Summer Outlook

2019

The *Summer Outlook Report* is an annual publication delivered by National Grid each spring. It presents our view of the gas and electricity systems for the summer ahead (April to September).

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

nationalgridSO

How to use this interactive document

Welcome

Thank you for reading our Summer Outlook report. As we look forwards to this summer, we are confident that there will be sufficient energy available to meet demand, and that we have the right tools in place to manage operability in all scenarios.

This year, we have responded to stakeholder feedback by trialling a new format for this document. We want to ensure that the *Summer Outlook* is as clear and succinct as possible, without losing the richness of the data that underpins our analysis.

In order to do this, we have produced a concise executive briefing pack. This aims to quickly put across key messages from the *Summer Outlook*, through interactive graphics. Accompanying this, we have produced an in-depth data workbook, with additional analysis that we know is valued by our stakeholders. We hope that this new format will enable you to interact with the *Summer Outlook* report in a way that meets your needs.

From 1 April 2019, the *Electricity System Operator (ESO)* will be a new legally separate company that will carry out our ESO function within the National Grid Group. Whilst this will provide focus to our electricity activities, facilitating whole system outcomes is also one of our key roles as an ESO going forward.

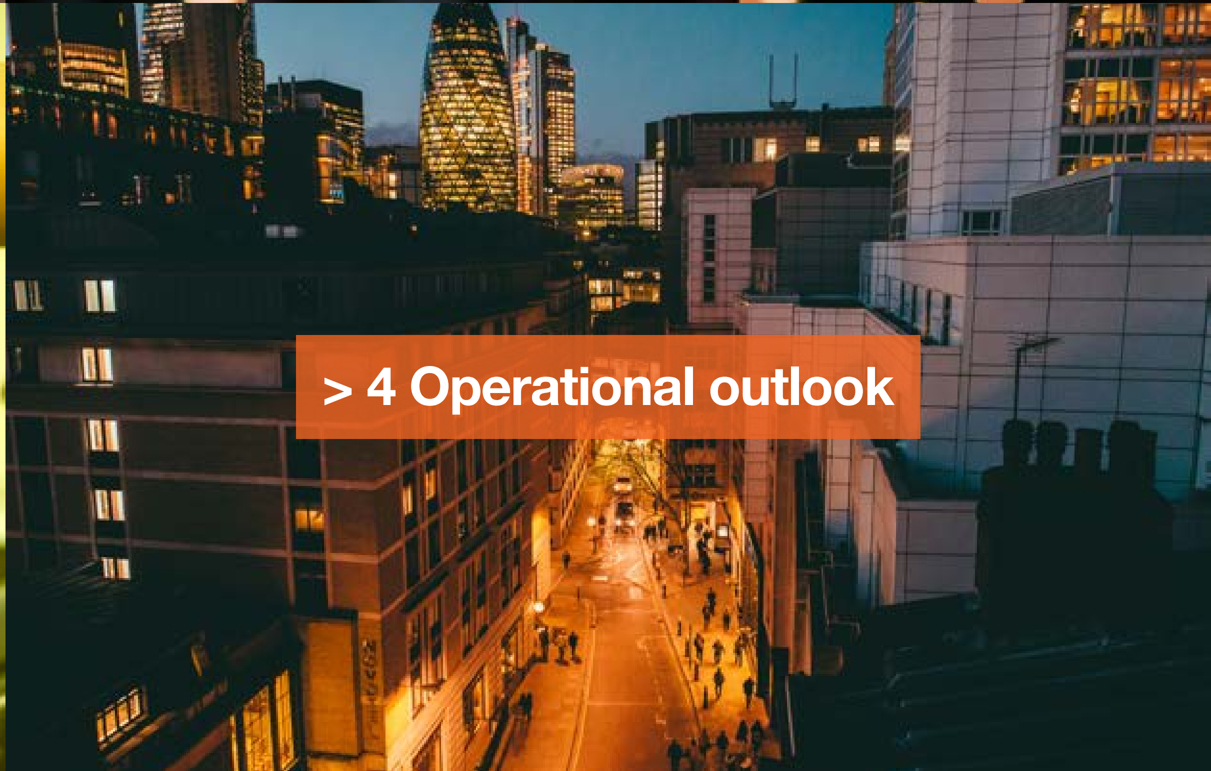
As we tackle the key energy challenges ahead of us, we expect to see increasing interactions between gas and electricity markets and operations. For this reason, documents such as the *Summer* and *Winter Outlooks* will continue to be produced on a dual fuel basis and we will continue to draw out and explore whole energy system themes in this year's *Summer Outlook*.

As always, we would really welcome your feedback so we can ensure our documents are as useful as possible. Email us at **marketoutlook@nationalgrid.com**, or you can join the conversation using social media via LinkedIn, Facebook and Twitter.

Fintan Slye
Director UK System Operator

Summer Outlook 2019

How to use this interactive document



1 Executive summary

Overview
Executive summary

1

We are confident that there will be sufficient supply available to meet energy demands for the coming summer. We anticipate similar gas and electricity demands to summer 2018.

2

We have the right tools and services available to manage operability for the coming summer, particularly during periods of low demand, or when access requirements increase for delivery of key maintenance work.

3

Whole system thinking is becoming increasingly important as long term trends of decarbonisation and decentralisation drive increased interaction between the gas and electricity transmission systems. In the short term this is primarily due to gas fired electricity generators balancing the intermittent output of renewable electricity generators.

4

We anticipate no additional operability challenges for this coming summer as a result of the UK's planned exit from the EU. We have tested our planning assumptions in a broad range of scenarios and via engagement with industry. These scenarios fall within our normal contingency planning.

Supply and demand
Executive summary

We are confident that there will be sufficient supply available to meet energy demands for the coming summer. We anticipate similar gas and electricity demands to summer 2018.

Electricity Demand – weather corrected demand seen on the transmission system at both a peak and minimum level will be similar to last summer, as the recent trend of increasing solar generation has slowed. Generation that is not connected to the transmission network (such as the majority of solar generation) reduces transmission demand as more demand is met locally.

Electricity Supply – we will be able to meet demand and our reserve requirement at all times throughout summer 2019 under all interconnector scenarios.

We do not think it is likely that we will need to instruct inflexible generation to reduce output in weeks when demand is low. However should this be necessary we have the tools to do so.

Gas Demand – during the summer gas fired electricity generation becomes a more significant component of GB demand, unlike winter when domestic heating dominates. This drives profiles to become more variable in line with renewable generation. We also anticipate greater levels of transit gas than last summer in response to market conditions.

Gas Supply – we anticipate increased liquefied natural gas (LNG) deliveries compared to last summer. Whilst this could provide competition for other supply sources, it is likely to result in greater transit flows to the continent.

Key statistics, electricity	
Electricity transmission peak demand	33.7 GW
Electricity transmission minimum demand	17.9 GW
Minimum available generation	39.8 GW

Key statistics, gas	
GB gas demand	25.2 bcm
Total gas demand	36.1 bcm

Above demand forecasts are weather corrected.

Operational outlook

Executive summary

We have the right tools and services available to manage operability for the coming summer, particularly during periods of low demand or when access requirements increase for delivery of key maintenance work.

Key messages – electricity

- Low transmission demand and high volumes of low inertia generation can cause operational issues over the summer.
- We will need to take day-to-day actions to manage system frequency in times of low demand. Usually this will involve working with flexible generation to reduce supply.
- Managing reactive power and voltage levels will continue to be challenging. We have tendered for the provision of (Enhanced) Reactive Power services for summer 2019 and 2019/20.
- Work continues to move smaller generation to new protection settings, which will reduce the need to manage system stability using operational tools.

Key messages – gas

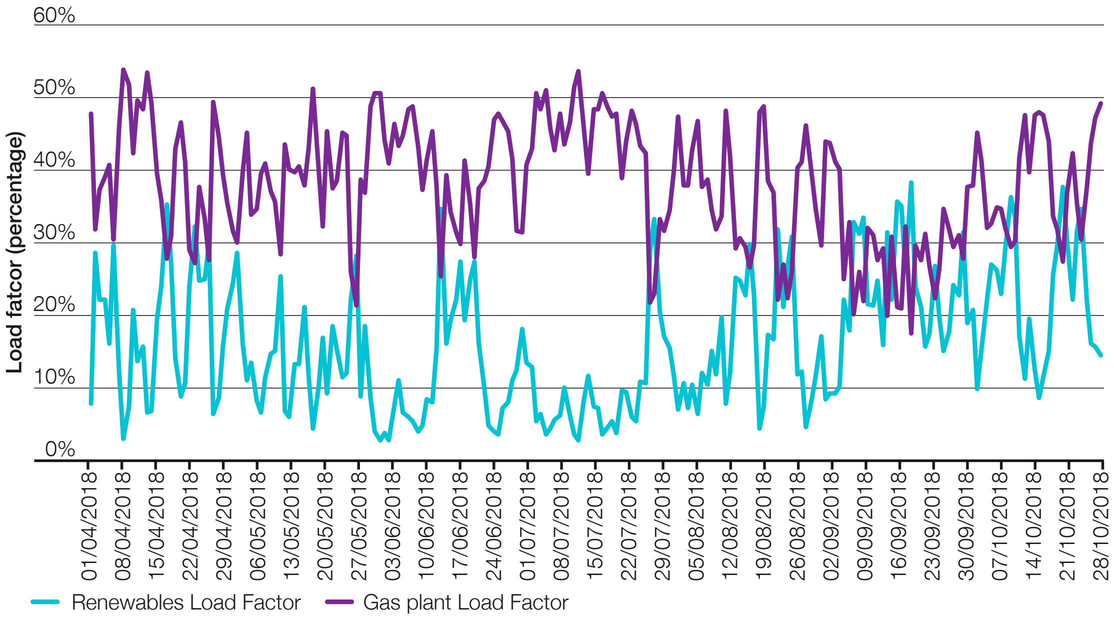
- Although the need for maintenance remains high, we anticipate no major risks to National Transmission System (NTS) access for the planned summer schedule.
- During summer months, gas fired electricity generation becomes a dominant component of gas demand. Its variability results in a need for close management of system pressures. We are reliant on timely and accurate physical notifications to minimise operability risks.
- We are expecting increased volumes of LNG supply, which affects flows of gas across GB. As LNG supply is less predictable than UK Continental Shelf supply, we must be prepared to operate the network in increasingly complex or new configurations at relatively short notice.

Whole energy system
Executive summary

Whole system thinking is becoming increasingly important as long-term trends of decarbonisation and decentralisation drive increased interaction between the gas and electricity transmission systems.

An example of this is how increased renewable generation on the electricity system, coupled with a gradual move away from coal, has a direct impact on the operation of the gas system.

