New Resource Partners | Energy & Climate Intelligence Unit

GB POWER TRANSITION: GET SMART

A LAYMAN'S GUIDE TO AFFORDABLE, FLEXIBLE, CLEAN POWER

Contents

Foreword

To observe that 'the energy system is changing' is as banal and yet as accurate as to point out that the Sun rises in the East. The reality is far more exciting: the energy system is changing faster than anyone predicted, in ways that are often radical and unforeseen, and with consequences that are generally beneficial for citizens.

What we can see is that the future is undeniably renewable. Wind and solar power are increasingly the cheapest new forms of generation – they are also the quickest to build, the most popular, and the technologies that most interest investors. The future replacement cost of power could well be the cost of replacing wind turbines on an existing foundation or replacing solar panels on an existing site. In the UK, in the decade it has taken to move from debating a new nuclear power station at Hinckley Point to building the jetty and seawall, we have expanded generation from wind more than 10-fold and from solar, 700-fold. That is not a carp against nuclear power, just part of the new reality that lies at the heart of the UK's, and indeed the world's, modern energy system. Together with approaches that make the system flexible and in so doing give people meaningful control over their energy choices and expenditure, it is inevitable that the future revolves around wind and solar – and this is the near future at that.

Yet such a fundamental transformation of a commodity essential for modern life needs to be smooth. Delivery of energy needs to continue secure from interruptions and debilitating cost increases. While real-world experience indicates that the energy system transformation is progressing smoothly and in most cases affordably, we cannot assume this will automatically continue. We need to do the research – the kind of research that New Resource Partners and ECIU present here – which shows that we can safely project the current confidence engendered by the experiences of the recent past into a future where we obtain more than half our electricity from wind and solar power. This will only become more and more important as countries seek to accelerate the decarbonisation of electricity generation and transport, ahead of decarbonising heat.

If you work in or commentate on energy, you have a simple choice: ride the engine of change, wherever it may take you, or rail against it. I have chosen the first option. In my career I have moved from running a traditional integrated utility to investing in a small but expanding challenger clean energy provider; and now, to being part of one of the leading global energy blockchain companies, seeking to facilitate the changes we are discussing. My trajectory reflects the rapid and profound changes taking place in energy. Whereas once the most interesting place to be was in a giant company generating gigawatts from coal, gas and nuclear power, now the cutting edge is all about the '4D' future – decarbonised, decentralised, digitised and democratised.

This is the future into which we are inexorably moving – ever more quickly, if the will of investors and the public is given free rein and markets designed to encourage innovation and competition. It is a future that we should embrace without any wistful backwards glances.

Paul Massara
CEO Electron, former CEO Npower

Executive summary

Like many countries, the UK is increasingly powered by the sun and the wind. Last year, these advanced technologies provided nearly one-fifth of our electricity. And if you believe any of the authoritative bodies on the future of the electricity system – the National Infrastructure Commission, for example – that one-fifth share is going to expand rapidly.

This being so, two essential questions need answering definitively:

CAN THE LIGHTS BE KEPT ON EVEN IN THE DEPTHS OF WINTER, IN A SYSTEM WHERE AS MUCH AS HALF OF OUR POWER COMES FROM VARIABLY-GENERATING WIND TURBINES AND SOLAR PANELS?

GIVEN THE CONTINUING PRESENCE OF GAS-FIRED POWER STATIONS, WILL ELECTRICITY BE MORE EXPENSIVE IN A FUTURE WHEREIN WIND AND SOLAR MEET HALF OF NATIONAL POWER DEMAND?

This report aims to answer both questions.

It begins with a date and a prediction: that by 2030 the UK will source half of its electricity from wind and solar. Far from extravagant, this is entirely consistent with Governmental, business and academic forecasts. National Grid predicts between 40% and 60% of generation will be from variable renewable sources by that year, while the Government's 2030 target sees only 15% of electricity generated from gas and none from coal.

Realistic projections of demand, of other generation (nuclear, biomass, hydro, gas) and of interconnection, demand-shifting and storage are added to this prediction.

The system is then modelled using New Resource Partner's REDM model, drawing on real-world data on wind and solar generation. The modelled system is then subjected to a tough test: an extreme three-week 'wind lull' in the middle of winter, when electricity demand is at its highest. The lights stay on, and do so with less gas generation capacity than there is currently. Gas-fired power stations and interconnectors are vital alongside baseload generation (nuclear, biomass and hydro), while demand-shifting and storage smooth out peaks; but the model shows that the system performs well.

Next, the cost of the system is calculated. If it is assumed that all renewable energy projects currently in the pipeline are built – which is somewhat inevitable given that commercial contracts have been agreed – is it cheaper to stop renewables build out once the pipeline is exhausted and let gas take the load, or to continue building renewables up to the 50% level? In 2030, which of the two systems would be cheaper to run over the course of a year? Is the additional build, connection and intermittency cost of renewables more or less than the additional running costs of the gas-fired power stations?

The test is another tough one. The model assumes no further fall in the cost of renewables, and that all additional flexibility is provided by gas-fired power stations. The conclusion is that the overall costs of the two systems are broadly comparable. Initially the high-renewables design costs slightly more, but by 2030 it is cheaper to keep the lights on than in a system that burns more gas.

It is likely that in the real-world, the high-renewables system would deliver electricity more cheaply than in the low-renewables alternative, for three reasons:

- It is widely expected that the cost of new wind and solar capacity will continue to fall
- The model assumes that all additional flexibility needed to accommodate the additional renewables comes from gas. In reality, the market would allow competition from other flexibility mechanisms, such as storage, imports and advanced demand-shifting.
- The high-renewables scenario does not include additional revenue streams from, for example, selling excess summer electricity to generate hydrogen – a market that is expected to emerge – or the export of excess power.

Finally, this report considers some simple changes in regulations and standards that, in our view, can help unlock the full potential of a flexible grid, allowing maximum room for innovation.

No report should claim that it can see into the future. Nevertheless, the findings presented herein are consistent with others that have emerged in recent months. In May, for example an analysis concluded that no new large gas-fired capacity will be needed before 2025, despite the closure of UK coal power stations. This analysis asks and answers the two fundamental questions that are sometimes raised as objections to the further expansion of variably-generating wind and solar energy – it shows that they need be objections no longer.

1. Wind & Solar are Already a Mainstay

"WHEN YOU LOOK BACK IN 10 YEARS FROM NOW, WE'LL SEE THIS PERIOD AROUND 2016-17 AS AN INFLECTION POINT. THE COST OF OFFSHORE WIND, ALSO SOLAR AND ONSHORE WIND, IS COMING DOWN AT SUCH SPEED THAT NOBODY COULD HAVE PREDICTED."

–Henrik Poulsen, CEO, DONG Energy[1]

1.1. Where We Are Today

Renewables are a mainstay of UK electricity. Together this group of technologies produced 29% of our electricity in 2017, up from 25% in 2016[2]. Even more significantly, and despite persistent exaggeration of the impact of their "intermittency", wind and solar PV power were producing 19.4% of all UK electricity by 2017[3](Figure 1).

KEY POINT: VARIABLE RENEWABLE ENERGY (WIND AND SOLAR PV) GENERATED 19.4% OF ELECTRICITY IN 2017.

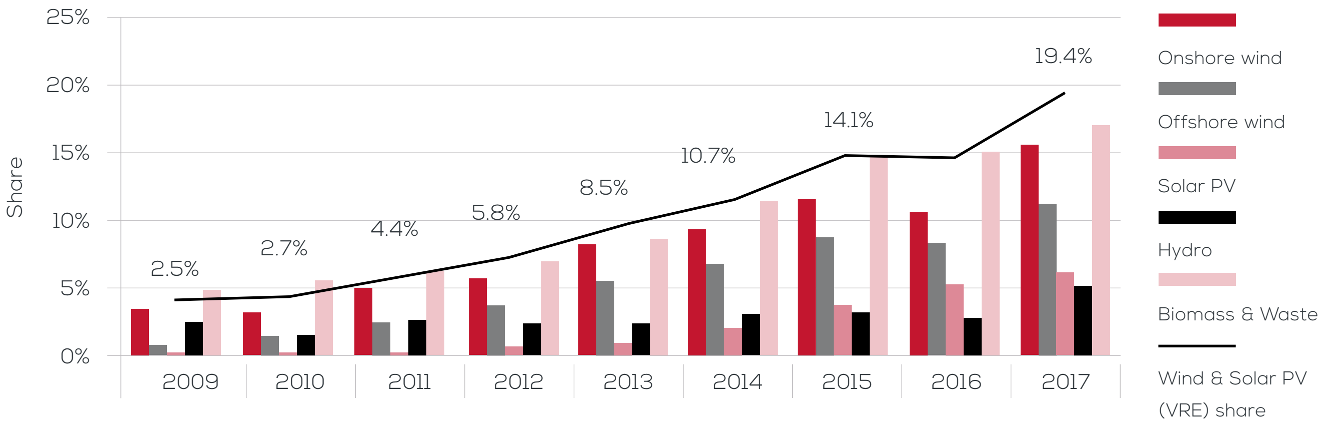


Figure 1: Renewables' share of electricity production
Data from BEIS 2018

The rise of renewables is not a solely British phenomenon, and other European countries utilise wind and solar more than the UK. Denmark leads: wind power made up 44% of its electricity consumption in 2017[4]. But Denmark is a special case: being part of two larger power systems (German and Nordic) makes it particularly flexible. But Portugal, Spain, Ireland and Germany all got more than 20% of their electricity from wind and solar in that year (Figure 2).

KEY POINT: MANY EUROPEAN COUNTRIES ARE UTILISING WIND AND SOLAR PV.

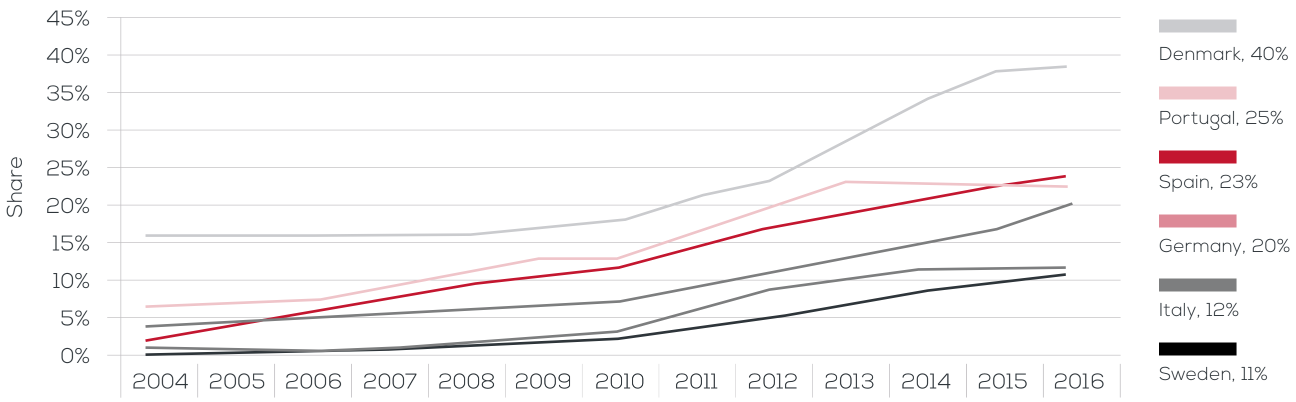


Figure 2: Rising shares of variable renewable energy in Europe to 2016, selected countries
Data from Eurostat 2018

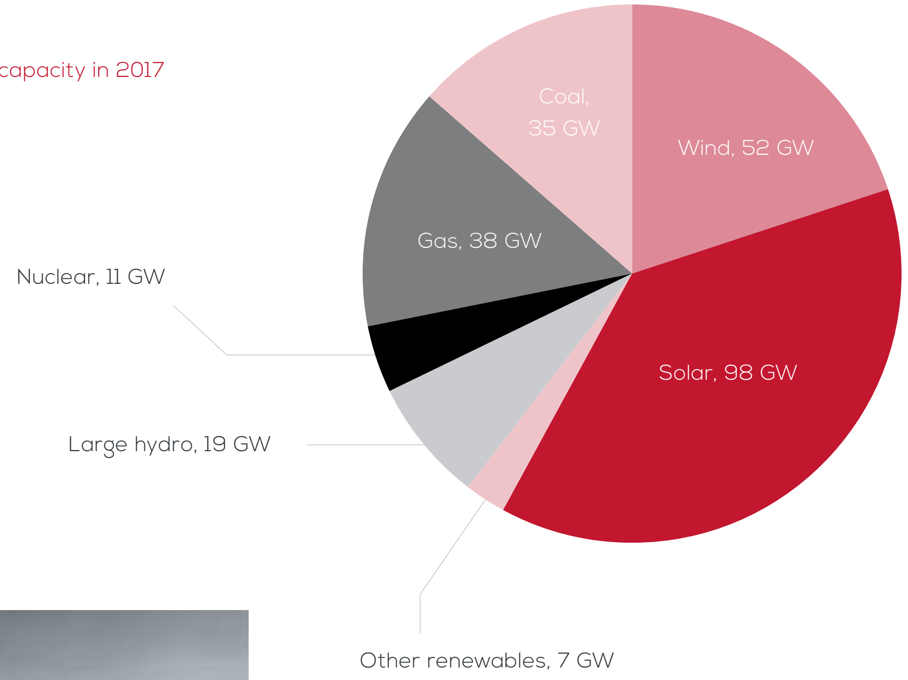
[1]Note that DONG has subsequently changed its name to Ørsted having divested its oil and natural gas assets. Source: Investment Observer 2018.
[2]Source: Carbon Brief 2018 | [3]This report focuses on the power system in the island of Great Britain. Though part of the United Kingdom, Northern Ireland is part of the Single Electricity Market of the island of Ireland. Most Government data is for the UK rather than GB. As Northern Irish installed capacity is an order of magnitude smaller than GB capacity, at times this report uses UK data as a proxy for GB.
[4]Source: Dansk Energi 2018

[5]Source: FS-UNEP 2017
[6]Source: FS-UNEP 2018

Worldwide investment in new renewable energy capacity surpassed investment in fossil fuel power plants some years ago[5]. In 2017, the worldwide renewable market was worth $280 billion (excluding large hydropower), roughly twice the investment in fossil-fired power plants. 157 gigawatts of renewable capacity were installed (exc. Large hydro), 61% of all generation capacity installed in that year. Investment in variable wind and solar PV represented 96% of the renewable total[6].

KEY POINT: RENEWABLES MADE UP 61% OF ALL NEW GENERATION CAPACITY WORLDWIDE IN 2017.

Figure 3: Global deployment of generation capacity in 2017
Data from FS-UNEP 2018



[7]Source: Arup 2017
[8]Source: DECC 2015

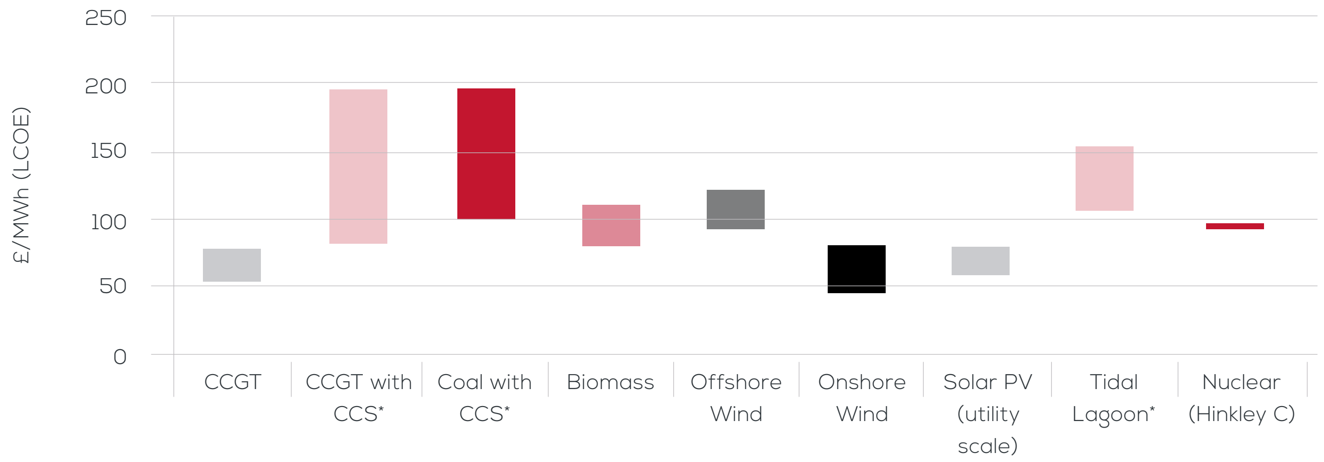
Factors driving this investment switch include public support, short project lead times, simplicity of technology, environmental concerns (air quality and climate change) and, notably, rapidly falling technology cost.

Onshore wind may already out-compete new build gas in the UK on cost. Arup estimated a unit cost in 2017 of around £50-55/MWh[7], although this has yet to be proven given the effective moratorium on new onshore wind in recent years. In any case, the UK's Department for Business, Energy and Industrial Strategy (BEIS) expects that both wind and solar PV will be competitive by 2020 – even if the cost of carbon is not included (Figure 4).

Meanwhile the cost reduction rate of offshore wind has confounded even its most optimistic advocates. In September 2017, the Moray East wind farm secured a contract to deliver offshore wind energy for £57.50/MWh in 2023. This was a dramatic fall in costs relative to BEIS expectations, at less than half of the average contract price awarded in the previous round of auctions in 2015[8].

KEY POINT: RENEWABLE ENERGY IS COMPETITIVE ACROSS THE BOARD BY 2020.

