Mark's Blog
Personal blog of Mark Howitt, founding director and CTO of Storelectric Ltd and recognised international expert in the energy transition

Analysis of National Grid Future Energy Scenarios 2023

Summary of Findings

National Grid's Future Energy Scenarios 2023 (NG's FES 2023[1]) is a small step forward on their 2022 document. It contains broader, for example considering aviation, shipping and railways (albeit only in terms of emissions, not energy consumption). We agree that "Whole system thinking helps decarbonisation" (p80); indeed, without it, decarbonisation will be unaffordable, impractical, excessively disruptive, unreliable and un-resilient.

It starts from a backdrop in which 2022-23 emissions were worse than in the previous year, for the first time in a decade[2]. This is partly due to the end of the COVID lockdowns, though they had mostly finished by the beginning of that year. The main reason is the dire shortage of naturally inertial long-duration energy storage (LDES) in the right locations, which FES 2023 and its recommendations do little to redress. This suggests more than an element of magical thinking in the future projections.

National Grid provides a number of focal areas, which are addressed in turn:

- Focus on consumers,
- Policy and delivery,
- Consumer and digitalisation,
- Markets and flexibility,
- Infrastructure and whole energy system,
- Navigating a fair transition to Net Zero

Net Zero Electricity by 2035

Although ostensibly laudable, the aim to decarbonise the electricity grid by 2035 will make it unaffordable, unreliable and fragile because the need for naturally inertial long-duration energy storage (LDES) has been ignored until recently, and still doesn't have the focus (strategy, regulations, market design) that it needs. Few (Storelectric's are the exceptions) can be profitable, merchant, in today's market.

Effects of Climate Change

The effects of climate change on the electricity system appear not to have been considered at all[3]. This is a very serious deficiency, which will affect supply, demand and networks in diverse ways. This has consequences in the technologies and network structure, which don't even get a mention in FES.

[1] https://www.nationalgrideso.com/future-energy/future-energy-scenarios

[2] Omitted from the text, but see Figure 1 p12, and the corresponding data table in sheet NZ.02

[3] https://storelectric.com/water-heat-and-energy/

Analysis of Demand

FES 2023's analysis of demand explicitly excludes "*additional demand for upstream primary energy sources or the conversion losses associated with production of some of these fuels, such as hydrogen*" (p68) which would more than double electricity demand. Such large differences have very large-scale effects on the electricity supply, transmission, distribution and system operation. This gross omission makes the remainder of the report unreliable and of limited use for planning.

Negative Emissions

Quite correctly, the electricity system is targeted to have negative emissions by 2050 to balance hard-to-abate sectors such as aviation and agriculture. The current two technologies for this are BECCS and DAC (Bio-Energy with Carbon Capture and Storage, Direct Air Capture). DAC is a nascent but promising field, CCS more developed and (for power generation at least) less promising, for reasons discussed separately. There are also nature-based projects such as reafforestation and the planting of seagrass.

CCS is treated as carbon neutral, but is not: even omitting the supply-chain emissions (e.g. for capture catalysts), capture rates are always below 100%, meaning that there are emissions. These residual emissions can be very large: in the Boundary Dam project they often exceed 60%, and most other projects keep their figures confidential.

The U (Use and) in CCUS is treated as equivalent to CCS, but is not. Use of carbon is merely a delay in its emission. It is valuable inasmuch as it displaces emissions where used, but is highly susceptible to double counting.

Both BECCS and DAC are exceedingly expensive and energy intensive; their operation also needs to mitigate supply-chain emissions. BECCS is also limited in the amount of biomass that is available for burning, without constraining the world's food supply. Therefore in a Net Zero or Net Negative emissions energy system, the need for them must be minimised. Ways of doing that include:

- Avoiding CCS generation where possible, other than BECCS, to minimise the additional negative-emissions plant required by the residual emissions;
- Avoiding unabated generation even more avidly;
- Only allowing zero-carbon generation and storage technologies.

FES does not take these three steps, instead relying greatly on CCS generation and ignoring its residual emissions; and unabated generation is included in the plans.

Electricity Storage

Despite many grave errors in the modelling that understate the need for storage, FES 2023 compliant scenarios require 33-52GW, 116-197GWh of electricity storage. Comparing the total GW and GWh of storage yields an average storage duration of 3.5-3.8 hours for the three Net Zero compliant scenarios. Given that nearly all battery

storage is typically 1 or 2 hours, also stated in the report, that means that at least as much longer-duration storage is needed, of 4-12 hours duration. But under 4 hours average duration will not keep the lights on during the evening peak and overnight, let alone through the *Kalte Dunkelflaute*.

On that subject, the Dunkelflaute is analysed for the first time, a good start that needs further refinement as it still requires imports, does not consider our climate becoming more aligned with mainland Europe's, errs in Germany's expected generation mix and does not consider a similar but shorter follow-on weather pattern before storage is replenished.

Hydrogen

Despite omitting many of the largest potential uses for hydrogen, FES 2023 nevertheless identifies a huge need for it, widely varying between scenarios, of up to 431TWh hydrogen. Adding in those uses (such as industrial and chemical processes, synthetic fuels and complex compounds like ammonia) would greatly increase the total need for hydrogen, even if some of the less-likely uses cited in the scenarios were discounted. FES forecasts much less hydrogen than most other forecasters around the world.

29-46 days' consumption is required. This is a massive amount, tens of TWh rising to hundreds if hydrogen demand is to grow to any close to most forecasters' levels.

Focus on Consumers

The focus on "consumers" is still as strong and misleading as ever.

1. Because a timescale is never mentioned, it means "consumers of today" at whose altar we sacrifice those of tomorrow, always seeking "least-cost options" for now, which eclipse all efforts at medium- and long-term considerations.
2. The focus on the energy cost is the opposite of a focus on consumers because the cost of generating electricity makes up 20-25% of today's electricity bills, down from 75-80% a decade ago, and dropping (which I analyse elsewhere this month). The rest is made up of the charges, levies and energy system costs that are escalating exponentially due to poor electricity system regulation and contracting[4].

Policy and Delivery

Policy and Delivery focuses on demand side strategy (both reducing demand and balancing demand profiles), energy efficiency (again reducing demand) and a focus on heat, which is about heat itself, largely ignoring how the energy is generated, distributed and balanced to produce that heat where and when needed. These are tickling the edges of the challenges, skirting around the edge of the big issues which are generation, storage, the transmission and distribution systems (network size and

[4] https://www.storelectric.com/challenges-of-the-electricity-transition/

shape), integration of system and network thinking, enabling projects to benefit from improving overall system costs etc., reliability and resilience. Focusing so heavily on demand abdicates the challenge of ensuring sufficiency and security of supply.

Consumer and Digitalisation

This again misses the point. Digitalisation (ungrammatical as it is, it should be digitisation) merely optimises the use of energy in the system; it doesn't ensure that there's enough there in the first place, or with suitable reliability, resilience or energy security. It cuts margins to the bone, virtually eliminating the ability of consumers to change behaviour or systems to react if there is some substantial change, such as a faster or slower roll-out of EVs, or energy supply challenges.

While it's important to educate consumers and help them change for Net Zero, the effects of most such initiatives (e.g. Smart Meters [which can at most reduce consumers' bills and network peak demand by ~5% according to their own publicity or, more realistically, 1-2%[5]], though smart-charging EVs [a much more marginal exercise than claimed[6]] is additional to that figure) is at best marginal. Other experts looking at an average £693 increase in energy bills think that as much as a mere £75 could be saved, in comparison with the price cap expected to rise to £2,800 by October – that's just 2.7%[7] and assumes that all consumers will have the time, inclination, incentive and ability to maximise their benefits: of those that have the inclination and ability, how many are earning little enough for £75 p.a. to be sufficient incentive?

Markets and Flexibility

There is still excessive focus on demand-side flexibility, and on scale to the exclusion of duration. There is no reflection on the extent to which it benefits or harms the wider electricity system. Yes, it adds flexibility options now, but it also reduces the price volatility on which (for lack of specific contracts) National Grid, Ofgem and the government are relying to incentivise storage.

The same applies to storage: they incentivise and celebrate it divorced from the concept of duration, Yet, above a certain level (to be calculated), contracts for short-duration storage cannibalise the revenue stack of long-duration storage (LDES). As there are many functions that the latter can do but the former cannot, this means that to incentivise LDES, the prices of those unique capabilities must rise to compensate. Therefore, above that level, such contracts merely add cost without adding capability.

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[5] https://www.thisismoney.co.uk/money/bills/article-4297996/Can-smart-meter-lower-energy-bills.html

[6] https://www.storelectric.com/vehicle-to-grid-and-shared-mobility/

[7] https://www.express.co.uk/finance/personalfinance/1618390/smart-meter-reduce-household-bill-uk-2023

Again, the focus on flexibility without duration misses the question of energy security. Omitting grid stability misses the questions of reliability and resilience.

Locational signals, if taken to National Grid's natural conclusions, will sub-divide our 50-100GW grid (depending on whether we're looking at now or the future) into hundreds of tiny sub-markets which, of their nature, will disadvantage the large and broadly-capable solutions that the grid most needs. Moreover, some of the technologies most essential to Net Zero (e.g. wind, large-scale long-duration inertial storage) have to be put in specific regions; penalising them inordinately for doing so would make the energy transition unachievable.

And market participation is geared around bringing into the grids ever increasing numbers of participants at the distribution level, small scale and short duration, which are exactly what is driving up the costs and hurting the reliability and resilience of the transmission grid.

Current regulations and market design have already led to a situation in which Wystem Operation costs grow over 14 times in the three years from when the UK crossed the threshold 16% renewables (because we have LDES for 5% of demand; the threshold would differ elsewhere). Each new GW of offshore wind requires over £3bn onshore grid reinforcement plus £300m p.a. thereafter, even without considering its effects on system operation costs and other related matters. There is no consideration of any of these things, of how and why we got into this position, or of how to improve matters.

Infrastructure and Whole Energy System

The whole-system thinking that is presaged by National Grid's Pathways to 2030 Holistic Network Design document (which I analyse elsewhere this month) is far too short-term to achieve the objectives without wasting a fortune on future re-work and without building enough grid to encourage new Net Zero compatible projects to come forward.

Inter-seasonal storage is just an assumed need. And National Grid seeks to jump to addressing it before (a) addressing the long-duration energy storage needs, i.e. 4 hours to 2.5 weeks duration, (b) determining how much seasonal storage is needed or (c) imagining any ways in which to incentivise reserve – which is why, in gas, the UK has just 3 days' reserve as compared with 3-9 months as standard in continental Europe.

Whole system competition is only about delivering something similar to what NG engineers have conceived. There is no concept that others may have ideas, initiatives and projects that offer radically improved alternatives (such as Storelectric's proposal to halve the size of grid needed for each offshore wind farm, with many other linked benefits) or considering any way of sharing the benefits with such project developers.

Grid Network

Analysis of the grid is incorporated into FES for the first time. This is a big move forward, but forecasts a doubling of grid capacity: most forecasters expect more than a tripling to accommodate the transition to renewables under current regulations and markets. As hydrogen is not fully considered, that should be doubled again. Consequent recommendations are not made, e.g. to put the hydrogen economy off-grid with LDES, and to connect renewables to the grid with LDES, that would mean that the grid only needs to be sized for electricity demand (and not power most electrolysis), rather than for intermittent supply. The potential savings are well over a trillion pounds in capital costs and £150bn p.a. operationally and financially.

Navigating a Fair Transition to Net Zero

Without all the considerations above, the transition to Net Zero will not be fair, affordable, reliable or resilient. Despite the section headed such on p13, National Grid is not "seeing the whole picture", excluding, for example:

- Medium- and long-term thinking;
- Large and broadly capable solutions;
- Solutions with cross-over benefits between network and system;
- As well as their many other shortfalls detailed in this document.

Regionalisation

Today the UK has a 50GW grid and (mostly) 50GW markets. There is some, but limited (e.g. TNUoS) regional incentivisation to push developers to think carefully about where they put their proposals.

National Grid wants to greatly enhance these regional signals, which is fine for those projects (e.g. batteries) that can locate anywhere but will make projects without such flexibility (e.g. offshore and onshore wind, large-scale long-duration storage of any type) much harder to fund. And by doing so, it would make the energy transition as a whole unachievable: how can we generate enough power without locating the offshore wind beyond the furthest extremities (north, north-west, north-east and south-west) of the British Isles? How can security of supply, energy affordability and sufficiency, and grid reliability and resilience be achieved (i.e. all those factors together, not just some of them) without large-scale, long-duration, inertial storage?

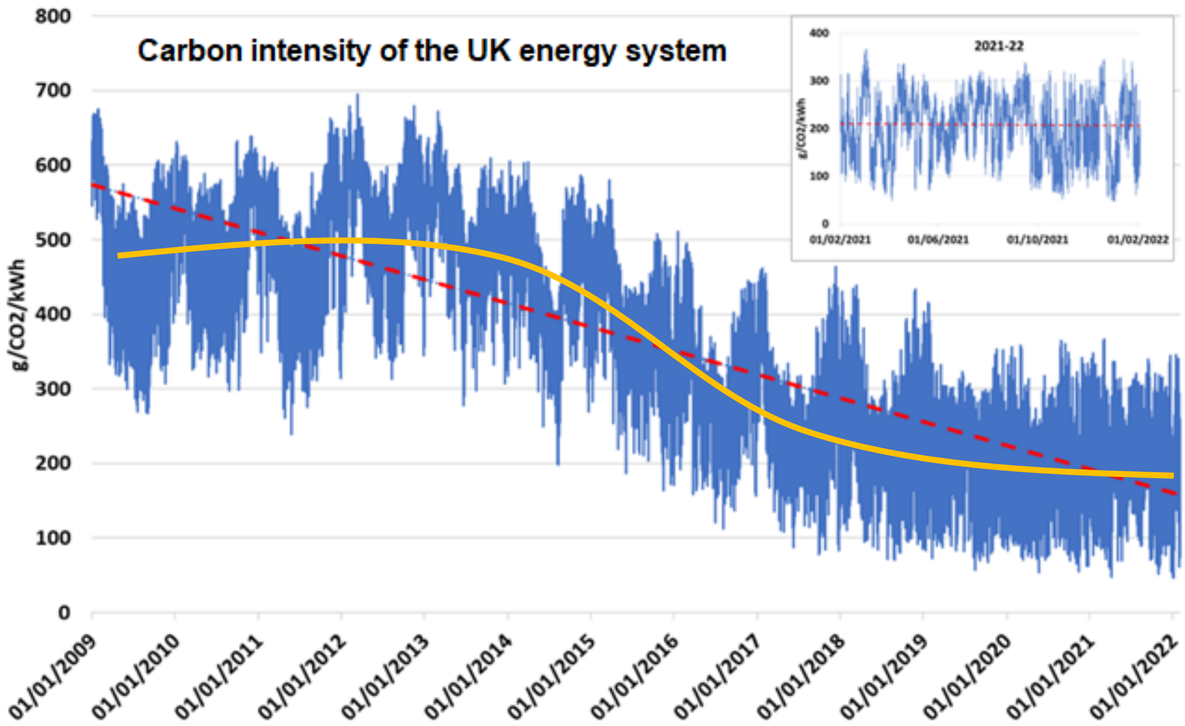
Another result of regionalisation is to salami-slice the current single markets for most grid services / products, which are 50GW but rising towards 100GW, into numerous mini-markets. Just look at retail to see what that means: reducing volume and variety while increasing costs both of the products themselves and of doing business. Suddenly a GW-scale solution would become so dominant in its mini-markets that they would not be permitted to contract at the scale most suited to their technology.

Their intense lobbying to magnify locational pricing is one of the worst possible ways forward. Not only is most generation, storage (other than batteries) and demand fairly locationally inflexible, but locational incentives would change over time based

on grid reinforcement actions, meaning that investors cannot forecast their costs, so killing investment incentives. It is a high volume low margin business, so increasing locational incentives above their present levels is totally destructive.

Net Zero

The energy transition is about replacing hydrocarbons with zero-emissions technologies, so Net Zero technologies must be at the scale of hydrocarbons (i.e. of power stations), or the objective will be missed by a very wide and/or costly margin. The power stations deliver energy, availability / dispatchability, grid stability, reliability, resilience, energy security, Black Start and other capabilities at the same time, indeed they do so concurrently with the same plants; therefore Net Zero technologies must do all these too: otherwise the energy transition will be unaffordable, unreliable and fragile which will lose both public and political support for it.



Source: Future Energy Scenarios 2022

The British grid's carbon intensity is shown in FES 2022 (but ignored this year) to be decreasing fast – though it increased recently, hopefully a brief up-tick. However, that is utter complacency, supported by fitting a straight line as a trend (the red dotted lines): the true trend (orange solid line) is an S shape, which would show that the grid's carbon intensity largely levelled out from 2019 and shows little sign of further improvement, as shown by the inset graph which flat-lines over the last two years. Indeed, without sufficient large-scale, long-duration, naturally inertial storage, and the regulatory and contractual arrangements to encourage it, little further improvement is achievable. This calls into question whether any of the scenarios, on

business as usual, will even come close to Net Zero as it questions whether the power sector would decarbonise at all, let alone by 2035.

Contents

Decarbonising Electricity by 2035

Government and Grid are focused on decarbonising electricity by 2035. That is 12 years away. A new grid connection takes that long, plus the time to design, finance, get permits for, win contracts for, and commission the plant. So this ostensibly laudable target means that nothing can be done that doesn't have an existing or in-progress grid connection, trying to deliver a 2050 electricity system on a 1950 grid design.

