Grid-scale electricity storage
using an innovative form of
Compressed Air Energy Storage

Matching the Solution to the Problem

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Introduction

This analysis is re-written in fundamental ways as compared with the 2017 analysis, because the Future Energy Scenarios have changed markedly, and largely for the better. Two of the scenarios are legally compliant to the Climate Change Act 2008, offering two extremes of compliant system: centralised and de-centralised.

Forecasts for most of the technologies are much more realistic, for example:

- Demand growth has been increased substantially in an attempt to accommodate the electrification of heating, transportation and industry;
- Nuclear power is delayed and reduced in expected volume;
- CCS has been put out until 2030 at the earliest.

Therefore this analysis has been re-done almost from scratch, to analyse its qualities and shortcomings. The analysis focuses largely on the two legally compliant scenarios, though considering the other two scenarios on occasion.

Conclusion

Despite these excellent improvements, there are a number of points of concern, for example:

1. Demand may be under-estimated by up to a factor of three:
    - Only half of the electricity required for manufacture of hydrogen appears to be taken account of,
    - Transportation demand appears to be greatly under-estimated,
    - The energy required for heating also appears to be greatly under-stated;
2. Interconnectors are still relied upon far too much;
3. Capacity margins turn negative quickly in all scenarios, and more so when de-rating factors are applied to generation;
4. Insufficient storage is planned, and no consideration is given to the duration of such storage, i.e. for how many hours at a time it can put electricity back into the grid;
5. The only large scale long duration storage conceived of is pumped hydro, the most expensive and geographically constrained such technology;
6. The market is riddled with overt and covert subsidies that distort it, currently costing over £2bn p.a. and forecast to double in 5 years;
7. The structure of the market needs transformation to reduce medium and long term costs, eliminate subsidies, level the playing field, incentivise cleanness and new technologies, and provide energy security in both its definitions;
8. Actions being taken now are greatly increasing the costs of the energy transition;
9. The industry needs to plan a viable zero-carbon future (or range of futures) and then analyse the actions and market structures required to achieve it, rather than to ride the bronco of change applying sticking plasters as we go.

The Scenarios

It is good that there are now two scenarios that comply with the Climate Change Act 2008; and, given that there are two, it is right to focus one on distributed generation and the other on centralised. We would contend that three of the scenarios should be legally compliant, with the third scenario being a mix of central and distributed, which we believe is the most likely outcome.

Community Renewables

This is one of the two legally compliant scenarios. To support a universal roll-out of electric vehicles, “hydrogen becomes the fuel of choice in this sector”, produced by electrolysis. In heating, no allowance is made in electricity generation mix for producing green gas for heating – there is not enough anaerobic digestion possible to supply the requirements, so electricity will have to be used in the process for at least some of it.

Generation is largely distributed, with small scale generation (including large growth in onshore wind) coupled widely with storage at that same distributed scale. The scenario concludes that little large scale long duration storage is needed, whereas in reality all distributed systems rely on the grid for back-up. Without substantial such storage on the grid, what can provide that back-up? Therefore a distributed system needs as much large scale long duration storage as a centralised system, though it would use such storage less frequently and would therefore have to pay for its availability by some other means such as a version of the Capacity Market – that is, subsidies by another name.

Two Degrees

This also complies with the Climate Change Act. Heating is largely by electrolytically produced hydrogen, and both smart technology and demand side actions reduce peak demand. Smaller vehicles are electric, larger ones hydrogen powered by 2050.

Generation moves largely to offshore wind and nuclear. Large scale storage is developed, with great reliance also on interconnectors. Widespread use of carbon capture and storage is envisaged, for flexible generation and for producing hydrogen by steam reformation.

Steady Progression and Consumer Evolution

These are the two legally non-compliant scenarios, and therefore not the main focus of this analysis. Both envisage widespread changes towards EVs with smart chargers that therefore are assumed to have minimal effect on grid peak demand; neither envisages widespread roll-out of hydrogen technologies for either heating or transportation. Both envisage development of significant amounts of nuclear generation, and both keep similar gas consumption to the present day, while accommodating some change in source – largely from domestic offshore production and towards shale gas.

Trends

De-Carbonisation

It is good that the two scenarios assume that the UK adheres to EU decarbonisation targets despite Brexit: what the report does not highlight is that the decarbonisation targets are treaty commitments of the UK that are separate from our EU membership and therefore will remain after Brexit. They are also a measure of the country's good global citizenship, and we must expect to have to adhere to them for future good relations with our trading partners regardless of Brexit provision.

Table 5.1 p97 shows the expected carbon intensity of electricity, though it omits any emissions relating to imported electricity – see Appendix C on interconnectors. They account for up to 11% of total annual demand in 2030, though dropping by 2050 to a range between 7% imports and 12% exports. National emissions figures should be increased proportionately on the assumption that imported interconnector-related emissions are comparable with the UK's (exports have no effect).

Also omitted are any emissions relating to biomass cultivation, shipment and processing, which are very substantial[1]. While the material used may be waste, the emissions required to ship it (principally from North America and the Baltic States) and process it (especially drying) prior to combustion are substantial, even if not at the scale proposed by reports such as the one referred to in the cited article.

De-Centralisation

All scenarios envisage an increase in de-centralised electricity production, largely based on rooftop solar and onshore wind generation, backed up with on-site batteries. In combination, they greatly reduce demands on the grid in terms of MWh, as well as smoothing electricity flows for short durations while the renewables are generating or the batteries are providing back-up.

However distributed generation and storage needs back-up from the grid: this is why the grid was built in the first place. During longer duration weather patterns, renewable generation can shrink to negligible scales for up to a fortnight at a time. Therefore all distributed systems, if they are to remain cost-effective (i.e. not having to finance enormous and expensive battery storage for long duration back-up), must rely on the grid for back-up. Therefore the grid needs sufficient energy supplies to provide such back-up. It cannot rely on interconnectors (see Appendix C), so must rely on a combination of baseload generation (energy from waste, geothermal, nuclear) and large scale long duration storage. While emissions are allowed and the plants remain operational, this would also include fossil fuelled power stations. That

[1] https://www.edie.net/news/10/UK-biomass-energy-generation-environmental-emissions-impact-report-NRDC/

combination must be sufficient to power the grid (both transmission and distribution grids) for a fortnight, to prevent blackouts or brown-outs (the jargon is increasingly referring to enforced demand-side measures, which are brown-outs by another name).

The Energy Trilemma

Until recently, governments and grids in Britain and throughout Europe (ENTSO-E is the trade body for transmission service operators of 38 countries) have defined their future needs as an energy trilemma: a need simultaneously to deliver affordability, clean energy and security of supply. Recently, however, all talk of the Energy Trilemma has vanished from BEIS, National Grid and Ofgem communications; however, this does not mean that the trilemma no longer exists: all three elements need to be delivered, or the country will suffer both political and economic consequences.

Security of Supply

Security of supply is currently conceived as keeping sufficient electricity in the system for its needs, a very narrow definition. While it is challenging enough to achieve this (and this is what FES 2018 is designed to achieve), it is jeopardised by omitting two other factors in security of supply: timescale and self-sufficiency.

Timescale means that we must be able to keep sufficient electricity in the system into the medium and long term futures. This involves ensuring that there is sufficient capital investment in appropriate plant and equipment to achieve that. This in turn involves planning for and incentivising the construction of such plant and equipment, preferably through standard contracts – see the proposed actions at the end of this paper.

Self-sufficiency recognises that we cannot rely on imports through interconnectors for actual demand (see Appendix C): interconnectors should be additional to a sufficient local supply, and thereby would serve to minimise system cost.

Technologies

Electric Vehicles

The forecasts for EVs (including all vehicles, this time) are for up to 36 million by 2040. Considering that the current total is 37.5 million[2], some vehicles will be hydrogen powered and some growth in car sharing is forecast, this is essentially a 100% transfer from hydrocarbon-powered vehicles to renewably powered vehicles.

[2] https://www.gov.uk/government/statistics/vehicle-licensing-statistics-january-to-march-2018 32.3m cars, 1.2m motorcycles, 4.0m LGVs, but excluding (as FES 2018 does, saying that they are likely to be LNG powered) 0.5m HGVs, 0.2m buses, 0.8m “other”

These vehicles consume 178.8TWh gasoline[3], or 4.77TWh per million vehicles. Community Renewables envisages only 89TWh total demand by 2050 (Two Degrees 88TWh), which presumes that electric and fuel cell vehicles are twice as energy efficient as hydrocarbon fuelled vehicles.

Charging EVs is only expected to add 3.3GW (Community Renewables) or 6.5GW (Two Degrees) to peak demand by 2050. Tesla cars on a single-phase home charger charge at 7.4kW or 11 miles per hour[4]. This will be a standard industry charging rate, as its limitation is the grid connection not the vehicle. Thus only 446k (Community Renewables) or 878k (Two Degrees) vehicles can charge at peak time, as compared with a total of 36 million vehicles on the road needing charging. (True, many are not used; but the others will be used more to compensate – this analysis is considering averages.) We believe that merely planning to charge 1.2% / 2.4% of vehicles at a time is far too optimistic a reduction in peak charging due to smart chargers.

Correctly, *"we now believe that the annual mileage for low emission cars will be more or less the same as it is for today's petrol and diesel fuelled internal combustion engine (ICE) cars."* (p73) As the average mileage is 9,086 per vehicle per year[5], or 25 miles per day, vehicles will need charging on average for 2.25 hours a day. FES is forecasting to displace 98.8% / 97.6% of charging from peak to off-peak times. This will have a substantial levelling effect on the daily demand curve, which cannot be met without huge amounts of storage due to the intermittency of most renewable generation. Yet the consequent reduction of peak/trough arbitrage prices (due to the substantial levelling of demand) means that such storage will need to be financed by different means – as a grid service rather than a trading operation. It is likely to be cost-effective to do this rather than to permit charging at all times, due to grid congestion issues; however it would require recognising in legislation and regulations that storage is a grid service, not a form of generation.

However, these assumptions and forecasts require some challenging; for example,

1. All the cars in the country, if turned into EVs that are 100% used for grid-connected storage, would account for only a part of the storage needs.
2. Where they charge from solar power (office, shopping), which is the proffered model, differs from where they would operate as grid-connected batteries, and nobody has proposed a cost-effective model for the financial flows.
3. Most people don't want their vehicles on less than half charge, which halves (or less) the energy/storage available.

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[3] Digest of UK Energy Statistics (DUKES) https://www.gov.uk/government/statistics/petroleum-chapter-3-digest-of-united-kingdom-energy-statistics-dukes

[4] https://www.tesla.com/en_GB/support/home-charging-installation This analysis will not change with the upgrade to 350kW chargers (p79) as 50 vehicles charging in parallel today yield the same load as 50 in sequence with the higher powered chargers; the main effect of this change is to greatly increase grid congestion and consequent reinforcement costs as the use of these high powered charges changes from location to location.

