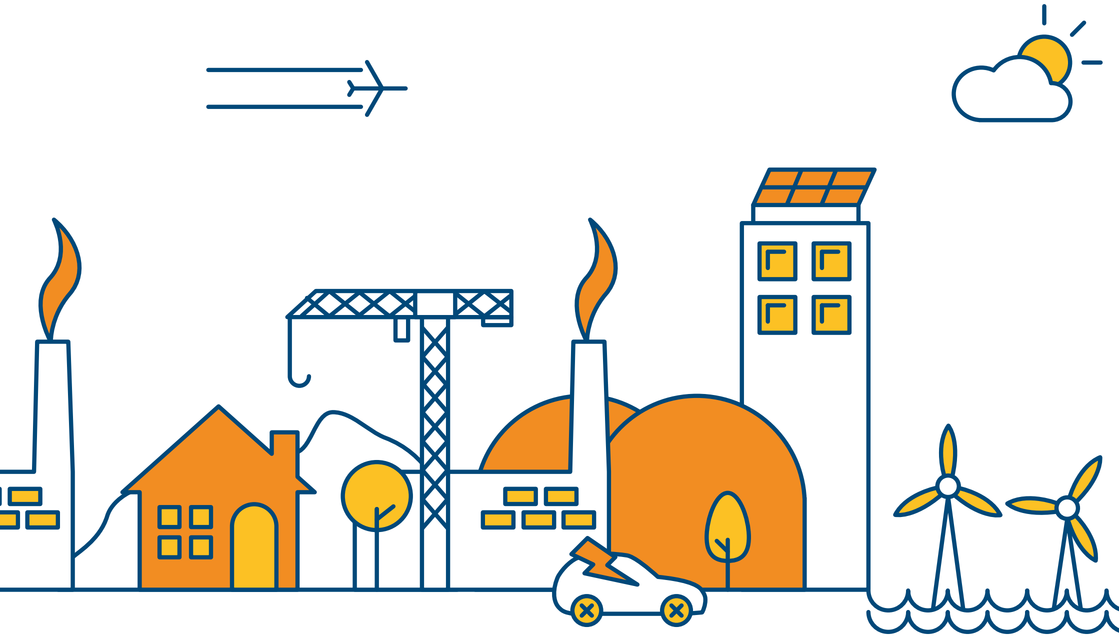
Summer **Outlook Report**

2017



APRIL 2017

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.

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

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

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

Welcome to our 2017 *Summer Outlook Report*, where we share our latest view on the gas and electricity systems for the summer ahead.

With summer just around the corner, I'm sure your summer planning is well advanced. I hope this report gives you the additional detail you'll need to finalise your preparations.

For electricity, this summer we expect to see lower peak and minimum demands on the transmission system. To make sure we're prepared, in February we completed a successful tender for the Demand Turn Up service, which offers opportunities for large energy users to voluntarily shift their energy usage in exchange for a payment. We dispatched this service for the first time in summer 2016 to help us manage periods when demand was low and generation output was high. It is just one of the tools and services we can use to balance the system during the summer. You can find out more about the other actions we can take in the operational toolbox section of the report.

For gas, we continue to see increasing variability in how gas comes onto and flows through the network, and how it is used throughout the day. Moving gas from where it enters the network to where it is needed presents us with new challenges in operating the system, particularly during the busy summer maintenance period. You can find out more in the report about how we're operating the network while planning for future requirements.

We want to support your preparations for summer by continuing to improve how we engage and share information with you. You'll find a new section in the report detailing some of the ways you can access the latest operational information for both electricity and gas. It also explains how you can get involved in events throughout the year, from consultations to operational forums. Hearing your views provides us with the information we need to help us deliver cost effective energy operations for consumers. We hope you'll find this section to be a useful source of information and want to get involved.

The *Summer Outlook Report* is just one in a suite of documents from the System Operator exploring the future of energy. To help you navigate the changing energy landscape, we've recently added two new publications; the *Gas Future Operability Planning* document and the electricity *System Needs and Product Strategy*. To find out more about these and all of our other publications, turn to page 6, or visit **our website**.

Thank you for taking the time to read this year's *Summer Outlook Report*. We want to make sure our publications are as useful to you as possible, so please let us know what you think. You can share your feedback via **our website** or by emailing us at **marketoutlook@nationalgrid.com**. You can also join the debate on Twitter using **#NGSummerOutlook** or on our **LinkedIn Future of Energy page**.

Phil Sheppard
Director of SO Operations

Contents

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 October). The report is designed to inform the energy industry and support their preparations for this summer and beyond.

Overview: Electricity summer 2017

We currently expect there to be sufficient generation available to meet demand for summer 2017. The periods of low demand that we typically see during the summer, particularly overnight and on weekend afternoons, have an impact on how we operate the transmission system. We focus on how we're responding to summer operability issues in the electricity chapter of the report.

For the last few years, we have seen both peak and minimum levels of demand on the transmission system continuing to fall. Actual summer minimum demand for summer 2016 fell to 16.8 GW, or 17.8 GW when corrected for weather. We expect this trend to continue this summer, with summer minimum demand 500 MW lower than the 2016 weather corrected outturn. The peak transmission system demand forecast for high summer is 35.7 GW, while the summer minimum is 17.3 GW.

With falling minimum demands on the transmission system, we anticipate there may be times this summer when there is more generation on the system than is needed. In order to balance the system, we will need to curtail flexible generation this summer. It may also be necessary to instruct inflexible generators to reduce their output during these periods of low demand.

To meet peak demand, we currently expect there to be sufficient generation and interconnector imports this summer. Based on operational data provided to us on 30 March, the minimum available generation is expected to be 38.0 GW in the week commencing 31 July. We are able to meet normalised demand and our reserve requirement in this week, and throughout British Summer Time, even in our low interconnector import scenario.

In the summer, greater flexibility is required to balance the system during periods of low demand and increased supply and demand variability. The operational toolbox explains the well-established actions we can take with generators of all types, as well as the newly introduced services we can access, to help manage operability issues.

Executive summary

Overview: Gas summer 2017

Great Britain (GB) benefits from highly diverse and flexible sources of gas supply. We receive gas from the UK Continental Shelf (UKCS), Norway, Belgium, the Netherlands and in the form of liquefied natural gas (LNG) from the rest of the world. We are confident that this range of supply sources will be sufficient to meet demand this summer.

Based on seasonal normal conditions, gas demand is expected to be lower than last year's weather corrected demand. This is predominantly driven by reduced gas demand for both electricity generation and storage injection. Total gas demand for this summer is forecast to be 34.0 bcm.

Gas from the UKCS and Norway will continue to account for the majority of GB's supply. Supplies from the UKCS are expected to be similar to summer 2016, while Norwegian supplies are likely to be slightly lower than last year's record high flows. We believe that deliveries of LNG to GB will increase from the very low levels we have seen over winter 2016/17.

We continue to see changes to where GB's gas supply comes from and how it is used within the gas day. This leads to operational unpredictability, particularly as clear trends from season to season are not yet apparent. We need to manage this need for a more agile network alongside a busy programme of maintenance during the summer months. By working with the industry to effectively share information in longer timescales, we can plan the most efficient and cost-effective network that continues to meet the needs of all of our customers.

National Grid's role

National Grid owns and manages the gas and electricity networks that connect homes and businesses to the energy they need.

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 customers' needs from the power stations and other electricity producers. Once that electricity enters our network, our job is to fine tune the system to make sure supply and demand 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 homes 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 section, we've brought together some of the other ways you can stay up-to-date throughout the year.

Publications from the System Operator

The outlook reports present our short-term analysis of gas and electricity supply and demand for the following six months. The reports are designed to support the energy industry's preparations for the season ahead. We'll be publishing our review of winter 2016/17 next month, in May. The consultation process for next winter will be launched separately, in early summer 2017.

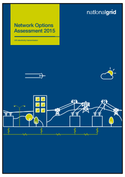
The outlook reports form part of a suite of publications from the System Operator on the future of energy. Each of the documents in this suite aims to inform the energy debate by highlighting a particular issue, and is shaped by engagement with the industry.

The starting point for much of 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.

For 2017, we have added a new publication to our suite of documents; the *System Needs and Product Strategy*. This document is designed to provide better market information and transparency in how we operate the system, and deliver a clear view of our future system needs, including the tools and services we'll require.

You can find out more about any of these documents by clicking on their front covers below or by visiting our **Future of Energy webpage**. To be the first to hear about publications and associated events, you can sign up to our mailing list via the website.

Figure 1.1
The key SO publications in 2017 and 2018

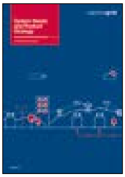


Network Options Assessment
January 2017

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

Summer Outlook Report
April 2017

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



System Needs and Product Strategy
April 2017

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

Winter Review
May 2017

A comparison between the past winter's actual energy demand and supply and our forecast.

Winter Consultation
June 2017

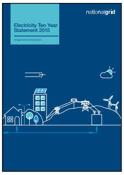
An opportunity to share your views on energy demand and supply for the winter ahead.

Future Energy Scenarios
July 2017

A range of plausible and credible pathways for the future of energy from today out to 2050.

Winter Outlook Report
October 2017

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



Electricity Ten Year Statement
November 2017

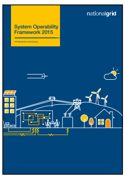
The likely future transmission requirements on the electricity system.

Gas Ten Year Statement
November 2017

How we will plan and operate the gas network, with a ten-year view.

Future Operability Planning
November/December 2017

How the changing energy landscape will impact the operability of the gas system.



System Operability Framework

How the changing energy landscape will impact the operability of the electricity system.

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 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 Thursday, 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 February 2017. 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 (**MIPI**) publishes information required under UNC and EU obligations, as well as additional information we feel is useful for the market.

Following extensive market trials, in November 2016 we replaced MIPI's existing web based platform with a new cloud based solution. The new platform is more resilient and provides a number of benefits for users:

- User friendly – data is easier to understand, with descriptions including publication frequency and units of measurement.
- Availability – data, both forecast and actual, is updated regularly and is available instantaneously to users.
- Flexibility – users can tailor their data requirements so they can access the information that is most relevant to them.
- No outages – unlike on the previous platform, most changes to the new system do not require system outages.

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 via the short survey on **our website** or by emailing us at **marketoutlook@nationalgrid.com**.

Chapter one

Fuel prices

Analysis of fuel prices helps us to understand changes in energy demand and supply, and trends in electricity generation. Current prices indicate that gas-fired generation is likely to be cheaper than coal-fired generation for summer 2017. This means that gas-fired units are likely to feature ahead of coal units in the electricity generation merit order, as they will be more economic to dispatch.

Key messages

- Due to its relative profitability, gas-fired generation is expected to feature ahead of coal-fired units in the generation merit order this summer.

Key terms

- **Generation merit order:** the sequence in which generators provide energy to the market. The order in which generators appear is based on how cost-efficient they are in producing energy, compared to other generator units.
- **Baseload:** generators providing continuous output from midnight to midnight every day.
- **Peak running:** generators providing output between 7am and 7pm. This includes the highest demand points throughout the day.
- **Price spread:** the price that energy can be sold for, minus the costs of producing it.

Overview

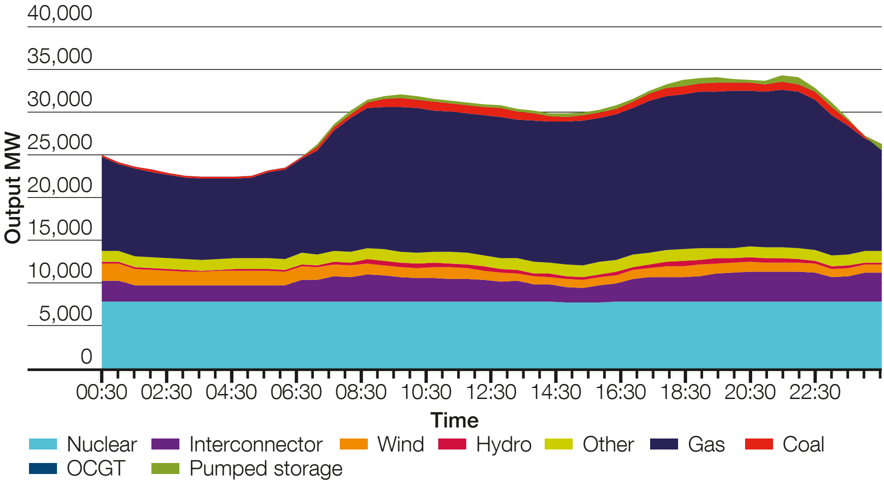
Short-term trends in fuel prices, such as for the summer ahead, have a significant impact on the type of electricity generation that runs. As a result of their input costs and efficiency, the most variable generator output is typically from gas and coal-fired power stations. To help determine which of these types of generators is more likely to run this summer, we calculate their relative profitability. This is based on the difference between their costs to produce energy, compared to the price at which they can sell that energy. Based on analysis of current prices, gas-fired power stations are expected to be cheaper than coal-fired generators this summer. This means that gas-fired units are likely to feature ahead of coal in the generation merit order, as they will be more economic to dispatch.

