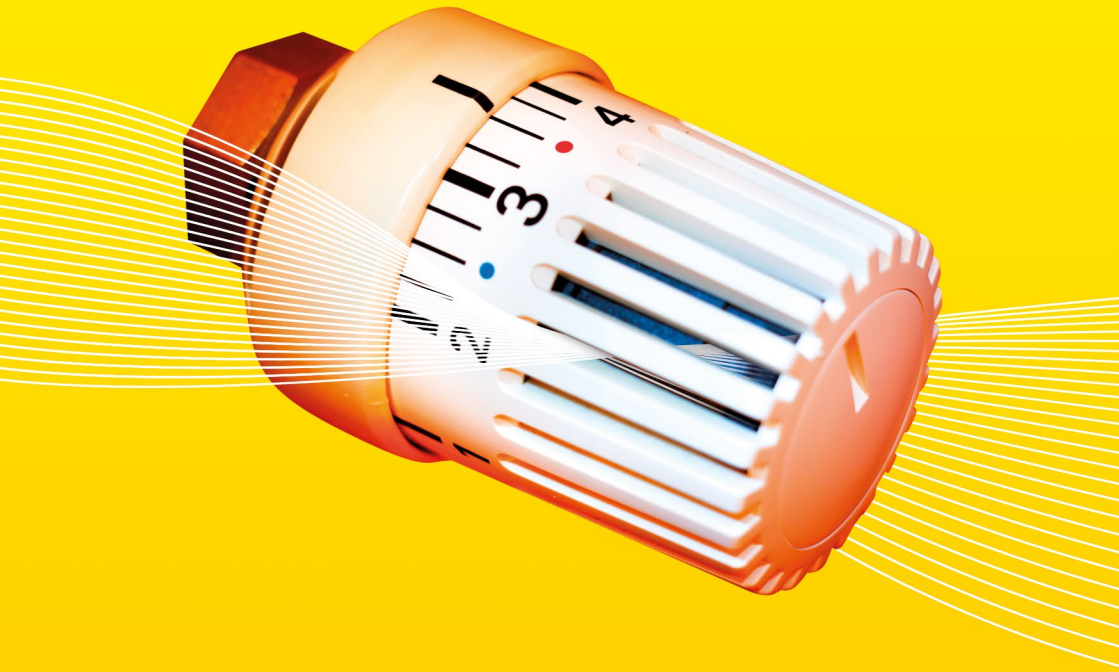


Winter Outlook

2018/19



How to use this interactive document

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



Home button

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



A to Z

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



Arrows

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

Hyperlinks

Hyperlinks are highlighted in medium and underlined throughout the report.

You can click on them to access further information.

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Executive summary

The *Winter Outlook Report* presents National Grid's view of supply and demand for the forthcoming winter for both gas and electricity with particular focus on security of supply. Our analysis is based on market insight and industry views provided via our winter consultation process and aims to present you with credible and robust information to allow you to prepare for the winter ahead.

For this winter, even under colder conditions than experienced in recent years, we are confident we have the right products and strategies in place to help us balance the gas and electricity networks.

Electricity margin (de-rated) is forecast to be higher this winter than we forecast for last winter

- At 7.1 GW¹, the de-rated margin for winter 2018/19 is forecast to be 0.9GW more than the forecasted margin of winter 2017/18. As a percentage of underlying demand, this equates to 11.7 per cent. The corresponding loss of load expectation (LOLE) is estimated as 0.001 hours per year. This is within the national reliability standard level of 3 hours per year.
- Both normalised and average cold spell (ACS) demand can be met in all weeks across the winter, under all interconnector scenarios. On a week-by-week basis, we expect transmission system demand to peak at 48.2GW, with the lowest level of operational surplus expected at the end of October and in the first half of December.

We would expect to see up to 2GW of customer demand management. Minimum demand is forecast to be 20.8GW during the Christmas period.

- We expect this winter to be different operationally to 2017/18. For the last two winters, gas was the cheaper fuel type for electricity generation, however, as global gas prices have risen, it is likely that coal will replace gas in the generation merit order for some of the winter.
- Forward prices in Continental European markets are expected to be lower than in GB, so we expect to see a net flow of power from Continental Europe to GB during peak demand periods, although occasionally not at full import. However, outages on the Belgian nuclear fleet, which have extended to November and beyond, could increase Continental prices and

create some uncertainty on interconnector flow direction. We expect GB to export to Ireland during peak times on both the Moyle and EWIC interconnectors.

We anticipate some price volatility, driven by the weather dependency of renewable generation and changes to cash out arrangements in the electricity balancing mechanism.

Gas supply margin is expected to be sufficient in all of our security of supply scenarios

- We expect there to be sufficient gas from a variety of sources to meet demand this winter. Supplies from the UK Continental Shelf and from Norway are expected to be high, similar to last year. The Aasta Hansteen field is due to start production and will add a further 23 mcm/d to Norwegian production.

¹ The margin has been calculated using the new formula as detailed in our 2018 *Winter Review and Consultation*. The formula was changed to reflect the growing levels of interconnection capacity. This change does not affect the margin in absolute gigawatt terms, but it does change the margin as a percentage of demand. For comparison, the margin under the old formula equates to 7.1 GW or 12.3 per cent.



Increased production could support increased delivery to Continental Europe or GB, depending on price. Storage, LNG and interconnectors are important components in the supply mix, providing flexibility to the market. We expect the cycling of gas into and out of storage to continue, similar to the patterns observed last year.

- The gas demand forecast for winter 2018/19 is 46.6 bcm, lower than the winter 2017/18 outturn (weather corrected). The 1-in-20 peak day demand is forecast at 472 mcm. The main driver for the lower gas demand is reductions in electricity generation. This is due to increased renewable generation and coal replacing gas in the electricity generation merit order for some or all of the winter as a result of higher gas prices. The lower gas demand is also down to the continuing increase in renewable generation.
- Average flows from IUK are expected to be lower. The

price differential between GB and Belgium will need to be higher this winter to cover the full costs of transporting gas through IUK compared to winter 2017/18. As a result, deliveries from BBL are likely to be higher. Price is important when we look at the other flexible sources of supply. High demand and high prices have drawn LNG away from the European markets to the Asian markets, especially China. Unless prices change we expect this to continue. Therefore, we are not expecting LNG output to be high on many days this winter.

Our whole system understanding continues to improve as we learn from operational events

- The rising forward gas price for the winter ahead is likely to have the biggest impact on the overall interaction between the two sources of energy. This alters the relative economics of the different

electricity generation types, impacting on gas demand and gas-fired generation.

- The cold snap on 1 March saw a gas linepack swing of 39 mcm/d (9 per cent of demand). We have explored this in more detail and examined how the gas system would cope if coal-fired generation had been replaced entirely by gas-fired generation. We demonstrate that the additional gas demand could have been met by a variety of gas supplies.
- System operability for both systems continues to be a challenge. We believe we have the right tools at our disposal that we can call upon this winter. We will continue to review our tools and processes and will develop new ones, as well as updating our existing ones, to ensure they remain fit for purpose. The notifications we use for both systems are outlined in our 'Operational toolbox' section.

Headlines

Electricity			
	2017/18 forecast	2017/18 actual	2018/19 forecast
De-rated margin at underlying demand level	6.2GW	–	7.1GW
Loss of load expectation (LOLE)	0.01 hours/year	–	0.001 hours/year
ACS peak underlying demand	62.3GW	–	60.5GW
Peak transmission system demand/Normalised demand	50.7GW	50.7GW	48.2GW
Weather corrected TSD	–	50.0GW	–
Minimum demand	21.3GW	18.6GW	20.8GW
Total maximum technical capability from generation	101.2GW	–	104.7GW
Interconnectors net imports	2.4GW	–	2.6GW
Maximum customer demand management (CDM)	2GW	–	2GW
Currently under all interconnector import scenarios, normalised demand can be met for the entire winter.			
Net flow of power across the interconnectors from Continental Europe to GB at peak occasionally not at full import.			
Net flow of power across the interconnectors from GB to Ireland during peak turning to import during high winds and periods of system stress.			

Gas				
	2017/18 Forecast	2017/18 weather corrected	2017/18 actual	2018/19 Forecast
Total demand	51.4 bcm	53.4 bcm	54.8 bcm	46.6 bcm
1-in-20 peak day demand	502 mcm/d	–	–	472 mcm/d
Cold day demand	419 mcm/d	–	–	407 mcm/d
Cold day non-storage supply forecast	354 mcm/d	–	–	360 mcm/d
Demand for electricity generation	12.4 bcm	12.7 bcm	12.7 bcm	7.0 bcm
Safety Monitor level	647GWh space 512GWh/d deliverability	–	–	429GWh space 387GWh/d deliverability ²

²To convert from GWh to mcm divide by 11.

Stakeholder engagement

The *Winter Outlook Report* provides our view of the gas and electricity security of supply for the forthcoming winter. It is informed by insight received from stakeholders across the energy industry via responses to our winter consultation and through regular conversations with industry participants.

Each year, our outlook reports evolve as we respond to your feedback. Your views shape

all aspects of the report, from the assumptions underlying our forecasts to the layout and

style. You can see how we are improving the report based on your feedback.

You said

A one-pager simply showing *Winter Review* and *Winter Outlook* highlights would be helpful.

More information relating to neighbouring markets.

More detail please, too high level.

We did

We have inserted a headline page with key figures from the publication.

We continue to explore EU and Continental markets and consider the impact of their behaviour on GB.

As with the *Future Energy Scenarios* document, we will be including the data workbook on our website to accompany the 2018/19 *Winter Outlook Report*.

“National Grid’s outlook for the forthcoming winter in terms of supply, demand and capacity margins is also useful, for example as a benchmark for our own forecasts. We also find NG’s explanation of how their methodologies for calculating demand and margins have changed useful as it provides a chance for stakeholders to comment.”

Please tell us what you think

We want to make sure that we continue to provide you with the right information to support your business planning. To do this, we’d like to know what you think about this publication. You can share your feedback by emailing us at marketoutlook@nationalgrid.com

Energy industry stakeholder

Key publications from the System Operator 2018/19



Network Options Assessment January 2018

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



Winter Outlook Report October 2018

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



Summer Outlook Report April 2018

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



Electricity Ten Year Statement November 2018

The likely future transmission requirements on the electricity system.



System Needs and Product Strategy April 2018

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



Gas Ten Year Statement November 2018

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



Winter Review and Consultation June 2018

A review of last winter's forecasts versus actuals and an opportunity to share your views on the winter ahead.



Gas Future Operability Planning November/December

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



Future Energy Scenarios July 2018

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



System Operability Framework

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

Stakeholder engagement

System Operator publications

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

The starting point for our analysis is the *Future Energy Scenarios* (FES). This document considers the potential changes to the demand and supply of energy from today out to 2050. To develop our scenarios, we consulted with a number of organisations through workshops, webinars and bilateral meetings. The scenarios provide a starting point for much of the analysis in this report, such as our electricity winter view and analysis of gas demand.

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

You can find out more about any of these publications, and how they incorporate insight from our stakeholders, by clicking on the document front covers

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**.

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 year. There are a number of sources of information you can access for the most up-to-date view, both for electricity and gas.



Electricity

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

Our demand forecasts are regularly updated throughout the year. 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. 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

We publish a range of data on the operation of the gas transmission network. The Market Information Provision Initiative ([MIPI](#)) publishes information required under Uniform Network Code (UNC) and EU obligations, as well as additional information we feel is useful, for example the [Prevailing view](#).

In this year's *Winter Outlook Report* we have included the key operational notifications for both gas and electricity as a reminder. This can be found in the '[Operational toolbox](#)' section of the report.

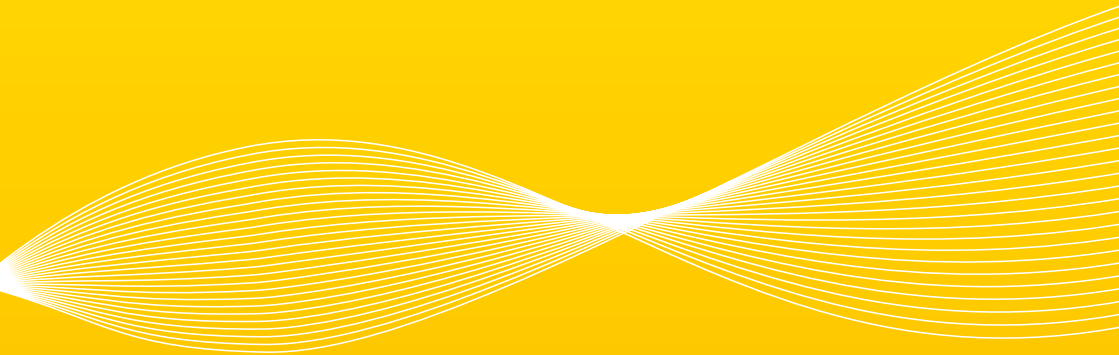
Events

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.

Chapter 1

Electricity

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Electricity winter outlook

This chapter sets out our current view of the electricity system for winter 2018/19. It details our analysis of expected demand and available generation, and outlines the tools and notifications we have available to help us balance the system.

Our winter view is an assessment of security of supply for winter 2018/19 based on probabilistic modelling. In comparison, the operational view is based on data provided to us by generators, updated weekly. As a result, while both sets of information are often similar, they are not directly comparable.

The chapter contains the following sections:

- Winter view
- Operational view
- Electricity demand
- Electricity generation
- Europe and connected markets.

Winter view

Our electricity analysis presents an assessment of security of supply for winter 2018/19. It is based on the EMR Base Case supply and demand assumptions.

Key messages

- The de-rated margin is calculated using the new 2018 margin formula.
- The de-rated margin for winter 2018/19 is projected to be 7.1 GW, or 11.7 per cent on an underlying demand basis.
- The corresponding loss of load expectation (LOLE) is 0.001 hours/year.

Key terms

- **Generation margin:** the sum of de-rated supply sources declared as being available during the time of peak demand plus support from interconnection, minus the expected demand at that time and basic contingency reserve requirement. This can be presented as either an absolute GW value or a percentage of demand (demand, plus reserve).
- **De-rating factors:** these are scaling factors applied to the maximum technical capability that account for breakdowns, planned outages and any other operational issues that may result in power stations not being able to generate at their normal level. They are based on the historic availability of plant during peak periods.
- **Loss of load expectation (LOLE):** a statistical metric used to describe electricity security of supply. It is an approach based on probability and is measured in hours per year. It measures the risk, across the whole winter, of demand exceeding supply under normal operation. It does not mean that there will be a loss of supply for 0.001 hours per year. It gives an indication of the amount of time across the whole winter that we, as the System Operator, may need to call on a range of emergency balancing tools to increase supply or reduce demand. In most cases, loss of load risk could be managed without significant impact to end consumers.

De-rated margin and loss of load expectation

In last year's *Winter Outlook Report*, we moved away from a transmission demand-based margin to a margin based on total underlying demand (UD). That is, total demand on both the transmission and distribution systems. This change was necessary to reflect the continuing growth in embedded

generation and the introduction of the Capacity Market (CM) which is open for all levels of supply sources. Displaying the margin in this way treats the transmission connected generation and distribution connected generation in a consistent manner.

This year, based on recent market observations, a further update is needed to the percentage

margin formula to reflect the growing levels of interconnection capacity, the implications of which are outlined in the 'spotlight'. The new formula will impact the margin when expressed as a percentage of demand, whilst the margin in GW terms remains unchanged.

Spotlight

The new 2018 percentage margin formula

As part of this year's *Winter Review and Consultation*, we discussed changes to the existing formula for calculating the margin based on underlying demand. The reason for the change is to reflect the expected growth in interconnection, and the potential of up to 18GW of total connection capacity to neighbouring countries by the late 2020s. The effect of higher interconnection undermines the existing formula in percentage terms as a representation of security of supply. It would also make historical benchmarking difficult.

The effect of higher interconnection would greatly reduce the net demand below the line in the percentage formula as seen in figure 1.1. By dividing by a smaller number below the line, the existing percentage margin would appear inflated, even for the same GW margin. The modification proposed to the formula removes interconnection from below the line in figure 1.2 in order to avoid this. The security of supply contribution of interconnection imports will still be included via the supply side calculation above the line. This will maintain consistency of the percentage margin number going forward, regardless of the growth in interconnection.



Figure 1.1
2017 Underlying demand formula
De-rated capacity margin:

(in GW terms) = $\text{Supply (GB) + Interconnection} - \text{Demand}$

(in % terms) =
$$\frac{\text{Supply (GB) + Interconnection} - \text{Demand}}{\text{Demand} - \text{Interconnection}}$$

Figure 1.2
2018 Underlying demand formula
De-rated capacity margin:

(in GW terms) = $\text{Supply (GB) + Interconnection} - \text{Demand}$

(in % terms) =
$$\frac{\text{Supply (GB) + Interconnection} - \text{Demand}}{\text{Demand}}$$

Winter view

Table 1.1 summarises the forecast for the winter 2018/19 margin at underlying demand level with the new modified

percentage margin formula. The LOLE is well within the national reliability standard level of 3 hours per year.

By comparison, the margin under the old formula equates to 7.1 GW, or 12.3 per cent.

Table 1.1

Summary of supply margin forecast for winter 2018/19

	2018/19
De-rated margin at underlying demand level	7.1 GW
Margin as a percentage of underlying demand	11.7%
LOLE at underlying demand	0.001 hours

Assumptions for supply, demand and interconnection

The total maximum technical capability from generation supply forms this winter has been forecast at 104.7 GW. This is based on both the results of the CM auctions, as well as from a range of other sources of market intelligence. This capacity

includes wind and solar, however, it excludes interconnectors. This is summarised by technology type in the chart in figure 1.3.

The latest view of total average cold spell (ACS) peak underlying demand is 60.5 GW, which includes contingency reserves (1.4 GW) to cover the largest in-feed loss.