Because government, Grid and Ofgem have spent a decade focusing on the "low-hanging fruit" and "quick wins" of the energy storage, without concurrently addressing the major challenges, we have a patched-together hotch-potch of quick fixes that is increasingly unaffordable, unreliable and fragile.

The Technology Innovation Needs Assessment (TINA)[8] said in 2012 that the country needs (by 2050) up to 59.2GW of storage with an average duration of 5 hours – and by 2020, up to 17.1GW of average 4.85 hours duration. Ever since then, the essential role that long-duration energy storage (LDES) must play in the grid has been recognised although little has been done to satisfy that need: not a single MW of 5-hour storage has been built since then. The principal reasons for this inaction has been the obsessive mis-quotation of a footnote in an Imperial College analysis that same year, for which see the section Energy Storage and Flexibility, below.

The result is that the need for LDES has grown greatly in both scale and duration, yet still none has been built, the markets are inappropriate to incentivise its construction, and regulations prevent its most effective means of deployment.

Moreover, this only considers LDES as providing flexibility and energy security. It ignores the need for natural inertia and its consequential ancillary, flexibility, resilience, power quality and Black Start capabilities[9], all of which naturally inertial LDES can provide as by-products. For lack of synchronous LDES, their costs are rising exponentially too[10]. But such storage (mainly pumped hydro and CAES; liquid air also does it, with shorter durations and lower efficiency, but without the same topographical or geological constraints) has long lead times. Sufficient cannot be built by 2035, least of all in its most effective deployment locations – between large-

[8] https://www.carbontrust.com/our-work-and-impact/guides-reports-and-tools/tinas-examining-the-potential-of-low-carbon-technologies – see Part D report, chart 2, p9. Ignore the breakdown of technologies that was guessed to fulfil the need: look at the totals. For duration, divide GWh by GW.

[9] https://storelectric.com/grid-stability-and-power-quality-challenges/ for some of them; https://storelectric.com/re-starting-net-zero-grids/ for Black Start.

[10] https://storelectric.com/challenges-of-the-electricity-transition/

scale renewable generation and the grid[11]. Yet this is what is needed to save trillions[12] and make the energy transition affordable, reliable and resilient.

The current regulatory system and market design are so poor that the author is unaware of any other than Storelectric's that can profit without subsidy in them.

Fuel Switching – Carbon Trading

The Fuel Switching section deals with transportation, heating and carbon trading. Transportation and heating (see Hydrogen) are considered elsewhere.

Carbon trading (p63) does not address the need to price emissions according to their societal costs, and to extend such charges to fuels for domestic and commercial use. Unless and until that is done, there will not be a level playing-field between clean energy and dirty, and clean energy will always need regulatory preferences and financial support of some kind. Moreover, there are many tax credits for aspects of dirty energy, such as oil exploration and extraction, which need to be removed. If the playing-field is levelled in this way, regulations can be neutral and no financial support is needed.

The simplest and most rigorous way of doing this is with an Emissions Added Tax, operating like a Value Added Tax, which also allows credits and charging at borders in order to level the playing-field between domestic and overseas supply. This is analysed in further detail elsewhere[13].

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[11] https://storelectric.com/saving-billions-on-grid-upgrades-jan23/

[12] https://storelectric.com/saving-trillions-in-the-energy-transition/, following the links for more details.

[13] https://storelectric.com/incentivising-clean-energy/

The Energy Consumer

Many of the changes listed are indeed required, and some more: it doesn't list a change for non-business drivers to renewably powered vehicles.

Electricity Demand Overview

The FES 2023 analysis has substantial shortfalls and omissions. In summary, its analysis of the many sources of demand:

- Under-estimates future energy demand:
  - Until recently the grid accounted for ~¼ of all UK energy use, with the remainder being used by heating, transportation, industry and other sectors:
    - Heating will be decarbonised largely by hydrogen (electrolysed using electricity, or chemically formed using electricity) and heat pumps (electricity);
    - Transportation will be decarbonised largely by electrification and fuel cells (hydrogen, as above);
    - Industry will be decarbonised largely by electrification, hydrogen heating and hydrogen processes;
    - Therefore electricity will rise to 75-90% of basic energy supply.
  - NG recognises the efficiencies of electricity use (e.g. 4x more efficient vehicle transmissions) without recognising the inefficiencies up-stream (e.g. of storage or electrolysis) or increased utilisation (mileage has consistently risen, even if total transportation fuel consumption has not due to improving vehicle efficiency; with the after-effects of the Coronavirus, an increasing proportion of transportation is personal vehicles, with decreasing public transport usage).
  - But every sector considered under-states future demand; for example:
    - Consumers are assumed to be unreasonably "prosumers";
    - Digitalisation is assumed to be energy-free;
    - Domestic heating rests on highly questionable assumptions of up-take (constrained by space, as much as anything) and efficiency, and ignores that below certain temperatures heat pumps become progressively less efficient until they stop working;
    - Transportation relies on excessive EV up-take beyond what the planet's resources can support, assumes at least 6x over-optimistic V2G support, and ignores ~30% system inefficiencies;
    - Industrial and Commercial demand concentrates on making plants and processes more efficient but totally ignores the electricity and hydrogen used in creating environmentally friendly fuels, feedstock materials and hydrogen substitution in processes such as iron and steel making.

Throughout FES 2023 there is little recognition that energy demand in 2021 and 2022 was distorted temporarily by the pandemic and then the Ukraine war. Trends must compensate for these, and more-or-less-rapid reversions to norm, if it is to be

credible. Instead, it appears to take 2021 and 2022 demand as part of an ongoing trend, p72.

Demand for Hydrogen and Synthetic Fuels / Chemicals

This analysis of system demand is totally inadequate. "*It does not cover additional demand for upstream primary energy sources or the conversion losses associated with production of some of these fuels, such as hydrogen*." (p66):

- This includes not only hydrogen, but other products for which both hydrogen and electricity is needed, e.g. synthetic:
  - Ammonia (both as a fuel for shipping and as a chemical feedstock),
  - Other chemicals (e.g. methanol),
  - E-fuels, for aviation and other specialist applications.
- Until recently, natural gas provided about half of energy demand, and liquid fuels another quarter.
  - Although electricity is likely to grow in proportion from a quarter to over a half, the residual is a very major exclusion.
  - As all of these are to be powered mostly by renewable electricity, with substantial inefficiencies in the synthesis processes, correcting this omission would more than double total electricity demand.
- Generation would have to more than double.
  - This pushes renewables into harder-to-connect and -build locations.
  - Other energy sources cannot greatly increase, e.g. biomass owing to a lack of fuel, and nuclear owing to a limitation on the rate of construction of power stations; so renewables would have to make up the difference.
- Transmission and distribution would have to more than double.
  - Reinforcing the grid already costs £3bn per GW new offshore wind[14].
  - The same analysis done just two years before suggested that the reinforcement cost was £1.75bn per GW[15].
  - The cost per GW is therefore growing exponentially as the energy transition progresses, due to insufficient long-duration energy storage (LDES), its unsuitable locations and the regulatory system and market design that make it this way.
- System operation would become much dearer, already over £8bn more (i.e. over 14 times more) in 2021-22 than just three years earlier, and increasing at an exponential rate[16].

Although heat pumps are 6x more efficient than hydrogen heating (see Hydrogen), two of the scenarios have huge amounts of the latter. Nonetheless, FES correctly notes that "*Based on the current environment and outlook, heat pump annual installation rates do not meet the Government's 600,000 per year target by 2028*"

14 https://storelectric.com/saving-billions-on-grid-upgrades-jan23/

15 https://storelectric.com/saving-billions-on-grid-upgrades/

16 https://storelectric.com/challenges-of-the-electricity-transition/

p69. This would put even greater reliance on hydrogen, magnifying the above issues.

Residential Consumers

One constant over recent years is "Residential consumers will need to start engaging with Time of Use Tariffs and forms of smart control and automation of energy consumption…" (FES 2022). On bills forecast in 2021 to rise eventually to £2,800 p.a., the potential savings that they advertise are £75, or 2.7%. (Bills are much costlier now, but are coming down again towards such figures.) Few will maximise those benefits. Many (e.g. those with health and mobility issues) have little opportunity to flex their usage. Of the remainder, those able to engage actively will be earning sufficient for £75 p.a. to be minimal incentive, especially in relation to the time they would spend each year doing so. Therefore the only realistic way of doing so would be to engage automated services that would charge less than one-third of the savings, to manage their demand without continual consumer input; FES 2023 correctly assumes that "automation optimises energy use for residential consumers in the background."

If one such service were to become very popular, or (as would be reasonably expected) many such services operate at roughly-correlated times, then it would create problems of its own as it switches large amounts of demand. Diverse services would produce correlated actions because they are trying to optimise demand based on identical market signals.

Turning down thermostats by half and one degree does indeed provide a step change in energy efficiency where it is done (Fig EC.07, p79), but it's magical thinking that such changes would happen in all locations in a single year, rather than gradually spreading through society over a number of years. The end-points on the "cumulative savings" graphs would be the same, but intermediate points lower.

FES 2023 is entirely correct in warning again (p81) that uptake of heat pumps is off track for what is needed, especially as they use one-sixth of the energy of hydrogen.

Industrial and Commercial Consumers

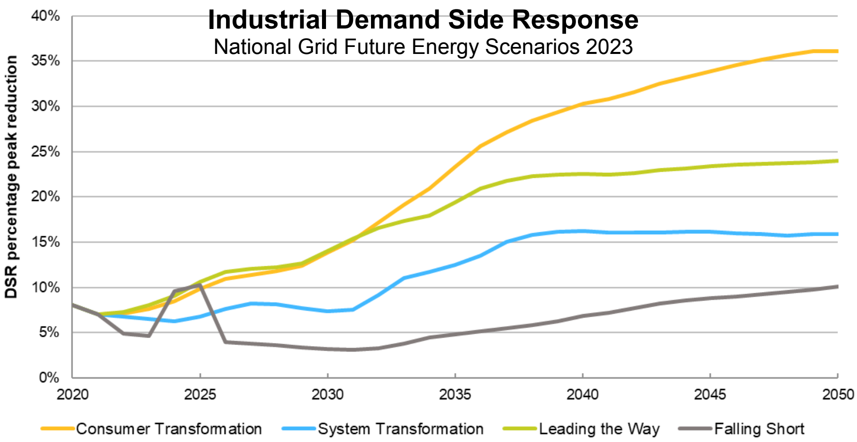
The big change this year is that "*fuel switching to hydrogen may take place further and faster than previously thought*" p70, which magnifies the issues involve with omitting the inefficiencies of hydrogen and its products, and the energy supply to make them. This applies mostly to two scenarios, and to industrial rather than commercial (p90-94) but, as noted elsewhere, the system loads for electrolysis and fuel / chemical synthesis are huge but ignored.

"*Some industrial consumers may need to re-locate in some scenarios to areas with hydrogen or Carbon Capture, Usage and Storage (CCUS) technology available to enable them to decarbonise*" (FES 2022). This is entirely correct, and the government needs carefully to consider the incentives necessary for doing so. The

best incentive would be an Emissions Added Tax[17], combined with one-off assistance with relocation. This is much less explicit in FES 2023, which only alludes to it: “*Industrial cluster locations for Carbon Capture Usage and Storage and hydrogen need to be carefully considered to maximise use of existing network infrastructure and avoid exacerbating system constraints*.” FES is therefore avoiding any discussion of the difficult consequences of the Net Zero energy transition, and ways in which it should and should not be regulated and managed.

FES 2022 correctly drew attention to the seven Zero Carbon Energy Clusters around the country – FES 2023 barely mentions them. Unfortunately the agendas of many of these have been deflected by the hydrocarbon lobby into blue hydrogen and CCS, which is not sustainable, discussed elsewhere in this document. But they do support the transition of local industrial and residential consumers to hydrogen and electricity, so are very beneficial, just not as beneficial as they should be.

As last year, the energy transition, as mapped by industrial sector, has curious de-emphasis of hydrogen even though that will be the principal way of decarbonising iron, steel and some other sectors. For example, electric arc furnaces using electrolysed hydrogen (rather than coal) as a reducing agent can be totally emissions-free. Some other chemical pathways will be replaceable with ones involving hydrogen and, for most applications, high-temperature heat will be from that source.



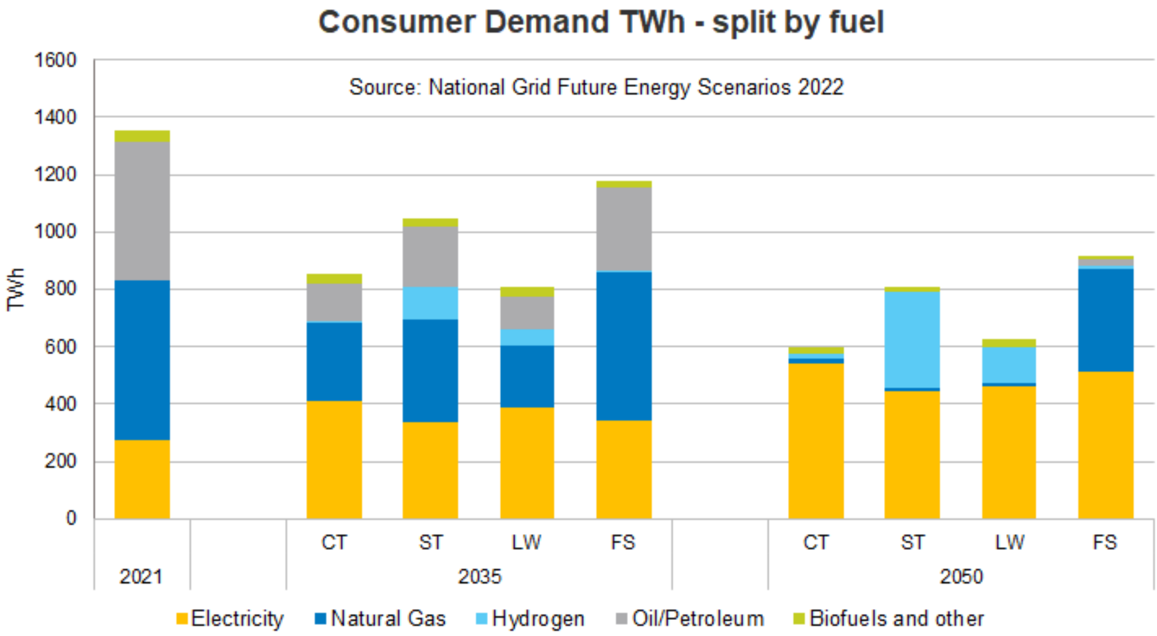
Industrial demand-side response is assumed to be very high. Yes, processes that use a lot of electricity can provide enormous amounts of DSR, but National Grid fails to realise that, beyond low levels of DSR, industry would have to stop in order to provide it. That involves employing people for overtime to do the work that they didn’t do while they were being paid to be idle; it requires changing (not just once, but constantly) shift patterns including paying for additional shifts at premium cost, it disrupts output and requires large buffer stocks, and it greatly reduces maximum plant capacity. So such large industrial DSR is not economically practical.

[17] https://www.storelectric.com/incentivising-clean-energy/

Data Centre Demand

It is curious how demand for energy for data centres varies by so much per scenario: by 2050. 5TWh for FS, 10TWh for ST, 15TWhfor CT and 20TWh for LW; and over 80% of that demand will have materialised by 2035. Surely, the amount of data centre consumption depends on things other than energy scenarios, and should be similar. Therefore a single demand figure should be chosen. This variation distorts the demand curve for each scenario and, consequently, the supply mix. However the percentage effects of this error are small (<2%) in comparison with total annual demand.

Consumer Demand by Fuel Type



In conclusion to this analysis of consumers, National Grid forecasts the demand by fuel type as per this graph, which is shown differently for each of the four scenarios. Note that this includes the distortion for data centres, discussed briefly above.

They take demand as being the yellow bar at the bottom, which is a major error:

- ♦ Natural gas is unlikely to have such a large part to play, as CCS is impractical[18].
- ♦ Hydrogen will derive mostly from electrolysis, as again CCS is impractical.
- ♦ Oil / petroleum will have to be from synthetic fuels, derived from hydrogen.
- ♦ All electrolysis and synfuel production require lots of electricity, greatly increasing electricity demand – though substantial parts of it may be demand that is not seen by the grid as the conversion is done directly from renewables.

[18] https://www.storelectric.com/carbon-capture-use-and-storage-ccus-and-ccs/

- Electrolysis hates intermittency, as does fuel synthesis, so suitably-scaled storage benefits electrolysis and fuel synthesis[19], and so needs inserting into the process. This has efficiency implications: the efficiency of storage reduces it, but the improvement in electrolysis / synthesis efficiency and equipment cost/life will greatly help.
- Therefore the total energy bar will be taller, and even most of the natural gas, hydrogen and oil/petroleum parts are provided by electricity.

Apart from that, the extent of demand reduction in all scenarios stretches credulity and sounds more like wishful thinking:

- Residential natural gas demand is transformed into electricity (heat pumps) at an assumed 5:1 efficiency improvement. This may be true, strictly, but to deliver the heat as required will require heat storage (high efficiency) where people have sufficient space and electricity storage (lower efficiency) in the majority of homes and commercial premises where they don't. Therefore an efficiency factor needs inserting for storage.
- ST and LW scenarios have substantial hydrogen-fired boilers. While they conveniently re-use infrastructure and equipment from natural gas, the fuel will be much dearer in comparison with electricity, and therefore few will want to use it. Thermodynamically, it is a waste of hydrogen, one of the highest forms of energy, created laboriously with energy-intensive activities, to turn it into low-grade (i.e. not industrial temperatures) heat which is the lowest grade of energy. It's more efficient to avoid the intermediate step of electrolysis, and use the electricity directly in heat pumps.
- There appears to be no consideration of the fact that heat pump efficiency deteriorates with ambient temperature, falling to zero at about -8^{o}C. As that temperature is approached, there will be wholesale switch-over from heat pumps to direct electric heating. Although this is likely to be infrequent enough to have little effect on total annual demand, it is likely to provide a spike in demand during the highest demand periods of winter. Unless it is planned for, and generation, storage and grid capacity provided for it, households and businesses around the country will either go without heating or crash the grid.