Figure 1
Load factor of renewable and gas fired electricity generation summer 2018



- Output from gas fired generation mirrors the output from renewable generation, increasing when renewable output decreases and vice versa.
- The resulting volatility in output required from gas fired generation also means the gas demand to these sites is more variable.
- In turn this variability has an impact on how we configure and operate the NTS, increasing flexibility requirements within and across days.
- The NTS compressor portfolio is increasingly relied upon to manage this variability in operational pressures.

EU Exit impact
Executive summary

We anticipate no additional operability challenges for this summer as a result of the UK's planned exit from the EU. We have tested our planning assumptions in a broad range of scenarios and via engagement with industry. These scenarios fall within our normal contingency planning.

Potential impacts concerning interconnector trading are discussed below:

- Currently when electricity is traded over interconnectors with connected markets in the EU a day ahead of real time, this is done using **implicit arrangements**. This makes trading faster and more efficient. In the case of a no deal exit from the European Union, these arrangements would no longer apply and interconnectors would have to move to fallback arrangements.

- In all scenarios trading will continue, and electricity will flow. It is expected to flow from lower to higher priced markets as is the case at the moment.

- In a no deal scenario, the mechanisms of cross-border gas trade are not expected to fundamentally change. Gas shippers mostly purchase energy and capacity separately, and there would be no change from this in the event of a no deal exit from the EU. The UK's Transmission System Operators (TSO's) expect to have continued access to the **Prisma gas capacity trading platform** to allocate capacity at interconnection points.

- Should the UK leave the EU with no deal, cross border trading of energy would take place outside of the single market framework, i.e. under World Trade Organisation rules for the majority of countries, where no free trade agreement has been negotiated. Furthermore, as is the case now, flows on both gas and electricity interconnectors may also be impacted by fluctuations in currency exchange rates.

Key publications from the System Operator

Executive summary

System Operator publications

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

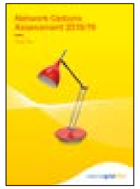
The starting point for our analysis is the *Future Energy Scenarios (FES)*. This document considers the potential changes to the demand and supply of energy from today out to 2050.

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

The *Operability Strategy Report* considers the current operability challenges the ESO faces and how these are likely to change in future.

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

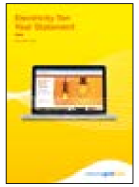
System Operator publications 2019



Network Options Assessment
January
The options available to meet reinforcement requirements on the electricity system.

Winter Outlook Report
October
Our view of the gas and electricity systems for the winter ahead.

Summer Outlook Report
Spring
Our view of the gas and electricity systems for the summer ahead.

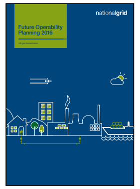


Electricity Ten Year Statement
November
The likely future transmission requirements on the electricity system.

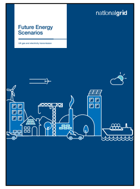
Operability Strategy Report
Summer 2019
Our view of future electricity system needs and potential improvements to balancing services markets.

Gas Ten Year Statement
November
How we will plan and operate the gas network, with a ten-year view.

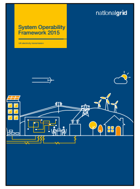
Winter Review and Consultation
June
A review of last winter's forecasts versus actuals and an opportunity to share your views on the winter ahead.



Future Operability Planning
November/December
How the changing energy landscape will impact the operability of the gas system.



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



System Operability Framework
Regular updates
How the changing energy landscape will impact the operability of the electricity system.

2 Electricity

In this section we present our current view of electricity demand for summer 2019.

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

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

Electricity demand

Key messages

In July 2018, we saw the lowest transmission system demand (TSD) on record at 16.3GW (actual demand based on actual weather including station load). This continued the downward trend in demand that we have seen on the transmission system since 2011, which has largely been due to an increase in distribution connected generation.

Our analysis suggests that this downward trend will slow this summer as the growth of distribution connected generation, mainly solar photovoltaics (PV), decreases and we anticipate minimal reductions in underlying demand. Therefore we expect the weather corrected demand in summer 2019 to be broadly similar to summer 2018.

- Minimum summer demand is expected to be 17.9GW.
- Daytime minimum demand is estimated to be 20.8GW.
- Peak demand for the high summer period is expected to be 33.7GW.

Further information can be found in the data workbook.

Table 1
Weather corrected transmission system demand for summers 2016, 2017, 2018 and normalised transmission demand for 2019.

Year	Summer minimum (GW)	Daytime minimum (GW)	High summer peak (GW)
2016	17.8	22.7	36.3
2017	17.6	21.2	34.4
2018	18.0	21.0	33.9
2019 (forecast)	17.9	20.8	33.7

Electricity demand

Summer system demands

Periods of low demand can have an impact on how we operate the transmission system. As a result, it is important that we understand the minimum levels of demand along with the peak demand that we can expect to see during the summer months.

Weekly peak demand

Figure 2 shows the weekly peak demand for summer 2018, and our forecast for 2019. Our peak demand for the high summer period between June and the end of August is 33.7 GW. This is 200 MW lower than last year's weather corrected demand.

Summer minimum demands

Historically, lowest demand on the transmission system has occurred overnight. However, growth of renewable generation has meant that lower demands may occur in the daytime. As Figure 3 shows, daytime summer minimum demand for 2019 is expected to be 20.8 GW, 200 MW lower than last year's weather corrected demand.

Furthermore, weekly overnight summer minimum demand for 2019 is expected to be 100 MW lower than last year's weather corrected demand, at 17.9 GW.

Figure 2

Weekly peak demand for summer 2018 against our summer 2019 forecast (weather corrected)

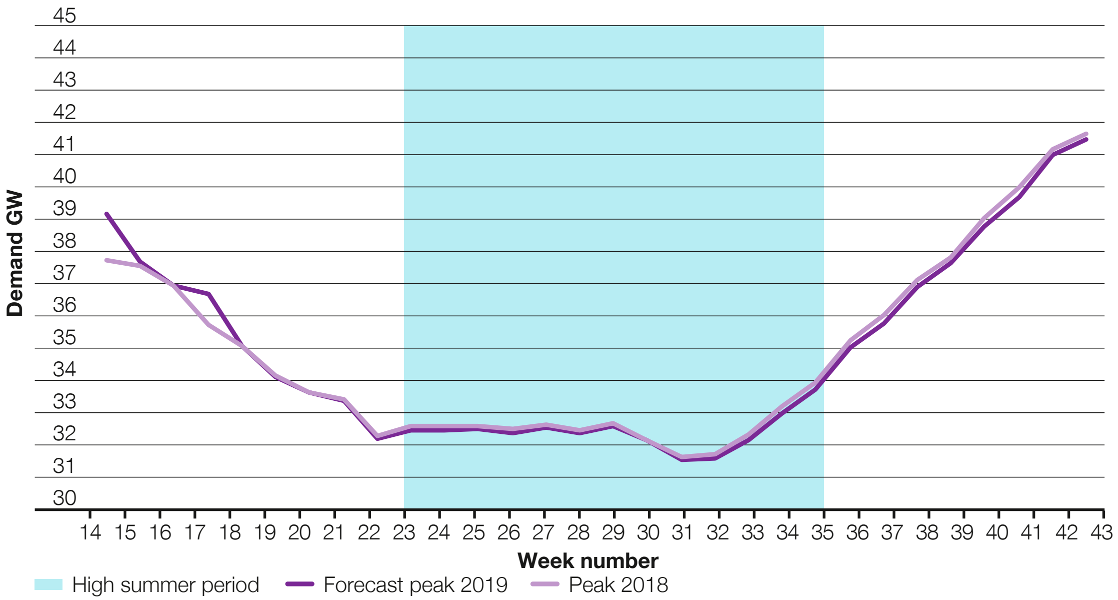
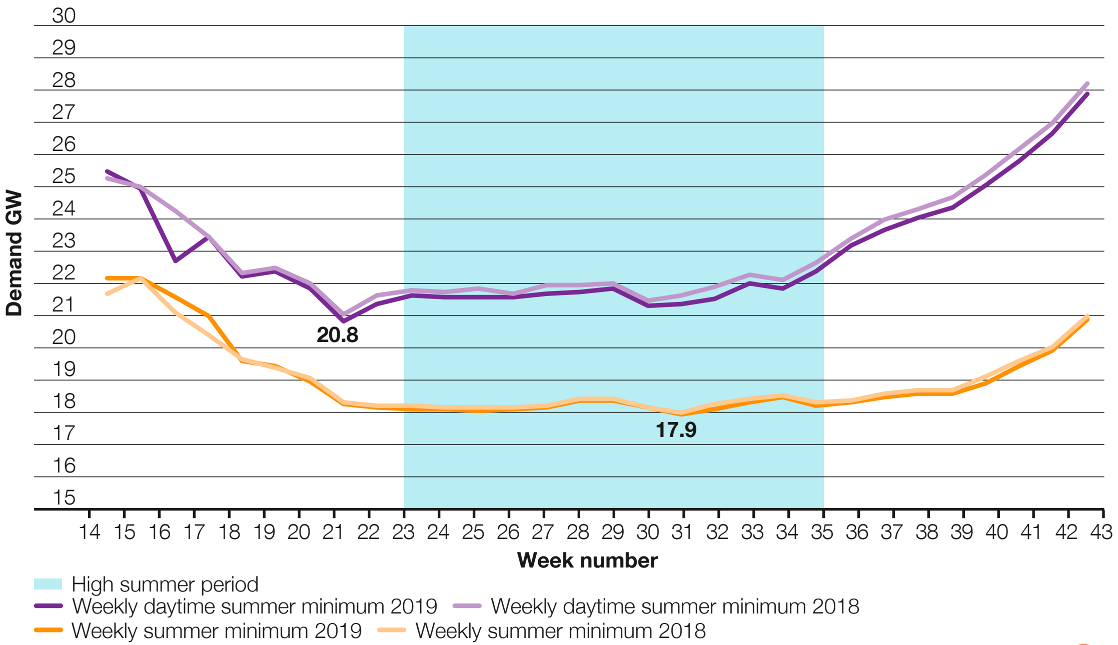


Figure 3

Summer minimum demands, 2018 and 2019 forecast (weather corrected)



Electricity demand

Daily demand profiles

Daily demand profile

During the summer months, solar generation has a more prominent impact on demand profiles. For a number of years, maximum solar generation output has coincided with the fall in demand after lunchtime.

Figure 4 shows the daily hourly demand profile from the high summer period in 2018. This helps us to forecast the daily minimum and daily peak demand timings for the coming summer.