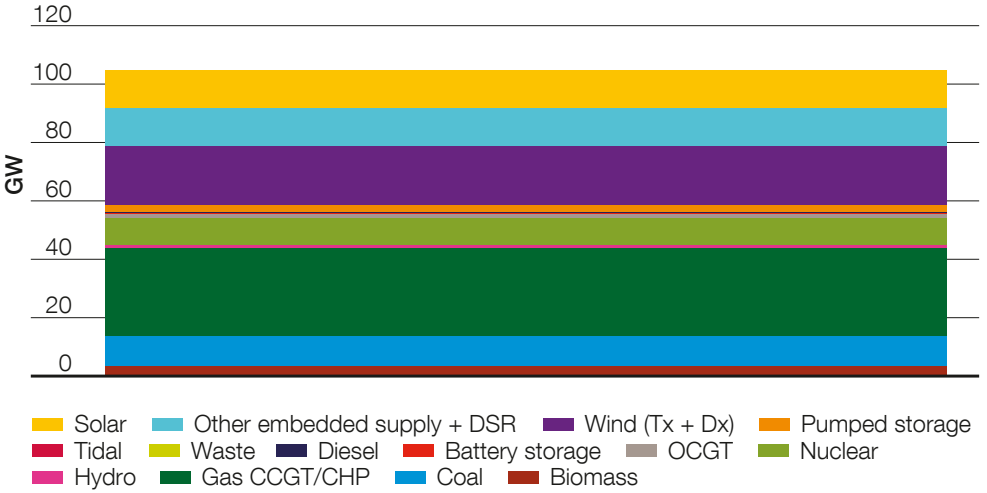
Based on this year's modelling of GB and interconnected markets, we have assumed 2.6 GW of net import flows to support GB supply adequacy this winter³.

³ Net interconnector import flows are based on flows under potential stress event conditions. Interconnector flows in the 'EU and connected markets' section are based on typical commercial flows plus/minus a high/low sensitivity.

Winter view



Figure 1.3
Generation capacity by technology type 2018/19



Operational view

Our operational view presents the current picture of operational surplus for each week of winter 2018/19, based on data provided to us by generators. This section continues to focus on transmission system demand, reflecting the current generation data available to the market.

Key messages

- Based on current data, demand is expected to peak in the first half of December.
- Current information indicates that the end of October and the first half of December will have the lowest level of operational surplus, due to a combination of the expected level of demand and planned generator outages.
- The Capacity Market is now in its second year of full operation. It is designed to deliver the required generation capacity or reduce the demand during times of system stress.
- Reforms to the electricity market, specifically the implementation of price average reference (PAR1) may cause price volatility in the short term. However, in the medium to long term it should reduce the total cost to National Grid, and ultimately consumers, in balancing the system.

Key terms

- **Operational surplus:** the difference between the level of demand and 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. Generators are then able to take this into consideration when planning their outages.
- **Operational Code 2 (OC2) data:** information provided to National Grid by generators. It includes their current generation availability and known maintenance plans.
- **Transmission system demand (TSD):** demand that National Grid as the System Operator sees at grid supply points (GSPs), which are the connections to the distribution networks. It includes the sum of national demand, the demand from power stations (600MW) and the base case interconnector export value (750MW).
- **Normalised demand:** forecast 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 could be with this standardised weather.
- **The Capacity Market (CM):** introduced by the UK Government as part of the Electricity Market Reform Programme to ensure the future security of our electricity supply.
- **Average cold spell (ACS):** A particular combination of weather elements that gives rise to a winter peak demand, which has a 50 per cent chance of being exceeded as a result of weather variation alone.
- **Equivalent firm capacity (EFC):** An assessment of the entire wind fleet's contribution to capacity adequacy. It represents how much of 100 per cent available conventional plant could theoretically replace the entire wind fleet and leave security of supply unchanged.
- **Breakdown rate:** a calculated value to account for unexpected generator unit breakdowns, restrictions or losses.
- **De-rate:** To lower the rated capability to take into account a reduction from unplanned outages or breakdowns.

Operational view

Table 1.2

Demand values

Normalised transmission peak demand	48.2GW
Minimum demand	20.8GW
Maximum customer demand management	2.0GW
Embedded wind capacity	5.9GW
Embedded solar capacity	12.9GW

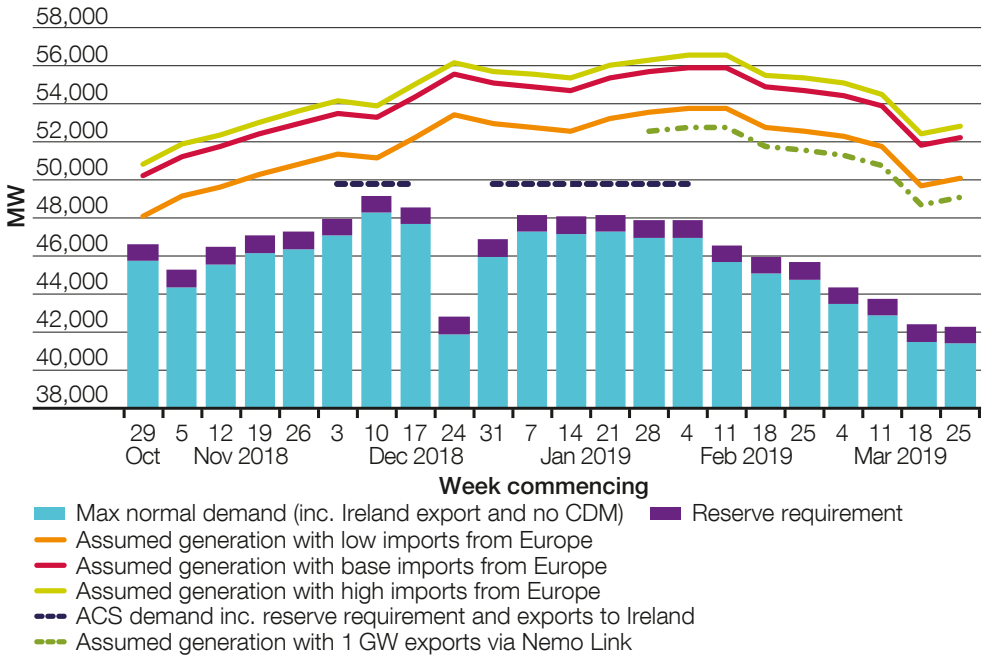
Our operational view is based on current generation availability data, otherwise known as Operational Code 2 (OC2) data. This data is the expected maximum output at peak demand for each week of the year. Generators provide the data which includes their known maintenance outage plans. Our analysis is based on the OC2 data provided to us as at 8 October 2018.

Figure 1.4 illustrates our operational view and it compares:

- expected weekly generation, which we have de-rated to allow for breakdowns and restrictions, with differing levels of interconnector flows
- weekly normalised demand
- average cold spell (ACS) demand.

It shows that there are good levels of operational surplus this winter.

Figure 1.4
Operational view winter 2018/19



We, as the System Operator, are required to carry an operating reserve to regulate system frequency and respond to sudden changes in demand and supply. We assume a basic real-time reserve requirement of 900MW for each week of our analysis; this is shown by the purple bars in figure 1.4.

Currently, under all interconnector import scenarios, normalised and ACS demand can be met for the entire winter. Please see the section on Europe and connected markets for details on GB's interconnectors. In it we produce three scenarios. All interconnector scenarios assume a net export of 750MW. The scenarios are as follows:

- low imports with zero flows from Continental Europe, resulting in net exports of 750MW

- base case of 2,130MW flows from Continental Europe, resulting in net imports of 1,380MW
- full imports, de-rated to 2,760MW flows, resulting in net imports of 2,010MW.

As you will see in figure 1.4, we have also added an additional scenario with the dash-dot line from the end of January. This reflects when the **Nemo link** is expected to go live and covers the uncertainty with flows associated with commissioning. The Nemo Link is an HVDC sub-sea link between GB and Belgium. The current forecast shows that we could facilitate full exports across the Nemo Link during this period.

The week with the lowest level of operational surplus is expected at the end of October

and in the first half of December. This is when we expect the highest level of demand which, when combined with planned outages, gives us the lowest level of surplus.

Figure 1.4 also shows the ACS peak demand which historically, has never occurred:

- before the first week in December
- during the Christmas fortnight
- after the first week in February.

As a result, we have not shown ACS demand for these weeks. From this November, in the low interconnector scenario, we believe that doubling the value of the costs incurred for demand disconnections and voltage reduction will create a greater incentive for industry participants to take corrective actions at times of system stress.

Operational view

The operational surplus is at a higher level than in previous years. This is because the CM provides a revenue stream to power stations that might otherwise have closed. Also, some larger units, which were unsuccessful in being awarded CM contracts, are expected to remain operational this winter. This could be due to higher wholesale prices driven by the rise in gas price and carbon costs. The price of coal has also increased slightly; currently, coal stations are expected to run above the least efficient gas stations for this winter.

During periods of forecasted low operational surplus, CM obligations and higher prices can apply. This means that generators are incentivised to move planned outages away from these times and make their units available.

Energy imbalance prices could be more volatile than in previous years because of a modification to the calculation known as PAR1. This could lead to a beneficial impact on generator units being available. We would also expect it will provide the interconnectors with a greater incentive to import if the system is tight and because of the higher value of loss of load (VoLL). We have included a spotlight which provides more details.

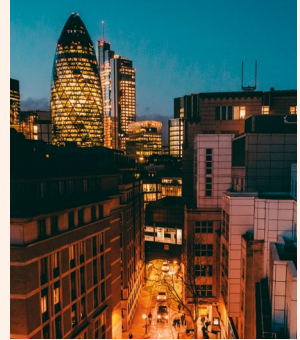
We base our operational view on the best data available to us. Changes to the notified generation and forecast demand will, potentially, alter this report's forecasted level of operational surplus. We do encourage the industry to regularly view the latest OC2 data, which is published every Friday on the **BM Reports** website⁴. From this data, we would expect generators to actively move their planned outages, where possible, away from periods where operational surplus is low.

⁴<https://www.bmreports.com/>

Spotlight

Introduction of price average reference volume of 1 MWh (PAR1) as part of P305 electricity balancing significant code review developments

Cash-out arrangements are operated in both the gas and electricity markets. They are designed to address the cost of energy balancing that National Grid has to pay when suppliers fail to balance their inputs and outputs within the relevant balancing period. As such, parties who are not in balance are charged according to how much it has cost National Grid to address the imbalance. These charges are known as cash-out prices. They are designed to incentivise market participants to balance their contractual and physical positions to avoid exposure to cash-out prices.



From 1 November, the cash-out price will move from PAR50 to PAR1 and the value of loss of load (VoLL) will increase from £3,000 per MWh to £6,000 per MWh. This means that the current arrangements for cash-out prices will change. Cash-out prices will be made ‘fully marginal’, by reducing the volume of actions on which the cash-out price is based, to 1MWh instead of 50MWh.

Ofgem believes “that the changes will strengthen the incentives on parties to make efficient balancing decisions and, by incentivising investment in flexible capacity and demand side response, should reduce the total cost to National Grid (and ultimately consumers) in balancing the system”.

The intention is to improve prices as a signal when the system is tight and ensure the market receives more accurate signals about the value consumers

place on flexibility. These price signals are essential as we move to a more intermittent generation mix. They will have an important impact on the operation and evolution of the electricity system by encouraging:

- the efficient dispatch and take-up of demand side response
- interconnectors to import during very tight margins
- market participants to provide, maintain and invest in flexible capacity.

Making the cash-out price more cost reflective will increase the price parties will be willing to pay for electricity and lowers the price they would be willing to sell their electricity for in the intraday markets. Therefore, it should incentivise them to balance.

In the medium to long term, there should be a reduction in energy balancing costs on consumer bills as a result of the reforms. This is due to the

savings made in balancing the system and achieving security of supply. However, there may be a modest increase in balancing costs in the short term before efficiency savings from more cost-reflective prices are realised.

As a result of these changes, energy imbalance prices may be more volatile and higher than previously observed, especially during times of system stress.

To see the current and historic cash-out prices go to:

<https://www.bmreports.com/bmrs/?q=balancing/systemsellbuyprices>

Links for further details:

<https://www.elexon.co.uk/>

<https://www.elexon.co.uk/mod-proposal/p305/>

Electricity demand

This section presents our current view of demand for winter 2018/19. Unless stated otherwise, all the demand values quoted in this section are transmission system demands (TSD). TSD is the sum of national demand measured at transmission level, the demand from power stations (600 MW) and the base case interconnector export value (750 MW).

Key messages

- Normalised and average cold spell (ACS) demand can be met in all weeks across the winter under all interconnector scenarios.
- Peak demand is expected to be 48.2 GW.
- Minimum demand is forecast at 20.8 GW.
- We saw the introduction of CMP264/265 in April this year, this could lead to a reduction in customer demand management (CDM).

Key terms

- **Transmission system demand (TSD):** 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) and interconnector exports.
- **Normalised demand:** forecast 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 could be with this standardised weather.
- **Average cold spell (ACS):** A particular combination of weather elements that gives rise to a winter peak demand, which has a 50 per cent chance of being exceeded as a result of weather variation alone.
- **Transmission network use of system (TNUoS):** charges allow the transmission network owner to recover the costs of installing, operating and maintaining the transmission network.
- **Triads:** are the three half-hourly settlement periods with the highest system demand. Triads can occur in any half-hour, on any day between November and February inclusive. They must be separated from each other by 10 days.
- **Triad avoidance:** occurs when industrial or commercial users reduce their electricity consumption (or use onsite embedded generation) when demand is expected to peak in order to avoid transmission charges.
- **Connection use of system code (CUSC):** is the contractual framework for connection to, and use of, the national electricity transmission system.
- **PAR1:** aims to make cash-out prices 'fully marginal' by reducing the volume of actions they are based on to 1 MWh.
- **The value of loss of load (VoLL):** is an assessment of the value that electricity consumers place on security of supply.

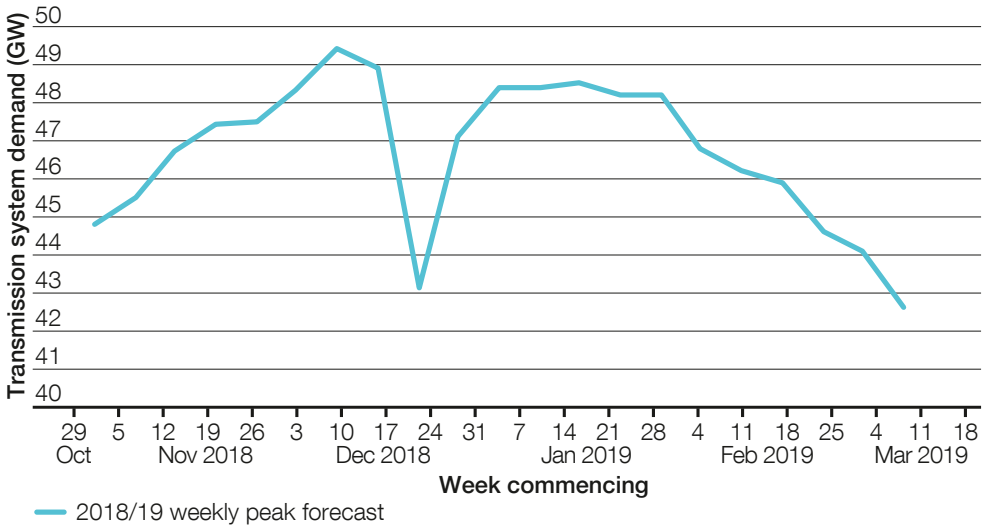


Our methodology remains unchanged from previous years in that we apply regression models to the averages of various weather variables for the past 30 years.

Figure 1.5 illustrates our forecast for the peak demands for each week over the coming winter. We base these values on the seasonal normal weather forecasts with an adjustment

to take account of normalised levels of embedded wind and solar generation. The week with the lowest peak demand is Christmas week.

Figure 1.5
Forecast of weekly peak demand for winter 2018/19



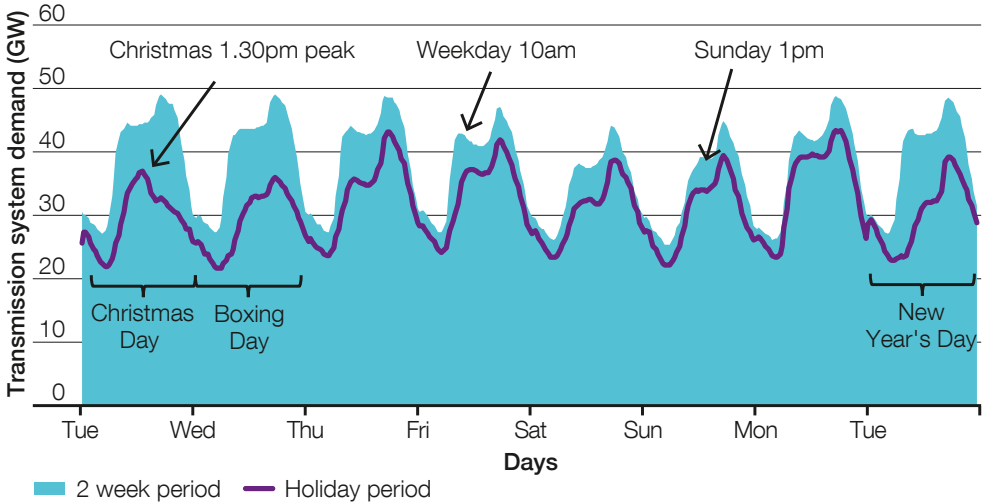
In figure 1.6 we can see that the Christmas holiday profile was lower than normal profiles when compared with the same days two weeks earlier. The profile for Christmas day is quite different

from all the other days with its peak occurring early afternoon, coinciding with people cooking Christmas lunch. The other days have their peaks occurring early evening. A similar effect to

Christmas day can be seen on Sundays when people tend to cook Sunday lunch, however, this does not create as much demand as to make it the day's peak.