Digitalisation and Markets

Digitalisation (if you'll excuse the poor grammar: it's a mistake coined in Brussels for digitisation) is put forward as a panacea. As well as grossly over-estimating its benefits (see above, *Prosumers, the Majority, and Aggregators*), it is seen as a very broad panacea. But digitisation only optimises the energy in the system, with limited movements in location and time; it does not create new energy. If there isn't enough, there just isn't enough – however well it's optimised.

"To deliver higher levels of flexibility, we need sharper market signals to incentivise the right outcomes." Correct. So why are the ministry, regulator and grid operators so focused on destroying market signals?

[19] https://www.storelectric.com/wp-content/uploads/2023/07/Hydrogen-and-CAES.pdf

- The cost of electricity is an ever-decreasing ~20% share of the price of electricity[20] – wholesale costs are ~30%, but these are themselves made up of both generation costs and further levies and charges;
- Price caps on consumer bills reduce market signals;
- Promoting ever more extreme forms of DSR and V2G, and salami-slicing that incentivises narrowly capable plants like batteries, creams off the higher-value revenue streams that are needed to pay for longer-duration storage, and therefore increases total system costs because the longer-duration storage is still needed and so must put up its prices for what these other sources cannot provide;
- Short-duration contracts prevent new plants being built, as only sweated assets can compete.

What the Digitalisation Strategy Addresses

The government's digitalisation strategy addresses the publication and exchange of data between the major players in the market, proposing to set standards for both publication amount and the structuring and formatting of such data to enable the players to exchange it. This is supposed to enable distributed resources to support system needs, such as Demand Side Response (DSR), Vehicle to Grid (V2G) and both trading and aggregation of distributed/domestic resources (which is part of DSR). In theory it will address issues such as getting the greatest benefits from SmartMeters (though doesn't address why they can only trade on half-hourly resolution) and trading/dispatching such resources.

What the Digitalisation Strategy Does Not Address

This strategy does not address matters such as:

- Trading energy: the strategy is about publishing and exchanging data, not about enabling digital trading;
- Ability to trade "energy plus", e.g. plus dispatchability, inertia etc.;
- Energy cost per transaction –
  - Varies from over 885kWh/transaction for Bitcoin and 102kWh/transaction for Etherium to 0.00017kWh/transaction for Hedera-based tokens,
  - "The growing energy consumption and associated carbon emission of Bitcoin mining could potentially undermine global sustainable efforts … the annual energy consumption of the Bitcoin blockchain in China is expected to peak in 2024 … this emission output would exceed the total annualized greenhouse gas emission output of the Czech Republic and Qatar" – ignoring all other currencies, and all other countries[21];
- Capacity of number and rate of transactions;
- Interoperability of different trading platforms;

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[20] https://www.ofgem.gov.uk/energy-advice-households/costs-your-energy-bill

[21] https://www.nature.com/articles/s41467-021-22256-3

- Ability of a single installation to trade seamlessly at multiple levels, e.g. a micro-grid trading both peer-to-peer and with the grid for Demand Side Response;
- Basing trading on energy and services provided, rather than on a currency –
  - The latter fluctuates in value with the value of the currency, providing enormous commercial risk, which needs offsetting by increasing prices, and some systems may contract for a certain value of energy which may deliver variable amounts of energy,
  - The former is a firm commitment as to what will be delivered to / purchased from the system/trader/provider;
- Ability for distributed creation of digital mirrors of physical capacity/capability –
  - Each plant will need to make its own capability available when it'll be available, and to withdraw capability for planned down-time,
  - Doing this centrally would be a huge, slow and unresponsive bureaucratic task that would limit the number (and hence lower limit of size) of transactions.

Transportation

Resource Sufficiency for EVs

All scenarios (p57-59) envisage about 35-40 million EVs in the UK (though p86 peaks at 31-32 milllion). An average EV battery uses "*about 8 kilograms of lithium, 14 kilograms of cobalt, and 20 kilograms of manganese, although this can often be much more depending on the battery size – a Tesla Model S' battery, for example, contains around 62.6 kg (138 pounds) of lithium*."[22] This is just for the battery, ignoring the rest of the vehicle. And they use rare-earth metals too: 0.2kg neodymium and 0.03kg dysprosium being the main ones[23]. Using 35M vehicles, and based on the fact that the UK's population is 0.8% of the world's (thereby allowing the developing world to develop), assuming that average vehicle life is 10 years, and conservative metal-weights per vehicle, this yields the following table:

	Kg / EV	Tonnes (UK) p.a.	Tonnes (world) p.a.	World output 2021 (T)
Lithium	8	28,000	3,500,000	115,300
Cobalt	14	49,000	6,125,000	131,000
Manganese	20	70,000	8,780,000	20,000,000
Neodymium	0.2	700	87,800	Rare earth
Dysprosium	0.03	105	13,125	Rare earth
	Total rare-earth production (all 14 metals) globally 2021: 210,000 tonnes			
	Note: this assumes an average vehicle life of 10 years.			

All these metals have many other uses, for example lithium in lightweight alloys, and all of them in batteries used in other equipment such as grids, portable devices, aviation, shipping, uninterruptible / back-up power supplies and other static devices. Purely from the viewpoint of resource availability, such targets are clearly not tenable.

Such data are often met with the claim that other battery chemistries are being developed. But lithium has an atomic weight of 3, by far the lightest metal. EV batteries already weigh between half and one tonne[24]; van, lorry and bus batteries would be many times heavier. Moreover, other chemistries do not match lithium's energy density per unit volume either, making batteries much larger. So the only viable alternative is hydrogen fuel cells.

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22 https://blog.evbox.com/ev-battery-weight

23 https://www.esru.strath.ac.uk/EandE/Web_sites/17-18/paradigmev/rare-earth-elements.html

24 https://blog.evbox.com/uk-en/ev-battery-weight

Other EV Considerations

In all scenarios, transportation consumes 56-67GWh per annum by 2050 (data table ED1), a dramatic reduction since last year's forecast of around 100TWh, without explanation. The estimates this year are also greatly at odds with the expectation that vehicle-to-grid flexibility could be as high as 20GW (data table FL.04).

Battery EVs also have a number of major problems, some of which have no technical fix and others whose fix would be prohibitively expensive. These include:

1. **Grid Reinforcement:** All the EV chargers would require tripling (at least – maybe up to 6x reinforcement) of every single level of the grid from the domestic connection through to the transmission grid, and all transformers and substations in between.
   - And the rush hour (large numbers wanting to use and/or charge their vehicles at the same time) would have to be stopped.
2. **Charging:** 40% of homes (principally poorer ones) don't have any dedicated parking spaces, and more have insufficient for their vehicles:
   - People will not want to walk substantial distances to find their vehicles;
   - Centralised parking/charging would take enormous public investment, and require the construction of large centralised facilities;
   - Public and commercial charging will always be more expensive than domestic;
   - Vehicle-to-grid electricity storage (V2G) won't work when vehicles cannot be left permanently connected;
   - Shared mobility would increase mileage substantially owing to empty journeys;
   - All this would reinforce rather than reduce wealth discrepancies.
3. **Weight and Distance:** It's inappropriate for heavy vehicles (insufficient power density per unit weight and volume) or for more heavily used vehicles (long re-charging times), for both of which hydrogen / fuel cells are better:
   - Energy density of lithium-ion batteries is only 1% of that of petrol or diesel;
   - Re-fuelling hydrogen vehicles will take little longer than petrol or diesel, whereas re-fuelling electric vehicles takes much longer;
   - Fast-charging greatly reduces battery life and places enormous stress on the electricity system supplying the charger, in turn requiring yet more local storage – and refer back to resource insufficiency above.
4. **Efficiency:** there is great emphasis on the efficiency of batteries in vehicles, and none on the inefficiencies of batteries themselves[25]; while this link looks at grid-connected batteries (and therefore apply to charge-point connected batteries), its considerations in fundamental efficiency and its lifetime deterioration remain valid for vehicles.

[25] https://www.storelectric.com/batteries-expensive-and-inadequate-solutions/

5. **Resource Sufficiency:** There isn't enough lithium in the earth's crust for all the vehicles of the world[26], even less cobalt and even less rare-earth metals. 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[27]. Electrifying just British cars "would require production of just under two times the current total annual world cobalt production, nearly the entire world production of neodymium, three quarters the world's lithium production and at least half of the world's copper production" according to leading scientists[28].
6. **Other vehicles:** The above comments all ignore:
    - Vans, buses and lorries;
    - Use of batteries in electricity systems, houses, portable and remote devices, or other applications such as aviation, shipping, rail etc.;
    - The short life and poor recyclability of batteries; or
    - Any of these considerations in any other country – there is sufficient lithium (ignoring the other metals, many of which are scarcer) for just 77% of cars world-wide[29], ignoring all other uses and considerations.

These are all dealt with in detail in the blog Electric Versus Fuel Cell Vehicles[30].

Autonomous Vehicles

All scenarios envisage a substantial reduction in the number of EVs as autonomous vehicles (AVs) are introduced in the 2040s. This is assumed to reduce EV electricity consumption, whereas it is more likely to have the opposite effect.

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[26] There is sufficient recoverable lithium in the world to power only 77% of vehicles by 2080, ignoring any use of lithium for the electricity sector (which uses three time as much energy as transportation, including gas as it will be replaced by both P2G and electrification), portable devices and other uses https://www.researchgate.net/publication/264854684_Lithium_Resources_and_Production_Critical_Assessment_and_Global_Projections.

[27] https://www.economist.com/news/briefing/21726069-no-need-subsidies-higher-volumes-and-better-chemistry-are-causing-costs-plummet-after (noting that "vehicles" primarily means cars, not vans, buses or lorries) -

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

[28] https://www.greencarcongress.com/2019/06/20190624-uk.html

[29] https://www.mdpi.com/2075-163X/2/1/65/pdf

[30] https://www.storelectric.com/electric-versus-fuel-cell-vehicles/

If people A, B and C need to go to locations D, E and F respectively, if they own their own vehicles there are three journeys: A-D, B-E and C-F. If they don't and are carried by a single AV without lift-sharing, there are twice as many journeys: A-D-B-E-C-F-next pickup. If there are time gaps between journeys, there will be additional trips to and from parking. Optimisation algorithms should mean that this does not double the mileage, but in any conceivable case, the mileage and hence energy consumption is increased. Moreover, road congestion will increase greatly: though partly alleviated by the ability of Avs to drive closer together without accident, they also need to take account of the fact that they share the road with many non-AVs.

The typical response to that is that there will be widespread lift-sharing. This does not happen today for various reasons, e.g. worries about

- Sharing a confined space with a stranger for a long time;
- Letting that stranger know where you live and work;
- Being constrained in coming-and-going times;
- Having to plan well ahead and organise one's activities around the times of the shared transport;
- Longer journey times for pick-ups, drop-offs and related detours.

EV Efficiency

It appears that the V2G proposals assume 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[31], which has to be applied twice – once for charging and once for discharging. The total round-trip efficiency is therefore 0.85 x 0.9 x 0.9 = 0.6885 or 69% round trip, or about the same as large-scale long-duration storage.

Efficiency also needs to be apply to fuel cell vehicles because of the inefficiencies of electrolysis (and other means of making hydrogen), the energy consumed in hydrogen distribution, and leakage/seepage at any point from hydrogen plant through distribution to fuelling and vehicles.

Smart Charging

The Scenarios include astronomical estimates (p87) of reductions in peak loads due to charging EVs smartly via smart meters. However, as noted, 40% of homes don't have parking spaces; many of the remainder don't have enough – and those that do cannot be expected to have a charger for each vehicle. Vehicles on public chargers are penalised for remaining connected for long. Vehicles not connected cannot provide smart services; and having to charge multiple vehicles from fewer chargers would reduce the amount of temporal flexibility that the owners have. All these reduce the extent of the benefit from smart charging.

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

This benefit is also a system-wide disadvantage as it reduces price volatility on which the system relies to provide financial returns on storage. Therefore, unless there are new storage-specific revenue streams, the storage will not be built.

It is interesting that, although FES does not anticipate that all cars need charging daily, reduction in peak demand could be as high as two-thirds. This means that the potential aggregated MW demand for EVs is twice peak demand for all other uses (except, as noted elsewhere, for the hydrogen economy which FES ignores). This emphasises how big an effect EVs will have on the need for network build-out, and raises questions as to whether sufficient energy demand is allocated to EVs.

Vehicle to Grid

FES 2023 depends on 8-14GW smart charging plus 4-20GW Vehicle to Grid (V2G) storage (p186), totalling 12-34GW flexiblity. This is much lower, and therefore better, than previous FES analyses, though it omits any consideration of duration or GWh. It also remains too high, as the following analysis shows. This reduction can only because they accepted at least some of the limitations of V2G; for example,

1. All the cars in most developed countries, if turned into EVs that are 100% used for grid-connected storage, would account for only a part of the storage needs – they consume similar amounts of energy to the entire electricity grid, with only a 2-4-hour range, only half of which at most (if the system works flawlessly) would be available to the grid. Therefore it lacks the duration to provide true back-up for renewables.
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.
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. Only a minority of vehicles will have dedicated charging, due to the number of homes without enough dedicated parking spaces for the number of vehicles they have.

Analysing this roughly,

- Vehicles will be at different states of charge, so assume 50% charged.
- Travelling capacity will need to remain in the vehicle, so halve that to 25%.
- Over its life, it loses ~20% of capacity, so average battery capacity is reduced by 10%, cutting the available amount to 22.5%.
- We can assume that no more than about ⅓ of such vehicles are left in personal parking spots attached to personal chargers overnight, so the capacity available to the grid is only ~7.5% of total EV battery capacity.
- Applying the 69% round trip efficiency, this drops to 5.2%.

- A typical car battery has 50kWh capacity[32], and there are ~30 million on the road in the UK, so available storage capacity is 7.76GWh for the highest-EV scenarios.
- Comparing this with the 34GW flexibility required in the highest-EV scenarios shows that this amount of flexibility can only be provided for under 14 minutes. As National grid will want to shift over at least an hour, this means that they have over-estimated the flexibility GW by at least a factor of 4.

Then this needs to be compared with the need: after sunset on a windless winter evening the country today consumes ~42GW x 5 hours = 210GWh, forecast by National Grid[33] to double by 2050.

And don't forget that all this consumes battery life.

Therefore the benefits of load shifting (smart charging, i.e. changing the time at which batteries are charged, again only available for the minority of vehicles being charged in private spaces on dedicated chargers) is their greatest benefit to the grid, with V2G (the ability to put charge back into the grid) a secondary benefit confined to smoothing small peaks in demand.

An Optimal and Workable Mix

Large-scale long-duration storage is much more cost-effective than using EVs for either load shifting or V2G. The other draw-backs of EVs far outweigh any advantages for the majority of vehicles – the ⅔ which are heavier duty and/or more intensively used, which may account for over 90% of mileage driven. However, this will also reduce the V2G flexibility by ⅔ again.

Therefore EVs are best suited for short-distance light-use applications.

And both money and effort need to be devoted to developing and commercialising non-PEM electrolysis technologies, and rolling out hydrogen fuelling points to filling stations everywhere.

Independent analyses of battery versus hydrogen-fuel-cell EVs are available[34].

Rail, Aviation and Shipping

Decarbonisation of these sectors is discussed (p78) only in relation to emissions. There is no recognition that the processes of creating the synthetic fuels will require renewable energy, which is therefore not accounted for in any of the scenarios.

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32 Example car battery sizes: Tesla Model S 75D is 75kWh; BMW i3 = 42kWh, Nissan Leaf = 40kWh, VW e-Golf = 36kWh, Ford Focus Electric = 33.5kWh

33 Future Energy Scenarios 2020

34 E.g. https://www.lexology.com/library/detail.aspx?g=1bf1cbf0-ac2f-4b39-a3de-2df77a9a515e and https://www.motorbiscuit.com/hydrogen-fuel-cells-vs-batteries/

Whole Energy System

The Putin Premium Is Not To Blame

The report p24 (FES in the Short Term) puts the blame for "the cost-of-living crisis, rising inflation and the spike in energy bills seen in 2022" on "recent global events" which led to sharp rises in wholesale energy prices, particularly of gas. But that ignores the fact that electricity prices did not drop much when gas prices reverted to approach historical norms[35]; and also that the cost of electricity accounts to less than 20% of its price.

In fact, the Putin Premium is only a small, short spike on a long-running exponential increase in whole-system costs. The rising trend is cause by:

- Poor and poorly implemented government strategy;
- Counter-productive regulations;
- Unfit-for-purpose energy market design;
- Insufficient LDES – in both scale and duration;
- Worsening shortage of natural inertia.

Synchronous LDES would solve these last two points, if the first three were addressed.