Generation merit order

The generation merit order describes the sequence in which generators provide energy to the market via the Balancing Mechanism (BM) at any given time. It is predominantly based on the price that energy can be sold for, minus the costs of producing it for each type of generator. This is called the price spread. 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 typically feature first in the merit order, providing continuous output known as baseload. Less cost-efficient generators may respond to peaks in demand, when the price at which electricity can be sold will be higher. As an example, figure 1.2 shows the output of different types of generators participating in the BM over the course of a typical mid-summer day, in the sequence they appeared in the merit order[1]. It is based on data from 17 August 2016. We expect generator output to follow a similar pattern in summer 2017.

Figure 1.2
Generator output for a typical mid-summer day



Nuclear power stations, shown in figure 1.2 in pale blue, typically provide a large proportion of the baseload in the summer. This is due to their low fuel costs and inflexibility to vary their output. 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.

[1] Figure 1.2 shows the output of generators participating in the Balancing Mechanism. As a result, it does not include embedded generation, such as solar PV and some smaller wind farms.

Fuel prices

These power stations are able to adjust their output in response to price signals as demand varies throughout the day. To help determine whether gas or coal-fired power stations are more likely to run this summer, we calculate the relative profitability of these two types of generators.

Assumptions

1. Cost of producing energy

Based on current forward prices, we have assumed fuel prices of 38.30 pence per therm for gas and $68.70 per tonne for coal. We then add transportation costs and carbon taxes in order to estimate the total cost of producing energy for both generator types.

2. Market price for energy produced

To determine the amount of money that energy can be sold for this summer, we have considered two forward markets; baseload and peak. Based on the current traded market price, we have assumed £39.40 per MWh for baseload and £43.00 per MWh for peaks.

3. Generator efficiency

Power stations have different efficiencies for converting input fuel into electricity output. For our analysis, we have used coal-fired generation efficiencies of between 30 and 39 per cent. Gas-fired power stations are more efficient at between 42 and 58 per cent. The volume of capacity at each efficiency is illustrated by the size of the bubbles in figure 1.3.

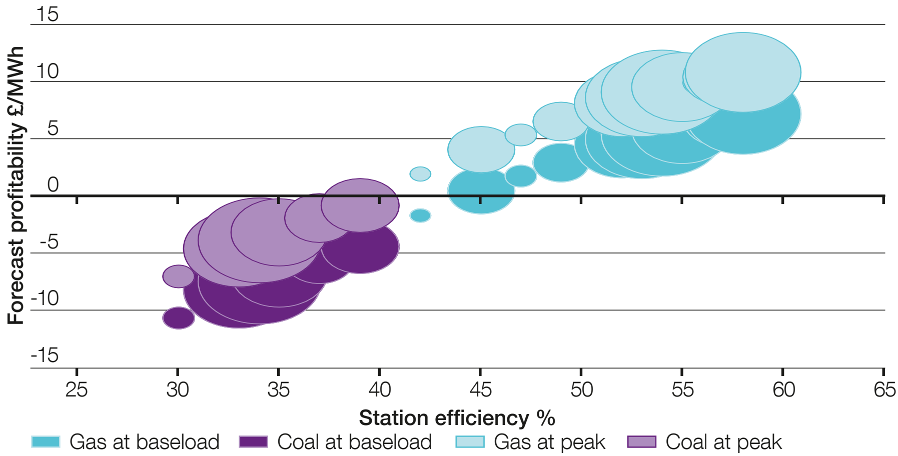
Results

Our analysis of the estimated profitability of gas and coal-fired generation this summer is shown in figure 1.3. Based on the current price spread, all gas-fired power stations would be able to make a profit this summer for running at peak. In addition, almost all gas-fired power stations would be cost-efficient for baseload. Based on current forward prices, it is unlikely that any coal-fired power stations would be able to generate a profit if providing baseload or for running at peak. As gas-fired power stations will be cheaper for both baseload and peak, they are more likely to feature ahead of coal-fired units in the generation merit order.

The cost of fuel and market prices for electricity will change as we progress through the summer. This may have an impact on the power stations closest to the zero profit/loss axis. For example, if the price spread becomes more favourable for coal, more efficient coal-fired power stations could generate a profit, while less efficient gas-fired power stations may make a loss if they choose to run. However, we expect that overall gas-fired generation will continue to be more economic throughout the summer.

Due to the relative profitability of gas-fired generation, we anticipate that some coal-fired power stations will choose to temporarily shut down over summer 2017. This means that these units may require up to 48 hours notice before they are ‘warmed’ and ready to generate again.

Figure 1.3
Forecast profitability of gas and coal-fired power stations for summer 2017



Chapter two

Summer demand and generation

Our summer view presents our analysis of demand for summer 2017, and the generation and interconnector capacity available to meet it.

Key messages

- We expect both peak and minimum demands on the transmission system this summer to be lower than the 2016 weather corrected outturn. This is predominantly driven by an increase in embedded generation.
- Generation capacity for the summer is expected to be 68.9GW.
- Based on forward prices, we expect there to be net imports of electricity on the interconnectors from Continental Europe to GB.
- We expect there to be net exports of electricity on the interconnectors from GB to Ireland during peak times, switching to imports overnight and during periods of high wind output in Ireland.

Key terms

- **Embedded 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 embedded solar and wind generation forecasts up to seven 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 the 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.

Overview

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 we can expect to see on the transmission system during the summer, as well as the demand peak.

This section presents our demand analysis for summer 2017, and the generation and interconnector imports that we expect to be available to meet it.

Summer demand

For the last few years, we have seen levels of demand on the transmission system continuing to fall. As a result, we expect demand this summer to be lower than the 2016 weather corrected outturn. This downward trend is largely due to an increase in embedded generation, particularly solar photovoltaic (PV), as well as a decrease in underlying demand. As embedded generation is connected to the distribution network, it is not visible to us and acts to reduce demand on the transmission system.

Table 2.1 summarises our demand forecasts for summer 2017. To provide a comparison, the weather corrected outturn demands from the previous three summers are also included.

This is the outturned demand we saw on the transmission system, with actual weather removed and the impact of normal weather added. Normal weather is based on a 30 year average of relevant weather variables.

We update our demand forecasts throughout the year. The demands published in this report are based on forecasts from February 2017. For the most up-to-date information, we encourage the industry to regularly view our latest forecasts on the **BM Reports website**.

Table 2.1
Historic and forecast summer demand

Year	Summer minimum (GW)	High summer peak (GW)	Daytime minimum (GW)
2014 weather corrected outturn	18.5	38.5	27.6
2015 weather corrected outturn	18.4	37.5	25.8
2016 weather corrected outturn	17.8	36.3	22.7
2017 forecast	17.3	35.7	20.8

Summer demand and generation

Assumptions

All of the demand figures quoted in this section are transmission system demands. These are based on national demand, plus a station load of 500 MW from the power stations generating electricity.

1. Underlying demand

Underlying demand removes the impact of weather and the day of the week. For 2017, underlying demand is likely to be 300 MW lower than summer 2016. This assumption is based on our analysis of underlying demand over the last 12 months.

2. Solar PV capacity

As of February 2017, embedded solar PV capacity was 11.7 GW. Based on our current 2–52 week ahead forecast, we assume a 150 MW increase in this capacity each month.

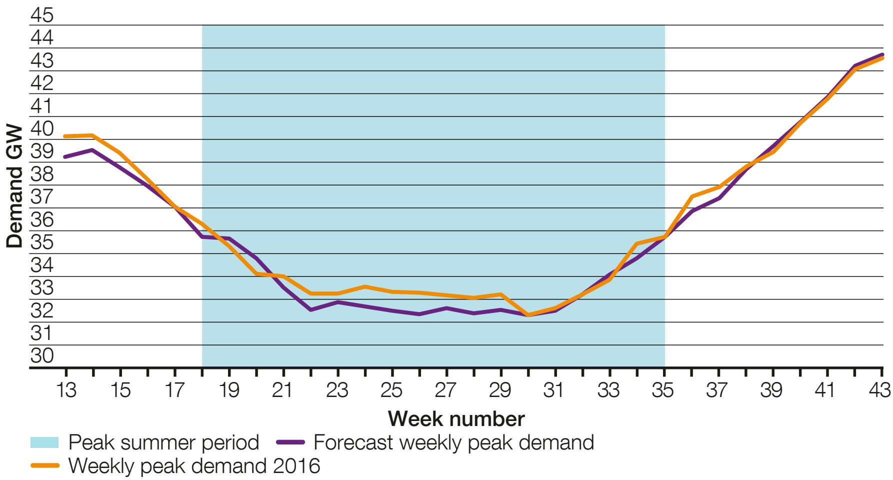
3. Embedded wind capacity

Embedded wind generation is expected to remain broadly flat this summer at 4.8 GW.

Peak demand

Figure 2.1 shows the weather corrected weekly peak demand for summer 2016, and our forecast for 2017. Our peak demand forecast for the high summer period between June and the end of August is 35.7 GW. This is 600 MW lower than last year's weather corrected outturn.

Figure 2.1
Weekly peak demand outturn for 2016 and our forecast for 2017

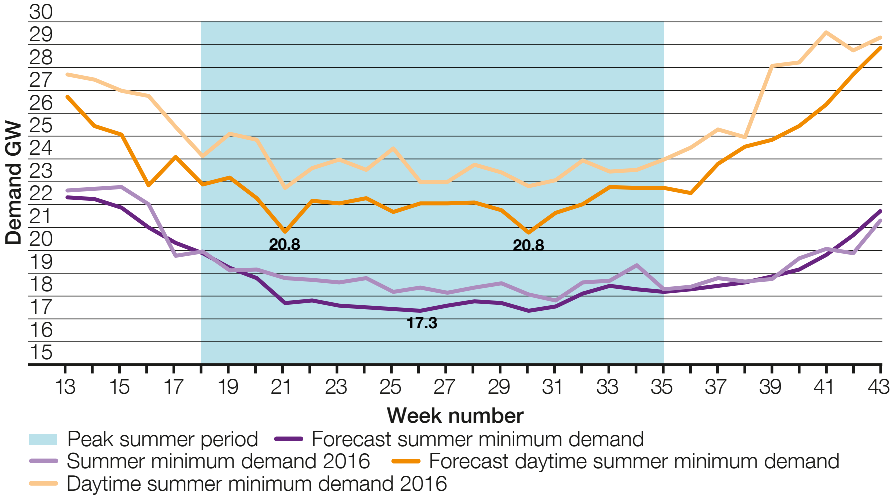


Summer demand and generation

Summer minimum demands

To support system operation, it is becoming increasingly important to understand the summer minimum demands we can expect to see on the transmission system. Figure 2.2 shows both the daytime summer minimum and summer minimum demand outturns for 2016, as well as our forecast for 2017.

Figure 2.2
Weekly minimum demand outturns for 2016 and our forecasts for 2017



Both the daytime summer minimum and summer minimum demands for 2017 are expected to be lower than previous years. The daytime summer minimum is expected to be 20.8 GW. This is 2 GW lower than the 2016 weather corrected outturn. The actual daytime summer minimum during summer 2016 was 20.3 GW.

The summer minimum for summer 2017 is expected to be 17.3 GW, which is 500 MW lower than last year's weather corrected outturn. Actual summer minimum demand for summer 2016 was 16.8 GW.

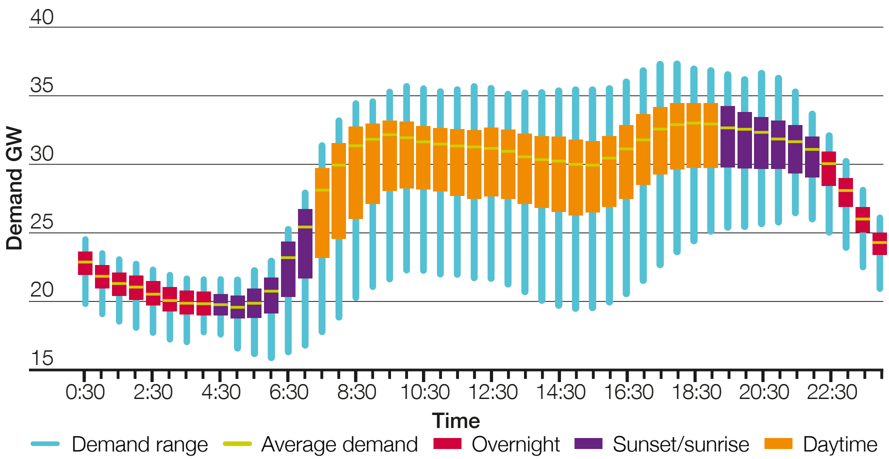
Daily demand

During the summer months, solar PV generation has an increasing impact on the daily demand profile. The daytime demands we see on the transmission system between 9am and sunset are suppressed by embedded solar generation. In addition, maximum solar generation output often coincides with the post-lunch reduction in demand. This acts to further reduce demand. You can find out more about embedded solar PV and how we incorporate it into our demand forecasts in the spotlight on page 23.