Electricity demand

Figure 1.6
2017 transmission system demand over the Christmas period compared with the previous 2 weeks



Both Christmas Day and Boxing Day have lower peaks than other days within the period and this includes New Year's Day. By 31 December, the profile is still

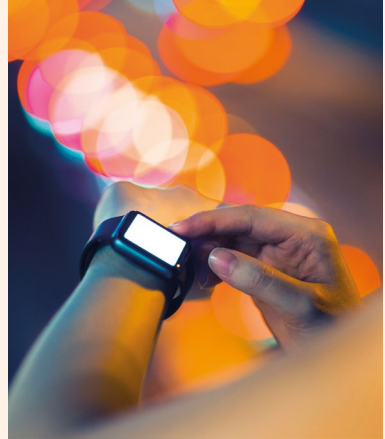
not quite back to normal. While New Year's Eve is not a national holiday, there is a weekend on one side and a bank holiday on the other. It is therefore likely

to have a demand profile similar to the other days in the Christmas week.

Spotlight

Possible impact of the phased removal of embedded benefits on customer demand management and Triad avoidance.

Electricity suppliers pay transmission network use of system charges (TNUoS) which are based on their net demand during the three peak demand or Triad periods. They can reduce their TNUoS costs by contracting with distributed generators to generate on their behalf during a Triad period. They can do this because the electricity produced by embedded generators is treated as negative demand during the Triad periods and therefore this reduces the supplier's TNUoS charges. Embedded generators receive 'Triad avoidance' payments, from suppliers for this service. These payments along with avoidance of other charges, are often referred to as 'embedded benefits'.



Ofgem has made the decision to begin to reduce the value of Triad avoidance payments so that they more accurately reflect the impact of embedded generation on network costs. This will be implemented via the CMP 264 and CMP 265 modifications⁵, which became effective from April 2018. The reductions will be phased in over three years.

This implementation could reduce the amount of customer demand management we see on the system during a Triad period as embedded generators will receive less money to generate over this period.

⁵https://www.nationalgrid.com/sites/default/files/documents/CMP264-265%20-%20Implementation%20Guide_0.pdf

Electricity generation

This section presents our current view of the generation available by type along with the assumed generator breakdown rates.

Key messages

- We currently expect there to be sufficient levels of generation and interconnector imports to meet demand throughout the winter.
- Distributed wind generation continues to increase year on year expecting to rise to 5.9GW this winter.

Key terms

- **Operational surplus:** the difference between the level of demand and 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. Generators are then able to take this into consideration when planning their outages.
- **Operational Code 2 (OC2) data:** information provided to National Grid by generators. It includes their current generation availability and known maintenance plans.
- **Equivalent firm capacity (EFC):** An assessment of the entire wind fleets contribution to security of supply. It represents how much of 100% available conventional plant would be needed to replace the entire wind fleet and leave security of supply unchanged.

The three levels of generation, shown in [figure 1.4](#) of our 'Operational view' section, take account of a range of interconnector flows. But they do not include any market responses to higher demands or tighter conditions, such as power

stations increasing their output levels for short periods.

We apply a breakdown rate, by fuel type, to the OC2 data, shown in table 1.3. We do this to account for unexpected breakdowns, restrictions or

losses. We base it on how generator units performed against their plans during peak demand periods⁶ over the last three winters. This year, we include biomass as a separate fuel type; previously this was grouped with coal.

⁶Peak demand periods are defined as the highest 20 per cent of demand half-hours, during November to February, between 10am and 8pm Monday to Thursday.

Table 1.3
Breakdown rates by fuel type

Power station fuel type	Assumed breakdown rate
Nuclear	8%
Hydro	3%
Coal	10%
Biomass	11%
Pumped storage	3%
OCGT	3%
CCGT	6%

For wind generation, we assume an equivalent firm capacity (EFC) of 15 per cent. This is the same level of wind we assumed in our 'Winter view' section.

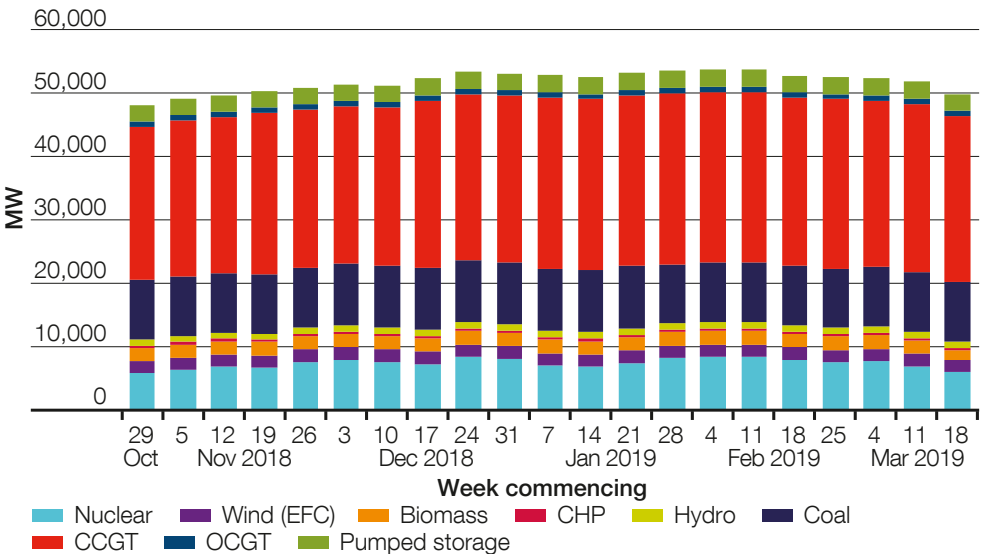
Figure 1.7 shows the weekly amount of generation we expect from each fuel type based on the OC2 data we receive from

generators with breakdown rates applied. The variations seen across the weeks are because of planned outages at power stations. The figure does not include interconnector flows.

The column stack in figure 1.7 reflects the running order we expect to see over the winter

period based on the cost of producing energy. Power stations with lower production costs will tend to run more often. Based on current fuel prices, we expect coal will run above the least efficient gas stations in the generation merit order, however, this could change if it gets colder.

Figure 1.7
Generation by fuel type



Europe and interconnected markets

In this section, we explore interconnector activity along with forward prices in GB and Continental Europe to help us forecast interconnector flows. We also provide a spotlight to explain the changes to our interconnector import scenario assumptions.

Key messages

- Forward prices for winter 2018/19 in Continental European markets are expected to be lower than in GB. This is in part due to the increase in renewable sources of capacity.
- Renewable generation output is weather dependent and this may create price fluctuations on the intraday market.
- We expect a net flow of power from Continental Europe to GB at peak times, occasionally not at full import.
- We expect GB to export to Ireland during peak times on both the Moyle and EWIC interconnectors. This may be reversed to import with high wind output in Ireland or during periods of system stress.
- The interconnector standard export value has changed during periods of peak demand to provide a more accurate outlook.
- There are no planned outages on the IFA and BritNed interconnectors and so we expect full imports into GB from France and the Netherlands under normal network operating conditions.
- There is more French nuclear capacity available this winter than last winter which should ease France's demand for imports in cold conditions.

Key terms

- **Import:** interconnectors flowing electricity into GB.
- **Export:** interconnectors flowing electricity out of GB.
- **Net import/export:** the sum of total generation flowing via interconnectors, either into or out of GB.
- **North-Western Europe (NWE) day-ahead coupling regime:** a mechanism that allows the free movement of electricity between integrated markets. It consists in selling electricity together with interconnection capacity, instead of separately.
- **Cross-border intraday market project (XBID):** integrated cross border within-day continuous trading between, currently, 14 European countries.
- **Transmission entry capacity (TEC) values:** flow limits that are applied to assets connected to and flowing into the transmission network.

Spotlight

Changes to interconnector scenarios assumptions and the impact on transmission system demand (TSD)

In this year's *Winter Outlook Report*, we have changed the expected export value on interconnectors during periods of peak demand to reflect historic observations from previous winters.

Previously we set the flow to Ireland at full export for both the Moyle and East West Interconnector (EWIC). This gave us an export value of 1,000MW (500MW capability on each). Now we have set it at a 750MW export value. We base this new value on the average observed flows at the peak demand period for each week of last winter.

We have also revised our Continental European interconnector scenarios to reflect what we saw last winter. We looked at how reliable the Continental European interconnectors were and applied those values to this year's scenarios.

We found there was a breakdown rate of:

- 11 per cent on the French IFA interconnector, which has a capability of 2,000MW
- 2 per cent breakdown rate on BritNed, which has a capability of 1,000MW.

Consequently, our interconnector flows have been recalculated, as follows:

- The high imports scenario is now 2,010MW. From Continental Europe, we now have an import flow of 2,760MW. To Ireland, we have an export flow of 750MW
- The medium or base imports scenario is now 1,380MW. From Continental Europe, we now have an average import flow of 2,130MW. To Ireland, we have an export flow of 750MW.

- The low imports scenario is now -750MW. From Continental Europe, we now have an import flow of 0MW. To Ireland, we have an export flow of 750MW.

As the price of GB energy is generally higher than that in Europe, we have not included an export scenario to Continental Europe. If the GB system does come under stress, we believe the price differential will widen further, based on the value of loss of load increasing to £6,000 per MWh this winter in accordance with the implementation of PAR1.

Table 1.4
Interconnector scenarios

Scenario	GB's net position at peak
Low	Export 750GW
Base (or medium)	Import 1,380GW
High	Import 2,010GW

Europe and interconnected markets

There are four existing electricity interconnectors between GB and its neighbouring countries. A new interconnector "Nemo Link"⁷⁷ is under construction which may come into commercial service at the end of January 2019. Once commissioned, it will provide a 1 GW capability between Belgium and GB.

The amount of electricity the interconnectors flow will depend on a number of factors including:

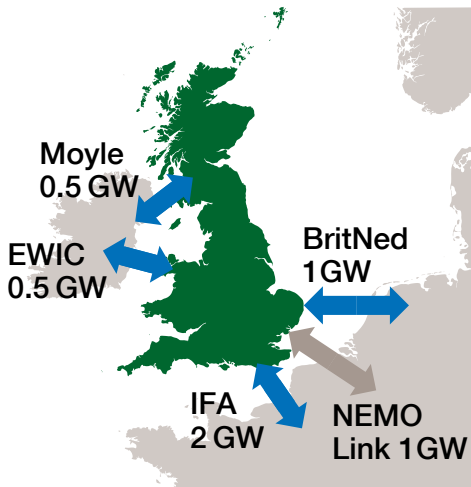
- the physical capability of the interconnector
- the price differential between the connected market places
- network access constraints.

In this section we explore each one of these factors in turn.

The physical capabilities of the interconnectors

Each of the interconnectors and their respective capabilities can be seen in figure 1.8. There are no planned outages this winter for the existing interconnectors, except EWIC. EWIC will be on planned maintenance on 4 November for one day. Please note the values quoted are maximum physical capacity and not expected flows.

Figure 1.8
GB's electricity interconnectors maximum physical capacity



Capacity Market (CM)

In 2014, the interconnectors were not eligible to participate in the Capacity Market's T-4 auction.

As a result, they hold no CM obligations for winter 2018/19, including interconnector capacity, as some CM capacity was secured by interconnectors

in the Early Auction. All interconnectors are eligible to participate in the CM for future delivery years from 2019/20.

⁷⁷<http://www.nemo-link.com>



European forward prices

With the exception of Nemo Link, currently, GB is linked to Continental Europe via two interconnectors. From France, there is the Interconnexion France-Angleterre (IFA) which has a 2 GW capability. From the Netherlands, there is BritNed which has a 1 GW capability.

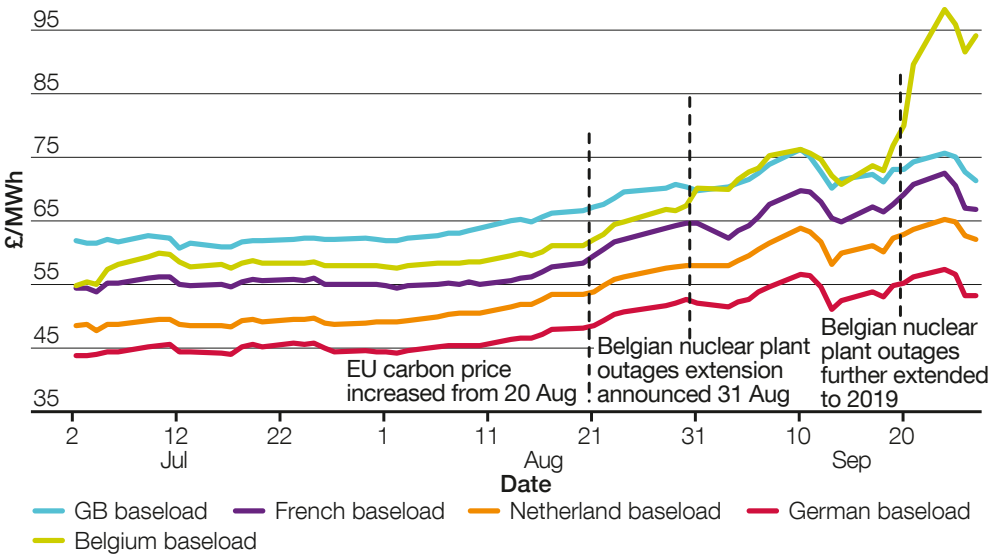
As previously noted, energy flows through the interconnectors are primarily driven by the price differentials between the markets.

The North-Western Europe (NWE) day-ahead coupling regime introduced implicit trading day ahead. It has resulted in a narrowing of prices between the Belgian, Dutch, French, Austrian and German markets. The introduction of the Cross-Border Intraday Market Project (XBID) in Continental Europe in late 2017 has also contributed to lower intraday trading prices on the Continent.

Figure 1.9 illustrates the forward prices for the 2018/19 winter products. Historically, GB prices are consistently above those of its Continental neighbours. On the 20 August 2018, the EU carbon prices began to rise. In response, the baseload prices in France, the Netherlands and Germany rose. But so too did GB's carbon prices. Although the price differentials are narrowing for this winter compared to prices in early August, they are still higher in the GB market.

Figure 1.9

Generation by fuel type



The baseload prices in Belgium are usually lower than in the GB market. Recently Belgian prices have escalated close to or higher than GB prices. This

is mainly driven by the extended outage on some Belgian nuclear plants. Belgian nuclear capacity is expected to be reduced to one reactor during November

following a recent announcement in late September. This increases uncertainties to flow direction either into or out of GB.

Europe and interconnected markets

Network access constraints

Transmission outages in the regions where interconnectors are connected could cause power flow constraints resulting in disruption to the flows through the interconnectors.

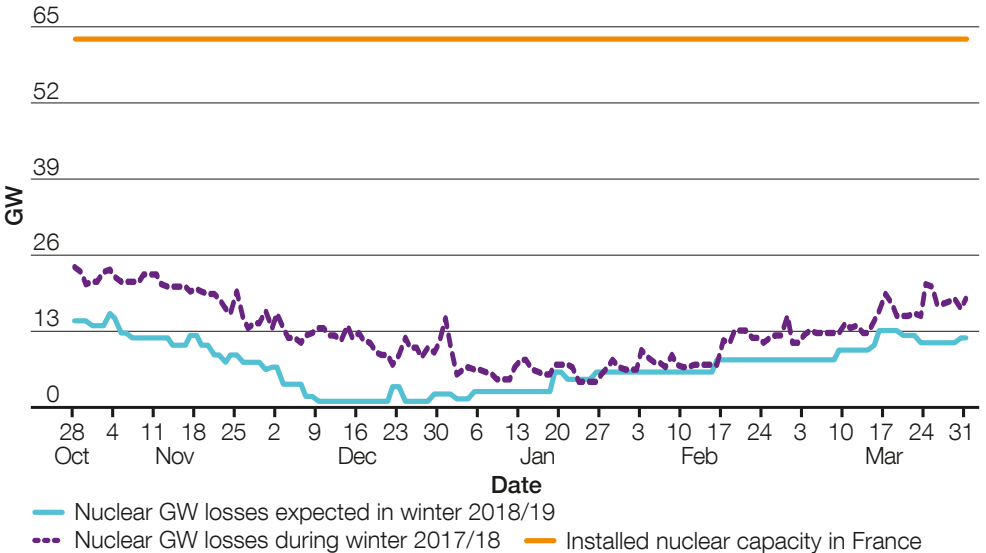
France

Figure 1.10 shows the effect of outages on the capacity of French nuclear sites for this winter, compared to winter 2017/18. The nuclear outages for this winter are much lower compared to last winter, especially between November and December.

The consequences of last year's extended outages were higher prices in France than in GB. This resulted in GB exporting. However, this year the outages are not expected to significantly affect interconnector flows between GB and France.

Figure 1.10

The impact on French nuclear capacity from planned outages 2018/19 and last winter's actuals



Germany

Up until August 2018, there were 55 coal-fired units in service in Germany across 35 sites. The total installed capacity was approximately 46GW. The energy generated by coal-fired plants up until August 2018 was 129 TWh. This equals 38.5

per cent of the total energy contribution during that period. If we compare the same period last year, there is a reduction in the amount of installed coal-fired capacity but an increase in energy outputs to 6.5 per cent on last year's 121.5 TWh. It is expected that about 50 per cent of current coal-fired capacity needs to be

phased out by 2030 in order for Germany to meet their carbon reduction target.

Renewable capacity (mainly wind, solar and biomass) has now reached a new record of 102 GW which equates to 49 per cent of total generation capacity.