Electricity Supply Overview

The analysis is equally deficient in its analysis of electricity supply: it

- Relies on electricity imports during "times of system stress" (high demand and/or low renewable generation) when most of our neighbours are doing the same concurrently and won't have a surplus to share;
- Assumes nameplate capacity of all generation (baseload, dispatchable and intermittent), interconnectors and storage;
- Takes output rating of storage regardless of duration, when shorter-duration (sub-4-hour) storage would be exhausted well before the end of an evening peak during times of system stress;
- Over-states distributed and digital solutions' benefits, which merely redistribute the energy in the system, without ensuring that there is sufficient at all times;
- Does not appear to give full consideration of all aspects of biomass energy –
    - ◊ Bizarrely, the Energy Supply and Demand chart p14-18 suggests that most biomass energy goes to waste, not to electricity and other fuels, whereas most abated natural gas (and virtually all "other fuels") is "used" despite the enormous losses of abatement;

[35] https://www.thisismoney.co.uk/money/bills/article-12165447/Wholesale-energy-prices-fallen-46-gas-electricity-bills-high.html – Domestic prices are still double historical norms. Note also that in their pie chart "Breakdown of Dual Fuel Bill", wholesale prices are only 34.63% of bills, which ignore the fact that wholesale prices themselves comprise 60-80% system costs and only 20-40% energy costs: this yields a best case that energy costs are only 13.85% (34.63% x 40%) of energy prices.

- Fails to apply a supply margin, whereas grids world-wide consider a margin of 10-15% above peak worst-forecast demand to be a minimum acceptable;
- Therefore under-states the need for storage in general and large-scale, long-duration storage in particular.

Hydrogen Supply Overview

The power required to electrolyse hydrogen, or create hydrogen derivatives such as methanol and ammonia, or to power hydrogen-converted industries such as iron and steel, are excluded from the FES analysis. This is, in aggregate, probably about as much energy again as the electricity system. Yet they have huge consequences on the electricity system, including:

- Twice as much generation overall.
- As all generation potential other than solar and wind are already used up in the provisions for the electricity system, this means that wind and solar must roughly triple – as would their need for storage (but see next point).
- As all of these industries hate intermittency, these renewables will need a higher proportion of LDES than the wind and solar being used to power variable demand.
- As all the best and easiest generation sites are already used up in the provisions for the electricity system, this means that wind and solar must be located in more-difficult locations, and on more-saturated parts of the grid.
- Under current plans, this tripling of renewable generation would go through the grid, requiring the grid to be tripled in size even compared with the tripling (or more) required to deliver electricity demand.
  - The grid is already planning to have 280-370GW generation capacity, up from 115GW now (Fig. ES.09, p128).
  - At £3bn grid reinforcement per GW new renewable generation[36], this will cost £495-765m – yet that £3bn/GW is still growing very fast, so it could easily cost £1trn or more.
    - Plus 10% of that per annum for operation, maintenance, finance and amortisation.
    - Plus many more billions for system operation costs[37].
  - Adding the hydrogen economy, on current plans, would double this again.

The hydrogen economy hates intermittency because it:

- Reduces efficiency due to powering-up and -down;
- Reduces plant life for the same reason;
- Requires much more plant per unit of output – ignoring efficiency issues, compared with powering them by baseload electricity, powering them by…
  - 40% load factor offshore wind requires 2.5 times as much plant;
  - 17% load factor solar requires 6 times as much plant;
  - Curtailed electricity requires 10-20 times as much plant.

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[36] https://storelectric.com/saving-billions-on-grid-upgrades-jan23/

[37] https://storelectric.com/challenges-of-the-electricity-transition/

The only way to avoid this is to take the hydrogen economy largely off the electricity grid, by powering it directly from renewables and matched LDES of suitable scale and duration[38]. This must be incentivised, and urgently – such systems take years, often over a decade, to design, permit and build. It would cost billions, but with the right regulatory system and market design, will not add significantly to the cost of the energy system: after all, continuing fossil fuel investments also cost billions. And such a system design is likely to be the biggest single step towards making green hydrogen cost-effective in comparison with blue and even grey hydrogen[39].

Energy Supply and Demand

The analysis of overall energy supply and demand p109 shows that currently the country's 1763TWh annual demand consists:

- 18% electricity;
- 42% gas (including 6% that is used to generate electricity; the rest is gas demand and losses);
- 40% "other fuels", mainly oil and a little coal;
- 17% renewables, mostly feeding electricity.

This adds up to over 100% as other fuels are used to generate the electricity. Simplistically, demand is 1/5 electricity and 2/5 each of gas (excluding for electricity generation) and oil.

The Consumer Transformation image p110 almost totally ignores hydrogen for land transportation and industrial uses, which are likely to be its biggest uses. Correctly it sees hydrogen as being a major fuel for aviation and shipping, which is likely to be via e-fuels for aviation, and synthetic ammonia and/or methanol for shipping.

The electricity required for land transportation under this scenario is over 41% of today's entire electricity supply. Not only is this undeliverable without budget-busting increases in investment in grid infrastructure, but there aren't enough lithium, nickel, cadmium and rare-earth metals in the planet for such plans to be globalised; we can't economically or morally justify taking vastly more than our fair share. See Transportation elsewhere in this analysis.

System Transformation p111 is much more reasonable in terms of its split between electricity and hydrogen, though it foresees ⅔ of hydrogen coming from reforming methane, which is unlikely given the problems of CCS – see Whole Energy System, section Carbon Capture, Use and Storage (CCUS) and CCS. Leading the Way (p112) is much better overall.

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[38] https://storelectric.com/hydrogen-and-caes/

[39] Green: powered by renewables. Blue: derived from methane, with CCS. Grey: derived from methane without CCS. Pink: powered by nuclear, which provides baseload electricity. Black: derived from coal, a process which creates three times as much CO_2 from the chemical process alone.

Effects of Climate Change on the Electricity System

The effects of climate change on the electricity system appear not to have been considered at all[40]. This is a very serious deficiency.

On the supply side, power stations may be unable to operate due to insufficient cooling water. Batteries and power electronics (inverters etc.) decrease in efficiency, require substantially increased cooling and similar parasitic loads, and deteriorate faster as temperatures increase. Hydroelectricity and pumped hydro dry up in many places. But Storelectric's CAES only suffers ~1.5% efficiency penalty from increasing ambient temperature from 15^{o}C to 40^{o}C. The technology mix needs to be considered carefully.

At the same time, energy consumption shifts from heating (in winter) to cooling (in summer). Air conditioning is likely to be a major growth industry, with consequent increases in loads especially in cities and business parks. EV efficiency will change. Again, the technology mix needs to be considered carefully, as solar is mostly generated in summer and wind in winter.

Not only supply and demand, but also the network itself will be affected, as different equipment is optimised for different temperatures and humidities. Weather patterns will often be longer-lasting, whether for better or for worse, affecting different parts of the system in different ways. Bad-weather events will become more extreme, leading (for example) to network disruption and to shut-downs of wind farms while little solar is being generated.

Consequences

The result of such predictions, and of regulatory directions, about which Storelectric has repeatedly warned, has been the black-outs of 9th August 2019, numerous near-misses ever since, rocketing costs and complexity of balancing, stability and ancillary services, and a strategy to move faster and further down the same dead end.

The principal views and actions of government, regulator and grid operators have 7-year horizons (2030 is considered "long term", though it's less than the lead time for a new transmission grid connection and should therefore be considered short-term[41]), and are based on responding to demand. These two factors alone guarantee that the energy transition targets will be missed, and the energy transition itself will be unaffordably expensive and disruptive.

Costs of the Current Strategy

Referring to previous Storelectric studies, the current strategy costs:

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40 https://storelectric.com/water-heat-and-energy/

41 National Grid's Operability Strategy and DESNZ' (formerly BEIS') Review of Electricity Market Arrangements both targeted 2030 as being "strategic" planning.

- Over £3bn one-off plus £300m p.a. unnecessary grid reinforcement[42], and additional (not evaluated) cost of balancing and stability, **per GW** additional wind generation;
- ~£4bn excess BSUoS[43] charges (roughly, the cost of interventions by the Control Room, or non-energy costs of running the system day-to-day) in 2020-21 versus 2018-19, rising exponentially since intermittent renewables passed 16% of energy supplies[44];
- Excess reliance on batteries[45], of which many are needed to deliver the same services as same-sized large-scale long-duration inertial storage like ours, and moreover, for which there is insufficient elementary lithium, cobalt and rare-earth metals in the earth's crust – ignoring how much smaller a proportion of which is exploitable;
- Excess reliance on imports through interconnectors[46], which not only will not be available (see above), but also our neighbours will have a political imperative to cut us off during times of system stress;
- Excess costs and difficulty of building and integrating renewable generation[47];
- £328m for 6 years' synchronous compensation 2020-26[48] that would be much cheaper if procured from inertial storage with suitable cost-saving revenue stacks;
- Complete under-estimate of the need for storage[49], with
- Excess reliance on Vehicle to Grid (V2G) and shared mobility[50].
- In short, it subscribes to most of the fads and fallacies of the energy transition[51].
- And that's before we consider the cost of the hydrogen economy, above, which is likely to double or triple it all.

Energy Flows

The energy flow projections (p106) show a number of concerning features, such as:

1. Inadequate storage (see separate section below);

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42 https://storelectric.com/saving-billions-on-grid-upgrades-jan23/

43 BSUoS = Balancing Services Use of System; the costs of the network itself are recovered in a different charge, TNUoS = Transmission Network Use of System.

44 https://www.storelectric.com/challenges-of-the-electricity-transition/

45 https://www.storelectric.com/batteries-expensive-and-inadequate-solutions/

46 https://www.storelectric.com/interconnectors-and-imports/

47 https://www.storelectric.com/enabling-renewables-to-power-grids-affordably-reliably-and-resiliently/

48 https://www.current-news.co.uk/news/national-grid-eso-claims-world-first-approach-to-inertia-awarding-328m-in-contracts

49 https://www.storelectric.com/calculating-the-need-for-storage/

50 https://www.storelectric.com/vehicle-to-grid-and-shared-mobility/

51 https://www.storelectric.com/fads-and-fallacies-of-the-energy-transition/

2. No losses from electricity storage –
   - Losses should range from 30% to 50% depending on the technology,
   - These losses should be grid-to-grid lifetime-average, which would put batteries to the lower (i.e. greater losses) end of that range;
3. Inadequate electrolysis –
   - None at all for vehicles,
   - No conversion losses to synthetic fuels, e.g for aviation (complex hydrocarbons) or shipping (ammonia, or possibly methanol);
4. Inadequate storage of hydrogen which, elsewhere in the report, is considered to provide seasonal storage –
   - Inter-year storage is not considered, although year-on-year variation in renewable generation can vary by as much as 10-15%;
5. Inadequate losses from electrolysis –
   - Electrolysis is considered to derive largely from renewables,
   - Electrolysis does not perform well with intermittent power supply, so storage is needed to level it out[52];
6. Negligible losses from CCUS –
   - CCS with just 80% capture rate imposes a 25-45% inefficiency on any power station to which it's attached – and that's the theoretical losses: Boundary Dam is the only large power station with CCS, and its losses are worse for much lower capture rate,
   - No allowance of energy consumption for transportation, compression and storage of CO2;
   - Zero leakage rate assumed – though compare with global leakage rates of natural gas which are currently huge[53] but unquantified[54] globally, with Russia being the worst emitter[55] but America Permian Basin leaking 1.4%[56] of all methane produced.
7. No losses from methane reforming;
8. No CCUS in methane reforming, with consequent inefficiencies and losses (see CCUS with generation, above);
9. Excessive biomass, despite the lessons from Ukraine in which global food shortages are created at least in part due to the use of crops in biomass – in amounts that exceed the losses of Ukrainian grain for food[57].

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[52] https://www.storelectric.com/wp-content/uploads/2023/07/Hydrogen-and-CAES.pdf

[53] https://www.newscientist.com/article/2306715-satellite-images-show-biggest-methane-leaks-come-from-russia-and-us/

[54] https://www.bloomberg.com/features/2023-methane-leaks-natural-gas-energy-emissions-data/

[55] https://www.bloomberg.com/news/articles/2021-06-18/gazprom-admits-to-massive-methane-leaks#xj4y7vzkg

[56] https://earth.stanford.edu/news/methane-leaks-are-far-worse-estimates-least-new-mexico-theres-hope#gs.707wpi

[57] https://www.economist.com/graphic-detail/2023/06/23/most-of-the-worlds-grain-is-not-eaten-by-humans

- The heavy reliance on "biomass imports" in two scenarios (p166) is just saying "someone else's problem". This won't work: the shortage is global.

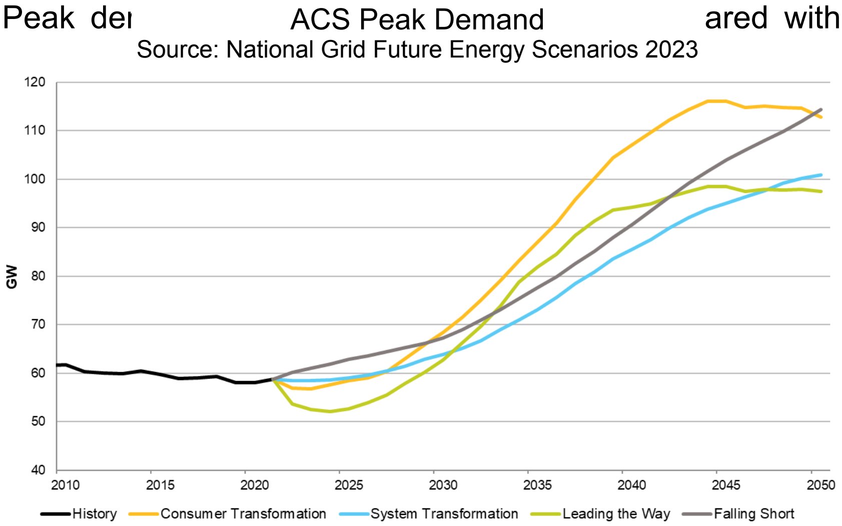
Overall Energy Demand

Overall energy demand p114 is a statistical whitewash. It shows interconnectors as exports. This ignores the fact that when we're short of electricity, we'll be seeking to import – mostly at the same time that neighbouring countries are also short of electricity and have none to export. Correspondingly, our times of export are likely to coincide with theirs, leaving our electricity nowhere to go. Interconnectors should never be a core part of the country's electricity plans. See Some Electricity Generation Technologies, Interconnectors.

Security of supply (p117) is ostensibly provided by dispatchable thermal power plants. But in every single scenario, the sum total of all power generation and all LDES is less than peak demand, meaning a reliance on imports through interconnectors. This remains the case even when demand response is added – and that is mostly short-duration and therefore not a solution. Moreover, unabated generation should not be used as it would require considerable offsetting by BECCS and DACS; and abated generation is not nearly as emissions-reducing or efficient as in these plans.

Peak Demand

Peak de ared with previous FES analyses, now approaching twice current peak demand; many independent forecasters predict that, with the energy transition of heating, transportation, industry and other sectors, it will be tripled.

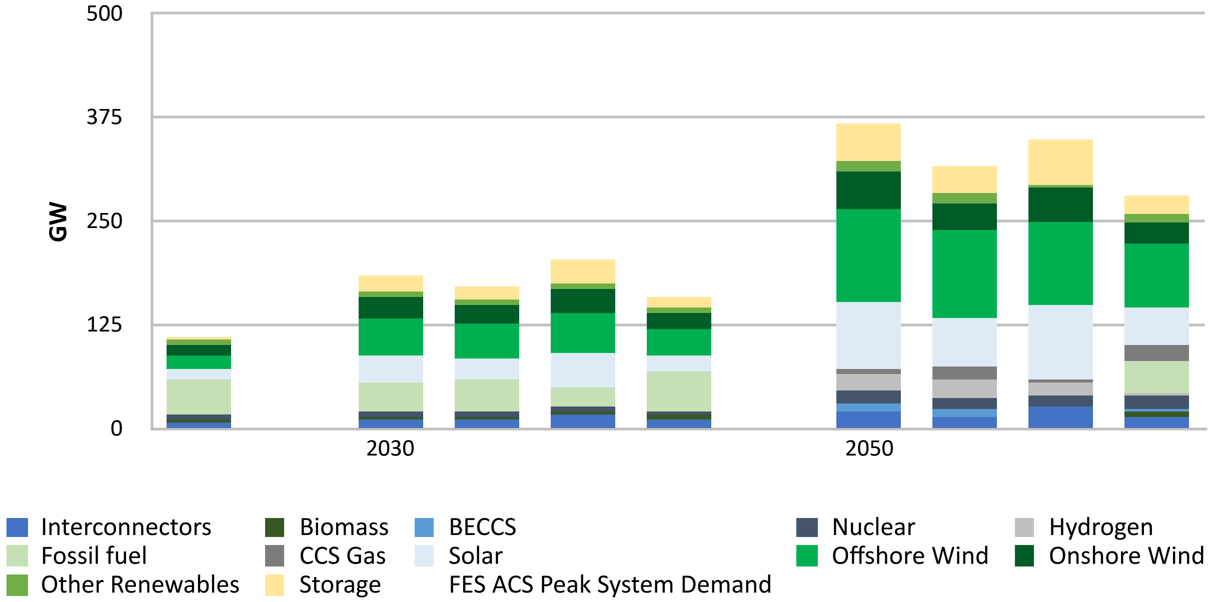


A Recipe for Widespread and Frequent Black-Outs

The mix of generation envisaged by National Grid in 2030 and 2050 is:

ES.10: Installed generation capacity, peak demand and percentage of decentralised generation capacity (GW)

The percentage shows the proportion of decentralised generation capacity.
Red diamond: ACS peak demand



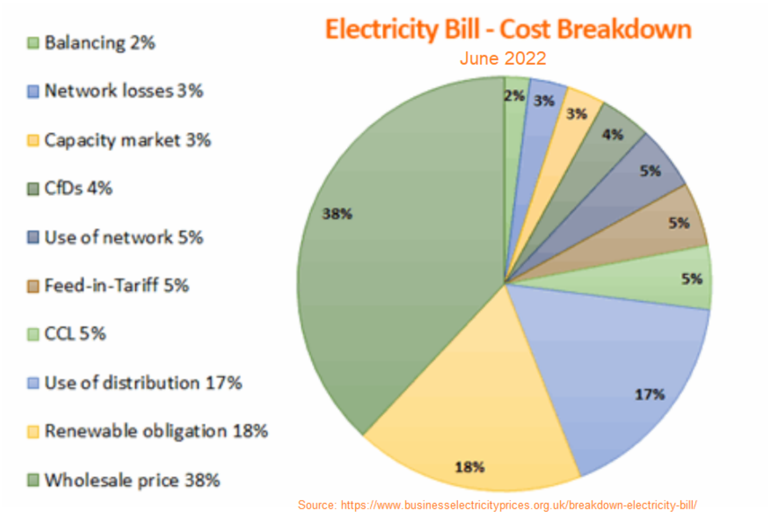
As with every FES for many years, this is a recipe for disaster, i.e. widespread and frequent black-outs:

1. Every scenario, over the entire period, relies on imports through interconnectors for actual electricity demand. They cannot be relied upon[58], as the Ukraine crisis proved: when our neighbours were short of (first) gas (then) electricity, they stopped flows into the UK and the interconnectors actually reversed their flows, leading to the UK having to engage in further multi-year contracts with coal-fired power stations.
2. Every scenario also relies on intermittent renewables for actual demand, whereas there will be frequent peak-demand times when renewables are collectively generating little or nothing. This is partially offset by storage, but nearly all the storage is short-duration and will therefore be exhausted well before the end of the evening peak in demand, not to mention overnight.
3. Gas CCUS is expensive and impractical.
4. Gas CCUS would require much more BECCS to offset (a) the inefficiencies of carbon capture in the power station and (b) emissions in the mining, refining and transportation of the gas.
5. If hydrogen is used for security of supply, then enough power station capacity is needed to replace all other insecure capacity: mostly interconnectors and intermittent generation.
6. The storage cited is all one "lump", in which case it all needs to be large-scale, long-duration; otherwise on a windless winter evening it would be exhausted by 6pm.
7. Having such high volumes of interconnectors, batteries, intermittent generation and decentralised (distribution-connected, or distributed) generation would need fantastic amounts of curtailment and payment for

[58] https://www.storelectric.com/interconnectors-and-imports/

naturally inertial plants to run throughout the year in order to provide some semblance of grid stability and resilience.

