room via BM Reports, but is usually within 24 hours of the suspected period of tightness. It is a routine tool that is designed to inform the industry of the forecasted position and the request for additional capacity to be made available. Additional capacity is most often required for the evening peak demand period.</p> <p>In response to an EMN being issued, we would typically expect more plant to be made available to the market and existing plant to run more reliably. In most cases this would prevent the need for further action and allow the notification to be withdrawn at a later time.</p> <p>In addition, a CMN may also be issued. It is independent of the EMN, meaning that one can exist without the other.</p> <p>If the market does not respond when an EMN is issued (or the response is not enough) there are a number of further actions that the System Operator can take. If all market options have been exhausted we are then able to use other services, such as maximum generation. This is a request made to power stations to generate at their highest possible output, in excess of normal technical and commercial parameters. Should these actions prove insufficient, it is possible to issue instructions to DNOs to request stages of voltage reduction to avoid the shortfall. This can make hundreds of megawatts available and in most cases goes unnoticed by consumers.</p>
Fast Reserve	E	<p>Fast Reserve is the rapid and reliable delivery of active power following receipt of an electronic despatch instruction from National Grid. It is provided as an increased output from generation or a reduction in consumption from demand sources. Active power delivery must start within two minutes of the despatch instruction at a delivery rate in excess of 25MW/minute and the reserve energy should be sustainable for a minimum of 15 minutes. Fast reserve is an additional energy balancing service used to control frequency changes.</p>
High Risk of Demand Reduction (HRDR)	E	<p>A High Risk of Demand Reduction (HRDR) provides early notification of an increased risk of demand reduction. It also provides additional information to DNOs and transmission connected customers about the location of a potential reduction. Recipients are required to prepare their demand reduction arrangements.</p>
Margins Notice	G	<p>This is a day ahead notice to provide a high level prompt to the market of a potential supply/demand mismatch, where forecast demand is greater than the expected available supply for the forthcoming Gas Day. The trigger level of demand is published on the National Grid Website on the Prevailing View page</p> <p>The Margins Notice is meant to encourage users of the NTS to take notice of the rolling Daily Margins Report and reassess their position in line with the prevailing forecasts. A Margins Notice will stay in place until the end of the gas day, unless it is superseded by a Gas Deficit Warning when it will be suspended.</p> <p>We publish a daily Margins Notice report providing industry with a rolling five day view of supply and demand data and information relating to the storage Safety Monitors.</p>
National Gas Deficit Warning (GDW)	G	<p>A Gas Deficit Warning notice is designed to encourage market participants to take action to address a forecast physical end of day NTS supply/demand imbalance. There are no predefined triggers and the warning is based on the judgement of the Gas National Control Centre. The decision to issue will be based on the information from any of the following sources:</p> <ul style="list-style-type: none"> • actual forecast supply • actual forecast demand • predicted closing linepack • actual linepack • market intelligence • other relevant information <p>The GDW can be issued in advance of or during the actual Gas Day; the GDW can be withdrawn, via notice, at any time.</p>

Product	Energy	Description
Negative reserve	E	<p>During periods of low demand, which typically occur overnight and on weekend afternoons, negative reserve is often scarce. This is due to a combination of conventional generation running at or near to their stable export limit (SEL), and response requirements being greater. As a result, during periods of low demand we may need to:</p> <ol style="list-style-type: none"> 1. Curtail or de-synchronise generation to maintain sufficient system foot room. We procure flexibility for foot room via a number of different services, including: <ol style="list-style-type: none"> a. Flexibility on nuclear power stations, which typically do not provide foot room. b. Decreased SEL on conventional generators, to directly increase foot room. c. Static high frequency response on conventional generators, to decrease overall foot room requirements. d. Optimising the demand profile on pump storage units, to maximise flexibility during the tightest periods. 2. Increase demand through demand side response services. This includes the demand turn up service. 3. Trade on the interconnectors to alter the total import/export levels on the system. This may occur when there is an indication ahead of time that insufficient negative reserve is available, coinciding with high interconnector imports. Trading would only be considered when it is economically beneficial to do so. <p>If a requirement for negative reserve could not be met through contracts, trading, SO to SO actions on the interconnectors or via the Balancing Mechanism, then National Grid may issue a negative reserve active power management (NRAPM) system warning to the industry. This warning is designed to encourage inflexible generators to reduce their output where possible to create downward flexibility on the system. At times of particularly low demand, or in represents a significant proportion of supply, actions taken to manage negative reserve are likely to result in low or even negative system sell prices (SSP). We encourage wind farms and generators to submit cost reflective prices to the Balancing Mechanism to allow us to manage low demand periods efficiently and economically.</p>
Negative Reserve Active Power Margin (NRAPM)	E	<p>A NRAPM may be issued if there is insufficient flexibility available to ensure that generation matches demand during periods of low demand. A localised NRAPM occurs where there is a danger that the combination of demand and inflexible generation within a constraint group can exceed the constraint limit of a portion of the network, in both cases there is a risk that NG may need to issue instructions to inflexible and non-BM participating plant.</p> <p>Localised NRAPM are more common in the north of Scotland due to the large volume of wind and water generation and relatively low demand.</p>
Positive reserve	E	<p>The combined requirement for regulating reserve and Short Term Operating Reserve (STOR) still exists during the summer. This helps to manage the variation between expected and actual generation and demand, as well as reserve for wind generation.</p> <p>National Grid enters into contracts with standby generation or demand reduction services to manage variations in demand and generation away from its instructed position. Where there is a market shortfall in the provision of available system head room, National Grid may consider taking specific actions to synchronise generation units or run them at part-loaded levels to create upward flexibility.</p>