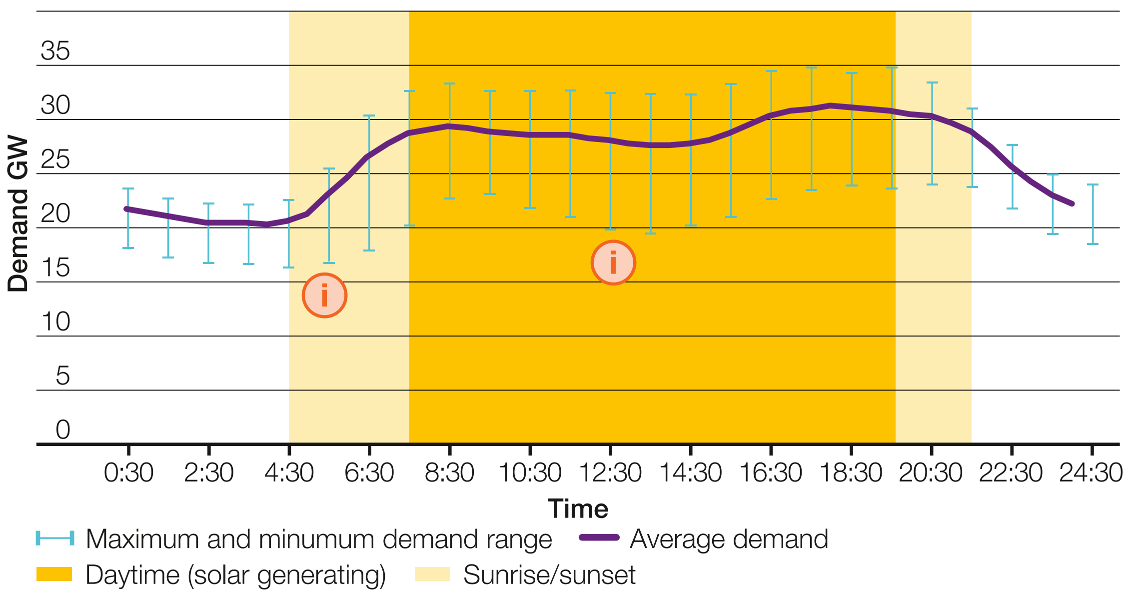
Minimum demand timings

Figure 4 suggests that the daily minimum demand is likely to occur between 5am and 6am. Demand then increases until 8am where it remains relatively flat until 4pm. After this, it starts to increase for the evening peak in demand.

Peak demand timings

Daily peak demand is largely influenced by the amount of solar radiation. For example, if the sun is shining all day, the peak demand is likely to occur either in the morning between 8am and 9am or after sunset. The daytime demands between 9am and sunset are suppressed by distribution connected generation (mainly solar PV).

Figure 4
Daily hourly demand profiles from the high summer period 2018



Spotlight

Update on Network Innovation Allowance (NIA) projects

Installed solar PV capacity is now over 13 GW and continues to have a significant effect on transmission system demand. We have continued to enhance our ability to predict solar generation accurately, and during the last 12 months we saw the implementation of a number of projects:

1

Following our NIA project with the Alan Turing Institute for Data Science, we developed and implemented a new machine-learning based national solar power model in September 2018. This is the first time that such technology has been used in our suite of forecasting tools. Compared to previous models, this new tool has reduced our mean absolute solar forecasting errors across all timeframes by approximately 33%. We now have an enhanced suite of solar forecasting models, including one from our NIA project with Reading University.

2

Also in September 2018, our NIA project with the Met Office furnished an improved data-feed of short-term forecasts of solar radiation, which is the key driver of solar power generation. The new values addressed the tendency to under-forecast solar radiation, and therefore solar generation.

3

Finally, our partnership with Sheffield University reached another milestone during the winter of 2018/19, with the release of an updated set of regional solar PV outturn estimates. These have enabled the production of regional solar PV forecasts, which we utilise to strengthen our studies of network planning and constraint management during 2019.
Real time solar PV generation output can be accessed here **www.solar.sheffield.ac.uk/pvlive**.

These projects are serving to improve the ESO's management of system balancing and network constraints in view of the significant impact of solar generation. We continue to explore and implement further initiatives to stay abreast of the changing energy landscape, and balance supply and demand accurately and economically.

Electricity Supply, including operational view

Key messages

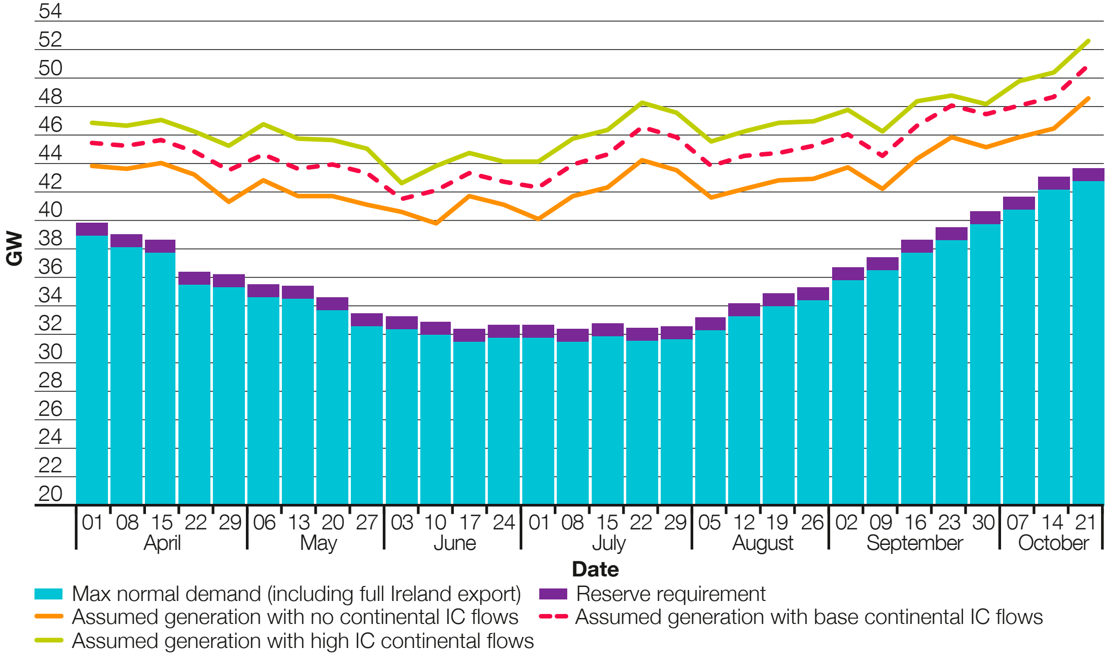
39.8 GW

Based on current operational data the minimum available generation is expected to be 39.8 GW in the week commencing 10 June (no continental interconnector flow scenario).

Demand

We are able to meet normalised transmission demand and our reserve requirement at all times throughout summer 2019 under all interconnector scenarios, including throughout the shoulder months of April and September.

Figure 5
Weekly generation and demand summer 2019



*Please note data on the BM reports website does not include interconnector imports/exports and is largely unadjusted (i.e. does not include derating or breakdowns – with the exception of wind where this is accounted for via the assumed load factor).

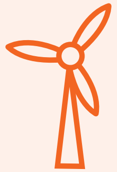
Electricity Supply, including operational view

Operational view:

- In the summer months, power stations carry out planned maintenance as there is typically lower demand and lower electricity prices than in the winter.
- To plan for the summer, the ESO uses OC2 data submitted weekly by generators, which includes planned maintenance dates. We also apply a breakdown rate to this data, to account for unexpected generator outages or restrictions close to real time.
- This is then modelled against forecast normalised transmission demand (including station load), plus a reserve requirement of 900 MW and a range of interconnector flows to provide a weekly view of the anticipated operational surplus (see previous figure, based on data provided on 14 March 2019).
- This operational view doesn't include any generator market response close to real time – for example if market prices increase, generators may move planned maintenance. For the latest OC2 data and operational view, see the **BM reports website**, updated each Friday.
- Based on current economic conditions, we expect some coal power stations to temporarily shut down during summer 2019. This has already been indicated by the loss of availability of two 500MW coal fired units. Power stations in this position may become available if the price increases until it is profitable to generate, or if our control room approaches them with enough notice. Furthermore, some plants may decide to close if it is no longer economical to run. A 2,000MW coal fired unit has announced closure from the end of September 2019.
- Further detail on available generation for the summer, breakdown rates etc. can be found in the data workbook.

Operational view continued

Key messages



Based on current data we expect that during some periods this summer inflexible generation output plus flexible wind output will exceed minimum demand (see Figure 6)

We therefore anticipate that we may need to take actions such as:

- requesting pumped storage units to increase demand by moving water back to their top lakes – (this increase in demand is shown by the pink demand line in Figure 6)
- curtailing flexible wind farm output at a national level via the Balancing Mechanism or via direct trades
- trading to reduce the level of interconnector imports.

All actions will be carried out in economic order, with cheaper actions taken first. At a local level wind may also need to be curtailed due to local constraints or other issues.

Operational view continued

In the summer, there is a significant reduction in transmission system demand, as there is less requirement for heating and lighting, and a higher output from distributed generation such as solar.

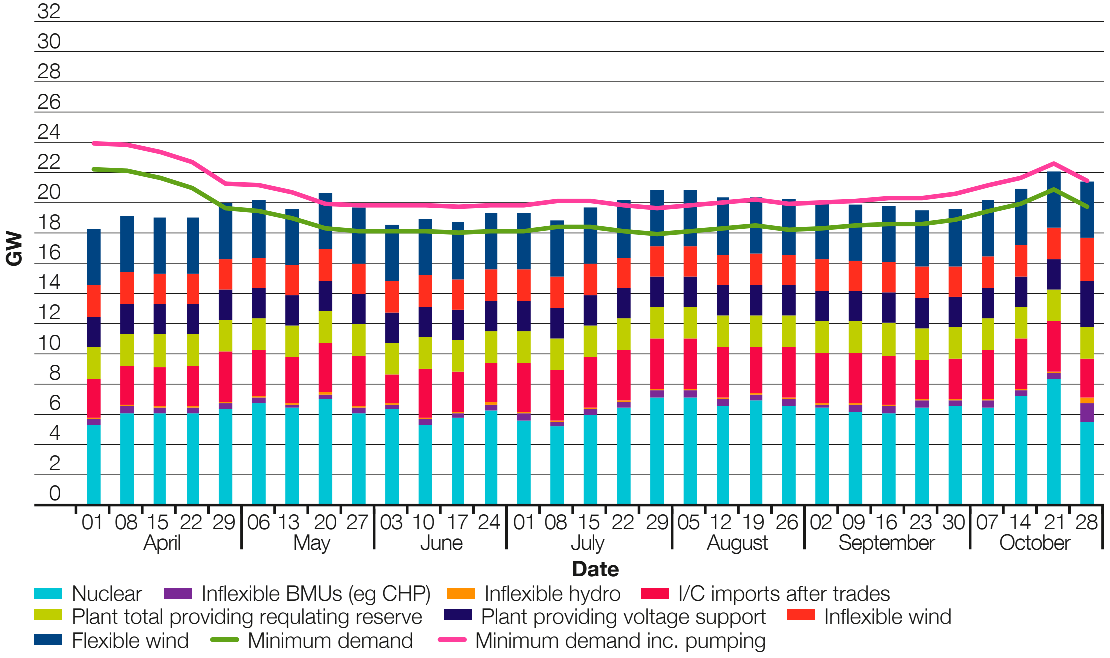
Throughout the summer, the ESO needs to keep the demand and supply of electricity in balance at all times. To do this, the system still needs to be able to respond to the largest generation or demand loss. We also need to maintain positive and negative reserve levels to account for forecasting errors and unanticipated reductions in generator availability close to real time (this is discussed in further detail in the operability toolbox section).