Figure 4: Electricity production cost (LCOE) by technology in 2020
Source: BEIS 2016, CCC 2017 (asterisks).



Notes: Levelised Cost of Energy (LCOE) is a measure of the lifetime cost of energy, accounting for capital, operating and fuel costs. LCOE for fossil-fired plants ranges from Low CAPEX and low fuel cost, to High CAPEX and high fuel cost. Nuclear value shown is the price agreed with EDF for electricity from Hinkley C (£97 per MWh in 2015 terms).

[9]I.e. a mean global temperature rise due to anthropogenic greenhouse gas emissions that is limited to 2°C.

1.2. Variability: No Problem

> "IT WAS SAID OUR POWER SYSTEM COULD NOT COPE WITH A SIGNIFICANT PERCENTAGE OF OUR POWER COMING FROM RENEWABLES. THE DOUBTERS HAVE BEEN PROVEN WRONG […] AND OUR ELECTRICITY SUPPLY REMAINS THE MOST RELIABLE IN EUROPE."

-Greg Clark, Secretary of State for BEIS, November 2016

Growing reliance on wind and solar PV raises new issues for network operation because these technologies are weather-driven and so cannot be turned on and off at will.

A few years ago, it was widely believed that having anything approaching today's output from variable renewables would cause major problems for the GB system operator, National Grid. System operators from Germany to Spain once claimed that just 1-2% of wind-generated electricity would destabilise grid frequency and lead to blackouts. In every case, they have discovered that much larger shares are perfectly feasible.

In its Future Energy Scenarios, National Grid acknowledges the pace and scale of energy transition in the UK. In its "Two Degrees" Scenario , the system operator forecasts that wind, solar and marine technologies could generate 61% of electricity by 2030 (Figure 5)[10].

KEY POINT: WIND, SOLAR AND MARINE TOGETHER COULD PROVIDE 61% OF ELECTRICITY IN 2030.

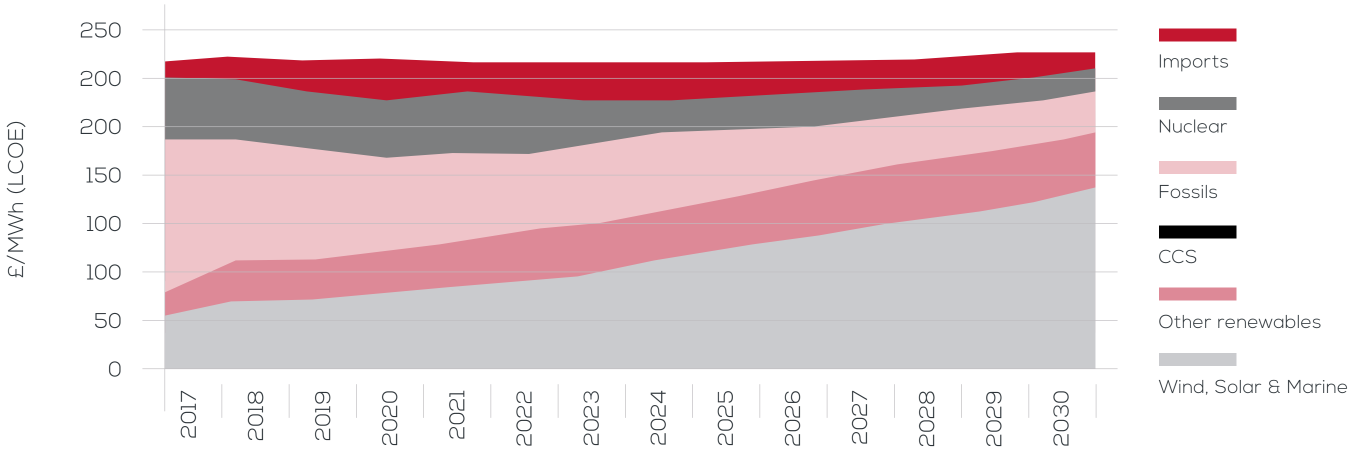


Figure 5: Electricity production in National Grid's "Two Degrees" Scenario
Data from National Grid 2018

These figures for wind and solar may end up being under-estimates. GB's prospects for building a new fleet of baseload nuclear power stations to open from 2025 onwards, as envisaged by BEIS (Figure 6), look increasingly unlikely. If fewer than the four new stations it envisages coming online by 2030 actually materialise, the generation gap will most likely be filled with a combination of technologies including wind and solar, as highlighted by the Committee on Climate Change (CCC) in its most recent Progress Report to Parliament[11].

KEY POINT: EXPECTATIONS OF NEW NUCLEAR MAY BE LESS THAN REALISTIC.

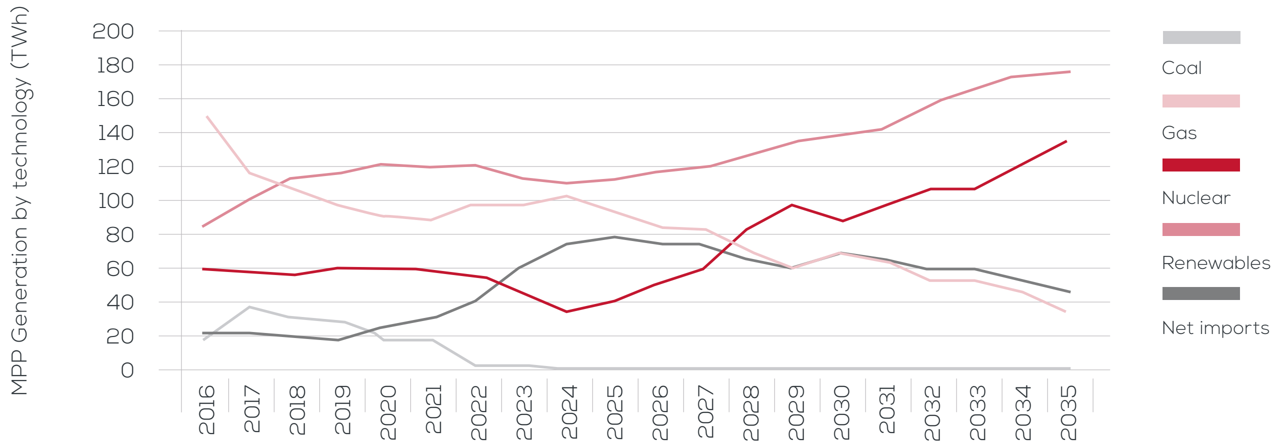


Figure 6: BEIS projections of electricity generation in 2035
Source: BEIS 2016

[10]And it is interesting to note that even in their most conservative assessment, wind, solar and marine would provide 40% of all electricity.
[11]Source: CCC 2018

2. More Flexibility is Needed

"OUR ENGINEERS SAY THAT 2015 WAS THE LAST YEAR WE OPERATED THE SYSTEM IN THE WAY IT HAS OPERATED FOR THE PAST FIFTY."

- John Pettigrew, CEO, National Grid[12].

2.1. The New Energy Paradigm

The advent of large-scale wind and solar does pose new challenges. For system operators, they mean an end to the old days when the output of the generation fleet could be predicted and planned months ahead. For utilities, they threaten the traditional energy-only business model[13]. For Ofgem and BEIS, they have brought the need for fundamental reform of the electricity market.

It is true that the job of balancing the supply and demand of electricity becomes more complex and dynamic. The keys to ensuring continued reliability with minimal cost are:

1. Better use of the four flexibility mechanisms: demand shifting, storage, trade with Europe, and flexible power plants; and
2. Smarter system and grid operation.

The conventional power system was good for conventional utilities. Electricity could be sold long in advance of the time it was actually generated and consumed (with a measure of day-ahead trading to allow for fine-tuning). So returns could be modeled with a high degree of accuracy and new investments planned accordingly. Utility disruption is perhaps most visible in RWE and E.ON in Germany, both of which have now split off their increasingly loss-making conventional arms from their renewables businesses.

In a conventional power system, demand does not react to the price of supply because most consumers are neither aware of prices, nor able to respond in time. So, the traditional "demand curve" repeats itself daily and seasonally in a fairly repetitive way, bar the odd unexpected storm, demand peak or other contingency (Figure 7).

Demand remains largely predictable today, though it is limbering up to become more responsive to price. But supply has changed a great deal. Cheaper renewable generation pushes conventional plants out of the "merit order", the cost-based order in which power plants are scheduled by the market to operate.

Thus the job of so-called dispatchable power plants (i.e. those whose output is not weather-driven) is becoming increasingly that of meeting net demand (i.e. the residual demand still to be met after wind and solar electricity has been accounted for). As the share of wind and solar PV on the system increases, this net demand becomes an increasingly moveable feast, only knowable with some confidence on the day before, as the weather comes into focus.

KEY POINT: TRADITIONAL POWER SYSTEM DEMAND COULD BE PREDICTED LONG IN ADVANCE.

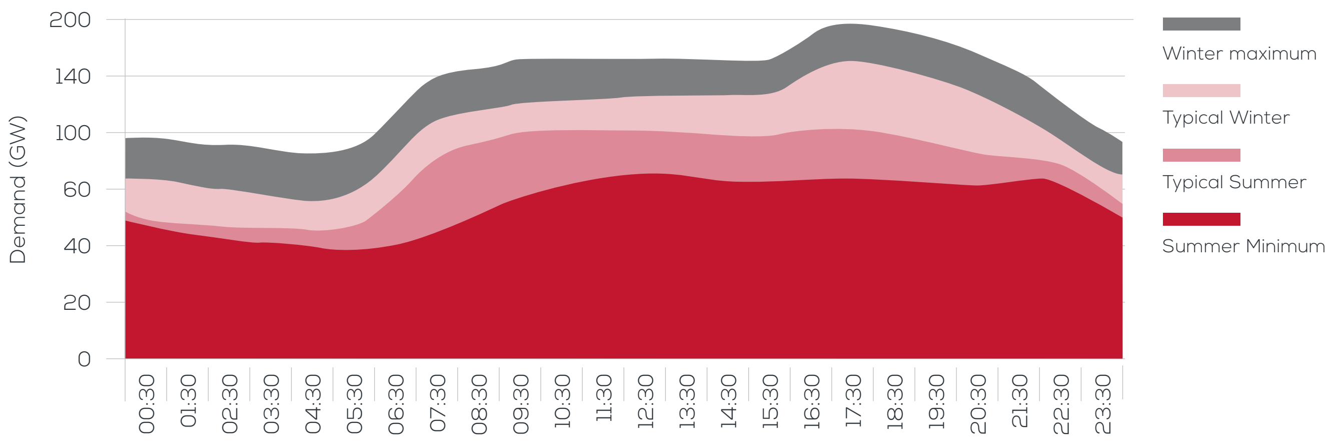


Figure 7: A conventional daily electricity demand curve
Source: National Grid 2011

Although reliable and predictable, the conventional power system was not very efficient in at least one important respect. The energy market ensured that generation capacity would be installed to a level as high as the highest peak, plus a certain system margin in case of outages. This means that many power plants are unused for much of the time. Recent research from Imperial College London suggests an average utilisation rate of 55% across all types of generation in 2015[14].

And as wind and solar PV share continues to rise there will increasingly be times when their output meets the entirety of demand. At such times, net demand is zero. This is already seen in regions of Germany, Denmark and Spain and it means there is no need for output from conventional power plants at such times, which has an impact on their revenue. Indeed, if gas plants are not to be moth-balled too soon then the design of the power market must evolve to reward them for the services for which they are still needed.

Nuclear power plants add to the flexibility conundrum. A given nuclear unit may be physically able to change its output to some extent; but if only baseload operation (i.e. generation more or less round the clock) is economic, otherwise at times of zero net demand pressure may build to curtail other types of plant.

And if wind power curtailment – 3% already in 2017[15] – rises above a sustainable level then the same economic problem arises, and GB would risk the spectacle of nuclear plants operating around the clock (to satisfy their investors), receiving generous and guaranteed prices all the while cheaper wind electricity is dumped.

In contrast, the cost of curtailing a gas plant may seem to be negative, as valuable fuel is saved. But if the gas plant goes out of business then there may be a cost measured in reduced system reliability when the wind falls away.

Fortunately, there exist already a number of flexibility mechanisms that have the potential not only to enable the power system to accommodate a very large share of variable renewables, but also to manage the inflexibility – economic or physical – of the nuclear power plants currently under in development.

[12]Source: Financial Times 2016
[13]Power plants also receive payments for system services, based on the availability of their capacity to operate, e.g. for frequency control.

[14]Source: Imperial College 2017
[15]This is due to grid bottlenecks. Source: Enappsys 2018

2.2. The Power of Flexibility

FLEXIBILITY CAN BE FOUND IN MANY OF THE DIFFERENT ASSETS THAT MAKE UP THE BRITISH POWER SYSTEM, IN THE WAYS ELECTRICITY IS GENERATED, DISTRIBUTED, STORED AND CONSUMED. THE ROUTE TO EFFICIENT AND RELIABLE DECARBONISATION OF THE POWER SYSTEM LIES IN MAKING BEST USE OF EXISTING FLEXIBLE RESOURCES, THEN DEPLOYING ADDITIONAL RESOURCES WHEN AND WHERE NEEDED. THIS REPORT FOCUSES ON FOUR KEY MECHANISMS:

Flexibility will be provided by a combination of these resources; none is a panacea. But these flexibility measures are described as 'no-regrets' options by the National Infrastructure Commission: they have wide system benefit (not just management of wind and solar).

1. **Demand shifting: moving a measure of electricity demand a few hours forward or back to fit better with variable timing of supply.**
2. **Energy storage: storing surplus electricity in one form or another, for use later.**
3. **Trade with Europe: exchanging supply surpluses and managing deficits in the usual way of trade.**
4. **Flexible power plants: generating electricity in specially designed, dispatchable power plants as necessary to make up the shortfall, and so meet net demand.**

For example, one important service traditionally provided by large conventional power plants is system inertia – the ability of large rotating masses in thermal power stations to help balance the electricity system. With sufficient system inertia, the rate of change of system frequency is easily controllable. With the closure of such plants, it could become difficult. However, "synthetic" inertia can be provided also by the other flexibility mechanism, e.g. batteries, reducing further the need for conventional plants.

[16]See http://powerresponsive.com/faqs/ | [17]The Economy 7 tariff for domestic consumers means that the hours from midnight to 7am are cheaper.
[18]Currently, the GB definition of demand shifting includes generation from small units "behind the meter" that a consumer may have installed, against contingencies for example. These can be turned on or off and so reduce / increase its consumption of power from the national grid. As such this is really supply-switching rather than demand shifting. If the generator is diesel-fired then this is sub-optimal for reasons such as local air pollution and CO2 emissions (diesel generation can be nearly as carbon-intensive as coal). | [19]See https://www.nationalgrid.com/uk/electricity/balancing-services/reserve-services/demand-turn as well as http://eciu.net/blog/2017
turn-it-up for a recent discussion of this new service.

2.2.1. Demand Shifting

"IF JUST 5% OF PEAK DEMAND IS MET BY DSR SOLUTIONS, THE RESPONSE WOULD BE EQUIVALENT TO THE GENERATION OF A NEW NUCLEAR POWER STATION".

- National Grid[16]

The market for electricity is unusual in that demand, historically, has been unresponsive to supply – at least in the short term. Demand shifting (a.k.a. demand-side response, DSR, demand response) is still a fairly new term in the mainstream. It encompasses actions by electricity consumers to alter their time of electricity consumption, moving it forward or back by a few hours to exploit cheaper prices during times of more plentiful supply.

Demand shifting is distinct from demand management actions, which are planned in advance. A smelter with a demand management contract, for example, can respond to a telephone call from the system operator by turning down its consumption to a pre-agreed and contracted level, and be compensated for doing so. In the domestic sphere, since 1978, some consumers have been incentivised to consume more at night and less in the day through the Economy 7 programme, among others[17].

While achieving the same outcome, demand shifting is a much more sophisticated and dynamic response by consumers, to provide flexibility in the very near-term – potentially instantaneously – and therefore useful in the management of near-term supply-side variability[18]. Consumers might be aggregated in advance so that their potential to respond is known ahead of time; but their actual response is not planned in advance, and is tightly linked to shifting market prices.

Reducing demand during peak hours ensures that the most expensive and least efficient power stations do not need to be fired up, thereby saving consumers money and reducing carbon emissions.

An ideally functioning market provides strong price signals indicating scarcity or abundance, to which consumers (and suppliers) can respond. While this is increasingly the case for wholesale market customers, it is not so for retail market (i.e. domestic) customers who pay a fixed price per kWh.

As well as to decrease demand, demand shifting can be used to increase it, for example when solar output is high during summer months. National Grid's demand "turn-up" service is now in place to improve the match between demand and solar output[19].

The gathering ("aggregation") of consumers into larger blocks could make the relatively small values represented by individual consumers more attractive to the market. Commercial and industrial consumers are more readily aggregated than domestic consumers at present.

Domestic smart meters will help: the right technology (not all smart meters are so smart) can communicate half-hourly consumption data to suppliers who could then offer their flexibility to the market, as aggregators. Smart appliances can automate demand shifting (thus reducing the effort of response – an important success factor). These could respond either to a signal from suppliers or directly to a physical signal from the power system.

The benefit of demand-shifting contracts is likely to be disproportionately large, as they could reduce greatly the need for peak (the most expensive) generation capacity. Replacing just 5% of peak demand with demand response would provide the equivalent of the power output of a nuclear power station, according to National Grid.

It seems clear that the UK is not exploiting demand shifting to its full potential. Government analysis and recent research suggests that demand shifting amounted to less than 2% of peak demand in 2014/15[20].