[5] https://www.racfoundation.org/motoring-faqs/mobility#a24 Calculation: 327.1 billion miles divided by 36 million vehicles divided by 365 days per annum

4. The bulk of the need for the storage is in the evening, when vehicles' charge is lowest, yielding a grossly disproportionate multiplication of point 3.
5. To roll out cars-with-solar widely, a high proportion of the parking spaces in the country would have to be fitted with chargers - who would bear the cost of that?
6. Distribution grids need upgrades at enormous cost.
7. NG forecasts greatly under-state the amount of electricity needed: in FES 2017, converting 50% of cars to EVs and 1/3 of homes to heat pumps was forecast to add 5% to electricity demand, despite the fact that vehicles and domestic heating each have similar energy demand to the entire electricity grid (NG explained the difference by saying they'd be "smart" which, to my mind, could save 10-20% but not ~90%).

2018 figures?

8. If the 40-60 gigafactories currently planned world-wide are built, they would exhaust the lithium deposits in all current and under-development fields in 2-10 years according to figures from The Economist[6]. Cobalt and other "rare earth metals" are in much shorter supply.
9. Autonomous shared vehicles, *"significant post 2040"* (p74) actually increase mileage (see p83) and hence load on grid, unless people share actual rides with strangers – which is unlikely in a culture of increasing suspicion of strangers: what would result from an assault by a fellow passenger? Therefore each ride is now two journeys (to go to the pick-up point, then to carry the passenger) instead of one.

V2G (Vehicle to Grid) services are forecast to total about 10GW in Community Renewables (p82 figure 4.23), greater than the 8GW of peak load from EVs. The above-listed challenges would need to be answered for this to be reliable. And it appears that FES 2018 assumes 100% efficiency in V2G services, which will not be attainable: a perfectly new battery requiring no cooling yields ~96% efficiency, whereas one approaching its end of life yields ~75%, so a reasonable assumed average efficiency would be ~85%; then there are converter efficiencies – 90% is reasonable[7], which has to be applied twice – once for charging and once for discharging. The total round trip efficiency is therefore .85 x .9 x .9 = 0.6885 or 69%

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[6] https://www.economist.com/news/briefing/21726069-no-need-subsidies-higher-volumes-and-better-chemistry-are-causing-costs-plummet-after -

Vehicles, 2016	25	GWh	750,000 vehicles
Mid-range: 2040 Bloomberg	15,500	GWh	465,000,000 vehicles
2040 OPEC	5,000	GWh	150,000,000 vehicles
2040 ExxonMobil	3,000	GWh	90,000,000 vehicles

Total lithium, 2016	180,000	tonnes in one year
2040 Bloomberg	111,600,000	tonnes in one year, just for vehicles
2040 OPEC	36,000,000	tonnes in one year, just for vehicles
2040 ExxonMobil	21,600,000	tonnes in one year, just for vehicles
Total available lithium in planet	210,000,000	tonnes
Years' output: 2040 Bloomberg	1.9	years, just for vehicles

[7] https://www.electronicdesign.com/power/understand-efficiency-ratings-choosing-ac-dc-supply graph

round trip. (Grid connected static batteries require cooling and therefore achieve lower grid-to-grid round trip efficiencies despite slightly more efficient converters.)

Heating

From the Foreword, *"Up to 60 per cent of homes could be using heat pumps by 2050."* (Community Renewables scenario.) Heat pumps carry two challenges: (a) power consumption and (b) cold weather cut-out, both of which are improving but both of which have natural limits to that improvement. There is no evidence that either challenge is considered in FES 2018, leading to the risks of (a) greatly underestimating electricity demand, particularly in winter, and (b) black-outs during cold spells as heat pumps cut out and buildings revert to (much higher electricity consuming) direct heating. FES 2018 envisages that the first of the issues is solved by having flexible control of heating systems, but heating can only be turned off for 15-30 minutes at a time before feeling uncomfortable, even with insulation of buildings to class C or above energy efficiency, whereupon its electricity consumption to revert to normal temperatures is increased above what it would have been under continuous use. Therefore the report assumes hybrid gas/electric heat pumps, which would greatly increase the cost of each installation and (due to the requirement to maintain a gas connection) operating costs.

Hydrogen

From the Foreword, *"Hydrogen could heat one third of homes by 2050."* (Two Degrees scenario.) But where does this hydrogen come from? Either there are vast assumptions about the introduction of CCS (Carbon Capture and Storage) into the methane reforming industry, together with zero electricity consumption during the energy-intensive reforming process, or there is a substantial electricity demand to either reform or electrolyse the hydrogen – or, more likely, a mix of the two processes.

Electrolysis consumes 41.4kWh/kg (335kJ/mole) of hydrogen produced, with a theoretical limit of 32.91kWh/kg[8]. Combustion yields 286kJ/mole[9] = 35.3kWh/kg. Thus burning hydrogen is 85.3% efficient as compared with electric heating, assuming all equipment and storage are 100% efficient. However, these are theoretical: the capabilities of current equipment yield efficiencies in the high 20s or low 30s % as (for example) gas turbines are actually 50-64% efficient burning gas, and less so burning hydrogen. Figure 4.26 (p87) indicates that 44TWh electricity produces 33TWh hydrogen, or 1.33TWh electricity per TWh hydrogen, 75% efficient.

"Gas demand, for residential heating, is currently 332 TWh." (p65). Accepting the assumed increase in EPC rating of buildings (p64). The only scenario in which a significant amount of heating derives from hydrogen boilers is Two Degrees, which forecasts that by 2050 9.1% of homes are heated that way. There is no statement as to the benefits of such increased EPC ratings, so we will assume that these homes

[8] https://www.quora.com/How-much-electricity-is-needed-to-produce-hydrogen-from-water
[9] https://www.quora.com/How-many-kWh-can-you-get-from-burning-1-litre-of-hydrogen-gas

require 7.5% of the heating equivalent of today's gas demand, or 25TWh. Given that hydrogen manufacture is ~75% efficient, and assuming identical 86%[10] combustion efficiency to gas and only limited additional transmission losses arrives at an overall 64.5% efficiency. The electrolysis of this hydrogen therefore adds 38.8TWh of unaccounted electrical demand to the system.

The remaining 10% of heating is to come from *"other forms of heating such as low carbon district heating, hybrid heat pumps and micro combined heat and power."* These are assumed in FES 2018 to consume no electricity.

"For the decarbonisation of heating, we consider the installation of heat pumps in residential buildings as a decentralised solution to reducing the number of residential gas and oil boilers." (p36). However hybrid air source heat pumps (p70) require the continued existence of boilers.

Hydrogen fuel cell cars are forecast to use 30TWh p.a. of hydrogen (Community Renewables, p78). Made by electrolysis (~ 75% efficient as above) and used in PEM fuel cells (50-60% efficient[11]) this adds 67-80TWh electrical demand to the system, of which only 33 TWh is accounted for (Fig. 4.26 p87), leaving 34-37 TWh unaccounted for.

Notes:

1. All these estimates of hydrogen consumption ignore the energy consumption required to pressurise hydrogen for transportation and use. Fuel cell vehicles, for example, are being designed to carry hydrogen at between 250 and 700 bar, whereas electrolysed hydrogen is typically at 55bar.
2. Methane reforming is ignored because (a) it requires significant but unknown amounts of energy to do, and (b) it requires CCS technologies which (see below) have not been developed cost-effectively and are not in the author's opinion likely to be so in the foreseeable future.
3. Hydrogen usage for heating ignores the higher energy consumption required to sustain the higher flow rates required, as flagged on p90.

Nuclear

Although nuclear expectations have wisely been reduced and delayed, and plans have switched largely from large nuclear power stations to Small Modular Reactors (SMRs), they still seem to be rather optimistic. Just to illustrate this, Hinkley Point C was first proposed in the 1980s, winning planning permission in 1990 but dropped in the early 1990s as being too expensive at £1.7bn[12]. The current 3.2GW plant was approved in 2007 for commissioning by 2017[13]. The latest delay puts the forecast commissioning date as 2027 and cost at over £20bn and £30bn subsidies through

[10] http://bpec.org.uk/downloads/CE30%20-%20Domestic%20heating%20by%20gas.pdf p4
[11] https://www.hydrogen.energy.gov/pdfs/doe_fuelcell_factsheet.pdf using Google's cached version as the original had moved
[12] https://en.wikipedia.org/wiki/Hinkley_Point_C_nuclear_power_station#1980s_PWR_proposal
[13] http://www.telegraph.co.uk/business/0/hinkley-point-c-new-nuclear-plant-timeline-of-the-story-so-far/

electricity bills[14] – the scenarios expect it to come on stream in 2026, a year ahead of current expectations and without provision for any further schedule slippage. As all but one current nuclear power stations should retire by 2030, this entire forecast is based on a total of 19GW new power stations with a forecast capital cost of £70bn[15] – which the current Hinkley Point C cost calls into question.

If therefore we shrink the Two Degrees forecasts of nuclear and CCS to the levels of Community Renewables, and reduce vehicle to grid by three-quarters, its capacity margin by 2050 shrinks by another 21.7GW; Community Renewables would only shrink by reducing the vehicle to grid by ¾, i.e. reducing by 3.3GW. But both of these still require the incentivisation of large scale long duration storage to make their storage forecasts credible.

Carbon Capture, Use and Storage

These scenarios do well in reducing and delaying expectations of carbon capture and storage (the report considers its use too – CCUS rather than CCS, though no commercially viable use has yet been found for such quantities of CO_2). Nevertheless CCS remains unaffordably expensive, much more so than nuclear: £27bn p.a. plus capital costs for 8MW abated coal fired power stations, without allowing for the inefficiencies introduced into the power generation process, according to aspirational figures from DECC's website which they removed when cancelling the two CCS power station projects in 2015. The introduced inefficiencies increase coal burn by around a quarter[16], raising its levelised cost of energy to well above that of other generation technologies[17].

Moreover, the In June 2017 the Americans cancelled the Kemper coal gasification and CCS project when its capital cost for a 582MW plant exceeded $7.5bn[18], i.e. $12.9bn/GW. If the Americans can't get it up and running despite paying considerably more than Hinkley Point (which is £20bn for 3.2GW, i.e. £6.25bn/GW or $8.4bn/GW), then what hope do we have of doing so?

Flexibility

Interconnectors are discussed at length in Appendix C; vehicle to grid (electric vehicles) and hydrogen are discussed above.