To help us forecast the levels of daily demand we can expect to see on the transmission system this summer, we have examined the profile from 2016. Figure 2.3 shows the half-hourly demand profile for high summer 2016. It shows the low to high range of demand across the day, as well as the average.

In 2016, the daily minimum demand occurred in the morning between 5am and 6am. The demand then picked up, before remaining fairly flat through the working day.

Figure 2.3
Half-hourly demand profile based on actual demand for high summer 2016



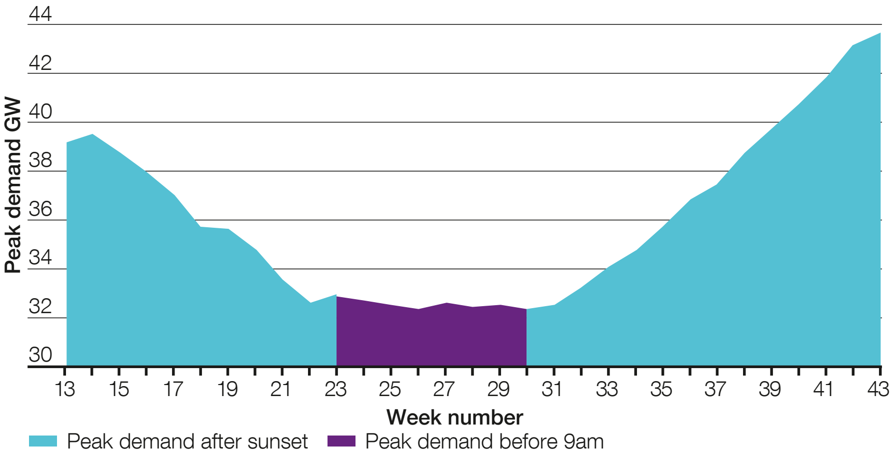
Summer demand and generation

When the daily peak demand occurs is significantly influenced by the level of solar radiation. On a bright sunny day, the peak demand is likely to occur either in the morning between 8am and 9am, or after sunset.

Figure 2.4 shows our analysis for the estimated timing of the peak demand for summer 2017, based on seasonal normal weather.

Our analysis suggests daily summer peak demand is likely to occur between 8am and 9am between weeks 23 and 30. This is due to late sunset times and solar PV generation. When the peak occurs will be dependent on weather conditions.

Figure 2.4
Estimated time of peak demand for summer 2017



Spotlight:
Embedded solar generation

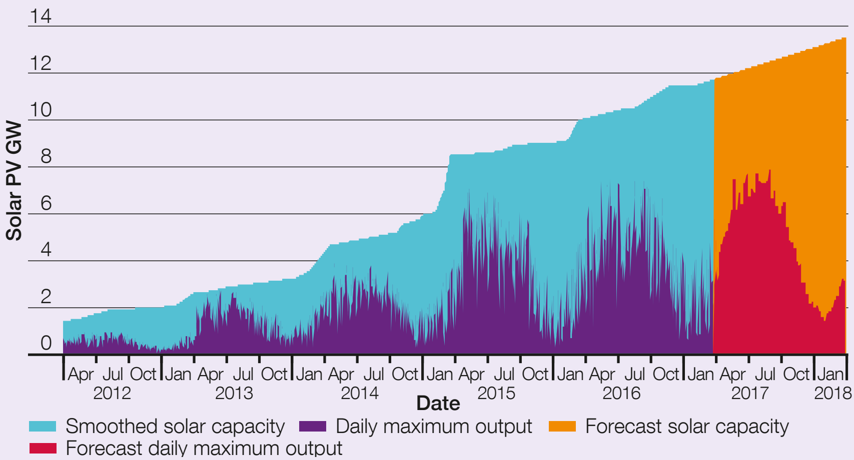
Like other forms of embedded generation, embedded solar PV generation is connected to the local distribution network, rather than to the transmission network.

Live metering is not available to the System Operator for embedded generation. As a result, historically it has not had the visibility of transmission connected generation. With the continuing rapid growth in solar PV generation capacity, it is becoming an ever more important component of our demand forecasts. We have embarked on a number of projects with external partners to address two challenges for forecasting solar PV output; installation visibility and generation variability.

How much embedded solar PV is there?
Embedded solar PV capacity has increased from 9.3 GW in February 2016, to 11.7 GW in February 2017. We expect this upwards trend to continue, with an additional 150 MW of capacity expected each month for the next 12 months. This equates to 13.5 GW of installed capacity by the end of February 2018.

Figure 2.5 shows historic PV capacity growth since 2012 and the daily maximum generation output. It also shows our year ahead forecast (March 2017 – February 2018) for both installed capacity and expected maximum daily output.

Figure 2.5
Historic and forecast PV capacity and daily maximum output



Summer demand and generation

Improving our solar PV forecasts
National Grid is leading a number of projects with external partners to significantly improve the monitoring and forecasting of solar PV generation.

In 2015, we embarked on a project with Sheffield Solar to improve the visibility of solar PV generation output. Our partnership has resulted in near real time estimates of national solar outturn, based on third party metered data from a sample of live sites. This data helps us to manage flows on the electricity network and is also used by the wider industry. The project will soon provide more localised data, to support the management of local flows and constraints on the electricity network. You can access live PV generation on the **Sheffield Solar website**.

Two further partnerships aim to help us address the accuracy of solar PV forecasts. The first, together with the Met Office, addresses known biases in forecast solar radiance, which have been a feature of current numerical weather models. One strand of this project will develop new post-processing techniques, using information from radiance observations to deliver more accurate forecast values. Improved radiance forecasts are expected to be delivered over the course of 2017. Core physics modelling development is also being supported by this project.

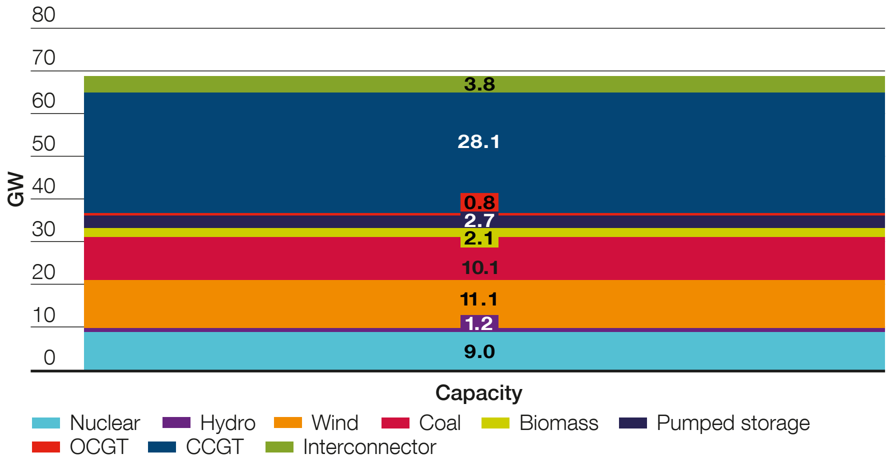
Our project with the University of Reading will provide insight into the variability of solar radiance, as well as looking at the methods we use to translate radiance values into solar power generation. Calculating how much generation output can be expected for a large area, such as the UK, is not as straightforward as applying a simple power curve to radiation values, but has more complicated dependencies. This partnership will help us to better understand the factors that need to be considered.

By harnessing the expertise of stakeholders across the industry, these projects have already delivered significant improvements to solar PV generation forecasts and monitoring. We expect further improvements to be delivered over the coming months, which will help us to more accurately forecast demand in the future.

Summer generation

Generation capacity
Figure 2.6 shows the generation capacity expected to be available for summer 2017. The total capacity available is 68.9GW. This is the maximum technical capacity of generation available; we have not applied a de-rating factor to account for breakdowns, outages or any other operational issues that may result in a plant having a decreased ability to generate at its normal level.
The capacity includes only the generation that is connected to the transmission system. We have accounted for the outage to the Moyle interconnector, which is expected to reduce its capacity to 250MW for the whole of the summer.

Figure 2.6
Generation capacity for summer 2017



Summer demand and generation

Interconnectors

Interconnectors link the GB transmission system to Continental Europe and Ireland. The current interconnection capacity between GB and other markets is 4,000MW.

France and the Netherlands

BritNed is a 1,000MW capacity interconnector to the Netherlands. It is expected to be at full capacity throughout summer 2017.

The Interconnexion France-Angleterre (IFA), which links France and the UK, has a capacity of 2,000MW. It is expected to be at full capacity for most of this summer, with the exception of two maintenance outages. Capacity will be reduced to 1,000MW between 19 and 26 June, and 1,500MW between 26 and 30 June. Capacity will again be reduced to 1,000MW for 10 days in September.

Ireland

The 500MW East West Interconnector (EWIC) to the Republic of Ireland will be on outage for five weeks, starting in mid-April, when capacity will be reduced to zero. It is expected to be at full capacity for the remainder of the summer.

The Moyle interconnector to Northern Ireland also has a capacity of 500MW. Capacity will be reduced to 250MW for the whole of the summer, due to a fault in the subsea cable.

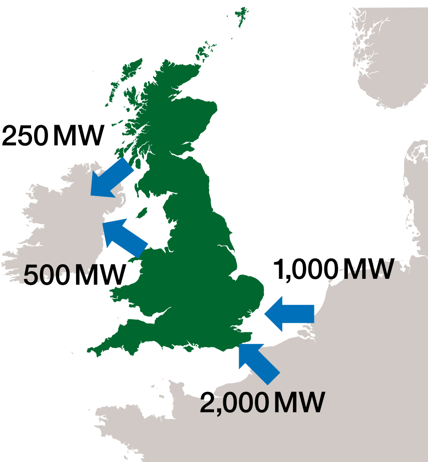
Prices

The direction that electricity flows on the interconnectors is primarily driven by the difference in prices between markets. The current price differential between GB and Continental Europe for summer 2017 is similar to previous years. Forward prices in GB are higher than those in both the French and Dutch markets. This is true for both baseload and peak times, (between 7am and 7pm on weekdays). However, although the difference in prices for baseload is greater than in previous years, the difference for peak times is smaller. As a result, we expect full imports into GB from Continental Europe on both BritNed and IFA throughout the summer, although there may be some volatility in flows during peak times.

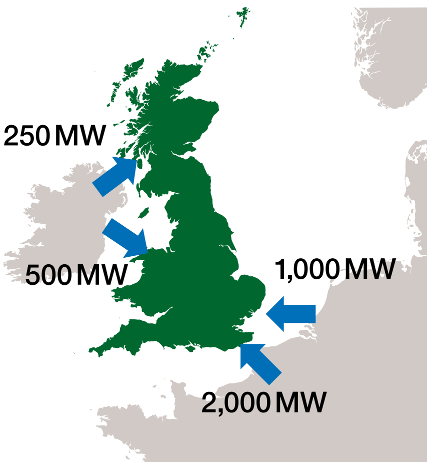
Based on current forward prices, we expect GB to be exporting to Ireland during peak times on both Moyle and EWIC. This is likely to switch to imports to GB during off-peak times overnight. Imports to GB are also likely when there is high wind generation on the Irish electricity system, due to lower prices in the Irish market and the technical restrictions on their system.

The expected flows for both peak and off-peak times are summarised in figure 2.7.

Figure 2.7
Projected interconnector flows for peak and off-peak times for summer 2017



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



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

Operational view

Our operational view is based on 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 across British Summer Time under three interconnector scenarios with low, medium and full imports.
- There is a possibility that we may have to issue instructions to inflexible generators to reduce their output between late April and the end of summer, in order to balance supply and demand.
- Some flexible wind generation will need to be curtailed this summer during periods of minimum demand to help us balance the system.

Key terms

- **Operational Code 2 (OC2) data:** information provided to National Grid by generators. It includes their current generation availability and known 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.

Operational view

Our operational view is based on current generation availability data, otherwise known as Operational Code 2 (OC2) data. This is submitted weekly by generators. In our analysis we have used data provided to us on 30 March 2017.

The OC2 data includes generators' known maintenance outage plans. As in previous years, we expect a large number of maintenance outages over the summer, as generators use the period of lower demand to prepare for winter. In order to account for unexpected generator breakdowns, restrictions or losses close to real time, we apply a breakdown rate to the OC2 data. This data is then modelled against forecast normalised transmission system demand, plus a reserve requirement, and a range of interconnector flows to provide a week-by-week picture of operational surplus.

