White Paper

Developing flexibility: the new cornerstone of the grid

How European regulators, industry and consumers are evolving to adapt to a low carbon energy future

This paper was initiated and developed by Eaton and the Renewable Energy Association (REA) with cross industry contributions including market data, insight and case studies.

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Bloomberg New Energy Finance

The report chapters

Executive summary: why flexibility is the essential cornerstone of a low carbon energy system

Multiple forces are driving the transition to a low-carbon energy future across Europe. These include political, consumer and economic pressures to reduce air pollution in cities, address climate change and above all exponential reductions in the cost of renewable energy and battery storage.

According to Bloomberg New Energy Finance (BNEF)'s respected 'New Energy Outlook' modelling, more than half the total electrical energy supplied to grids in large European economies, including the UK and Germany, will be coming from variable renewables by 2030. On the demand side, an equally seismic change is coming with the mass adoption of electric vehicles (EVs) and electrification of heat.

While this transition is inevitable as it is driven by economics, its cost is not. According to BNEF, the transition will be faster and less costly if flexible technologies and energy markets become the cornerstone of the grid. That is because both wind and solar power add to variability in supply and mass EV charging will add greatly to variability in demand over short intra-day timescales. To avoid the need for costly grid upgrades and back-up generation, the system must become more flexible to smooth resulting peaks and troughs in demand and supply over short timescales.

This paper explores the current regulatory barriers to a more flexible electricity system and the steps needed to ease the transition to a low carbon economy. Today, grid regulation in most European countries is designed for a centralised electricity generation model. The paper describes how regulators, policymakers and industry are responding today to the challenges of the energy transition. It also includes recommendations on the regulatory and market design changes needed to unlock private investment in the technologies required for a more flexible energy system.

The primary focus of the paper is the UK and German markets but with additional case studies and commentary from several other North European markets including Norway, the Netherlands and France.

The paper concludes with a summary of our core regulatory asks that, if addressed, will help unlock the private investment needed in the technologies that are ready now to develop the flexibility needed to ease the transition to a high renewable and clean energy future.

This paper was initiated and developed by Eaton and the Renewable Energy Association (REA). We are particularly thankful to the following organisations for their contributions including market data, insight and case studies: Drax, Upside Energy, Good Energy and Bloomberg New Energy Finance.

Section 1: The political and economic forces driving the energy transition and requirement for flexibility

The global Paris climate agreement, reached in 2015, compels policymakers to legislate to reduce carbon emissions and a coal phaseout by around 2030. Sensing the associated risk of being left holding worthless coal stocks, many investors are now either divesting from fossil fuels, or putting pressure on fossil fuel companies to diversify into cleaner energy. Economic drivers favouring renewables in Europe are exponential declines in the cost of wind and solar power combined with rising carbon prices. On top of that, there is the trend towards electrification of transport and heat, which provides new and substantial sources of demand for generated renewable electricity.

In this section, we focus on the most pervasive of these drivers: the falling cost of renewables and the electrification of transport.

The major drivers behind the energy transition

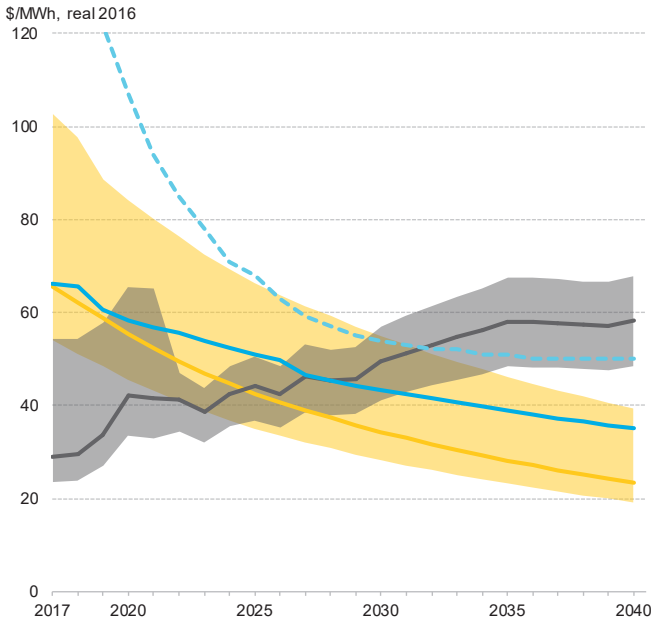
The falling cost of renewables

In Europe, BNEF projects that the all-in ("levelised") cost of onshore wind will approximately halve by 2040, compared with today's levels and that the cost of solar and offshore wind power will fall by two thirds.[1] BNEF estimates that the cost of batteries will fall by about three quarters. These cost reductions are driven by a combination of technology innovation, manufacturing economies of scale and deepening supply chains.

BNEF expects these cost reductions are already leading to a series of "tipping points".

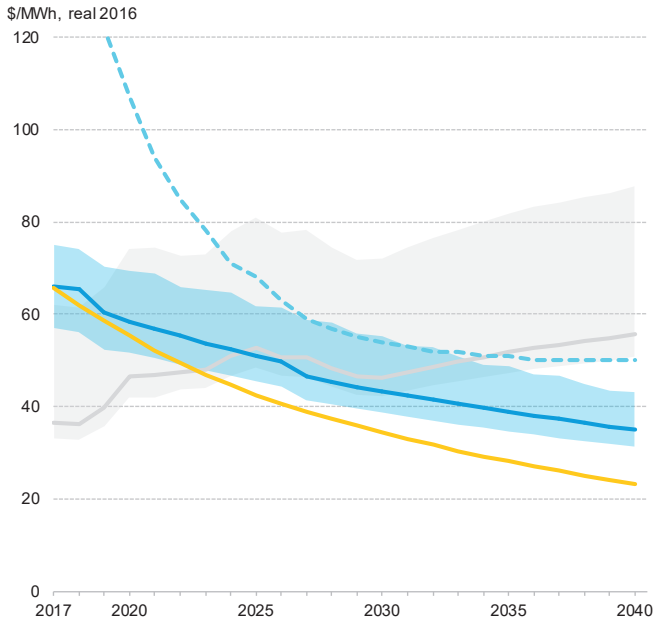
1. First, grid-scale photovoltaic and onshore wind are already becoming the cheapest source of new power generation, out-competing new-build coal and gas in Europe. However, this may not be a major driver for renewables growth on its own, since sluggish electricity demand growth in Europe, due in large part to dramatic improvements in energy efficiency, means that there is limited demand for additional power generation.
2. Second, by the mid to late 2020s, the next tipping point is reached: the cost of the power produced by most new wind and solar projects falls below that of existing gas and coal plants (Figure 1). Already, new onshore wind and solar are cheaper than the short-run operating cost of some existing coal and gas in Europe. That will become generally the case around 2025-2030. New research indicates that this crossover may come even sooner: a study by the think-tank Energy Innovation recently found that new wind and solar power were already cheaper than three-quarters of existing coal power plants operating in the United States.[2] Whether new wind and solar actually displace more expensive, operating fossil fuel plants will also depend on notions of energy security, and that fossil fuel capacity may still be required as a source of flexible back up when wind and solar are unavailable.
3. Third, rooftop solar power displaces grid electricity. Already, roof-top solar power is cheaper than grid power in many European countries. However, solar needs to be much cheaper, for the electricity bill savings to pay off the upfront cost in less than five years or so - the point that many households may choose to install. Falling battery costs may help reduce that payback period faster, by helping households use more of their home-generated solar power. Adoption of roof-top solar will also depend on overcoming regulatory barriers, for example to help tenants benefit.

LCOE forecast for wind and PV, and generation cost range of existing coal in Europe



Source: Bloomberg New Energy Finance - 2017 New Energy Outlook

LCOE forecast for wind and PV, and generation cost range of existing gas in Europe



Source: Bloomberg New Energy Finance - 2017 New Energy Outlook

Onshore wind | Utility-scale PV | Offshore wind | Gas | Coal

Figure 1.

[1] BNEF 2017, 'Beyond the Tipping Point Study', Commissioned by Eaton and the REA

[2] Energy Innovation & VCE 2019 The Coal Cost Crossover

Rising EV adoption

More people are now turning to EVs due to falling costs and perceived environmental benefits. This has triggered a scramble among automakers to develop EV models and by governments to develop the enabling charging infrastructure.

EVs are already competitive on cost of ownership for high-use applications because their running costs are lower than internal combustion engines. Adoption will accelerate as the EV price premium falls in line with reducing battery costs. Unsubsidised battery electric vehicles (BEVs) will become cost competitive with internal combustion engines in the next decade, on a three-year total cost of ownership basis according to the consultancy Aurora.[3] Meanwhile, public awareness is growing of the risks that conventional vehicles pose to health and climate change. That is translating into targets for diesel bans in cities and in some countries, the setting of dates for national bans on all internal combustion engines. EVs have additional soft attractions, such as cleanliness, silence and absence of exhaust smell, which could further accelerate adoption.

EVs can accelerate the growth in renewable energy, amplifying two of the biggest energy trends today, by providing wind and solar with a new route to market. That is because EV charging can in theory be tailored to avoid peak demand periods, aligning with times when wind and solar power are available providing renewables with higher demand and prices. That function critically depends on EV charging becoming smarter, for example responding to price signals in the power market, or remotely controlled by operators seeking to balance the electricity system.

The challenge of variability

The main challenge associated with wind and solar energy is its variability. Wind and solar rise and fall according to when they are available. Without steps to integrate them, this will lead to problems both when variable renewables are in excess and in deficit.