[14] http://www.telegraph.co.uk/business/2017/07/03/hinkley-nuclear-costs-climb-almost-20bn-start-delayed/
[15] http://namrc.co.uk/intelligence/uk-new-build-plans/
[16] http://www.world-nuclear.org/information-library/energy-and-the-environment/clean-coal-technologies.aspx (see table 1)
[17] For American LCOE costs (UK ones are higher), see table 1b (p8): LCOE for CCS coal is $132.2 - $140 https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf
[18] https://en.wikipedia.org/wiki/Kemper_Project and https://www.smithsonianmag.com/smart-news/major-clean-coal-project-mississippi-shut-down-180963898/

Storage

FES 2018 is correct that storage can support, and needs to access, multiple revenue streams (a "revenue stack"). It is also correct that the benefits of storage are compounded when integrated with other projects such as intermittent generation or interconnectors. And it is true that there is a substantial need for storage that is unconstrained in location, for distributed roll-out to provide localised and short duration balancing services.

The mix considered by FES 2018 is batteries at both transmission and distribution scales, vehicle to grid batteries (above), DSR (below), pumped hydro and interconnectors. All other storage technologies are omitted, thereby greatly adding to potential costs not only in generation, balancing and imports, but also in energy security and national balance of payments.

Batteries are optimally up to 20-40MW with optimal durations of 1-2 hours. Doubling either size or duration adds roughly 85% to capital costs; doubling the size or duration of larger scale technologies adds much less – for adiabatic CAES[19] the figure is around 30%. The larger scale technologies are not efficient at scales below ~2-MW (or 5MW for LAES), and they all provide true inertia rather than EFR, so they barely compete with batteries.

It is possibly in recognition of this lack of vision as to how batteries can support the volumes of flexibility required that there is almost no further discussion of them, despite the large increase in storage capacity required in all scenarios (p106): how they can provide the requisite volume of energy is not addressed, as batteries cannot store enough energy (size x duration) due to their limited size and even more limited duration. Various studies also suggest that they have a much more limited life than advertised, especially if used in quick bursts for the faster balancing and ancillary services[20] which tends to be their main justification and business case. Other studies show that they are much less efficient (grid-to-grid) than advertised[21].

Pumped hydro: It is curious and highly indicative of past interactions that, despite claiming not to "back winners", National Grid identifies pumped hydro rather than large scale long duration storage which could also be provided by CAES, adiabatic CAES and LAES systems, all of which have lower costs, greater geographical flexibility, better proximity to both generation and demand, lower environmental impact (they don't flood valleys) and larger overall potential. Despite all these advantages, little effort has been made by BEIS, Ofgem and National Grid to

[19] CAES = Compressed Air Energy Storage, see www.storelectric.com
LAES = Liquid Air Energy Storage, see www.highviewpower.com
[20] E.g. 'Battery energy storage efficiency calculation including auxiliary losses: Technology comparison and operating strategies, authors F.M. Gatta ; A. Geri ; S. Lauria ; M. Maccioni ; F. Palone ' (available with a subscription to the IEEE www.ieee.org) and also https://www.energiforskning.dk/sites/energiteknologi.dk/files/slutrapporter/bess_final_report_forskel_10731.pdf
[21] http://www.networkrevolution.co.uk/network-trials/electrical-energy-storage/ Electrical energy storage cost analysis paper – see round trip efficiency including parasitic losses, chart on p6

support the development and construction of first-of-a-kind plants of these UK-developed technologies, thereby impeding their development against their corporate imperatives to encourage the development of new technologies and solutions to known problems. Equality of opportunity and a level playing field is sought.

Faraday Challenge: As an aside, it is very curious why, having taken the excellent decision to support the development of a new industry in electricity storage, the government decided to waste £246m on the Faraday Challenge, when:

1. The UK is playing 20-30 years' catch-up in lithium technologies;
2. We lead the world in other storage technologies, if only we can have some support to build commercial first-of-a-kind plants;
3. There is no battery manufacturing in the UK;
4. Of the 40-60 gigafactories that have been announced, not one of them in the UK, and there is no room for more as that many would already deplete global resources of lithium in 2-10 years (see Electric Vehicles, above).

The Politics of Storage

Yet energy storage (both grid and battery scale) and DSR can help deliver the energy priorities of every single significant national political party:

1. By providing a market for nearly every MWh generated by renewables, it reduces or eliminates the need for renewables subsidies – assuming fossil fuels are not subsidised, thereby reducing the subsidies part of both energy prices and tax bills;
2. By supplying peak demand, the most polluting, expensive and unprofitable fossil fuelled power stations can be not only switched off but also (if we have enough storage capacity) demolished, benefitting energy prices, the environment and the profitability of the generating companies;
3. By absorbing power during peaks in renewable generation and troughs in demand, the remaining power stations can operate as baseload, again benefitting energy prices, the environment and the profitability of the generating companies;
4. By working with both non-dispatchable power generation and the grid as a whole, storage and DSR can smooth the transition to a fossil fuel free grid;
5. By enabling non-dispatchable generation to supply variable demand at all scales, storage and DSR enable the transformation of transportation, heating and industry to clean electricity sources;
6. By relying on locally generated electricity, storage and DSR can enhance energy security and grid resilience both nationally and regionally.

Combined with renewable power generation, these can deliver:

7. Falling energy prices, as the input power is free;
8. Vastly reduced pollution and emissions; and
9. Energy security, as they are all generated from local resources like wind, sun, tide and waves, rather than imported fossil fuels or interconnected electricity.

Demand Side Response

The two 2050 compliant scenarios are expected to offer about twice as much demand side response (DSR) as the other two scenarios. Roughly, industrial DSR (p60) is forecast at 1GW for all scenarios, doubling to 2GW for the non-compliant scenarios by 2040 (then remaining constant) and 4GW for the compliant ones by 2050. No residential DSR is proposed.

FES 2018 then takes these figures as being the available to reduce peak demand on the grid, which is not wholly the case. This is because if a process is turned off/down now, then it cannot be turned off/down again within a few hours: the business has to be able to conduct its business. DSR is a short duration solution that is best used for absorption of short duration spikes in demand / short term troughs in generation. Therefore these DSR volumes need to be split into multiple "packets" because the nature of both variable demand and intermittent supply is to provide multiple such spikes within those few hours. It is therefore reasonable to split DSR into, say, 3 "packets" of (for the compliant scenarios) roughly 1.5GW, 1.5GW and 1GW. Therefore the maximum benefit to meeting actual demand is 1.5GW.

There is another issue not accounted for: compensatory peaks (bounce-backs) in demand after the DSR period is finished. If, for example, a heating process is switched off/down for 15 minutes, then at the end of that period heating demand will be above the norm in order to get the process back up to the correct operating temperature. The same applies for refrigeration processes. This reduces the benefit of DSR: if it is used in a peak demand period, then the compensatory peak is also during the same peak demand period.

The scenarios are more realistic about the benefits to the system of Time of Use Tariffs (p69), though we believe that use of them will be significantly below even these current forecasts due to (a) not wanting to be bothered with active management of energy consumption as the much-touted 2% target savings are simply not worth the effort for most people, and (b) not wanting to out-source such active management by connecting appliances and systems to the internet, for reasons of both autonomy and fear of hacking. However we have no alternative figures to offer or studies to cite, so will make nothing more of this point.

Total Demand

Considering total energy flows, the comparison between change in electricity demand and change in gas and transport-related[22] gasoline demand is forecast to decrease as follows for the two 2050 compliant scenarios:

[22] Transport-related gasoline is calculated in the table below by taking the 2050 number of renewably powered vehicles as 100% that saves 178.8TWh of gasoline p.a., and apportioning that gasoline consumption in direct proportion to the number of renewably powered vehicles each other year.

Community Renewables - Change in total demand in year (TWh)					
	2017 baseline	2020	2030	2040	2050
Gas*	576.5	-27.4	-137.5	-237.0	-356.5
Oil**	178.8	-3.2	-49.0	-166.4	-178.8
Electricity	0.0	-4.9	9.0	21.7	14.7

Two Degrees - Change in total demand in year (TWh)					
	2017 baseline	2020	2030	2040	2050
Gas*	576.5	-21.4	-104.3	-264.6	-414.0
Oil**	178.8	-2.8	-39.2	-135.8	-178.8
Electricity	0.0	-6.2	6.9	12.1	6.0

* Gas demand = residential + commercial + industrial

** Transportation. Fuel: gasoline from DUKES; vehicles from FES 2018

This begs the question: how come 520.6TWh energy demand Community Renewables) vanishes by 2050? This “vanished” demand is greater than total grid demand at any time:

(TWh)	**Community Renewables**	**Two Degrees**
Total "vanished" demand	520.6	586.7
Baseline electricity demand	319	319
2050 electricity demand	464	396
% of baseline "vanishing"	**163%**	**184%**
% of 2050 "vanishing"	**112%**	**148%**

The comment *“In all our scenarios, total energy demand is reduced by 2050. This is due to factors such as improved energy efficiency and a reduced output from gasfired electricity generation”* seems inadequate. The gas demand in this analysis excludes demand for gas-fired generation. This leaves energy efficiency as the only explanation offered by National Grid, from which demand reductions of the order of 10-30% could normally be expected. This therefore does not quite account for a drop in non-generation whole-system energy demand by 62-65%.

And this “vanished demand” should be increased by the electricity required to make hydrogen (see Hydrogen, above), estimated above at 38.8 TWh (Two Degrees only) for heating and 34-37 TWh for fuel cell vehicles (both compliant scenarios). Taking the mid-point 35.5 TWh for transport, **“vanishing” demand increases to 556.1 TWh (174% of baseline) for Community Renewables and 661 TWh (207%) for Two Degrees.** Therefore FES 2018 may be under-stating demand by a factor of up to 3.

Nevertheless, the remainder of this report will assume that National Grid is correct in its forecast electricity demand.

Generation Mix

FES 2018 considers all generation by nominal capacity[23]. This yields the following:

Community Renewables (GW)	2017	2020	2030	2040	2050
Dispatchable (no interconnectors)	67.7	63.8	55.4	69.1	72.2
Interconnectors	4.0	7.0	16.5	16.5	16.5
Intermittent renewables	31.8	39.7	86.3	148.6	178.8
Demand	59.4	58.7	63.8	75.9	78.5
Capacity margin excl. interconnectors	14%	9%	-13%	-9%	-8%
Capacity margin incl. interconnectors	21%	20%	13%	13%	13%
Interconnectors as % of demand	7%	12%	26%	22%	21%

Two Degrees (GW)	2017	2020	2030	2040	2050
Dispatchable (no interconnectors)	67.7	64.0	60.1	67.0	65.3
Interconnectors	4.0	7.0	19.8	19.8	19.8
Intermittent renewables	31.8	40.2	81.0	125.3	139.2
Demand	59.4	58.7	63.8	75.9	78.5
Capacity margin excl. interconnectors	14%	9%	-6%	-12%	-17%
Capacity margin incl. interconnectors	21%	21%	25%	14%	8%
Interconnectors as % of demand	7%	12%	31%	26%	25%

Such capacity margins almost guarantee blackouts before 2030, if there is one of the regular weather patterns that yields many days of negligible renewable generation during winter. These are avoided today because we carry more dispatchable generation capacity than peak demand.