The operational view does not take into account any market response by generators to high demand or tighter conditions. We know that generators have greater flexibility in planning summer outages. 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 Thursday on the **BM Reports website**.

Chapter two

Operational view

Assumptions

1. Demand
The demand used in our operational view is normalised transmission system demand (TSD). This includes the demand we expect to see from power stations generating electricity (the station load at 500 MW) and interconnector exports. We have assumed 750 MW of export to Ireland for the period of peak demand.

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. However, we have assumed a reserve requirement of 0.9 GW for each week of our analysis. This is shown in figure 2.9 as a purple bar above the normalised demand.

3. Generator breakdown
The operational data provided to us by generators includes only their known maintenance outages. 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 2.2. They are based on historic summer breakdown rates from 2016[1].

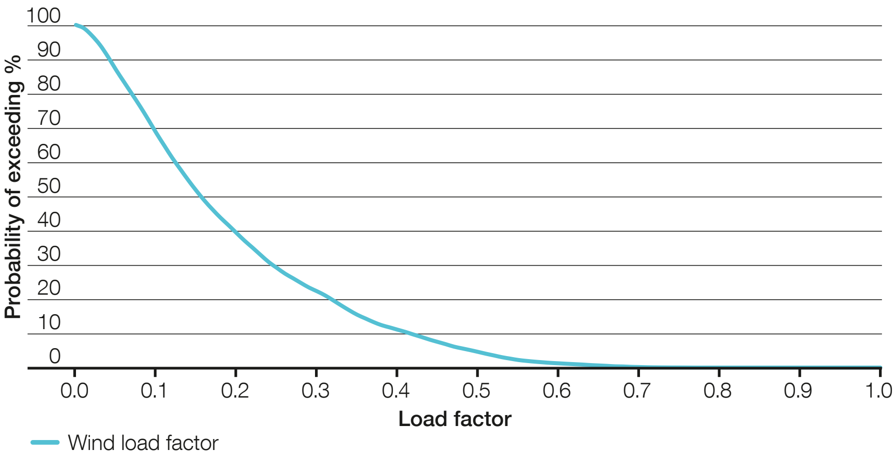
Table 2.2
Assumed breakdown rates for summer 2017

Generator type	Assumed breakdown rate
Nuclear	9%
Hydro	80%
Coal and biomass	12%
Pumped storage	2%
OCGT	5%
CCGT	11%

[1] Historically, breakdown rates were based on an average taken over three years. With a large number of changes in the generation mix, we believe it is now more relevant to use only the most recent observations.

To determine how much output we could reasonably expect from wind generation this summer, we use a load factor. This is calculated from the historic wind farm load factor distribution for summer daytimes, shown in figure 2.8. We use the median wind load factor of 16 per cent in our analysis.

Figure 2.8
Summer daytime wind load factors



4. Interconnectors

Our analysis is based on three interconnector scenarios for periods of peak demand, shown by the line graph in figure 2.9. All of the scenarios assume full export to Ireland, which adds 750MW to expected demand. Each scenario includes a varying level of import from Continental Europe:

- Low imports of 500MW, resulting in a net export of 250MW.
- Medium base case of 1,800MW, resulting in a net import of 1,050MW.
- Full interconnector imports of 3,000MW, resulting in a net import of 2,250MW.

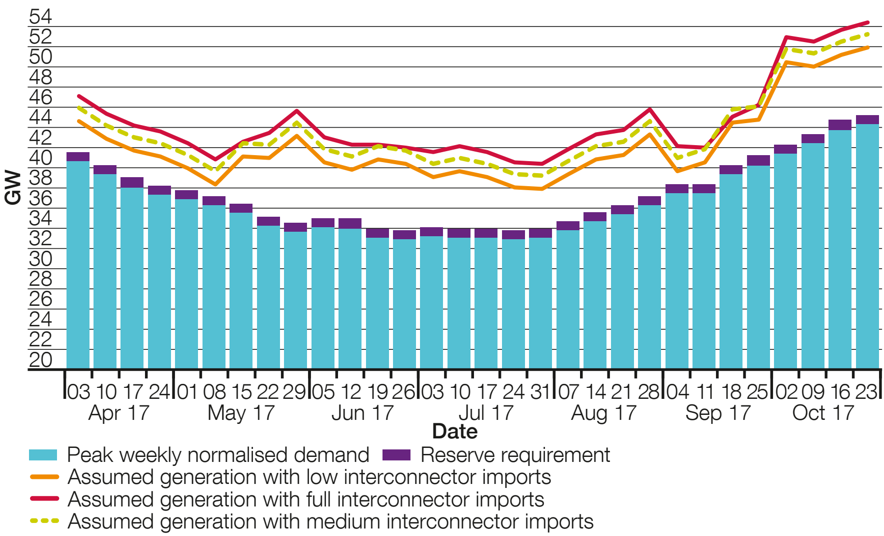
Chapter two

Operational view

Results

Figure 2.9 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 30 March.

Figure 2.9
Operational view summer 2017



In the summer months, maintenance outages reduce the amount of generation available. 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. Based on current economic conditions, we also expect some coal power stations to temporarily shut down during summer 2017. You can find out more about this in the fuel prices section on page 11. 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 38.0GW in the week commencing 31 July. We are able to meet normalised demand and our reserve requirement in this week, and throughout the summer period, even with low interconnector imports. As shown in figure 2.9, the amount of available generation increases at the beginning of October. This is in response to the introduction of the Capacity Market (CM). Capacity contracted via the CM is available earlier than the contingency balancing reserve services we procured for last winter, which were available from November.

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 up-to-date information, we encourage the industry to regularly view latest OC2 data, published each Thursday on the **BM Reports website**. Unlike the operational view presented here, the data presented on BM Reports is largely unadjusted, except 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.

System operability in periods of low demand

In the summer, there is a significant reduction in the demand we see on the transmission system. As a result, we need to make sure that there is sufficient flexible generation on the system to meet this demand while maintaining sufficient frequency response. This ensures that the system can respond to the largest generation or demand loss. It is also necessary to maintain positive and negative regulating reserve levels to account for forecasting errors and reductions in generator availability close to real time.

To help us to understand the actions 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. We then add the output of flexible wind. These forecasts are updated weekly throughout the summer and can be found on **our website**.

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, we apply a load factor to each generation type. These load factors, which are shown in table 2.3, are based on historic availability data 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. You can find out more about expected interconnector flows this summer on page 26 of the summer demand and generation section. The load factor for flexible and inflexible wind is determined from figure 2.10. 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 46 per cent.

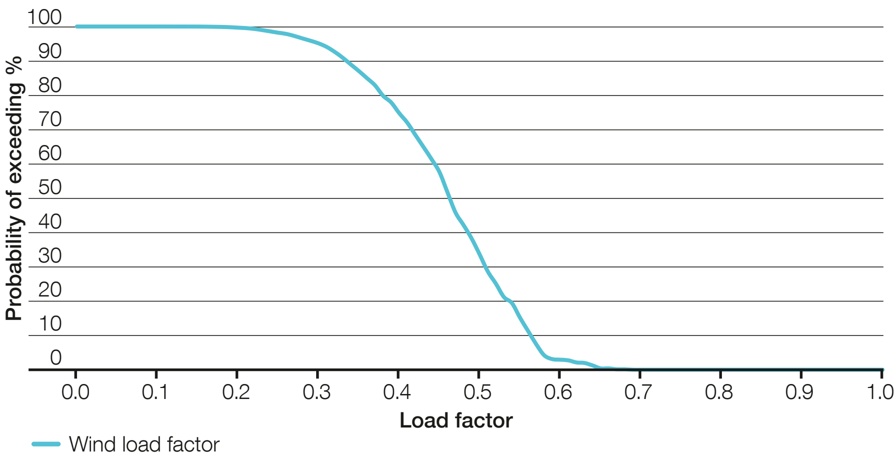
Chapter two

Operational view

Table 2.3
Inflexible load factor assumptions at minimum demand

Generator type	Load factor
Nuclear	0.93
Inflexible Balancing Mechanism units	0.91
Inflexible hydro	0.10
Flexible and inflexible wind	0.46
Moyle interconnector	1
East West Interconnector	1
BritNed	0.70
Interconnexion France-Angleterre	0.50

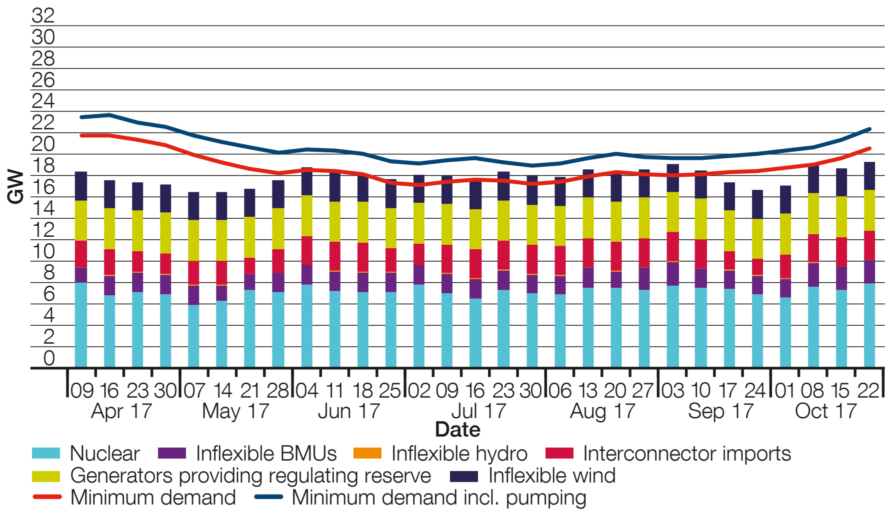
Figure 2.10
Wind load factors at minimum demand



Results

Figure 2.11 shows a weekly view of the cumulative minimum output expected this summer from less flexible generators. This is based on the availability submitted to us by generators, multiplied by the load factors described above. It includes the synchronised plant required to meet our frequency response and reserve requirements. This output is compared to the weekly minimum demand profile, together with pumped storage demand at an assumed load factor of 70 per cent.

Figure 2.11
Weekly minimum demand and generation profiles



Based on current data, we anticipate that we will need to take action this summer to manage periods of low demand. This may include asking pumped storage units to increase demand by moving water back to their top lakes, or trading 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 and will inform and engage with inflexible generators where necessary.

Operational view

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. The flexibility of wind farms allows us to issue curtailment instructions if necessary, requesting their output to be reduced 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 decreasing demand at the summer minimum and fewer flexible generators running overnight.

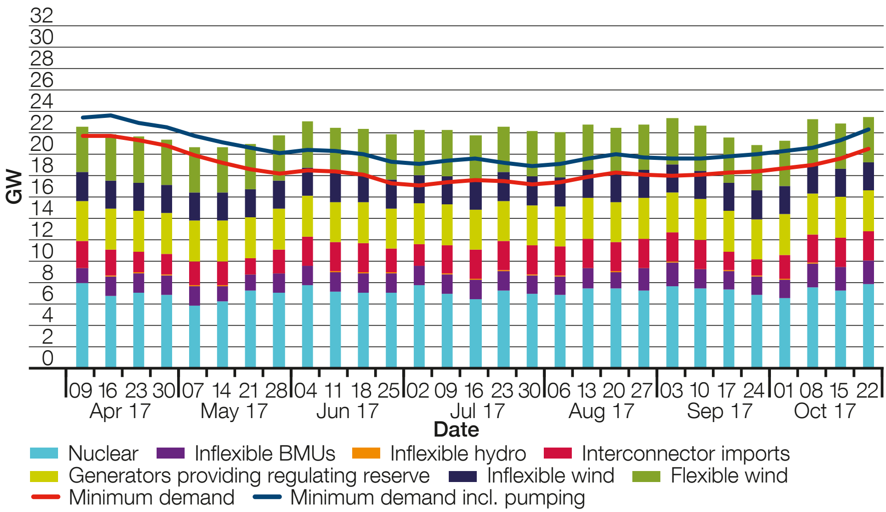
In figure 2.12, flexible wind farm output has been added to the cumulative minimum output, assuming the same wind load factor of 46 per cent. It shows that if flexible wind does not contribute to meeting the frequency response and regulating reserve requirements, it will need to be curtailed this summer to ensure that supply does not exceed demand.

This curtailment will either be carried out via the Balancing Mechanism or direct trades. There is a possibility of curtailment from the end of May up until clock change in October, depending on wind conditions.

If wind contributes to the reserve requirement, this would reduce the size of the flexible wind block and displace some of the conventional generation providing these services. Initially, high frequency response and negative regulating reserve are likely to be the most economic services for wind farms to provide.

To help us to manage periods of low demand in the most efficient and economic manner, we encourage generators that currently do not meet their obligation to provide frequency response to do so. The submission of cost reflective prices for the provision of frequency response also enables us to make appropriate economic decisions.