To help us understand actions we may need to take this summer, we model levels of inflexible generation, and inflexible generation plus flexible wind output against forecast minimum demand each week (see Figures 6 and 7).

These forecasts are updated weekly and can be found on our **website**.

As discussed previously, minimum demand is likely to take place in the early morning, or in the afternoon when output from distributed generation is at its highest.

Figure 6
Generation and minimum demand by week, summer 2019



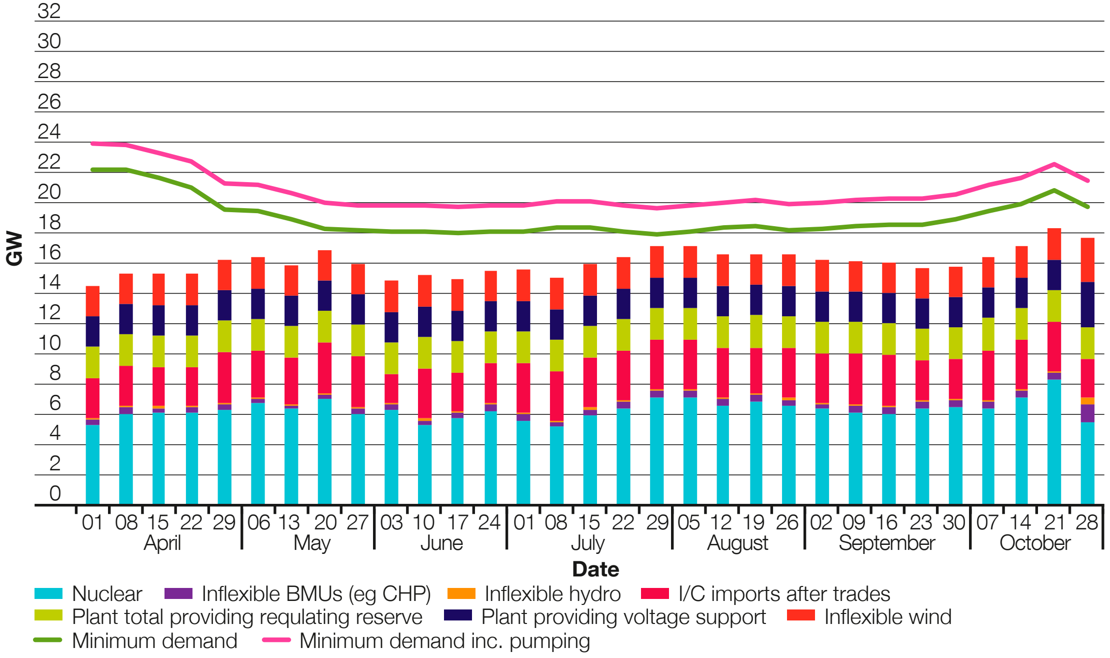
Operational view continued

Key messages

Based on current data, we do not expect **inflexible generation** output alone to exceed minimum demand in summer 2019.

- The ESO can undertake a number of actions if supply risks being higher than demand. Usually these involve working with **flexible generation** to reduce supply.
- If however these actions are not sufficient to bring supply and demand into balance, further action may need to be taken.
- Based on current data, we do not expect **inflexible generation** output alone to exceed minimum demand in summer 2019.
- If however demand levels fall close to the level of inflexible generation on the system, we can issue a national or local **Negative Reserve Active Power Margin (NRAPM)** notice. This is a request to encourage more flexible parameters from generators, and inform participants of a risk of instructions to inflexible generation. To date a limited number of local NRAPMs have been issued, and no national NRAPM has been issued. You can read more about NRPAMs on our **website**.
- In the longer term the number of actions we take as an electricity system operator is likely to increase as we continue to see reduced demand at the summer minimum (with more distributed generation capacity), and fewer flexible generators running overnight and in the afternoon.

Figure 7
Inflexible generation and minimum demand by week, summer 2019



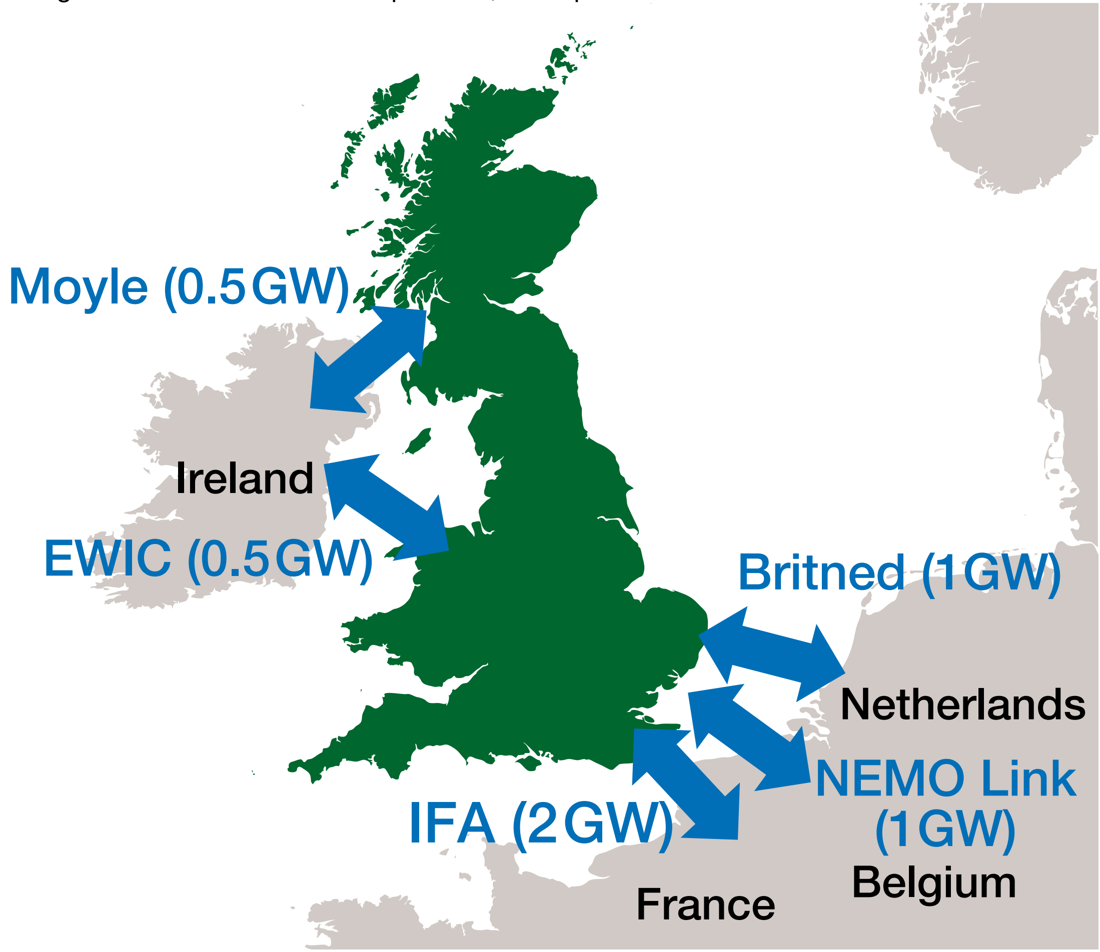
Europe and interconnected markets
(Electricity)

Context

There are 5 interconnectors connecting the GB electricity market with the Netherlands, Belgium, France and Ireland. The direction electricity flows on these is determined by price, with electricity flowing from cheaper areas to more expensive areas.

As renewable generation continues to grow in both GB and connected markets, relative prices will be largely influenced by the weather, which impacts demand and the amount of available renewable generation. Flows of electricity may also be impacted by network constraints, and these will be managed by collaboration between the ESO and interconnectors.

Figure 8
Interconnector capacities.
This figure shows interconnector capabilities, not expected flows.



Europe and interconnected markets
(Electricity)

A development since last summer was the launch of the Integrated Single Electricity Market (ISEM) in Ireland on 1 October 2018. This integrated the all-island (Ireland and N Ireland) and European electricity markets, which was expected to help deliver increased levels of competition and lower prices.

In addition, the NEMO link interconnector, connecting GB and Belgium, successfully went live for commercial service on 31 January 2019.

Interconnectors may undertake planned outages over the summer, or experience fault outages. A table of current fault outages and planned outages for each interconnector is listed in table IC-0.

Table 2
Planned and current interconnector outages, summer 2019

Interconnector (full capacity)	Planned outages (resulting capacity)	Current outages
France: IFA (2 GW)	01–26 April (1 GW) 04–06 June (1 GW) 17–28 June (1 GW)	None
The Netherlands: BritNed (1 GW)	13–17 May (0 GW) 16–20 Sept (0 GW)	None
Belgium: Nemo (1 GW)	23 Sep–4 Oct (0 GW)	None
Ireland: EWIC (0.5 GW)	07–13 May (0 GW) 21 May (0 GW) 28 May (0 GW) 19–21 Aug (0 GW)	None
N. Ireland: Moyle (0.5 GW)*	12 – 20 June (0 GW)	None

*Moyle currently has less commercial capacity, subject to TEC values: currently 307 MW for import and 450 MW for export.

Spotlight
Review of interconnector flows summer 2018

Key messages

Imports
As anticipated, GB day ahead electricity prices remained above prices in connected European markets for most of summer 2018, leading to net imports on these interconnectors.

Exports
As expected we also saw net exports of electricity on interconnectors to Ireland during peak, switching to imports overnight.