Appendix

Product	Energy	Description
Rate of change of frequency (RoCoF)	E	<p>In the period immediately following a large demand or generation loss, but before frequency response services start to deliver, the rate of change of frequency can be relatively high. A large volume of embedded generation has loss of mains protection equipment for RoCoF. This is designed to detect when the generator has been disconnected or islanded from the rest of the transmission system. If the RoCoF is high enough, loss of mains protection can operate. This has the potential to cause embedded generation to stop generating leading to further disturbance and a possible cascade effect. To manage this issue, the distribution code has been modified to require embedded sites to be able to withstand frequency changes of 0.5-1.0Hzs (depending on capacity). Almost all embedded sites have had their protection equipment adjusted.</p> <p>Actions to curtail the demand and generation loss or to increase system inertia are particularly likely during periods of low inertia. These periods predominantly occur overnight and during weekend afternoon periods, but are possible throughout the day during the summer minimums and when levels of non-synchronous generation are high. Actions might include:</p> <ul style="list-style-type: none"> • Trading on the interconnectors to reduce them from full import or full export, to reduce the potential largest loss. • Taking bids on generators, to reduce the potential largest loss. • Contracts, trades or Bid Offer Acceptances (BOAs) for additional synchronous machines, to increase inertia. <p>In the future, when the level of RoCoF capacity at risk has reduced to a sufficiently small level, it will also be possible to hold additional low frequency response to manage the total potential demand or generation loss that may result in a further RoCoF loss.</p>
Reserve	E	<p>National Grid currently manages different types of reserve in order to maintain system security under a range of credible scenarios. Reserve can be thought of as the requirement for a total amount of head room (positive reserve) and foot room (negative reserve) provided across all generators synchronised to the system.</p> <p>Reserve is required to:</p> <ul style="list-style-type: none"> • account for errors in demand, wind and solar forecasting • cover demand and generation losses in the period from day ahead to real time, and • facilitate the holding of high frequency dynamic response. <p>In the future, the requirement to hold reserve is likely to increase. This is because of the continued growth in solar PV capacity and the need to manage the additional variability in demand between four hours ahead and real time.</p>
Response	E	<p>System frequency is a continuously changing variable that is determined and controlled by the second-by-second balance between demand and generation. NG must ensure that sufficient generation and/or demand is held in readiness to manage all credible events that might result in frequency variations for example, a sudden drop in generation or demand leading to an imbalance between supply and demand. There are two types of frequency response services, dynamic and static.</p> <p>Dynamic response services there is a time delay of up to 2 seconds between a frequency changing event occurring and the system starting to deliver. Dynamic response providers do not have to deliver until 10 seconds after the event.</p> <p>Static response services do not begin to operate until a certain frequency is reached.</p> <p>The requirement for response services increases during periods of low inertia.</p> <p>Routes for procurement of response services:</p> <p>Mandatory frequency reserve – via the Balancing Mechanism</p> <p>Contracting in advance in the form of:</p> <p>Firm frequency response (FFR) – provision of dynamic or static response to changes in frequency</p> <p>Enhanced frequency response (EFR) – providing response within one second of a frequency deviation</p>
Risk of system disturbance	E	<p>This notification will be issued to users who may be affected when NG knows there is a risk of widespread and serious disturbance to the whole, or part, of the National electricity system.</p>