Figure 2.12
Weekly minimum demand and generation profiles including flexible wind output



In the analysis above, we have only considered the potential for wind curtailment at a national level. It is also possible that we may need to curtail wind at a local level this summer. These local issues are likely to be caused by constraints on the system resulting from faults, maintenance or network design. These issues may result in a higher level of generation in an area than is needed or that can be safely exported to other areas on the electricity network. You can find out more about constraints in the operational toolbox section on page 45, as well as accessing the latest forecasts for potential wind curtailment on **our website**.

Operational toolbox

In our role as System Operator, National Grid must manage a number of operability issues during periods of low demand. This section 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

- Greater flexibility is required to manage the system during periods of low demand and increased supply and demand variability.
- National Grid has access to well-established actions with generation of all types, as well as newly introduced services, to help manage operability issues.

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.

Overview

Greater flexibility is required during periods of low demand, especially in the summer, to accommodate increased within day supply and demand variability. Historically, these requirements have been met with minimal intervention from the System Operator. More recently, the changing generation mix and varying demand profiles have increased the need for direct System Operator intervention to maintain system security.

The National Electricity Transmission System Security and Quality of Supply Standards[2] (NETS SQSS) establish a coordinated set of criteria and methodologies for the planning and operation of the transmission system.

These standards govern operability considerations such as loss of supply capacity, frequency conditions, voltage conditions, overloading of equipment and system stability. In our role as System Operator, National Grid takes actions to manage all of these aspects of the transmission system using a range of tools and services that are outlined in this section. This may include well-established actions with generation of all types, as well as newly introduced services with demand side providers.

Requirements, tools and services

Reserve

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. The concept of head room and foot room is illustrated in figure 2.13.

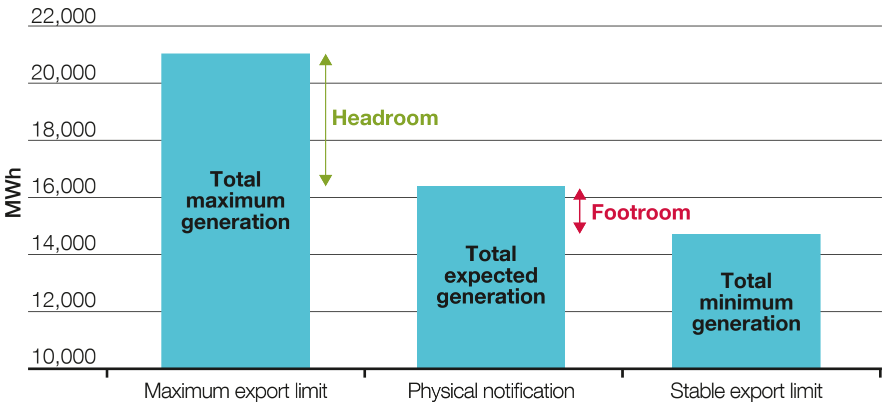
Reserve is required to:
- account for errors in demand, wind and solar forecasting
- cover demand and generation losses in the period from day ahead to real time, and
- facilitate the holding of high frequency dynamic response.

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.

[2] More information on the SQSS can be found at http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/System-Security-and-Quality-of-Supply-Standards/

Operational toolbox

Figure 2.13
An illustration of head room and foot room



1. Negative reserve

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:

- Curtail or de-synchronise generation to maintain sufficient system foot room. We procure flexibility for foot room via a number of different services, including:
  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.
- Increase demand through demand side response services. This includes the Demand Turn Up service that was successfully introduced in summer 2016. You can find out more about this service in the spotlight on page 41.
- 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.

If a requirement for negative reserve could not be met through contracts, trading, SO-SO actions on the interconnectors or via the Balancing Mechanism, then National Grid may issue a negative reserve active power management (NRAPM) system notification to the industry. This notice is designed to encourage inflexible generators to reduce their output where possible to create downward flexibility on the system. You can find out more about how we model inflexible generation during periods of low demand in the operational view section on page 33.

At times of particularly low demand, or in periods where inflexible generation 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 generators to submit cost reflective prices to the Balancing Mechanism to allow us to manage low demand periods efficiently and economically.

2. Positive reserve

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.

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.

Spotlight: Demand Turn Up

With the rapid pace of change in the supply side of the energy market, the role that the demand side can play is becoming increasingly important.

The Demand Turn Up service encourages large energy users and small generators to either increase demand or reduce generation when there is excess energy on the system. This excess typically occurs overnight and during weekend afternoons in the summer.

The service was successfully introduced in summer 2016, when we issued 323 instructions for the dispatch of 10,800MWh. The majority of these instructions were enacted to create foot room on the system, particularly overnight during July and August in response to high wind speeds. The remainder were issued either to help manage constraints or by our project partners, Western Power Distribution, to meet distribution requirements.

Summer 2017

For 2017, we're offering two routes for those interested in providing the Demand Turn Up service:

- **Fixed Demand Turn Up –** procured for the whole of British Summer Time via a tender that completed in February 2017.
- **Flexible Demand Turn Up –** where parties can bid their availability and prices on a weekly basis throughout the summer.

So far for summer 2017, we've procured 138.6MW of fixed volume. Providers are from across GB, with 15 sites proposing to reduce generation to supply Demand Turn Up, and 5 sites shifting their demand.

We'll be procuring the Flexible Demand Turn Up service throughout the summer. Potential providers can find out more information about how to get involved by visiting our **website** or by emailing **commercial.operation@nationalgrid.com**.

Chapter two

Operational toolbox

System inertia

System inertia is a measure of how resilient system frequency is to change. It acts to slow down the rate of change of frequency when there is demand or generation loss. In the period immediately following a large loss, but before frequency response services start to deliver, the rate of change of frequency can by relatively high. This is especially true at times of low inertia, which are prevalent during periods of low demand.

The growth in non-inertial generation capacity, including embedded wind and solar PV, is displacing types of generation that have historically provided inertia. This is causing a decrease in the levels of inertia on the system. Further details on the impacts of low and decreasing levels of system inertia can be found below in the response and rate of change of frequency sections. At times of low inertia, National Grid may take actions to de-synchronise non-inertial generation and synchronise generation that is able to provide inertia. These actions enable us to manage overall inertia levels and mitigate the impact on response and rate of change of frequency.

Response

System frequency is a continuously changing variable that is determined and controlled by the second-by-second balance between demand and generation. National Grid must make sure that sufficient generation and/or demand is held in automatic readiness to manage all credible events that might result in frequency variations[3]. These variations may be caused by a disturbance, such as a sudden drop in generation or demand, leading to an underlying imbalance or 'mismatch' between demand and supply.

There are two main types of frequency response services; dynamic and static. Dynamic frequency response is a continuously provided service used to manage the normal second-by-second changes on the system. Static frequency response is typically a discrete service, triggered at a defined frequency deviation.

The requirement for response services increases during periods of low inertia. This is due to a number of factors:

- For dynamic response services, there is a time delay of up to two seconds between a frequency changing event occurring and the service starting to deliver. In addition, dynamic response providers do not have to fully deliver until 10 seconds after an event.
- Static response services do not begin to operate until a certain trigger frequency is reached.
- System frequency moves more quickly during times of low inertia, as the rate of change of frequency is higher. As a result, the time that it takes for system frequency to deviate towards statutory limits (50.0 Hz ± 0.5 Hz) decreases.
- As inertia decreases, the time at which the greatest frequency deviation occurs can fall within 10 seconds of the event. By this time, dynamic response will only have partially delivered.
- Greater levels of dynamic response are therefore required to account for the expected partial delivery of response by all service providers.

[3] More information on frequency response requirements and services can be found at http://www2.nationalgrid.com/UK/Services/Balancing-services/Frequency-response/

In the short term, there are three main routes for the procurement of response services:

- Mandatory Frequency Response via the Balancing Mechanism; or
- Contracting in advance in the form of:
  - Firm Frequency Response (FFR), which is the firm provision of dynamic or static response to changes in frequency.
  - Enhanced Frequency Response (EFR), which provides response within one second of a frequency deviation.

In the longer term, a number of projects exist to secure a greater proportion of response. These include working with demand side providers[4], wind farms and highly flexible assets that can provide response in shorter timescales.

Rate of change of frequency

As previously discussed, 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 (RoCoF) can be relatively high. A large volume of embedded generation has loss of mains protection[5] 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 rate of change of frequency is high enough, RoCoF based loss of mains protection can operate. This has the potential to cause embedded generation to stop generating, leading to a further disturbance and a possible cascade effect.

To manage this issue, the Joint Distribution and Grid Code working group recommended changing the protection settings on RoCoF relays for generators above 5 MW. These changes were due to be fully implemented by August 2016. However, industry data suggests that significant levels of embedded generation are still at risk of a trip from RoCoF. Accordingly, National Grid regularly takes actions to manage the rate of change of frequency.

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:

- 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.

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 response to manage the total potential demand or generation loss that may result in a further RoCoF loss.

[4] Further information about balancing services opportunities for demand side providers can be found at http://www.powerresponsive.com/

[5] Further information on Loss of Mains Protection and the joint Distribution Code and Grid Code Workgroup can be found at http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/Grid-code/Modifications/GC0035-GC0079/

Operational toolbox

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, exacerbated by the running patterns of generation during low demand periods.

National Grid has put in place a number of long-term actions to manage occurrences of high voltage. This includes a significant capital investment programme in reactive compensation assets, engagement with the distribution network operators, and Grid Code amendments for accessing MVArs (units of reactive power) on solar and wind generation.

In the short term, a number of tools exist that enable the running of specific generators to access their MVAr capability, where forward indications of plant running indicate it is prudent and cost-effective to do so.

These actions include:
- 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.
- Trading actions within day, when running patterns are more volatile.
- 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, and flexible plant avoiding running overnight.

Constraints and power flows

The amount of power that flows from one area of the transmission network to another is equal to the difference between the demand and generation in that area. This flow of power can sometimes be limited by the physical capability of the transmission equipment connecting the two areas. This is called a constraint. 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.

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.

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 notification 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 outside of the Balancing Mechanism, known as emergency instructions, to control flows of power.

Black Start

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 warming of units is required. We are currently exploring a number of alternative providers, upgrades at existing sites and new technologies for the economic provision of Black Start services.

Chapter **two**

Operational toolbox

System operation

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:

- 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.

This means that none of the requirements in this section can be considered in isolation, and instead a whole system optimisation approach is necessary.

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. You can find out more about how we manage these interacting factors in the case study below.

System operation during periods of low demand: 6–7 August 2016

To help illustrate the complex interactions that can occur between different operability requirements, particularly during periods of low demand, it is useful to use a real life example. The weekend of 6–7 August 2016 was warm, with high wind and solar generation output. As a result, National Grid saw very low levels of demand on the transmission system. This occurred at the same time as low levels of system inertia.

Over the weekend, we took a number of actions to help manage the system. Some of these satisfied multiple requirements, while others addressed a specific requirement but increased the need for action in other areas:

- Synchronous generators were providing support for voltage and system inertia over the weekend. However, as only the most efficient generators were economic to run, National Grid needed to take actions to support these.
- To resolve voltage constraints, National Grid synchronised additional units in key locations. This also acted to support system inertia. We accessed these units via the Balancing Mechanism and forward energy trades.
- As synchronous generators must export a minimum amount of power, actions taken to resolve voltage can have an impact on the requirements for negative reserve. To resolve this, National Grid reconfigured a generator that could run with a lower minimum export via a constraint management contract.
- Overnight and into Sunday, National Grid reduced interconnector imports from France and the Netherlands using forward energy trades. This had the double benefit of improving the requirement for negative reserve, as well as reducing the largest instantaneous power in-feed loss risk. This meant that the system could be operated securely with lower levels of system inertia.
- We also dispatched the Demand Turn Up service. As discussed in the spotlight on page 41, this service encourages large energy users and generators to either increase demand or reduce generation when there is excess energy on the system. In certain locations, dispatching this service also reduced the volume of wind generation that needed to be constrained and improved the negative reserve requirement.

The chain of events over this particular weekend in August 2016 demonstrates the complex interactions between different operability requirements, where actions to resolve one issue can have an impact on others. Actions to operate the system are always taken on an economic basis, taking into consideration the interaction of all these factors.

Chapter three

Gas demand

For summer 2017, gas demand is expected to be lower than last year's weather corrected demand. This is predominantly driven by lower levels of gas demand for electricity generation and storage injection.

Key messages

- We expect there to be less gas demand for electricity generation than last summer. This is because of lower overall electricity demand, as well as the continuing increase in renewable generation capacity. Renewable generation displaces the demand for all types of thermal generation, including gas-fired power stations.
- Ongoing technical issues at the Rough long-range storage facility mean there is uncertainty around the site's availability for injection this summer. Rough will be completely offline for at least part of the summer. This is expected to reduce the gas demand for storage injection.
- The Corrib gas field is now delivering at its maximum rate. We anticipate that this will keep exports to Ireland at a low level, similar to last year.