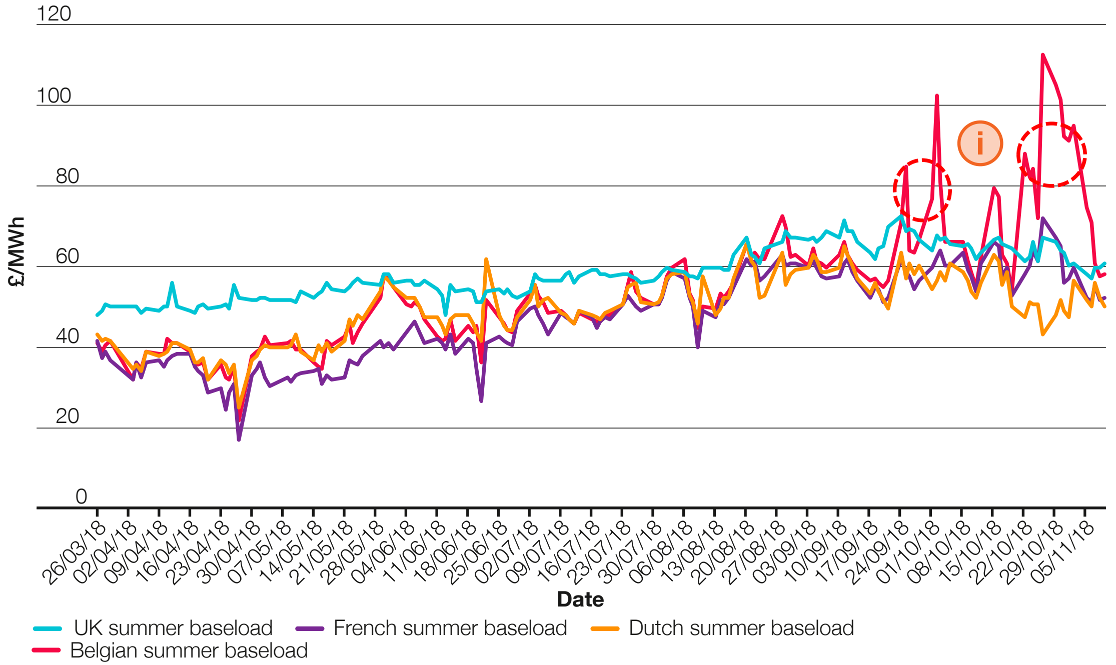
Spotlight

Review of interconnector flows summer 2018

Figure 9 shows GB and European day ahead electricity baseload prices for summer 2018. As can be seen here, the GB day ahead baseload price was consistently higher than connected markets for most of the summer leading to net imports into GB.

On some occasions from September 2018 onwards, Belgian prices peaked at much higher levels than GB (circled) due to outage extensions on the Belgian nuclear fleet. Once these were resolved, Belgian prices dropped back close to previous levels.

Figure 9
Day ahead baseload prices, summer 2018



Spotlight
Review of interconnector flows summer 2018

Table 3 shows interconnector flows during the daytime, overnight and at peak times (5pm to 8pm) for summer 2018 (Nemo is not shown as it was not operational). All interconnectors were importing for most of the overnight periods, particularly those connected to continental Europe.

In the daytime, the picture changed for the Moyle and EWIC interconnectors that moved to export for more daytime hours. At peak, the distinction between continental European and Irish interconnectors is again clear, with the former importing power from Europe for almost all peak hours.

Table 3
Interconnector flows summer 2018

	IFA	Moyle	Britned	EWIC
Daytime (7am to 7pm)				
Import	95.6%	20.7%	88.0%	32.7%
Floating	0.0%	0.3%	5.5%	13.6%
Export	4.4%	79.0%	6.5%	53.7%
Total	**100.0%**	**100.0%**	**100.0%**	**100.0%**
Overnight (7pm to 7am)				
Import	97.1%	62.8%	92.5%	71.8%
Floating	0.0%	0.1%	4.1%	12.3%
Export	2.9%	37.1%	3.4%	16.0%
Total	**100.0%**	**100.0%**	**100.0%**	**100.0%**
Peak hours (5pm to 8pm)				
Import	99.4%	19.9%	94.3%	38.9%
Floating	0.0%	0.1%	3.1%	12.7%
Export	0.6%	80.0%	2.6%	48.3%
Total	**100.0%**	**100.0%**	**100.0%**	**100.0%**

Europe and interconnected markets
(Summer 2019)

Key messages

2019
Forward prices for summer 2019 are expected to remain higher in GB than continental Europe. We therefore expect there to be net imports of electricity on interconnectors from continental Europe to GB for most of the summer.

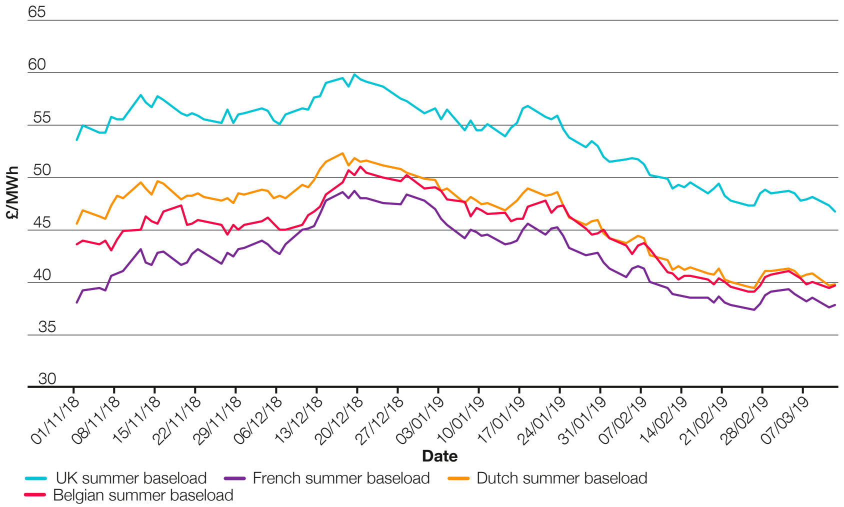
Imports
We expect imports into GB at peak times via the IFA, BritNed and Nemo Link interconnectors although occasionally not at full import. Weather variations will also affect flows at all times, including peak.

Exports
We expect GB to export to Northern Ireland and Ireland during peak times on the Moyle and EWIC interconnectors. This may be reversed to import with high wind output in Ireland or during periods of system stress. The availability of coal fired generation in Northern Ireland will also impact flows on the Moyle interconnector.

Figure 10 shows that forward prices for baseload electricity for summer 2019 in GB are still higher than the corresponding prices in the French, Dutch and Belgian markets. Therefore we expect to see similar import/export patterns as last summer. NEMO link, as a new interconnector, is expected to behave similarly to Britned as their market prices and physical capabilities are similar.

In previous years, there were some periods when IFA exported from GB to France driven by lower available French generation due to nuclear outages. Planned French nuclear outages for this year are lower than previous summers, so are not expected to significantly affect interconnector flows. Further detail can be found in the data workbook.

Figure 10
Day ahead baseload prices, summer 2019



Europe and interconnected markets (Summer 2019)

In addition, only two of the four coal-firing units in Northern Ireland were awarded a 12-month contract by the Northern Irish SO to support system stability and security of supply. Should other units close, this may encourage more exports through the Moyle interconnector.

Forecast flows at peak (5pm to 8pm) and overnight (7pm to 7am) are summarised in Figures 11 and 12, which show flows under a high import scenario, based on historic breakdown rates (see data workbook for further detail).

Figure 11
Forecast interconnector flows at peak 5pm to 8pm, high import scenario

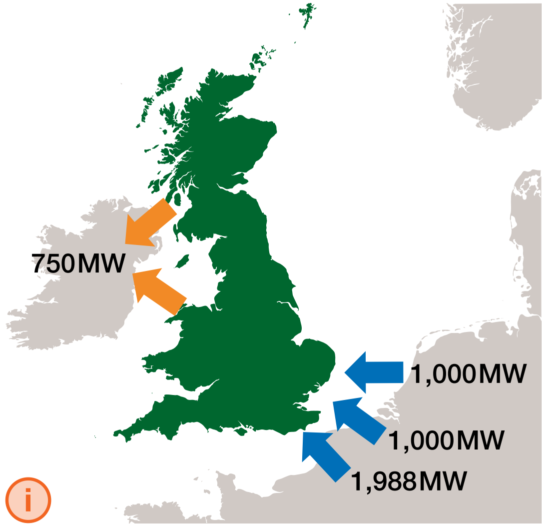
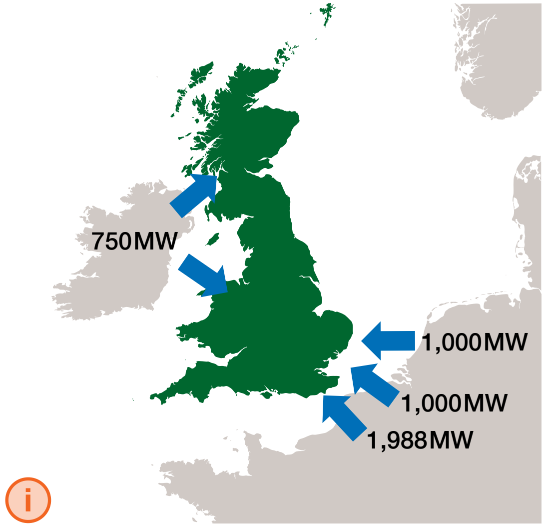


Figure 12
Forecast interconnector flows overnight, high import scenario



3 Gas

In this section we look at the projected demand for gas to cater for heating, industry, electricity generation and export needs. We explore the supplies of gas we expect to see this summer and the impact of global markets on both supply and demand patterns.

Gas demand

Key messages

EU export

Total gas demand across the network in summer 2019 is expected to be greater than in summer 2018 on a weather corrected basis. This is due to an expected increasing flow of transit gas into Europe as prices drive greater volumes of LNG to be delivered into UK terminals.

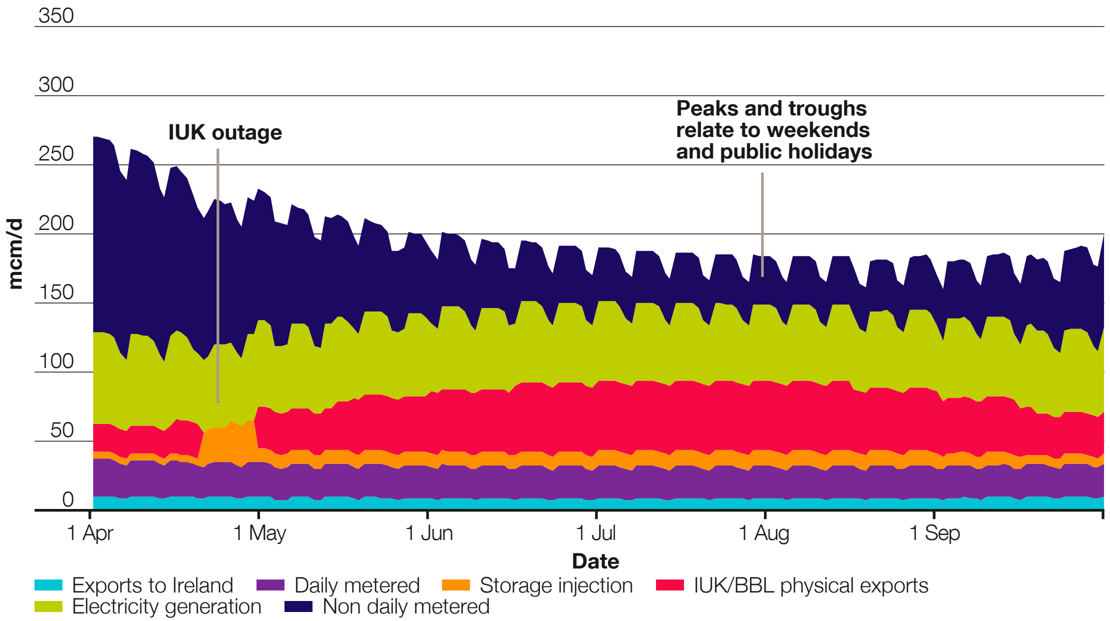
Renewables

Gas demand for GB electricity generation remains steady but, due to increased use of renewables and gas/coal price spreads, presents a variable profile of consumption.