Overview of Continental European interconnectors

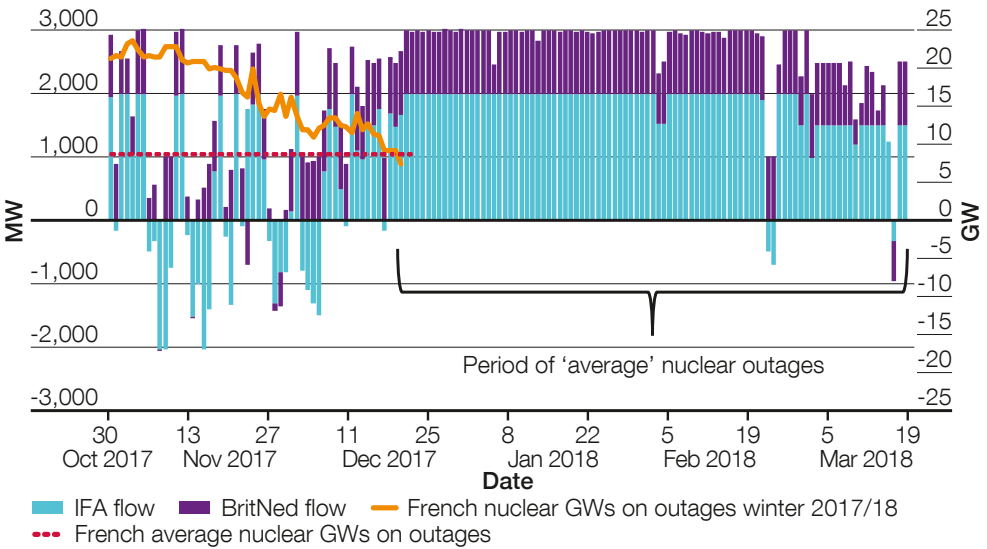
Based on the prices for the 2018/19 winter products, and no planned outages on both interconnectors, we would expect full imports into GB from France and the Netherlands under normal network operating conditions. The flow over Nemo

Link would depend on the status of commissioning work and the price differentials between the GB and Belgian markets at the time. There may be some fluctuating flows during peak times, but these are the exception. We expect occasional variations in the interconnector flow pattern during peak times. This is caused by changes in weather

conditions, which will affect renewable generators across the region. Figure 1.11 illustrates the flow directions for peak times last winter. Once the extended outages of the French nuclear plants returned to normal, after 21 December 2017, the occurrences of peak time exports from GB were rare.

Figure 1.11

Peak time flows across the Continental interconnectors (positive MW values mean imports into GB)



Irish connected markets

GB is linked to Ireland via two interconnectors. From Wales, there is the East West Interconnector (EWIC) which has a 0.5GW capability this winter. From Scotland, there is the Moyle interconnector. This has a 0.5GW capability; however, flows will be subject to transmission entry

capacity (TEC)⁸ values, which are currently 307MW for import and 450MW for export.

Three generating units in Northern Ireland failed to win capacity contracts in the all Irish T-1 CM auction, which was effective from 1 October 2018. The owner of the units has announced that it

is likely to close two of them as a result. However, the Northern Ireland regulator and the owner have stated that they will make a definitive decision on these sites "in due course". Should the units close then it will encourage more exports through the Moyle interconnector to meet Northern Ireland's demands.

⁸Flow limits that are applied to assets connected to and flowing into the transmission network.

Europe and interconnected markets

Overview of the Irish interconnectors

The Irish interconnectors generally export from GB to Ireland, especially via the Moyle interconnector. However, there have been a few occasions when

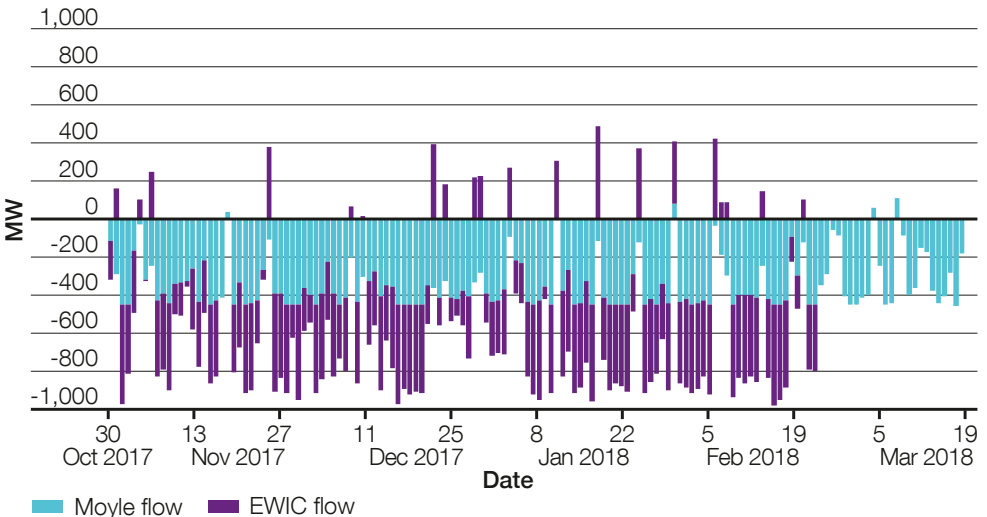
EWIC exported into GB. During the cold snap at the end of February/early March 2018, EWIC was on outage and therefore was unavailable for either imports or exports. Based on historical data analysis and possible plant closures in Northern Ireland

(see table 1.5 and figure 1.12), we expect GB to export to Ireland during peak times and import overnight. We also expect imports into GB during periods of high wind and system stress.

Table 1.5
Periods of import and export overnight for Irish connectors, winter 2017/18

Status (7pm – 7am)	Moyle	EWIC	EWIC (outage corrected) ⁹
Import	65%	61%	76%
Floating (no flow)	0%	20%	0%
Export	35%	19%	24%

Figure 1.12
Peak time flows across the Irish interconnectors (positive MW values mean imports into GB)



⁹ EWIC outage-time corrected flows are shown as there was an outage on EWIC between 28 February 2018 and 29 March 2018.

Forecast flows for winter 2018/19

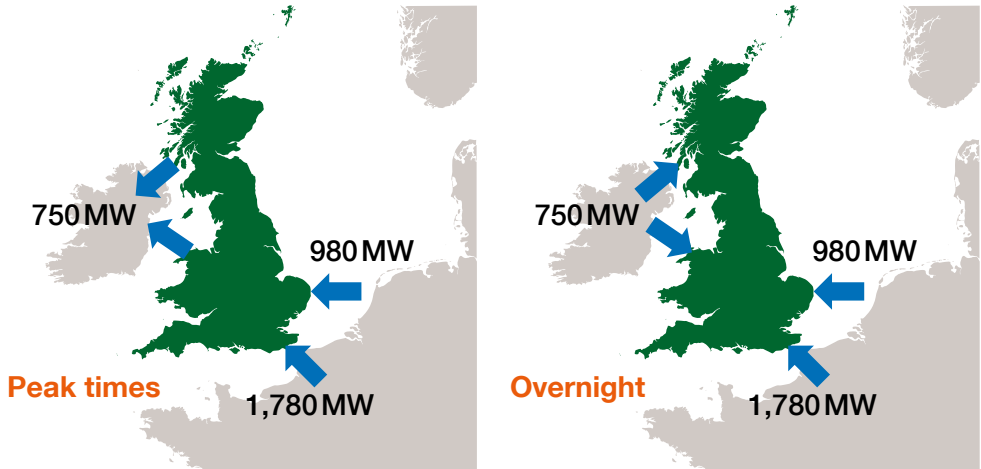
The forecast flows on the interconnectors, during peak and off-peak times, are summarised in

figure 1.13. The Nemo Link is not included due to the uncertainties associated with commissioning work. Once the interconnector successfully goes live, we expect

potentially a 1 GW export flow from GB during peak times based on current price differentials and low availabilities of Belgian nuclear plant.

Figure 1.13

Forecast flows (high import scenario) on the interconnectors for winter 2018/19



Interconnector net flows for winter 2018/19

The following scenarios assume full export to Ireland via the EWIC and Moyle interconnectors during peak times. Each scenario includes a varying level of imports via IFA and BritNed interconnectors including an additional scenario for the Nemo Link:

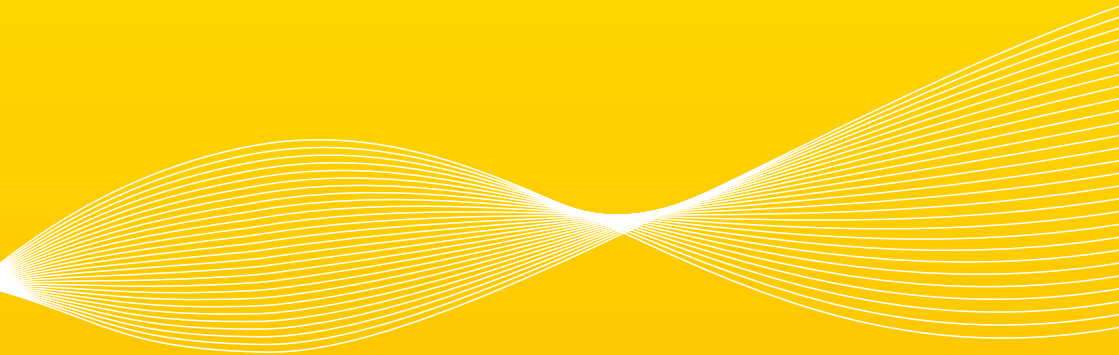
- Low imports scenario of 0 MW, resulting in a net export of 750 MW from the GB market.
- Base or medium imports scenario of 2,130 MW, resulting in a net import of 1,380 MW to the GB market.
- High imports scenario of 2,760 MW, resulting in a net import of 2,010 MW to the GB market.¹⁰
- Extra 1,000 MW export via Nemo Link (subject to Nemo Link's commissioning work).

¹⁰ Interconnector flows in this section are based on typical commercial flows plus/minus a high/low sensitivity, unlike those used in the 'winter view' which are based on flows under potential stress event conditions.

Chapter 2

Gas

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Gas winter outlook

This chapter sets out our current view of the gas system for winter 2018/19. It details our analysis of supply and demand, and the preparations we have made to make sure we are prepared for the winter ahead.

The chapter contains the following sections:

- Winter view
- Gas demand
- Gas supply
- EU and connected markets.

Winter view

This section considers our responsibilities as System Operator and our obligations for gas security of supply, and how these might be met under colder than normal conditions, including those that last for a long time.

Key messages

- Our modelling demonstrates sufficient supply margin to accommodate all security of supply scenarios.

Key terms

- **1-in-20 peak demand:** the level of demand that, in a long series of winters, with connected load held at levels appropriate to the winter in question, would be exceeded in one out of 20 winters, with each winter counted only once.
- **Non-storage supply (NSS):** gas that comes from sources other than gas storage. This includes supply from the UK Continental Shelf (UKCS), Norwegian imports, European imports and imports of liquefied natural gas (LNG).
- **N-1 assessment:** a risk assessment to demonstrate that UK gas supply infrastructure is resilient to all but the most extreme and unlikely combinations of severe infrastructure and supply shocks.
- **Cold day:** the demand forecast for the coldest day in an average (or seasonal normal) winter.
- **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.

Network capability and peak day supply margins

National Grid has the responsibility to ensure the safe, reliable and efficient operation of the high pressure gas network, the national transmission system (NTS). National Grid owns and operates this network, and we are responsible for transporting the gas from where it flows into our network and on to our connected customers. Security of the gas supply network is assessed by the European Commission using the N-1 test.

As the System Operator, the N-1 assessment means we have to ensure that:

- the NTS is designed and built to meet a 1-in-20 peak day demand as required under the Gas Transporters Licence. This is defined as the amount of infrastructure (pipes and compressors etc.) needed to transport the gas that would be required by our customers in the coldest day of winter, in the coldest winter we could expect in a 20 year period.

- the high pressure gas network has sufficient redundancy to meet a 1-in-20 peak day demand, even with the failure of the single biggest piece of infrastructure. This is referred to as the N-1 assessment.

In summary, we need to be able to transport the amount of gas to sustain a 1-in-20 peak day demand and in the event of losing a major piece of the network, we still have sufficient capacity in the network to allow us to accomplish this.

Winter view

Peak demand

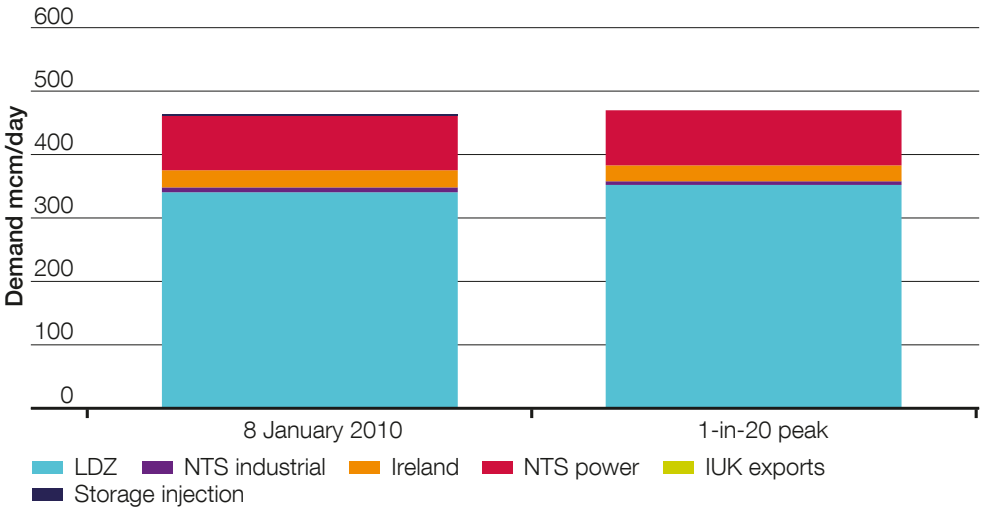
When considering the potential peak demand for gas, we look at 1-in-20 peak demand. Calculating

the 1-in-20 peak allows us to be prepared for colder conditions. The forecast 1-in-20 peak for 2018/19 is 472 mcm per day.

This is slightly greater than the highest recorded gas demand which occurred in January 2010 with a demand of 465 mcm.

Figure 2.1

1-in-20 peak day demand forecast and highest demand day



Cold day and peak day assessment

Figure 2.2 shows the anticipated gas demand for a cold day, and on a peak day under 1-in-20 conditions. Here we consider gas supply for each of these scenarios.

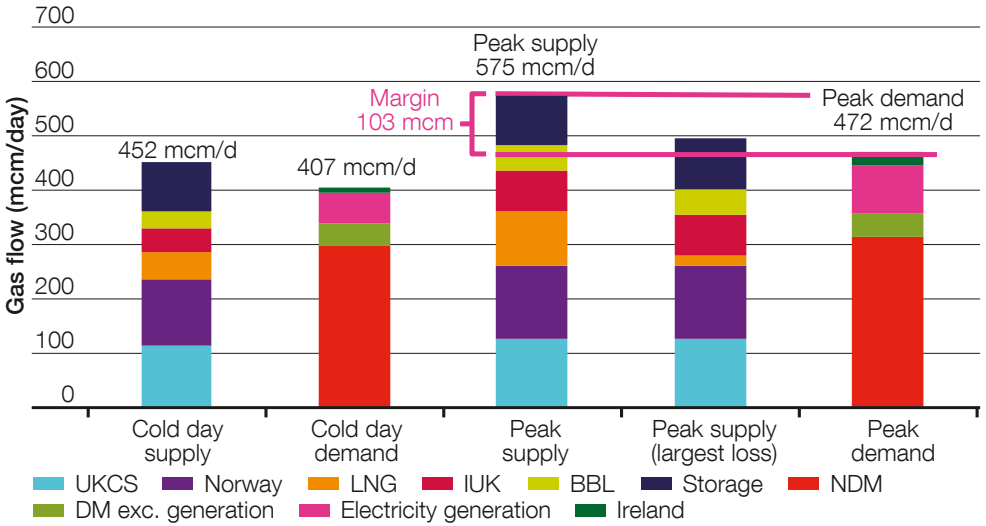
For winter 2018/19, the cold day demand forecast is 407 mcm/d.

The non-storage supply forecast for winter 2018/19 is 360 mcm/d, to which 92 mcm of storage can be added. This means that the gas supply we expect to be available in our cold day supply forecast is in excess of the forecast cold day demand, as shown in figure 2.2.

The figure also shows the forecast 1-in-20 peak day demand which is 472 mcm/d for winter 2018/19.

For winter 2018/19, the non-storage supply forecast under 1-in-20 conditions is 483 mcm/d. To this, 92 mcm of storage can be added. This means that there is a margin of available supply over demand under 1-in-20 conditions of 103 mcm.

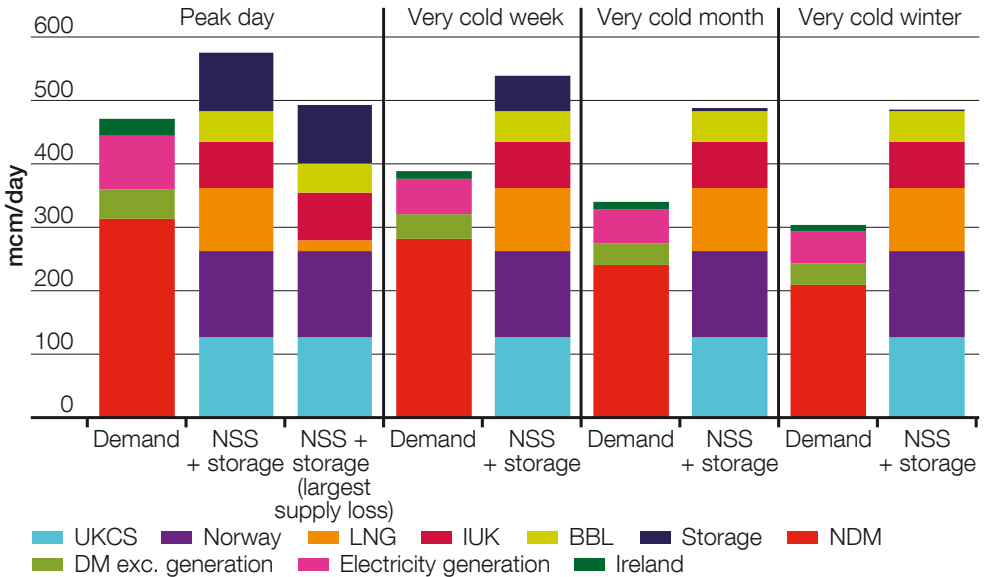
Figure 2.2
Supply and demand on a cold day and a 1-in-20 peak day



Security of the gas supply network is assessed using the N-1 test, described earlier. For winter 2018/19, the test is passed as the loss of supply associated with the failure of the largest piece of gas infrastructure would be around 81 mcm/d, which is less than the supply margin of 103 mcm.