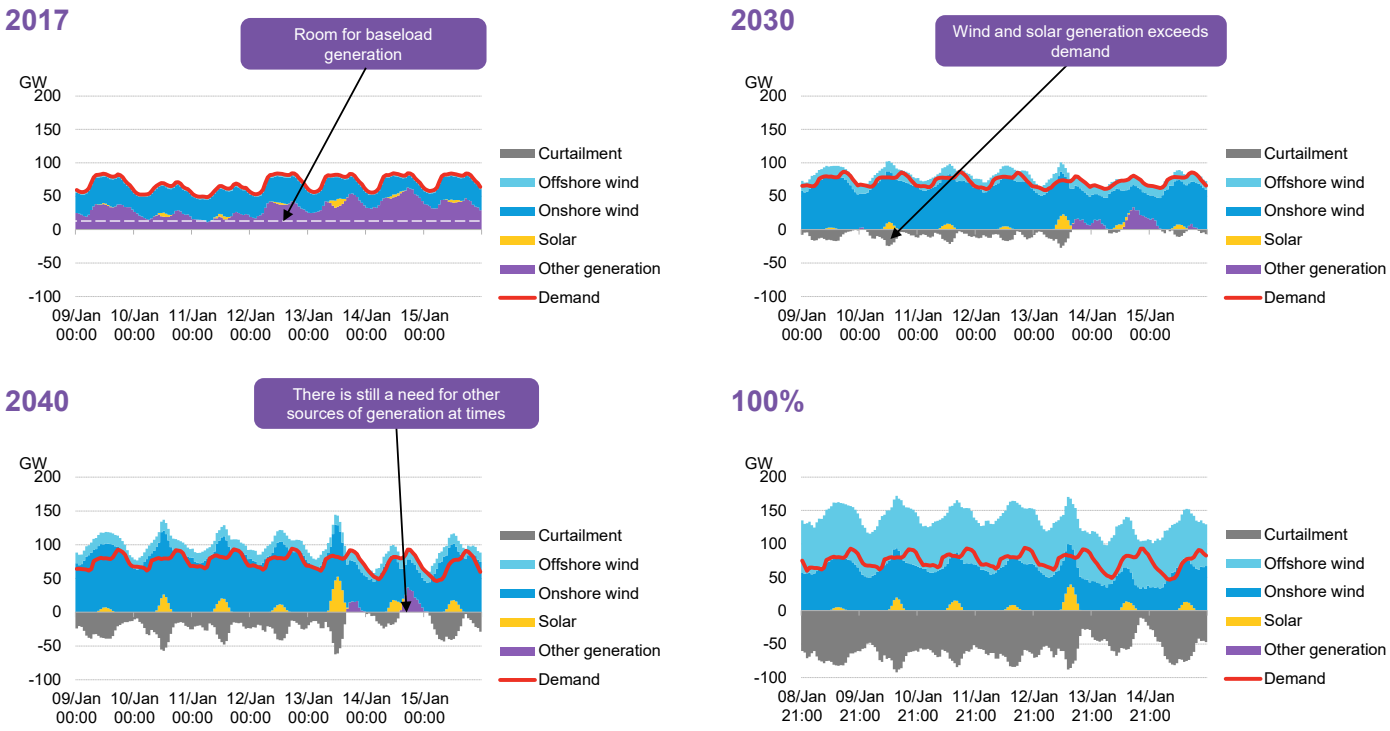
When wind or solar generation is available

As variable renewables acquire ever higher market share, there will be entire days and weeks with almost no need for baseload generation, which traditionally supplied a certain minimum (base) electricity demand (load) around the clock. This is illustrated in Figure 2 taken from the 2017 BNEF Beyond the Tipping points study. Such baseload – less flexible coal and nuclear power – will have little role in this high-renewables future for whole weeks and months as early as 2030 in both Germany and the UK.

Without flexible loads or energy storage systems, additional renewable generation will then become less valuable and such generation will increasingly struggle to earn a return on investment.

In addition, as their market share grows, wind and solar may have to be disconnected or curtailed (the grey areas shown in Figure 2), when they are in excess to preserve system stability. Grid operators prefer to maintain minimum levels of synchronously spinning turbines ("synchronous generation"), for frequency and voltage control. And curtailment of renewables may also be required where there are grid constraints, for example inadequate transmission between a large wind farm and sources of demand.

Highest wind and solar output week



Note: a week is defined as a 168 hour period, not a calendar week.

Figure 2. Germany: weekly, monthly and seasonal variability

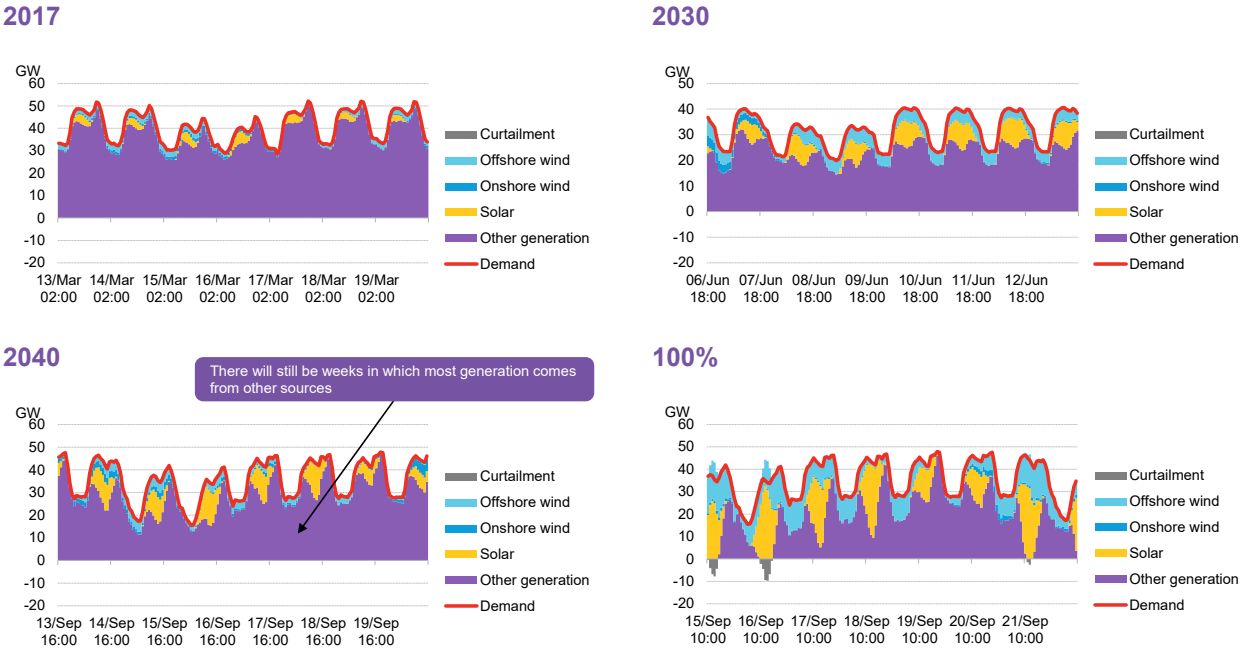
[3] https://www.auroraer.com/wp-content/uploads/2018/10/Aurora-Report-Full-Opportunities-in-EV-charging-at-CI-sites-October-2018.pdf

When wind and solar are unavailable

Conversely, when wind and solar are unavailable, there will be a reduction supply which must be met by back-up generation. Figure 3 models the lowest wind and energy output week in the UK which shows that even by 2040, there will be weeks in which most UK generation will need to come from non-variable renewable sources (the purple zone). The same is true for the German market models in the same report.

Other back-up capacity, such as gas power plants, will also be less required as the market share of wind and solar grows, and will become increasingly idle, with fewer opportunities to earn money. But they will still be needed when neither wind nor solar power are available, for example during periods of high pressure with low wind in winter months. Figure 4 shows steep declines in the energy produced and utilisation of traditional generation assets in Germany, which will increasingly challenge their economics.

Lowest wind and solar energy output week



Note: a week is defined as a 168 hour period, not a calendar week.

Figure 3. UK: weekly, monthly and seasonal variability

Back-up capacity & declining utilisation

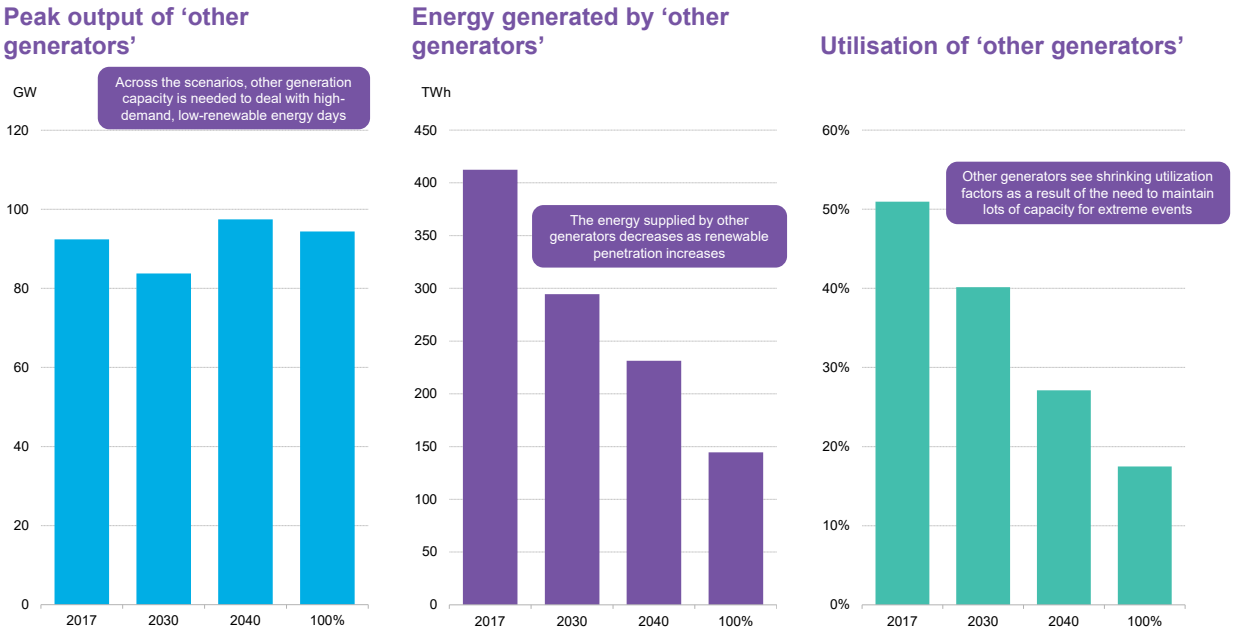


Figure 4. Germany: overview of scenarios and issues

Market solutions to maintain their viability include much higher energy prices at times of scarcity, or non-energy market incentives, such as capacity payments. Maintaining a large fleet of largely idle gas plants will raise system costs.

More flexible capacity will still be required to cope with daily variation, such as at sunset in the case of solar power, when generation falls just as demand is rising to cater for peak evening consumption for domestic lighting, cooking and entertainment. The sharp drop in solar power requires a steep ramp up in alternatives sources of supply or controllable demand, expressed as ramp rate in gigawatts of capacity per hour.

Flexibility is the new cornerstone of the grid

We have described some problems associated with a rising market share of variable renewables such as wind and solar power if these are not integrated properly.