Another significant impact on demand uncertainty continues to be the effect of weather on non-daily metered (NDM) demand.

Figure 13

Forecast gas demand profiles for summer 2019 – seasonal normal weather conditions



Gas demand

Table 4
Forecast total gas demand for summer 2019 and history for previous summers

bcm	2014 actual	2015 actual	2016 actual	2017 actual	2018 actual	2018 weather corrected	2019 forecast
NDM	9.9	11.3	11.1	10.4	10.6	11.4	10.8
DM + Industrial	4.4	4.2	4.1	4.4	4.1	4.1	4.3
Electricity generation	9.2	8.3	11.6	10.5	10.3	10.3	10.1
GB Total	**23.5**	**23.8**	**26.8**	**25.3**	**24.9**	**25.7**	**25.2**
Ireland	2.7	2.8	1.7	1.6	1.6	1.6	1.6
Export to Europe	3.8	5.0	5.2	7.0	4.5	4.5	7.0
Storage Injection	3.6	3.4	2.6	2.5	2.3	2.3	1.9
Total[1]	**33.8**	**35.2**	**36.4**	**36.6**	**33.3**	**34.2**	**36.1**

Hover over bcm rows to highlight relevant information

- In summer 2019, we expect to see non-daily metered demand slightly higher than last year, aligned with seasonal normal weather conditions. Further information about NDM demand can be found in the data workbook.
- Daily metered (DM) demand is expected to decline year on year, mirroring the reduction in energy intensive industries and energy efficiency improvements. However, significant new connections can slow that trend, and this year we anticipate a DM demand that is slightly higher than last year.
- Gas demand for electricity generation is expected to be slightly lower than last summer, as a result of lower overall electricity demand and increasing renewable generation.
- Overall we expect total exports to Ireland over the summer period to be largely the same as last year, despite the decline of production from the Corrib field.
- With increasing LNG in the global market, we expect to see gas continuing to be routed to where the price is more attractive in Europe (See page 32).
- Overall storage injection this summer is expected to be lower than last summer as a result of the warm winter. (see page 29).

[1] All totals include NTS shrinkage and will therefore not tally.

Europe and interconnected markets
(Gas)

Key messages

Our projection for 2019 is an increase in exports to Europe via the IUK interconnector in comparison to last summer.

In recent years, IUK has closed for maintenance during June. This year, the maintenance window is planned much earlier, in April.

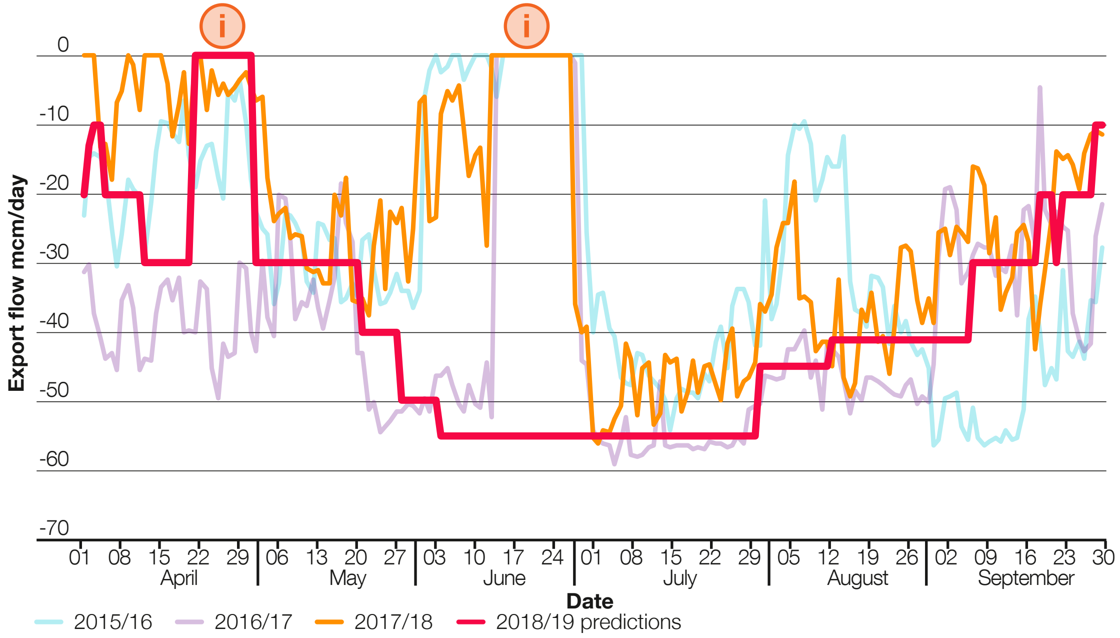
The GB gas market is connected to Belgium by the IUK interconnector, and to the Netherlands via the BBL interconnector.

In recent years, gas has tended to flow from GB to Belgium for most of the summer and from Belgium to GB during the winter months through IUK. This trend is largely driven by price differentials between GB and European markets, so occasional days of import to GB might be expected during the summer if prices dictate. It is increasingly influenced by the availability of LNG being delivered to UK terminals.

Figure 14 shows export flows in the last three summers, and our projection for 2019 is an increase in export to Europe in comparison to last summer.

This is the first year that IUK has not had all its flows covered by long term contracts. All of the existing contracts expired at the end of September 2018. Currently about 55% of export capacity is covered by contract. Going forwards, contracts are likely to be booked on a much shorter term basis.

Figure 14
IUK Export Flows



Also this year, the BBL pipeline, between Bacton in the UK and Balgzand in the Netherlands, has indicated that it will make gas transportation possible in both directions from the summer of 2019.

Currently there is no firm exit baseline capacity however, as with any other site, non-obligated firm capacity could be made available by National Grid in addition to interruptible.

Gas storage

Key messages

Storage

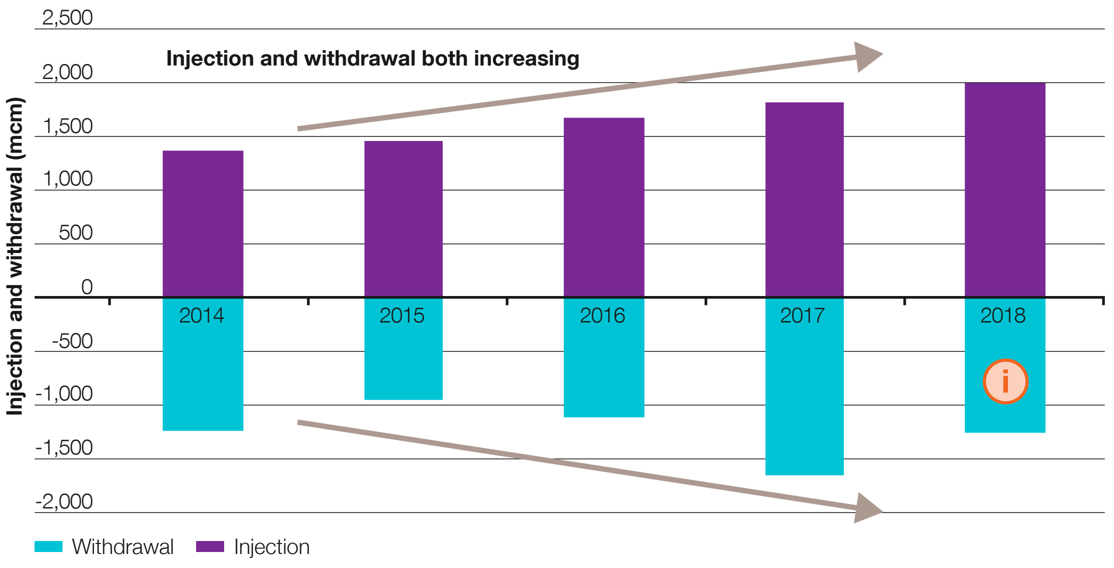
Overall storage injection over summer 2019 is likely to be lower than last year. This is because of the relatively high level of medium-range storage (MRS) stock at the end of winter 2019, due to a milder winter.

We expect continued day-to-day cycling into and out of (MRS) in summer 2019.

Outage

We anticipate that significant storage injection is likely during the 2 weeks that the IUK interconnector is on outage. This outage is taking place earlier than usual in the summer, and hence we expect to have higher stock levels than are typical during the early summer months.

Figure 15
Increasing trend of day to day cycling

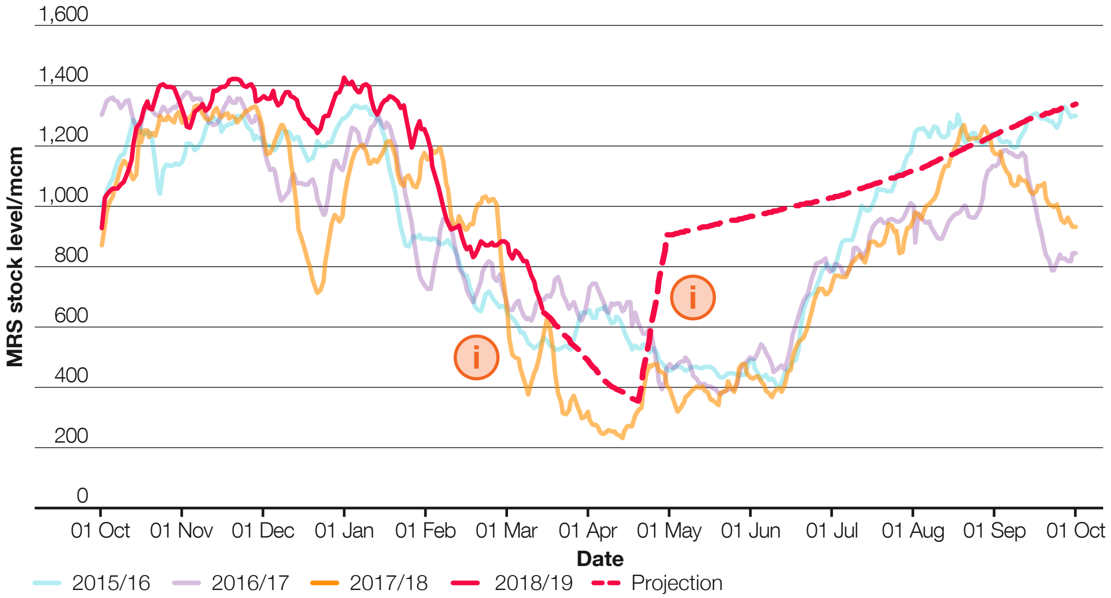


With the closure of Rough as a seasonal facility and its subsequent reclassification as a production field; the remaining storage in GB is medium-range storage (MRS). This has increased in total volume over recent years.