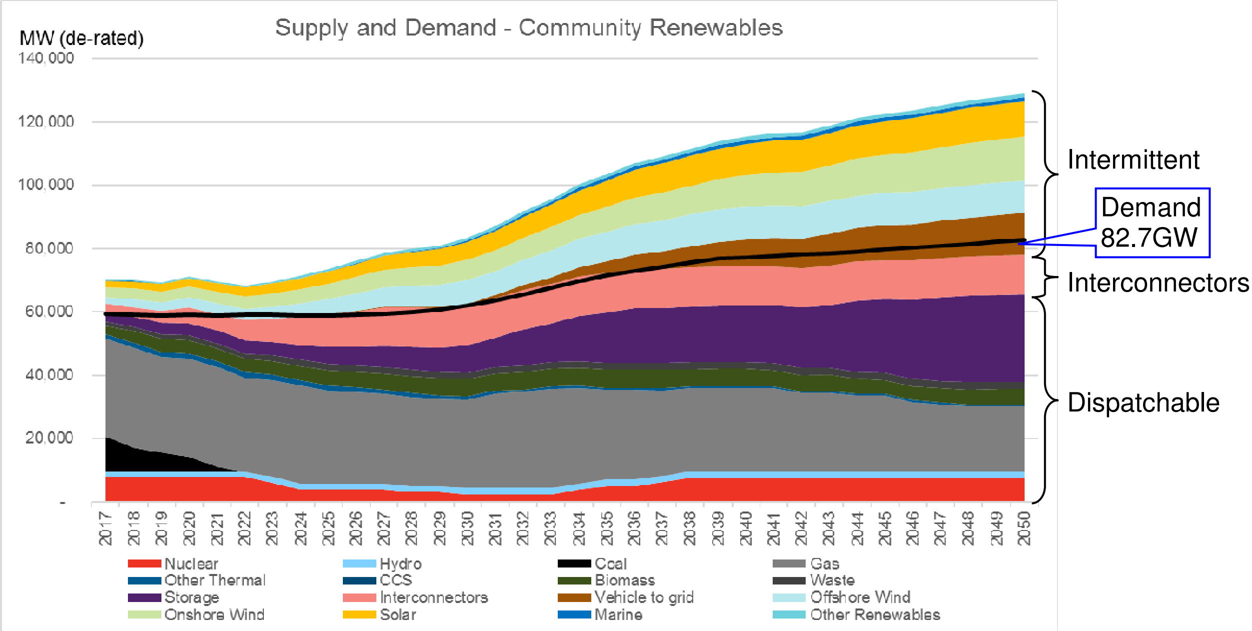
However, nominal capacity is not reliable capacity. Our analysis by de-rated capacity[24], gives a different (and much worse) picture:

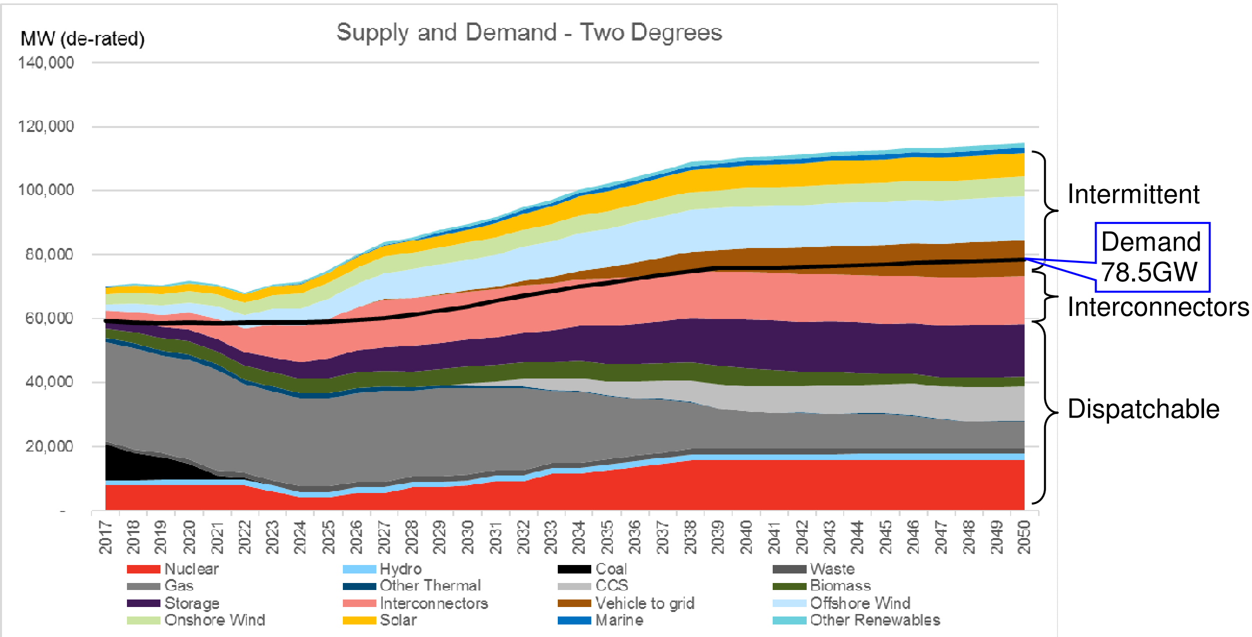
Community Renewables (GW)	2017	2020	2030	2040	2050
Dispatchable (no interconnectors)	59.7	56.3	49.5	62.2	65.7
Interconnectors	3.0	5.2	12.4	12.4	12.4
Intermittent renewables	7.7	9.7	21.6	40.7	50.8
Demand	59.4	59.1	62.0	77.2	82.7
Capacity margin excl. interconnectors	0%	-5%	-20%	-19%	-21%
Capacity margin incl. interconnectors	5%	4%	0%	-3%	-6%
Interconnectors as % of demand	5%	9%	20%	16%	15%

Two Degrees (GW)	2017	2020	2030	2040	2050
Dispatchable (no interconnectors)	59.7	56.5	53.5	59.8	58.5
Interconnectors	3.0	5.2	14.8	14.8	14.8
Intermittent renewables	7.7	9.9	21.2	35.9	41.8
Demand	59.4	58.7	63.8	75.9	78.5
Capacity margin excl. interconnectors	0%	-4%	-16%	-21%	-26%
Capacity margin incl. interconnectors	5%	5%	7%	-2%	-7%
Interconnectors as % of demand	5%	9%	23%	20%	19%

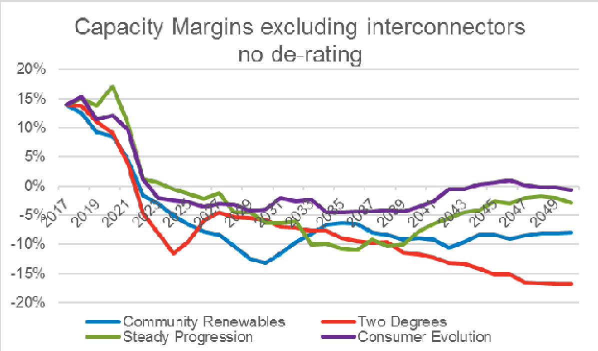
[23] Dispatchable = nuclear, hydro, coal, waste, gas, other thermal, CCS, biomass, storage
[24] De-rating factors for biomass, coal, gas, hydro, interconnectors, nuclear, storage, energy from waste, using T-1 de-ratings: https://www.emrdeliverybody.com/Lists/Latest%20News/Attachments/114/Capacity%20Market%20Auction%20Guidelines%20July%207%202017.pdf
De-rating factors 2017 for wind, DUKES Chapter 5, paragraph 5.43: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/729379/Ch5.pdf
De-rating factors 2017 for solar, DUKES Table 5.7 footnote (4): https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/731590/DUKES_5.7.xls
De-rating assumptions: CCS = gas CCGT; Other Thermal = coal; Vehicle to Grid = 0.66 x Storage as vehicles are often not available; Waste = biomass; Marine = offshore wind; Other Renewables = onshore wind

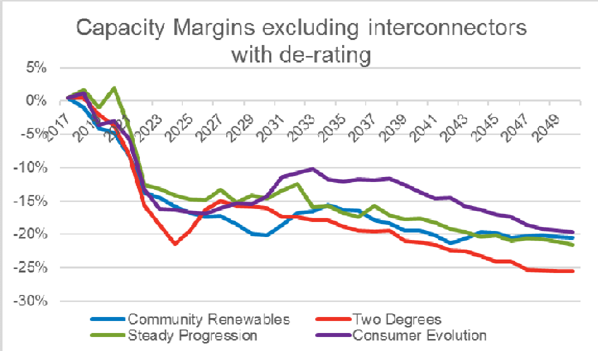
Considering the annual graphs shows it a different way:





This lack of capacity margin is true for all four scenarios:





The picture deteriorates still further when one analyses the likelihood of the various technologies coming onstream in time to meet these forecasts:

1. The scenarios' expectations of nuclear generation have been shrunk, which seems advisable. Nevertheless, nuclear is likely to be later than envisaged by FES 2018: Two Degrees forecasts about 1GW per annum coming on stream from 2026 to 2038, peaking at 15.8GW; Community Renewables is about half that. 2026 is already a year before the currently forecast commissioning date of Hinkley Point C; and other power stations are well behind in their development.
2. CCS is highly dubious – see below. Two Degrees forecasts 10.7GW by 2050, none for Community Renewables.
3. Storage is forecast at 16.6GW for Two Degrees and 27.9GW for Community Renewables, yet the country is in no way encouraging the development of any storage capacity above megawatt scale – and all the capacity the country is encouraging is of short duration (batteries), which would actually remove them from the "dispatchable" count and render the above capacity margins much worse.
4. Vehicle to Grid (11.4 / 13.1GW) appears to be relying on much more capacity than FES2018 is forecasting in its own demand forecasts, especially if it is of long enough duration to make a difference for more than brief spikes in demand.

Security of Supply

Security of supply means two things principally: keeping power reliably in the grid to meet variable demand, and being in charge of the source of that power. Not only does these scenarios fail on the first measure by 2030, as above, but also they fail on the second: the reliance on 12.4GW / 14.8GW interconnectors, added to 20GW / 8GW gas-fired power stations using imported natural gas means that the country will depend on other countries for 41% / 28% of its electricity needs.

System Balancing

Page 95 discusses the increasing challenges of intermittency as such power sources grow in market share, suggesting that the answer is in a combination of *"market development, new technologies and new ways of designing and operating networks"* and interconnectors. The first group of these are all small scale and short duration, and cannot accommodate the energy volumes even if enough of them were built to manage peak flows. And interconnectors are not the solution either – see Appendix C. And so far the energy transition is still at the relatively easy stage in which intermittent renewables supply less than 30% of overall system demand; the challenges will multiply as that threshold is approached and passed.