The potential is much greater. Ofgem suggests that approximately 3 GW of turn-down demand shifting and 1.9 GW of turn-up might be made available in GB today, if important barriers were removed[21]. Aurora Energy Research believes the GB potential to lie around 8 GW – 5GW from industry and commerce, and 3 GW from domestic customers. And the Association for Decentralised Energy finds that the potential could be 9.8 GW in 2020, nearer 9% of peak demand[22].

Demand shifting in the United States is more advanced, having been embarked upon earlier. Across the seven regional wholesale electricity markets of the US, peak demand response potential stood at 6.2% of peak demand in 2015[23], while in New England the proportion reached 10%[24].

2.2.2. Energy Storage

Electricity cannot be stored cheaply for long, but it can be turned into other energy forms that can be. As potential energy in water behind a dam, as electrochemical energy in a battery, as compressed air underground, and in a host of other forms, energy can later be turned back into electricity virtually instantaneously to provide energy and/or services to the grid.

Surplus wind and solar energy can be stored for use during calm days, night time demand, or the morning upswing in demand. Storage can help manage grid bottlenecks and avoid expensive and time-consuming grid upgrades, or the constraint payments to renewables that otherwise result, i.e. energy that might otherwise have been just surplus to requirements at the time it was produced, finds value.

Like interconnectors and demand response, storage offers flexibility in two "directions," to a conventional power plant's one. On a windy day when gas plants make way for wind energy, once they reach their minimum output level they can drop no further without shutting down completely. In contrast, a storage unit can go from maximum output to zero and then begin to charge until it is filled up again[25].

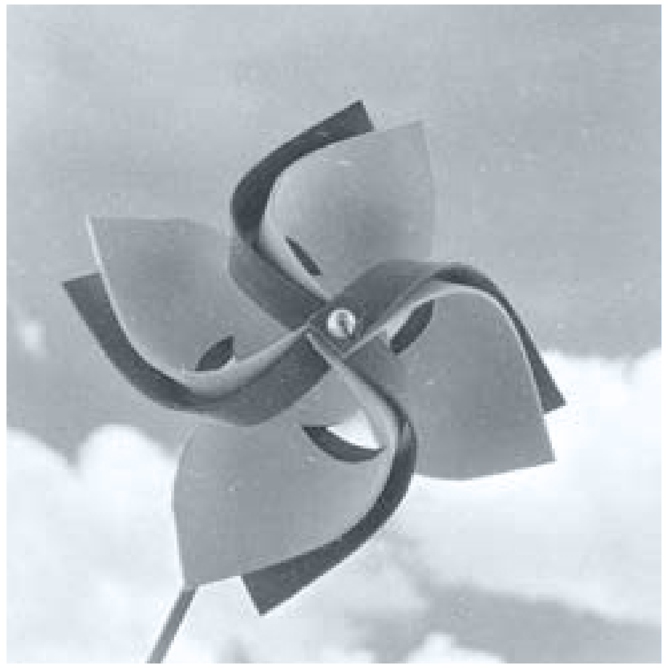
But storage is no panacea, not yet at least. The rate at which it can charge and discharge is only half of the story. A critical arbiter of a storage plant's value is the amount of energy it can store, expressed as a power to energy ratio. A high ratio means that a battery at full output will be exhausted quickly; while a lower ratio means it will be capable of output at full throttle for longer. Both have merits and are suited to different applications.

The Smarter Network Storage battery, for example, installed at a UK Power Networks substation in Bedfordshire, was the first large battery project in the UK (though already small by today's standards). It was commissioned in 2016, with a maximum output of 6 MW, for a duration of about 100 minutes (i.e. 10 MWh), giving it a power to energy ratio of 1 : 1.7.

In contrast, pumped hydropower plants have a power to energy ratio of around 1 : 10, so the roughly 3 gigawatt's of installed capacity today can – if required – produce power at full for around 10 hours (30 gigawatt hours), until there is no more water in the upper reservoirs to run downhill and through the turbines.

Though falling fast, the cost of battery cells today limits the energy storage of battery projects (i.e. the cost of the additional cells is not covered by the revenues available to such projects). This means for example that "one-hour batteries" are still common (i.e. 1 : 1). The February 2018 capacity market auction recognised this by lowering the "de-rating" factor of battery projects according to the duration of their output, i.e. reducing payments to batteries of shorter duration.

Among storage technologies, only pumped hydropower is fully commercial today[26]. It makes up 99% of the approximately 140 gigawatts (GW) of energy storage installed worldwide. However, the last pumped hydro installation in GB was commissioned in the 1980s. Originally developed to provide flexibility to manage inflexible nuclear power plants, the market has since stalled.



[20]Source: Green Alliance 2016
[21]Source: Ofgem 2016a
[22]Not including combined heat and power (CHP) plants and back-up generators installed behind-the-meter at industrial sites (5.3 GW). Source: ADE 2016.
[23]In ISO / RTO markets. Source: FERC 2015.
[24]Source: ISONE 2016
[25]Source: Vassallo 2013

But with the new need for flexibility resulting from wind and solar PV, the market is stirring again, including a proposed 100 MW scheme in North Wales (Glen Rhonwy), as well as a 400 MW scheme at Glenmuckloch, and plans to extend by 600 MW the existing Cruachan plant, both in Scotland.

Battery storage is much younger, and developing fast, as reflected in its steeply falling cost curve. The cost of Lithium ion (Li-ion) batteries, currently at around $180/kWh, has fallen by 79% since 2010, a rate to rival that of solar PV; and costs are expected to fall by more than 60%, to $70/kWh by 2030[27].

The recently crossed $200/kWh threshold is important: at this point battery projects become competitive with others sources of flexibility such as new open cycle gas plants; and new applications become more viable, such as hybridisation with solar and wind farms.

Installed battery storage capacity reached around 200 MW in GB by the end of 2017. The 10 MW plant at Carrickfergus coal-fired power station in Northern Ireland was the first fully commercial battery, with plans to extend to 100 MW. Drax is furthering its departure from coal with plans for a 200 MW battery plant at its site in North Yorkshire[28].

Meanwhile the project pipeline extends to some 8 GW in total, and the National Infrastructure Commission has found that up to 15 GW of storage could be deployed economically by 2030[29].

Major battery energy storage potential will also be realised in the deployment of electric cars, vans and other vehicles. There are around 135,000 plug-in cars in the UK as of January 2018[30]. The CCC targets 60% sales of electric cars and vans by 2030, and the Government in its Clean Growth Strategy targets an end to the sale of fossil-fuelled cars and vans by 2040[31].

National Grid forecasts that there could be as many as 10.5 million electric vehicles by 2030[32]. If each can store 40 kWh of electricity (which is the present norm for a Nissan Leaf), then this fleet would represent some 420 GWh of energy storage, more than a thousand times the grid-connected battery storage deployed today.

How to harness this storage so that it can be used to balance the grid is in its infancy. A number of commercial companies are exploring it, such as EDF's V2GO scheme, and the Government announced a £30 million fund to explore the potential in February 2018[33].

The potential is as yet unclear, but a simple estimate suggests the potential is large. A vehicle connected to the grid must be stationary, and the RAC Foundation estimates that cars are parked at home for 80% of the time[34]. If the 2030 fleet envisioned by National Grid could provide just 23% of its stored energy during a peak demand hour[35], this would be enough to cover demand for that hour entirely.

[26]In a pumped hydropower plant, water can be pumped uphill back into the reservoir at appropriate times (during surplus / low power price) for release through the turbines at a later time.
[27]Source: Bloomberg 2018
[28]See https://www.drax.com/press_release/drax-starts-planning-process-battery-storage-gas-options/
[29]Source: NIC 2016
[30]See http://www.nextgreencar.com/electric-cars/statistics/

2.2.3. Trade With Europe

Great Britain is connected to the European mainland via three gigawatts capacity of high voltage cables, to France (the IFA interconnector) and to The Netherlands (the BritNed interconnector). A further 4 GW of interconnectors have reached final investment decision and are expected to come on stream before 2020. The Nemo line, for example, currently under construction between GB and Belgium is scheduled for commissioning in 2019.

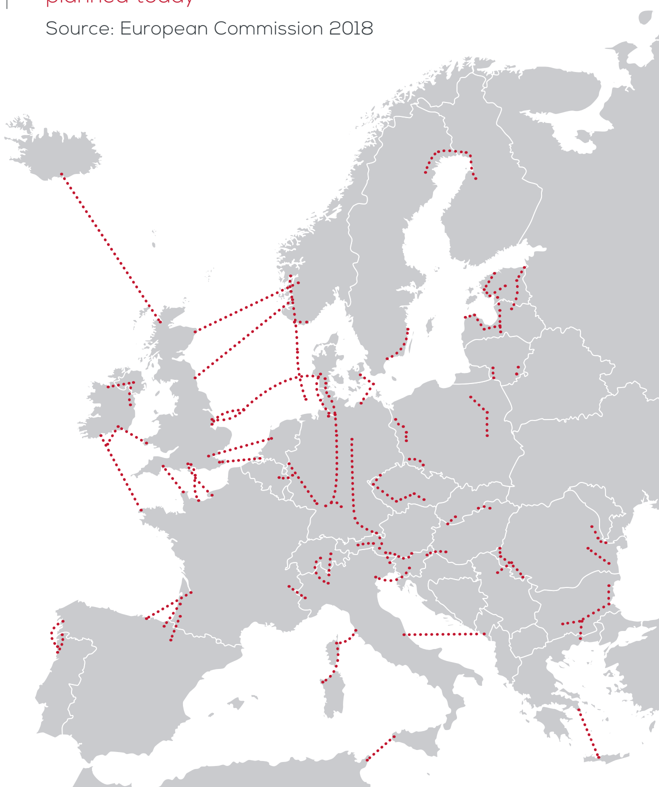
The Committee on Climate Change expects that up to 11 GW of interconnectors could be operating in 2030 (CCC 2017), while the National Infrastructure Commission expected this level to be reached in the early 2020s (NIC 2016). 17.5 GW of interconnector projects, at various stages of development are listed on the European Commission's European Interconnector interactive map between GB and its neighbours (Figure 8).

As with any kind of trade, both GB and its neighbours benefit. For GB it is has represented an important support to security of supply and cheaper prices. And as the European electricity market develops so that the day-ahead and intraday electricity markets can include these cables, they will represent an increasingly important flexibility resource. While GB is currently a net importer, some projections see GB becoming a net exporter of low cost wind power to neighbouring nations[36]. (Germany, for example, earned €2 billion from export of surplus electricity in 2015[37].)

Norway, for example, has a large installed capacity of, and additional potential for, pumped hydropower capacity. Surplus wind power is imported from neighbours and used by Norwegian hydropower companies to pump water uphill into their reservoirs, which can then be released – and electricity exported – when the wind drops. Two interconnectors to Norway are planned from Scotland and the North of England, which would allow Norway to share the value of its pumped hydro facilities.

Figure 8: European high voltage interconnectors planned today

Source: European Commission 2018



KEY POINT: EUROPEAN INTERCONNECTOR PROJECTS WILL PLAY A MAJOR ROLE IN SMOOTHING THE AGGREGATED OUTPUT VARIABILITY OF WIND, SOLAR AND MARINE POWER STATIONS.

[31]Source: BEIS 2017 | [32]Includes plug-in hybrid electric vehicles (PHEVs). Source: National Grid 2017b. | [33]Source: https://www.gov.uk/Government/news/30-million investment-in-revolutionary-v2g-technologies | [34]Source: https://www.racfoundation.org/motoring-faqs/mobility#a5 | [35]National Grid's 2 Degrees Scenario sees peak demand of 65 GW in 2030 (source: National Grid 2017b) | [36]See http://publicinterest.org.uk/offshore/ | [37]Source: Frauenhofer Institute 2016

2.2.4. Flexible Power Plants

Traditionally, the term "flexible" was applied to dispatchable power plants, i.e. those which can be turned on and off, burning stored fuel such as gas, coal or biomass, or releasing water from behind a reservoir. And it is quite possible that there will long remain a role for fast-response power plants that burn some form of fuel. But there are important limits on the extent to which such plants can provide flexibility:

1. Maximum ramp rate: the fastest rate at which the plant can change its output.
2. Minimum stable level: the lowest a plant's output can limber down before it has to be turned off completely.
3. Number of cycles: plants may be limited technically and/or by warranty in the number and extent of changes in their output.

In the minds of many, large gas-fired plants still represent the greatest flexibility opportunity. But investor interest in such plants is minimal, partly due to revenue uncertainty in the wholesale energy market. Only one, ESB's 880MW plant at Carrington in Manchester, has been commissioned in recent years (in 2016).

This revenue uncertainty results from the rapid rise of wind and solar PV, which once built have near-zero instantaneous generating costs. The "merit order effect" sees gas-fired plants pushed from their usual role as price-maker by these low marginal cost technologies. And this situation has not been eased by years of uncertainty stemming from long energy market reform.

Indeed, whether fuelled by natural gas, hydrogen or biogas, gas plants in the flexible power system of the future will see very different operating patterns from today. Instead of being planned in advance, their operation too will be weather-driven: ramping output up and down, more frequently and more steeply, in reaction to the changing output of wind, solar and marine power plants.

Operating for less of the time, they will continue to receive payment for the energy they produce, but increasingly this will be supplemented for payments for their dependability - their availability to operate should they be needed to do (hence the arrival of the capacity market in 2014). And while the overall capacity of gas plants will diminish somewhat, the amount of electricity they generate will fall dramatically (Figure 9).

New gas-fired technology is evolving to fit this new requirement. For instance, GE has installed a new 570 MW combined cycle power plant (CCGT) to replace EDF's previous coal-fired plant, at Le Bouchain in France. This highly fuel-efficient plant can power up from zero to full output in just 30 minutes, which is about 25% faster than conventional combined-cycle gas plants. Open-cycle "peaking" gas plants are still faster, and well suited to providing fast response to fluctuating wind and solar output, with capacity growing due to lower costs than combined-cycle alternatives, and greater demand for such peakers.

The four flexibility mechanisms described in this chapter are complimentary, rather than in competition with each other. For example, DSR can be more suited to short-term fluctuations in supply whereas gas units can run for hours or days without problem. Rather than prescribing capacities of each mechanism, a well-functioning market will determine the most effective balance.

KEY POINT:
AS ENERGY REVENUES FALL, DISPATCHABLE POWER PLANTS' REVENUE WILL RELY MORE HEAVILY ON PAYMENTS FOR DEPENDABILITY.

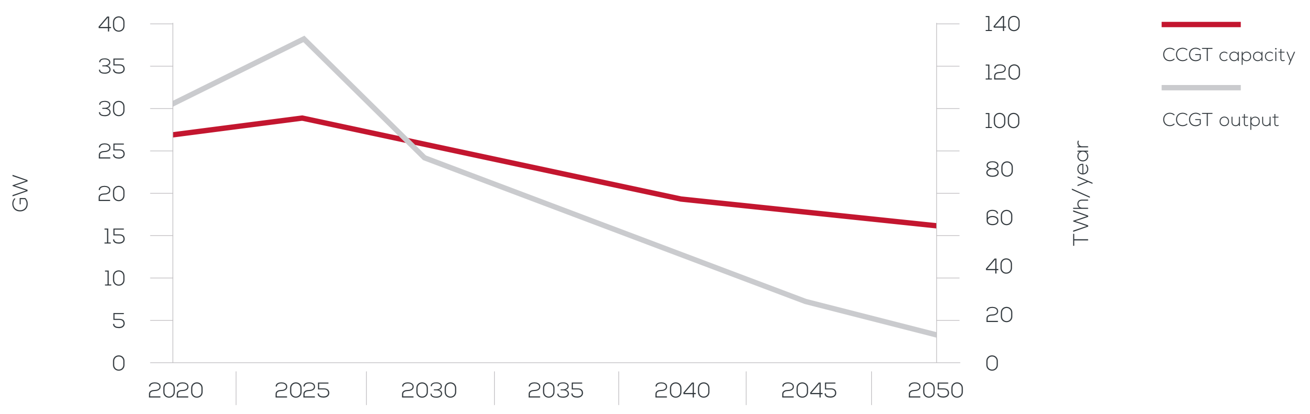


Figure 9: Projected gas capacity and energy production to 2050
Source: Carbon Trust 2016

3. What About When the Wind Doesn't Blow?

This is a common question, and reflects a widely held concern about "intermittent" renewables, particularly with regard to wind power (solar output being more regular).

The second related question is: how long will such periods – lulls in the wind – last? This is debatable because the answer depends on the geographic area being assessed. This chapter explains the challenge and lays out a conservative approach to its assessment.

3.1. What Makes a Lull?

How frequent are lulls? How long do they last? A commonly held understanding of the answer to these questions would go a long way to understanding the extent of the challenge they represent.

To complicate matters, the answers differ according to the source, and sometimes for good reasons. Is it a lull across Great Britain that is the concern? Or, given its interconnected role in the European power market, should we consider a lull across North West Europe, or over the entire of Europe, or even beyond that? Would Brexit mean we cannot rely on imports at all and must instead plan the power system in isolation from our neighbours?

The issues are as follows:

1. The extent to which the weather differs across Europe at any given time, such that the output of wind farms is smoother if aggregated over larger areas;
2. The extent to which such differences can be capitalised on by interlinking grids and trading more widely; and
3. The extent to which adjacent power markets can and should share their flexible resources to manage wind energy lulls (and surpluses).

Imperial College London and the Swiss Institute for Atmospheric and Climate Science, among others, define seven distinct wind regimes in Europe. Their research makes the point that – if wind capacity is dispersed across these seven regimes – then the result would be fewer and shallower lulls in the output of aggregated European wind capacity[38].