8. Such high percentages of distributed generation would add huge costs to the system: nearly all distributed systems rely on the grid for back-up, so the grid needs enough dispatchable capacity at all times to provide that back-up.
   - This means that above a certain level (to be determined), any distributed generation merely adds costs to the system: it would cannibalise the revenue streams of the transmission-connected generation which would then have to raise its prices to achieve economic viability.
   - This kind of cost increase is done all the time by National Grid, claiming that for services A, B and C they are procuring at best prices while other plants have to put up the prices of services X, Y and Z to compensate for the lost revenues.
   - This is why the cost of generating electricity is only about 20-25% of the electricity price, down from 75-80% a decade ago. In the pie chart[59], note that the wholesale price of electricity itself includes ~50% charges and levies on generation.



The Wrong Energy Mix

Every scenario shows too little solar generation in proportional to wind. In order to mirror seasonality of demand, five times as much wind is needed as compared with solar[60], in terms of energy output – the TWh graphs p125-127. Instead, the ratios are one solar to (wind):

- Consumer Transformation 9.1
- System Transformation 11.0
- Leading the Way 6.9
- Falling Short 11.0

Diverging from this 5:1 ratio requires increased LDES and/or generation, either of which increases the costs of the energy transition; and the increased generation either exceeds emissions targets (requiring offsetting negative emissions) or

[59] https://www.businesselectricityprices.org.uk/breakdown-electricity-bill/

[60] https://nottingham-repository.worktribe.com/index.php/output/19759244/short-medium-and-long-duration-energy-storage-in-a-100-renewable-electricity-grid-a-uk-case-study

consumes zero-carbon generation capacity and thereby reducing potential negative-emissions BECCs.

Low carbon dispatchable power (p135) is very high, because a majority is BECCS (for which feedstock is an issue) and hydrogen (which is expensive and has very low whole-system efficiency). The efficiency of the hydrogen generation cycle from renewables to hydrogen and back to the grid is currently mid-20s % efficient, realistically achievable mid-30s %; theoretical best low-40s %. This compares with LDES which is 60-75% efficient. This halving of efficiency requires a doubling of renewable generation to achieve it, and corresponding grid reinforcement. This efficiency is bearable when the alternative is power shortages, e.g. for seasonal storage. Where there are other alternatives such as LDES, those are much better.

Nuclear Generation

Nuclear generation (p137-141) is very helpful to the energy mix. About 60% of demand is baseload, and nuclear (including Small Modular Reactors, SMRs) is best operating at baseload: flexing its output is not only pure energy waste (it's done by absorbing the output in boron and/or graphite rods), but it costs money (those rods) and shortens the life of the plant – hence the maintenance problems of the French nuclear fleet, because they have been flexing their output for years.

Moreover, one MW of baseload electricity is equivalent to:

- ~3GW offshore wind plus ~3GW LDES;
- ~4GW onshore wind plus ~4GW LDES;
- ~6-10GW solar plus ~6-10GW LDES.

In the above equations, LDES must have over 2 weeks' duration to out-last the *kalte Dunkelflaute* – the most expensive and difficult form of LDES. Clearly, when viewed in this way, vast economies are to be made by matching baseload supply with baseload demand, and using intermittent supply for variable demand which would need much shorter-duration storage. This has knock-no benefits of disproportionately reducing the requirement for renewable generation and so greatly reducing whole-system costs. All these benefits would result from considering LDES as being necessary for the renewables, rather than (as per current thinking in the ministry, based on nothing more than marginal prices for generation) for renewables.

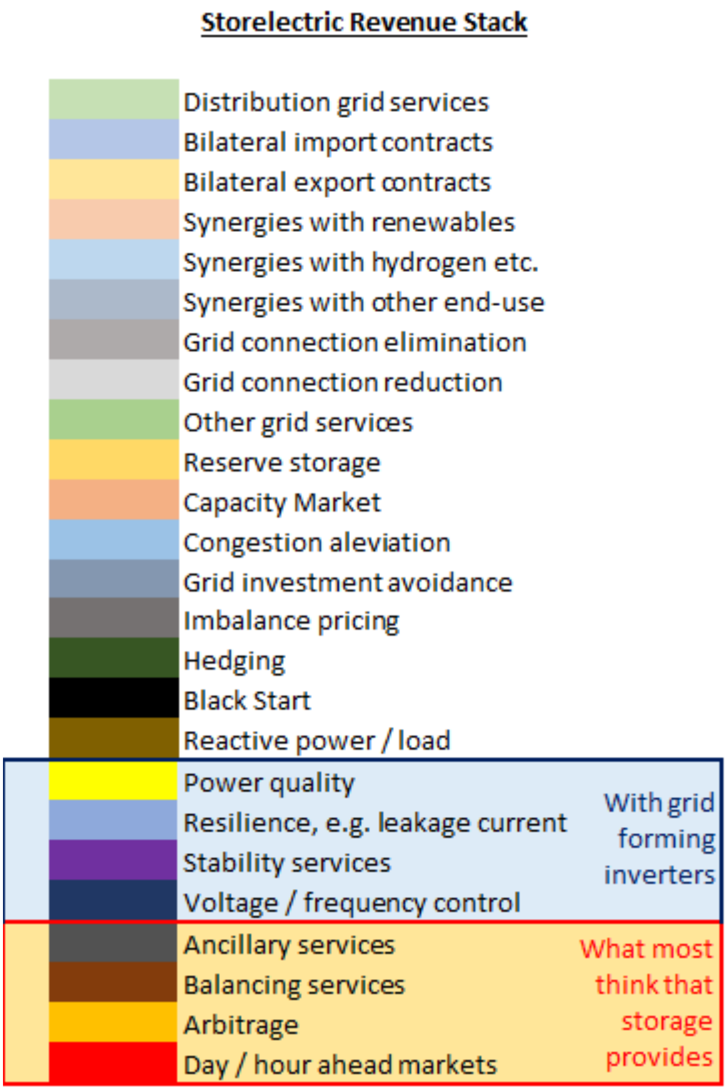
Distributed Generation and Revenue Stacks

National Grid, the ministry and the regulator consider dispatchable resources (p142-144) as entirely beneficial, reducing the load on transmission-connected resources and the transmission grid. This is largely fallacious.

Nearly all distributed resources depend on the grid for back-up. Therefore, regardless of the amount of distributed resources, the transmission grid needs enough generation, storage and grid network to power it all for when that back-up is needed. Distributed generation and storage can benefit the system and make it

cheaper, but only up to a limit: as soon as it starts to cannibalise the revenue streams required by the centralised resources.

The transmission-connected resources can do some necessary things that distributed ones cannot, and can do other things more efficiently and cost-effectively: all this is why the grid was created in the first place. All such assets need a given amount of revenue and profit to be built, maintained and operated. These revenues come from a variety of services that they provide, known as a revenue stack: Storelectric's is shown here.



As soon as distributed resources start to eat into the necessary revenue stack of transmission-connected resources, the latter must increase their prices for their unique services to compensate. This merely adds to the total cost of the system. So there is a threshold (to be calculated) above which additional distributed generation and storage merely add cost and not capability.

Dispatch Models: A Statistical Approach to Forecasting

Part of the problem is the grid's statistical approach to forecasting. Two aspects of this are their use of de-rating factors and of dispatch models for medium- and long-term forecasting.

De-rating factors[61] are assumed to be the output that a plant provides. They are not: they're an average between when it's producing 100% and when it's producing reduced amounts or nothing at all. When plants are all dispatchable, that difference doesn't matter. When most are intermittent, they can all fail at the same time, such as a windless winter evening – and, because such weather patterns cross frontiers,

[61] https://www.emrdeliverybody.com/CM/Capacity.aspx

Technology	Generic ALF
Biomass	49.5396%
CCGT_CHP	51.0635%
Coal	20.3859%
Gas_Oil	0.4602%
Hydro	41.8887%
Nuclear	75.8434%
Offshore_Wind	49.4981%
Onshore_Wind	36.0719%
Pumped_Storage	9.7926%
Tidal*	23.1000%
Wave*	2.9000%
Solar*	10.8000%

Source: National Grid ESO, figures for 2021-22

our neighbours will often be suffering the same shortfall at the same time, further increasing the problem of averages.

For different types of storage, the factors apply from the table below:

Name for technology class	Plant Types Included	De-rating factor (ECR 2018)
Storage by duration in hours for T-1 and T-4 auctions[26]	Conversion of imported electricity into a form of energy which can be stored and the re-conversion of the stored energy into electrical energy. Includes hydro Generating Units which form part of a Storage Facility (pumped storage), compressed air and battery storage technologies.	Dura'n: T-1: T-4: 0.5hrs 17.50% 14.91% 1.0hrs 34.21% 29.40% 1.5hrs 50.00% 43.57% 2.0hrs 62.80% 56.68% 2.5hrs 71.96% 66.82% 3.0hrs 78.09% 73.76% 3.5hrs 81.57% 77.78% 4.0hrs 95.52% 80.00% 4.5+hrs 95.52% 95.52%
DSR[27]		84.28%

nationalgridESO | Electricity Market Reform Delivery Body

From the same report, the de-rating factors for interconnectors are:

Table 10: Simulation results: 2022/23 imports as percentage of interconnector capacity

		FES						Stress 5%					
Country	**Historical**	**Average**	**BC**	**CR**	**TD**	**SP**	**CE**	**Average**	**BC**	**CR**	**TD**	**SP**	**CE**
Ireland	5	30	42	26	24	26	30	33	36	31	30	31	37
France	55	78	59	77	81	85	86	75	68	73	77	79	77
Belgium	67	56	36	55	57	67	65	42	35	39	43	44	49
Netherlands	70	47	27	41	45	62	57	34	28	31	33	39	40
Norway	96	98	100	98	98	98		92	92	93	93	90	

Interestingly, despite large amounts of fossil fuelled generation still remaining on the continent, the "stress 5% figures" (i.e. those during times of system stress) are all (except Ireland, which is a net demand during peak times) reduced compared with the average. This is a harbinger of us not being able to rely on them at all in future. The grid's fundamental duty is to provide sufficient electricity to meet at all times, so all capacities must be planned around the most stressed times unless blackouts will be tolerated.

Therefore any calculation of sufficiency of supply using nameplate capacities will yield inadequate results. Applying these figures to the above supply and demand table would yield even more worrying results.

Dispatch models are excellent for looking at the grid today and in the near future. But National Grid, Ofgem and BEIS use them for the medium- and longer-term future too, where they break down. Every step into the future requires assumptions and educated guesses; the further into the future, the more important these are as a proportion of the whole. By about 3-5 years hence, the result is no longer credible. Instead, other means need to be found to establish the needs of the grid over such periods of time – methods such as Calculating the Need for Storage, below.

Carbon Capture, Use and Storage (CCUS) and CCS

The natural gas strategy all depends on Carbon Capture, (Use and) Storage, or CCS / CCUS.

Usage of captured carbon is at a very early stage of development, with some promising lines of development – however these are all at very early (mostly theoretical and laboratory) stages. And most of them result in the re-emission of the CO_2 later on because it's put into products such as synthetic fuels which are later burned, and plastics which is later thrown away. The UK parliament has released a briefing on this[62]. Therefore usage does not carry promise of major CO_2 emissions reduction in the near future, so the principal target for national emissions reduction must remain CCS. And usage means are currently prohibitively expensive, though future developments may solve that challenge.

[62] https://researchbriefings.parliament.uk/ResearchBriefing/Summary/POST-PB-0030 ("CCC Report")

CCS is expensive and imposes inefficiencies on the host system, e.g. the power station. It is also not 100% effective (though the unstated assumption throughout is that it is 100% effective) and both costs and resultant inefficiencies rise exponentially as the percentage of carbon captured rises. For example, CCS increases coal burn by a quarter for the same power output[63], raising its levelised cost of energy to well above that of other generation technologies[64]. A well-financed Canadian project at Boundary Dam[65] found that CS imposed 40% inefficiencies on the power station while only capturing 90% of the CO_2 emissions. It is notable that increasing capture rates increases capital and operational costs and imposes greater inefficiencies on the host plant.

But the most neglected element of CCUS is its hazardous nature. It captures, transports and stores for millions of years a gas which is colourless, odourless, poisonous and heavier than air: any leakage (such as from an earth tremor or equipment failure) would cause an asphyxiating cloud which would roll over the ground wherever a light wind blows it, including over population centres, much like a World War 1 gas attack. Making large networks safe in decentralised installations would be virtually impossible, so it must be concentrated in clusters.

Emissions cannot be avoided in certain industrial processes such as the cracking of limestone ($CaCO_3$) into lime (CaO) for cement[66]: chemically, $CaCO_3 \Rightarrow CaO + CO_2$. CCS is necessary for such processes. But it is not necessary for power generation: renewables plus large-scale long-duration storage such as Storelectric's is cheaper, more efficient and more environmentally friendly. Even nuclear is cheaper than gas plus CCS. There may be benefits in building a few CCS power stations that piggy-pack on industrial CCS clusters, but elsewhere it is neither affordable nor sensible.

For such reasons, the Americans cancelled many projects before construction, such as the Kemper coal gasification and CCS project when its capital cost for a 582MW plant exceeded $7.5bn[67], 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?

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[63] http://www.world-nuclear.org/information-library/energy-and-the-environment/clean-coal-technologies.aspx (see table 1)

[64] 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

[65] https://www.saskpower.com/Our-Power-Future/Infrastructure-Projects/Carbon-Capture-and-Storage/Boundary-Dam-Carbon-Capture-Project

[66] This chemical reaction alone accounts for >4% of global emissions, over half of the total emissions (8%) from cement manufacturing, most of the rest being from heat input to the process: https://www.bbc.co.uk/news/science-environment-46455844

[67] https://en.wikipedia.org/wiki/Kemper_Project and https://www.smithsonianmag.com/smart-news/major-clean-coal-project-mississippi-shut-down-180963898/

Integrated Thinking

While claiming to address the whole energy system, there is very little in the structure, control and operating frameworks within the system that actually does so, for example:

- Proposals that benefit the physical grid, contract prices, system operability / controllability, offshore networks (OFTOs) and renewable generation cannot happen because there are no mechanisms for:
  - Putting all interested parties together to discuss the proposals, its costs and its benefits,
  - Modelling and evaluating it, with input from all parties,
  - Sharing the benefits with the project developers / operators,
  - Establishing joined-up or coordinated contracts;
- Technologies that must necessarily deliver more than one contract type concurrently (see Revenue Stacking and Salami Slicing[68]);
- Providing contracts of a length that correlates with plant life and roles, e.g.
  - Sufficiently long[69] to encourage new build (most is done with special financial instruments that distort and mute markets, but have 15+-year durations),
  - If non-grid solutions are implemented to benefit grids (e.g. storage to reduce grid connection and reinforcement), it cannot be removed from the system at the end of the contract without multi-£billion investment to reinforce both grid and connections, so such contracts must be life-of-plant duration, exactly analogous to the physical grid which it's replacing.