All of these are part of the solution, but together they do not provide a whole solution: the missing link is sufficient large scale long duration storage, which is not being supported or incentivised in any way – and in fact is being discouraged by both the current and proposed regulatory definitions of storage, by short contract lengths, and by its exclusion from support such as NIA/NIC support and CfDs. It should be an absolute priority to encourage development of such technologies by supporting first-of-a-kind plants, and then to enable roll-out without subsidy by levelling the playing field.

System Costs

Existing Subsidies

There are many subsidies hidden in the electricity system. For example,

- Interconnectors rely on the double subsidy of cap-and-floor contracts and zero grid access charges;
- Interconnectors also provide a UK-financed subsidy to overseas generators owing to their lower grid access charges and carbon prices, and the fact that the difference between these and the UK versions are not charged on import;
- Nuclear power relies on a very highly priced cap-and-floor regime;
- The total cost of the balancing and ancillary services market has increased by ~£1bn since 2010, which represents additional system costs for balancing intermittent renewables without sufficient large scale long duration storage;
- The £1bn Capacity Market seems to be a subsidy dressed up as a market, to keep fossil fuelled power stations in operation to balance intermittent renewables;
- A negative subsidy (i.e. unwarranted cost) is imposed on storage by triple charging (to import and to export, plus the cost embedded within the price of the purchased electricity) which is currently proposed to reduce to double charging, still an unwarranted commercial disadvantaging.

The balancing/ancillary markets and Capacity Market subsidies alone are already over £2bn p.a. and expected to double within 5 years and to keep on increasing[25].

The two compliant scenarios rely on 15.75GW nuclear power. This is proving to be one of the most expensive energy sources available. It also relies on 8.3GW CCS, analysed above. It also relies on 19.7GW interconnectors which are only viable with.

[25] More details available in a Storelectric white paper Curtailment: the Tip of a Growing Iceberg, available on request

In contrast, Storelectric's CAES has a cheaper levelised cost of electricity than a gas-fired peaking plant and can therefore balance the entire system cost-effectively and (on a level playing field) without subsidy.

The electricity system can only deliver cost-effective energy to UK consumers if the playing field is levelled.

Affordability

While policy makers talk about energy cost, they mostly focus on its price. These have become divorced from each other, with cost (including both overt and covert subsidies) rising as fast as price (£/MWh wholesale) falls. Already more than half of most commercial bills is made up of non-price levies and costs; this should be under one-quarter, preferably <20%, to pay for transmission and distribution costs alone, and to penalise anti-social behaviour such as excessive consumption of fossil fuels.

Contract Length

This focus on lowest price today and in the near future is the driving force behind the

Another tilt in the regulatory playing field is the short term nature of all contracts. This favours investments that have a short pay-back time, and hence those that have a short operational life and/or small scale.

- The cheapest way to deliver a 2-year contract is to patch up a fully amortised plant for an additional 2 years' life.
- Following this contract, it is repeated; only the plant is older, more polluting, more expensive to patch up and maintain, and less reliable.
- This repeats at ever increasing cost until the plant dies of old age.
- Then electricity needs to be imported or new plants built with subsides.
- The cheapest way to deliver a 15-year contract is with a new plant.
- The total cost over 15 years is less under a 15-year contract than under 7½ x 2-year contracts, and in the meantime sufficient capital investment has been put into new plant to keep the system young, without subsidy, with benefits in security of supply (both definitions), reliability and cost.

Again, the electricity system can only deliver cost-effective energy to UK consumers if the playing field is levelled.

Costly Responses

In response to these shortfalls, National Grid is taking increasingly costly measures such as creating the Capacity Market in which, according to a recent government consultation document[26], "Two CM auctions have now been held, for delivery in 2018/19 and 2019/20 respectively. Whilst, given the target levels that were set, the auctions procured relatively little new capacity…" for about £2bn.

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26 https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/504217/March_2016_Consultation_Document.pdf

Added to that, the Winter Outlook Report 2015 states that to cope with narrowing markets, National Grid "developed a set of new balancing services (NBS) to help us to manage the uncertainty and tightening margins over last winter. … Demand-Side Balancing Reserve (DSBR) and Supplemental Balancing Reserve (SBR)". "The total costs incurred in the procurement and testing of the new balancing services was £31.2m." This total is likely to increase in future years: "On 3 June 2015, we announced the procurement of the 2.56 GW of additional electricity reserve for the winter 2015/16", compared with the 1.05GW purchased the previous winter.

In FES 2017, National Grid states that there will be "a growth in balancing tools and technologies", but admits that "What technologies will be utilised has yet to be established by the marketplace"[27]. This must grow: "As intermittent and less flexible generation grows at transmission and distribution level, the ability to flex generation and demand is becoming increasingly important"[28].

Since then, further market mechanisms have also been created, adding to the costs of maintaining the system, such as Supplemental Balancing Reserve, Enhanced Frequency Response and Demand Side Top-Up. It appears that additional patches or sticking plasters are being added to a worn-out regulatory framework at ever-increasing rates, tackling the symptoms of the problem rather than its causes, the largest of which is the system-wide loss of inertial generation and load.

Revenue Stacking

Large scale long duration plants of most types rely on stacks of diverse revenue streams to be profitable. This sticking plaster approach to the challengers of the energy transition means that each issue is turned into a contract / revenue stream, one at a time, as it is discovered and quantified. The largest and most remunerative ones (e.g. EFR) are contracted first, because those are the most urgent and greatest need.

Because these needs are addressed individually and with short term contracts, short-lived and small-scale solutions (e.g. batteries) are used to deliver them. Long-lived and large-scale solutions that address many such challenges, and especially those which tackle the root cause of the problems, cannot be financed under short term salami-sliced contracts: they need an entire revenue stack. But the salami slicing, sticking-plaster approach creams off the most remunerative parts of the revenue stack rendering the remainder of that stack less profitable, and therefore building in a need for higher overall prices – i.e. subsidies hidden within the markets.

To minimise the overall system cost and maximise its security of supply, and to do these over the short, medium and long terms, a better approach is to address the causes of the problems, principally the need for clean (i.e. low or preferably zero emissions) inertial generation and load. Contracts for these should be let for a suitable time. They should then be contracted to deliver whatever other services

[27] Spotlight, p63
[28] Sources of Flexibility, p64, first sentence

they can deliver cost-effectively to the system, thereby giving them their entire revenue stack without any increase in price, without any overt or covert subsidy. It is only after this is complete that shortfalls should be evaluated and let in narrow, shorter duration contracts.

Failing to minimise overall system cost in this way will not remove the business case for large scale long duration renewables, because the need will remain. The main effect of such failure is to increase its cost to the system.

OFGEM Recognition and Actions

While Ofgem have expressed the need for storage in the past, currently all storage requires special consideration. This vastly increases regulatory uncertainty for investors and developers alike.

Recent pronouncements from Ofgem and BEIS are quoted in Appendix D.

There is no regulatory category for energy storage, so storage equals consumption plus generation, neither of which is related to time or demand. This means that:

1. For grid connection applications, if DNOs propose the storage (e.g. Leighton Buzzard, Eigha, Orkney), it is deemed to create capacity; if anyone else proposes it, it is deemed to consume capacity;
2. Although charging and discharging are countercyclical and will largely be determined by the Grid's / DNO's needs, grid connections must be paid for that are sized for maximum charging during peak demand and discharging during trough demand, adding ridiculous and unnecessary costs to the project (unless the DNO is proposing it…);
3. DNOs are prevented from investing in storage over the 5MW waiver;
4. Although National Grid can invest in interconnectors, which take and return grid power, they cannot invest in storage (or even research into storage technologies via NIA / NIC or other mechanisms) even though they and the consumer would greatly benefit from it;
5. There can be no contracts for storage services;
6. Electricity has to be purchased and sold regardless of when balancing services is wanted, therefore if the services are wanted off-peak using energy stored at other times, there will be a loss – though this will only become a substantial issue when availability of dispatchable electricity drops to levels below the levels of off-peak demand variability, and therefore not for more than a decade.

Ofgem have proposed to define storage as a sub-set of generation, which is fundamentally wrong – they are more like interconnectors:

- Neither technology generates electricity;
- Storage moves electricity in time, as interconnectors move it in location;
- Therefore storage is a grid service / feature, much as interconnectors are.

National Grid Recognition and Assessment

The Grid recognises that “Electricity storage could be significant for the future balancing toolkit. It has the potential to offer valuable services to the SO [System Operator], broader industry, and ultimately the end consumer.” (FES 2015) Even on this restricted remit, National Grid assesses every area of policy and action relating to storage as either very poor (“red”) or inadequate (“amber”):

- Policy and regulatory developments are amber, with a regulatory definition of storage and other regulatory changes promised but not yet delivered. There remain many issues with levies and charges (including double charging of storage with the Levy Control Framework and Climate Change Levy).
- Commercial development is amber due to lack of multiple clear revenue streams, or price signals – especially Time of Use tariffs, though they omit Time of Use generation contracts which would provide a much stronger signal. The outlook is improving, with Demand Turn Up and other enhancements, but these are mostly focused on small scale storage and there are issues with stacking some revenue streams at scale. There is no business model to evaluate network reinforcement deferral or other benefits.
- Technological developments are amber because the levelised cost of electricity of batteries and flywheels is too high. There are improvement in Li-ion battery storage costs, but they don’t see other technology improvements – still failing to see or support Storelectric’s more cost-effective and better-designed system.
- System need (i.e. how well the system is coping without storage) remains amber, with good response to the new EFR service being more than balanced by growing flexibility challenges and the uncertainties of an ever-changing regulatory framework. In the 2015 report this section then describes how storage can match non-dispatchable supply with variable demand, and identifies a need for storage to “provide a cost-effective solution to that need” – but this year’s assessment gives no thought at all to larger scale storage.

National Grid concludes: “Storage has the potential to be a significant contributor to the future flexibility requirements of the system. As storage becomes more cost-competitive and the identified barriers are removed, we anticipate a significant rise in new storage deployment.”

Energy Industry Actions

Until now, the renewable energy industry has been balkanised, with each industry association and consortium pressing for special treatment, subsidies, market instruments etc. The result is increasingly costly and incoherent, and provokes counterproductive reactions like the creation of the Capacity Market.

Since the politics means that we should be pushing on an open door, the renewable energy industry (generation, storage and DSR) should get together and propose one single, viable and affordable road map that outlines a single, coherent set of actions that government and grid should take in order to achieve one of a small range of potential solutions.

The potential solutions should include maximum and minimum scope for each technology in the mix. The technologies should include, for the electricity industry:

- Onshore and offshore wind;
- Rooftop and farmed solar (focusing on wide scale rooftop deployment);
- Tidal range and flow;
- Biomass (limited due to other future demands on farmland, globally);
- Wave;
- Storage at every one of the five scales outlined above;
- Demand side response (up to 3-5% of maximum demand).