Even with an optimum dispersal of wind power capacity, this smoothing effect would never make wind as dependable as an equivalent capacity of a fuel-fired technology, but it would diminish the extent of lulls. This is where much of the value of interlinking European grids is to be found – though it is not the only value – and a large number of high voltage interconnector projects are in development today (Figure 8)[39].

KEY POINT: VARIABLE RENEWABLE ENERGY (WIND AND SOLAR PV) GENERATED 17.5% OF UK ELECTRICITY IN 2017.

[38]Source: Grams et al. 2017
[39]The original motivation of interconnected European grids was the reduction and harmonisation of power prices.
[40]See for example ERPUK 2015.

3.1. Planning for the Worst

This analysis presents a simple, highly conservative approach to gauging how GB would manage in the event of an extended lull. In an exercise to demonstrate system resilience, we assume that such a lull will occur, and have engineered the most extreme case.

This is not intended to be pessimistic. Rather, when the maximum possible extent of the extended lull is assumed, this exercise sheds light on the maximum extent of the need for flexibility. Different flexible resources can be modeled then, to meet that need.

Supply and demand in 2030 was modeled using New Resource Partners' Renewable Energy Deployment Model. 2030 provides a realistic time-frame in which variable renewable energy – wind and solar – could come to provide 50% of all electricity (this is less than projected by National Grid in its Two Degrees Scenario – cf. Figure 5).

Real hourly demand data for 2016 were used, with growth based on BEIS projections. Demand falls slightly to 2024, continuing the energy efficiency trend of the last decade (demand peaked in 2005), then picks up in line with BEIS's expectations of demand growth resulting from increased sales of electric vehicles.

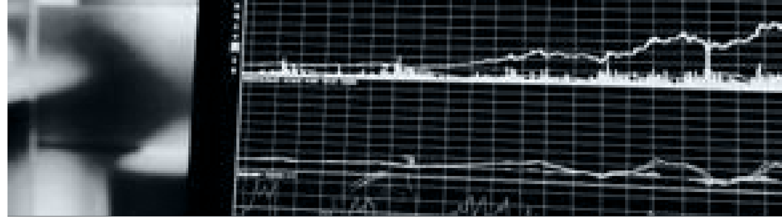
Real hourly wind and solar PV resource data from 2016 were used. No sufficiently extreme lull in wind output occurred for the purposes of this exercise, so an artificial extreme and extended lull was engineered, lasting three weeks. Three-week periods of low wind and solar output have been observed, though not entailing the almost total absence of wind output throughout as modeled here[40]. Our lull occurs in January, when electricity demand is at its annual high, to maximise the stress-test.

Installed capacities for all generation technologies follow BEIS projections up to 2020, after which wind and solar capacity is increased (largely at the expense of fossil) to meet 50% of electricity demand by 2030. 55% of the additional variable renewable capacity is assumed to be offshore wind, 10% onshore wind, and 35% solar PV. The amount of dispatchable nuclear, biomass and hydropower capacity is assumed to grow modestly (Table 1). Coal capacity is zero.

One of the objectives of the scenario is to estimate the amount of gas capacity needed to manage the extended wind lull. This means that gas capacity is not predetermined in the model (unlike other supply technologies); rather the amount of gas capacity installed is an output of the model, calculated to ensure that demand is met at all times.

Gigawatts capacity installed	Nuclear	Biomass	Hydro	Solar PV	Offshore wind	Onshore wind
2017	9*	5	2	12	5	12
2030	11	7	3	41	19	21

Table 1: Installed generation capacities in the 50% Wind and Solar Scenario
2017 data from BEIS
*Note: new nuclear may include the power plants currently under construction or in planning at Hinkley in Somerset, Wylfa in Wales, Sizewell in Suffolk, among others.



3.2. Flexible Power in Action

Using the methodology described above, the scenario shows how the GB energy system offers resilience in an extreme lull in the winter of 2030. This is a worst-case event that would lead to maximum stress on the electricity system in terms of supply availability.

On January 1st 2030, power is mainly provided by wind and nuclear power, with lesser amounts coming from biomass and hydro[41]. Then, at midnight on January 3rd, the wind begins to drop. It is overcast so when day comes solar power remains low. By mid-afternoon, wind output has fallen to just 500 MW, a little more than 1% of the 40 GW installed capacity, where it will stay for three weeks (Figure 10a-c). (Again, this is extremely unlikely: extended wind lulls do occur but there are periods wherein it recovers at least partially.)

Without the wind resource, a gap opens between supply from dispatchable renewables plus nuclear, and demand. In this simplified case, the extent of this gap represents the supply that needs to be provided by the four flexibility mechanisms. These are to some extent interchangeable; for example, altering the availability of demand shifting will have an impact on the need for the other three, though there are important differences, for instance in the duration of their availability (see Chapter 2).

KEY POINTS: 1) WHEN THE WIND FALLS, FLEXIBLE POWER ASSETS CAN STEP IN AND MAINTAIN RELIABLE ELECTRICITY SUPPLY.

2) ONCE THE MAXIMUM EXTENT OF THE LULL CHALLENGE IS UNDERSTOOD, THE FLEXIBLE RESOURCES NEEDED FOR ITS MANAGEMENT CAN BE QUANTIFIED.

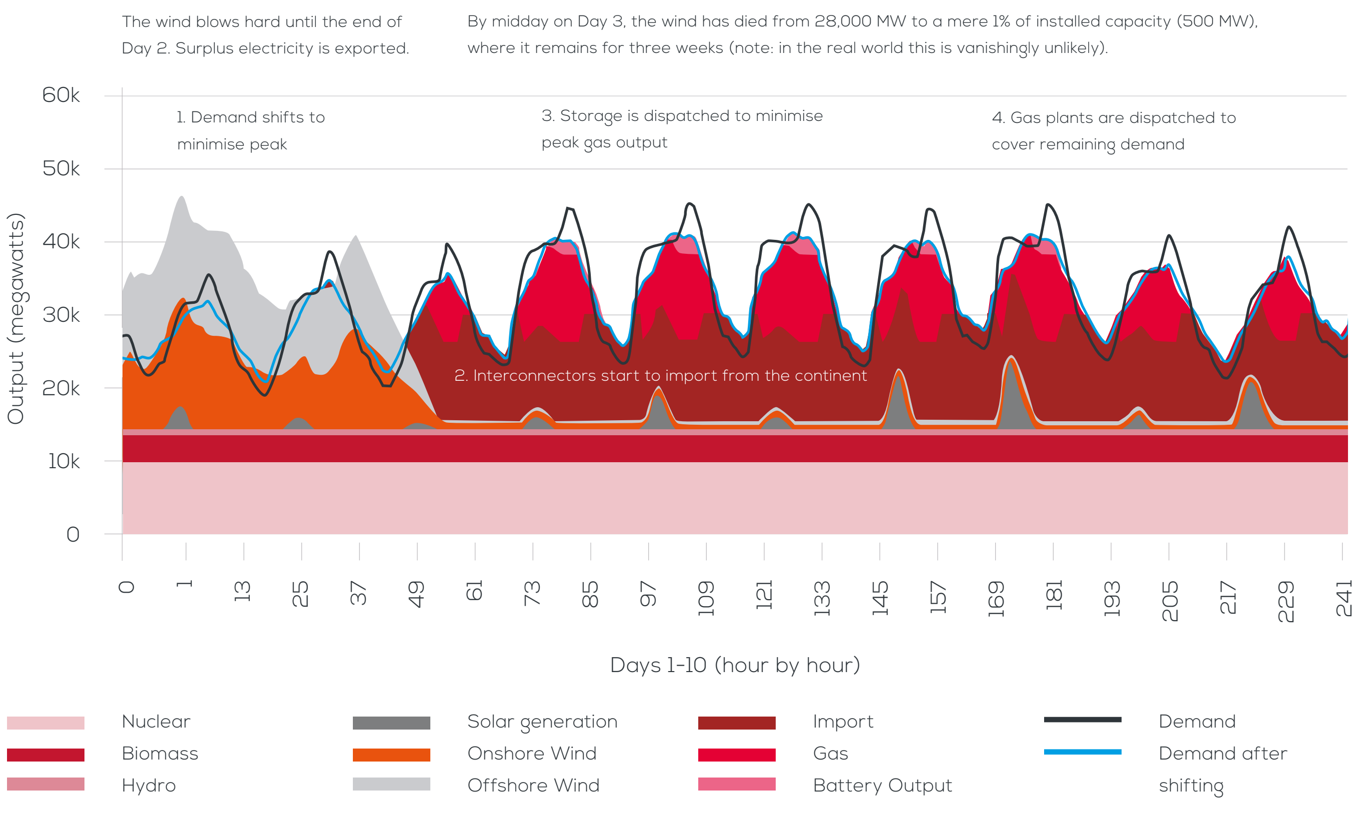


Figure 10a: Days 1-10
Managing an exaggerated winter wind lull with an illustrative flexibility portfolio

The days are almost completely calm. Demand continues to shift, interconnectors to import. Storage assets are used more heavily as demand rises above 50,000 MW and gas capacity continues to ill in as required.

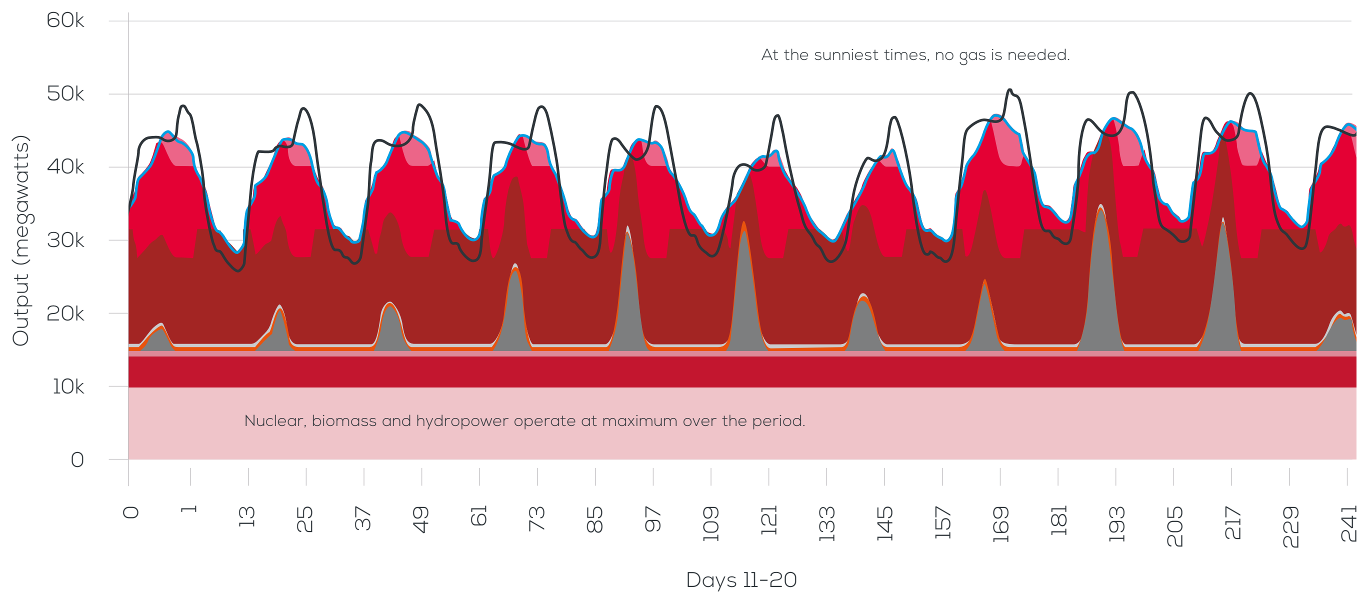


Figure 10b: Days 11 – 20
Managing an exaggerated winter wind lull with an illustrative flexibility portfolio

At the end of a third straight week of calm, the wind picks up again. Gas plants are dispatched to zero. Imports reduce, and storage assets no longer needed to meet peak are available again for other power market applications.

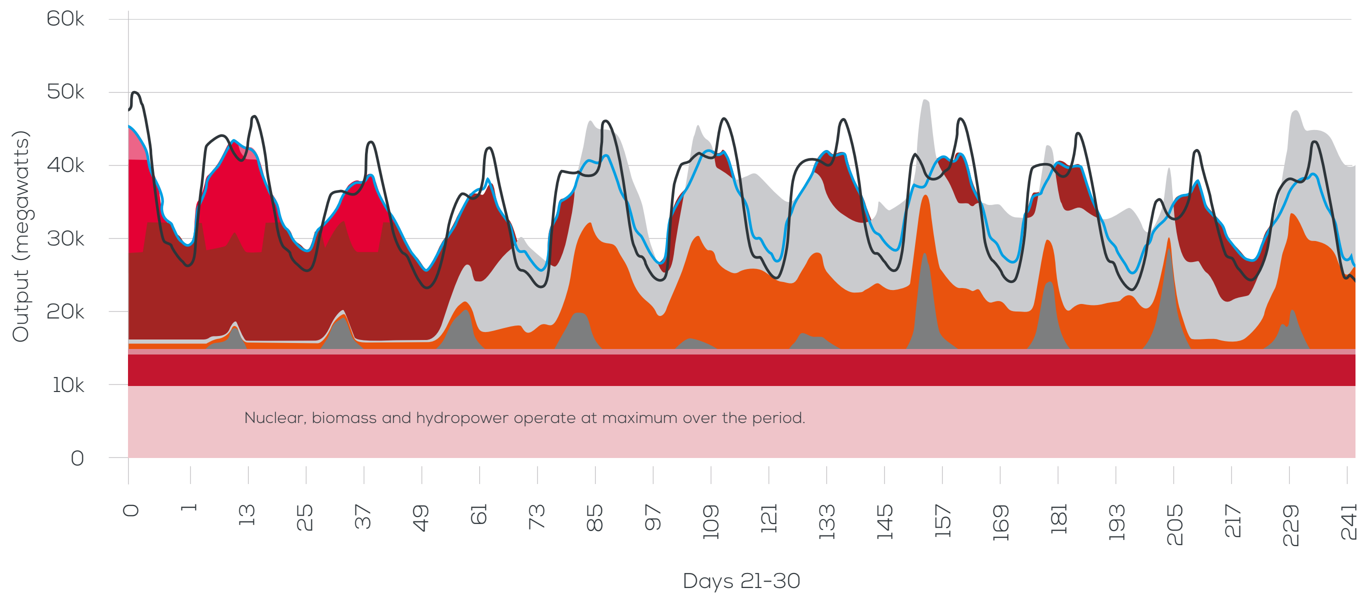


Figure 10c: Days 21 – 30
Managing an exaggerated winter wind lull with an illustrative flexibility portfolio
Source: New Resource Partners 2018

3.2. Flexible Power in Action

It is not known with any certainty what the capacities of the four flexibility mechanisms will be in 2030, nor the extent to which their capabilities will have evolved, but reasonable assumptions can be made based on present best practice (Table 2).

Flexible resource	Description	Assumptions for 2030
Demand shifting	Electricity consumption can be shifted forward or back six hours from any given hour consumption can be shifted forward or back six hours from any given hour.	10% of peak demand can be shifted, less in fact than that already achieved in 2014 in New England in the USA[42].
Storage plants	Storage capacity of all kinds: pumped hydro, Lithium-ion and Redox flow batteries, etc.	A portfolio of 15GW of pumped hydro and battery storage, in line with the National Infrastructure Commission's assumptions in 2016[43].
	Ratio of power to energy.	Stored power to energy ratio of 1:2. This is conservative. Pumped hydro plants have a ratio of 1:10, while some battery technologies that may be widely deployed by 2030 (e.g. Redox flow) may have ratios as high as 1:5[44].
Trade with Europe	Interconnections to France, Belgium, the Netherlands, Norway, Ireland, etc.	Installed capacity is 19.7 GW, up slightly from the already existing pipeline of 17.5 GW in 2018.
	Availability for import.	Daytime availability: 60%. Night time availability: 80%. Night time availability is assumed to be higher as demand on the continent is lower. The 2018 Capacity Market auction assumes that 63% - 85% of current interconnector capacity will be available to meet winter peak[45].
Gas capacity	A combination of combined cycle (90%) and open cycle (10%) gas plants, old and new.	**14 GW. This is an output of the model (not an input like the others) and is discussed below.**

Table 2: Assumptions about the four flexible power sources in the 50% Wind & Solar Scenario, 2030

The behaviour of the four flexibility mechanisms is as follows:

1. Firstly, demand is shifted within the parameters described in Table 2. In Figure 10 this shifts the demand to be met from the black line to the blue line.
2. Storage plants are dispatched in such a way as to minimise demand peaks and the amount of gas capacity needed, within the bounds of their energy storage limits (pink area in Figure 10).
3. Import from adjacent markets (orange area) is assumed in line with the assumptions in Table 2.
4. Finally, gas plants are dispatched until the storage plants are recharged / refilled, and until residual demand has been met (grey area).

This conservative analysis demonstrates that even an unrealistically severe lull in the wind resource need have no impact on GB's ability to "keep the lights on", even when wind and solar together provide half of our electricity over the course of a year.

Only some 14 GW of gas plant are required to be present on the system to meet demand in the most extreme wind lull event, as compared with the 32 GW of gas in our BEIS Reference case in 2030[46]. This is 38% of the 37 GW of gas capacity operational in 2017.

With demand shifting, imports and storage, this 14 GW of gas is sufficient to manage the variability of the 81 GW of wind (on and offshore) and solar PV combined. This effectively dismisses the myth, still occasionally cited, of the need for "megawatt for megawatt" fossil-fired backup.