Winter view

Figure 2.3
1-in-20 peak day and demand for prolonged periods of cold weather



Gas supply and demand in severe conditions

As well as considering a cold day and a peak day, we also wanted to assess the risks in the case of prolonged cold periods. In order to do this, we modelled gas supply and demand for a peak day, a very cold week, a very cold month and a very cold winter.

Figure 2.3 shows the daily level of gas demand and supply estimated for a 1-in-20 peak day,

a very cold week, a very cold month and a very cold winter. The cold week, month and winter are taken from the 1-in-20 load duration curve. Load duration curves are published every year in our Gas Ten Year Statement¹¹.

In this example there is no loss of supply infrastructure, and for all time periods the modelled supply is sufficient to meet demand. As the graph shows, the longer the cold weather continues, the smaller the

contribution storage can make to supply as stores of gas become depleted. You can also see that demand decreases as the time period considered gets longer. This is a consequence of the way the severe condition is defined. A very cold week might be seven days below freezing. A very cold month of the same severity would not be 30 days below freezing as a month like this would be far more severe.

¹¹ <http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/Gas-Ten-Year-Statement/>

Gas demand

In this section we consider daily and seasonal gas demand for the winter for the different sectors. We examine potential demand under cold, seasonal normal and warm weather conditions. We also consider demand under 1-in-20 peak conditions.

Key messages

- We expect that gas demand for the winter of 2018/19 will be lower than the demand for winter 2017/18.
- The main reason for this reduction is the reduced output from gas-fired electricity generation. This is due to more renewable generation being built and also our expectation that coal-fired generation will be cheaper to run than lower efficiency gas-fired generation for some parts of the winter due to higher prices.

Key terms

- **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.
- **Seasonal normal conditions:** a set of conditions representing the average weather 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.
- **1-in-20 peak demand:** The level of demand that, in a long series of winters, with connected load held at levels appropriate to the winter in question, would be exceeded in one out of 20 winters, with each winter counted only once.
- **NTS shrinkage:** is made up of 3 components. Unaccounted for gas (UAG) is unallocated gas or gas that is lost or stolen from the system. Own use gas (OUG), gas that is used in the running of the system e.g. compressor fuel. And calorific value shrinkage (CVS) where gas of a particularly low or high CV enters the distribution network which differs with the flow weighted average CV of gas entering that network.
- **Weather corrected demand:** The expected or actual demand for gas with the impact of the weather removed (this is calculated by converting actual demand to demand expected at seasonally normal weather conditions).

Gas demand

Seasonal demand

Demand for gas can be considered in five categories.

- **Demand for heat in residential and commercial properties**

This sector is very sensitive to weather. Customers in this category are usually on non-daily metered (NDM) contracts. This means that their meters are read monthly, or at longer intervals. Residential demand is by far the biggest part of the NDM sector.

- **Demand in industrial properties**

Gas is used to provide space heating, heat for processes, or is used as a raw material. This sector is less sensitive to the effects of the weather than the NDM sector. Customers in this category are nearly always on daily metered (DM) contracts. This means that their meters are automatically read every day. They may be connected to the high pressure transmission network, or to a lower pressure distribution network.

- **Gas for electricity generation**

Electricity generation has some sensitivity to weather, but also depends on the hours of darkness. Gas-fired generation, as a proportion of total electricity supply, varies with the amount of electricity from renewable sources. It is also dependent on the relative cost of generation at gas-fired and coal-fired power stations.

- **Gas for export**

GB has two gas interconnectors that have the capability to export gas out of the country. The first is Moffat, which is a gas interconnector link to Ireland. This interconnector is only physically able to flow gas one way, out of GB and into Ireland. The other is the IUK interconnector, which links the GB and Belgian gas networks. This interconnector is capable of flowing gas two ways, allowing both the import and export of gas. Where gas is exported to Ireland or Belgium, this is counted as part of overall GB demand.

- **Gas for storage injection**

This is gas which is put ('injected') into a gas storage facility. There are several medium-range storage facilities connected to the high pressure gas network. We anticipate that shippers will inject gas into, and withdraw gas from these facilities many times over the course of the winter. This is known as cycling.

Further detail on gas storage can be found in the 'gas supply' section.

Figure 2.4
Forecast daily gas demand 2018/19 under seasonal normal conditions

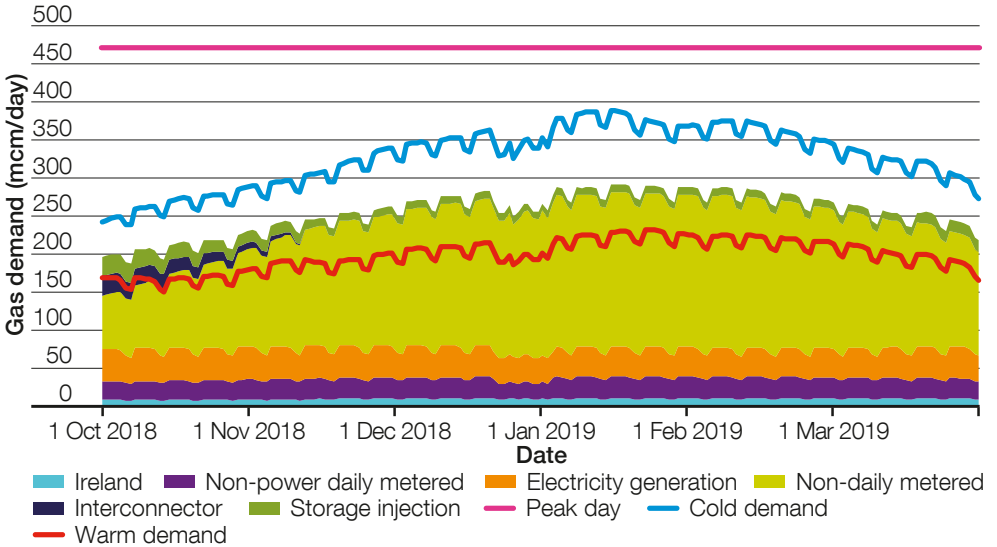


Figure 2.4 shows the forecast daily gas demand for winter 2018/19 under seasonal normal conditions. The demand for non-daily metered customers is the largest element of this demand, and follows a weekly profile with less use of gas at weekends.

Domestic gas demand, industrial gas demand and gas for electricity generation all reduce over the Christmas period.

As can be seen from the seasonal contour of NDM demand, it is the component of demand that

is most sensitive to the weather, with other components of demand staying fairly constant across the winter season. We explore weather sensitivity in the spotlights to follow.

Gas demand

Table 2.1

Winter demand – forecast and weather corrected history

October to March	Weather corrected history					Forecast
bcm	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
NDM	29.0	29.3	29.6	29.7	30.6 ¹²	29.8
DM + industrial	5.2	4.9	4.7	5.0	4.9	4.8
Ireland	2.9	2.9	2.6	1.6	1.8	1.8
Electricity generation	7.9	8.7	10.4	13.8	12.7	7.0
Total demand	45.1	46.0	47.5	50.3	50.1	43.7
IUK export	0.6	1.5	2.7	0.8	0.7	0.6
Storage injection	1.8	0.9	1.2	1.8	2.3	2.3
GB total¹³	47.5	48.3	51.4	52.9	53.4	46.6

Gas demand compared to previous winters

Table 2.1 shows how our forecast gas demand for winter 2018/19 compares with previous winters' weather corrected output. To enable a clear comparison across years, we have included historic demand corrected for the effect of the weather. The forecast for 2018/19 has been updated to reflect the strong rise in NBP prices in August and September 2018; this is outlined in our spotlight in the 'Whole system overview' section.

Our forecast NDM demand for winter 2018/19 (29.8 bcm) is close to the weather corrected demand for winter 2017/18. Gas demand in individual properties is decreasing thanks to improved

home insulation and more efficient boilers. However, the growth in the number of buildings being connected to the gas network has largely offset this reduction. We therefore expect that residential gas demand for winter 2018/19 will be broadly similar to that seen in recent years.

Demand from the DM and industrial sectors (excluding electricity generation) have not shown any particular trends in recent years. We therefore expect that demand from this sector in winter 2018/19 will be similar to the demand seen last winter. Likewise, we have forecast that exports to Ireland will be similar to last year's levels as we are not expecting significant differences in production from the Corrib gas field.

In contrast, gas used for electricity generation is predicted to fall considerably compared to winter 2017/18. This is mainly due to the growth of renewable electricity generation and also our expectation that coal-fired generation will be cheaper to run than lower efficiency gas-fired generation for some parts of the winter due to higher gas prices.

We are expecting slightly lower exports via the IUK interconnector to Belgium. This is because there are currently reduced capacity bookings for exports on this interconnector for the coming winter. This is further discussed in the 'EU and connected markets' section.

¹² Please note that this is slightly different to the figures reported in the *Winter Review and Consultation* document due to a slight change in the treatment of IUG.

¹³ All totals include shrinkage and therefore columns will not tally.

Gas supply

This section provides our forecast view of gas supply and its sources.

Key messages

- There are sufficient gas supplies from a variety of sources to meet winter 2018/19 demand.
- We expect to see maximum flows from the UKCS for winter 2018/19.
- We expect high flows from Norway, similar to levels seen across winter 2017/18.

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 between Balgzand in the Netherlands and Bacton in the UK.
- **IUK:** the Interconnector (UK) Limited is a bi-directional gas pipeline connecting Bacton in the UK and Zeebrugge in Belgium.
- **Liquefied natural gas (LNG):** natural gas that has been converted to liquid form for ease of storage or transport. It is formed by chilling gas to -161°C so that it occupies 600 times less space than in its gaseous form.
- **Non-storage supply (NSS):** all gas supplies to the national transmission system (NTS), excluding storage.
- **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 price of gas. It is usually quoted in pence per therm.
- **Title transfer facility (TTF):** a virtual trading point for natural gas in the Netherlands, created in order to facilitate trading in the Dutch market.

In this section we look at the supplies of gas that we expect to receive from different sources. As we did last year we have considered 'beach' supplies, gas from the UK Continental Shelf (UKCS) and from Norway, in a separate section from other sources. Beach gas can be expected to run at close to maximum levels through most of the winter. In contrast, the non-beach supplies, storage, liquefied natural gas (LNG) and gas imported through the

interconnectors will be more responsive to gas prices, in both the GB and global gas markets.

Total supply

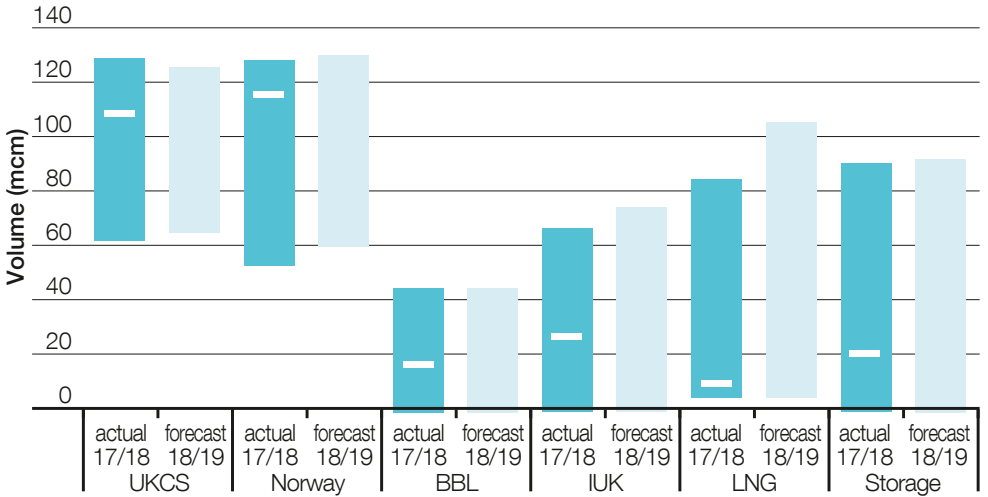
For the winter ahead, we do not forecast the total volume of gas that we expect from each source but concentrate on the ranges that we expect for each. This is more useful from an operational viewpoint. We also consider the flow that we might expect from each source on a cold day. Figure 2.5 shows the forecast

range for this winter and the range observed in winter 2017/18 for each supply type. The average flow seen in winter 2017/18 is also shown as the white bar.

Our forecast ranges are based on historical flows and on market intelligence. For some sources, we also consider the physical capability of the infrastructure.

Gas supply

Figure 2.5
Historic and forecast ranges for gas supply



Forecast and observed ranges are also shown in table 2.2. In the table we have included our projections for a 'cold day'. The forecast for the total of the non-storage supply (NSS) on a cold day is used in the Margins Notice process (discussed in

more detail in the 'Operational toolbox' section). The Margins Notice is designed to alert the industry to a possible supply and demand imbalance.

The cold day is taken from day 1 on the average load duration

curve¹⁴. Load duration curves are published every year in our *Gas Ten Year Statement*¹⁵. For winter 2017/18 we have also included the range of flows from all days where total supply exceeded 350 mcm/day.

¹⁴ A load duration curve is designed to provide an estimate of the total demand in a gas year above any specific demand threshold.

¹⁵ <http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/Gas-Ten-Year-Statement/>

Table 2.2

Historical and forecast ranges

		2017/18			2018/19	
(mcm/d)	Forecast range	Observed range	Cold day	350 + range	Forecast range	Cold day
UKCS	70 – 121	62 – 128	109	65 – 128	75 – 125	115
Norway	60 – 136	53 – 128	120	86 – 125	80 – 130	120
BBL	0 – 45	0 – 45	30	10 – 45	0 – 45	30
IUK	0 – 74	0 – 67	45	7 – 66	0 – 74	45
LNG	5 – 100	5 – 84	50	5 – 84	5 – 100	50
Total NSS			354			360
Storage	0 – 92	0 – 90		12 – 90	0 – 92	

Beach gas

UKCS

Our UKCS projections are based on information received from producers as part of our annual Future Energy Scenarios stakeholder engagement process. The lowest daily flow last winter was much lower than our forecast. This was due to the shutdown of the Forties pipeline in December, which removed over 40 mcm/day from the UKCS supply. Table 2.2 shows that our forecasts for the range and the cold day estimate are all higher than winter 2017/18.

There have been a number of changes since last winter. The former long-range storage site at Rough has now been reclassified as a producing field and is included in our UKCS projections.

The UKCS terminal at Theddlethorpe closed in August 2018 by which time deliveries through the terminal were less than five mcm/day. The owners, ConocoPhillips, had announced the closure in 2017 so we have not included it in our forecast for this winter.

Norway

Supplies for Norway were high last winter and we are expecting similar deliveries this winter. The low end of the range shown in figure 2.5 was due to an unexpected shut down for maintenance purposes.

The Aasta Hansteen field is due to start production in quarter 4 2018 and will add 23 mcm/day to Norwegian production. Production at the Troll field through the summer has been higher compared to last year.

The Norwegian offshore gas network is very flexible and increased production could support increased delivery to Continental Europe, to GB, or both, depending on the prices in the different markets.

In summary, gas supplies from the UKCS are expected to be high, and deliveries from Norway are expected to be similar to winter 2017/18.

EU and connected markets

This section explores the impact of global markets on gas flows in GB.

Key messages

- Average flows from IUK are expected to be lower due to the expiry of long-term contracts. As a result, deliveries from BBL may be price sensitive.
- Global LNG demand is rising as fast as supply and LNG delivery remains difficult to predict.

Key terms

- **BBL:** a gas pipeline running from Balgzand in the Netherlands to Bacton in the UK.
- **IUK:** is an interconnector. It is a bi-directional gas pipeline connecting Bacton in the UK and Zeebrugge in Belgium.
- **Liquefied natural gas (LNG):** natural gas that has been converted to liquid form for ease of storage or transport. It is formed by chilling gas to -161°C so that it occupies 600 times less space than in its gaseous form.
- **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 price of gas. It is usually quoted in pence per therm.
- **Title transfer facility (TTF):** A virtual trading point for natural gas in the Netherlands.

Belgium and the Netherlands

The GB network is connected to the Belgian market by the bi-directional IUK interconnector, with a capacity of 74 mcm/d. GB also receives gas from the Dutch market through the 45 mcm/day BBL interconnector.

Until 2016 both interconnectors held long term contracts with shippers that covered all the capacity in the lines. One of the BBL contracts expired in December 2016 at which point flows through BBL fell sharply. We reported on this in our *Winter Review and Consultation*, published in 2017. Last winter, the difference in price between the Dutch TTF hub and the GB NBP price was high enough to

support shorter term capacity bookings in BBL, enough for flows to reach the maximum physical capability.