All these problems can be tackled by adding more flexibility to the system. Energy consumers can be paid to reduce demand when the system is stressed, also known as demand-side response (DSR). They may achieve this using battery storage to store cheap renewables when these are in excess for use later when needed. As electric vehicle (EV) market share grows, their batteries can also be used as flexible capacity. This is possible if they use "smart chargers" which vary the rate of EV charging according to system needs. DSR does not mean people have to make sacrifices since they can choose to vary the controllable loads they do not need at a specific time. For example, they do not need to know the exact time that their car is charging, or their electric water heating is operating.

Such flexibility can shift demand from times when renewables are in deficit, to times when they are in excess. This will reduce curtailment when renewables are in excess and the need for mostly idle back-up when they are in deficit, thus boosting overall system efficiency. By displacing fossil fuel backup, such as gas power plants, flexibility can cut carbon emissions. Further, by increasing the rate of use of the remaining back-up it can enable more efficient and cost-effective use of these resources. By aligning peak renewables supply with peak demand and therefore higher power prices, flexibility can also add value to wind and solar and enable faster growth.

In countries with a rapidly growing variable renewables market share, such as Britain and Germany, there will be a growing market through the 2020s and beyond for such load-shifting technologies. We note in this paper that highly flexible markets and technologies, such as DSR, batteries and smart EV charging, only balance the grid on an hourly and daily basis. Longer term load and supply shifting over weeks and months will also eventually be needed and will be provided by a number of technologies not discussed in this paper. This will be particularly true at very high levels of variable renewables market share, to address seasonal demand-supply mismatches and during protracted low-wind, low-solar weather events.

So, we see that instead of inflexible baseload, the grid will require flexibility to complement wind and solar. Flexibility will be the new cornerstone of the grid. Looking into these flexibility options in more detail, we see that they are all available already. What is missing today are the market structures and regulation to give them equal market access.

Demand-side response (DSR)

As mentioned earlier, DSR is a voluntary reduction in demand during times of system stress, for example during peak load periods which in Europe is often in the early evening from 5-7pm. Energy users can be incentivised to reduce energy demand in this way for example through time-of-use contracts with their energy supplier, offering cheaper electricity during off-peak periods. DSR can be divided between dispatchable DSR, which permanently reduces demand for a short period, and non-dispatchable DSR, which merely shifts demand to another time, called load shifting. The latter can shift demand within the day to coincide with high renewable generation periods and so reduce both curtailment and the need for back-up generation at times of low renewables output. BNEF estimates that DSR in Europe will grow by more than 30 GW through 2040.[4]

Energy storage

Energy storage can be divided between batteries, which can adjust over exceptionally short time-scales, to smooth out short-term renewable volatility and longer-term options, where the main technology today is pumped hydroelectric storage.

Batteries can instantly shift between charging and discharging and are thus able to respond exceptionally quickly to fulfil a range of flexibility requirements. For example, they can respond to variation in grid frequency under so-called primary reserve regulation. They can support short-term load-shifting to smooth the hourly and daily variability of renewables. In this way, they can help reduce both curtailment and the need for back-up capacity. BNEF projects that grid-scale battery storage in Europe will grow by 9 GW through 2040.

At extremely high levels of variable renewables, nearing 100% market share, load-and supply-shifting across entire weeks and months will become necessary. This will call for long-term storage options such as pumped hydropower, which are available today and technologies still under development, which may include synthetic fuels based on a combination of hydrogen obtained from water hydrolysis and captured or recovered CO^2. Long-term electricity storage only becomes relevant in extremely high-renewables scenarios because it is only at these levels that some curtailment will extend across entire months due to excess renewables which could instead be usefully stored to replace back-up capacity when renewables are in deficit.

Interconnection

Interconnectors are cross-border cables which link different electricity markets and countries. They enable one to system operator to import or export generation to another. Interconnectors can provide an important source of flexibility because different markets may suffer system stresses at different times because of their different location. That applies both to supply, where windy weather in one market may not extend to another, enabling the export of renewables surpluses and to demand, where evening peak demand in one market can be met by surpluses in a different time zone through geographical load shifting. Interconnection can thus perform a similar role to DSR and battery storage, but over the long term and even seasonally, as well as hourly and daily.

[4] BNEF 2017 Beyond the Tipping Point

In general, interconnection has been shown to be vital to integrate variable renewables. For example, the International Renewable Energy Agency (IRENA) found that 49% of wind power in Denmark was integrated due to interconnection to neighbouring countries, which could use or store Danish wind power surpluses.[5] Similarly, Ireland has reduced wind power curtailment by half through its sub-sea interconnections to Britain, IRENA finds.

BNEF analysis indicates that in the Nordics there is more than enough flexible hydro capacity to balance local wind and solar power, even in a 100% renewables scenario. That is because Norway and Sweden have ample hydropower capacity, which reduces the need for wind and solar. As a result, even decades into the future, there is little or zero curtailment of variable renewables in the Nordic market. Further facilitating the availability of Nordic hydropower, water inflows are lowest during frozen winter months, when Norwegian wind power is highest. As a result, the region has ample, spare back-up hydropower capacity which it can export via interconnections to other European countries such as Britain and Germany, where wind and solar will reach a much higher market share. Their interconnection to Nordic countries can thus provide an important source of flexibility going forward.

Smart electric vehicle (EV) charging

The adoption of EVs is a major new trend which is about to turn electricity markets on their head. This will drive a rapid electrification of the transport system in a very short period. Aurora forecasts that EVs in Britain and Germany will grow respectively to a base case of 17 million and 23 million in 2040, from 140,000 and 200,000 in 2018. Across Europe, BNEF projects some 114 million EVs by 2040, compared with around 700,000 today.

These EVs can either be a grid curse, straining local networks to breaking point, or a blessing by helping smooth peaks and troughs in power demand and supply. The outcome depends on whether EV charging is smart or dumb (see Box A). If EVs are charged in a smart way, they can increase network resilience and ease the integration of variable renewables. Smart charging can shift peaks in demand to times of peak renewables supply. BNEF analysis shows that a large fleet of smart chargers can lower the grid system cost both of adding EVs and integrating renewables.

By smoothing out peaks and troughs in electricity demand, smart charging can avoid investment in costly back-up generation and of network upgrades to cater for additional EV demand. And by shifting electricity demand to times when wind and solar power are available, it adds a new route to market for renewables, making these more profitable. EV charging caters for flexibility in this way, because most vehicles are used for low mileage on predictable routes and end-points and are parked most of the time. As the International Renewable Energy Agency (IRENA) states: "Each EV could effectively become a micro grid-connected storage unit with the potential to provide a broad range of services to the system."

Smart or dumb?

In this briefing, we define three categories of EV chargers: standard ("dumb") chargers that charge the vehicle at a fixed rate according to local power availability; smart chargers which charge according to network needs, whether in response to remote operators or price signals; and bidirectional or vehicle-to-grid (V2G) chargers that can both charge from and discharge to the grid, offering the most flexibility. There are different kinds of smart charging. At the simplest level, electricity suppliers could motivate EV owners to charge their cars at night, through "time-of-use" tariffs. At a more advance level, EV chargers could respond dynamically to local power prices or network availability.

At present, EVs are not charged in a smart way. Their owners charge them mainly at home, when they return from work, in other words coinciding with the evening peak demand period. EVs thus act as a fixed load that increases existing stress on the system. As EV concentration increases, charging infrastructure will also run into grid limitations, such as sub-stations, transformers and cable sizing, as it has done in Norway. This is especially the case if EVs do not charge flexibly, and there is greater use of fast chargers.

A smart charging scenario does have some system requirements, however. Most significantly, it requires 24-hour access to a deep network of EV chargers, implying high investment in workplaces and leisure destinations. And it requires car owner acceptance of remote or automated charging of EV batteries, according to network conditions and the introduction of digital technologies which enable smart charging. There would still be a need for rapid chargers at motorways to allow long-distance journeys. But such chargers would be a minority. With appropriate investment in a very widespread charging network, most EVs could be connected most of the time to relatively low-power, ubiquitous chargers, instead of using very fast chargers whose proliferation could turn EVs into a grid curse. Installing and maintaining charging points with their storage buffers and control systems in homes, parking lots, commercial buildings and streets represents a large business opportunity. Deployment of EV charging infrastructure at sufficient scale and speed will require an acceleration of building code revisions which are still at an early stage in the EU.

[5] https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2019/Feb/IRENA_Innovation_Landscape_2019_report.pdf

Prosumers and aggregators

Prosumers are residential and commercial energy consumers who also generate power, in their homes, communities and businesses. Typically, they will be equipped with solar PV or geothermal energy or a ground-source heat pump, perhaps coupled with battery storage or an EV. In its November 2017 "Tipping Point" study, commissioned by Eaton and the REA, BNEF projected that installed capacity of small-scale solar power would rise fourfold in Europe over the next three decades, to 284 GW and 46 GW of associated small-scale battery storage. Prosumers provide a public service financially as a new source of private infrastructure investment. They can also contribute to system security as a new source of flexibility since a core feature of the prosumer is increased flexibility of demand and supply. They can exploit new options, for example to store solar generation for use during peak demand periods, or to delay charging an EV until off-peak periods, thus smoothing peaks and troughs in demand and supply. Prosumer growth cannot be guaranteed however, as this depends on regulatory and economic signals such as taxes, network charges and energy costs.

Aggregators are intermediaries who use smart grid software to operate thousands of distributed energy assets in tandem as if they were a single virtual power plant. Those resources could include roof-top solar panels, wind turbines, small-scale battery systems and EV chargers. By combining complementary resources such as wind and solar in this way, aggregators can accelerate the grid integration of variable renewables. Where aggregators combine prosumer generation and controllable demand assets, they can sell grid balancing services via an electricity exchange or in the wholesale market. This can be achieved once they reach a critical mass of assets equivalent to the capacity of a conventional power plant. Aggregators may thus become increasingly important, both as a source of revenue for prosumers, and to boost system security.

Smarter grids

As prosumers proliferate, the grid will have to be increasingly responsive, to manage and balance electricity generation, storage and consumption, in two-way electricity flows. This is a big shift from the status quo where power flows only in one direction from central large power plants to millions of homes. Enabling two-way flows of electricity to and from consumers and ever proliferating local sources of generation will require greater network automation, enabled by data. The proliferation of EVs will add to the variability of demand across low-voltage networks and the requirement to control and route power at the level of every EV charger and power circuit, and to store and release power on demand, according to any building's power requirements and power availability and cost.