We have seen an increasing trend of these sites being used for day-to-day cycling, as shippers take advantage of gas price swings over shorter timescales. You can see the increasing trend in Figure 15 Storage behaviour can differ significantly across different years as a result of this price driven trend.

Gas storage

Figure 16
MRS stock levels



MRS starts to fill when IUK shuts down for maintenance. There is no export route for the supplied gas, so it goes into storage. The IUK outage is in April this year (earlier than usual) and we expect that significant storage injection is likely during those two weeks of outage. We therefore expect to have higher stock levels than are typical during the early summer months.

Total injection over the summer typically has a dependency on the level of MRS at the end of winter. MRS stocks are currently higher than last summer as a result of the mild winter (see Figure 16)

Gas supply

Key messages

We expect that there will be sufficient gas to meet demand in summer 2019.

Supplies from the UK continental shelf (UKCS) and Norway continue to be the dominant components.

We anticipate increased levels of LNG in comparison to last summer, and excess supply being exported to Europe in response to gas prices in both GB and global gas markets.

Table 5
Forecast and historic gas supply by source

bcm	2014 actual	2015 actual	2016 actual	2017 actual	2018 actual	2019 forecast
UKCS	15.1	15.9	16.2	17.4	16.8	**16.8**
Norway	7.4	11.3	12.4	13.1	13.3	**12.4**
Continent	2.2	0.3	0.5	0.1	0.1	**0.1**
LNG	7.5	6.2	5.3	3.2	1.4	**5.3**
Storage	1.3	1.1	1.2	1.9	1.3	**1.4**
Total	33.4	34.8	35.6	35.7	32.8	36.1

The UKCS continues to be the most significant supply of gas to the UK. We are expecting aggregate supply in summer 2019 to be similar to summer 2018.

Norway supplies gas through pipelines to Germany, Belgium and France as well as to GB. Norway production has been high over the winter and is expected to remain so. However due to the expected increase in LNG supply we believe it is unlikely that we will see flows that are as high as seen in the past few years.

Our projection for 2019 is an increase in exports to Europe via the IUK interconnector in comparison to last summer.

Hover over bcm rows to highlight relevant information

LNG deliveries are sensitive to the world market and production capacity has grown rapidly in recent years. They offer a more flexible response to increasingly volatile supply and demand patterns than offshore production. We continue to see this additional LNG supply being transported to Europe via the interconnector, in response to price trends. However, the locational diversity of LNG supply is changing the way we operate our networks.

Overall storage injection over summer 2019 is likely to be lower than last year. This is because of the relatively high level of MRS stock at the end of winter 2019, due to a mild winter.

Liquefied natural gas (LNG)

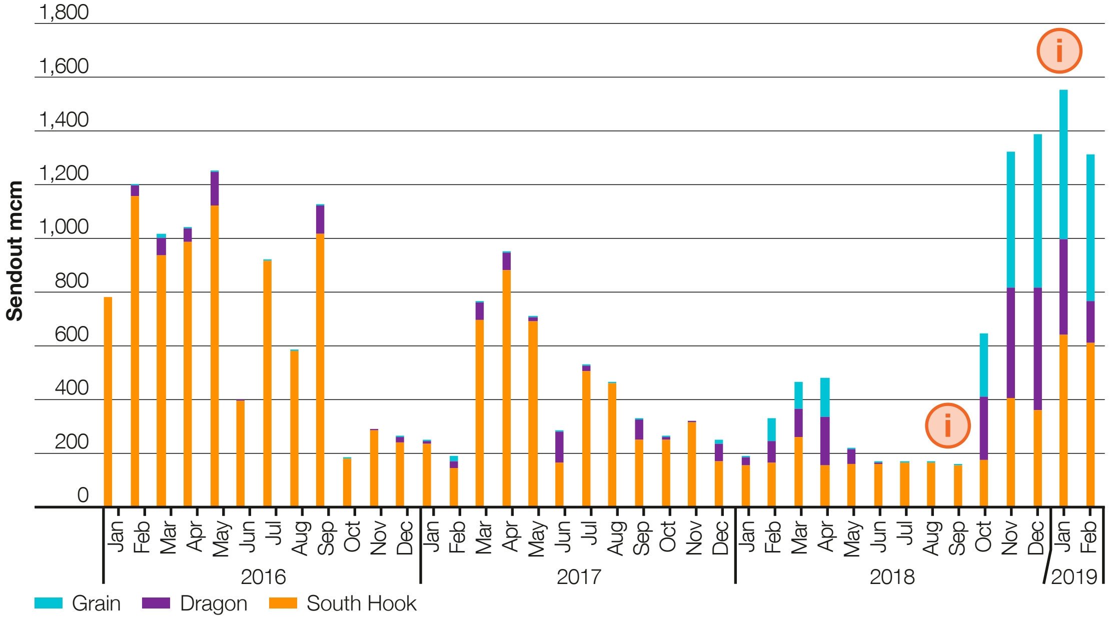
Key messages

We expect that LNG deliveries this summer will be substantially higher than last summer, but will not match the high rates seen in winter 2018.

LNG deliveries to NW Europe were higher during last winter than for many years. New liquefaction capacity has come on line in many producing regions, and total production capacity has grown faster than global LNG demand.

LNG shipping costs rose sharply during the winter, making Europe a more profitable market than Asian markets for cargoes from the US and from Yamal in NW Russia. The combined effect of this has been that cargoes have been delivered to GB, to all three terminals. As a result, we expect much higher LNG deliveries this summer compared to last year.

Figure 17
LNG monthly send-out



Liquefied natural gas (LNG)

Figure 18
LNG delivery cargoes

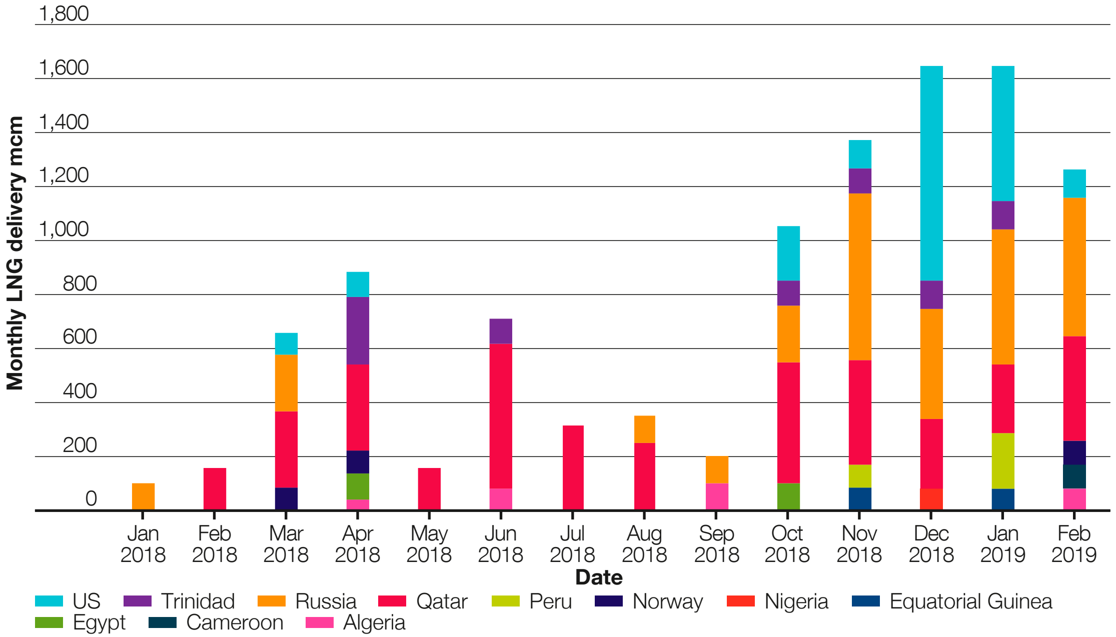


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Figure 18 shows the increasing variety of source and scale of vessel delivery.

Spotlight

Transit gas

We continue to experience gas being delivered to GB and supplies that are in excess of combined demand for GB and Ireland are then transported through our networks for onward export into Europe. This is known as transit gas.

Although gas demand is lower during the summer months, total demand is only approximately 25% lower than in winter. As a result we see export flows via the IUK interconnector offsetting the reduction in GB and Ireland gas demand. We are also currently anticipating LNG deliveries that are substantially greater in summer 2019 than last year, as discussed.

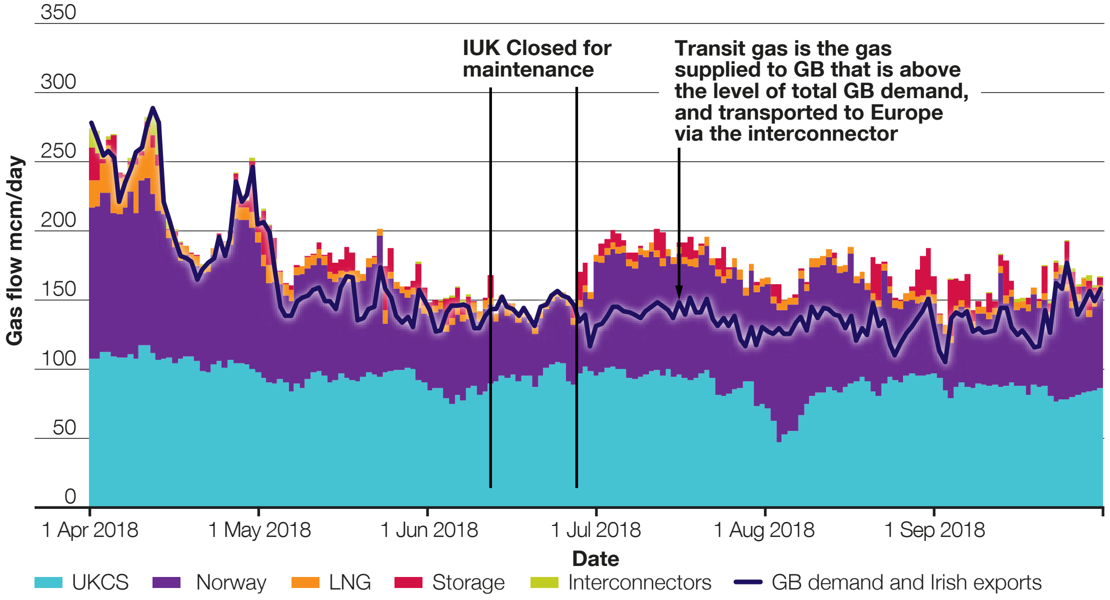
The effect on our network is that the historical pattern of transporting the majority of gas North to South no longer exists. Supply patterns are more evenly distributed around the country, and on occasions we have to reverse the flow, moving gas from South to North.