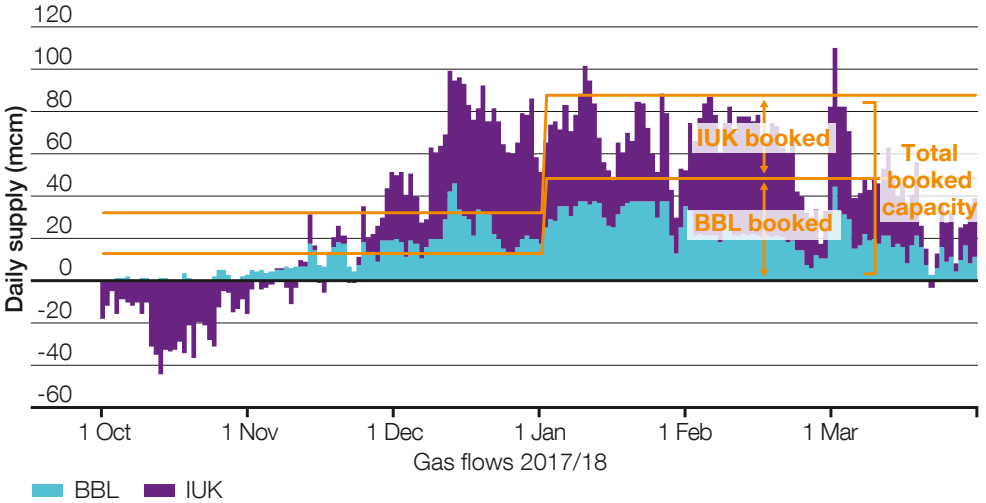
Long term contracts for capacity in IUK expired at the end of September 2018. Based on the experience at BBL in 2016, we expect that average flows through IUK will be lower this winter than last winter.

Both IUK and BBL have sold shorter term capacity in their pipelines. At the start of September, BBL had contracts covering nearly 20 mcm/d from October to December, and 39 mcm/d (87 per cent of the physical capacity of the line) for January to March. IUK had

contracts covering 13 mcm/d from October to December and 49 mcm/d (66 per cent of physical capacity) from January to March. There are further opportunities through the winter for shippers to buy capacity covering months or quarters. Capacity can also be bought for the day ahead in the short term auctions. This is more expensive than longer term contracts, but, as we saw last winter, if the price of gas in the GB market is high enough, shippers may take up this option.

In figure 2.6 we show the aggregate of the booked capacity in the two interconnectors compared with the actual flows from winter 2017/18.

Figure 2.6
Historic and forecast ranges for gas supply



In figure 2.6, we show the capacity bookings for winter 2018/19. The lines are shown as aggregate capacity; for October to December, there is 20 mcm/d for BBL and 13 mcm/d for IUK, giving a total of 33 mcm/d. We have also shown the daily flows for winter 2017/18. If imports in winter 2018/19 are similar to those shown for winter 2017/18 then the daily flows in December will be much higher than the booked capacity. Short term capacity bookings will be needed. However, from January to March

the aggregate booked capacity is much higher; 39 mcm/d at BBL and 49 mcm/d at IUK, giving a total of 88 mcm/d. Flows similar to last winter will only exceed booked capacity on a few days.

From 1 January 2018, BBL was integrated into the title transfer facility (TTF) market area. This allows shippers to transport gas between the TTF and the national balancing point (NBP) market area more cheaply and easily. On the other hand, the expiry of long term contracts in IUK means

that it will be more expensive to transport gas through IUK than it was last year. Taking these two changes together, it seems likely that BBL will be more heavily used than IUK. The greater physical capability of IUK will still be available if needed to meet high demand in GB. The balance between IUK and BBL may have changed since winter 2017/18. However, there are no suggestions that the aggregate gas supply from the two interconnectors will be inadequate.

EU and connected markets

Groningen

The Netherlands has two separate gas networks for gases of different qualities. The Groningen field produces gas with lower calorific value called L gas (or sometimes referred to as G gas). This is used for all residential heating in the Netherlands but is unsuitable for export to GB through BBL. Gas with a higher calorific value, or H gas, is produced from some Dutch fields and also imported from other countries. GB imports through BBL are all H gas.

Extraction of gas at Groningen over many decades has led to seismic activity in the Groningen area. As a result, the Dutch government has decided that production at the field should be reduced. Production will be cut from 21 bcm/year in gas year 2017/18 to 12 bcm/year by 2022/23, and should end by 2031. Production from Groningen this winter will not be governed by a simple cap. It will be dependent on the weather and will at all times be no more than is necessary to meet security of supply.

If there is a shortfall in L gas, as a result of the reduction in gas produced by the Groningen field, it can be made up by converting H gas into L gas by adding nitrogen. It is possible that using H gas in this way could leave less available for export through BBL. However, the Dutch Transmission System Operator (TSO) has published analysis¹⁶ that shows that the network is capable of transporting enough H gas to meet all the need for conversion, as well as gas for export through BBL. There should be no network reasons why gas is not available at BBL. Flows of gas will depend on the difference in price between the NPB and TTF hubs, in common with all other imports of gas.

LNG

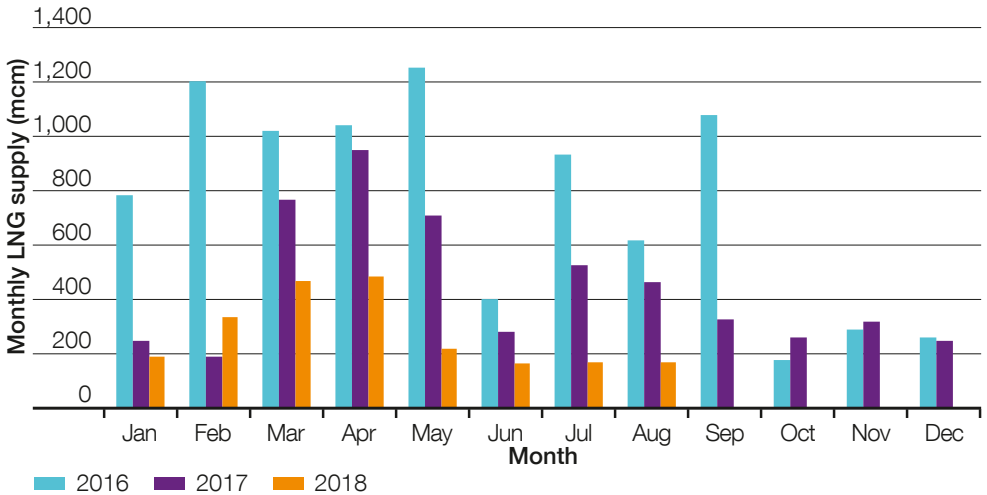
In seven out of the last eight months, supply of LNG to the network has been lower than in the same period in previous years. This is illustrated in figure 2.7. Even in April and May, months when LNG supply has usually been high, supplies were less than half the levels seen in 2017, which were already lower than 2016 values.

Demand for LNG is high in Asian markets, especially in China. Chinese demand is expected to grow as gas replaces coal in the heating sector. High demand, and associated high prices, has drawn LNG away from European markets. New supplies of LNG are being developed but demand is increasing as fast as supply. We are not expecting LNG supply to GB to be high on many days this winter, though it is likely that, if demand and price rise substantially, LNG will flow as it did at the end of February 2018.

¹⁶ <https://www.gasunie.nl/en/news/addendum-network-development-plan-2017-nop2017>

Figure 2.7

Monthly LNG supply for the last three years



There are some developments that may affect the LNG market, though it is difficult to say how these could affect deliveries to the GB market.

- China and the US are engaged in a trade war and have imposed tariffs on each other's goods. The supply of US LNG to China has been excluded so far, but if tariffs are imposed, this might reduce flows. China is a major customer for US LNG, though supplies to South Korea and Mexico are greater. If deliveries to China are disrupted, it is not clear what might happen. If the regional market is rebalanced, with supplies switching from South Korea to China, and more US LNG going to South Korea, then the impact on North West Europe would be small.
- Deliveries of US pipeline gas to Mexico are increasing. This may reduce deliveries of US LNG to Mexico and release the LNG to the global market.

- A new liquefaction terminal at Corpus Christi in Texas is due to start production during winter 2018/19. In addition, the next phase of the Sabine Pass terminal in Louisiana is expected to start producing in the fourth quarter of 2018. Gas from the testing and commissioning stages of an LNG development is usually placed on the spot market. Each of these will add five million tonnes of LNG to the market. This equates to a total of 13 bcm.
- The owners of the South Hook gas terminal have been granted a modification¹⁷ to their gas quality specification. This means that they will be able to accept LNG from a number of different sources. At the moment South Hook only receives cargoes from Qatar.

Storage

Storage is an important component of gas supply, and, like LNG and interconnectors, provides flexibility to the market. In recent *Winter Outlook reports* we have shown that both injection and withdrawal of gas in storage has increased in recent years. We are expecting that trend to continue. At [the start of September there was around 1 bcm of gas in storage.

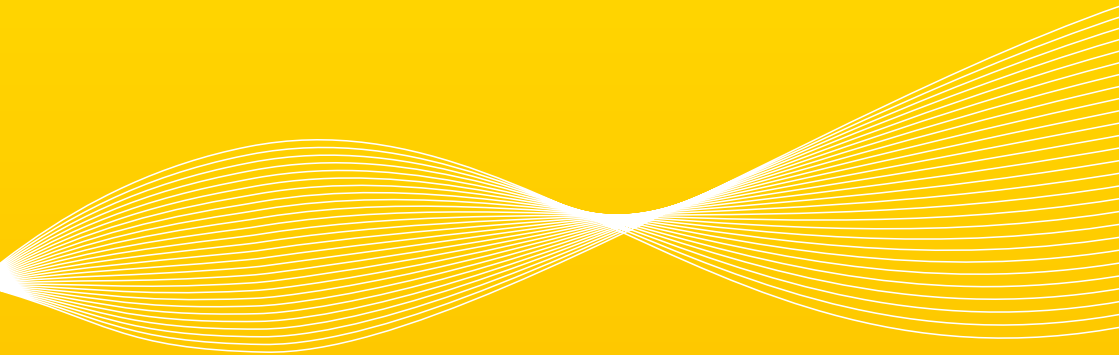
The Hole House Farm storage site was mothballed in July 2018. This has removed a total of 35 mcm of storage space while also reducing the amount of gas that can be delivered on a day by 5 mcm/d (the deliverability). The loss of storage space will be more than offset by the commissioning of new salt caverns at Stublach, which will add 100 mcm of space, though there will be no increase to deliverability.

¹⁷ <https://www.gasgovernance.co.uk/sites/default/files/ggf/book/2018-04/Representation%20-%20South%20Hook%20LNG%20Terminal%200645.pdf>

Chapter 3

Electricity and gas

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Operational toolbox	66



Electricity and gas winter outlook

This chapter explores the relationship and interdependences of the gas and electricity systems. Our whole system understanding continues to improve as we learn from operational events.

The chapter contains the following sections:

- Whole system overview
- System operability
- Operational toolbox.

Whole system overview

In this section we look at the things that have an impact on both the electricity and gas networks.

Key terms

- **Clean dark spread:** the revenue that a coal-fired generation plant receives from selling electricity once fuel and carbon costs have been accounted for.
- **Clean spark spread:** the revenue that a gas-fired generation plant receives from selling electricity once fuel and carbon costs have been accounted for.

Spotlight

Impact of changes in gas prices on gas-fired generation

Fuel switching takes place in the electricity market when the dark spread is higher than the spark spread (see key terms) and it becomes more profitable to generate electricity from coal rather than from gas. The opposite takes place when the spark spread is higher than the dark spread. There are several factors that can influence fuel switching, such as relative gas and coal commodity prices, and carbon pricing policy.

In the UK over the last three years, gas-fired electricity generation has generally been more profitable than coal-fired generation, due to a number of factors including low gas prices. However, March 2018 saw a reversal of this pattern for a short period of time. Gas prices increased dramatically in response to cold weather.

More recently, in September 2018, both the day ahead and winter 2018/19 NBP prices were at a level where we would expect

to see some fuel switching in the electricity market. This has influenced our forecast of gas-fired generation over the winter period. As a result, we anticipate there will be periods of time when it will be more profitable to generate electricity from coal than from gas. Should gas prices fall, this may no longer be the case. Latest gas price information is publicly available, at <https://www.theice.com/endex>

Spotlight

Interaction across the gas and electricity systems (1 March 2018)

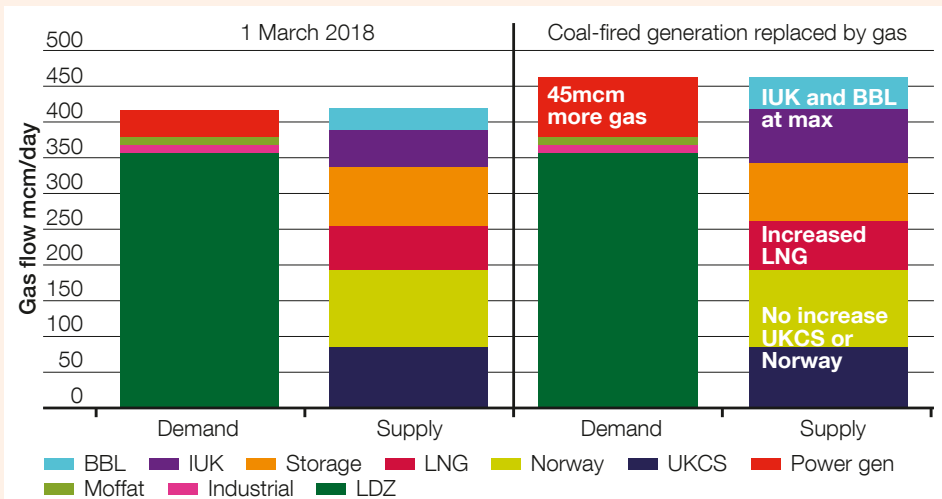
As discussed in our 2018 *Winter Review and Consultation* document, the cold weather front at the end of February 2018 brought unseasonably low temperatures and heavy snowfall. This affected GB's energy networks and assets and led to consumers turning up their heating. In addition, the cold spell fell outside of Triad season, and therefore there was no customer demand management on the electricity side.

The events of 1 March highlight one of the ways that the gas and electricity systems interact and are interdependent. In this case, supply issues affecting gas assets, alongside high demand

for gas, led to a significant gas price increase. This then led to a change in the running order of plant in the electricity market, with coal-fired generation becoming more economic to run than gas-fired generation. Coal stations generated 27% of the electricity needed for the day, and gas demand was reduced due to less gas-fired generation running. In line with government policy, unabated coal generation will be phased out by 2025. As a result, we wanted to analyse what a situation similar to 1 March 2018 would have looked like without any unabated coal generation available, in order to understand the impact on both the gas and electricity markets.

Our analysis showed that had coal-fired generation been replaced entirely by gas-fired generation on 1 March, this would have led to an additional 45 mcm of gas demand over the day. This additional demand could have been met by the IUK and BBL interconnectors flowing at their maximum, and more liquefied natural gas (LNG) being put into the system. However, this may have required associated changes to expected LNG deliveries to support continued flow.

Figure 3.1
Gas demand and supply with coal-fired generation replaced by gas





Whilst coal-fired generation could have been entirely replaced by gas, it's unlikely that we would see this exact scenario in a winter after 2025. This is because:

- by the time the coal-fired capacity has gone, there will be other electricity generation capacity in place, and it is unlikely that all of this will be gas-fired
- increasing gas demand to increase output at gas-fired generation plants would have caused the gas price to increase further. In turn, this could have led to other generation plants becoming economic to run
- an even higher gas price could also have encouraged other market response mechanisms such as demand side response.

Spotlight

How does the weather affect demand for energy?

Gas demand

In winter, there are different types of demand for gas. Some of these types of demand are more sensitive to weather, and others less so. For example, as the temperature drops, people in residential and commercial buildings will turn their heating on or up. Wind also plays a part here. Increased wind during cold weather increases the wind chill factor, and hence we feel colder when there is more wind. Gas boilers are used to heat around 80 per cent of buildings in the UK, so significantly more gas is used as heating is turned on or up across the country. As a result, this type of gas demand is very sensitive to weather.

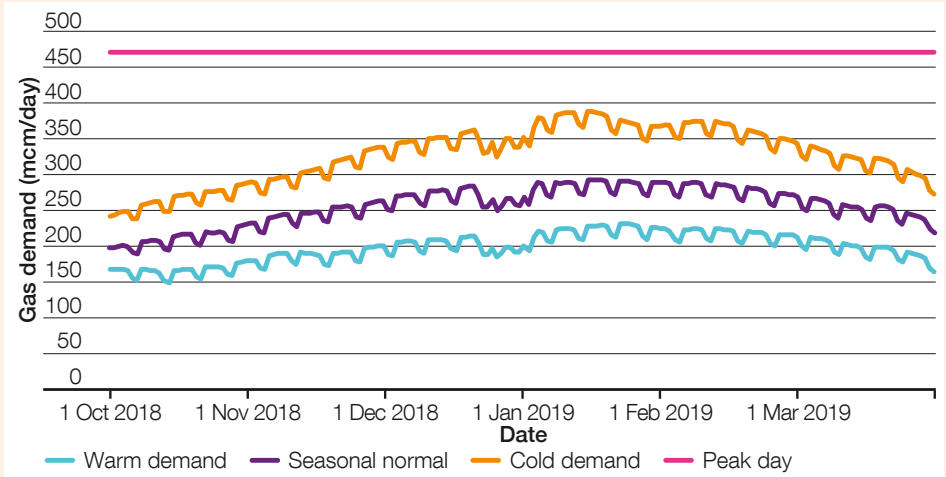
Gas used in industrial processes tends to be less sensitive to weather, as output from factories, for example, won't tend to change in line with the weather.

Gas for electricity generation is also sensitive to weather but in a different way than gas used for heating. For example, if there is little wind on one day, there will be less electricity generated by wind turbines, and so gas-fired generation may have to increase its output to fill the gap. Similarly, the make up of electricity generation will be influenced by the length and amount of sunshine on a winter's day, as this impacts how much electricity can be generated by solar panels. When forecasting gas demand in the longer term (more than a few days ahead), we assume that the weather will be normal for the time of year, a condition called seasonal normal. Figure 3.2 shows how the forecast daily gas demand for winter 2018/19 could change depending on whether the weather is colder or warmer than seasonal normal. The warm and cold demands shown are

based on smoothed 1-in-20 warm and cold weather, calculated from moving 7 day periods. There is more discussion of our representation of weather available on our [website](#). The main component of demand driving this change is a change in NDM demand as a result of temperature. Figure 3.2 also shows the anticipated demand for 1-in-20 peak conditions.