One example of a specific technology change is in the role of circuit breakers. Traditionally, these halted electricity flows to control surges which could damage electrical equipment following a fault. Their role is now expanding to facilitate the remote or automated direction of electricity flows to make medium voltage networks bidirectional. Similarly, smart circuit breakers are also needed in the home, for example to disaggregate electrical loads and allow utilities to offer different related tariffs, for example for home EV charging. Enabling such change will require the support of regulators that have to approve network investment as part of the regulated asset base of operators. It is unclear today whether regulators will approve such an increase in investment.

National examples: Britain, Germany and the Nordics

The BNEF studies referenced in this report analysed the impact through 2040 of different levels of flexibility on system-wide cost and carbon emissions in high-renewables electricity markets. BNEF investigated how these impacts varied between Britain, Germany and Nordic countries.[6,7] According to the BNEF analysis, in Britain, variable renewables would account for a half of total generation by 2040, and a decade earlier in Germany. By contrast, variable renewables played a much smaller role in the Nordic grid, rising to around 15% market share in 2030, before falling, because of ample hydropower capacity. In both Britain and Germany, BNEF found that introducing greater system flexibility was essential to control costs and maintain system stability.

Regarding cost, in both Britain and Germany, system operators today call upon power plants to dispatch electricity to the grid according to the short-term cost of generation. Renewables and nuclear power are least-cost because of very low fuel and other operating costs and so are dispatched first, followed by gas and coal power plants. That means there will be extended periods when renewables cater for almost all demand as wind and solar market share grows and fossil fuel power plants barely run at all. However, in the absence of flexibility provided by the likes of battery storage, DSR and smart EV charging, both countries require a similar level of fossil fuel back-up capacity in 2030 and 2040 as today, because the variability of wind and solar means that there will still be hours and days when wind and solar fulfil only a negligible portion of total electricity demand. But this backup may be rarely called upon, making it extremely inefficient and costly. Also, in a less flexible system, renewables generation will more often exceed demand, leading to wasteful curtailment, where wind and solar are available but un-used.

Regarding system stability, a higher market share of variable renewables increases the amount of generation that has to be added or removed over short time periods, say of 1 hour, for example at sunset, in the case of solar power. These so-called ramp rates rise dramatically, more than doubling in Britain by 2040, and more than trebling in Germany (See Figure 5). One important consequence is that less flexible, slower responding, conventional generation becomes less economic, such as nuclear, coal and lignite generation, because they are unable to ramp up and down rapidly. In addition, more frequent ramping, or cycling, of conventional power plants may increase their wear and tear, and maintenance costs.

[6] BNEF 2018 Flexibility Solutions for High-Renewable Energy Systems: United Kingdom

[7] BNEF 2017 Beyond the Tipping Point

Growing system volatility

Distribution of hourly ramp rates across the year

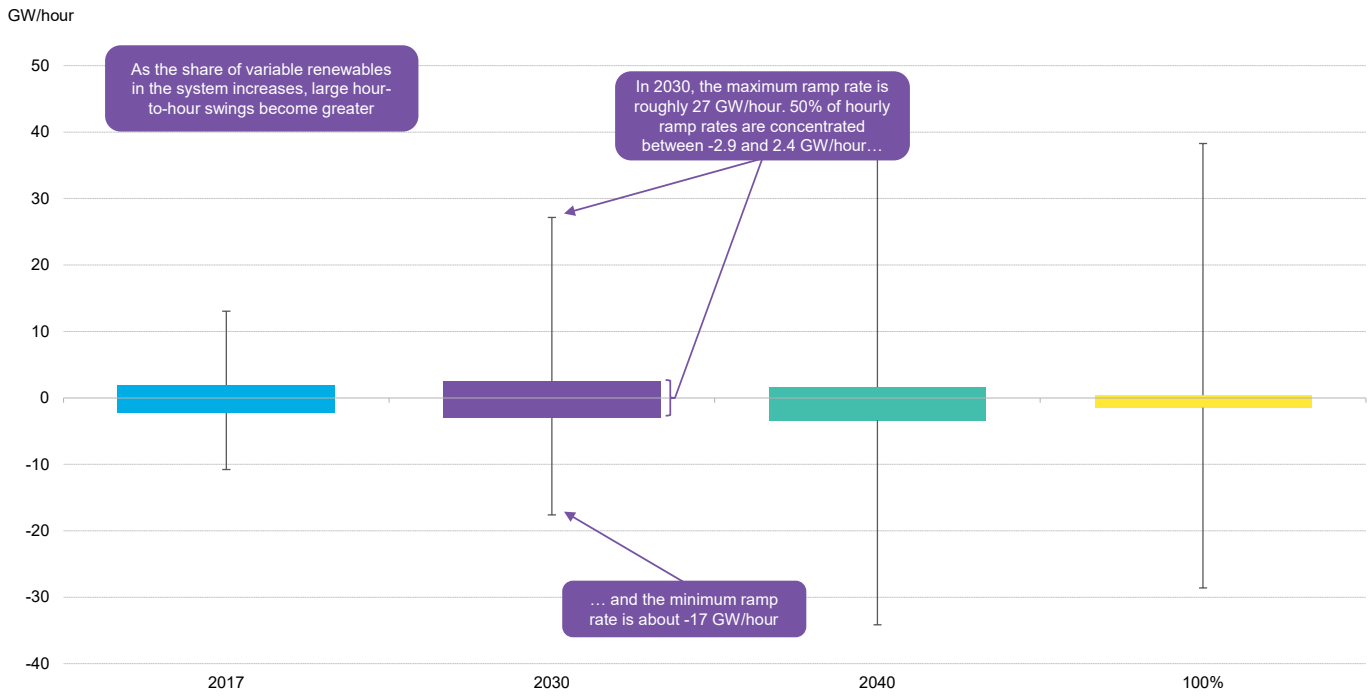


Figure 5. Germany: overview of scenarios and issues

In both countries, Nordic interconnection is seen as a valuable and low-cost source of low-carbon flexibility. Long-term flexibility, to balance the grid over weeks and months, is not seen as a priority in the near term. But at very high levels of variable renewables, higher curtailment could be reduced by shifting surpluses, such as excess German solar in summer and UK wind in winter, to shoulder months when they are less available and so displace largely idle back-up capacity.

Nordic interconnection could provide this, allowing exports of renewables in peak supply months, and electricity imports to cover shortfalls at other times. Britain presently is planning by the early 2020s three interconnector links to Norway and Denmark with a combined 4.2GW of capacity. Germany already has 2.8 GW of interconnection to the Nordics and plans to build an additional 2.8 GW through the 2020s.

Flexibility is low-carbon as well as low-cost, BNEF finds

In November 2018, BNEF in partnership with Statkraft and Eaton, launched a report - 'Flexibility Solutions for High-Renewable Energy Systems' - which explored newer possibilities for solving the flexibility challenge in the UK and Germany. The report modelled the impact of storage, demand response, flexible electric vehicle charging and interconnections to Nordic hydro. Although both countries are on a path to higher renewable penetration, BNEF's analysis led to different conclusions about the role of flexibility in each nation's transition.

Building on BNEF's New Energy Outlook (NEO), this report developed scenarios to explore alternative futures for the power system, depending on how each flexibility technology mentioned above might develop in the coming years.

The report analysed seven scenarios that were all variants of the NEO base case (published in June 2018) and contained some degree of demand response, flexible EV charging and a relatively large volume of batteries. The low-flex scenario considers the consequences if these technologies are substantially held back, whereas each of the other scenarios introduces or accelerates a single 'new' source of flexibility.

In the UK, BNEF found that failing to adopt new sources of flexibility increased system costs by more than a tenth in 2040 and increased carbon emissions by more than a third (See Figure 6). Costs were higher because demand was met inflexibly by building more renewables, with resulting curtailment, and more conventional generation. Emissions were higher because low flexibility resulted in a higher need for fossil fuel generation, including unabated CCGT and unabated peaking gas for grid balancing as opposed to zero-carbon, flexible technologies such as DSR, storage and smart EV charging.

The exception is where EV adoption is sharply accelerated, which raises system costs because of greater investment in generation to meet higher electricity demand. Flexible technologies have a dramatic impact on carbon emissions, due to multiple system impacts: reduced need for gas and peaker electricity back-up; reduced transport emissions due to flexible EV charging; and better grid integration of variable renewables, increasing investment returns to wind and solar, and enabling higher market share.

Table 10: Summary of scenario outcomes in 2030

Scenario	System cost	Emissions	Fossil capacity as share of peak demand	Renewable share of generation	Zero-carbon share of generation
NEO (base case)	32.8 GBPm/TWh	16.8 MtCO2	49%	74%	88%
Relative change vs NEO					
Low-flex	3%	9%	10%	-1%	-1%
High uptake of EVs	2%	-19%*	0%	1%	0%
High uptake of EVs and flexible charging	0%	-30%*	-7%	2%	1%
High uptake of storage	-2%	-13%	-12%	1%	1%
High uptake of flexible demand	1%	1%	1%	0%	0%
Interconnection to the Nordics	-2%	-25%	-11%	3%	3%

Table 11: Summary of scenario outcomes in 2040

Scenario	System cost	Emissions	Fossil capacity as share of peak demand	Renewable share of generation	Zero-carbon share of generation
NEO (base case)	39.8 GBPm/TWh	11.6 MtCO2	34%	80%	94%
Relative change vs NEO					
Low-flex	13%	36%	45%	-1%	-2%
High uptake of EVs	4%	-88%*	3%	1%	0%
High uptake of EVs and flexible charging	4%	-96%*	0%	1%	0%
High uptake of storage	0%	1%	-1%	0%	0%
High uptake of flexible demand	-5%	2%	-10%	0%	0%
Interconnection to the Nordics	-2%	-24%	-10%	2%	2%

*Source: BloombergNEF. Note: Colour scales differ between columns, but in all cases green is desirable. *Emissions for EV scenarios include a negative contribution from emissions displaced in the oil sector.*

Figure 6. UK scenario outcomes

In Germany, BNEF made similar findings. A particular challenge in Germany (See Figure 7), however, was that flexible technologies favour high-carbon technologies as well as renewables generation, at least through 2030. That is because smoothing the variability of wind and solar allows remaining, conventional generation to operate more continuously, favouring less flexible power plants such as coal and especially lignite. This allows lignite generation to remain on the system, slowing the growth in wind and solar. By 2040, however, renewables costs fall to a level where they displace even existing lignite generation, and system flexibility becomes critical to integrate these new renewables. The problem through 2030 is the low cost of lignite generation which would necessitate an early coal and lignite phase out via policy action. Indeed, shortly after the report was published, the German government in early 2019 announced plans to shut down all its coal-fired plants by 2038 at the latest.