And increasing the capacity of other flexible resources assumed in 2030 would decrease the amount of gas capacity needed still further. Demand shifting is assumed to amount to only 10% of peak, a level observed in some US markets already today.

Our storage assumption is also conservative, with a power to energy ratio of just 1 : 2, given that the ratio for Redox flow batteries, which may be deployed in volume by 2030, is already nearer 1 : 5, three times the ratio of commercial lithium-ion projects today.

This analysis highlights the great importance of European collaboration. In the case of an exit from the European Union, interconnectors will remain instrumental in the continued management of variable renewables. If an exit were to diminish the opportunity for investment in new interconnector capacity and/or reduce the liquidity of trade on existing interconnectors, their flexibility value would be constrained.

In such an eventuality, greater focus might be placed on building the demand response market as well as new storage technologies capable of economically storing large amounts of energy, including the expansion of the pumped hydro fleet.

Having established that even extreme variability / intermittency events need have no impact on the reliability of GB electricity supply, from a technical perspective, the next chapter asks what the cost of the 50% Wind & Solar Scenario – with much augmented flexibility – would be, relative to a more conventional future.

[42]Source: FERC 2015 | [43]Source: NIC 2016
[44]Such as redT's existing though smaller scale technology, see https://redtenergy.com/story/storing-solar-unlocks-grid-services-revenueindustrial-park-uk/
[54]Source: National Grid 2017c | [46]BEIS central projections are used.

4. System Costs of 50% Wind & Solar

"IF WE GET THIS RIGHT A SMART POWER REVOLUTION COULD SAVE CONSUMERS £8 BILLION A YEAR."

- National Infrastructure Commission[47]

An electricity system comprising 50% wind and solar power will require much greater use of flexible resources than is the case today (gas plants, energy storage, demand shifting, trade). Inflexibility, like variability, also has a system impact; and a measure of either must be balanced by a measure of flexibility.

Estimates of system costs, a.k.a. integration costs, or "whole system" costs (the cost of energy plus the cost of integration), vary dramatically. Extreme over-estimates (e.g. megawatt for megawatt back up) are becoming less common as experiences with solar and wind grow, and as the value of flexibility to the wider power system – e.g. in the management of inflexible nuclear – becomes clearer.

Additional transmission costs are another element of integration costs, and are not modeled in this analysis. For instance the output from remote wind power plants might be constrained by a weak grid between them and city load centres, which might need to be reinforced therefore. This has been the case historically between Scottish wind power and load centres to the south.

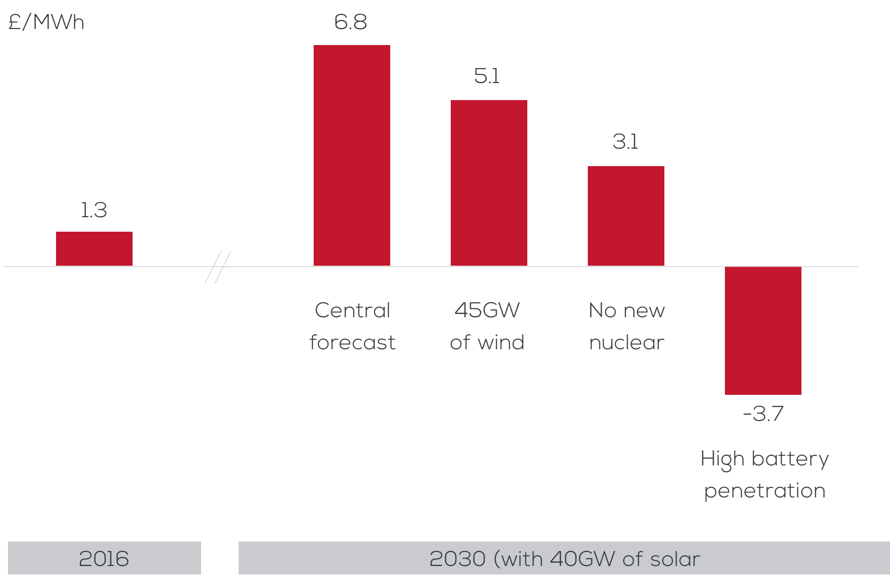
However, grid reinforcement, such as the Western Link commissioned in December 2017, a sub-sea cable running down the west coast, will benefit the wider system[48]. And local battery storage can help avoid grid constraints in lower voltage grids.

4.1. Quantifying Integration Costs

Recent analysis from Aurora Energy Research has found that the integration cost of the 11 gigawatts of solar PV installed in Great Britain by 2016 amounted to just £1.30 per MWh, or 1.6% of the production cost of large scale solar plants[49]. Their analysis goes on to envisage 40 GW of solar PV in 2030, when the integration cost rises to £6.80 per MWh.

This is equivalent to just 11.5% of the solar production cost modeled in 2030 in the 50% Wind & Solar Scenario. And this is for solar alone: if the rest of system evolves towards the flexible paradigm, the integration cost falls sharply (Figure 11).

[47]Source: NIC 2016
[48]See http://www.westernhvdclink.co.uk/
[49]http://www.solar-trade.org.uk/wp-content/uploads/2016/10/Intermittency-and-the-cost-of-integrating-solar-Aurora-Energy-Research-September-2016.pdf
[50]Note that wind capacity will incur its own integration cost. The Aurora analysis directly addressed solar integration cost only.
[51]At a storage cost of £100/kWh down from approximately £300/kWh at the time of the study.



KEY POINT: INTEGRATION COST OF VARIABLE RENEWABLES FALLS IF THE SYSTEM BECOMES MORE FLEXIBLE.

Figure 11: System cost of solar PV, £/MWh
Source: Aurora Energy Research 2016
Note: This research does not account for possible transmission and distribution costs.

The complementarity of wind and solar – i.e. that their peak outputs coincide rarely – means that, taken together, they are more manageable. While wind output follows no regular daily pattern and can only be predicted with good accuracy starting on the day ahead, solar PV output follows a clear daily pattern that, subject to cloud cover, can be more readily forecast. In Aurora's research, with 45 GW of wind also deployed by 2030, the solar integration cost falls by a quarter, to £5.10 / MWh[50].

The analysis further found that the inflexibility of nuclear power plants increased solar integration costs. A freeze on nuclear capacity halved solar integration cost in 2030 (to £3.10 / MWh), because more flexible technologies would be deployed to fill the gap.

Finally, Aurora found that the solar integration cost would go negative (-£3.70 / MWh) with the deployment of 8GW of storage technology, which is to say that solar plus storage would have a net system benefit[51]. This is because storage enables low value electricity (generated off peak, or when wind/solar output exceeds demand) to be stored and sold when it has value, while taking the place of costly gas peakers: a double dividend.

The Aurora research is just one example of a study into whole system costs. Others – including from Frontier Economics and from Imperial College – also show that integration costs are not excessive.

Importantly, the system cost of wind and solar may be outweighed by savings resulting from their deployment. While it is true that there is a cost to variability, it is equally true that the cost of renewable energy technology continues to fall rapidly; and once built electricity is produced at close to zero cost. In contrast the cost of gas fuel projected by BEIS is significant, volatile, and rising as a result of the rising cost of carbon.

4.2. Is 50% Wind & Solar More Expensive?

So, the variability of wind and solar power plants has a cost, and this amounts to the cost of the additional flexible power needed to manage their output – minus the benefit that flexible power brings to the wider power system, as highlighted in Figure 11. Thus more demand shifting to manage wind and solar output also means less need for (expensive) gas peakers to manage other factors – the inflexibility of nuclear, for example, and unexpected demand peaks. And when electricity is cheaper across the water it can be imported – if the interconnectors have been built.

But the economic part of this analysis (and in contrast to the lull analysis above) sets out to quantify what the integration costs would be of 50% wind and solar, if all flexibility were to be provided only by gas power plants and demand shifting. In other words if for some reason additional storage and interconnector capacity were to fail to materialise. This is done for simplicity's sake, but it is important to note that the results consequently reflect higher costs than would be seen if all four flexibility mechanisms were present in the cost analysis. This must therefore be considered as a highly conservative analysis[52].

We compare the 50% Wind & Solar case with a "BEIS Reference" case to establish which is the more expensive overall. In a nutshell, if the avoided cost of gas fuel and carbon outweighs the cost of renewable capacity – and system reliability remains constant (the lights stay on) – then the system with the higher share of wind and solar will be cheaper.

As before, an extended lull occurs in January, while the rest of the year is based on real wind/solar resource and demand data[53].

The BEIS Reference scenario is based on the Government's projections for installed wind and solar capacity in 2030, and 2016 resource data. Combining these two sets of data results in approximately 28% of electricity production from wind and solar PV in 2030.

Turning to electricity production cost: actual or estimated CfD "strike prices" were chosen where available over Levelised Cost Of Energy (LCOE). This was done to reflect recent price evolution observed in the market. For example, offshore CfD strike prices fall from £120 per MWh for projects commissioned in 2018, to a much lower price than that expected by BEIS, of £57.50 per MWh for those commissioned in 2023. This reflects the Hornsea Project Two strike price seen in December 2016. Conservatively, no further price reduction over the period from 2023 to 2030 was assumed.

For onshore wind, estimated CfD costs were taken from analysis by Baringa, falling from £80 per MWh in 2018 to £46 per MWh in 2030[54]. For nuclear, the Hinkley C project strike price of £92.50 was used[55].

For other technologies, BEIS central cost projections were chosen (LCOE). To these was added a margin of +10% to account for such factors as developer profit and financing costs, bringing them into line with the Contract for Difference (CfD) strike prices used for wind and solar[56].

Figure 12 describes the total cost of electricity in GB, annually, under the two scenarios modeled. The cost is the same in both scenarios until 2020, as the supply mix is assumed to be the same up to that point, wind and solar deployment only accelerating in the 50% Scenario from 2021 onwards.

To 2024, the BEIS Reference Scenario shows a lower cost, the cost of deploying the additional wind and solar capacity outweighing fuel savings and avoided carbon cost. Both show a steady fall in cost as demand for power continues to fall.

Then the situation reverses. Both scenarios show an increase in whole system cost, reflecting BEIS's assumptions of new demand growth, and the cost of new nuclear capacity commissioning in 2024. However, the cost of carbon, rising steadily over the period, as well as falling renewable technology cost and ever greater fuel savings mean that the 50% Scenario cost rises more slowly than BEIS Reference,

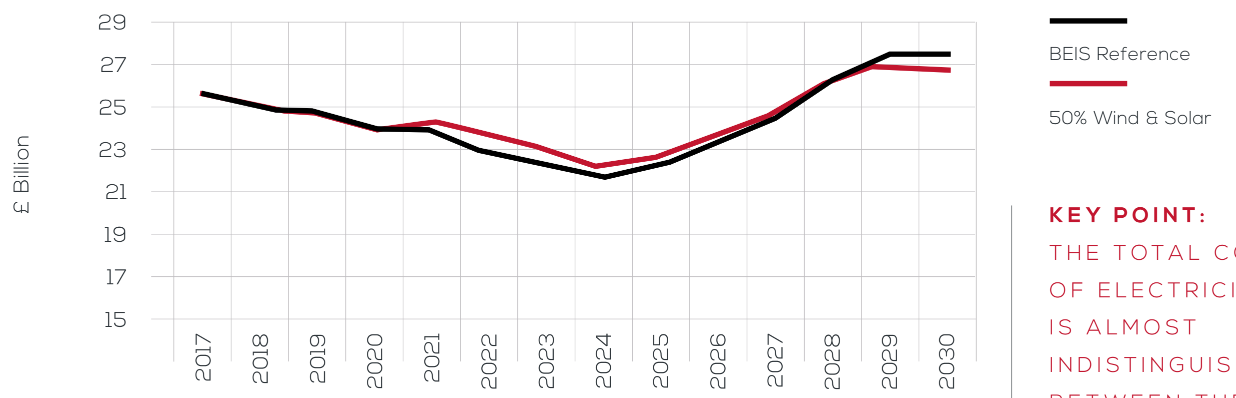


Figure 12: Total cost of electricity in the 50% Wind & Solar, and "BEIS Reference" scenarios

Source: New Resource Partners 2018

KEY POINT:
THE TOTAL COST OF ELECTRICITY IS ALMOST INDISTINGUISHABLE BETWEEN THE TWO SCENARIOS.

The total cost of electricity in the 50% Wind & Solar scenario is £26.7 billion (Table 3), while in the BEIS Reference scenario it is greater, at £27.5 billion; and this is likely to be an underestimate of the savings that would result if storage and trade with Europe were included in the analysis also.

This analysis concludes that a GB system in 2030 wherein 50% of all electricity is from wind and solar would be comparable with, and if anything marginally cheaper than, a BEIS Reference case with only a 28% wind and solar share.

Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
BEIS Reference	25.7	25.1	24.7	23.9	23.9	22.8	22.3	21.7	22.3	23.4	24.4	26.3	27.4	27.5
50% Wind & Solar	25.7	25.1	24.7	23.9	24.4	23.7	23.1	22.2	22.6	23.5	24.4	26.0	26.9	26.7

Table 3: Total cost of electricity in the 50% Wind & Solar, and "BEIS Reference" scenarios-- (£bn)

[52] In addition, a full costing of all four flexible resources would require modeling based on market prices, which was beyond the scope of this analysis.
[53] Data is from 2016 extrapolated to 2030. | [54] Source: Baringa 2017 | [55] As nuclear capacity is the same under both scenarios, it does not affect the outcome.
[56] Levelised Cost of Energy reflects the cost of building and operating a power plant over its lifetime. A CfD strike price is assumed to reflect LCOE plus financing costs plus developer margin.

Figure 13 shows the cost of the gas-fired generation that would be required to meet demand when wind and solar output are low, per megawatt hour of wind and solar generation. It should again be noted that this is in a scenario without electricity imports or storage; although this is not the case now, nor likely to be in 2030, it can be used as a highly conservative proxy for the cost of supporting the variability of wind and solar.

KEY POINT: THE FLEXIBILITY COST OF WIND AND SOLAR CAPACITY UNDER HIGHLY CONSERVATIVE ASSUMPTIONS AMOUNTS TO 12% OF THE AVERAGE PRICE OF WIND/SOLAR ELECTRICITY.

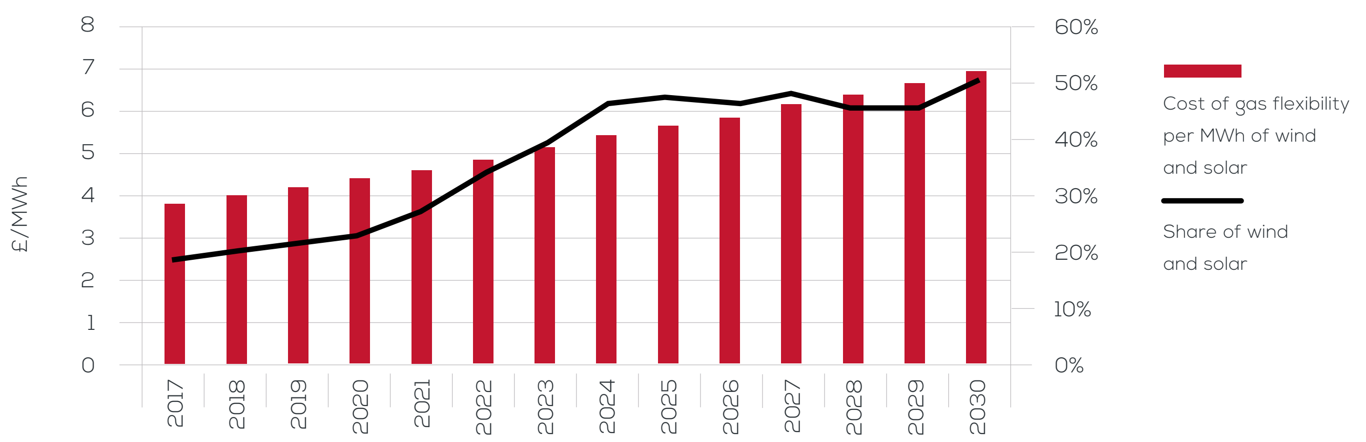


Figure 13: Cost of gas flexibility per MWh of wind / solar PV generation in the 50% Scenario
Source: New Resource Partners 2018

The gas-fired flexibility cost rises from £3.9 / MWh in 2017, to £6.8 / MWh in 2030, about 12% of the average CfD strike price for variable renewables in that year. The 2030 value is of the same order of magnitude as found by Aurora Energy Research for a combination of wind plus solar (£5.1 / MWh) though higher (cf. Figure 11). While both consider approximately the same amount of wind and solar capacity, the difference between them may reflect the very conservative nature of our analysis.

This analysis also finds a potential to benefit from exports of surplus wind and solar electricity to adjacent European markets. In our BEIS Reference scenario, 280 terawatt hours (TWh) of electricity are generated, of which 6 TWh are available for export. In the 50% Wind & Solar scenario, total generation amounts to 313 TWh, of which 40 TWh are available for export. It is difficult to put a value on this export, as the market price it will fetch will be volatile and hard to predict. It will be affected by wind/solar output profiles of importing countries, as well as the extent to which European countries are interlinked in 2030. But at a market price range of £35-£45 , this export volume could be worth in the region of £1.4 billion to £1.8 billion per annum[57].

[57]In line with current night-time baseload prices on EPEX Spot (EPEX Spot 2018).