Forward Thinking

There is little forward view: a page per scenario (p203-207), with few figures, is totally insufficient. The lead times to construct both grid and also many assets such as large-scale long-duration storage, are such that a 10-year view would yield totally insufficient investment to achieve Net Zero.

The current policy of maximising asset utilisation (which is, more accurately, "sweating assets") has led to a system in which most of the grid, at both transmission and distribution level, is both modelled on the 1950s-1970s economy (they don't seem to have notice that the economy's and country's structure have changed in the last 50-70 years) and almost totally saturated, unable to take significant new assets without major grid investment. Both the cost and lead time of such grid investment prohibit many very beneficial proposals being brought forward, greatly impeding both the energy transition and the adaptation of the system to modern patterns of supply and demand.

The purpose of the current policy is to reduce costs by not "gold-plating" the grid, which was always a mythical concept. Building grid to plan instead of reacting to

68 https://www.storelectric.com/wp-content/uploads/2021/08/Revenue-Stacking-and-Salami-Slicing.pdf

69 https://www.storelectric.com/issues-with-ever-shortening-contract-durations/

demand can be up to ⅔ cheaper, as evaluated in South Australia (the Energy Networks Association has the details), and provides a more adapted and resilient grid. The argument that unnecessary assets end up being built is wrong, because (a) the savings are so great that any surplus construction merely dents the benefits, and (b) eventually all the assets will be used, which is what has happened with the current grid that has been so mis-represented as "gold-plated". It's only because long-term needs were prioritised that we have a grid at all, and that the grid was built robust enough to cope with the last 30-40 years' underinvestment due to current policies.

Quantifying the Challenge and Hoping for the Best

"Net zero will only be possible if we start implementing measures now. We can't wait until 2050" (p39, FES 2022). Very true, but under current regulations, the appropriate amount, scale, durations and capabilities of technologies enabling the energy transition will not be built. Quantifying the challenge and hoping for the best will not work. Two prime examples are:

1. National Grid complained recently that they had been showing multi-million-pound constraint costs around the Scottish borderland, yet no projects had been proposed to alleviate it. That is because of current regulations and contract terms.
2. Large-scale electricity storage: National Grid have been forecasting a need for tens of GW of storage, a substantial proportion large-scale, yet no such plant has been started. The nearest to it is the Highview demonstrator, which is only happening because of tens of millions of pounds worth of government innovation funding. Until the right regulations and contract terms are in place, including incentivisation for first-of-a-kind plants (this applies to any technology), they will not be built.

Unless and until there are contracts of appropriate durations[70], there is no guarantee that assets built against demonstrated need will continue to be needed: National Grid may undertake some other work that ruins their business case.

Unless and until there are suitably broad contracts[71] for a plant's capabilities, there will remain potential for a plant to become legally and/or commercially un-viable at some point – especially broadly-capable and large-scale plants of any type.

Unless and until there is a suitable regulatory system[72] that incentivises all that the grid needs, and lets contracts accordingly, there will have to be ever-increasing and ever-costlier interventions to get the right services – and, like all centrally-planned systems, it will be far inferior to a truly market-based one.

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[70] https://www.storelectric.com/wp-content/uploads/2021/03/Issues-with-Ever-Shortening-Contract-Durations.pdf

[71] https://www.storelectric.com/wp-content/uploads/2021/08/Revenue-Stacking-and-Salami-Slicing.pdf

[72] https://www.storelectric.com/wp-content/uploads/2021/05/A-21st-century-electricity-system.pdf

Unless and until storage has its own regulatory definition[73] and regulatory provisions, as storage and not as a sub-set of generation, based on the definition and regulatory provisions of interconnectors or substations (which are also grid services that don't generate any new electricity), to level the regulatory playing-field, then the British electricity industry will never build enough, and always be dependent on uncertain imports during times of system stress[74] from overseas generation subsidised by the British energy system.

The scenarios all have the rosy prediction of net-exporting by 2040. This will not happen without the above changes. In fact, all that has gone wrong with the energy system is due to the lack of such basic easily developed and implemented solutions. And if quantifying the challenge and hoping for the best will not work, this is especially true when the quantification is wrong, as we will see below.

Network Challenges of the Energy Transition

The energy transition has many challenges of its own[75]. It is largely (but not wholly) about replacing rotational turbine-based generation with renewables.

- Turbines are dispatchable, meaning that we can vary their output on demand; renewables are mostly intermittent, meaning that they're available in certain weather or times of day. So the first part of the challenge is turning intermittency into dispatchability. That's about time-shifting energy, which means storing it when we have surplus for use when we have need.
- Turbines are rotational: they spin with real inertia, which provides grid stability and which is the basis of a number of other grid stability services.
- Turbines also produce other benefits such as reactive power and reactive load, to keep the system working smoothly.

Renewable generation's intermittency means that their grid connections need to be sized for peak output, not average output or demand, so in March 2022 National Grid put out their Network Options Analysis that said they have to invest almost a billion pounds in network reinforcement for every gigawatt of offshore wind that we're going to connect until 2025 – and those being connected after that date will cost increasingly more. In July 2023 they increased that to £1.37bn per GW. Adding the costs of connecting up balancing and ancillary services, it is reasonable to expect that each new GW electricity will require £1.75bn grid reinforcement.

But this is not all: operation and maintenance (5% of this, every year) and amortisation (another 5% p.a.), it also costs £175m p.a. to maintain the additional grid for each new GW of renewable electricity.

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[73] https://www.storelectric.com/wp-content/uploads/2021/03/Regulatory-Definition-of-Storage.pdf

[74] https://www.storelectric.com/wp-content/uploads/2021/03/Interconnectors-and-Imports.pdf

[75] For a fuller treatment, see https://www.storelectric.com/challenges-of-the-electricity-transition/

We can avoid many of those billions of pounds-worth of expenditure, and the eyesore grid they'd have to build.

Short Termism and its Problems

The regional analyses show that "the largest demands today are in the big cities, and particularly the south of England", yet the last four decades' focus on the short term have ensured that the grid is largely as it was designed for the British economy in the 1950s.

The entire process of planning and regulating the grid is exceedingly short-term. The longest vision, NG's Network Options Assessment, focuses on a 10-year timescale; with such thinking, the grid would never have been built in the first place, leaving the entire economy struggling and held back. More recently National Grid has produced a report Pathway to 2030: Holistic Network Design[76] – yet 2030 is only 7.5 years away. An example of such short-termism was the much-touted (though, thankfully, not achieved) "second dash for gas" to achieve 2025 emissions targets even though 2030 emissions targets would have turned most such power stations into stranded assets. The only way to avoid such waste is to prioritise 30- and 50-year timeframes – which will ensure a cheaper, more reliable and more resilient grid in those timescales without increasing greatly the cost to today's system/consumer.

As most grid-connected assets that are developed today will still be operational in 2050, all new developments must be one of:

- 2050 compliant (i.e. emissions-free);
- Convertible to 2050 compliant; or
- Short-life assets that will be replaced before emissions targets exclude them from markets.

If short-life assets, emissions relating to disposal and replacement should be taken into account, as should global resource availability in comparison with forecast global demand, e.g. lithium, cobalt and rare-earth metals.

Proactive Grid Development

It is worth recalling that the grid was only built because of whole-system, long-term thinking. For that reason, it was developed and extended based on forecast rather than current needs. This has been caricatured politically as "gold-plating the grid", with a focus over the last decades on increasing utilisation. But in reality,

- Building the grid in a measured and rational programme ahead of need is as much as two-thirds cheaper than building it reactively against need, as discovered in Australia; the Electricity Networks Association can cite excellent examples from South Australia and elsewhere, to support this statement.
- Even if such demand did not materialise at the expected time, it has materialised since, so the benefits of investing in such more rational and

[76] https://www.nationalgrideso.com/future-energy/the-pathway-2030-holistic-network-design

measured ways greatly outweigh the small number of years for which a given part of the grid was under-utilised.

- And the current method means that now there are large and unknowable numbers of projects that are just not being proposed because of the cost of reinforcing the grid to accommodate them, slowing down the energy transition and reducing the quality of the entire system.

Excessive Costs for Consumers

The result of all this is that system costs are rising so fast that a pro-market government has instructed a market regulator to intervene in the free operation of markets by imposing a cap on consumer electricity prices.

The poor design of market mechanisms means that all manner of levies and charges are added to electricity bills. A couple of decades ago, these totalled under 25% of consumers' bills, paying for grid upkeep, and balancing and ancillary services. Now they account for over 50% and still rising inexorably. This in turn means that plants are deriving a majority of their revenues from activities other than providing energy and the services necessary to maintain the grid, distorting market price signals; the price cap distorts them further.

Strategic Network Investment

Considerations for Network Planning

This is the first time that FES has considered network investment, which is a good development. Network Planning must go hand-in-hand with not only the planning of supply and demand but also (omitted here) of the need for ancillary services such as:

- Balancing services, turning intermittency into dispatchability;
- Stability services, based on natural inertia and including voltage and frequency control;
- Ancillary services, based on speed of response (a narrower definition which should be adopted by the system) that enable the system to recover from faults;
- Operability services, such as reactive power/load, leakage currents and phase-locked loops;
- Power quality services;
- Restoration services, principally Black Start.

Grid Reinforcement

Grid reinforcement is predicated on having to reinforce the grid to absorb the intermittency of renewable generation. This means that, after deducting curtailment, grids need to be sized for peak generation, not peak demand.

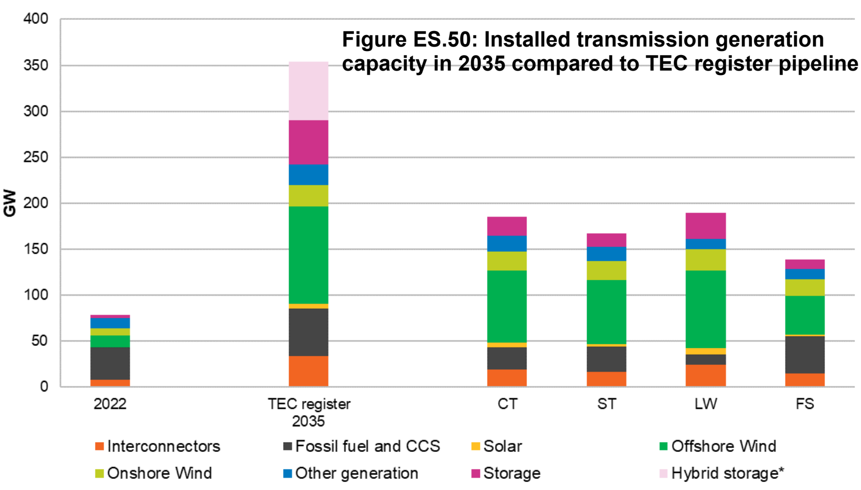

Figure ES.50: Installed transmission generation capacity in 2035 compared to TEC register pipeline

Although the scenarios plan to increase grid connections from 78GW in 2022 to 139-189GW in 2035, these plans (or at least, their extrapolation to 2050) should bear in mind the discussions above, that FES totally underestimates the amount of renewable energy required in the energy transition, not least for hydrogen.

All studies show that sizing grids for peak generation of renewables will require more than tripling their size, which Breakthrough Energy considers unaffordable even for

America[77]. McKinsey concurs[78]: "*The energy transition will require a dramatic increase in capital spending on the electric grid, delivered at an unprecedented pace*." Indeed, based on Ofgem / National Grid's own figures, each new GW of offshore wind already requires £3bn[79] onshore grid reinforcement, rising sharply: just two years before, the cost was £1.75bn[80].

If storage were to be connected to the grid through LDES of sufficient scale and duration, then the output from the combined renewable generation and storage would be according to demand, not supply. The grid is already sized for demand, so reinforcement would be local rather than regional and national. Moreover, if the LDES is synchronous (i.e. naturally inertial), then all the additional services would be provided at the same time and place, avoiding the need for sourcing, connecting and dispatching all the additional services listed above[81]. The result would save over £1trillion capital costs for the British energy transition, plus £150bn per annum in operational and financial costs[82]. If retro-fitted to existing large-scale renewable generation, such storage could liberate 10-20GW capacity for new grid connections (p173), which are one of the biggest single factors constraining and slowing the energy transition, other factors being the financial system[83] (for which a solution is proposed here[84]) and the regulatory system / market design[85] (for which a solution is proposed here[86]).

Black Start

Such a configuration could even provide Black Start. National Grid announced (by email 20th July, not yet on its website) "*the successful energisation of the SP Energy Networks distribution and transmission network assets, with multiple distributed energy resources (DERs) contributing to the distribution restoration zone (DRZ)*" using storage with a grid-forming inverter as the anchor generator.

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77 https://www.breakthroughenergy.org/scaling-innovation/modeling-the-grid

78 https://www.mckinsey.com/business-functions/operations/our-insights/global-infrastructure-initiative/voices/upgrade-the-grid-speed-is-of-the-essence-in-the-energy-transition

79 https://storelectric.com/saving-billions-on-grid-upgrades-jan23/

80 https://storelectric.com/saving-billions-on-grid-upgrades/

81 https://storelectric.com/challenges-of-the-electricity-transition/

82 https://storelectric.com/saving-trillions-in-the-energy-transition/

83 https://www.storelectric.com/wp-content/uploads/2021/03/HM-Treasury-Disincentivisation-of-Decarbonisation.pdf

84 https://storelectric.com/incentivising-clean-energy/

85 https://storelectric.com/where-grid-regulation-went-wrong/

86 https://storelectric.com/21st-century-electricity-system/

But this seems to be rather exaggerating to say that it's energised the transmission grid. It energised a transformer, but nothing on the grid at a voltage level above, let alone the entire grid section at the higher voltage - which is necessary before it can claim to have energised any grid at higher voltage. The Re-Starting Net Zero Grids analysis[87] still hasn't been disproved: according to National Grid's own previous work, Black Start must be top-down, by synchronous plant like Storelectric's.

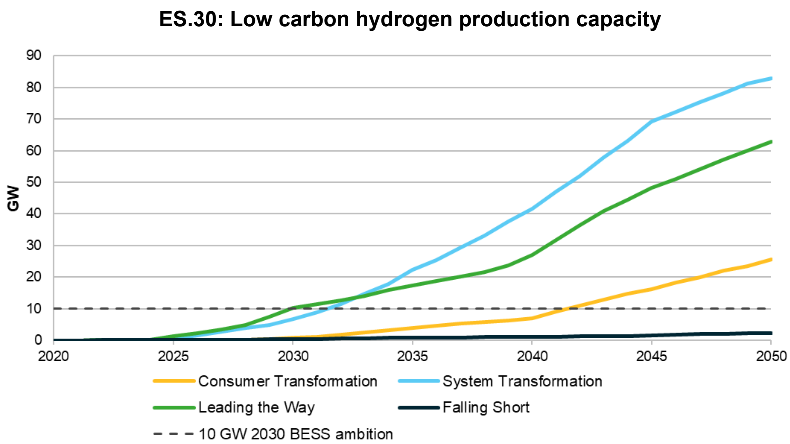
[87] https://storelectric.com/re-starting-net-zero-grids/

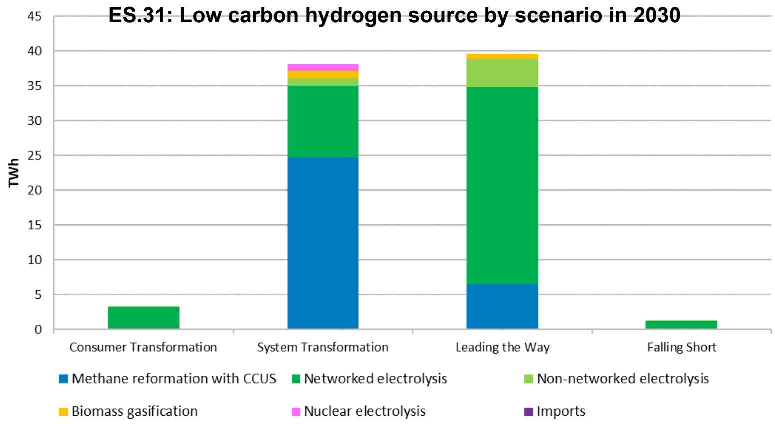
Hydrogen

Future Hydrogen Demand

FES 2023 is pessimistic about future growth of hydrogen: "*There is only enough hydrogen in the pipeline to meet the government target of 10 GW. We believe all the projects coming online and in time is less likely and therefore only seen in Leading the Way*." (pp108, 147-156) It correctly says that "In order for this to happen, policy support and consistency is required", but we see exactly this happening.

In our view, National Grid's reluctance to plan for hydrogen is because it would require (as analysed in Whole Energy System, Hydrogen Demand Overview, in this report) a tripling of renewable generation and of grid infrastructure on the current regulatory trajectory. While the renewable generation increase will be necessary, the infrastructure construction will not, provided the hydrogen economy is powered with LDES and little or no connection to the electricity grid[88].





As discussed below, only System Transformation has realistic assessments of future hydrogen demand for industry and transportation. Therefore only its hydrogen supply total are reasonable.

What is not reasonable is the proportion that is expected to come from methane reformation, which is not only more emitting than projected (owing to the inadequacies of carbon capture) but will also be much more expensive: its current costs allow for a carbon price that is less than one-sixth of the societal cost of carbon, and excludes the costs of CCS. For the proportions of different types of hydrogen formation, Leading the Way is much more credible, especially if powered by renewables connected directly to suitable-scale/duration LDES.