Product	Energy	Description
Safety Monitor	G	<p>The Safety Monitor is an amount and deliverability of gas that needs to remain in storage in order to supply those customers that cannot be safely or immediately isolated from the gas network. The Safety Monitor calculates how much gas is needed to supply these customers for a winter period based on a 1 in 50 winter. It is there to maintain the safety of the system by maintaining adequate pressures on the network, rather than to support security of supply. There has not been a breach of the safety monitor level since it was introduced in 2004.</p> <p>The space requirement of the Safety Monitor is made up of the 'Protected by Monitor' and 'Protected by Isolation' elements. The total space requirement is then divided equally across all storage types and facilities. We also calculate the rate that the gas needs to be delivered into the NTS for the Safety Monitor, based on the amount of gas being held in storage. Defining space and deliverability helps market participants to plan for the winter ahead and helps to indicate the likelihood of a safety monitor breach.</p>
SO to SO actions	E	<p>Also known as Cross Border Balancing, SO to SO action is the operational exchange of energy between the national system operators. For example, this may take place between National Grid and RTE. The activation timescales are generally after the market closes (<1hour ahead of real-time) with the volumes and prices dependent on system conditions. As a result, this service is not firm and can be withdrawn by either system operator if system conditions do not permit the exchange of energy. The cost of this service is generally more than counter trading as it is based on the balancing action costs available to each system operator.</p>
System inertia	E	<p>This is a measure of how resilient a system frequency is to change; it serves to slow down the rate of change of frequency when there is a demand or generation loss.</p> <p>The growth of non-inertial generation for example, embedded wind and solar PV is displacing generation that has historically provided inertia. This is causing reduced levels of inertia in the system. At times of low inertia, NG may take actions to de-synchronise non-inertial generation and synchronise generation that is able to supply inertia like power stations or hydro.</p>
System operation	E	<p>In order to maintain system security at all times, National Grid needs to meet all of the above system requirements simultaneously. However, due to the physical properties and capabilities of different tools and services, an action taken to meet one or more requirements may also have an impact on other requirements. For example:</p> <ul style="list-style-type: none"> • A unit de-synchronised to manage negative reserve and power flows could also decrease system inertia, response provision and positive reserve. • A unit synchronised to manage local voltage requirements can also help with system inertia, response and positive reserve, but may cause a negative reserve issue. <p>This means that none of the requirements in this section can be considered in isolation, and instead a whole system optimisation approach is necessary.</p> <p>For these reasons, the System Operator may avoid actions with some generators that are seemingly higher up in the merit order. For example, conventional generation may be left to run at a time when wind farms are curtailed. This is because the conventional generators are providing some combination of frequency response, reactive power support or an inertia contribution, whereas the wind farms are not. Actions to operate the system are always taken on an economic basis, based on the interaction of all these factors.</p>

Glossary

Word	Acronym	Section	Description
BBL	BBL	Gas	A gas pipeline between Balgzand in the Netherlands and Bacton in the UK. You can find out more at www.bblcompany.com
billion cubic metres	bcm	Gas	Unit of volume used in the gas industry. 1 bcm = 1,000,000,000 cubic metres
BritNed		Electricity	BritNed Development Limited is a joint venture of Dutch TenneT and British National Grid that operates the electricity link between Great Britain and the Netherlands. It is a bi-directional interconnector with a capacity of 1,000MW. You can find out more at www.britned.com
Capacity market	CM	Electricity	The capacity market is designed to ensure security of electricity supply. This is achieved by providing a payment for reliable sources of capacity, alongside their electricity revenues, ensuring they deliver energy when needed.
Carbon price floor	CPF	Electricity	A price paid by UK generators and large carbon intensive industries for Co2 emissions.
Combined cycle gas turbine	CCGT	Various	A power station that uses the combustion of natural gas or liquid fuel to drive a gas turbine generator to produce electricity. The exhaust gas from this process is used to produce steam in a heat recovery boiler. This steam then drives a turbine generator to produce more electricity.
Compressor		Gas	Compressors are used to move gas around the transmission network through high pressure pipelines. There are currently 68 compressors at 24 sites across the country. These compressors move the gas from entry points to exit points on the gas network. They are predominately gas driven turbines that are in the process of being replaced with electric units.
Daily metered	DM	Gas	A classification of customers where gas meters are read daily. These are typically large scale consumers.
Distributed generation			Generation connected to the distributed networks, the size of which is equal or greater than 1 MW and up to the mandatory connection thresholds of the onshore transmission areas. The thresholds are 100MW in NGET transmission area, 30MW in Scottish Power (SP) transmission area and 10MW in Scottish Hydro-Electric Transmission (SHET) transmission area.
Demand side response	DSR	Various	A deliberate change to an industrial and commercial user's natural pattern of metered electricity or gas consumption, brought about by a signal from another party.
East West Interconnector	EWIC	Electricity	A 500MW interconnector that links the electricity transmission systems of Ireland and Great Britain. You can find out more at www.eirgridgroup.com/customer-and-industry/interconnection/
Embedded generation		Electricity	Power generating stations/units that don't have a contractual agreement with the national electricity transmission System Operator (NETSO). They reduce electricity demand on the transmission system.
Equivalent firm capacity	EFC	Electricity	An assessment of the entire wind fleet's contribution to capacity adequacy. It represents how much of 100% available conventional plant could theoretically replace the entire wind fleet and leave security of supply unchanged. EFC is currently assumed to be 22%.
EU Emissions Trading Scheme	ETS	Gas	An EU wide system for trading greenhouse gas emission allowances. The scheme covers more than 11,000 power stations and industrial plants in 31 countries.
European Union	EU	Various	A political and economic union of 28 member states that are located primarily in Europe.
Future Energy Scenarios	FES	Various	The FES is a range of credible pathways for the future of energy out to 2050. They form the starting point for all transmission network and investment planning, and are used to identify future operability challenges and potential solutions. You can find out more at http://fes.nationalgrid.com/