5. What Needs to be Done?

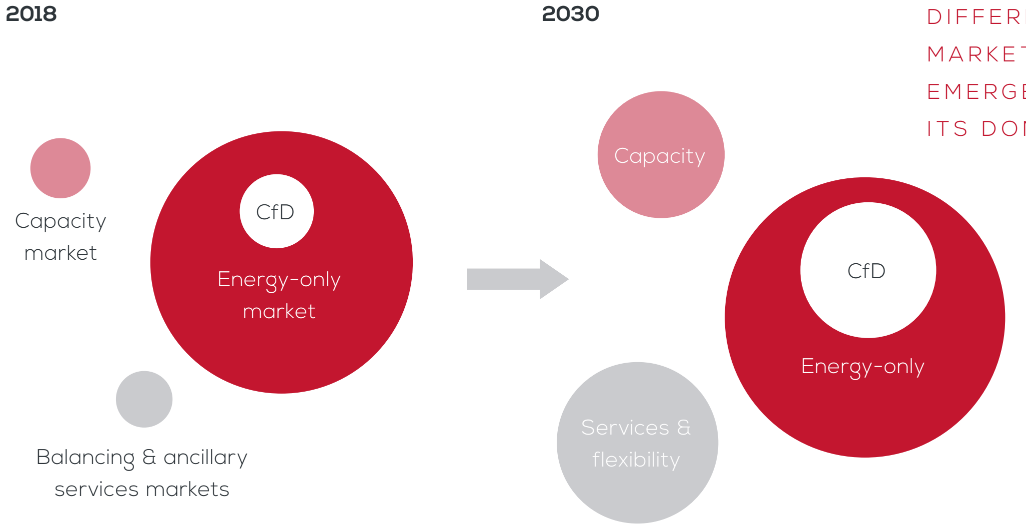
Flexible and renewable power technologies alone are not enough to solve the energy trilemma of reliable, clean, least-cost power. The marketplace also must evolve so that their value is properly recognised, so investment in the right balance of technologies is stimulated. And existing plants – those that are still needed at least – need to continue to be able to make money. This means that Government must lead additional policy and regulatory change: energy market reform.

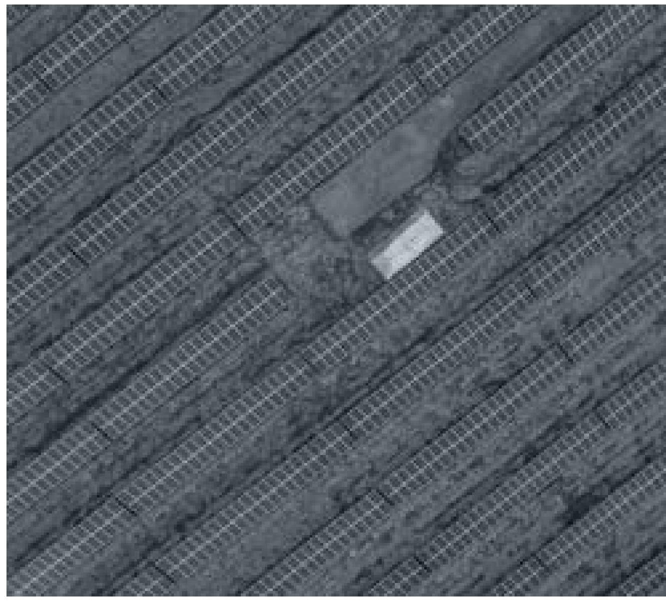
Because of the enormous strategic importance of energy to the economy, and because the energy sector encompasses natural monopolies (e.g. a single power grid), the Government has for decades had to regulate it carefully.

And if energy is too important to be left entirely to the invisible hand, this is doubly so in times of profound change. So there has been much recent intervention by Government. The Contract for Difference (CfD), a mechanism that evolved originally in equity markets, has been applied to new offshore wind and nuclear projects since 2013 to provide their investors with revenue certainty. And the Capacity Market has come into being to ensure adequate generation capacity is available in winter to meet annual peak demand.

Indeed, when once almost all value resided in the wholesale energy market, with important ancillary services thrown in, today those services are far more in focus, and compensated more competitively as a result. And it is likely that the dominance of the wholesale electricity market will have been much eroded by 2030, as these other markets grow, driven largely by rising share of variable renewables, the consequent desire for new gas plants, and the ongoing nuclear push (Figure 14).

KEY POINT: TODAY MOST VALUE RESIDES IN THE ENERGY-ONLY MARKET; BY 2030 CONTRACTS FOR DIFFERENCE, THE CAPACITY MARKET AND FLEXIBILITY EMERGE TO CHALLENGE ITS DOMINANCE.





And these new markets will themselves need to evolve to the point where they better reflect the value of new flexible energy infrastructure – storage, demand response, trade, and flexible generation – in the balancing of increasingly variable energy supply.

When the energy transition is complete – and equilibrium among affordability, sustainability and reliability has emerged – the regulatory scaffolding may no longer be needed; but so far it has proved itself to be essential in driving down the cost of renewables, and building investment in new flexibility.

Much progress has been made in redesigning the market, but it is far from complete. To enable an unimpeded transition to a clean, flexible, reliable power system, the Government, Ofgem, and stakeholders generally, need to consider six sets of issues.

1. Build a flexibility market. The four flexibility mechanisms need to find value for their services, and with sufficient certainty, to attract large-scale private sector investment.

2. More last-minute trading. Wind and solar output is known with more certainty as the time horizon approaches. Deeper and more liquid trading is needed on the day-ahead and intra-day markets, to help balance their output affordably.

3. Let all flexible players play. Market rules exclude certain flexible power providers in certain cases. Persisting historical regulation needs to be updated that otherwise prevents the participation of new flexible resources.

4. More trade with Europe, not less. New transmission links are needed with mainland Europe and, regardless of the UK's future trade relationships with the EU, the UK should continue to be able to buy and sell flexibly with adjacent markets.

5. Smart local markets. Many solar and wind power plants, and flexible power assets, are connected to low voltage, local grids. The management of these grids, and trade among the stakeholders connected to them, need to be more dynamic.

6. Encourage new flexible power technologies. To balance the output of majority-share solar and wind, without fossil fuels, new flexibility mechanisms are likely to be needed in due course, such as hydrogen and electric vehicle-to-grid technologies.

5.1. Build a Flexibility Market

A wholesale electricity market values the commodity of electricity generated; it does not value the characteristic of that electricity's being **available if needed**[58]. (An availability market of sorts has long existed – for reserve power – but this is small-scale, against demand uncertainty and contingency management.)

Electricity Market Reform (EMR) is intended to bring about investment in a more sustainable, reliable and affordable energy system. The 2013 Energy Act brought into being among other things a "Capacity Market" that rewards the availability of electricity generators to operate when needed. It was intended to counteract the perception of investors that energy market revenues had become less certain than before. Energy decision-makers worried that this would result in the early retirement of power plants and inadequate investment in new ones. EMR is set for a five-year review before the end of 2018, giving the Government an opportunity to bring in policies to boost grid flexibility.

Energy market uncertainty results from the already large share of wind and solar power on the system. Prices reflect the short-run marginal cost of production (SRMC). For fuel-less wind and solar, SRMC is near zero, so these power plants undercut more expensive gas-fired plants.

The Capacity Market rewards power plants that bid in successfully on an annual basis, for their availability to generate – or in the case of large consumers to reduce consumption (demand shifting) – when called upon.

Though a positive step, this design is not best for the long-term. It works while winter demand remains the main challenge. But as the share of wind and solar rises, the task becomes to ensure that sufficient flexibility is present not only when output lulls occur when demand is high, but also when the opposite is true – when output is high and demand low.

For example, in summer 2017 National Grid expected summer minimum demand to coincide with high solar PV output with the result that some dispatchable plant would need to be curtailed[59]. (A certain amount of demand turn-up, a new service first introduced in 2016, was also procured).

Flexibility markets are appearing. In the Californian and Mid-continent (MISO) markets in the USA, system operators actively assess the need for flexibility on an ongoing basis. This is an important first step that could be emulated. The next is to change the market to reward flexibility explicitly, not just capacity availability. So far, only a few markets do this. For example, the independent system operator of California has recently brought in new real-time "flexible ramping" products to encourage fast response 15 minutes and 5 minutes ahead of real time[60].

So the winter Capacity Market of today, which mainly supports existing fossil-fired plants, should give way to a Flexibility Market, to incentivise investment in the four flexibility mechanisms. These are needed to be available to change their production or consumption as the weather changes. This flexibility could be traded as a product or range of products covering different time-scales within the day-ahead, rather than one to four years ahead as in the present Capacity Market.

5.1.1. The Value of Flexibility

In its Smart Power report[61], the National Infrastructure Commission (NIC) flagged the savings likely to result from demand shifting. The NIC suggests that if 5% of peak demand were shifted (up from 1-2% today), rather than relying on peakers, the system cost would be £200 million less each year.

In parts of the country such as Cornwall, wind and solar power can already be surplus to local demand at certain times. Grid bottlenecks may mean that this surplus has to be curtailed. Nationwide, curtailment resulted in compensation to power plant owners of £340 million in 2014[62]. Reinforcing the grid (e.g. building new power lines) to open up these bottlenecks is expensive and the local planning process can be time-consuming; but there are two smart power alternatives: local demand turn-up (whereby consumers are encouraged to use electricity at times of peak supply, particularly overnight and during summer weekend afternoons when demand is low); and storage to absorb the surplus and return it to the grid when it is needed.

Imperial College and Cambridge University research (and one of the key inputs to the NIC's report) found that the gross annual savings from a move to flexible power system would amount to £3 - £3.8 billion in 2030[63].

A recent Carbon Trust report with Imperial College found that a cumulative saving of £1.4 - £2.4 billion by 2050 would be made with the cost of the flexible resources themselves included; and found in favour of multiple sources of flexibility, rather than over-reliance on any one or other. The same report, which sought to establish the "net regret" of inaction to increase flexibility (including cancelling measures already in place) would lead to an avoidable cost of £9 billion by 2050[64].

[58]The Balancing Mechanism is the exception to this, rewarding power plants that can give a little more or a little less at the request of the System Operator to fine-tune the demand supply balance in the minutes before real time. But the amounts involved are small, neither enough to recompense plants suffering from displacement in the merit order effect, nor to incentivise new build. | [59]Source: National Grid 2017a | [60]See https://www.caiso com/informed/Pages/StakeholderProcesses/FlexibleRampingProduct.aspx | [61]Source: NIC 2016
[62]Source: Policy Exchange 2016

5.2. More Last-Minute Trading

Most electricity in GB is traded months in advance of its production. This made sense historically as demand was predictable months in advance, too, and fuel could be stored without difficulty. But the demand goalposts are no longer steady. Instead of simply demand, it is net demand that supply must meet (the residual demand net of wind and solar output). And net demand fluctuates with the weather, which only becomes more predictable when it is near.

Forward trading of electricity remains attractive of course: a major energy consumer may wish to manage the cost of its manufacturing process, for example. But when an existing position is updated on the day-ahead and/or on the day itself ("intra-day"), this can unlock flexibility that may have additional value when wind and solar output is changing rapidly.

But the vast majority of electricity never makes it to the spot market. In 2016, only around 175 TWh of electricity was traded day-ahead or intraday, about 12% of total electricity trade (1,432 TWh)[65], and this has been the case fairly steadily since 2012 (Figure 15). In contrast, in the Nordic power market the vast majority[66] of electricity is traded on the day-ahead through the Nord Pool power exchange spanning Nordic and Baltic countries[67].

Most GB electricity is generated by power stations owned by the vertically integrated "Big Six" companies, then sold to consumers by the same, without recourse to the power exchanges[68]. If the opposite were true and like the Nordic Market the majority of electricity were traded on the day ahead then, as wind and solar share grows, the ability to produce energy or reduce energy consumption in real-time (i.e. to respond flexibly to net demand) could be compensated through high prices (though volatile) during dark or still periods.

But as it is, the flexibility value of the "dark" 85% or so of electricity may not accrue to its original producers, reducing the incentive to invest in more flexible power plants and demand response businesses.

KEY POINT:
NEAR-TERM TRADING IS LARGELY UNCHANGED SINCE 2012, AND INTRADAY HAS FALLEN SLIGHTLY.

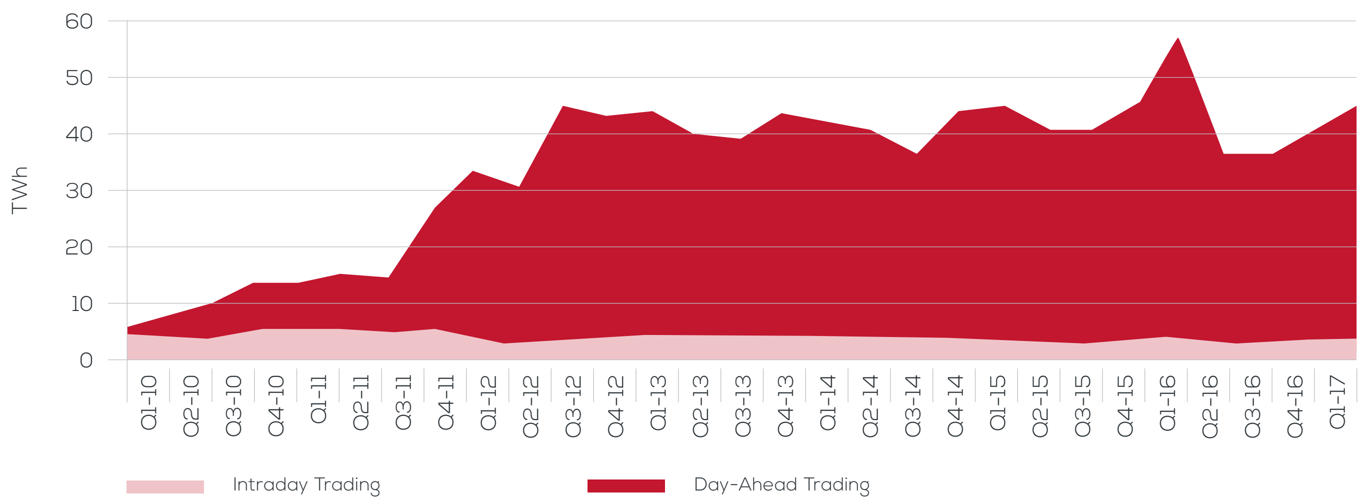
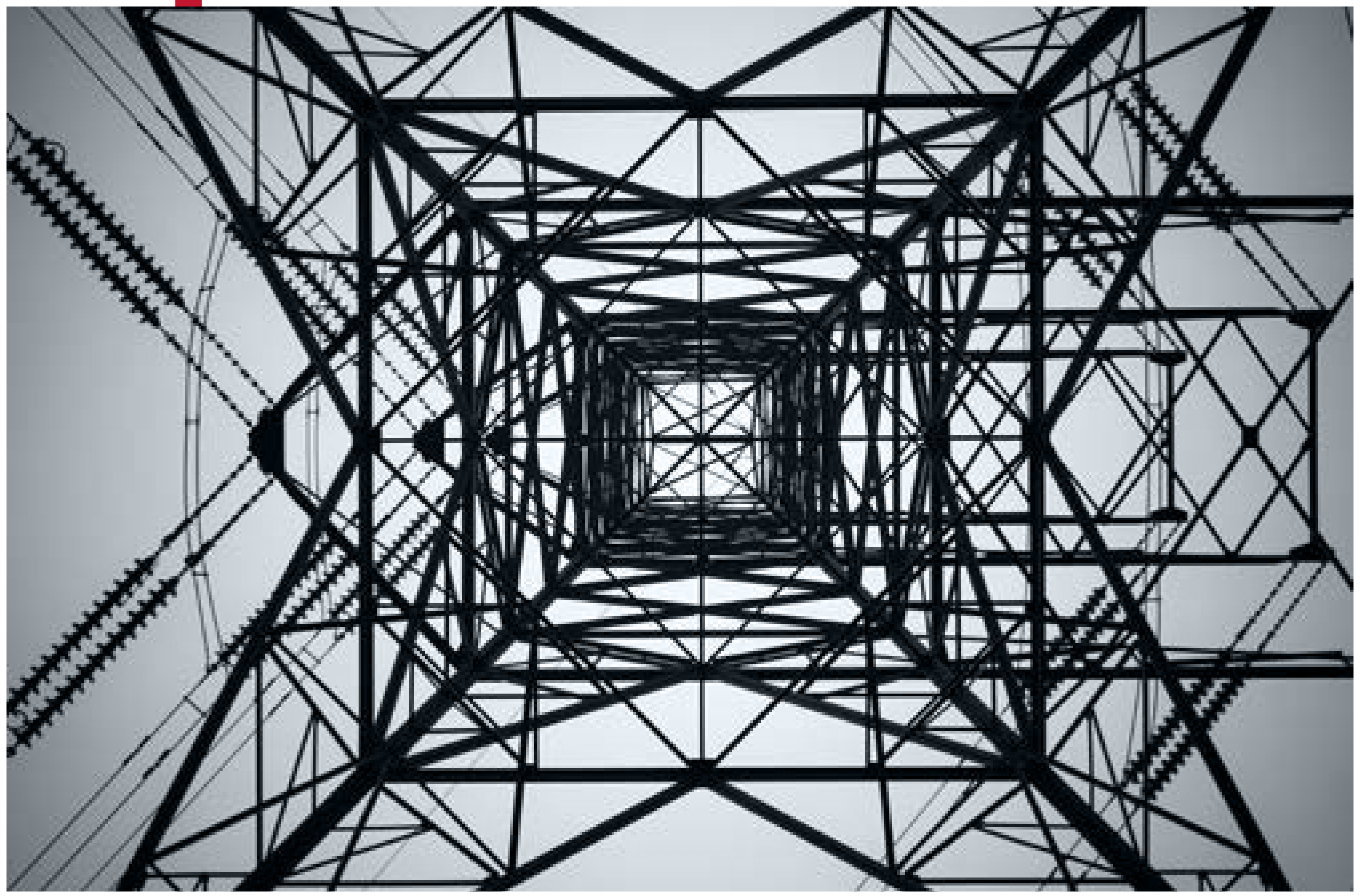


Figure 15: Near-term exchange-based trading in GB
Source: Ofgem 2017



Greater intraday trading would improve the supply demand balance remaining to be resolved after trading stops by the system operator using its various and rather less transparent and accessible mechanisms.