Weather corrected demand allows us to look at actual or expected demand for gas with the impact of the weather removed. It helps us to understand if there are variables other than weather that are driving a change in demand. It also allows for a clear comparison of gas demand across different years, as the effect of each year's weather is removed.

Figure 3.2
Forecast gas demands



Spotlight

How does the weather affect demand for energy?

Electricity demand

Electricity demand can be categorised into sites that are half-hourly metered (typically larger buildings and industrial sites) and non half-hourly metered – generally domestic buildings.

A much smaller proportion (around 8%) of homes and other buildings in GB use electricity for heating. So, temperature does have some impact on electricity demand for heating, for both half-hourly and non half-hourly metered sites. However, this sensitivity is much lower than for gas demand.

Unsurprisingly, the hours of darkness in a day impact electricity demand for lighting. For example, around 20% of the electricity homes use at peak time is for lighting. The hours of darkness in a day can be well predicted by season, but will also be influenced by cloud cover day to day.

The weather will also strongly impact the amount of electricity demand seen on the transmission network. This is because a significant proportion of electricity generation located on the distribution network is renewable, using the sun or wind to generate electricity. When these generators are able to generate, they can meet electricity demand in the local area, and the amount of demand seen on the transmission network will fall. Similarly, an increasing number of buildings have renewable generation located on site (for example, solar panels on roofs). When it is sunny or windy, these sites are able to generate some or all of their electricity needs, and the net electricity demand of these sites will fall.

As a result, we expect that minimum electricity demand on the electricity transmission network will move from very early in the morning (a time of very low demand) to around

2pm on a summer weekend day (when low demand coincides with high output from distributed solar generation). During winter, we would expect minimum demand to be early in the morning.

For electricity, we use a measure called 'normalised demand' to consider expected demand for electricity with the impact of the weather removed. This is a forecast 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 demand could be with the effect of the weather removed.

System operability

This section focuses on some of the operational challenges and conditions that we have faced during previous winters. These challenges influence how we adapt the way we operate the gas and electricity networks.

Headlines

For gas:

- In response to our winter consultation, we explore in more detail the supply and demand behaviour during the highest linepack swing day of 2018.
- We expect variations in network pressures to continue as a result of volatility in supply and demand patterns.

For electricity:

- We compare key statistics from the last cold winter in 2012 with winter 2017/18's unseasonably cold weather.

Key terms

- **National transmission system (NTS):** the high pressure gas transportation system consisting of compressor stations, pipelines, multi-junction sites and offtakes. Pipelines transport gas from terminals to offtakes and are designed to operate up to 94 barg.
- **Linepack:** the volume of gas within the national transmission system pipelines at any time.
- **Linepack swing:** the difference between the amount of gas in the system at the start of the day and at the lowest point during the day.
- **Instantaneous supply/demand:** supply/demand position at a given moment in time.
- **End of day balance:** the net position of supply and demand at the end of the gas day.

Electricity

Figures 3.3 and 3.4 illustrate how the energy landscape has changed in the last five years. The infographics detail a comparison of winter conditions, operational strategies and energy levels for winter 2012/13 and 2017/18 and the corresponding peak day for each.

Comparing the peak day, in figure 3.4, we see that although winter 2012/13 was warmer, demand was 5.7 GW higher than in winter 2017/18. The main contributors are the efficiency gains of appliances (such as lighting)

and the substantial increase in embedded generation. In figure 3.3 and 3.4, we see that both peak and seasonal transmission demands have dropped over the last 5 years mainly because of this.

Unsurprisingly, coal generation in 2012/13 has largely been replaced by gas generation in 2017/18. This is as a result of the large combustion plant directive (LCPD) and increasing carbon prices.

In winter 2012/13 on the peak day demand, an operational

notice (NISM) was issued for the purpose of alerting industry to our forecast position and requesting additional capacity to be made available. However, no notification was issued on the peak day in winter 2017/18. This would indicate that in 2017/18, the margin was sufficient to accommodate the demand level.

What is evident is how much the generation mix has changed in a short period of time. This would indicate that managing future imbalances might be quite a different story as the energy landscape continues to evolve.

System operability

Figure 3.3
Winter transmission energy

Winter 2012/13 152 TWh	Vs	Winter 2017/18 128 TWh
5.5°C	 Average temperature	6.3°C
43%	 Coal	12%
24%	 Gas	42%
19%	 Nuclear	20%
5%	 Wind	14%
2%	 Hydro	2%
4%	 Interconnectors	6%
3%	 Biomass	4%

Figure 3.4
Winter peak day

2012 12 Dec 17:30	Vs	2018 1 Mar 18:30
56.4 GW	 Transmission Demand	50.7 GW
-0.6°C	 Average temperature	-1.6°C
38%	 Coal	22%
36%	 Gas	32%
13%	 Nuclear	13%
1%	 Wind	20%
4%	 Hydro	5%
2%	 Interconnectors	5%
4%	 Biomass	3%



Gas Case study

The causes and consequences of the high linepack swing on 1 March 2018

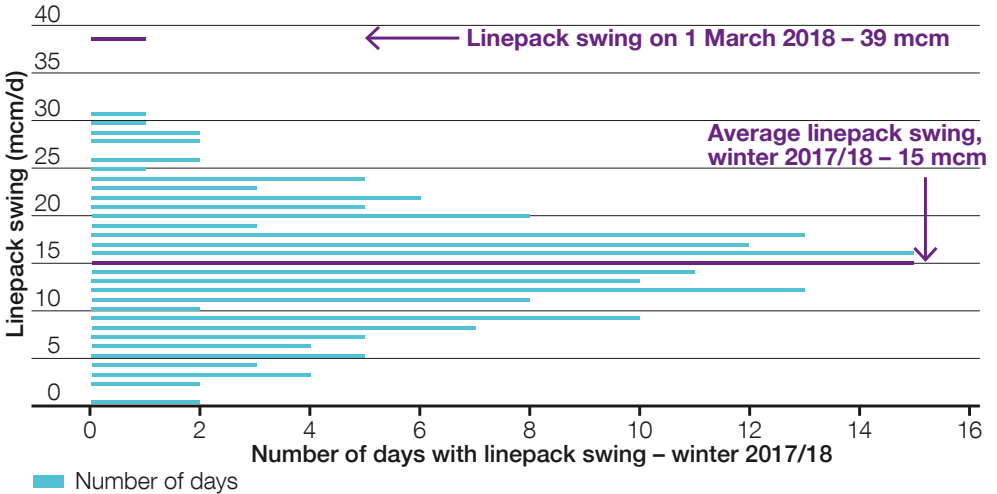
In our 2018 *Winter Review and Consultation* document, we published a case study looking at the events of 28 February through to 2 March. During this time, the NTS experienced its highest ever linepack swing of 39 mcm. In response to your feedback we explore the supply and demand behaviours that led to this very large swing, and examine the implications.

The amount of gas within the NTS at any time is known as linepack. Linepack levels can change as shippers put gas into the NTS and take it out. This affects the pressure of the gas within the pipes. If more gas is being put into the system than is being taken out, the pressure will rise, and vice versa.

The impact of linepack swing on gas pressures will be different in different locations. Typically, there will be a greater impact for areas that are located at the periphery of the network. As System Operator, it is our responsibility to ensure that gas pressures stay within safe limits at all times.

Figure 3.5 shows the differing levels of linepack swing in winter 2017/18 along with the number of occurrences. With an average swing of 15 mcm/d across the whole winter, this would suggest that the 39 mcm/d linepack swing experienced on 1 March is an outlier. It represents nearly three times the average linepack swing for that winter, and is significantly higher than the next highest linepack swing experienced during winter 2018.

Figure 3.5
Levels of linepack swing and the number of occurrences



Gas Case study cont.

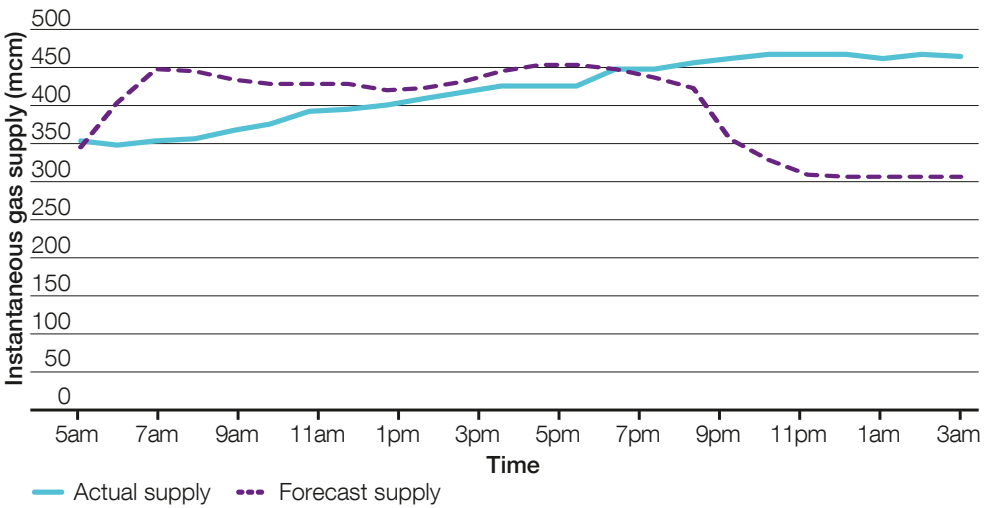
What happened?

At 10pm on 28 February 2018, the predicted linepack swing for the following day was 14 mcm. However, there were a number of supply losses overnight. During the early hours of gas day 1 March, very low temperatures

contributed to the formation of ice on many offshore platforms. This led to issues with asset operation and resulted in offshore supply losses. As a result, forecast supply for 1 March was much lower than expected, particularly in the first part of the day.

However, later in the day, as gas prices rose, gas flowed into GB through the interconnectors. As assets were brought back on line, more gas was able to flow into the NTS from the UK Continental Shelf and Norway.

Figure 3.6 Instantaneous supply gas day 1 March



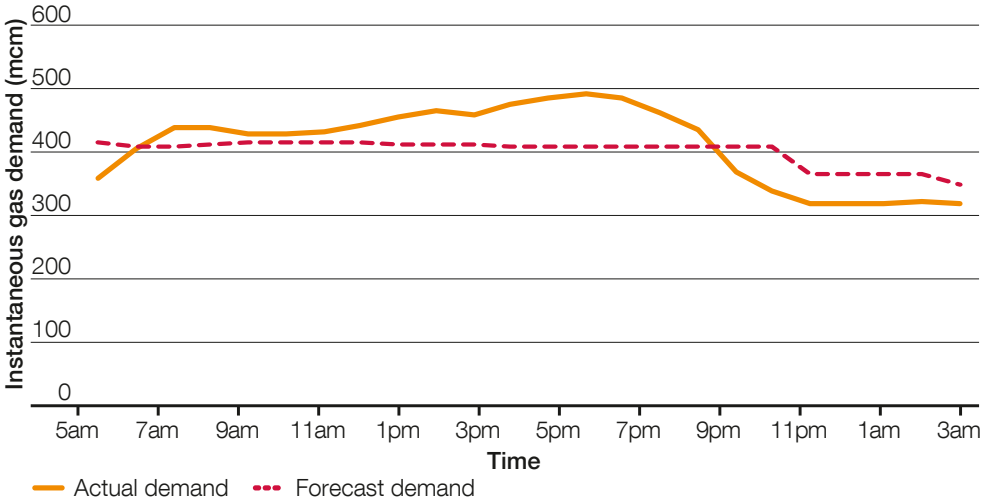
On the distribution network, gas demand was revised upwards. This was because the very cold

weather meant that people were expected to stay at home, resulting in increased residential

gas demand between 8am and 10pm.

Gas Case study cont.

Figure 3.7
Instantaneous demand 1 March



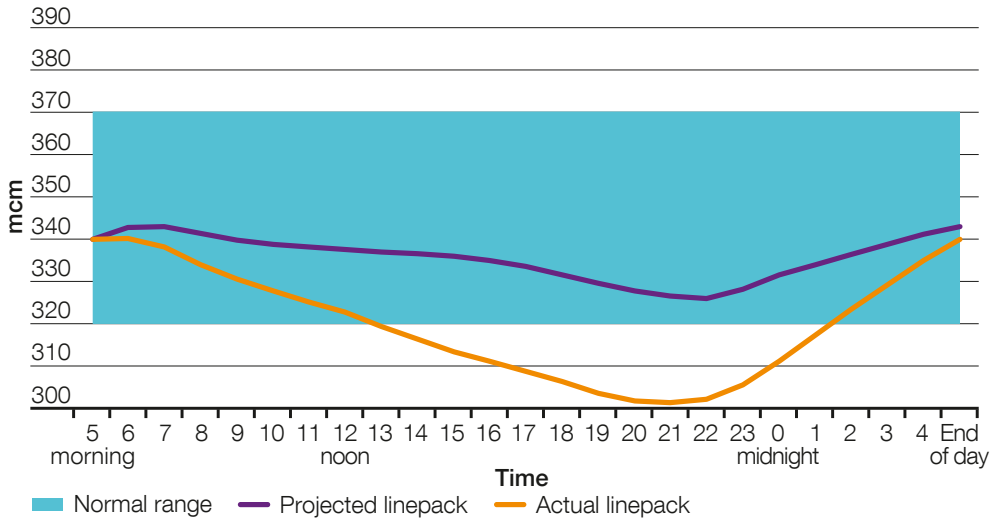
The lower than forecast levels of supply in the early part of the day, and the increasing level of

demand in the middle of the gas day, meant there was a long period of significant imbalance

between supply and demand. This led to linepack being depleted.

Gas Case study cont.

Figure 3.8
Linepack swing



At around 9pm, linepack began to increase. The events of the day led to an extreme linepack swing of 39 mcm.

Consequences

The continued depletion of linepack in the early part of 1 March led to a steady decrease in operating pressure on the NTS throughout the day. Eventually this led to the lowest ever recorded linepack (and hence pressure) on the NTS, at around 9pm. Without adequate gas pressure on the NTS, it becomes more difficult to move gas to where it is needed.

As pressure on the NTS fell on 1 March, it became more challenging to keep the compressor fleet running in sub-zero temperatures with gas at pressures well below normal operating levels.

Despite these operational challenges, we were able to maintain delivery of gas and uphold offtake pressures.

Operational toolbox

As the System Operator, we can issue a range of notifications to the market to raise awareness of system conditions. Some of the operational notices that can be issued in more challenging conditions are described in this section.

Key electricity messages:

- There are no changes to the electricity operational notifications expected this winter.

Key gas messages:

- We are reviewing the Gas Deficit Warning and Margins Notice in consultation with industry.
- The aggregated Operating Margins booking for 2018/19 is 676GWh, with maximum deliverability of 540GWh/day.
- The preliminary safety monitor storage space requirement for winter 2018/19 has been set at 429GWh¹⁸ of space, with deliverability of 387GWh/day. National Grid will keep the safety monitor under review both ahead of and throughout the winter.

Key terms

- **Space and deliverability:** The holding capacity of a facility is referred to as 'space' and the rate at which gas can be withdrawn from the facility is referred to as 'deliverability'.

¹⁸To convert GWh to mcm divide by 11.

Operational toolbox

Electricity notices

The Capacity Market (CM) was introduced by the UK Government as part of the Electricity Market Reform (EMR) programme. It aims to ensure the future security of our electricity supply by providing a payment for reliable sources of capacity, alongside electricity revenues, to ensure the delivery of energy when it's needed. With the introduction of the CM came two new notifications which we can use to manage security of supply. Here we provide you with an explanation of each to remind you of the tools we may call upon during times of system stress. We have also provided some important links to further information and to our dedicated [website](#).

Electricity margin notice (EMN)

The EMN is the first of the hierarchy of notifications issued by National Grid to manage security of supply.

It is part of the first level of operational notifications issued at times of system stress. An EMN can be issued any time by our Control Room via our BM Reports, but is usually within 24 hours of the expected period of tightness. It is a routine tool that is designed to inform the industry of the forecasted position and to request additional capacity to be made available. Additional capacity is mostly required for the evening peak demand period.

In response to an EMN being issued, we would typically expect more plant to be made available

to the market and existing plant to run more reliably. In most cases, this would prevent the need for further action and allow the notification to be withdrawn later.

If the market does not respond when an EMN is issued, or the response is not enough, there are a number of further actions that we can take. If all market options have been exhausted, we can then use other services, such as maximum generation. This is a request made to power stations to generate at their highest possible output, in excess of normal technical and commercial parameters.

High risk of demand reduction (HRDR)

An HRDR notification is an early notification to inform Distribution Network Operators (DNO) and transmission connected customers of the increased risk of a demand reduction and the location of that potential reduction. Industry participants are required to prepare their demand reduction arrangements.

Capacity Market notice (CMN)

A decision to issue a CMN is based on data provided by industry participants. A calculation predicts the shortfall between forecast volumes of demand on the electricity transmission system (plus the volume of operating margin held in reserve by National Grid) and the supply declared by generators. If there is a risk of a national shortage of generation (500MW or less), National Grid generate an automated notice four hours in advance. The market is expected to respond

to this notice by adjusting its position, with providers either delivering energy or reducing demand against their agreement.

Capacity providers are required to meet their capacity obligations. Failure to do so will result in financial penalties. Alternatively, if they over-deliver on their obligations, they may be eligible for additional payments.

There is no formal dispatch mechanism in the CM. In the event of a CMN being issued, we recommend that industry participants make themselves aware of further operational information available to the industry closer to the notice activation time. These include, for example, the [BM reports website](#).

A CMN will be issued by National Grid via a dedicated website www.gbcmn.nationalgrid.co.uk/. All industry participants and stakeholders can view this website. They can also subscribe for automated email and SMS alerts. The CMN can be cancelled if the situation improves, based on data being updated in real time.