Table 100: Summary of scenario outcomes in 2030

Scenario	System cost	Emissions	Fossil capacity as share of peak demand	Renewable share of generation
NEO (base case)	40.8 EURm/TWh	144 MtCO2	81%	75%
Relative change vs NEO				
Low-flex	0%	-3%	-1%	1%
High uptake of EVs	1%	-7%	-1%	2%
High uptake of EVs and flexible charging	1%	1%	-5%	-1%
High uptake of storage	0%	4%	-2%	-1%
High uptake of flexible demand	1%	-1%	0%	0%
Interconnection to the Nordics	-1%	0%	-4%	0%

Table 11: Summary of scenario outcomes in 2040

Scenario	System cost	Emissions	Fossil capacity as share of peak demand	Renewable share of generation
NEO (base case)	48.6 EURm/TWh	109 MtCO2	56%	83%
Relative change vs NEO				
Low-flex	8%	-15%	19%	3%
High uptake of EVs	1%	-18%	-7%	2%
High uptake of EVs and flexible charging	-1%	-26%	-22%	4%
High uptake of storage	0%	-11%	-3%	3%
High uptake of flexible demand	0%	2%	-1%	0%
Interconnection to the Nordics	-2%	-11%	-4%	3%

Source: BloombergNEF. Note: Colour scales differ between columns, but in all cases green is desirable. Emissions for EV scenarios include a negative contribution from emissions displaced in the oil sector; net imports included in renewable share of generation.

Figure 7. Germany scenario outcomes

Case study: Good Energy shows why flexibility will be increasingly important to match demand and supply

The UK-based green electricity supplier, Good Energy, provides a glimpse of why flexibility will become critically important to balance demand and supply at the national level going forward.

Good Energy commits only to supply to renewable power to its customers. It does this by directly contracting power purchase agreements with more than 1,400 renewable electricity operators, including solar and wind power. To fulfil its green electricity commitment, at any moment Good Energy must as closely as possible balance both demand from its customers and renewable power supply from its generators – something it is able to do most of the time (see graph below). As a result, the company has an excellent, detailed view of the task of meeting consumer demand with variable and other renewables supply.

Good Energy reports that it now plans to support battery storage, whether as an owner-operator or through long-term contracts, to match demand and supply even more closely.

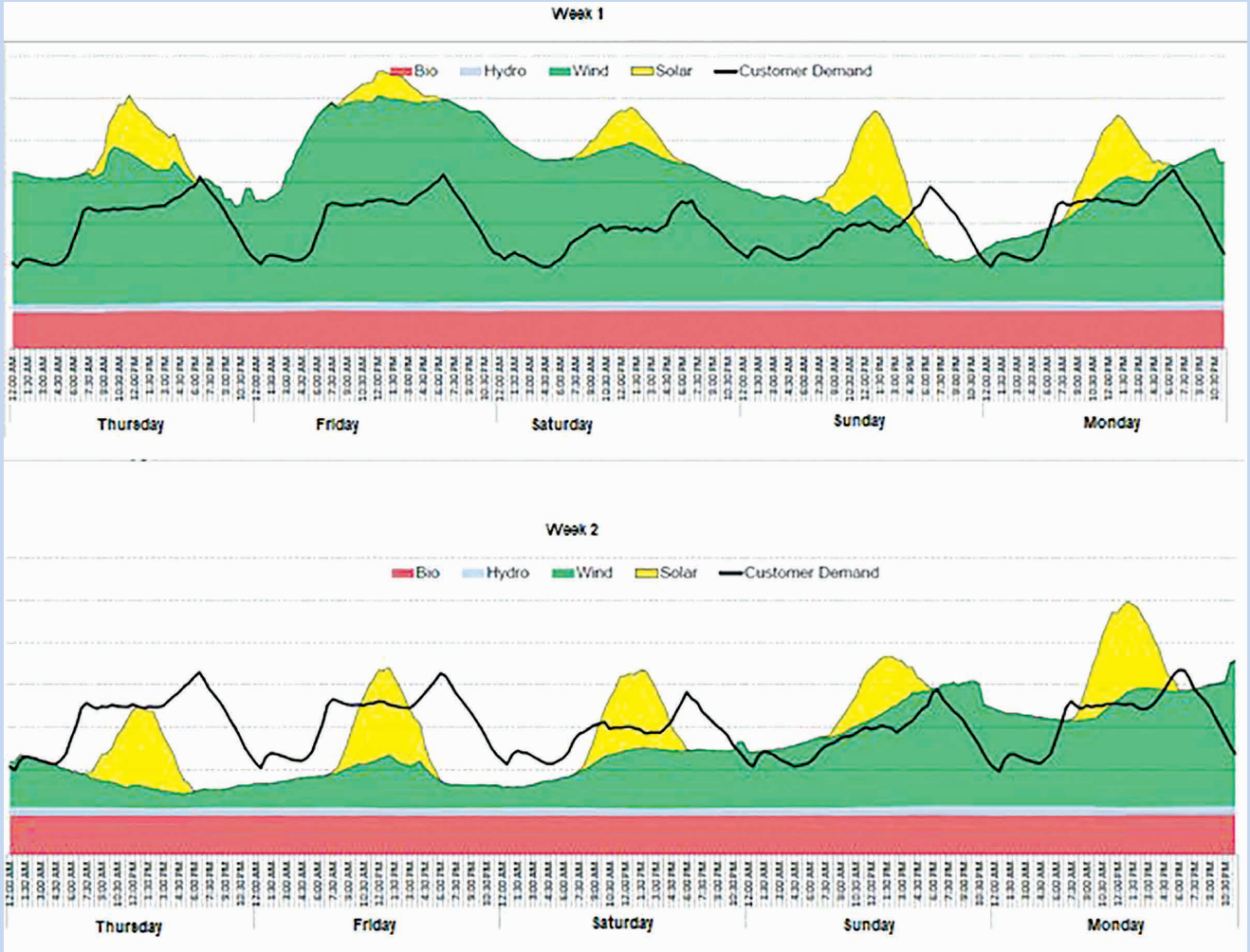


Figure 8.

Section 2: Gap analysis - a summary of current versus ideal grid regulation

We found in the previous section that the electricity system will increasingly be built around renewables and flexibility as the least-cost and cleanest electricity system. Flexibility will become the core grid function, the cornerstone of the grid. That is where technologies and business models such as smart EV charging, battery storage, DSR, interconnection, prosumers and aggregators of distributed energy resources will come in.

But the market for flexibility services at present is artificially limited by a legacy network that has operated in fundamentally the same way for more than a century. In this section, we describe some practical examples of how present regulations perpetuate the electricity system of the past, for example through connection charges, availability requirements, minimum size thresholds and capacity and ancillary market rules. Collectively, these legacy regulations discourage investment in flexibility and so delay a shift to majority renewables and increase system costs overall. Where electricity markets reform is taking place, this may be happening in an incremental way that heightens complexity and uncertainty and leaves investors with limited visibility regarding how they will be compensated and a less convincing business case.

The urgency of a low-carbon transition demands a different approach. For example, in the near term, we will need to install tens of thousands of smart and bidirectional EV chargers in distribution networks, to integrate EVs and balance renewables supply. Because of the scale of such a project, there will be bottlenecks, and it will take several years. There is little or no implementing regulation today, nor within sight, mandating such chargers. Regulators appear to overestimate the capacity of the market to act quickly.

In the remainder of this section, we summarise some of the key regulatory building blocks required to implement the new electricity system and reflect on where we are today. We focus in depth on two key European markets, Britain and Germany, but also refer to other countries, and highlight successes and best practices elsewhere, using case studies.

Recognising Enabling Technologies

1. Smart and bidirectional EV chargers

What is needed:

- We define three categories of EV chargers: standard chargers that charge the vehicle passively at a fixed rate according to local power availability; smart chargers which charge according to network needs, whether in response to price signals or remote operators; and bidirectional or vehicle-to-grid (V2G) chargers that can both charge from and discharge to the grid, offering the most flexibility.
- BNEF analysis, summarised in Section 1, shows how important smart chargers are to help integrate variable renewables, by shifting peak demand to times of peak supply. Smart charging can also lower the system cost of adding EVs, for example by avoiding the need for local grid upgrades, and new-build generation capacity to meet higher EV-related electricity demand.
- To date, the debate about EV charging infrastructure has focused on the number and power of charging points, rather than whether chargers are smart, or bidirectional. Bidirectional chargers are needed because of the grid services they provide. But they have a higher upfront cost, thus requiring regulation that offers a market for their services and that mandates their rollout.

Where we're at:

- Availability of standard EV chargers: data from the International Energy Agency show that Germany has overtaken Britain in the deployment of publicly accessible EV chargers, while the Netherlands leads both.
- New EU charging rules focus on the numbers of chargers, rather than their flexibility
  - Non-residential buildings that are new or undergoing major renovation and have more than 10 parking spaces will need to be equipped with at least one charging point and with power line ducting to allow subsequent installation for 20% of parking spaces.
  - By 2025, member states will have to set out a minimum number of charging points for non-residential buildings with more than 20 parking spaces, and measures to simplify deployment, for example by streamlining permitting and approval procedures.
  - There is no requirement to make EV charging "smart", or to install V2G.
- Availability of smart and bidirectional (V2G) chargers
  - In both Britain and Germany, only a handful of either smart or V2G chargers exists. In the case of V2G chargers, there is also limited EV compatibility.
  - In Britain, an EV bill passed in 2018 gave the government powers to require EV chargers to be smart in future, for example to vary the rate of charge or discharge, by automated or remote control. But that is a long way from mandating the deployment of such capabilities today.[8] In its "Road to Zero" report setting out the future of EVs in Britain, the government only stated that chargers today should be "smart ready", again without defining this. The government's statutory National Infrastructure Commission, by contrast, last year estimated that smart charging would save £2 billion annually in electricity system costs and recommended that "smart charging should therefore be the default option for home charging".
  - In Germany, there are uncertainties in the legal underpinning for V2G chargers, for example tax payable on sales to the grid, and the application of electricity generator rules and codes when discharging to the grid.