Consequently more intraday trading is desirable. Yet intraday trading has dropped slightly since 2010. This is in marked contrast to Germany for example, where with the strong rise of solar power trading close to the moment of "gate closure" when the market closes, has more than trebled over the same period[69]. So it is hoped that in GB this trend will reverse. And this may be encouraged by the decision of EPEX Spot (previously APX) in November 2017 to reduce intraday lead-time[70], allowing trading to continue up to just 15 minutes ahead of delivery.

[63]Assuming a CO2 equivalent energy sector emissions target of 100gCO2/kWh. | [64]Source: Carbon Trust 2016 | [65]Source: Ofgem 2017c | [66]The Norwegian energy ministry calculated that 93% of 2015 electricity consumption in the Nord Pool area was traded through the exchange. See https://www.nve.no/energy-market-and-regulation wholesale-market/norway-and-the-european-power-market/ | [67]Nord Pool also includes one of the two GB power exchanges, N2EX. | [68]The Big Six include, in order of number of customers, British Gas, SSE, RWE npower, EDF Energy, E.ON UK and Scottish Power. | [69]Source: EPEX Spot 2017 | [70]The time between the end of trading and the delivery of electricity.

5.3. Let All Flexible Players Play

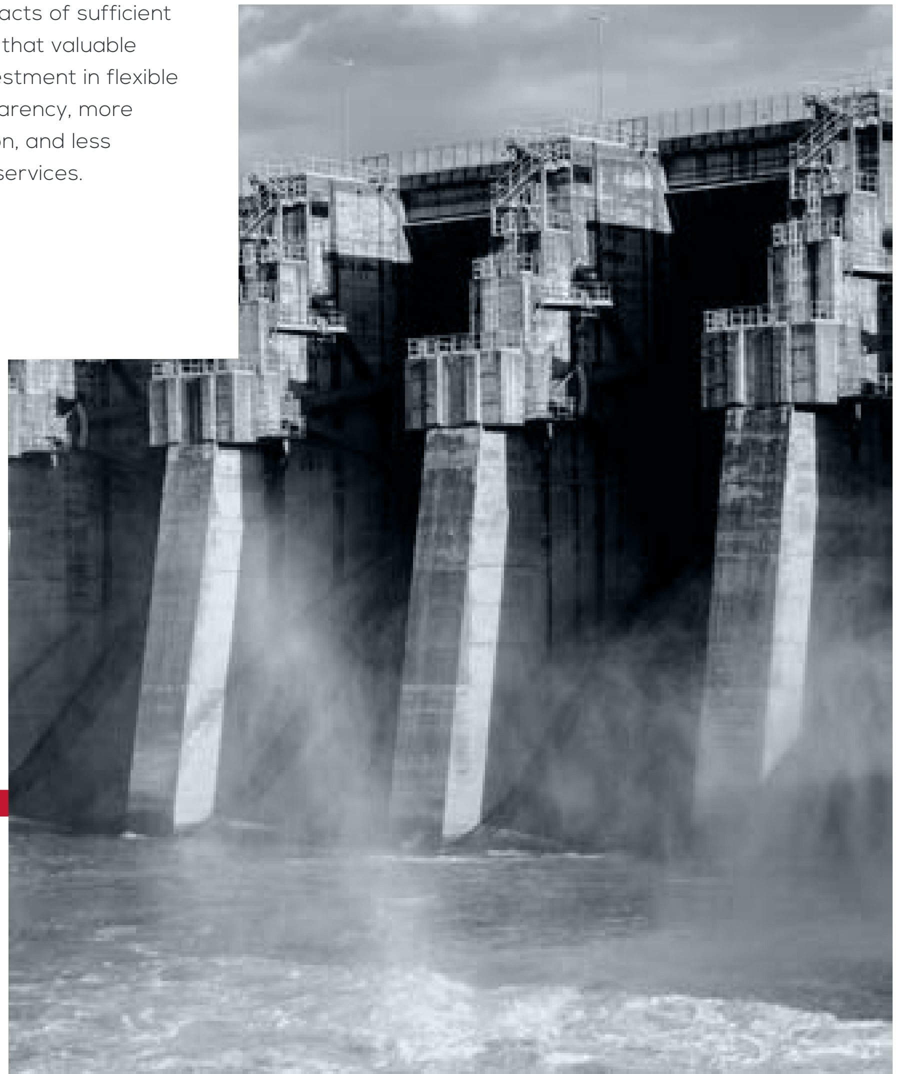
Conventional power plants have for many decades provided not only energy but also services crucial to National Grid's reliable operation of the grid that can loosely be referred to as flexibility services (though "ancillary" services is more common). As conventional plants reduce in number, displaced by renewables, National Grid needs to ensure it can still access these important services.

New potential providers of flexibility, like storage plants and demand aggregators, find it difficult to access the markets for these services however, which is unsurprising given that they have evolved around conventional plants. Even new market rules can be a problem. That the Capacity Market was designed to support conventional power plants is signalled by the fact that only 0.36% of the capacity contracted in its first auction in 2014 (for delivery in 2018) was of the demand shifting type[71]. This has changed however: in March 2017 there was a capacity market auction specifically for (turn-down) demand response.

New players may be unable to secure contracts of sufficient duration to attract investors with the result that valuable flexibility is locked out. In a nutshell, new investment in flexible assets would be supported by more transparency, more simplification, more open market competition, and less technology-specific procurement of these services.

What is needed is a careful opening of three markets to new flexible players in such a way that competition is enhanced without unintended impact on consumers or system reliability:

1. The Capacity Market, where the Government procures sufficient capacity to manage peak demand;
2. The Ancillary Services Market, where National Grid procures a range of services to support the reliable operation of the grid, day to day; and
3. The Balancing Mechanism, where National Grid can make use of additional energy offered by power plants, after trading has ceased.



5.3.1. Flexible Market Design

Many market design aspects limit the involvement of new flexible power assets, particularly demand aggregators and storage plants. For instance, some ancillary services are procured non-competitively.

One important factor relates to the duration of contracts. Contracts for two important ancillary market services are limited in duration[72]. Meanwhile, in the Capacity Market, unlike new-build dispatchable power plants that can expect a 15-year agreement in the annual four-year-ahead auctions, no agreement with a DSR aggregator has been awarded of longer than one year.

In contrast, all capacity providers in the PJM market in the USA are awarded contracts of the same duration. A middle ground of 5-7 year duration has been suggested in responses to Ofgem's recent consultation, but Ofgem does not yet accept that demand aggregators need to show long-term cash flow to potential investors[73].

A second important challenge relates to limitations on the "stacking" of flexibility-related revenue streams (the ability to earn income from multiple sources by providing different services).

For example, the provision by energy storage plants of Firm Frequency Response (FFR) – an important ancillary market service[74] – is not possible alongside energy market arbitrage activity. While there are good reasons for this (in doing arbitrage the plant may be unable to honour its FFR commitment), the existing monthly FFR procurement schedule constrains storage owners from switching quickly between the two markets as conditions change. National Grid is expected to introduce weekly auctions of FFR capacity in December 2018; this should increase the ability of battery owners to switch and thus optimise their revenue model.

Until very recently, only conventional power plants could offer their services to National Grid in the Balancing Mechanism[75]. Ofgem in a recent consultation stated that it was minded to allow direct access by aggregators to the Balancing Mechanism[76] , and this process has begun with two demand response aggregators now contracting.

More can be done however to open up these markets to flexible players. Other problematic factors include pre qualification criteria, financial requirements, testing processes, and metering requirements, which are found by many new flexibility providers to be unduly expensive or onerous.

5.3.2. Defining Storage

The energy sector is seeing such a pace of change that it is unsurprising that regulation has not always kept up. The absence of a definition of storage as a separate asset class in the 1989 Electricity Act has resulted in excessive costs to owners of storage plants, relative to conventional generation assets.

Ofgem closed a consultation in November 2017, which suggests that storage will be redefined as a distinct asset class (within generation), which is expected to remove these excess costs. Every effort should be made to ensure that historical accident does not reduce the ability of flexible power assets to compete on a level playing field.

[71]Source: National Grid 2014
[72]A maximum of 30 months for Firm Frequency Response (FFR), and four years for Enhanced Frequency Response (EFR).
[73]Source: Ofgem 2017b p.53

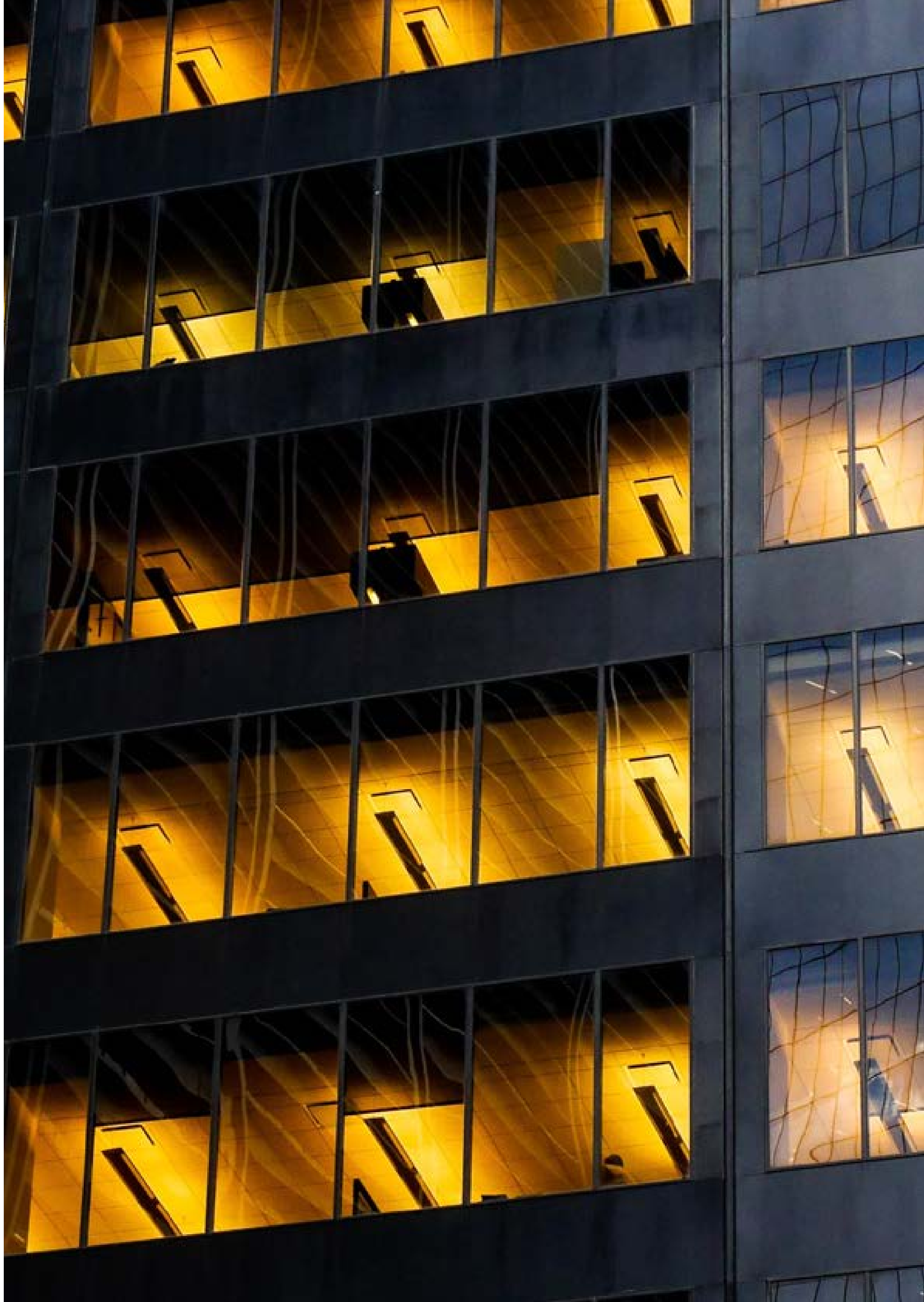
5.4. More Trade With Europe, Not Less

The trend towards increased interconnection among European markets has become very important for the integration of wind and solar power. Being weather dependent, at higher shares of electricity these technologies result in local surpluses that, if traded further afield, may find value; while import can help manage local deficits. The ability to trade is greatly enhanced if national markets are deeply interconnected and able to trade flexibly within the weather forecast time-frame (e.g. the use of interconnectors can be readily switched from import to export).

Electricity is a good that under EU law can cross borders without tariffs. If the UK leaves the EU and the European electricity market, then its ability to trade electricity with its neighbours may be jeopardised.

It has already been established above, in the chapter on managing the wind lull, that interconnectors – the power cables connecting GB to its neighbours – are a vital source of flexibility. It is unclear what the impact of Brexit would be on investment in the planned pipeline of new interconnectors, but delay – at least – is likely.

In the interests not only of cheaper electricity, security of supply, and to enable wind and solar power integration, deeper market coupling with the continent is highly desirable. Government should make every effort to ensure that trade with neighbouring markets continues, and indeed is deepened.



[74]Frequency response entails e.g. a power plant changing its output to support stable system frequency.
[75]The Balancing Mechanism is one of the tools National Grid uses to resolve the remaining imbalance between supply and demand in the time remaining after trading has ceased and before delivery.
[76]Source: Ofgem 2017b p.23

5.5. Smart Local Markets

Conventionally, electricity flows from gigawatt-scale power plants through a high voltage transmission grid actively managed by National Grid, and down into lower voltage distribution grids maintained but essentially left to their own devices by Distribution Network Operators.

But more and more consumers are changing into producer-consumers, not only consuming energy but also at times exporting electricity into the distribution network. In 2016, 27% of generation capacity was connected to these passively managed networks, up from just 8% just five years before[77].

In itself this reverse is not a great technological challenge. But it implies an essential logistical change, to more active management of the distribution networks. It would mean 1) that consumers and the small power plants (conventional, renewable, storage, etc.) connected to them would be monitored and managed in real-time by newly formed Distribution System Operators; and 2) that these local networks would be managed in collaboration with National Grid.

DSOs could procure local balancing services from new providers of flexibility such as storage and demand shifting, ideally through market platforms operated close to real-time, in order to avoid curtailment of wind/solar, avoid congestion, and to manage local grid stability. Such market platforms are beginning to emerge, and may in future be based on blockchain or distributed ledger technology.

In 2017 the creation of Distribution System Operators became a serious objective of Government and Ofgem, but it remains unclear when it will be completed.

5.5.1. Going Local

The transformation of DNOs to DSOs is not the end of the localisation trend. DSOs will increasingly procure local balancing services to manage the higher voltage parts (e.g. 132 kV) of their networks. But another entirely new model of energy markets is emerging, wherein producer-consumers trade energy services directly with one another, right down at the domestic level.

Truly local energy markets will still rely on the existing network for the distribution of electrons, and for resilience – and the owners of the network would need adequate remuneration for these services. But increasingly the independent supplier of energy – the third party buying energy from producers and passing it on to consumers – may find itself surplus to requirements in some cases.

A number of these local markets for energy are emerging. In Cornwall, Centrica with the DNO Western Power Distribution, is developing a market of a few hundred houses and businesses, to share energy and underlying data using a blockchain. To the East, a local flexibility market is emerging with the involvement of another DNO, UK Power Networks. And others initiatives – some similar, some quite different – are emerging in the US, The Netherlands, South Australia, Japan, Korea, and elsewhere.

The Brooklyn Microgrid in the USA is one of the more advanced, having been in place for all of one year. It is based around two city blocks in Brooklyn, New York, and shares solar power produced on the roofs of participating residents, while money changes hands through the same blockchain technology as being trialled in the Cornwall Local Energy Market[78]. In April 2018, Verv completed the first UK-based energy trade using blockchain, a step towards enabling residents greater control over renewable energy sources located on homes and housing estates.

One variation on this theme is the Distribution System Platform that launched in June 2018 in New York, a collaboration including National Grid, and in support of New York State's Reforming the Energy Vision initiative[79]. The pilot will forecast the value of electricity at the level of a university campus and so enable owners of energy production and local flexibility to trade together independently.

In GB, which already has a highly meshed grid, these local energy markets may end up as simply the smallest markets within a series of concentric markets, up to national and (Brexit notwithstanding) continental scales. In contrast, in the developing world, particularly where high voltage grids are weak or absent, local markets may displace the national model altogether.

[77]Source: National Grid 2017b

5.6. Invest in New Sources of Flexibility

Many believe that nuclear power and/or gas plants will remain essential for maintaining the adequacy of British power. And it is likely that the full decarbonisation of power – as well as of heat and transport – would imply greater flexibility than is feasible at present through the four flexibility mechanisms discussed above, particularly when gas is removed from the mix.

To manage wind and solar variability, particularly seasonal cycles and extended lulls in wind output that last too long to be managed by today's commercial battery technology alone, new supply technologies may be needed, as well as new approaches to energy storage.

Two major potential sources of flexibility stand as candidates. The first is the wide-scale electrification of transport and heating, which is commercial today in both cases. The second is hydrogen, produced using surplus electricity and fed into the existing gas grid (with certain upgrades[80]), and which is further from market-readiness. Both present significant challenges and opportunities.