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.
- **Composite weather variable (CWV):** a single measure of daily weather. It is a combination of temperature and other weather variables, including wind speed. The purpose of CWV is to define a linear relationship between the weather and non-daily metered gas demand.

Overview

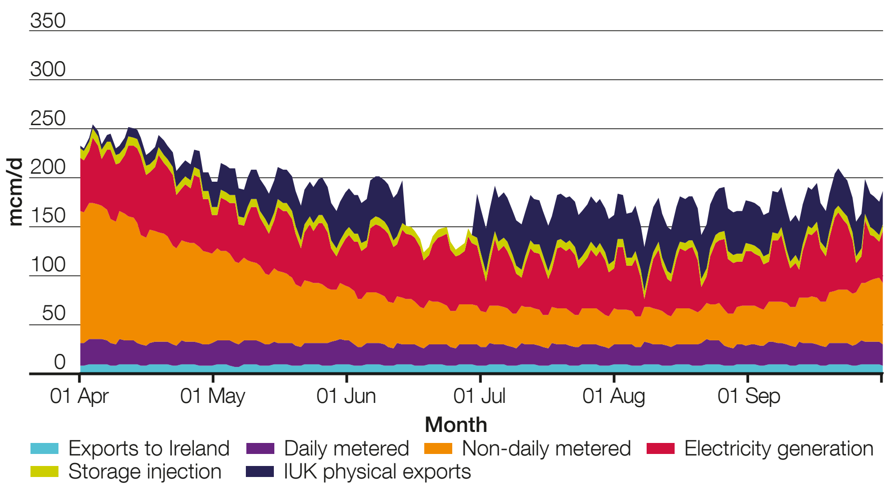
Gas demand this summer is expected to be lower than the 2016 weather corrected demand. This is the case across all categories of gas demand. However, the lower overall level of demand for summer 2017 is predominantly driven by reduced gas demand for both electricity generation and storage injection.

Gas demand can broadly be split into two types; demand that is sensitive to weather, and demand that responds to price or other signals. We will address each of these separately in this section.

Total gas demand

Our forecast for gas demand for summer 2017 is shown as profiles for the season in figure 3.1, and in aggregate in table 3.1. For comparison, table 3.1 includes the actual and weather corrected values for summer 2016.

Figure 3.1
Forecast gas demand profiles for summer 2017



Chapter three

Gas demand

Table 3.1
Forecast total gas demand for summer 2017 and history for previous summers

bcm	2012 actual	2013 actual	2014 actual	2015 actual	2016 actual	2016 weather corrected	2017 forecast
NDM	13.0	12.3	9.9	11.3	11.1	11.1	10.8
DM + Industrial	4.8	4.5	4.4	4.2	4.1	4.1	4.0
Ireland	2.7	2.7	2.7	2.8	1.5	1.5	1.5
Electricity generation	8.3	7.7	9.2	8.3	11.6	11.6	10.0
IUK export	3.9	2.6	3.8	5.0	5.1	5.1	5.9
Storage injection	3.0	5.3	3.6	3.4	2.5	2.5	1.5
Total	**36.0**	**35.0**	**33.8**	**35.2**	**35.9**	**36.0**	**34.0**

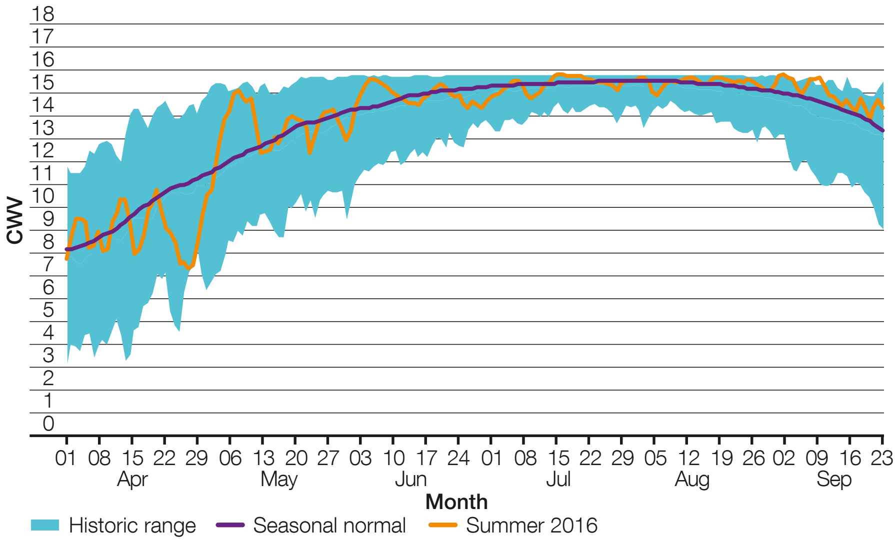
Weather sensitive gas demand

Gas that is used for space heating, to keep buildings warm, is sensitive to the effects of the weather. Although temperature has a significant influence, wind speed is also important. In addition, there is a seasonal effect. For example, a temperature of 15°C in February would feel quite mild, but would probably not prompt people to turn off their central heating systems. In July, a temperature of 15°C may be perceived as cool, but would not typically prompt people to turn their heating back on. As a result, the same temperature in February would result in higher gas demand. In our analysis, we combine the effects of temperature, wind speed and the season in a single quantity called the composite weather variable (CWV).

Gas for space heating is captured in the non-daily metered (NDM) demand. The NDM sector includes all residential demand, as well as demand from small to medium industrial and commercial customers. Our forecast for the NDM sector for the summer, shown in table 3.1, is slightly lower than last summer's weather corrected demand. This reflects a continuing decline in space heating demand, driven by the increasing efficiency of appliances and levels of insulation. As shown in orange in figure 3.1, our NDM demand forecast ranges from approximately 140 mcm/d in April, down to just over 30 mcm/d during the day on weekends in July and August. These forecasts assume that the weather will be typical for the time of year, referred to as seasonal normal.

When we analyse historic gas demand we typically use a weather corrected value. This shows what the demand would have been under seasonal normal weather conditions. In table 3.1, you can see that the weather corrected demand and the actual demand for summer 2016 were extremely close; the difference is only in the second decimal place, which is not shown in the table. This suggests that the weather in summer 2016 was, on average, close to seasonal normal conditions, as shown in figure 3.2.

Figure 3.2
Composite weather variable for summer 2016

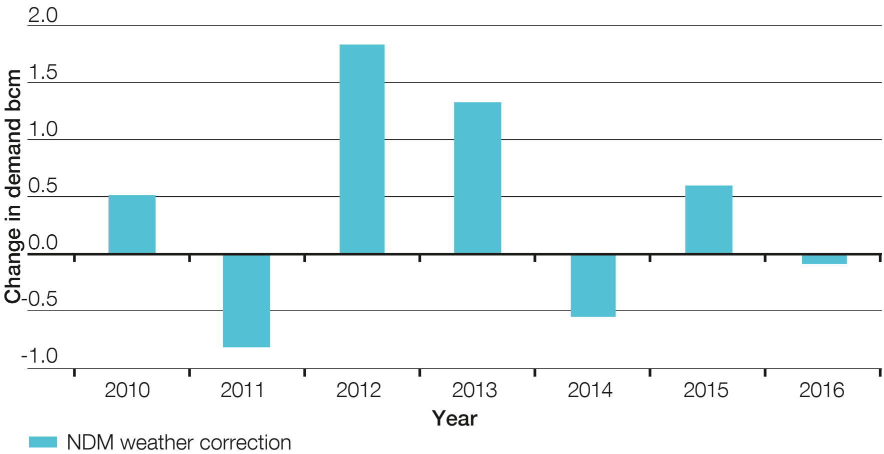


Chapter three

Gas demand

Unlike in 2016, in some summers the weather can be very different from seasonal normal conditions. Figure 3.3 shows the effect that the weather has had on summer demand since 2010. For example, 2012 was a cold and wet summer. As a result, NDM demand was approximately 1.8 bcm higher than we would have expected under seasonal normal weather conditions.

Figure 3.3
The effect of weather on NDM demand



Although gas demand for space heating is predominantly driven by the effect of weather, it also shows some response to gas prices. However, gas prices for end users are generally based on tariffs that respond to long-term trends in wholesale prices, rather than the shorter term prices described in the fuel prices section on page 11. As a result, the effect of prices on gas demand for space heating is less visible for the season ahead. You can find out more about the effect of changing prices on gas demand in our longer term modelling, published in our ***Future Energy Scenarios***.

Non-weather sensitive gas demand

Gas for electricity generation
The largest proportion of non-weather sensitive demand is the demand for electricity generation. This is shown by the red section in figure 3.1. The use of gas for electricity generation depends on the electricity demand and the relative profitability of gas-fired power stations, compared to other types of generators. You can find out more about the types of power stations that are more likely to run this summer in the fuel prices section on page 11.

We expect overall electricity demand this summer to be lower than last summer. As discussed in the fuel prices section, gas-fired power stations are expected to be more economic to dispatch than coal-fired generators this summer. However, there is more renewable generation available this year, which will reduce the demand for all types of thermal generation. As a result, we expect gas demand for electricity generation to fall to 10 bcm.

Daily metered demand and industrial load
The daily metered (DM) market is predominantly made up of larger industrial and commercial customers. Although some gas is used for space heating to keep factories warm, 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 3.1, is essentially flat across the summer. Demand in the DM sector has been declining for many years, mirroring the decline in energy intensive industries. There is also a continuing drive towards greater energy efficiency. We expect DM demand to be slightly lower than the weather corrected value from last summer, at 4 bcm.

Exports to Ireland
Gas is exported to Ireland (both to Northern Ireland and the Republic of Ireland) and the Isle of Man via an interconnector that is connected to the GB transmission system at Moffat in southern Scotland. The high proportion of gas used for electricity generation in these markets means that there is little weather sensitivity in the export flow. The light blue area in figure 3.1 shows flat demand across the summer.

We expect gas exports to Ireland to be similar to 2016. The Corrib gas field, off the North West coast of Ireland, started production last year. This has reduced the requirement for gas exports from GB. We expect a flow of 1.5 bcm this summer, well below the long-term pre-Corrib value of around 2.7 bcm.

Gas demand

Other categories of gas demand

Storage injection

Long-range storage is used to provide additional seasonal gas supply. Shippers typically inject gas into storage throughout the summer when the gas price is expected to be lower, and withdraw it in the winter when gas prices are expected to be higher. Rough is the only long-range storage site connected to the transmission system in GB; it is a depleted gas field 29 km off the coast of Easington in Yorkshire.

Centrica Storage Limited, the owners and operators of Rough, have been experiencing technical problems at the facility since 2015. We have considered the impact of these issues in previous outlook reports. You can also find out more information on the **Centrica Storage website**. On 28 February 2017, Centrica Storage applied to Ofgem for permission to reduce the capacity that they are obliged to offer to the market before the start of the storage year (1 May) to zero for storage year 2017/18. Storage injection had already been halted until at least 1 July 2017. While Centrica Storage have not ruled out the possibility of making capacity available later in the year, for this year's *Summer Outlook Report* we have assumed that no gas will be injected into the Rough facility before the end of September 2017. However, the facility may be able to return to injection depending on the outcome of the well testing programme. This is currently scheduled to be completed by the end of June 2017.

Medium-range storage also provides seasonal supply. With short injection and withdrawal times, medium-range storage can respond more quickly than long-range storage to changes in the gas price. As a result, we would usually expect shippers to both inject and withdraw gas throughout the summer. Figure 3.1 shows the aggregate of all injection into storage.

Exports to Europe

The GB gas market is connected to Belgium by the IUK interconnector, joining Bacton on the Norfolk coast to Zeebrugge. Flows through the IUK interconnector respond very 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 throughout the summer and from Belgium to GB in the winter. However, this trend is by no means certain, and price fluctuations in the two markets mean that gas can flow in either direction at any time. As part of our forecasting, we consider forward prices in both the NBP and Zeebrugge markets. Based on these, we currently expect gas to be flowing from GB to Belgium this summer. In summer 2016, exports to Belgium reached a five year high. Flows increased after injection into the Rough long-range storage facility were suspended in June 2016. Under our assumption of no gas injection into the Rough facility before the end of September, we expect to see higher IUK export flows this summer.

Gas supply

With a range of sources, gas supplies to GB are expected to be sufficient to meet forecast summer demands.

Key messages

- Supplies from the UKCS and Norway will continue to make up the majority of GB's supply. Supplies from the UKCS are expected to be similar to summer 2016, while Norwegian supplies are likely to be slightly lower than last year's record flows.
- We expect LNG imports this summer to increase from the very low levels seen over winter 2016/17.