2. Smart meter rollout and dynamic consumer pricing

What is needed:

- A prerequisite for dynamic tariffs is the rollout of digital meters which record electricity use in real time.
- Dynamic tariffs offer financial incentives for consumers to change behaviour, for example to shift to off-peak demand periods in response to market price signals. As we saw in Section 1, such demand-side response (DSR) can lower the system cost of high market share variable renewables and EVs, by reducing the need for renewable energy curtailment and fossil fuel back-up generation. Dynamic tariffs may offer consumers different prices, for example according to the time of day they use electricity (time of use tariffs) or may incentivise them to use less electricity at any one time

[8] http://www.legislation.gov.uk/ukpga/2018/18/pdfs/ukpga_20180018_en.pdf

(peak tariffs). More sophisticated tariffs might disaggregate household loads, with different tariffs for controllable loads such as EV charging or electric heating, and for non-controllable loads, such as cooking. Under such a model, EVs could be charged far more aggressively, at very high prices at peak times and at very low tariffs at off-peak times – in particular late evening and early morning hours.

Where we're at:

- Smart meter rollout
  - In Nordic countries, there is already near-universal, national rollout of digital meters.
  - Britain is presently in the middle of a major smart meter rollout programme, targeting all households by 2020. While that target will be missed, the rollout is happening at an increasing pace. There were initial problems, with the deployment of meters that lost their smart functionality when a customer switched supplier.
  - In France, the main district service operator, Enerdis, is more than halfway through a similarly large-scale, national smart meter deployment programme.
  - In Germany, smart meters are still unavailable. At present, only one manufacturer has achieved certification, and a mandatory rollout will be delayed until at least a second product becomes available, to avoid a monopoly market. At the end of January, the German federal agency for security and ICT reported that this certification process was ongoing, and smart meters were not ready for rollout.
- Introduction of dynamic tariffs
  - In Britain, due to its smart meter rollout, dynamic pricing is now becoming available. For example, Octopus Energy has introduced an "Agile tariff" which tracks wholesale power prices and advises customers 24 hours in advance of low-cost periods (see Case Study X).
  - In Germany, dynamic tariffs are unavailable, because of the absence of digital meters. In France, the introduction of dynamic tariffs is expected shortly, to follow its smart meter programme.

Case study: Domestic tariffs that encourage peak shaving in Norway

As EV rollout continues in Norway, it is becoming increasingly important for consumers to control their peak demand, and especially when they charge their EVs at home. To date, EV charging was often during the evening peak period, which is unsustainable, not least because many homes are at the end of long, low-voltage power lines.

In 2020, Norway is expected to roll out "peak tariffs" for domestic consumers, with similar incentives already available for commercial and industrial customers. Under these tariffs, the supplier calculates the average peak demand across the three, 15-minute, peak-demand periods in any given month. The customer pays a fee of around €15/kW, for this calculated kW figure. Customers also pay a regular energy bill per unit of electricity consumed (ie per kWh).

The customer is thus incentivised to demand less electricity at peak times and put less strain on the grid. This kind of tariff can help smooth out EV charging demand. Customers might reduce their peak use by charging their EV at night, or by using a battery which they can charge during off-peak times, to discharge to the EV when most convenient. Such smarter behaviour can avoid the need for costly local network upgrades.

Case study: Octopus Energy finds Britain's first time of use tariffs cut peak demand by a quarter

The UK energy supplier, Octopus Energy, last year introduced its "Agile" tariff, which allows customers with digital meters to respond to day-ahead wholesale power prices, tailoring their consumption according to price.

Under its Agile tariff, Octopus updates its unit rates at 4pm every day, for every half-hour interval of the following day. The supplier then tracks and charges for consumption according to those half-hourly prices. Prices are typically highest from 4-7pm and lowest around 11pm-5am. Octopus has made it possible for customers to automate their price response, so that they don't have to track prices, or turn their appliances on and off manually. They did this by pairing with the IFTTT app, which can instruct various digital appliances via the smart meter to operate only within a certain price range. Octopus reports that peak demand fell by an average 28%, upon the introduction of the tariff, indicating the potential system savings in avoided network upgrades from a wider rollout of similar tariffs. EV owners reduced their peak consumption the most and saw the biggest savings.

Case study: Good Energy pilots identifying demand from individual appliances

Good Energy considers that its customers are more focused on sustainability than the average energy consumer because they pay a little more for the renewables products that Good Energy offers. As a result, the company could pilot forward-looking approaches to demand management.

Through an EU-funded project, "BestRES", Good Energy has explored the benefits of live energy information on a household electricity bill and the resulting relationship with their energy needs. Good Energy gave participating customers real-time information about their disaggregated load, to the level of individual appliances, and their time of use of such appliances.

The goal was to encourage customers to review their decisions about energy consumption during peak versus

off-peak times. Good Energy offered tariffs that rewarded customers for shifting demand to off-peak times. The pilot offered a glimpse of the advantages of time of use consumer tariffs. By disaggregating loads, electricity suppliers can encourage customers to shift demand for particular, non-time-sensitive loads, such as EV charging.

Case study: UK proposed flat rate network charging: going in the wrong direction?

At present, Britain's energy regulator Ofgem is consulting on changing the way it passes residual network charges to domestic consumers. Historically, networks charges were calculated per unit of electricity consumption. As a result, households who invested in solar panels, and consumed less grid power, also paid lower network fees.

Ofgem has concluded that this situation is unfair, and risks passing higher residual network fees to poorer consumers who cannot afford solar panels. As a result, the energy regulator has proposed to increase the flat-rate component of electricity bills, to £64 annually for all consumers. This means that households will have a smaller incentive to install solar panels and battery storage which reduce dependence on the grid. And it means that households who have already installed solar and/ or battery storage will be hit most. The Ofgem chart below shows how present ("baseline") bills will rise under its proposed "fixed charges", for consumers with solar or battery storage.

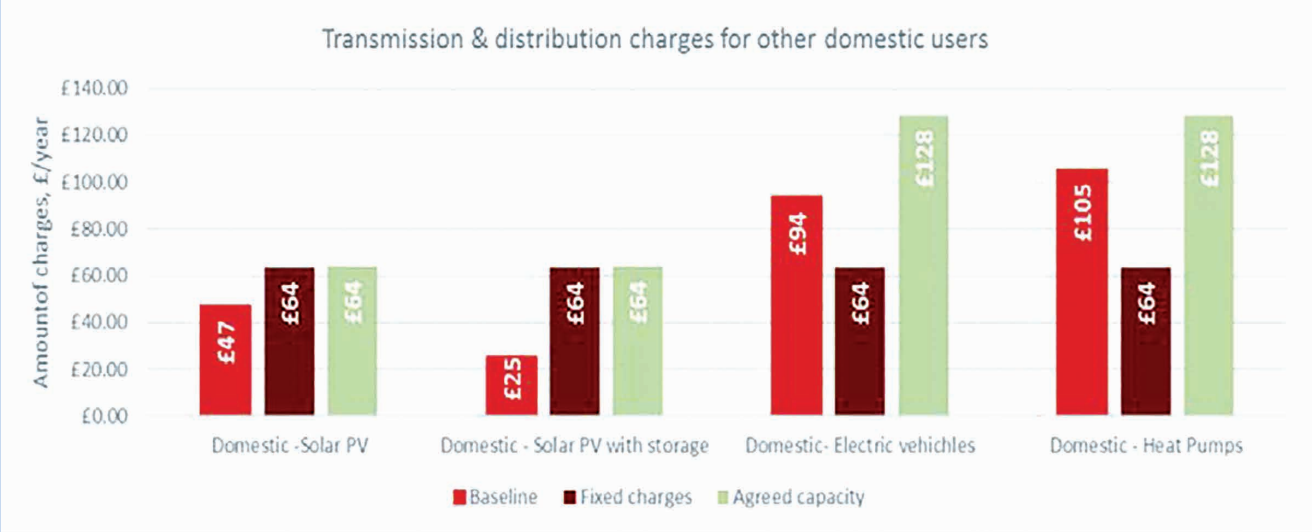


Figure 9.

Improving Access to Energy and Non-Energy Markets

Fair tax treatment and network charging for distributed assets

What is needed:

- Distributed storage, DSR and generation should be treated fairly, compared with conventional large-scale generation. For example, battery storage should not pay network fees both for charging and then discharging the same electricity, as often is the case at present.

Where we're at:

- At present, storage is typically treated as both generation and consumption, requiring two grid connections for import and export, and may be billed for both.
  - In both Britain and Germany, battery operators pay standard network fees both for charging from and discharging to the grid. In Britain, the government plans to classify storage as a subset of generation, to provide short-term certainty. In Germany, there is no regulation in the pipeline.

Equal access to ancillary services and capacity markets

What is needed:

- Increasingly, electricity will be provided and managed by small, decentralised wind and solar power, DSR, batteries and smart EV chargers, instead of big, centralised power plants. Many markets have not caught up, however.
- All resources should compete on a level playing field in markets including balancing markets, where the grid operator matches demand and supply in real time; ancillary services markets, which contract assets to maintain system stability and grid frequency; and capacity markets, which allocate a certain minimum capacity several years ahead, to avoid blackouts. Current grid regulation in most countries favours centralised generation assets, through connection, testing and metering provisions, availability requirements, capacity payment haircuts for storage assets, and other administrative costs and minimum size thresholds. These hurdles penalise aggregators of small, distributed assets, over big power plants.
- What is needed is new solutions, to cut the costs and administrative hurdles which are slowing down the participation of distributed energy resources in modern energy markets.

Where we're at:

- In the United States, The Federal Energy Regulatory Commission (FERC) last year passed an order (Order 841) which mandated all eight U.S. wholesale market operators to ensure storage participated on a level playing field in all available markets, including energy, ancillary services and capacity markets. No such measure exists in Europe. The FERC rule still failed to clarify the role for aggregated distributed storage, however.