First, electrification, particularly of transport: the batteries in electric vehicles could provide significant flexibility by feeding electricity back into the grid on demand, when unused and connected. This service would be compensated and thus defray their running costs. This so-called "vehicle to grid" (V2G) technology is being trialed in Denmark at present, for example[81].

(It is important to note that the grid-based charging of electric vehicles – as distinct from their discharge back into the grid – will as their numbers grow need to be scheduled carefully with electricity supply and other demand. If this "smart" charging were not to occur, EVs could lead inadvertently to increased peak demand for electricity, and pose particular challenges to local grid capacity.)

Heat can be stored easily, so that surplus wind and solar need not be dumped. But the total electrification of heating services could lead to enormous over-capacity during warmer months, which suggests that electrification alone of the entire energy sector, might be to take the approach too far[82].

There may be a major role for hydrogen in the years ahead. New technologies are emerging that allow its sustainable production. Today production is mainly through steam reforming of natural gas; new approaches require significant development and cost reduction still. Electrolysis and photolysis are alternative routes: the splitting of water into hydrogen and oxygen using electricity or light respectively. Though electrolysis is much closer to being commercial than photolysis, it too is roughly twice the cost of steam reforming.

Many approaches to the use of hydrogen for flexibility have been put forward. One example is the coupling of offshore wind plants with electrolysis: hydrogen could be produced when electrical output is surplus to requirements, piped elsewhere, or stored. As with battery storage, this could enable cheap electricity to be sold later, at profit, with the added advantage that gas is more readily stored than electricity.

Hydrogen trials are underway. Solar-powered production of hydrogen by electrolysis for use in fuel-cell powered cars, among other applications, is being trialed at Swindon[83]; while the injection of up to 20% hydrogen into the gas grid is being trialed at Keele in Staffordshire.

These technologies are well on the way to being proven with the exception of photolysis, which is still in the lab. But they can not yet compete with the more established flexibility mechanisms described earlier. Both greater electrification and hydrogen may play a role, as may many other emerging technologies, and will increase in importance particularly if carbon capture from gas-fired electricity remains uneconomic.

In addition, these emerging technologies offer the opportunity for the UK to take the lead in the development of new flexible technologies, for which the global market will only grow. The UK is far from alone in deploying wind and solar power, and is in a position to monetise its developing experience of new flexible technologies through exports.

[78]Source: Mitchell 2018
[79]See https://www.opusonesolutions.com/news/national-grid-launches-distributed-system-platform-with-buffalo-niagara-medical-campus-members/
[80]Importantly, much of the British gas network will have been upgraded by 2030 to plastic pipes, which do not suffer from the embrittlement effects of hydrogen on iron and steel. | [81]See https://www.bloomberg.com/news/articles/2017-08-11/parked-electric-cars-earn-1-530-feeding-power-grids-in-europe
[82]Source: DECC 2013 | [83]See https://hondanews.eu/gb/en/corporate/media/pressreleases/4106/uks-first-commercial-scale-green-hydrogen-refuelling-facility-opens-in

6. Conclusions

Wind and solar alone already generate 19% of GB electricity. BEIS expects onshore wind and large-scale solar to compete fully with all conventional alternatives by 2020, while this is already the case in some instances. This may, depending on Government decisions, herald their accelerated deployment, as envisaged by National Grid in its (more ambitious) Two Degrees Future Energy Scenario, which forecasts that 61% of electricity will be generated by wind and solar in 2030.

To avoid unnecessary cost, the additional supply variability that results must be managed by a move to a smarter and more flexible power system. Ofgem in its 2017 Smart Systems and Flexibility Plan estimates the overall savings to consumers of doing so of up to £40 billion by 2050.

This report shows that even the most exaggerated becalming of the wind is no threat to reliability if sufficient smart, flexible energy infrastructure is present. This finding is particularly notable because unrealistic concerns about the reliability of wind power and consequent need for "back-up" continue to pervade media and politics.

In our modeled 50% Wind & Solar Scenario, if the wind drops to near zero for a three-week unbroken period, which is vanishingly unlikely, four flexibility mechanisms can be called upon to uphold the system and keep the lights on: demand shifting, energy storage, trade and flexible power plants. Unleashing the four flexibility mechanisms will allow the proportion of electricity generated from variable sources to be ramped up to levels required to meet national decarbonisation targets, maximise the efficient use of ever-cheaper renewable energy, and maintain the excellent security of supply that the UK is accustomed to.

Even if, as in this analysis, gas plants were to provide almost all flexibility, with a measure of demand shifting, a 2030 power system with 50% wind and solar generation would be cheaper than BEIS's expected outcome (28% wind and solar), by at least £0.8 billion.

This is because additional fuel savings and avoided carbon costs outweigh the cost of deploying additional wind and solar capacity. And if GB deploys the full range of flexibility mechanisms, then this saving will be considerably larger. These findings should encourage the UK Government to step up its efforts to facilitate investment in wind and solar power particularly, at utility and local scales, and to continue to develop energy markets to reward flexibility.

Six major areas of focus by Government and regulators would release further flexibility:

1. Build a market for flexibility: reward the four flexibility mechanisms according to their merits.
2. Encourage more trading of electricity close to real-time ("last-minute") to unlock existing flexibility.
3. Allow all flexible power sources to compete by removing market barriers and revisiting regulation where appropriate.
4. Trade more, not less, with Europe, ensuring that a departure from the internal European energy market is either avoided or mitigated.
5. Active management of low voltage grids by independent Distribution System Operators. Encourage the development of local markets for energy and flexibility.
6. Nurture new and large additional sources of flexibility, such as electrification of heat and transport, and hydrogen as a major energy vector.

Figure 16 arranges these tasks on an indicative time line to 2030. The establishment of a flexibility market that is accessible to all forms of flexible power according to their merits is the most important early task. Much new flexibility is resulting from private sector innovation, which above all needs to be able to find value in the marketplace, in order to attract investment.

KEY POINT: THERE IS MUCH TO BE DONE BY GOVERNMENT AND REGULATORS IN ORDER TO BUILD FLEXIBILITY, TO MAXIMISE THE VALUE OF WIND AND SOLAR POWER.

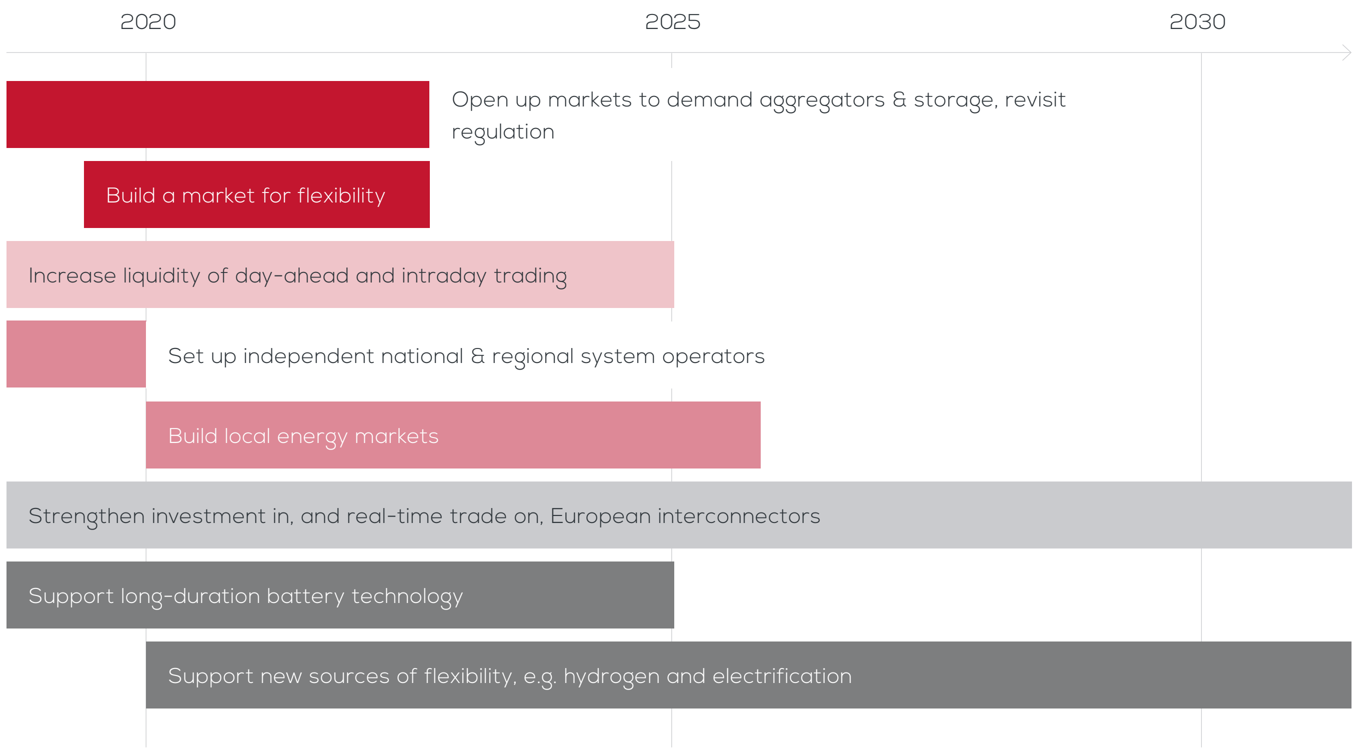


Figure 16: A suggested timeline for flexibility tasks

At the other extreme is increased effort to support the development of battery technology, in line with the Government's Faraday Challenge launched in 2017, and with focus on longer duration energy storage. In the same vein, proper investigation is needed of the case for hydrogen as a new energy vector, both as a long-term form of energy storage, as well as potentially to partially replace natural gas in the heating sector.

The barriers to wind and solar PV are largely historical: variability is relatively new (on the supply-side at least) so traditional approaches to balancing supply and demand are no longer appropriate. Variable renewables represent an affordable route to reliable, sustainable electricity with minimum CO_2 emissions. And provided that the market is well designed to reward flexibility, then the spectre of the wind lull blows away, even as GB comes to rely on these technologies for the majority of its energy needs.

Appendix

Appendix 1: Renewable Energy Deployment Model (GB_Lull)

Cost Module
Objective: compare system cost of 50%VRE Scenario with cost of BEIS Ref Scenario

Base Data
- Capacity by technology type.
- Capacity factors are inputs
- LCOE

Assumptions/inputs
- Year on year increase in capacity actor (from technology improvement)
- The 50% VRE Scenario is the same as the BEIS Reference Scenario until 2020. After this point gas plant is retired and replaced by wind onshore and offshore, and solar PV in adjustable proportions (TWh).
- Proportion of CCGT to OCGT plants (TWh).
- Proportion of onshore wind types (TWh).
- Proportion of solar PV types (TWh).
- Proportion of hydro types (TWh).
- Other costs - including developmer margins and financial costs.

Three options for cost of flexibility:
1. Based on gas backup for the entire additional VRE production.
2. Based on gas backup when VRE is not available (data from Lull Module).
3. Manual input.

Lull Module
Objective: assess the flexible resources needed to manage a 50% wind & solar share of electricity

Base Data
- Energy demand in 2016 and 2030 (hourly resolution for 1 year).
- Solar resource (hourly resolution for 1 year).
- Onshore wind resource (hourly resolution for 1 year).
- Offshore wind resource (hourly resolution for 1 year).

Assumptions/inputs
- DSR potential (% of peak demand).
- Demand change y/y (to extrapolate the demand from 2016 out to 2030).
- Storage ration (MW output / MWh energy stored).
- Interconnection availability – day.
- Interconnection availability – night.
- Gas (GW) dispatched to meet net demand.
- Max gas capacity factor (to ensure the CF of gas plants from the lull module does not go above a level that allows for no contingency).

Order of calculations
1. Calculate the demand after applying DSR. DSR is intended to shave off peaks and smoothen the demand over a period of +/- 6 hours.
2. Priority dispatch is given to renewables:
   - Solar, onshore wind, offshore wind, hydro, marine.
3. Priority dispatch is also given to nuclear. No coal assumed in 2030.
4. Dispatch of flexible resources:
   - Interconnectors are dispatched first, up to the limit of availability set in the assumptions.
   - Secondly, gas plants are utilised up to a specified capacity and utilisation limit.
   - When underutilised, gas plants and interconnectors are used to charge the storage assets.
   - Thirdly, storage is deployed in order to satisfy the remaining demand.
5. The optimisation of the model is dominated by the utilisation of gas variable. This must be toggled until the entirety of demand is met.

Outputs
Energy generated by each technology on an hourly basis.
Export potential (overproduction from intermittent and inflexible generators).
Amount of energy from flexible resources: used to inform the cost module.

Appendix 2: Carbon Pricing

Carbon pricing has an important bearing on the cost of natural gas-based generation of electricity as modeled in this paper. Since 2005, the cost of carbon emissions has been monetised through the European Union's European Emissions Trading Scheme (EU ETS). This is based on the trade of allowances – one for each tonne of CO2 emitted (tCO2). In addition, in the UK, a carbon floor price has been introduced, the value of which is set by the Government.

The ETS works as follows: a cap is set on the total amount of greenhouse gas emissions allowed across the EU, and this cap is lowered over time. Companies can trade emissions allowances, but each must surrender allowances equivalent to its emissions at the end of each year, or suffer fines.

For a number of reasons, including a surplus of allowances, the ETS price has long ranged well beneath the social cost of carbon that it is intended to capture. The UK introduced the CPF in 2013 to ensure that a minimum cost would be associated with emissions. It is not an EU-wide measure – though it is debated in France, Germany and The Netherlands – and so is considered by some to impose an unfair disadvantage on UK business.

The Renewable Energy Deployment Model as configured for this analysis allows for three options regarding the level of the carbon price:

1. BEIS Reference: in which carbon prices remain at the levels assumed by the Department for Business, Energy and Industrial Strategy (BEIS 2016).
2. CPF Only: in which the CPF reflects the total price on carbon. The CPF is set at £18/tCO2 until 2021. The value beyond this date is expected to be set at a hearing in Autumn 2018. We assume that £35/tCO2 will be reached by 2030, a conservative projection given that the initial 2013 plan mooted a price of £70/tCO2 in 2030 (Sandbag 2013).
3. Goal-seek: in which a 'goal seek' can be run on the carbon price. In this analysis, this was to identify the carbon price at which an equal total system cost
4. results in both scenarios (BEIS Reference and 50% Wind & Solar).

The main analysis in this paper assumes carbon pricing as anticipated by BEIS (i.e. Option One in the above), reaching £48/tCO2 in 2030. Figure 17 illustrates this, compared to the cost that would result in system cost parity in 2030.

The carbon price in 2020 is £24/tCO2. In the Goal-seek case, the price then increases by £0.4/tCO2 each year until it reaches £29.50/tCO2 in 2030, at which point the total electricity system cost under the two scenarios is the same. In other words, the minimum carbon price at which the total electricity system cost in the 50% Wind & Solar Scenario is the same as in the BEIS Reference Scenario is 61% of the level assumed to be the case by BEIS.

KEY POINT: THE PRICE OF CARBON WOULD HAVE TO BE JUST 61% OF THAT ASSUMED BY BEIS IN 2030, FOR THE SYSTEM COST OF THE TWO SCENARIOS MODELED TO BE EQUAL IN THAT YEAR.

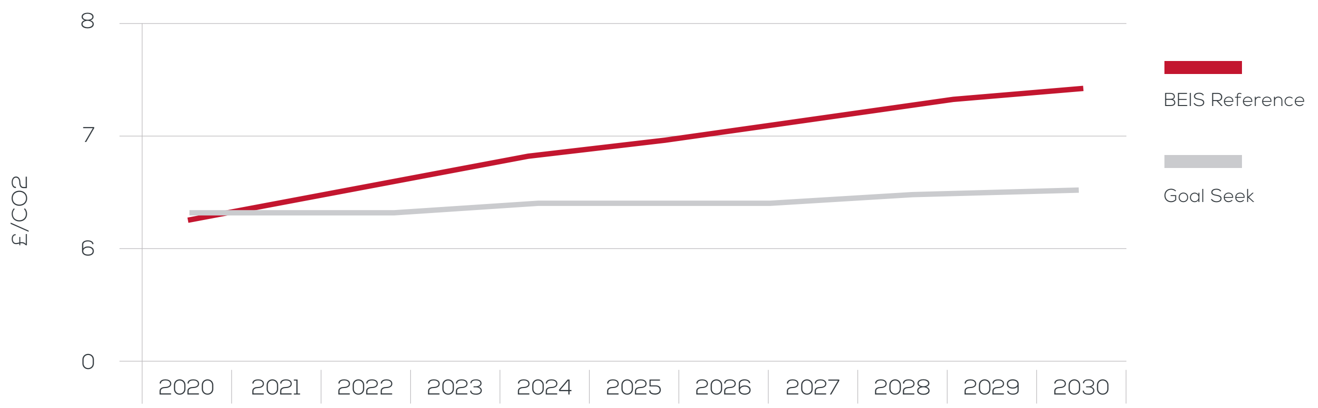
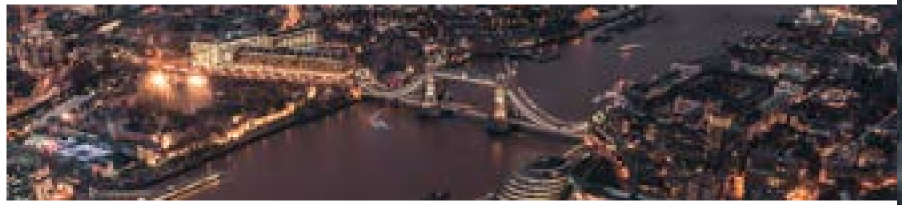


Figure 17: Minimum carbon price to achieve electricity system cost parity in 2030



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