More information can be found at: www.emrdeliverybody.com/cm/home.aspx

www.ofgem.gov.uk/electricity/wholesale-market/market-efficiency-review-and-reform/electricity-market-reform/capacity-market-cm-rules

<https://gbcmn.nationalgrid.co.uk/faq> www.bmreports.com

Demand control imminent (DCI)

A DCI notice may be issued to provide short-term notice when a demand control instruction is expected in the following thirty minutes. The warning is sent to the DNOs and transmission connected demand that a DCI has been published on the **BM reports** website.

Demand control instruction

This instruction can be spread nationally to manage a system margin shortfall or concentrated locally, for other system operation challenges, to limit the consequences on the wider network. The instruction will contain the level of reduction required to avoid the shortfall and specifies the demand control stages required. The DNO can reduce voltage on its network without affecting customer supplies and, in subsequent stages, they can disconnect portions of demand. The instruction can relate to up to 40 per cent of the DNO's total demand and is split into stages of voltage reduction and demand disconnection.

Gas notices

National Grid's role

In our role as System Operator of the high pressure gas network, we act as Residual Balancer. This means that we must ensure the overall balance of gas on the NTS is within safe physical operating limits at all times. A selection of operational tools can be used to achieve this, including some that are mainly used when conditions on the network are more challenging.

Gas Margins Notice (MN)

A Margins Notice is a day-ahead announcement to the market indicating there is a potential gas supply and demand imbalance for the next gas day. The MN is designed to encourage NTS users to reassess their balancing position against the forecasts in the rolling Daily Margins report. The daily margin notice gives all energy industry participants a rolling five day view of gas supply and demand, as well as data relating to the storage safety monitors, and is published on our **website**.

Once an MN notice has been issued, it cannot be withdrawn and will stay in place until the end of the gas day to which it applies, unless it is superseded by a Gas Deficit Warning.

A review of the Margins Notice process is currently underway.

Gas Deficit Warning (GDW)

The purpose of a GDW is to provide a message to GB market participants to provide more gas or reduce demand. We will issue a GDW if there is a shortfall in gas supply compared to gas demand that presents a material risk to the end of day system balance.

There are no predefined triggers for a GDW, which is based on the judgement of the Gas National Control Centre. A GDW was issued for the first time on 1 March 2018, as discussed in our 2018 *Winter Review and Consultation* document.

Both the MN and the GDW processes are described in more detail on our **website**¹⁶.

An update to the gas Margins Notice and Gas Deficit Warning consultation

As discussed in our 2018 *Winter Review and Consultation* document, we have engaged with industry to review the gas Margins Notice and GDW processes to see if they can be improved. Any proposal for change would need to be appropriately justified and balanced against any costs of implementation and wider impacts.

This issue was discussed at the July and August 2018 meetings of the Transmission Workgroup, and the following questions were considered:

- How could the forecasts used for the Margins Notice be improved?
- Is there further information that customers and stakeholders could provide that would improve processes and forecasts?

¹⁶ <https://www.nationalgrid.com/uk/gas/balancing/margins-notices-mn-and-gas-deficit-warnings-gdw>.

Operational toolbox

- Do the current notices provide the right information to allow market players to take timely action?
- Should the names of notifications be changed?
- Should demand side response arrangements be reformed?

A number of industry parties have contacted us with their views and support of a review of these processes. National Grid raised a request proposal UNC669R Review of the Gas Deficit Warning (GDW) and Margin Notice (MN) Arrangements on 7 September that seeks a review of the processes, timeliness and information provision associated with our gas security of supply notices. It also seeks to review the name of the Gas Deficit Warning notice, as it considers this may not adequately reflect its purpose and could be misinterpreted by the public. The request for review follows the use of the GDW on 1 March this year. Also, we recognised changes in the electricity market since the current arrangements were introduced as additional drivers for a review.

Alongside this work, we will review the demand side response arrangements that are currently in place for the gas market.

Further detail will be available via the Transmission Workgroup, for more information please see <https://www.gasgovernance.co.uk/tx>

Operating margins (OM)

OM is an amount of gas that we purchase each year. OM gas can be used in the immediate period following operational stresses to maintain system pressures in the period before other balancing measures become effective. It can also be used to ensure the safe shutdown of the gas system in the event of a Network Gas Supply Emergency.

The full criteria for the use of OM are set out in the System Management Principles Statement available at <https://www.nationalgrid.com/sites/default/files/documents/System%20Management%20Principles%20Statement%20-%20Effective%20April%202017.pdf>

We have obligations under the UNC and the Safety Case to maintain OM at various levels and at various locations throughout the year.

Further information about operating margins can be found on our [website](#).

Safety monitor

The safety monitor describes an amount and deliverability of gas that needs to remain in storage over the winter period in order to supply customers that cannot be safely or immediately isolated from the gas network. The safety monitor calculates how much gas is required to supply these customers across the whole of a severe 1-in-50 winter. The safety monitor exists to maintain the safe operation of the gas system by maintaining adequate pressures on the network, rather than to support security of supply.

The space requirement of the safety monitor is made up of the 'protected by monitor' and 'protected by isolation' elements:

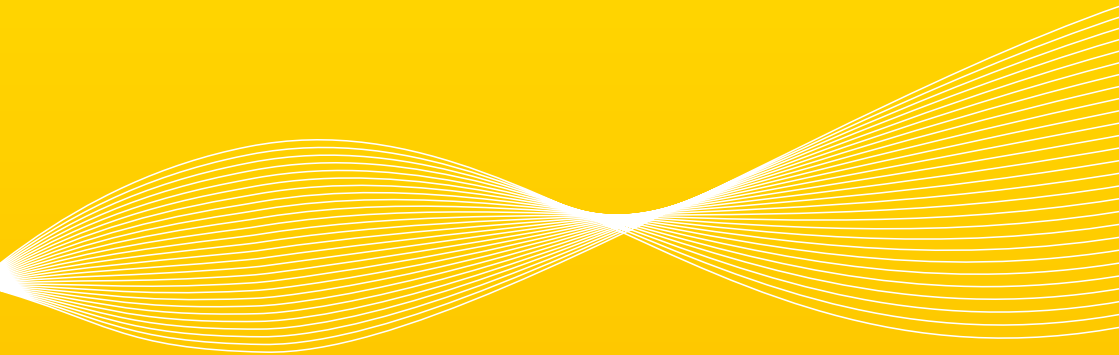
- Protected by monitor applies to sites that cannot be safely isolated from the gas network, for example domestic properties. Where there is not enough non-storage supply across the winter to meet this demand, this is the volume of gas that needs to be available in storage to ensure these properties are never isolated from the network.
- Protected by isolation applies to sites that could be safely isolated from the gas network, but not immediately. As a result, there is an additional gas demand associated with the time it would take to safely isolate them from the gas network.

The total space requirement from these two elements is then divided across storage facilities. There has not been a breach of the safety monitor level since it was introduced in 2004.

National Grid sets a preliminary safety monitor well ahead of the winter period, with a further update in the autumn. This is then kept under review for the whole winter. You can find more information about the safety monitor on our [website](#). The preliminary safety monitor storage space requirement for winter 2018/19 has been set at 429GWh of space, with deliverability of 387 GWh/day.

Chapter 4

Glossary



Glossary

Word	Acronym	Section	Description
Average cold spell	ACS	Electricity	ACS methodology takes into consideration the variability in weather due to people's changing behaviour, e.g. more heating demand when it is colder and the variability in weather dependent demand distributed generation e.g. wind generation. These two elements combined have a significant effect on peak electricity demand.
'Behind the meter' generation			It is a way businesses can reduce their energy costs by generating their own power generally via a renewable energy generating facility, e.g. solar PV.
BBL	BBL	Gas	A gas pipeline between Balgzand in the Netherlands and Bacton in the UK. You can find out more at www.bblcompany.com
billion cubic metres	bcm	Gas	Unit of volume used in the gas industry. 1 bcm = 1,000,000,000 cubic metres
BritNed		Electricity	BritNed Development Limited is a joint venture between Dutch TenneT and British National Grid that operates the electricity link between Great Britain and the Netherlands. It is a bi-directional interconnector with a capacity of 1,000MW. You can find out more at www.britned.com
Capacity Market	CM	Electricity	The Capacity Market is designed to ensure security of electricity supply. This is achieved by providing a payment for reliable sources of capacity, alongside their electricity revenues, ensuring they deliver energy when needed.
Capacity bookings		Gas	Shippers can buy rights to flow gas into (or offtake gas from) the NTS by buying NTS pipeline 'capacity'. Entry capacity delivers gas and NTS exit capacity offtakes gas. A shipper needs to hold one unit of capacity in order to flow one unit of energy onto (or off) the system. This is known as the 'ticket to ride' principle.
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 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.
Customer demand management	CDM	Electricity	Where industrial or commercial users change their pattern of energy consumption. This may be to avoid using energy at peak times.
Darkest peak		Electricity	Peak half-hourly demand between 5pm and 7.30pm during Greenwich Mean Time.
Daily metered	DM	Gas	A classification of customers where gas meters are read daily. These are typically large scale consumers.
De-rated capacity		Electricity	De-rated capacity is the capacity of generation reduced to best reflect what is expected to be available in real-time. The reduction is to account for unexpected outages or breakdowns and other restrictions to the generators which is based on historic performance.



Word	Acronym	Section	Description
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.
Distribution connected generation		Electricity	Any generation that is connected directly to the local distribution network, as opposed to the transmission network. It includes combined heat and power schemes of any scale. Generation that is connected to the distribution system is not usually directly visible to National Grid and acts to reduce demand on the transmission system.
East West Interconnector	EWIC	Electricity	A 500MW interconnector that links the electricity transmission systems of Ireland and Great Britain. You can find out more at www.eirgridgroup.com/customer-and-industry/interconnection/
Embedded generation		Electricity	Power generating stations/units that don't have a contractual agreement with the national electricity transmission System Operator (NETSO). They reduce electricity demand on the transmission system.
Equivalent firm capacity	EFC	Electricity	An assessment of the entire wind fleet's contribution to capacity adequacy. It represents how much of 100% available conventional plant could theoretically replace the entire wind fleet and leave security of supply unchanged. EFC is currently assumed to be 22%.
European Union	EU	Various	A political and economic union of 28 member states.
Export		Various	Interconnectors flowing out of GB.
Firm NTS capacity		Gas	Capacity purchased by market participants that is financially and contractually guaranteed to be available. However, events like plant or equipment failure may mean we can't honour our commitment.
<i>Future Energy Scenarios</i>	FES	Various	The <i>FES</i> is a range of credible pathways for the future of energy out to 2050. They form the starting point for all transmission network and investment planning, and are used to identify future operability challenges and potential solutions. You can find out more at http://fes.nationalgrid.com/
Gigawatt	GW	Electricity	A measure of power. 1GW = 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.
Import		Various	Interconnectors flowing into GB.
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).
Interconnector		Electricity	Electricity interconnectors are transmission assets that connect the GB market to Continental Europe. They allow suppliers to trade electricity between these markets.
Interconnexion France-Angleterre	IFA	Electricity	The England-France Interconnector is a 2,000MW link between the French and British transmission systems. Ownership is shared between National Grid and Réseau de Transport d'Electricité (RTE).
LDZ demand		Gas	Local distribution zone (LDZ) demand refers to the total amount of gas used by gas consumers connected to the distribution networks.
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.

Glossary

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/
Load		Various	The energy demand experienced on a system.
Loss of load expectation	LOLE	Electricity	Used to describe electricity security of supply. It is an approach based on probability and is measured in hours/year. It measures the risk, across the whole winter, of demand exceeding supply under normal operation. This does not mean there will be loss of supply for 3 hours per year. It gives an indication of the amount of time, across the whole winter, which the System Operator (SO) will need to call on balancing tools such as voltage reduction, maximum generation or emergency assistance from interconnectors. In most cases, loss of load would be managed without significant impact on end consumers.
Medium-range storage		Gas	Gas storage sites that have short injection/withdrawal times. This means they can react quickly to demand, injecting when demand or prices are lower and withdrawing when they are higher.
Megawatt	MW	Electricity	A measure of power. $1\text{ MW} = 1,000,000\text{ watts}$.
Million cubic meters	mcm	Gas	Unit of volume used in the gas industry. $1\text{ mcm} = 1,000,000\text{ cubic metres}$.
Moyle		Electricity	A 500MW 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 Britain and nearby offshore waters. It is owned and maintained by regional transmission companies, while the system as a whole is operated by a single System Operator (SO).
National transmission system	NTS	Gas	A high pressure gas transportation system consisting of compressor stations, pipelines, multi-junction sites and offtakes. Pipelines transport gas from terminals to offtakes and are designed to operate up to pressures of 94 barg.
Non-daily metered	NDM	Gas	A classification of customers where gas meters are read monthly or at longer intervals. These are typically residential, commercial or smaller industrial consumers.
Non-storage supply	NSS	Gas	All gas supplies to the national transmission system storage.
Normalised demand		Electricity	Demand assessed for each week of the year based on a 30 year average of each relevant weather variable. This is then applied to linear regression models to calculate what the demand would have been with this standardised weather.

Word	Acronym	Section	Description
Negative reserve active power margin	NRAPM	Electricity	The insufficient NRAPM warning is a request to encourage more flexible parameters from generators, and inform participants of a risk of emergency instructions. A NRAPM may be issued if there is insufficient flexibility available to ensure that generation matches demand during periods of low demand. A localised NRAPM occurs where there is a danger that the combination of demand and inflexible generation within a constraint group can exceed the constraint limit of a portion of the network; in both cases there is a risk that NG may need to issue emergency instructions to inflexible and non-BM participating plant. Localised NRAPM are more common in the north of Scotland due to the large volume of wind and water generation and relatively low demand.
Net import/export			The sum of total generation flowing via interconnectors either into or out of GB.
Off peak firm capacity		Gas	Off peak capacity is made available to the market at offtake points where it can be demonstrated that firm capacity is not being utilised.
Operational Code 2 data	OC2	Electricity	Information provided to National Grid by generators. It includes their current generation availability and known maintenance outage plans. You can access the latest OC2 data throughout the year on the BM Reports website at www.bmreports.com
Opening linepack	OLP	gas	The amount of gas in the NTS at the start of the gas day.
Open cycle gas turbine	OCGT	Various	Gas turbines in which air is first compressed in the compressor element before fuel is injected and burned in the combustor.
Peak		Various	The maximum requirement of a system at a given time, or the amount of energy required to supply customers at times when need is greatest. It can refer either to a given moment (e.g. a specific time of day) or to an average over a given period of time (e.g. a specific day or hour of the day).
Profiling		Gas	The rate at which gas is put into or taken off the transmission system during the gas day. A flat profile corresponds to a consistent rate across the day.
Reserve		Electricity	<p>National Grid currently manages different types of reserve in order to maintain system security under a range of credible scenarios. Reserve can be thought of as the requirement for a total amount of head room (positive reserve) and foot room (negative reserve) provided across all generators synchronised to the system.</p> <p>Reserve is required to:</p> <ul style="list-style-type: none"> • account for errors in demand, wind and solar forecasting • cover demand and generation losses in the period from day ahead to real time, and • facilitate the holding of high frequency dynamic response. <p>In the future, the requirement to hold reserve is likely to increase. This is because of the continued growth in solar PV capacity and the need to manage the additional variability in demand between four hours ahead and real time.</p>
Residual balancer		Gas	Users of the gas system are incentivised to balance supply into, and demand from, the network. If this balance is not expected to be achieved on any given day, the System Operator (National Grid), as residual balancer, will enter the market and undertake trades (buys or sells) to seek to resolve any imbalance.
Seasonal normal demand		Gas	The level of gas demand that would be expected on each day of the year. It is calculated using historically observed values that have been weighted to account for climate change.
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.

Glossary

Word	Acronym	Section	Description
Station load		Electricity	The onsite power station requirement, for example for systems or start up.
System Operator	SO	Various	An entity entrusted with transporting energy in the form of natural gas or electricity on a regional or national level, using fixed infrastructure. The SO may not necessarily own the assets concerned. For example, National Grid operates the electricity transmission system in Scotland, which is owned by Scottish Hydro Electricity Transmission and Scottish Power.
Transmission system demand	TSD	Electricity	Demand that National Grid as System Operator sees at grid supply points (GSPs), which are the connections to the distribution networks. It includes demand from the power stations generating electricity (the station load).
Triad		Electricity	Triads are the three half-hourly settlement periods with the highest system demand. Triads can occur in any half-hour on any day between November and February. They must be separated from each other by at least ten days.
Triad avoidance		Electricity	Triad avoidance occurs when some industrial and commercial users reduce their electricity consumption when demand is expected to peak, in order to avoid transmission charges.
Title transfer facility	TTF	Gas	A virtual trading point for natural gas in the Netherlands.
Underlying demand		Electricity	A measure of demand that removes the effect of weather and the day of the week.
UK Continental Shelf	UKCS	Gas	The UK Continental Shelf (UKCS) comprises those areas of the sea bed and subsoil beyond the territorial sea over which the UK exercises sovereign rights of exploration and exploitation of natural resources.
United Kingdom of Great Britain and Northern Ireland	UK	Various	A geographical, social and economic grouping of countries that contains England, Scotland, Wales and Northern Ireland.
Weather corrected demand		Electricity	The demand expected or out turned with the impact of the weather removed. A 30 year average of each relevant weather variable is constructed for each week of the year. This is then applied to linear regression models to calculate what the demand would have been with this standardised weather.
Weather corrected demand		Gas	The demand expected with the impact of weather removed. Actual demand is converted to demand at seasonally normal weather conditions, by multiplying the difference between actual CWV and expected CWV by a value that represents demand sensitivity to weather.
<i>Winter Review and Consultation</i>	WRC	Various	The <i>Winter Review and Consultation</i> document is our annual report comparing winter forecasts with what actually happened. The review is designed to help industry to understand what happened and begin to prepare for the winter ahead. The purpose of the consultation is to gather valuable stakeholder insight in order to inform our analysis for the <i>Winter Outlook Report</i> .
Within-day		Gas	Defined as any operation that takes place during the 'gas day' (05:00 hrs to 04:59 hrs).

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