This should be backed up by a comparable portfolio of technologies, including:

- Storage at all 5 identified levels (domestic, local, area, regional, national);
- Flywheels;
- Demand side response;
- Interconnectors.

In order to be both comprehensive and coherent, this road map (and also Future Energy Scenarios) should also include actions that will need to be taken to accommodate the transfer from fossil fuels to renewable electricity of:

- Heat (especially through heat pumps);
- Transportation;
- Industry.

The list of actions included in the proposal should include:

- Support for research and early stage development;
- Support for later stage development, proportional to the scale of solution being provided (e.g. more finance for a tidal or grid-scale storage demonstrator than for a heat pump or domestic-scale storage demonstrator);
- Support for first deployments, on a sliding scale, e.g. full CfD for 100% of the capacity of the first-off, decreasing linearly by 10% of capacity and 5% of price for each subsequent one, with particular designs to be suited to need –
    - ◊ Incentivising the generation of power when it is wanted,
    - ◊ Recognising input costs as well as output costs,
    - ◊ Recognising the particular features of each group of technologies;
- Serious carbon tax or carbon permit price, matched by corresponding subsidies to prevent serious damage to the fuel poor, and to industry – but the subsidies must not be matched with consumption, in order to incentivise economy and the development of alternatives;
- A government office in charge of all this, with sub-offices for each part of it;
- Regulatory definition of storage, so that Grid and DNOs can invest in it, so its countercyclical operation and grid control of energy flows must be taken into account during any connection study / action, and so there can be recognition that storage requires both power purchase and power sale;

♦ Regulatory definition of a way in which Grid and DNOs can act purely as carriers between two private contractors, e.g. major generation and storage, storage and major consumption, major generation and major consumption.

BEIS / Ofgem / National Grid Actions

The only ways to avoid such a situation would be to invest in either lots of new generation (if gas-fired, this would be in breach of international treaty and moral obligations that would survive Brexit), or massive-scale storage. The latter will enable us to meet our emissions obligations by enabling us to use renewable generation to power not only peak demand but also much baseload demand. To do this without any ongoing subsidies would require:

1. Long term contracts (15 years) for energy, which would actually deliver cheaper electricity over their term than a succession of 1- and 2-year contracts, and therefore pay for themselves –
   - ♦ If 1/3 of all contracts were let for 15 years, solely for new plant, then that would presume a plant life of 45 years, which is about right,
   - ♦ If a second 1/3 of all contracts were let for 7.5 years, solely for plant which either is new or has received major capital investment (e.g. overhaul, upgrade), then this would ensure plant efficiency and security of supply,
   - ♦ If the final 1/3 of all contracts were let for 2 years with all plants being eligible, then this would ensure that all have markets and prices would not rise excessively;
2. Incentivise environmental performance without subsidies, by using contract length:
   - ♦ A zero emissions plant receives the full contract length,
   - ♦ A plant with emissions equivalent to a coal-fired power station is eligible for half the contract length,
   - ♦ There is a linear relationship between these two extremes;
3. Incentivise new technology introduction (the construction of a first-of-a-kind [FOAK] plant), again without subsidy, by means of enforceable letters of intent –
   - ♦ The letter would say that the System Operator will buy the services that the plant will offer when it can offer them (so as to allow for long grid connection times) under the contracts on offer at the time and at the prices on offer at the time (i.e. no subsidy or special contracts) to a maximum of 25% of any given contract type (so as to avoid market distortions),
   - ♦ Such letters are issued prior to planning and grid connection applications (the intention of these letters is to guarantee a market and thereby bring in private sector investment, without subsidy, to do those as well as to build the plant),
   - ♦ Such letters remain valid for as long as there is significant progress (including seeking investors),
   - ♦ Because no subsidy is involved, only plants that expect to be competitive would call for such subsidies,

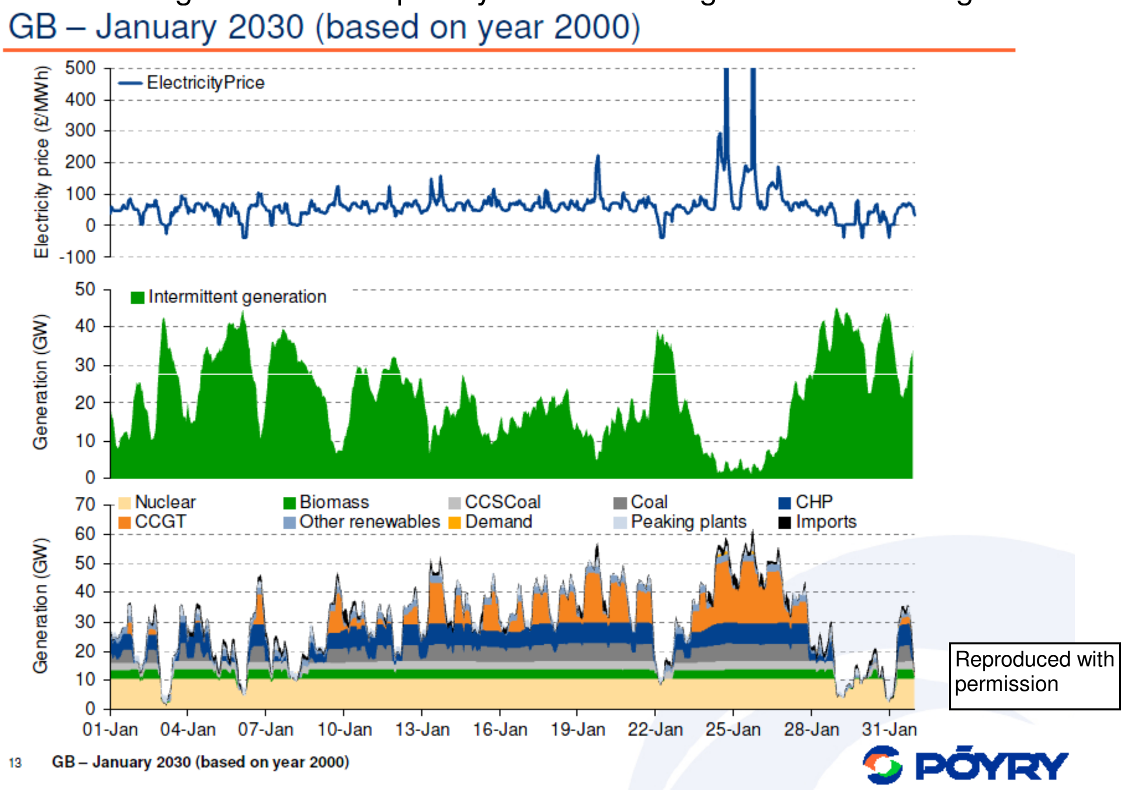
- If the government were to wish to support R&D (e.g. via InnovateUK), then it could do so, but this would be a separate decision – and neither the letter nor the support should exclude the other,
- For each technology, do this for one FOAK at distribution scale and one at transmission scale, provided that the two sizes were at least a factor of 5 (maybe 10?) different in size, because such changes in scale carry their own challenges;

4. Establishing in law a regulatory definition of storage to be based on that of interconnectors, to avoid double charging in both capital and operational costs for grid connections, and to enable contracts to be let for storage services;
5. Phasing out of subsidies to fossil fuel generators (e.g. the Capacity Market);
6. Preferably, a re-design of the market to base it around renewable generation and storage with some nuclear baseload, rather than today's market structure which is essentially based on nuclear and coal baseload with gas variable generation, and patch after patch (new contracts and rules are being introduced at an ever-increasing rate) to cope with a modern generation mix.

Appendix A: Poyry and TINA Analyses of the Challenge

The Scale of the Problem – Poyry

The graph below superimposes the actual wind pattern of January 2010 on the forecast generation mix and demand pattern of 2030 on the assumption that all forecast wind generation has priority access to the grid over all other generators:



The following results stand out clearly:

1. When the wind blows strongly, even baseload generation (which should never be turned off – mainly nuclear and coal) has to be turned down / off – six times during one month for nuclear. When demand is lower (e.g. in summer), this could happen more often. Instead of switching them down / off, the system is made much more efficient if that amount of wind energy is stored.
2. Even variable generation (such as gas) operates much more efficiently and with lower emissions if operated as baseload – like driving a car on a motorway rather than round town. This is only achieved if there is sufficient storage. Incidentally, this is why traditional generators are currently going through very difficult financial times: while their revenues are reduced (due to being switched off / down so much), their costs are increased (wear and tear, efficiency of burn, average cost of fuel – because a greater proportion of their fuel is being bought at peak).
3. The scale of variability of wind production is 60GW. Therefore to absorb such variation, 60GW storage would be ideal. However some of this can be made

up by, principally, Demand Side Response and batteries – each to an economically feasible level of 2-3GW.

4. For long periods (e.g. from late December to 10th January, and from 29th January onwards, in this example), there is highly fluctuating wind generation that remains almost continually above 30GW, meaning that the amount of energy needed to be stored is enormous (up to 5TWh) in order to make other power stations operate efficiently and with minimal pollution.
5. This power is needed when the wind doesn't blow, e.g. from 24th to 27th January. Such non-generating weather systems can stand over most of western Europe for up to 10 days at a time, every three years (estimated by us at 5-10TWh) – and more often for shorter periods and/or smaller regions. Therefore, if peaking and back-up power stations are to be shut down completely, at least 10 days' non-baseload energy needs to be stored.
6. And all this ignores the effect of solar, wave and tidal generation….

So the scale of the problem is 60GW, 5-10TWh. But in the shorter term, the balancing requirement for variable demand is 30GW, of which about 3GW is currently being met by pumped hydroelectric storage.

Scale of the Problem – TINA

Another analysis of the problem, the Technology Innovation Needs Analysis[29] by the Low Carbon Innovation Co-ordinating Group (LCICG), which is the biggest inter-departmental group in the British Government's civil service, identifies that Britain requires 27.4GW of storage (in the range of 7.2 to 59.2GW), with a capacity of

Chart 2 EN&S technology deployment scenarios

Area	Sub-area	Units	2020 deployment		2050 deployment	
			GW	GWh	GW	GWh
Storage	Pumped hydro	GW or GWh	4.3 (3.1 - 6.6)	21 (15 - 33)	8.2 (3.3 - 17.3)	41 (16 - 87)
	CAES		1.8 (0.2 - 3.8)	9 (1 - 19)	7.1 (0.7 - 15.3)	35 (4 - 76)
	Sodium-based batteries		0.5 (0.1 - 1.1)	2 (1 - 6)	1.9 (0.5 - 4.6)	9 (3 - 23)
	Redox flow batteries		0.3 (0.1 - 0.9)	2 (1 - 4)	1.4 (0.4 - 3.5)	7 (2 - 18)
	Lithium-based batteries		0.4 (0.3 - 0.9)	0 (0 - 3)	1.7 (1.2 - 3.6)	2 (2 - 10)
	Flywheels		0.1 (0.1 - 0.1)	0 (0 - 0)	0.5 (0.3 - 0.6)	0 (0 - 0)
	Supercapacitors		0 (0 - 0)	0 (0 - 0)	0 (0 - 0)	0 (0 - 0)
	Thermal-to-electric storage		1.7 (0.2 - 3.6)	8 (1 - 18)	6.7 (0.8 - 14.3)	34 (4 - 72)
	Total		**9.1 (4.1 - 17.1)**	**43 (19 - 83)**	**27.4 (7.2 - 59.2)**	**128 (31 - 286)**

128GWh (31 to 286GWh). This is 5 hours' storage at rated capacity, coinciding with the duration of the winter evening peak: almost no grid-connected battery in the world has more than 2 hours' storage because it is not cost-effective.