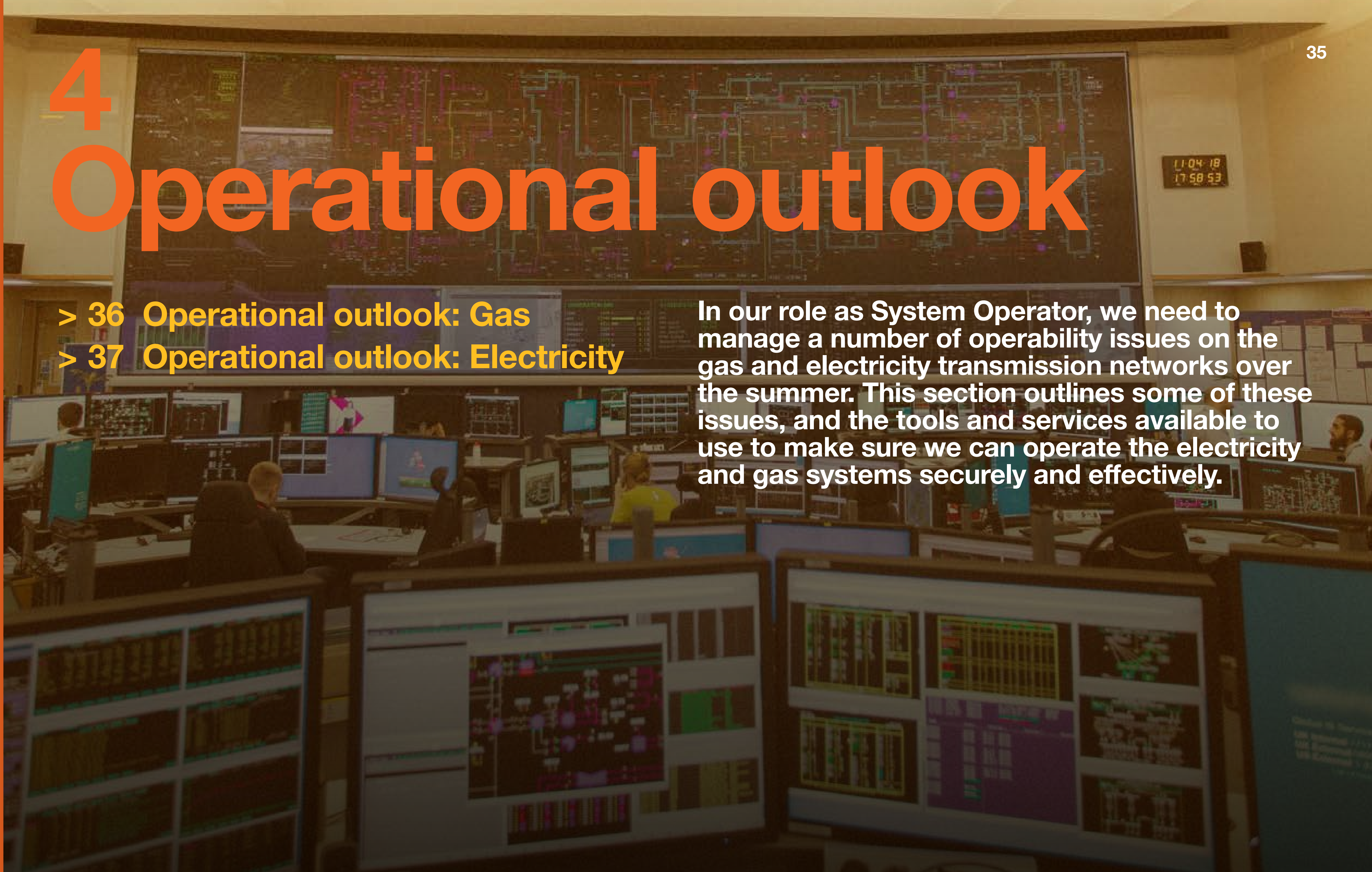
Sale of forward flow capacity in IUK is dependent on expected demand in Europe, and transit gas could increase into the future, as a result of increased fuel switching in Europe from coal to gas.

For almost the entire summer of 2018, more gas was being supplied than was actually needed to satisfy combined GB demand and Irish exports (shown by the dark blue line on Figure 19).

The surplus of supply was exported to Europe. From early-June through to mid-September, supplies from UKCS and Norway alone were greater than the demand. Norwegian gas was using GB for onward transit to the rest of Europe. The only time that supply and demand were aligned was in June when IUK was closed for annual maintenance.

Figure 19
Increasing trend of day to day cycling





4 Operational outlook

In our role as System Operator, we need to manage a number of operability issues on the gas and electricity transmission networks over the summer. This section outlines some of these issues, and the tools and services available to use to make sure we can operate the electricity and gas systems securely and effectively.

Operational outlook
(Gas)

Key messages

The volume of maintenance remains high, but there are no major risks to NTS access.

The variability of gas fired electricity generation has an impact on the management of system pressures.

Overall supply patterns become less predictable when larger volumes of LNG are delivered to GB terminals.

We must be prepared for non-standard and short notice re-configuration of the network.

We are reliant on timely and accurate demand nominations.

During the winter months, the most dominant driver for gas demand is the need to provide heat. This dynamic changes in the summer months as temperatures increase. Instead the most significant driver for gas becomes gas fired electricity generation.

Gas for electricity generation also has an element of weather sensitivity as it responds to the varying levels of generation from renewables. When clusters of Combined Cycle Gas Turbine (CCGT) generators exist in a particular region, this variability can have an increasing impact on regional pressure management.

Having timely and accurate physical notifications from CCGTs helps us to identify and manage the risk of variability across the network.

Increasing levels of LNG supply will impact patterns of gas flow across GB, potentially reducing the traditional north to south flow, and resulting in non-standard configuration of the network.

With LNG supplies being relatively closer to areas of demand, we could continue to see a reduction in compressor usage for bulk gas transmission, but we must be prepared for the possibility that LNG supply falls away, which can happen in summer due to price sensitivity.

This rapidly changing dynamic of the network means that we must be prepared to use compression at relatively short notice to maintain system locational pressures.

Our thoughts on the longer term impacts of this are now being shared in the **Gas Future Operability Planning** document.

System pressures are tending to become higher in the summer, than previously experienced, as a result of increasing levels of transit gas. As a result we must place greater focus on enabling safe access for the summer maintenance schedule.

We continue to engage closely with the industry to ensure that outages are coordinated and we will always aim to facilitate maintenance on the network with minimal disruption to our customers.

You can find more details on our website. The final **Maintenance Plan** is published at the end of March.

Improving Access to Data

In response to a number of recent industry engagements, National Grid has mobilised a programme of work to identify and deliver enhancements to the operational data currently provided to the industry through its website. For more information please refer to our **Operational Data User Guide**.

Operational outlook
(Electricity)

Key messages

The key factors that cause operational challenges for the electricity transmission system during the summer are:
- low transmission system demand (making it difficult to balance demand and supply, and affecting reactive power and hence voltage levels)
- high proportions of low inertia generation (making it more difficult to manage system frequency).

Both of these factors are impacted by the weather, so it can be difficult to forecast in advance what services will be needed. We will use a number of tools to manage these challenges.

In order to balance supply and demand, the ESO can take various additional day-to-day actions, as described in the electricity supply section. In addition, a number of specific tools can be used when system conditions are challenging.

In the summer of 2019 the ESO may need to:
- use footroom services in periods of low demand to ensure that there is enough negative reserve on the system
- take actions to manage local network constraints. The Western High Voltage Direct Current (HVDC) link will help to relieve congestion on the transmission network between Scotland and England
- issue a local or national Negative Reserve Active Power Margin (NRAPM) notice if demand levels fall close to the level of inflexible generation on the system (further described in the electricity supply section) You can read more about NRPAMs on our website
- use tools to manage the rate of change of frequency (RoCoF) and vector shift (see next slide)
- manage reactive power in different regions, to keep voltage levels stable. In periods of low demand, this is likely to be actions to reduce the amount of reactive power on the system. These could include:
  - setting up contracts in advance with appropriate generators. These would ensure minimum profitability so that these generators keep generating (and providing reactive power capability) in periods where they might otherwise have been uneconomic
  - undertaking trading actions within day, or taking bid / offer acceptances via the Balancing Mechanism so that generators provide reactive power capability.

We have also tendered for the provision of Reactive Power Services for summer 2019 in the South Wales and Mersey regions, and for Enhanced Reactive Power services in Scotland for 2019/20.

Spotlight

Update on loss of mains protection settings for smaller generators

All generators have loss of mains protection systems, designed to shut the generator down if there is an issue on the network they are connected to. Traditionally, these systems would monitor conditions on the electricity network such as the rate of change of frequency (RoCoF) or vector shift events, to understand if there was a network issue.

As system conditions have evolved to accommodate an increase in renewable generation and closure of conventional generation, these historic loss of mains protection techniques, such as RoCoF and vector shift, have become less suitable. There is a risk therefore that generators shut down when they don't need to, and several generators shutting down at once can in itself cause network problems, such as a sudden fall in system frequency. As a result, balancing actions are having to be taken on the transmission system to manage both RoCoF and vector shift.

Industry work is underway to systematically address the issues in this area. Last summer, NG ESO, UK Power Networks, SSE and Western Power Distribution jointly carried out an accelerated vector shift change programme. This ensured that generators in the most high risk areas changed their protection settings away from vector shift. As a result, the risk of a large number of generators shutting down following a vector shift event has been reduced to within manageable limits. Remaining changes to both vector shift and RoCoF relays will take place as part of the wider change programme.

The Distribution Code modifications under DC0079 to change the loss of mains protection settings at all generators greater than 5 MW and any new generators below 5 MW have already been implemented. The next phase of DC0079 is to ensure the loss of mains settings at existing generators with capacities below 5 MW, or any generators which use vector shift protection, move to more suitable relay settings as will be mandated by the Distribution Code. Pending approval from Ofgem, the implementation of this retrospective change will start this year.

As the volume of generation which has moved to these new protection settings increases, the need to manage RoCoF and vector shift using operational tools will be relaxed.

If you own or operate generation which is a) connected to the distribution network, and b) uses vector shift or RoCoF setting below 1 Hz/second for the loss of mains protection, you may be able to receive a payment. This would support changing the protection ahead of the compliance deadline. Look out for more information from the ESO and your distribution network owner over spring 2019.

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