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 GB.
- **IUK:** the Interconnector (UK) Limited is a bi-directional gas pipeline connecting Bacton in GB 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

GB benefits from highly diverse and flexible gas supplies. We receive gas from the UK Continental Shelf (UKCS), Norway, Belgium, the Netherlands and in the form of liquefied natural gas (LNG) from the rest of the world. The amount of gas supplied from each of these sources varies and is dependent on production, competition with other markets, and on the level of gas demand. We are confident that this range of supply sources will be sufficient to ensure gas demand is met this summer.

Chapter three

Gas supply

Total gas supply

Our forecast for summer 2017 gas supplies is shown in figure 3.4 and table 3.2. For comparison, we have also included supplies from the last five years.

Figure 3.4
Gas supply forecast for summer 2017 and history for previous summers

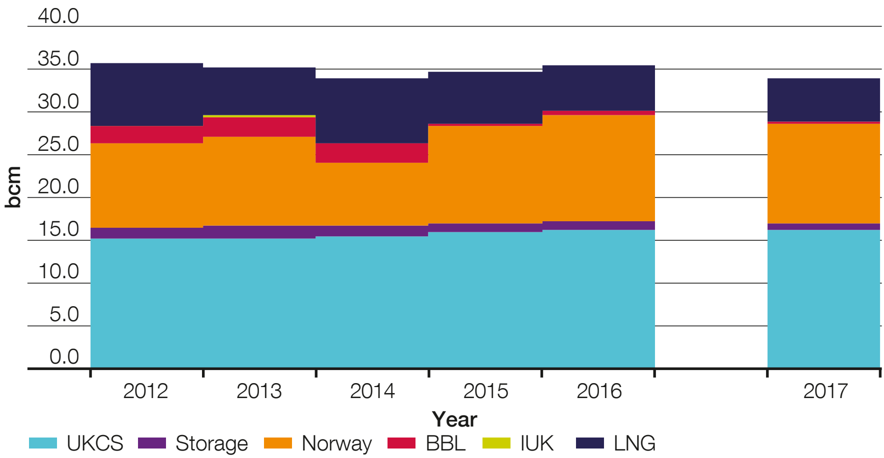


Table 3.2
Forecast total gas demand for summer 2017 and history for previous summers

(bcm)	UKCS	Norway	LNG	Continent	Storage	Total
2012	15.1	9.8	7.5	2.1	1.4	35.9
2013	15.1	10.6	5.8	2.3	1.5	35.4
2014	15.3	7.6	7.6	2.2	1.3	34.0
2015	15.9	11.3	6.2	0.3	1.1	34.8
2016	16.1	12.3	5.3	0.5	1.2	35.4
Average	**15.5**	**10.3**	**6.5**	**1.5**	**1.3**	**35.1**
2017	16.1	11.8	5.1	0.2	0.8	34.0

UKCS and Norway

We expect that gas from the UKCS and Norway will continue to follow recent trends and account for the majority of GB's supply. Gas supply from the UKCS is expected to be very similar to summer 2016. After many years of steep decline prior to 2012, UKCS production has more recently held steady and even increased slightly. New fields, such as Cygnus, and increasing production at Laggan and Tormore, have offset the decline and closure of older fields. Gas from the UKCS has no other market. As a result, if the fields produce, the gas flows to GB[1]. Although the revival of UKCS production is unlikely to be sustained in the long term, we expect flows this summer to be similar to last year, totalling 16.1 bcm. You can find out more about our longer term projections for UKCS production in our ***Future Energy Scenarios***.

Supplies from Norway were higher than we expected during summer 2016. Gas from the Norwegian Continental Shelf is supplied to GB, Germany, Belgium and France. Although the aggregate production and export to these markets declined over summer 2016[2], and reached a long-term low in September due to maintenance, supplies to the GB market reached a five year high. We believe that there will be high flows to GB again this summer, totalling 11.8 bcm. This is above the five year average, but lower than the record levels of last year.

Continental gas: IUK and BBL

As discussed in the gas demand section on page 55, IUK is a bi-directional interconnector connecting the gas markets of GB and Belgium. Flows via the IUK interconnector respond to the difference between the gas prices in these markets. Based on current forward prices, we expect gas to be flowing from GB to Belgium throughout the summer, with the possibility of occasional reverse flows.

Gas supplies from the Netherlands via the BBL interconnector have declined sharply in recent years. The major source of supply in the Netherlands is the huge Groningen field. Since 2014, output from Groningen has been capped to alleviate the risk of seismic activity. The production quota was further tightened in both 2015 and 2016. Reduced output from Groningen has contributed to a marked reduction in imports via BBL over the last two summers. There has been a further reduction in BBL flows since the expiry of long-term capacity contracts at the beginning of December 2016. As a result, we expect imports via BBL to be very low again this summer. With a reduction in BBL flows and IUK expected to be exporting for much of the summer, gas supplies from Continental Europe are expected to total 0.2 bcm.

[1] There is some UKCS gas that flows directly to the Netherlands, but we do not consider that here.

[2] http://www.npd.no/en/news/Production-figures/2016/December-2016/

Gas supply

LNG

The global market for LNG makes it increasingly challenging to forecast how much will be delivered to GB. Market intelligence has suggested for some time that we are on the verge of a glut of LNG as new supplies come on line. Although global LNG production rose during 2016, this did not mean that more gas was available for North West Europe, as demand in Asian and Middle Eastern markets increased. In our 2016/17 *Winter Outlook Report*, we said that we expected more LNG to be delivered to GB throughout the winter. Instead, LNG deliveries fell to a record low from 1 October 2016.

The destination of LNG cargoes is only partially determined by the prices in different markets. In figure 3.5, you can see that prices on the NBP and Japanese markets were very similar in May and June last year. However, as shown in figure 3.6, LNG imports to GB in June 2016 were at their lowest for the summer.

Figure 3.5
Historic and forward prices for NBP and Japanese LNG

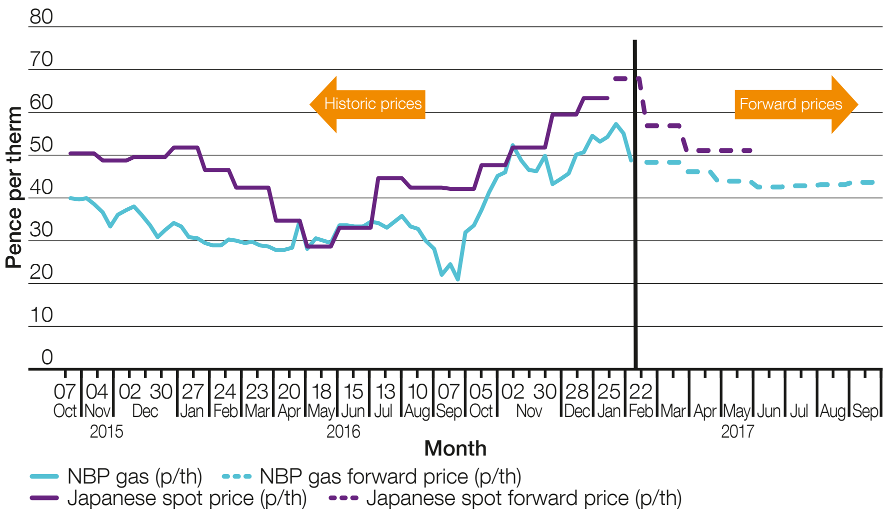
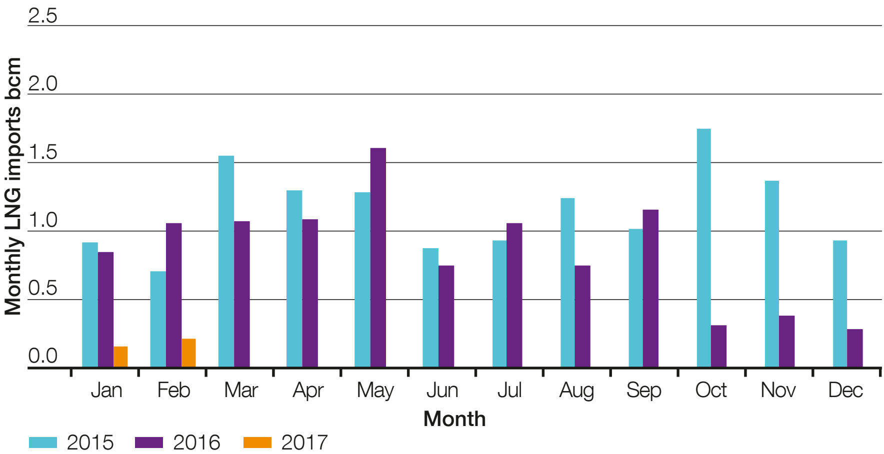


Figure 3.6
Monthly LNG imports



The difference between the NBP and Japanese forward prices in the early summer is less than we have seen for most of the winter. Together with an expected increase in production in Australia and the United States, this leads us to believe that deliveries of LNG to GB will increase from the very low levels we have seen over the winter. Although forecast gas demand for summer 2017 is lower than for last year, we expect LNG imports to respond to the reduction in other supplies. As a result, we expect there to be only slightly lower levels of LNG imports compared to last summer, of 5.1 bcm.

Gas system operations

We continue to see changes to GB's gas supply and how it is used within the gas day, with clear trends from season to season not yet apparent. This variability has an impact on how we configure and operate the transmission system. By working with the industry to better understand this variability, we can plan the most efficient and cost-effective network that meets the needs of our customers.

Key messages

- We expect to see more variable patterns of gas supply and demand this summer, as industry players respond to movements in GB and European gas and electricity prices.
- Facilitating the movement of gas to where it is needed within shorter timescales has an impact on how we operate and maintain the transmission system.
- It is important that we receive details of expected supply and demand flows in a timely manner, to help us configure the network efficiently and economically.

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.

Overview

The way the gas network is being used by our customers is changing, with more variable patterns of gas supply and demand. Market players, such as terminals, storage facilities, LNG shippers and power stations, are becoming ever more reactive to energy prices. National Grid needs to make sure that the network is more agile than ever to facilitate shorter lead times for changing flows. This flexibility requires investment in a continuous planned maintenance programme. Much of this maintenance typically takes place over the summer months.

To ensure we can configure the network efficiently and economically, it is important that we receive details of expected supply and demand flows in a timely manner. In the *Winter Outlook Report*, we highlighted the challenges associated with receiving information in the current short timescales. Since then, we have continued to engage with industry players to better understand the future requirements of our customers and encourage provision of information from our customers in longer timescales.

Variability of gas supply and demand

Historically, GB's gas demand was met predominantly by supplies from the UK Continental Shelf (UKCS) entering the National Transmission System (NTS) in the north. This UKCS gas was supplied and consumed predictably throughout the gas day. The NTS was built to transport gas based on this consistent flat profile of supply and demand, with compressor stations configured to move gas from its entry point in the north to where it was needed throughout GB. Over the last few years, we have seen more variable patterns in where GB's gas comes from and how it is consumed. This has an impact on how we operate the transmission system.

To help illustrate this variability, we have examined supply and demand patterns over the last three summers, and the impact of these on how we operate the transmission system. Each of these summers shows just how variable gas supply and demand can be, and the difficulty in identifying clear trends. This reinforces the importance of us working together as an industry to share information so that we can continue to facilitate the efficient operation of the network.

Summer 2014

During 2014, gas flows on the network were fairly predictable and a relatively narrow range of supply and demand patterns were observed. This meant that we were able to meet our customers' requirements while managing maintenance plans with minimum revision.

Summer 2015

During summer 2015, high flows of LNG entered the network from the South Hook terminal at Milford Haven. This was coupled with higher demand for gas exports to Continental Europe via IUK. When gas enters and exits the transmission system without being consumed in GB, this is known as transit gas. Moving this transit gas from where it entered the network in Wales to the point of demand on the interconnector in the east, required a significant amount of compression. We were able to meet our customers' requirements, although the high flows of LNG did generate some minor difficulties in executing our maintenance plans.

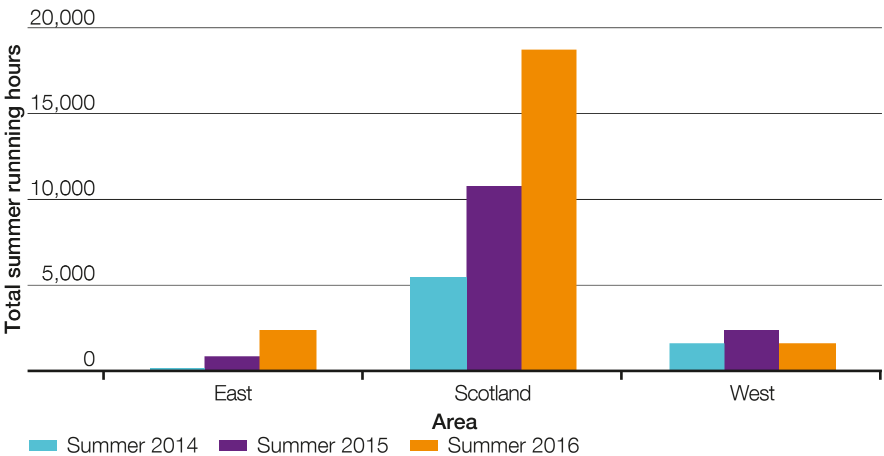
Gas system operations

Summer 2016

Summer 2016 was a challenging period for operating the network. In our 2016 *Summer Outlook Report*, we expected supplies from the UKCS and Norway to be fairly predictable. What both we and the market did not fully account for was the rapid increase in gas supplies due to the Rhum field, off the north east coast of Scotland, coming back on line. The re-introduction of this field resulted in much higher than anticipated flows at the St Fergus terminal due to the blending requirements to achieve the relevant gas specification. The proportion of the total GB supply arriving at this one terminal was the highest experienced in recent years, with more than 50 per cent of the total daily gas supply entering through this single point on the network on a number of days.