88 https://storelectric.com/hydrogen-and-caes/

Fuel Switching for Heating

In two scenarios, hydrogen is envisaged to be in widespread use for heating, p60-62. This means domestic and commercial heating; FES considers industrial heating elsewhere. But hydrogen is one of the highest quality (in thermodynamics jargon, high-enthalpy) energy carriers, and low-temperature heat is the lowest quality. While energy conversion from high to low quality is efficient, the reverse is not; and the greater the difference, the worse the conversion rates. This is why heat storage for use as electricity cannot even theoretically exceed ~42% round trip efficiency, and practically only about ⅔ of that (28%).

Therefore using high-quality energy for low-quality use is a total waste. Indeed, even the Hydrogen Science Coalition, whose interest is in promoting the use of hydrogen, accepts that "*the heat pump route is nearly six times more energy efficient than heating with green hydrogen*."[89] Yet FES only applies a factor of 2.81 times (p101) because it ignores the fact that the factor for hydrogen is below half, when both are measured as "*units of heat for every unit of electricity consumed*." Comparing capped prices is not a tenable comparison when looking at the future, after the caps will have been removed. Therefore domestic and commercial (and much industrial) heating with hydrogen is not a practical option, other than in very specific cases, and would be considerably more expensive than the alternatives.

High-temperature heat is higher quality, which is why hydrogen is practical for some industrial heat applications.

That said, hydrogen boiler uptake (p82-83) ignores the fact that most boilers being installed for natural gas are, these days, compatible with hydrogen. The focus on the lack of "assurances of future hydrogen demand" and the concern about the need to convert the gas network do not consider the plan to fill the gas system with 5-15% hydrogen before any conversions occur. To this extent, it therefore does not matter that "*there are no hydrogen boilers in Consumer Transformation due to the lack of a widespread infrastructure for delivering hydrogen to homes*." This partial dilution of gas will create enormous demand for renewable energy to power the electrolysis and other hydrogen formation technologies, all of which is excluded from the FES analysis.

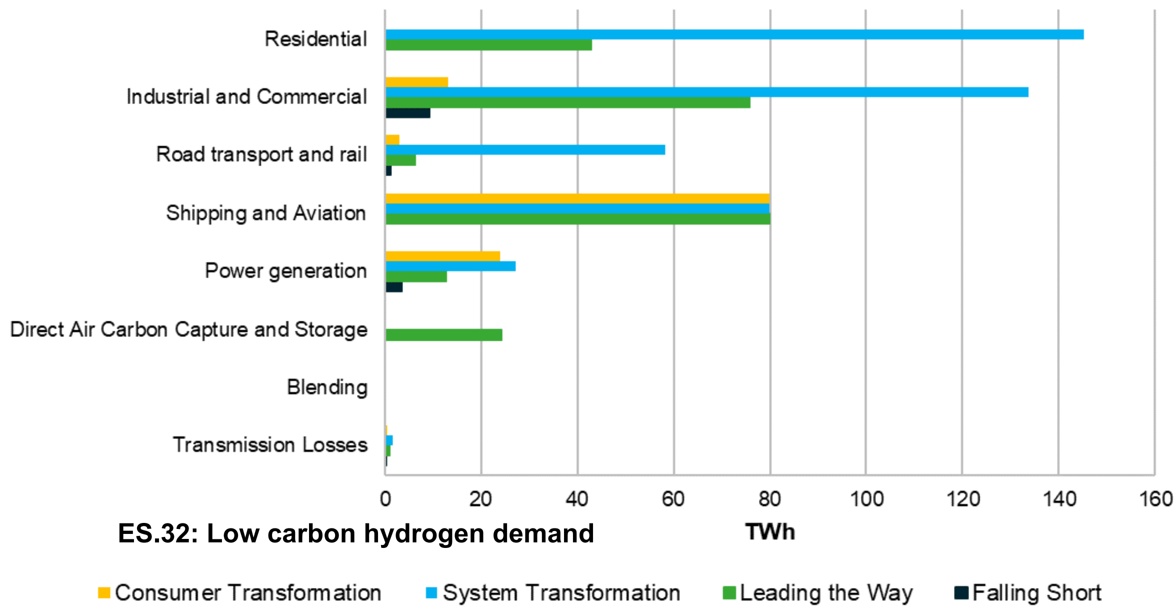
Uses of Hydrogen

Hydrogen is envisaged mainly for combustion in turbines to produce dispatchable and reserve electricity, the provision of high-intensity heat and heavy transportation. This omits its main uses, all cited above, of:

- Reducing agent in iron and steel making, and comparable industries;
- Feedstock for the creation of synthetic fuels and complex chemicals such as ammonia, methanol and complex hydrocarbons;
- Chemical industry, especially in new chemical pathways that avoid or reduce emissions;

[89] https://h2sciencecoalition.com/blog/hydrogen-for-heating-a-comparison-with-heat-pumps-part-1/

- Feedstock / precursor chemicals for other clean fuels;
- Light transportation;
- Non-transportation uses of fuel cells.



ES.32: Low carbon hydrogen demand

While transportation use is included in FES' analysis of transportation, it is included at much too low a market penetration – see *Transportation*, above. Combustion in turbines is too costly and inefficient (whole-cycle) to displace large-scale long-duration electricity storage. All in all, the expected amount of hydrogen is under-estimated.

Using hydrogen to balance intermittent generation is not practical:

1. Electrolysis and fuel synthesis (including methane reformation) hate intermittency, which reduces both efficiency and plant life;
2. Many times more electrolysers (and synthesis plants) are needed for the same output if they are only producing intermittently – and such plant is very expensive;
3. It doesn't balance the "variable demand" side of the equation, as electricity storage does – unless it's then combusted, for which see below.

Hydrogen Networks

With so many of these chemical and industrial plants, and hydrogen fuelling stations, being distributed around the country, this would require conversion of the natural gas grid to hydrogen. But since all of these applications require very or fairly pure hydrogen, there is no benefit at all in having blended natural gas and hydrogen in the network. The only feasible use for such mixtures is to feed into boilers during a transitional period for avoiding the need to change such boilers wholesale, especially if a large proportion are hydrogen-ready. But electric heating (especially with heat pumps) is cheaper, and blended gas in the system would prevent the development of

a network of industries and fuel stations, thereby impeding the roll-out of hydrogen consuming technologies, so impeding the energy transition as a whole. Moreover, adjusting the gas-consuming equipment would be very expensive as multiple adjustments and purchases would have to be made as the hydrogen percentage is increased gradually: in general terms the flame size, shape and temperature are different, and 50% more gas volume is used for the same energy output.

The best way to roll out hydrogen would be to base initial usage locations on the towns near the seven hydrogen hubs currently being developed. These would be 100% hydrogen – a single conversion. As more hydrogen becomes available, these hydrogen grids would be expanded to neighbouring areas until eventually they merge. This would naturally lead to regionally-focused, but interconnected, hydrogen economy clusters; demand outside the clusters would be met through the converted natural gas pipeline network, which would take the strain off the electricity grid. Project Union[90] (p156) is an excellent, if belated and slow, start on this: most of our European neighbours (especially the Netherlands[91]) are well ahead of the UK on developing their own national hydrogen networks.

Apart from very specific applications (e.g. fuel tanks), transportation outside pipe networks is very difficult and expensive as hydrogen is so light. One lorry can carry 3 tonnes of compressed hydrogen. To carry more, it would have to be maintained at cryogenic temperatures below -252.9 °C, its boiling point (or slightly warmer if pressurised). Therefore it is likely that non-piped transportation would be done in other forms, such as ammonia or methanol; this implies that conversion into complex chemicals is likely to be done on the same pipe network as hydrogen production.

Hydrogen Power Stations

Combusting hydrogen in turbines is, at ~60%, (theoretically) almost as efficient as burning natural gas. But this does not take into account the inefficiencies of electrolysis (or other means of producing hydrogen) and transportation. The theoretical best efficiency of the cycle renewable generation to electrolysis to transportation to combustion in a turbine to electricity on the grid is in the low 40s %. Mid-thirties % is realistically achievable; today it's at the mid-20s %. And the total capital cost is higher than that of 70% efficient adiabatic CAES, and even of 75% efficient pumped hydro.

Therefore the only justification for hydrogen power stations is energy security, for seasonal or annual fluctuations. But this envisages having sufficient hydrogen power stations, and stored hydrogen, to power the entire grid for long periods of time – and which is very rarely used. That envisages fantastic expense for reserve capacity, which the energy system hitherto has never afforded, and is never likely to afford.
Hydrogen Supply

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90 https://nationalgas.com/document/139641/download

91 https://www.gasunie.nl/en/projects/hydrogen-network-netherlands

Hydrogen Production – Electrolysis

Hydrogen production by electrolysis ("green hydrogen") is envisaged "to maximise the use of renewable electricity generation", levelling the intermittency of generation and also producing during periods of congestion. This is true but highly uneconomic and, even so, only addresses half of the challenge.

It is highly uneconomic because 6-8 times as much electrolysis capacity per unit of output hydrogen is needed if its in-feed electricity is solar, as compared with baseload input. For offshore wind the multiple is 2.5-3, for onshore wind it is 4-5. All of these are uneconomic in both capital and operational costs, as compared with using large-scale long-duration storage to deliver near-baseload energy to the electrolysis plant. Near-baseload requires ~6-12 hours' duration; true baseload would require ~2 weeks' duration (336 hours); so the optimum will be an economic balance of the cost of increasing storage duration intersecting with the decreasing cost of electrolysis.

All projections of electrolysis are based on the two main technologies in use currently: Proton Exchange Membrane (PEM) and Alkali. Both are very expensive in both capital and operational costs as both the membrane and the alkali are consumables. PEM is safer but necessarily low-volume; scale-up requires hundreds or thousands of cells. Alkali is intrinsically larger-scale but with big health, safety and cost issues in procuring and handling the alkali and disposing of the waste.

Instead, new high-volume electrolysis processes need to be developed. A number of these have been proposed in the past, but not funded – mainly due to funding ministries' innate conservatism. Among these technologies, Storelectric has patented[92] using the heat of compression to catalyse electrolysis; this will be developed when the company has sufficient revenues from its CAES to fund and resource it.

Hydrogen Production – Methane Reformation

Otherwise known as Grey, Black or Brown hydrogen, Steam Methane Reformation (SMR) is the principal way in which FES 2022 envisages hydrogen to be produced in the System Transformation scenario, with it being a substantial minority in Consumer Transformation. Essentially methane is broken into hydrogen and CO2 by a chemical reaction with steam: $CH_4 + 2H_2O = 2H_2 + CO_2$.

This process is already too expensive to substitute methane economically, without CCS. With CCS ("blue hydrogen"), plant efficiency will drop and, although CO_2 capture will be cheaper owing to the higher concentrations, both expensive and less than perfect (See *Carbon Capture, Use and Storage (CCUS) and CCS*, above). This in turn will require negative-emissions installations such as DACCS (Direct Air CCS) and BECCS (Bio-Energy with CCS), adding further costs and inefficiencies to the whole system.

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[92] Patent family WO2019GB52168

Hydrogen Storage

Hydrogen storage volumes are considered for the first time in FES, p192. This is, of course, as variable as they hydrogen demand forecast. This storage corresponds (comparing with p110-113) with 29 days' supply for Leading the Way, 35 days for Consumer Transformation and 46 days for System Transformation. Whether or not this number of days' supply is adequate is for modellers to analyse in detail, but up-rating the amount of hydrogen in the forecast as per previous comments should correspondingly up-rate the amount of storage needed.

Volumes of 12-56TWh storage can only be achieved with geological storage, such as is offered by Storelectric. Note that this is not the total storage volume needed: if (as is usual) 40-60% of the stored hydrogen is cushion gas, the remainder being usable, then storage capacity needs to be around twice that amount. In extremis, much of the cushion gas can be used, but this should be kept as a reserve.

Transition to Hydrogen

It is good that the natural gas network is planned to be re-purposed to hydrogen. Not discussed is how this will be done. Most proposals and trials look at mixing hydrogen into methane, but hydrogen needs 50% more volume per joule of output, increasing required gas flows; it also burns much hotter. These change the flame characteristics, requiring conversion of hydrogen combustion devices. (Conversion is also required to avoid hydrogen leakage and embrittlement, owing to the small molecule size in comparison with that of methane.) Because of the conversions for thermal and volume-flow reasons, diluting the grid in stages such as 20%, 40%, 60%, 80% and 100% hydrogen would require multiple conversion exercises[93], each on the scale of the conversion from town gas to North Sea gas; converting straight from methane to pure hydrogen is one single (albeit slightly dearer) conversion exercise and therefore much cheaper, less disruptive and manageable in terms of human resource availability. This suggests that roll-out should not be by such stages, but should instead be 100% conversions of different areas, sequentially expanding from hydrogen hubs – probably using the British government's Low Carbon Clusters[94] as those initial hubs. This is at least partially accepted p105.

FES 2022 expects (p94) that nearly all heating will be converted to three main technologies: heat pumps and electric heating, burning hydrogen in boilers, and hybrids of the two. The hydrogen would be carried in National Grid gas pipelines, converted from carriage of methane. Please see above (Residential demand) for the shortfalls of this.

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[93] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/760508/hydrogen-logistics.pdf

[94] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/803086/industrial-clusters-mission-infographic-2019.pdf

Natural Gas Demand

FES (p157-164) does not consider the future main drivers for gas demand, ignoring many factors including:

1. The current carbon price is around one-sixth of the societal cost of carbon, and will surely tend towards the higher figure;
2. CCS plans don't include the emitting plants bearing anything remotely resembling the full cost of CCS systems;
3. Nor do they take account of the inefficiencies that CCS impose on the parent plant, such as 30-60% efficiency penalty on power generation;
4. Nor do they take account of the inadequacies of carbon capture technologies, which
    - Get exponentially dearer as 100% capture rates are approached,
    - Don't achieve their designed capture rates, and
    - Require corresponding investment in negative-emissions plant.

Therefore, as the country wakes up to such freeloading by the fossil fuel industry, these implicit subsidies and hidden problems will be exposed and stopped, making natural gas uncompetitive for most applications.

Some Electricity Generation Technologies

Bioenergy

With an increasingly insecure food supply, and shortages world-wide, pressure on agricultural land must be minimised. Today, the challenge is the loss of Ukrainian supply, but that's only a foretaste of what global warming has in store for the planet even without any wars to exacerbate matters. As sea levels rise, fertile deltas and plains will be flooded, and as semi-desert desiccates, so farmland is lost and adjacent farmland rendered less productive. This will not be compensated for in full, or anything close to fully, by bringing new regions of marginal land (especially in the taiga and boreal forests) into production: not only are these distant from both the inputs and transportation links needed, but also converting those lands will again add to global warming. Therefore, the availability of fuel for bioenergy will always remain quite restricted.

As the report points out, "negative emissions from Bioenergy with Carbon Capture and Storage (BECCS) and other Greenhouse Gas Removal (GGR) methods are still required to offset emissions from sectors of the economy which are 'hard to abate'." However, that means that if emissions can (in practical terms) be abated in other ways, it should be. That means avoiding fossil fuelled generation + CCS, and hydrogen from methane + CCS, since sufficient large-scale long-duration storage (especially if naturally inertial) can replace the former, and electrolysis can replace the latter. The costs of emissions from such technologies should reflect the costs and inefficiencies of the BECCS required to compensate for them.

It is notable that about ¾ of energy input to BECCS (biomass with CCS) is shown as losses, and only ~¼ as electricity output. BECCS is an exceedingly inefficient technology as well as an extremely expensive one, for which reasons the need for it should be avoided where possible, e.g. by deriving hydrogen from electrolysis rather than methane reformation and (necessarily imperfect) CCS, and by large-scale long-duration electricity storage rather than fossil fuelled power stations with (necessarily imperfect) CCS.

Moreover, the forecasts for BECCS are for balancing the output of combustion of fossil fuels, and ignore the need to balance emissions in their extraction, refining and transportation; considering those aspects would require a huge and unsustainable increase in forecast BECCS.

Gas

Although "transitioning towards Net Zero while maintaining a reliable and affordable energy system for all will require a continued, if different, role for natural gas as it cannot be used in a Net Zero world without its emissions being captured", there is little realisation of the costs and inefficiencies of CCS and CCUS[95]. Equally, there is

[95] https://www.storelectric.com/carbon-capture-use-and-storage-ccus-and-ccs/

insufficient appreciation of the low costs and vast benefits of the large-scale, long-duration, naturally inertial storage that is available today and could, if rolled out, make gas generation (even with CCS) unnecessary as well as comparatively expensive and inefficient, whether for energy security, balancing, reserve, grid stability, power quality or the other purposes for which power stations are used today. And it doesn't have to cost the grid anything: just to put the right contract structures in place, following which it would be built and operate commercially.

As gas consumption reduces, so power stations need to charge increasingly unaffordable amounts for just being there in reserve, and for frequently warming up "just in case". And warming up causes emissions too, which then entail more BECCS. If they are not paid such exorbitant amounts per unit of energy produced, then there will be no business case to keep them open.

There is absolutely no need for shale gas, whose extraction and refining are enormously polluting and emitting, and which would require vast expansion of BECCS to compensate.

Nuclear

Nuclear energy is under-valued by the current contracting systems. This is because we pay the same for all electricity regardless of its value – see Paying for What We Need, above. This leads to the perception that a high "strike price" is uneconomic for the electricity system as this price is compared with the CfD price of intermittent, asynchronous wind or solar energy.

A second value of nuclear is its energy density per unit area: ~5GW per square mile, as compared with wind (~60MW) and solar (~30MW).

A third value is that it can be put in parts of the country that are further from wind, saving on grid network costs – and these savings are additional to the network savings from its dispatchable / baseload nature.

And while it is highly cost-effective for long-duration storage to provide balancing for variable demand, it is much more cost-effective for nuclear to provide baseload input to match baseload demand.