Glossary

Word	Acronym	Section	Description
Gigawatt	GW	Electricity	A measure of power 1 GW = 1,000,000,000 watts.
Great Britain	GB	Various	A geographical, social and economic grouping of countries that contains England, Scotland and Wales.
Grid supply points	GSP	Electricity	A connection point between the transmission system and the distribution system.
Interconnector (UK) limited	IUK	Gas	A bi-directional gas pipeline between Bacton in the UK and Zeebrugge in Belgium. You can find out more at www.interconnector.com
Interconnector		Gas	Gas interconnectors connect gas transmission systems from other countries to the national transmission system (NTS) in England, Scotland and Wales. There are currently three gas interconnectors that connect to the NTS. These are: IUK interconnector to Belgium, BBL to the Netherlands, Moffat to the Republic of Ireland, Northern Ireland and the Isle of Man
Interconnector		Electricity	Electricity interconnectors are transmission assets that connect the GB market to Continental Europe. They allow suppliers to trade electricity between these markets.
Interconnexion France-Angleterre	IFA	Electricity	The England-France Interconnector is a 2,000MW link between the French and British transmission systems. Ownership is shared between National Grid and Réseau de Transport d'Electricité (RTE).
Linepack		Gas	The volume of gas within the national transmission system (NTS) pipelines at any time.
Linepack swing		Gas	The difference between the amount of gas in the system at the start of the day and at the lowest point during the day.
Liquefied natural gas	LNG	Gas	Natural gas that has been converted to liquid form for ease of storage or transport. It is formed by chilling gas to -161°C so that it occupies 600 times less space than in its gaseous form. You can find out more at http://grainig.com/who-are-we/ing-in-the-energy-mix/
Load		Various	The energy demand experienced on a system.
Loss of load expectation	LOLE	Electricity	Used to describe electricity security of supply. It is an approach based on probability and is measured in hours/year. It measures the risk, across the whole winter, of demand exceeding supply under normal operation. This does not mean there will be loss of supply for 3 hours per year. It gives an indication of the amount of time, across the whole winter, which the System Operator (SO) will need to call on balancing tools such as voltage reduction, maximum generation or assistance from interconnectors. In most cases, loss of load would be managed without significant impact on end consumers.
Medium-range storage	MRS	Gas	Gas storage facilities designed to switch rapidly between injection and withdrawal to maximise the value from changes in gas price.
Megawatt	MW	Electricity	A measure of power 1 MW = 1,000,000 watts.
Million cubic meters	mcm	Gas	Unit of volume used in the gas industry. 1 mcm = 1,000,000 cubic metres
Moyle		Electricity	A 500MW bi-directional interconnector between Northern Ireland and Scotland. You can find out more at www.mutual-energy.com
N-1		Gas	Condition used in a security of supply test, where total supply minus the largest single loss is assessed against total peak demand.
National balancing point (NBP) gas price	NBP	Gas	Britain's wholesale NBP gas price is derived from the buying and selling of natural gas in Britain after it has arrived from offshore production facilities. The wholesale market in Britain has one price for gas, irrespective of where it has come from. It is usually quoted in pence per therm. You can find out more at https://www.ofgem.gov.uk/gas/wholesale-market/gb-gas-wholesale-market