- In Britain, the National Grid three years ago introduced a sub-second Enhanced Frequency Response market, to deal with the increasing volatility expected as a result of the growth in wind and solar power. The fast response time of batteries makes them well-suited to compete in such a market. However, there are certain barriers in this and other markets which still make it difficult for smaller, aggregated batteries to compete. These barriers include size thresholds and asset tests that impose cost and administrative hurdles.
  - Size thresholds
    - Ancillary services markets: Already, assets of as little as 1 megawatt can bid into UK ancillary services markets, and in theory individual assets smaller than that within an aggregated portfolio.
    - Balancing mechanism: The National Grid is about to trial allowing individual assets as small as 1MW to bid into the balancing mechanism, within larger aggregated portfolios offered by so-called "virtual lead parties".
    - Capacity market: Energy assets as small as 0.5MW can bid.
    - Asset tests
    - To access both ancillary services markets and the balancing mechanism, distributed assets at present must be tested individually, for example to show that they can follow frequency. Such tests are quite detailed, involving running the test, and extracting and presenting relevant data. In addition, each asset must have a frequency meter installed, to measure the local grid frequency that they must follow and respond to. Frequency meters retail at around £250, or 5% additional cost for a medium-sized, behind the meter battery. These kinds of rules were originally written for larger centralised power plants, whose cost ran into tens or hundreds of millions of pounds, where the incremental cost of a frequency meter was therefore negligible.
  - Capacity market de-rating
    - In 2017, Britain's National Grid reduced (de-rated) the payments received by battery storage participating in the capacity market, on the basis that the capacity market required assets to be able to provide power for 4 hours, and storage was expected to be limited to 1 hour. Storage providers disputed the change, on both the grounds that it was unexpected, and doubting that capacity providers would ever have to provide emergency power for 4 hours.
    - Coupled with new emissions limits under the EU's Medium Combustion Plant Directive, which blocks the participation of diesel generators in capacity markets, the battery storage de-rating change has encouraged private equity firms to invest in unabated gas peakers, contradicting the goal of achieving a zero-carbon grid in the medium-term.
- In Germany, participation in frequency response markets is subject to a minimum size threshold of 1MW.
  - Aggregators can bid aggregated assets of 1MW in frequency response markets, but these have to be individually certified, and guarantee individual availability.
  - However, there is discussion to enable group-based prequalification criteria, for EV fleets to provide flexibility services. This might work through administrative pre-approval of all charging points of a specific design, rather than individual review of each charging point for standards compliance.

- In France, Battery aggregators must pass a 1MW size threshold to participate in frequency response markets. The threshold is a barrier for aggregators of thousands of residential barriers, but less so for commercial and industrial sites.
- In Finland, the utility Fortum has contracts with more than 2,000 customers to regulate their water heaters remotely at night, to smooth out a peak demand period in the evening, and so help balance the grid, under its "Fortum Spring" initiative.

Case Study: Amsterdam Arena – Fair access to grid services markets boosts the business case for large-scale battery storage

Eaton and its commercial partners last year commissioned a 3MW energy storage system, comprising new and used Nissan EV batteries, in Amsterdam's Johan Cruijff ArenA. The arena is the home for AFC Ajax, and the stadium for the Dutch national team, as well as for concerts, dance events and business meetings. The 3MW battery is coupled with a 1MW roof-top solar system.

The business case of the 3MW battery has been boosted by multiple revenue streams. The primary role of the battery-solar PV system is to provide an uninterruptible power source (UPS) for the stadium, when in peak use, in the event of a grid emergency. It has the capacity to provide power for 1 hour of peak stadium demand, reducing the need for more carbon-emitting, on-site diesel generators. When the stadium is not fully in use, the battery has three additional revenue streams. First, it can sell frequency response services, via access to the Netherlands' frequency control (FCR) market. Second, it increases the self-consumption of the on-site solar generation, thus increasing savings on more expensive grid electricity, while exporting the surplus. And third, it can drive achieve power price arbitrage, between cheaper, off-peak and more expensive peak demand periods.

Case Study: UK's Upside Energy – What fair market access means for distributed energy resources

Upside Energy has developed a technology platform, to enable a route to market for distributed energy resources, from battery storage to small-scale generation and electric vehicles (EVs). The company works alongside manufacturers, owners and operators as well as power traders, utilities and system operators to enable aggregated blocks of distributed resources to bid into various energy and non-energy markets.

In Britain, Upside Energy wants fair access for distributed energy resources to the balancing mechanism and ancillary services markets. At present, National Grid requires testing of individual assets to ensure they can follow grid frequency, an important function to be able to provide services such as dynamic firm frequency response. A less onerous approach, to avoid the testing of hundreds or thousands of individual batteries, would be to require frequency following capability as a manufacturing industry standard. Regulators would then randomly test industry compliance at the factory.

In addition, to avoid the cost of installing frequency meters on individual batteries, Upside Energy considers a better way would be for the National Grid to provide regional grid frequency signals, that all players follow, given that frequency barely varies according to the location of individual batteries. Such reforms to National Grid testing procedures could help unlock the huge flexibility potential of EV batteries, which are already available in large numbers, but make little or no contribution to system stability. Upside Energy can provide a route to ancillary services markets for such EVs, via their trading software platform. Present National Grid frequency metering procedures pose one additional hurdle, given that vehicles have no fixed location, which might require under present rules testing of multiple charging sites as well as multiple vehicles. The above changes would alleviate this issue, as well.

Case study: Eaton's EnergyAware UPS enables large commercial loads to give back to the grid

Data centres are a good example of a large commercial load that has the potential to support the power grid and be compensated for the flexibility services provided. Data centre operators require resilient power infrastructure no matter what happens in the grid. To achieve this, they typically deploy UPS systems and on-site generation with back-up generators. Eaton's EnergyAware UPS enables its data centre operator customers, such as Microsoft [www.eenews.net/stories/1060089417] to make money from their existing UPS systems by helping energy providers balance sustainable energy demands. Large data centre operators, such as co-location and cloud service providers, can be compensated for immediate adjustments to power demand that help the grid avoid power outages, without compromising critical loads.

Eaton has performed two pilots with TSOs. One, with Svenska Kräftnet, and another with Statnett, in Norway. Both pilots proved that UPS technology fits perfectly for rapid frequency regulation type services. Frequency regulation in this context is more focused on very short time frequency variations – timescales of seconds – caused by minute variations in production, disturbances as well as reduced amounts of inertia in the grid. Eaton makes use of its the Digital Signal Processors (DSP) built into its UPS systems to perform real-time sampling of the AC waveform, which allows its gear to react autonomously to these frequency variations within milliseconds instead of relying on a central grid signal.

While UPS systems today are not used to reduce peak demand or time of use, this is certainly possible with investment in larger batteries. UPS technology could easily be linked to various energy management schemes behind the meter, or more demanding grid support schemes. With new business models, such as revenue sharing and aggregators investing in additional hardware required for more lucrative services, this is possible today.

Flexibility markets

What is needed:

- A first step to recognising and incentivising flexibility is to define it in primary legislation. Such a definition will establish the product, and so facilitate its pricing and participation in various markets.
- Markets for flexibility are important, to reveal pricing for investors, and availability for grid operators.
  - Electricity markets in general might be reformed so that participation is limited to firm capacity. Energy analyst, Dieter Helm, for example, has proposed combining capacity market auctions and auctions for renewable energy through a new requirement for "equivalent firm capacity". That would see baseload (such as gas and nuclear) compete with variable renewables (wind and solar) plus storage.[9]
  - Local network operators might tender for flexibility services, as an alternative to conducting grid upgrades. Operators traditionally earn a regulated rate of return on a capital base which includes sub-stations, transformers and cables. That approach can incentivise the build-out of networks, over more cost-effective means to integrate variable renewables, such as contracting with third party providers of battery storage and demand-response. Network operators might be incentivised to choose the latter if they were able to earn a return on operational expenditure, removing the preference to own and operate assets over paying third parties to provide local flexibility to balance the grid.
- Flexibility markets, where they exist today, often provide short-term visibility on possible cash-flows for flexibility assets. To ensure long-term cash flow visibility, flexibility markets, however they are organised, would ideally provide predictable, long-term cash flows, for example via a combination of multi-annual contracts and annual auctions guaranteed to run for several years.

Where we're at:

- In the United States, we have seen utilities tender for firm renewables capacity, via reverse auctions for variable renewables plus storage, for example by Xcel Energy in Colorado. Generally, storage works best with solar, because of the predictable diurnal cycle, and ease of battery daily charging and discharging. There are no such tenders in Europe.
- Also in the United States, there are isolated examples of district operators being incentivised to contract for flexibility rather than build out grid infrastructure. In New York, such a "non-wires alternative" operates in the Brooklyn microgrid, for example.
- In Europe, local markets for flexibility barely exist. However, under the EU's recent Clean Energy Package, there is a new requirement for Distribution Network Operators (DNOs) to become more proactive network managers, as Distribution System Operators (DSOs). The goal is to manage local networks more cost-effectively, to integrate distributed energy resources (DER), rather than simply to manage and upgrade wires and sub-stations. That change could see the role of network operators widen, to include procurement of flexibility services from DER, via local auction platforms.
- In Britain the government department for Business Energy and Industrial Strategy (BEIS) and the energy regulator Ofgem two years ago published a "Smart Systems and Flexibility Plan"
  - Anticipated network operators becoming system operators, for example developing markets that incentivise flexibility as a cheaper alternative to network reinforcement.
  - UK Power Network (UKPN) is one of the most advanced DNOs creating such online tendering platforms. In May, UKPN made its biggest tender to date on its Piclo Flex platform, contracting some 18MW of flexible capacity.
- In Britain, markets where battery storage have a competitive advantage generally have shorter contracts than markets tilted towards big power plants. For example, firm frequency response markets have a contract term of one week, short-term operating reserve of four months and reactive power of one year. That contrasts with 15-year contracts available for capacity in general under the UK capacity market.

Case study: Britain's Drax - how flexibility incentives might work

UK-based Drax Group was once best known as the owner of the largest coal power plant in western Europe. It is now diversifying into multiple alternatives, as it broadens its offering under a low-carbon energy transition. These alternatives include flexible, low-carbon electricity generation, such as from biomass, pumped storage and run-of-river hydro, as well as downstream energy services, through its acquisition of two business-to-business supply companies, Haven Power and Opus Energy.

As a part of this downstream expansion, Drax is now exploring whether it can market behind-the-meter storage to its new business customers. A first step is to drive down installation costs in battery trials. The next would be to seek out markets, where Drax sees a lack of visibility presently in Britain. Two key problems are the low volumes and experimental nature of emerging flexibility markets at the distribution level, and the short-dated nature of more established contracts for system-wide flexibility services.

Drax considers two options for better incentivising flexibility. First, system operators should provide more transparency on how long-term, future service requirements are likely to evolve. This could include ensuring that flexibility contracts can be tied into, and are stackable with, capacity market contracts. Sharing better information, enabling whole system outcomes and forecasting how the system needs may develop in the coming years will enable informed investment decisions that minimise overall costs for consumers. Second, Ofgem could tighten the National Grid's Electricity System Operator (ESO) cost targets and incentivise the ESO to use a blend of short-term and longer-term contracts to manage cost volatility. This should reduce price risks for consumers and, at the same time, provide clearer investment signals for flexibility providers.