We are reliant on compressor stations in Scotland to move gas from its point of entry on the network to where it is needed across GB. Typically, less compression is needed in the summer when the system is balanced, allowing us to plan maintenance on the compressor fleet. However, in summer 2016, Scottish compression was needed to move the high levels of supply from St Fergus to demand points across GB, and to facilitate transit flow to Continental Europe. This was combined with lower export requirements via the Moffat interconnector due to the Corrib gas field, off the north west coast of Ireland, reaching its maximum flow rate. As shown in figure 3.7, there was a significant increase in total network compressor running hours of 214 per cent from summer 2014 to 2016. These factors meant that we needed to continually revise our maintenance plan, particularly in Scotland, in order to continue to meet customer expectations.

Figure 3.7
Compressor running hours summer 2014 – 2016



Summer 2017

The supply of gas from the UKCS and Norway is expected to be fairly high this summer, mirroring the rates seen across 2016. Other sources are likely to be more responsive to short-term market conditions. Storage injection is likely to be significantly reduced this summer due to the restrictions at the Rough long-range storage facility. You can read more about this in the gas demand section on page 55. As a result, we anticipate that customers may utilise the ability to fill storage stocks in Continental Europe via the IUK interconnector.

LNG importation has been low since October 2016 due to the more favourable market conditions across Asia. We expect to see an increase in LNG importation through spring and summer 2017, although global availability and prices will continue to influence the delivery destination of cargoes.

Increasing demand variation is always more noticeable during the summer, as commercially sensitive offtakes such as storage sites, interconnectors and some power stations, seek to be more responsive to fluctuating GB and European energy market prices. For example, CCGTs may want to respond to changes in the electricity market, where the notice periods can be shorter and the ramp rates higher than the equivalent in the gas market. You can find out more about the impact of prices on power stations in the fuel prices section on page 11.

The variable supply and demand requirements that we are likely to continue seeing throughout summer 2017 reinforce the need for a more agile network that is able to respond to customer needs, without impacting other users of the NTS.

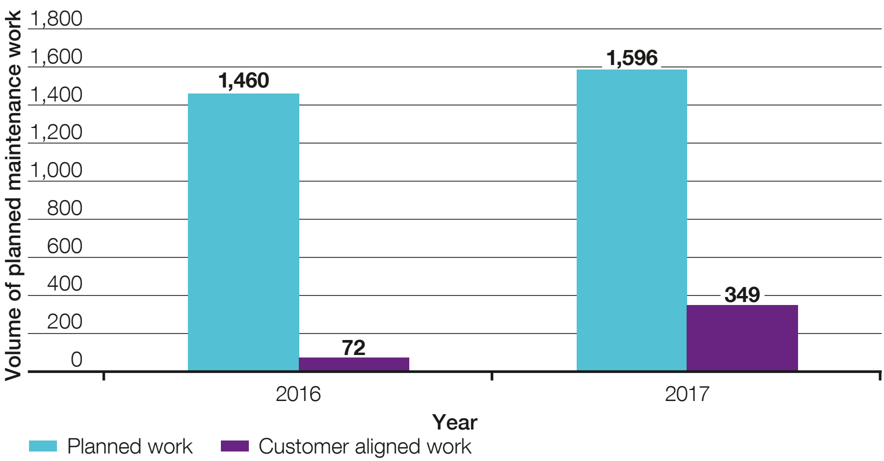
Gas system operations

How we're responding

To make sure that we can meet the demands from our customers both this summer and in the future, we are continuing to reinvest in our network. Running assets, such as compressors, more frequently to facilitate customer requirements increases the need for maintenance. As a result, the volume of maintenance we undertake has increased year-on-year. Figure 3.8 shows how the volume of planned maintenance work has increased between 2016 and 2017.

We have engaged with all affected parties regarding the planned maintenance for summer 2017 and we will always aim to facilitate the necessary investment with minimum disruption to our customers. You can find out more information on the 2017 maintenance plan, as well as related publications and contact details, on **our website**.

Figure 3.8
Volume of maintenance on the transmission system for 2016 and 2017



To ensure the network is configured to its optimum efficiency throughout the summer and beyond, it is important that the information provided to the System Operator is timely and accurate, with market participants operating in accordance with the information they have submitted. This allows us to plan the most efficient and cost-effective network, and to take fewer operational or commercial actions to balance the system. As the energy landscape continues to change and our customers use the network within day in different ways, we will continue to monitor and engage with the industry so we can better understand the level of flexibility required. You can find out more on our **industry information website** or at one of our regular **operational forums**.

Chapter four

Glossary

Word	Acronym	Section	Description
Balancing Mechanism	BM	Electricity	The Balancing Mechanism is a regulated market framework used to balance supply and demand in each half hour trading period of every day. If National Grid predicts that there will be a discrepancy between the amount of electricity produced and what will be in needed during a certain time period, they may accept a 'bid' or 'offer' to either increase or decrease generation or consumption.
Baseload		Various	The permanent minimum load that a system experiences.
Baseload		Electricity	Generators that can consistently provide the output needed to satisfy the minimum level of demand over a 24 hour period.
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	A 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 1,000 MW. You can find out more at **www.britned.com**.
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.
Composite weather variable	CWV	Gas	A single measure of daily weather. It is the combination of temperature and other weather variables, including wind speed. The purpose of CWV is to define a linear relationship between the weather and non-daily metered gas demand.
Compressor		Gas	Compressors are used to move gas around the transmission network through high pressure pipelines. There are currently 68 compressors at 24 compressor 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.
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 500 MW interconnector that links the electricity systems of Ireland and Great Britain. You can find out more at **www.eirgridgroup.com/customer-and-industry/interconnection/**.
Embedded generation		Electricity	Any generation that is connected to the local distribution network, rather than to the transmission network. 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.
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.
Flexible generation		Electricity	Types of generation that can respond quickly to changes in demand. It includes interconnectors and large wind farms that are participating in the Balancing Mechanism.
Foot room		Electricity	The ability of a generation plant to allow output to decrease without going below its minimum output level and disconnecting from the system.

Word	Acronym	Section	Description
Frequency response		Electricity	An ancillary service procured by National Grid as System Operator to help ensure system frequency is kept as close to 50 Hz as possible. It is also known as frequency control or frequency regulation.
Future Energy Scenarios	*FES*	Various	The *FES* is a range of credible futures that have been developed in conjunction with the energy industry. They are a set of scnearios covering the period from now to 2050, and are used to frame discussions and perform stress tests. 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/**.
Generation merit order		Electricity	The sequence in which generators provide energy to the market. The order in which generators appear is based on how cost-eficient they are in producing energy, compared to other generator units.
Generator capacity		Electricity	The total capacity of all generators.
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.
Head room		Electricity	The operation of generation plant below its maximum output levels to allow output to increase if needed.
High summer		Electricity	The period between 1 June and 31 August, or weeks 23 to 35 of the year. This is when we typically see higher demand on the transmission system, caused predominantly by an increase in the use of cooling systems in the warmer months. It is also when most generators plan outages for maintenance.
Inflexible generation		Electricity	Types of generation that are less able to respond quickly to changes in demand. This may be because they require long notice periods to step down or ramp up their output, or they have obligations which influence when they can generate. Examples include nuclear, combined heat and power stations, some hydro generators and most wind farms.
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 which 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.
Interconnector exports		Various	The flow of energy, either gas of electricity, out of GB.
Interconnector imports		Various	The flow of energy, either gas of electricity, in of GB.
Interconnexion France-Angleterre	IFA	Electricity	The England-France Interconnector is a 2,000 MW 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.

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Word	Acronym	Section	Description
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://grainlng.com/who-are-we/lng-in-the-energy-mix/**.
Load		Various	The energy demand experienced on a system.
Load factor		Electricity	The proportion of output that we can reasonably expect to see for a given capacity.
Long-range storage		Gas	There is one long-range storage site on the National Transmission System; Rough, situated off the Yorkshire coast. Rough is owned by Centrica Storage Limited. The site mainly puts gas into storage (injection) in the summer and takes gas out of storage (withdrawal) in the winter.
Medium-range storage		Gas	Medium-range storage sites have short gas injection and withdrawal times. This means that they can react quickly to demand, injecting when demand or prices are lower and withdrawing when they are higher.
Megavar	MVAR	Electricity	Megavar or mega volts amps reactive is a measure of reactive power.
Megawatt	MW	Electricity	A measure of power. 1 MW = 1,000,000 watts.
Million cubic meters	mcm	Gas	A unit of volume used in the gas industry. 1 mcm = 1,000,000 cubic metres
Moyle		Electricity	A 500 MW bi-directional interconnector between Northern Ireland and Scotland. You can find out more at **www.mutual-energy.com**.
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**.
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 Great Britain and nearby offshore waters. The NETS 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, multijunction sites and offtakes. Pipelines transport gas from terminals to offtakes and are designed to operate up to pressures of 94 barg.
Negative reserve active power management system notification	NRAPM	Electricity	A notification issued to the industry to encourage inflexible generators to reduce their output where possible. This creates downward flexiblity on the system.
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.
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 by generators to National Grid. It includes their current generation availability and known maintenance outage plans. You can access the latest OC2 data throughout the year 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.

Word	Acronym	Section	Description
Operational surplus		Electricity	The difference between the level of demand and the generation expected to be available, modelled on a week-by-week basis. This information helps to inform the market how much surplus is expected to be available.
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).
Peak running		Electricity	Generators providing output between 7am and 7pm. This includes the highest demand points throughout the day.
Price spread		Electricity	The price that energy can be sold for, minus the costs of producing it.
Reactive power		Electricity	Reactive power is measured in megavar (MVAR) units. 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. These flows of reactive power have a direct impact on the voltage levels seen across the network. National Grid routinely intervenes to optimise the levels of reactive power on the network.
Seasonal normal conditions		Gas	A set of conditions representing the average that we could reasonably expect to occur. We use industry agreed seasonal normal weather conditions. These reflect recent changes in climate conditions, rather than being a simple average of historic weather.
Short Term Operating Reserve	STOR	Electricity	Short Term Operating Reserve (STOR) is a service for the provision of additional active power from generation and/or demand reduction.
Stable export limit	SEL	Electricity	The minimum value at which a Balancing Mechanism unit, under stable conditions, can export to the electricity transmission system.
Station load		Electricity	The onsite power station electricity requirement, for example for systems or start up.
Storage		Gas	Storage facilities hold gas in underground salt caverns or depleted gas fields. The holding capacity of a storage facility is referred to as space, while the rate at which gas can be withdrawn is known as deliverability. There are two types of storage sites connected to the National Transmission System; medium-range storage and long-range storage.
Synchronised		Electricity	The condition where a generator or other source connected to the transmission system has an identifical frequency and phase relationship to the system.
System inertia		Electricity	A measure of how resilient the system is to changes due to disturbances. Disturbances may be caused by a sudden drop in generation or demand, which results in a system imbalance.
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.
System sell prices	SSP	Electricity	The 'cash-out' or 'imbalance' prices. They are used to calculate imbalance charges. These settle the difference between contracted generation or consumption, and the amount that was actually generated or consumed in a particular half hour trading period.
Transit gas		Gas	Gas that enters and exits the National Transmission System without being consumed in GB.
Transmission system demand	TSD	Electricity	Demand that National Grid as the 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) at 500 MW.

Glossary

Word	Acronym	Section	Description
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 outturned 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. As weather is one of the main drivers of the difference in demand from one day to the next, we take out its impact to understand other important underlying trends.

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You can write to us at:
Future Outlook team
System Operator
National Grid House
Warwick Technology Park
Gallows Hill
Warwick
CV34 6DA

YouTube: National Grid UK

Twitter: @nationalgriduk

LinkedIn: National Grid

Facebook: NationalGridUK

nationalgrid

National Grid plc
National Grid House,
Warwick Technology Park,
Gallows Hill, Warwick.
CV34 6DA United Kingdom
Registered in England and Wales
No. 4031152

www.nationalgrid.com