Glossary

Word	Acronym	Section	Description
National electricity transmission system	NETS	Electricity	High voltage electricity is transported on the transmission system from where it is produced to where it is needed throughout the country. The system is made up of high voltage electricity wires that extend across Britain and nearby offshore waters. It is owned and maintained by regional transmission companies, while the system as a whole is operated by a single System Operator (SO).
National transmission system	NTS	Gas	A high pressure gas transportation system consisting of compressor stations, pipelines, multi-junction sites and offtakes. Pipelines transport gas from terminals to offtakes and are designed to operate up to pressures of 94 barg.
Non-daily metered	NDM	Gas	A classification of customers where gas meters are read monthly or at longer intervals. These are typically residential, commercial or smaller industrial consumers.
Non-storage supply	NSS	Gas	All gas supplies to the national transmission system excluding short, medium and long-range storage.
Normalised demand		Electricity	Demand assessed for each week of the year based on a 30 year average of each relevant weather variable. This is then applied to linear regression models to calculate what the demand would have been with this standardised weather.
Operational code 2 data	OC2	Electricity	Information provided to National Grid by generators. It includes their current generation availability and known maintenance outage plans. You can access the latest OC2 data throughout the year on the BM Reports website at www.bmreports.com .
Open cycle gas turbine	OCGT	Various	Gas turbines in which air is first compressed in the compressor element before fuel is injected and burned in the combustor.
Peak		Various	The maximum requirement of a system at a given time, or the amount of energy required to supply customers at times when need is greatest. It can refer either to a given moment (e.g. a specific time of day) or to an average over a given period of time (e.g. a specific day or hour of the day).
Profiling		Gas	The rate at which gas is put into or taken off the transmission system during the gas day. A flat profile corresponds to a consistent rate across the day.
Residual balancer		Gas	Users of the gas system are incentivised to balance supply into, and demand from, the network. If this balance is not expected to be achieved on any given day, the System Operator (National Grid), as residual balancer, will enter the market and undertake trades (buys or sells) to seek to resolve any imbalance.
Seasonal normal demand		Gas	The level of gas demand that would be expected on each day of the year. It is calculated using historically observed values that have been weighted to account for climate change.
Station load		Electricity	The onsite power station requirement, for example for systems or start up.
System operability		Gas	The ability to maintain system stability and all of the asset ratings and operational parameters within pre-defined limits safely, economically and sustainably.
System Operator	SO	Various	An entity entrusted with transporting energy in the form of natural gas or electricity on a regional or national level, using fixed infrastructure. The SO may not necessarily own the assets concerned. For example, National Grid operates the electricity transmission system in Scotland, which is owned by Scottish Hydro Electricity Transmission and Scottish Power.
Transmission system demand	TSD	Electricity	Demand that National Grid as System Operator sees at grid supply points (GSPs), which are the connections to the distribution networks. It includes demand from the power stations generating electricity (the station load).

Word	Acronym	Section	Description
Triad		Electricity	Triads are the three half-hourly settlement periods with the highest system demand. Triads can occur in any half-hour on any day between November and February. They must be separated from each other by at least ten days.
Underlying demand		Electricity	A measure of demand that removes the effect of weather and the day of the week.
UK Continental Shelf	UKCS	Gas	The UK Continental Shelf (UKCS) comprises those areas of the sea bed and subsoil beyond the territorial sea over which the UK exercises sovereign rights of exploration and exploitation of natural resources.
United Kingdom of Great Britain and Northern Ireland	UK	Various	A geographical, social and economic grouping of countries that contains England, Scotland, Wales and Northern Ireland.
Weather corrected demand		Electricity	The demand expected or out turned with the impact of the weather removed. A 30 year average of each relevant weather variable is constructed for each week of the year. This is then applied to linear regression models to calculate what the demand would have been with this standardised weather.
Weather corrected demand		Gas	The demand expected with the impact of weather removed. Actual demand is converted to demand at seasonally normal weather conditions, by multiplying the difference between actual CWV and expected CWV by a value that represents demand sensitivity to weather.

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Future Outlook team
System Operator
National Grid House
Warwick Technology Park
Gallows Hill
Warwick
CV34 6DA





National Grid plc
National Grid House,
Warwick Technology Park,
Gallows Hill, Warwick.
CV34 6DA United Kingdom
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