[29] https://www.carbontrust.com/resources/reports/technology/tinas-low-carbon-technologies/ Energy Networks and Storage report chart 2 p9 which splits it down into various technologies without considering the costs of doing so (batteries of all kinds with the required 5-hour durations and pumped hydro are much dearer than CAES) or availability (they exceed the country's pumped hydro potential), or the availability / practicality of the technology (thermal-to-electric stopped when Isentropic went into administration in 2016 http://www.eti.co.uk/programmes/energy-storage-distribution/distribution-scale-energy-storage, long before FES 2017 was published, despite £14m investment by ETI, http://www.eti.co.uk/news/eti-invest-14m-in-energy-storage-breakthrough-with-isentropic).

This analysis only looks at supporting the country's currently forecast variable demand, assuming that baseload demand will continue to be supplied by nuclear and gas plants. Therefore if nuclear is to fail to materialise in sufficient volume (which looks increasingly likely), and we cannot increase the gas generation lest we exceed our treaty obligations on emissions, this storage requirement must be increased greatly to accommodate baseload generation.

Even taking the 27.4GW figure at face value and looking at cost-effective developments only, we can expect it to be made up of (additional to what was in place at the publication of the report) 2-3GW (2-3GWh) demand side response, 2-3GW (2-3GWh) batteries, 8-12GW interconnectors and 2GW (20GWh) total of all existing pumped hydro planning applications. This totals 12-18GW (24-26GWh), leaving an unmet need for 7.4-13.4GW (102-104GWh) which Storelectric can supply more cheaply than gas-fired peaking plants.

Appendix B: Electricity Storage Solutions

Most so-called “grid-scale” storage is at a scale of 10s of MW, and 10s of MWh. While extremely useful for local issues (e.g. capacity enhancement, islanding at small scale, maximising output from small to medium scale renewable generation) and for short timescale issues (e.g. frequency and voltage response), it completely misses the big problem. It may be grid connected, but it’s not grid scale. Doubling either size or capacity increases capital costs of an installation by typically 85% as the number of cells needs to be doubled.

In contrast, Storelectric offers truly grid-scale electricity storage, with each 500MW, multi-hour plant costing only £350m (£460m for the first-off), and a levelised cost less than that of a gas-fired peaking plant. It can be up to 100% renewable. This complements all the other storage technologies on offer, and works equally with renewables and fossil fuel generated power, thereby supporting the transition also. Doubling its size or capacity (assuming that the capacity increase is matched with thermal storage – the higher-cost but lower-emissions option) typically increases its capex by about one-third.

What is needed is an entire raft of electricity storage technologies, which we split:

Scale	Power	Capacity	Technologies Best Suited
Domestic	<100 kW	<250 kWh	Batteries, supercapacitors, flywheels
Local	<1 MW	<5 MWh	Batteries, supercapacitors, flywheels, cryogenic
Area	<10 MW	<50 MWh	Cryogenic, heat, large batteries, flow batteries
Regional	<100 MW	<500 MWh	CAES, pumped hydro, poss. flow batteries, heat
Grid	>100 MW	>500 MWh	CAES, pumped hydro, (future) hydrogen

The market can also be segmented by response time.

There is room in the market for all the technologies that deliver one or more services cost-effectively. For the next decade or two, our main competition is not each other – it’s ignorance and bad policy.

Distributed Schemes

Many propose that distributed generation and storage will solve the problem. It is true that they will go a long way towards solving the problem, but every single distributed storage scheme of attainable (not even cost-effective) cost relies on the grid to provide back-up power when batteries are exhausted and generation is lower than demand. So where does the grid get its power from, to provide this back-up?

Demand Side Response (DSR)

Currently DSR is defined to include both consumer-owned generation which accounts for 80% of capacity, and demand displacement (temporary reduction in demand when required, to be made up later, e.g. switching off freezers for 15 minutes, to be re-cooled later) which accounts for 20% of capacity. This is unfortunate: consumer owned generation (mostly diesel generators) is the costliest and most polluting form of generation, whereas demand displacement uses very little extra energy overall and is the most cost-effective means of absorbing peaks and surges in demand. The former needs to be abandoned, while the latter deserves its place in the energy mix.

Batteries (Non-Flow)

The most fashionable technology is lithium ion batteries, though it has competitors in other lithium- and sodium-based chemistries, and in lead-acid; each has its advantages and disadvantages. A major disadvantage of lithium is that there isn't enough of it (or of cobalt and other esoteric metals) in the earth's crust to support the grids of this planet, so it's much better used in applications where its weight, bulk and energy density are at a premium: portable equipment and transportation.

Supercapacitors, Flywheels, Flow Batteries, Pumped Hydro

Supercapacitors and flywheels are best for ultra-short duration. Cryogenic is otherwise known as Liquid Air Energy Storage, fairly expensive and complex but without geographical limitations. Flow batteries' dirty secret is that they tend to involve swimming pools full of concentrated acid. All batteries have environmental issues related to mining, refining, processing and disposal. Pumped hydro is ~98% of installed capacity, ~75% efficient (higher numbers for some plants rely on in-flowing water), flood one or two valleys, are considerably dearer than CAES and have few potential locations that tend to be very remote from both supply and demand.

Compressed Air Energy Storage (CAES)

CAES has some geographical limitations but potential locations are widespread world-wide. It comes in 2 versions: diabatic (traditional) and adiabatic (such as Storelectric). Compressing air to a typical 70 bar (~30x car tyre pressure) heats it by ~605oC, but the air must be stored at close to ambient because it's stored underground in salt caverns (nothing else is big or cheap enough; though other geologies will be available in future) and the geology requires it. Expanding it to regenerate the electricity cools it to below -150oC. Traditional CAES puts the heat back in by burning gas: inefficient (42–50% round trip) and polluting (50–70% of the emissions of an equivalent sized CCGT). Adiabatic CAES extracts the heat of compression, stores it separately and puts it back in during expansion, increasing efficiency to 60–70% and eliminating emissions; hybrid technologies are possible.

Note that batteries tend to quote their efficiencies as “gross” rather than round trip. The difference is the cooling, power conversion etc. Thys grid connected batteries’ actual round trip (i.e. grid-to-grid) efficiency is 42–68% depending on scale, on day 1; by year 5–8 their heat losses have tripled and so efficiency drops. CAES efficiencies are quoted as grid-to-grid.

But how much?

The Grid identifies up to almost 6GW of DSR potential in the economy (fig. 3.5.1) by 2025, shrinking to 5GW by 2038, in the most optimistic scenario, a significant proportion of which (two-thirds of current 1.8GW capacity, in the FES 2016 report) is highly polluting and therefore (in the medium term) unwanted diesel generation and should therefore be disregarded. A proportion of that will never be realised, as many customers will never want to hand over control of their washing machines or other equipment to electricity companies. Another reducing factor is that if needed two or three times during a peak (e.g. the classical advertisement breaks during a popular programme), different DSR assets need to be used for each. Note that peak demand will already have been reduced by 1.6GW by widespread adoption of time-of-use tariffs (figure 3.5.4), reducing scope for DSR.

The prevalent market view is that DSR is valid for up to 3-5% of peak demand. Beyond that, we would be paying £billions to degrade our first-world grid to a third-world grid. (In a first-world grid, when I switch on a switch, the electricity is there; in a third world grid, it will think about it.) But 5% of peak demand is still 3GW, an immense 75 times current capacity – there’s room in the market for all these suppliers, too.

Appendix C: Interconnectors

In FES 2018, "electricity imported through interconnectors is counted as zero carbon when calculating GB emissions." (p33) This is perverse, and is not balanced by an accounting for the emissions of exports. Moreover, as nearly all EU countries are planning to be importing peak electricity during periods of low intermittent generation, this fantastic assumption of zero emissions imports is replicated across the continent – at just the time when emissions are greatest as peaking plants are turned on to support peak demand, again throughout the continent.

The planning models used by FES 2018 compare the prices of electricity and services through interconnectors with domestic ones. However they ignore the subsidies of free grid access (i.e. single charging – for access charges within the price of the electricity bought, as opposed to triple charging for storage, proposed to reduce to double charging), cheaper grid access costs in Europe, cheaper carbon price in Europe, and no charging of the differential as it is imported. Remove these implicit subsidies and the economic benefit of interconnectors greatly diminishes. Indeed, FES 2018 explicitly recognises this with regard to carbon prices (but not grid access charges) on p109.

In their Electricity Capacity Assessment Report 2013[30], Ofgem completely discounted reliance on any power from interconnectors – though they have modified their views since then. Not only do all our neighbouring countries suffer comparable shortfalls in generation capacity with Britain's, but also their demand patterns are similar. The corollary of these two factors is that if we are allowed to draw power through interconnectors when our neighbours also want it, we are likely to be paying high prices in order to do so. Nevertheless, at times when these neighbours' systems are not stressed, interconnectors provide ample electricity at reasonable marginal prices, and serve an excellent purpose in lowering Britain's overall energy prices.

As if to emphasise this point, "In February 2015 National Grid Nemo Link Limited and Elia, the Belgian Transmission System Operator, signed sign a joint venture agreement to move ahead with the Nemo Link"[31] even though Belgium was the first country in Western Europe to be planning openly for rolling black-outs[32] to make up for potential generation shortfalls, and Belgium's interconnection capacity is 3.5GW, or 25% of their 14GW peak demand[33], as compared with Britain's current 4.15GW, or under 7% of peak demand.

Yet National Grid is accelerating its reliance on interconnectors, from the current 4.15GW to 23.3GW by 2040 (Two Degrees scenario).The fact that we saw strong

[30] https://www.ofgem.gov.uk/publications-and-updates/electricity-capacity-assessment-report-2013 p41-44
[31] www.nationalgrid.com
[32] http://datafable.com/rolling-blackout-belgium/viz/
[33] http://energy.sia-partners.com

flows into the UK during peaks in winter 2014 is due primarily (in my opinion) to the exceptionally warm winter noted in the Winter Outlook Report 2014, rather than to their reliability when demand is high: as stated, “French and Belgian supply is expected to be relatively tight until 2020 due to closure of old fossil fuel plant and some nuclear reactors. As conditions vary and put more stress on the market in coming years, this could lead to more volatile prices and therefore interconnector flows between GB and the continent. This is particularly the case over the peak demand of the day.”