[9] https://www.gov.uk/government/publications/cost-of-energy-independent-review

Section 3: Challenges and opportunities posed by regulatory change: a spotlight on the UK

In the previous section, we described examples of how regulation could unlock private investment in a more flexible electricity system. We then compared and contrasted those examples with actual regulation in some west and north European countries today. In this section, we dive into the case of UK regulation in more detail, to discuss recent policy announcements and what is needed to tilt investment into a more flexible, future energy system. This section includes supporting commentary by one of this paper's key sponsors, the UK's Renewable Energy Association (REA).

Recent and ongoing UK power market reform

Britain's energy regulator, Ofgem, is presently embarking on multiple reforms to how it charges electricity suppliers, generators and consumers for using the grid. These charges can be divided between "forward-looking" and "residual" charges. Forward-looking charges are intended to incentivise suppliers, generators and consumers to invest in the electricity network for the benefit of all, which would include investing in flexibility that avoids grid upgrade costs. Residual charges are intended to cover the balance of costs incurred in running the electricity network.

Ofgem is carrying out these reforms in parallel tracks, first focusing on residual charges, where its focus is to promote fairness and reduce the ability of more sophisticated or affluent consumers to use small-scale generation and storage to exploit the way system network charges are presently calculated. Second, Ofgem will reform forward-looking charges, which might benefit investors in flexibility. The likely outcome is still unclear, with implementation from around 2022 or 2023. Following is a brief review of recent and ongoing reforms, especially regarding residual charges.

Removal of benefits for front-of-meter small-scale generation and storage

Electricity suppliers pay network charges according to their use of the transmission grid during certain peak times during winter. They can reduce their net demand on this transmission grid by buying electricity from batteries and small-scale generation on the low-voltage distribution network, which to date have not paid such charges. Until recently, if suppliers reduced net demand during key peak periods in winter, used to calculate network charges (called "Triad"), they could generate big savings, and pass these savings to small-scale generation and storage. In 2017, Ofgem cut these so-called "embedded benefits" to small-scale generation and storage on the low-voltage distribution grid by more than 90%, to £3-7/kW from around £47/kW, in response to complaints from the owners of big power plants on the transmission grid.

New charges for behind-the-meter small-scale generation and storage

Ofgem is now planning further reforms to how big energy consumers pay for residual charges for use of the grid, under a Targeted Charging Review (TCR). The overall approach is similar to removing "embedded benefits" for front-of-meter distributed energy resources. This time, the impact will be on behind-the-meter assets including storage, which until now big energy consumers have used to cut their network fees by avoiding grid electricity consumption at targeted peak times. Until now, big energy users were charged for transmission network use according to their demand in certain peak winter periods. And they were charged for use of the low-voltage distribution network according to their consumption at certain of the day, with the biggest levy during the evening peak period. In both cases, they were incentivised to install batteries and on-site generation for DSR which reduced their demand at these times. The latest indications are that Ofgem will scrap this approach, replacing it with a flat-rate charge, according to broad categories of consumption profile. Energy users with solar PV or battery storage are therefore likely to pay more going forward.

In related reforms, going forward, Ofgem plans to pass network charges to residential customers as a flat-rate charge, instead of a charge per unit of energy consumed. This new approach will most impact consumers that have invested in roof-top solar and battery storage as a way to reduce their energy demand. Their bills will rise the most, under the expected reform, while bills for households with the most electricity consumption will fall the most.

Finally, Ofgem is planning to require both front-of-meter and behind-the-meter distributed energy resources to pay towards the running of the balancing mechanism, for the first time. This is the mechanism used by the National Grid to match demand and supply in real time.

Ending of roof-top solar feed-in tariffs, smart export guarantees and VAT increases

In March 2019, the UK government scrapped feed-in tariffs for roof-top solar, which paid a certain sum both per unit of solar power generation and export to the grid. In another negative development for new roof-top solar projects, the UK government is expected shortly to end lower VAT rates for residential solar and battery storage, raising VAT to the standard 20% rate, from 5%.

The positive news is that the feed-in tariff scheme will soon be replaced by the recently announced "Smart Export Guarantee". The details of this scheme were announced by the UK's Department for Business Energy and Industrial Strategy (BEIS) in early June 2019. In short, it will enable onshore wind and solar photovoltaic exporters with up to 5MW capacity to receive a payment for their exported electricity. Licensed suppliers with more than 150,000 domestic customers will be required to provide at least one tariff offer to any eligible exporter (and they are free to offer more than one tariff). Other suppliers may participate on a voluntary basis. According to the Government, the scheme is due to come into effect from the end of December 2019.

A more coordinated energy policy: an REA perspective

To date Ofgem and Government have removed embedded benefits for distributed generation and storage, has plummeted de-rating factors for batteries in the UK Capacity Market (decreasing revenues) and eliminated roof-top solar feed-in tariffs. Plans would now see an increase in network charges for behind the meter solar and batteries, scrapped VAT breaks for residential solar and battery storage and flat-rate network charges which will erode household incentives to install solar and storage.

In early June, the government announced a new scheme to replace roof-top solar and small renewable feed-in tariffs, to require suppliers to pay a market rate for solar generated by their customers, through a so-called "smart export guarantee". While we greatly welcome the announcement of any replacement policy, the policy lacks teeth and the cumulative effect of the other reforms undermine the business case for distributed renewable generation and storage just at a time when the electrification of transport and heat create new demands and strains on the system.

These negative changes are coming in advance of other Ofgem reforms, still uncertain, which may incentivise flexibility, as well as the National Grid's System Needs and Product Strategy (SNAPS), aimed at improving market access for small-scale DER and storage. As a result, investors see new risks from investing today and may therefore be inclined to invest in alternatives, such as gas peaking power plants.

In terms of the industry perception and a way forward, first, it would be better to manage complex reforms concurrently, so that the overall objective and outcome is clear. Second, successive rounds of consultations give an impression of constantly changing, disjointed energy policy, undermining investor confidence. This makes it time-consuming and expensive to understand and engage with policy. Third, Britain might benefit from a clearer, long-term renewables and flexibility target, and a roadmap combined with policies that will deliver new capacity for getting there. That target might apply to 2040, for example, with a roadmap describing implications for 2020, 2025 and 2030. Investors can then invest, with a better understanding of the risks and potential upsides.

Section 4: Concluding remarks and our key regulatory asks

The authors of this report regard the following as some of the key changes needed to unlock the investment needed in flexibility services and technology. It is not meant to be exhaustive, but rather focus on the changes that can be made today and make an immediate positive impact.

End regulatory uncertainty, with clear medium-term targets and a roadmap for getting there

While the regulatory regime is in a state of flux, large-scale investment will be delayed. In Britain, France and Germany we see near-identical stories, where the business case for flexibility assets including battery storage is unclear.

Conversely, the Nordic market has benefited from a very stable and beneficial (see below) regulatory environment with a careful introduction of new rules.

Public intervention to create a deep and transparent flexibility market

For some time, the Nordic countries have enjoyed multiple and transparent markets mechanisms with different time horizons where all energy futures, physical products (Nord Pool Elspot and Elbas) and ancillary services are traded or procured openly. This ensures market access and facilitating data collection, thus contributing to the credibility of revenue projections.

There is also a low threshold to participate in Frequency Regulation (FR) tenders to help with grid stability, with a different price point per kW for small and large installations. This is important as it creates a liquid market for storage capacity behind-the-meter, where it is most efficient for the economy as it is where the largest number of services can be 'stacked' to enhance the economic value of those assets.

We would like to see this model replicated elsewhere – and ideally going further to foster a flexibility market with standard products, durations and futures. Otherwise, a balkanised system will mean that operators trying to source flexibility to firm variable renewable delivery, reduce peak grid loading or avoid imbalance charges, will incur high transactional costs to find flexibility rather than simply procuring on the market.

Enable everyone to share the economic benefits of flexibility

Behind-the-meter flexibility assets are a unique opportunity for energy consumers to change their position in the energy economy from "passive price takers" to supplier of a key commodity – flexibility. Consumers, either on their own or through associations (e.g. for social housing) should be able to monetise these assets to control their energy bills and benefit from the energy transition. This can be mediated either by independent flexibility coordinators (today mostly aggregators) or energy distributors offering favourable conditions to flexible consumers. In all cases, transparent market pricing mechanisms would strongly benefit consumers. The certification regime for sites wanting to participate in grid ancillary services needs also needs to be greatly simplified.

The economic operators best placed to source flexibility cost-effectively for the economy could be the energy distributors. This is because their power sources will vary (in variable vs. firm capacity, proportion of embedded generation etc.), the charges and penalties from DSOs will vary (in function of where their customers are) and they should be free to offer to their consumers whichever contract best suits their mix: for instance, aggressively rewarding customers for installing and making available flexible capacity behind-the-meter if they have a high proportion of variable renewables and face congested networks.

Equally, they will end up paying less for the generation capacity that lack flexibility, incentivising producers to firm their generation capacity. They could use their knowledge of where they incur costs to guarantee cash flows for investors in a way that aggregators will struggle to do.

Certification regime

The certification regime for sites wanting to participate in grid ancillary services needs to be greatly simplified. With the installation of smart meters, the code should just mandate the type of technology and record-keeping needed, not require the case-by-case certification that was possible and appropriate when flexibility assets were large power stations.

Continue and accelerate the rollout of smart meters & dynamic pricing

We strongly support the rollout of smart meters. Further, it is essential that the technology is deployed universally and as quickly as possible in a way that supports the development half hourly settlements to enable time of use 'smart' tariffs. We also support load disaggregation behind-the-meter, with different regimes for EV charging, storage+solar and the rest of the loads. For instance, EV charging should be subject to much steeper ToU as Ofgem has recommended, while storage should not be charged DUoS / TNUoS every time it transacts with the network (for instance for frequency response). Load disaggregation may enable households to be compensated for demand-response in a simple, verifiable way.

Mandate smart EV charging infrastructure

Priorities for EV charging infrastructure deployment must go beyond numbers and power of chargers, to mandating that they are bidirectional. The majority of chargers going forward should be mandated as bidirectional. No European country mandates the rollout of bidirectional chargers.

The EU's recent Clean Energy Package is a step in the right direction. But the most relevant implementing directive, the revised Energy Performance of Buildings Directive, only requires EV charging electrical infrastructure for new-build public and workspace car parks, and for existing car parks from 2025.[10] There is no requirement or mention of bidirectional chargers. That falls a long way short of driving a rollout of bidirectional or even smart EV chargers.

For more information visit: **www.eaton.com/energytransition**

[10] Revised Directive on the energy performance of buildings, Available at: https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32018L0844&from=EN

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