“However, GB is not the only European country expecting de-rated margins to fall in the next six winters. … Our analysis also suggests that, at the moment, there are no evident complementarities between GB and its interconnected markets as we have very similar patterns of demand and supply availability.”
- Ofgem Electricity Capacity Assessment Report 2013

Note: the BritNed interconnector costs £0.5bn for 1GW of uncertain supply; longer interconnectors are dearer. Storelectric will in future provide 1GW of certain supply for £0.7bn.

Because of their function in lowering overall energy prices and making up for domestic energy shortfalls, Storelectric’s CAES does not supplant the need for interconnectors, but works with them. Indeed, CAES at either end of one could increase the energy transported by that interconnector by up to 6 times, depending on the energy profile at either end of the interconnector. Like CAES, interconnectors are therefore not the solution, but an important part of the solution.

Interconnectors and Brexit

Currently Britain is in the single market, regulated by the European Court of Justice. This ensures that if we pay enough, our neighbours have to sell us the electricity, and to do so tariff free. According to FES 2017, "our analysis currently assumes tariff free access to EU markets under all scenarios.[34]" This is the rosiest possible scenario, which is therefore a very rash assumption – and the more so as the government has consistently said that we will leave both the single market and the jurisdiction of the ECJ. Worse, this means that all our neighbours would then be free to tell us that they prioritise their consumers at any price.

It is worth noting that this entails importing 1/6 – 1/4 (depending on scenario) of the country's peak demand by 2025, making up (by the same year) over one quarter of our total energy demand, through interconnectors from neighbouring countries. Not only does this indicate a massive domestic energy generation shortfall, but it also risks making Brexit negotiations hostage to our needs: we will be compelled to come to whatever agreement is necessary in order to be able to import these volumes, potentially weakening our opportunity to negotiate countervailing export market access such as for financial and other services.

It is also worth noting that interconnectors are part funded by the European Commission's Connecting Europe Facility (CEF), and rely on this to a greater or lesser extent for their financial viability. The innovation budget of the EU is funded by 6 countries more than the membership, including Norway, Switzerland and Azerbaijan, so it is possible for the UK to continue to use it – provided we pay into the budget, which may cause political issues in the UK. It is also possible for the UK to provide its own equivalent to CEF (and Horizon 2020 etc.) money, but that would require duplicating administration and an administrative layer to co-ordinate with the EU at both governmental and project levels.

Interconnectors and Emissions

Finally, the assumption that "electricity imported through interconnectors is counted as zero carbon when calculating GB emissions" (p33) must be challenged. Imports carry a proportion of emissions in their generation mix, unless specifically contracted from zero carbon sources. At times of low renewable generation, when the UK will be importing the highest proportion of our electricity, neighbouring countries are often undergoing similar weather patterns to ours, or continuations of the same pattern; therefore they too would be experiencing low intermittent generation. Consequently they would (like the UK) be turning on peaking plants to satisfy demand, and carbon intensity increases. For this reason it is safer to assume that electricity imported through interconnectors has an average carbon / emissions content ***higher than*** the average carbon / emissions content of the grid from which it is being imported. Therefore this use of interconnectors merely fudges the emissions figures and guarantees that the country will fail to meet its decarbonisation commitments.

[34] P66, Interconnectors

Appendix D: Ofgem and BEIS Recognition

From the Smart, Flexible Electricity System consultation paper published jointly by BEIS and Ofgem, November 2016:

- "And, as well as meeting new challenges, we must seize the opportunities enabled by a smart system – including ... the use of advanced energy storage technology." Covering letter from Greg Clark, Minister.
- "It builds on the position paper on Flexibility we published last year. In that, we stated our priorities were the roles of storage and ..." Ofgem Foreword.
- "In line with the plans both Government and Ofgem set out last year, we have considered a range of options to deliver a smart energy system, including: removing barriers to storage and DSR; ..." Towards a smart, flexible energy system para.20.
- "We have found that storage faces a number of barriers", as an introduction to a request for ideas to remove those barriers. Towards a smart, flexible energy system para.22.
- "Government has identified a number of potential priority areas over the next 5 years: ... storage costs. ..." Towards a smart, flexible energy system para.50.
- Towards a smart, flexible energy system, Table 1:
    - "In the final plan we will set out implementation tasks and timelines for: Any further measures to make it easier for storage to connect to the network - A decision on regulatory definition for storage and whether a new licence is required".
    - "Our aim: a level playing field for DSR and storage competing with other forms of flexibility and more traditional solutions."
- In the National Infrastructure Commission's report on Smart Power recommendation 2a) was that "DECC and Ofgem should review the regulatory and legal status of storage to remove outdated barriers and to enable storage to compete fairly with generation across the various interlinked electricity markets. The reforms should be proposed by Spring 2017 and implemented as soon as possible thereafter." https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/505218/IC_Energy_Report_web.pdf - note 17 to Introduction, Table 2.
- 2. Removing policy and regulatory barriers, 2.1 Enabling storage
    - "1. There is increasing interest in energy storage as a potential source of flexibility for our energy system"
    - "2. Falling costs are one element of bringing forward large scale storage projects – the market and its structures must also recognise and reward storage for the value it brings to the energy system."
    - "3. We are seeking views on solutions; both for individual barriers and whether some solutions could address multiple barriers e.g. regulatory clarity."

So BEIS and Ofgem are keenly aware of the need for storage at all scales from domestic to grid scale, and are actively seeking ways of enabling it to happen, and to remunerate it fully. Unlike other storage solutions, we can demonstrate strong profitability and IRRs in today's market with today's regulations: all these changes being contemplated merely add to our potential.

From BEIS (UK gov't) ***Building Our Industrial Strategy*** *consultation:*

This paper "also consults on the technologies which the new Industrial Strategy Challenge Fund could support, including: smart and clean energy technologies (such as storage …)"

"The government has also asked Sir Mark Walport, the Government's Chief Scientific Adviser, to consider the case for a new research institution as a focal point for work on battery technology, energy storage and grid technology [by] early 2017 ."

"To ensure that new energy technologies are developed here – and the UK benefits from global investment in this area – we have doubled support for energy innovation, and are

Recognition of the Need and Government Wrong Actions

Some people have recognised the scale of the problem:

> "Electricity storage has the potential to provide savings of more than £10 billion per year by 2050—that is £400 per household" – Lord Grantchester in parliament, 18/7/13
>
> "......... we have designed the enduring capacity market to ensure that demand reduction and storage can participate effectively by running capacity auctions both four years ahead and one year ahead of when capacity is expected to be required.   ...." – Baroness Verma, DECC minister, in parliament 18/7/13
>
> "Electricity demand peaks at around 60GW, whilst we have a grid capacity of around 80GW – but storage capacity of around just 3GW. Greater capability to store electricity is crucial for these power sources to be viable. It promises savings on UK energy spend of up to £10bn a year by 2050 as extra capacity for peak load is less necessary." – Chancellor of the Exchequer George Osborne, 9/11/12
>
> "Reports from Imperial College show that the cumulative value to the UK of flexibility [in power generation] is £60bn by 2030." – Electricity Storage Network in 2014 (not on website now, www.electricitystorage.co.uk)

So where has the government's and other public / semi-public bodies' financial support gone?

- £billions to subsidise fossil fuelled power stations, through the Capacity Market;
- £1bn to subsidise fossil fuelled power stations, through CCS demonstrators (while these 2 projects were cancelled after considerable costs, CCS power generation remains a government priority and continues to attract funding);
- £10s of millions to subsidise area scale projects such as Quarry Battery, Highview and Isentropic;
- £10s of millions to subsidise batteries, at similar or smaller scale;
- Negligible support to regional or grid-scale storage.

Likewise, all government incentives (Capacity Market, CfDs, ROCs etc.) are geared towards production regardless of the time at which it is needed, and none towards either storage or making electricity available at the time needed. This could easily change: for example, the government could increase substantially the value of CfDs and ROCs to renewable generation on condition that it generate baseload power, or dispatchable power, thereby incentivising renewable generation to contract with storage and to support its development.

Since June 2015 the government has announced large restrictions to CfDs and the end of ROCs. This greatly reduces the investability of new technology projects: CfDs provided the only guaranteed sales, albeit with prices fluctuating with the market, within limits. The National Grid is not permitted to offer contracts for longer than 2-3 years, which does not create financial-market "bankability" for new technology investment. Moreover, all of these (as well as CfDs, from 2014) are let by auction which means that even such short term contracts cannot be relied upon. The government needs to permit long term (10-20 year) contracts, some of which are awarded without auction for new technologies in the widest sense.

Appendix E: About Storelectric and the Author

About Storelectric

Storelectric (www.storelectric.com) is developing truly grid-scale energy storage using an innovative form of Compressed Air Energy Storage (CAES). This uses existing, off-the-shelf equipment to create installations of 500MW, 2-21GWh with zero or low emissions, operating at 68-70% round trip efficiency, at a cost of £350m (€500m) (estimated for 3rd – 5th plant), and a levelised cost cheaper than that of gas-fired peaking plants (OCGT). Capex is one-third that of pumped hydro per MW and 1/75th per MWh; similar to 10-year target prices of batteries per MW and less than 1/1,000th per MWh. There is potential in the UK to store the entire continent's energy requirements for over a week; potential in mainland Europe and the USA is greater still, with global roll-out planned.

The next stage is to build a 40MW, 200MWh pilot plant with over 62% efficiency (grid-to-grid), using scale versions of the same technology, for which Storelectric is currently raising funds. Construction will take 2-3 years from funding, and the first full-scale plant a further 3-4 years. The consortium includes global multinationals who cover all the technologies involved, their installation, financial and legal aspects.

Storelectric has a second technology, CCGT CAES, which is the only CAES technology that is retro-fittable to a suitably located gas-fired power station (either CCGT or OCGT). As such it is a very good value technology that can almost halve emissions and add storage-related revenue streams, giving new life to stranded assets. It is an excellent transitional technology.

In the future, Storelectric will further develop both these and hybrid technologies, and other geologies for CAES.

About the Author

Mark Howitt is a founding director of Storelectric. He leads Storelectric's technical and operations, minimising technological risk, maximising efficiency and environmental friendliness, and speed to market. His degree was in Physics with Electronics. He has 12 years' management and innovation consultancy experience world-wide. In a rail multinational, Mark developed 3 profitable and successful businesses: in commercialising his technology, in logistics and in equipment overhaul. In electronics manufacturing, he developed and introduced to the markets 5 product ranges and helped 2 businesses grow strategically.