Renewables Mix

As analysed by Nottingham University for the Energy Research Accelerator[96], the monthly generation profiles of solar and wind are mirror images of each other. Therefore the right proportions of each (roughly 20-25% solar) will provide monthly output averages that map seasonal variation in demand.

96 https://www.era.ac.uk/Medium-Duration-Energy-Storage

There will be shorter-term fluctuations in demand, and multi-year cycles in renewable generation. These can be largely accommodated by a ~10-25% over-build of renewable generation, which is much cheaper than any storage strategy.

There may be a residual quantitative case for hydrogen generation, but the load factors are likely to be so low that no economic case will ever be affordable.

Interconnectors

FES relies on interconnectors for actual demand (145, 197-8), which one cannot do: by 2040 every Western European country except Iceland, Norway and Switzerland will rely on imports during times of system stress. Iceland is too remote (exceedingly costly interconnectors, very much longer than any other in the world) and low spare capacity (evaluated at 1GW). Norway will prioritise exports to Scandinavia and Germany, and Switzerland to its neighbours. Brexit gives our neighbours a political imperative to cut us off during times of system stress, such as after sunset on a windless winter evening and weather patterns that extend this for days, which frequently cover neighbouring countries. Therefore we cannot rely on interconnectors to keep our lights on when we need them to; their proper place is to ensure that normal energy prices are reasonable. This is a brief summary of a previous analysis[97].

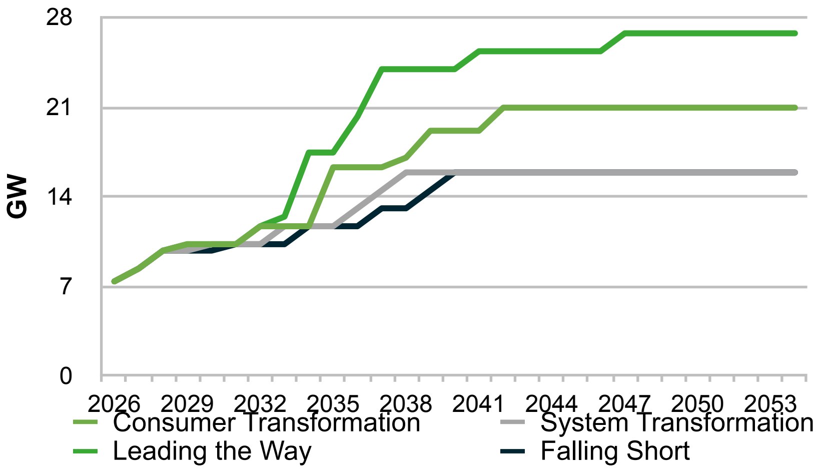

Figure ES.25: Interconnector Capacity

All this was proved in 2022:

- Prices rocketed when there were widespread shortages of renewable generation[98];
- When half of French nuclear generation was closed for maintenance, interconnector flows were reversed to take power from the UK, sending both British and French peak electricity prices through the roof and threatening widespread black-outs[99];

[97] https://www.storelectric.com/interconnectors-and-imports/

[98] https://www.bbc.com/news/uk-england-london-62296443

[99] https://www.reuters.com/business/energy/why-nuclear-powered-france-faces-power-outage-risks-2022-12-09/

- When Russia turned off the gas supply to Germany, they closed their gas interconnectors even to their EU neighbours, to conserve their own stocks for themselves[100];
- In January 2023 Norway, one of the only countries expecting to have surpluses in times of system stress, passed legislation permitting them to cancel any export contracts during such times[101].

The consequence of this is plans for a totally inappropriate surge in interconnection from 5GW to 22-52GW by 2050. This will merely add costs to the system by cannibalising revenues from storage, which we will still need for when interconnectors cannot provide the energy. And the capital cost per GW of interconnection to (say) the Netherlands is very similar to the cost of same-sized 8-hour adiabatic CAES, on which the country can rely.

Also ignored is the fact that interconnectors are DC, i.e. asynchronous. Therefore any such interconnection requires further capital investment and both operational and contractual costs to provide stability services, for example using synchronous condensers – £328m for six years from five plants in January 2020, with needs increasing in parallel with renewable generation and interconnection. These stability services can be provided much more cheaply by almost any long-duration storage technology, provided that they have a suitable revenue stack.

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100 https://www.ft.com/content/09ac0ab9-ad4a-4586-9a14-3921a4d60216

101 https://www-regjeringen-no.translate.goog/no/aktuelt/bedre-styring-av-forsyningssikkerheten/id2960788/?_x_tr_sl=auto&_x_tr_tl=en&_x_tr_hl=en-GB

Energy Storage and Flexibility

FES 2023 compliant scenarios require 32-52GW of electricity storage. Comparing the total GW and GWh of storage yields an average storage duration of 3.6 hours for the three Net Zero compliant scenarios. Given that nearly all battery storage is typically 1 or 2 hours, also stated in the report, that means that at least as much longer-duration storage is needed, of 4-12 hours duration.

As a result of all the dreadful errors described above in this analysis, storage capacity (excluding the grossly over-estimated V2G) is forecast at 23-52GW (23GW is the non-compliant scenario). While this looks substantial, this is only nameplate capacity and doesn't even consider the essential measure of duration. Indeed, most of the discussion is about batteries, which cannot cost-effectively scale up in this way. Nor do the batteries provide the other services that inertial storage does: up to 6 batteries are needed to provide the entire range of services that a single inertial storage facility can deliver concurrently from a single same-sized unit. Not to mention that there are not enough resources in the earth's crust to build them. Batteries are indeed an unaffordable and inadequate option[102].

The report does mention longer-duration storage, notably pumped hydro, but offers no way in which it will be incentivised: there are no such projects on the table that were not on the table a decade ago, and they have not proceeded due to systemic regulatory and contractual problems addressed elsewhere in this analysis. And CAES, the most cost-effective of the lot, is not even mentioned – solely because the ministry, regulator and grid have not enabled a first-of-a-kind to be built.

The discussion on flexibility perpetuates the insistent misunderstanding of a 2012 Imperial College report[103] which said not to talk about storage, but about flexibility ***and duration***, stating that "Resource adequacy requires several hours of storage duration, if peaking generation is to be displaced securely, based on the shape of the demand profile derived for 2030." What is the point of flexibility if it is exhausted part-way through need, such as after sunset on a windless winter evening, when it's needed through the entire evening peak and even overnight? Flexibility must never be discussed without duration, however much reports such as this insist on doing so.

And this ignores the fact that their identified need for storage is so under-stated, which is why whole-system costs are escalating exponentially.

Flexibility

FES brings out their persistent, insistent error that "*Flexibility is defined in FES as the ability to shift the consumption or generation of energy in time or by location.*" (p177) A focus on "flexibility" without the concept of "duration" has been a mantra in

102 https://www.storelectric.com/batteries-expensive-and-inadequate-solutions/

103 https://www.imperial.ac.uk/media/imperial-college/energy-futures-lab/research/Strategic-Assessment-of-the-Role-and-Value-of-Energy-Storage-in-the-UK.pdf

government, grid and regulatory circles ever since they started misunderstanding a 2012 Imperial College / Carbon Trust report[104] that focused on flexibility but also analysed duration, identifying that the greatest value of storage was at 6 hours' duration – they ignored that last part (e.g. p12 footnote "*Resource adequacy requires several hours of storage duration, if peaking generation is to be displaced securely, based on the shape of the demand profile derived for 2030.*").

Flexibility is defined exclusively as meeting changing supply or demand, without any thought to the length of time over which such changes will, i.e. measured in MW (c.f. graph FL.01, p178). There is much less importance placed on duration / volume of that need, i.e. MWh. The primary focus is therefore that "*Large amounts of short-duration flexibility will be needed to match supply and demand within the same day*", which ignores that times of system stress (e.g. after sunset on a windless winter evening) last long enough to need long-duration storage even within a day. A secondary focus is on demand side response, which is necessarily short-duration, and V2G (Vehicle-to-Grid) which will not only be much less than predicted, but also limited to an hour or two. The entire discussion of Key Insights (p179) is enumerated in GW, not GWh; even the single statement of need for longer-duration storage (p180) is in GW only, and all the proposed "markets and whole energy system investment) are geared towards scale and not duration.

Demand response at the levels foreseen in p184 amount to rolling brown-outs, which will destroy British industry and commerce. Demand response is always considered in terms of the electricity supply, not in terms of disruption of output, or of having to mess around with people's lives at little notice because they must change their shift patterns to suit the energy supplier.

Locational pricing

Saying that "Market reform is needed to provide the locational signals" is just plain wrong. Most consumers, most generation and most storage (other than batteries, which are expensive and inadequate solutions[105]) cannot choose their locations. Nor can they, when locational price signals change, move – therefore their financial position cannot be forecasted, which would kill investment. As electricity is a high-volume, low-margin industry, current price signals are more than adequate to provide the location incentives for plants that can respond to them; most can't. The location pricing proposal is one of the worst possible proposals to bring forward[106].

Long-Duration Storage

Despite many grave errors in the modelling that understate the need for storage, FES 2023 compliant scenarios require 33-52GW, 116-197GWh of electricity storage.

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[104] https://www.imperial.ac.uk/media/imperial-college/energy-futures-lab/research/Strategic-Assessment-of-the-Role-and-Value-of-Energy-Storage-in-the-UK.pdf

[105] https://storelectric.com/batteries-expensive_and_inadequate_solutions/

[106] https://storelectric.com/locational-pricing/

Comparing the total GW and GWh of storage yields an average storage duration of 3.5-3.8 hours for the three Net Zero compliant scenarios. Given that nearly all battery storage is typically 1 or 2 hours, also stated in the report, that means that at least as much longer-duration storage is needed, of 4-12 hours duration. But under 4 hours average duration will not keep the lights on during the evening peak and overnight, let alone through the *Kalte Dunkelflaute*.

Long-durational storage requirements are indicated in the graphs on p182. They look enormous, but there is no GW value put to them: storage (indeed, all flexibility) must always be defined in terms of both GW and GWh. Nor is there any discussion of the actions needed to be taken to incentivise them, the market design, contract structures, revenue stacks, lead times to deliver, whether or not synchronous, comparison of technologies… Lip service only, guaranteed to result in a failing system.

There is some discussion on p194, but no in-depth analysis. And, given the "revenue stack" considerations elsewhere, crucially there is no realisation that long-duration storage can provide short-duration services: this is planning to waste billions in money. National Grid's thought piece on storage doesn't even realise that in May 2022 China opened an adiabatic storage plant and declared 8-9 more in the pipeline; Australia and California are also building them; and Storelectric has very well-validated technology that beats both on price and efficiency.

The *kalte Dunkelflaute* (German for "Cold Dark Doldrums") is discussed (p211-218). This is up to a fortnight with renewable generation below 10% of nameplate capacity over much of the continent. It is excellent that they have considered this period, and analysed it for the first time. However, the forecast requires significant imports at certain times, especially at the end of the ten days analysed, which will not be available because neighbouring countries will be enduring the same conditions, and therefore be unable to export. If the Dunkelflaute were to last the full fortnight over the UK, as it does regularly over continental Europe (and this summer's move of the jet stream shows that it is quite possible for our weather patterns to be so aligned), this would be much worse. Moreover, better weather-alignment would mean no high-wind periods, of which there are four during the analysed ten days.

The German stack is evidently not tenable, as they are scheduled to close all their nuclear power stations in the next few years. And this analysis is only for two and a half days.

The duration also doesn't consider the eventuality that a subsequent similar (even if shorter) weather pattern follows before storage is re-charged.

In short, this analysis is a good start, but needs more work.

Potential Electricity Storage Routes to 2050 Thought Piece

This thought-piece[107] (referred to in the text, end of p194) puts adiabatic CAES efficiency at 56%. The Chinese plant achieves est. 56-58%, Hydrostor 60-62%, and Storelectric's (which is much cheaper than either) 68-70%. Meanwhile, LAES has dropped its claim of 65% and aspires eventually to 60% terminal-to-terminal, as opposed to the whole-system efficiencies cited for CAES. Batteries are quoted as 90-95% which is their rating terminal-to-terminal and on day 1; when measured whole-system and lifetime-average, they are 50-62%[108], and a rapidly-deteriorating asset must be managed throughout. Flow batteries are also quoted terminal-to-terminal. They need to research the market better.

How Much Storage Is Needed?

By coincidence, the UK electricity system's required supply margin is roughly equal to the expected zero-carbon dispatchable and baseload generation (e.g. nuclear, biomass, BECCS but ignoring gas + CCS). By a simple but rigorous calculation of the need for storage[109], the gigawatts of storage required is therefore roughly equal to peak demand, which ranges from 97.5GW to 114.2GW (the low figure is the Leading the Way scenario; the high figure is Falling Short, which is close to Consumer Transformation).

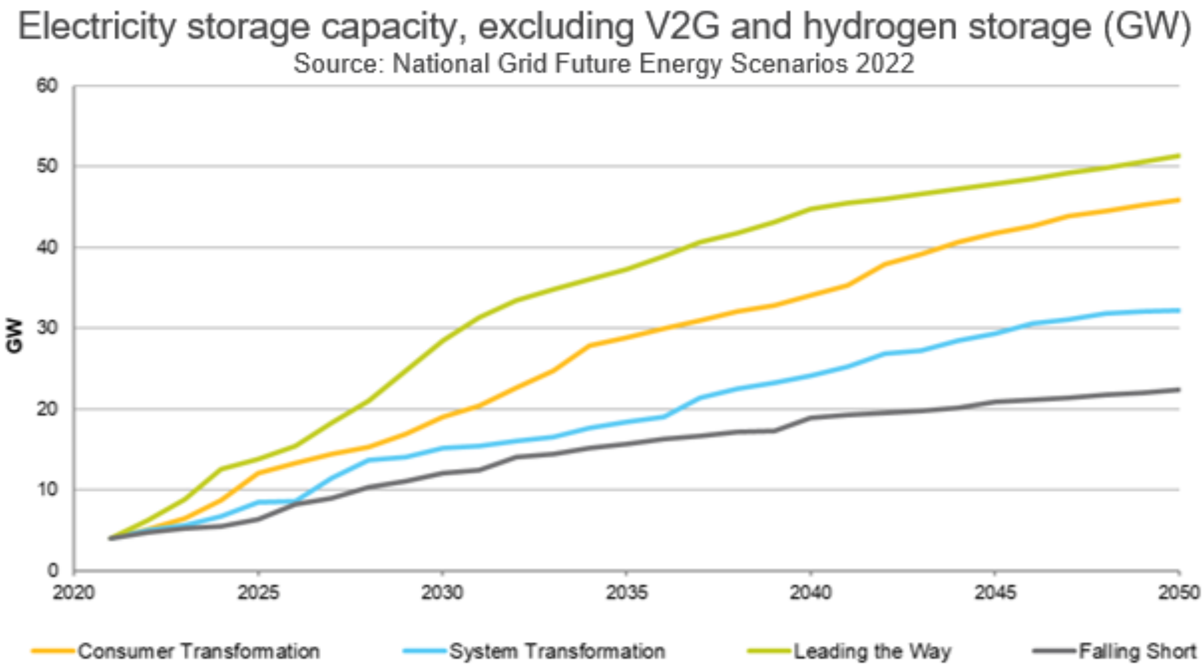
As the zero-carbon generation is likely to be prioritised, and the storage kept in reserve, the duration of storage required is equal to all demand over the longest period (2 weeks) of low-renewable generation, which coincides with extreme demand that will be increasingly extreme for electricity as heating is decarbonised, minus the output during that period of zero-carbon generation, plus a reserve, which we estimate at 46-69TWh, based on National Grid's forecast demand in their three Net Zero compliant scenarios.

This is a very different amount of storage from National Grid's calculation:

107 https://www.nationalgrideso.com/document/273166/download

108 https://storelectric.com/batteries-expensive_and_inadequate_solutions/

109 https://www.storelectric.com/calculating-the-need-for-storage/



Electricity storage capacity, excluding V2G and hydrogen storage (GW)
Source: National Grid Future Energy Scenarios 2022
GW
60
50
40
30
20
10
0
2020
2025
2030
2035
2040
2045
2050
Consumer Transformation
System Transformation
Leading the Way
Falling Short

Regulatory Issues

Paying for What We Need

In the current electricity system, the price per MWh of electricity is the same regardless of its value. Thus 1MWh of intermittent, asynchronous generation is paid the same as 1MWh of dispatchable/baseload, synchronous generation. The former is much less valuable as it requires the procurement and connection of balancing, ancillary, stability, power quality and resilience services; the latter provide such services as a by-product of the energy. Therefore its energy is much more valuable.

The grid has made big strides towards remedying that anomaly by creating revenue streams to reward those additional benefits. However the way in which this has been done leads to a great deal of salami-slicing of outputs[110], which make new plants with broad capabilities and large size impossible to finance and build unless covered by a special long-duration financial instrument to guarantee its future profitability.

Moreover, even these partial contractual improvements ignore the benefits to the grid network itself from dispatchability (which requires much less capacity per unit of energy carried than does intermittency) and synchronicity (which means that additional services don't need to be sourced and connected up, and there are no "disturbed areas" between the intermittent generation and its balancing and stability services.

Carbon Price

We expect that emissions prices, in whatever form (e.g. carbon tax, emissions permits and trading) will increase rapidly towards the ranges (as evaluated by the British government in 2022[111]) that range from central figures of £241/tCO2e (pounds per tonne of CO_2 equivalent) in 2022, rising to £378/tCO2e by 2050 (and a "high series" range of up to £568/tCO2e in 2050).

Different sources of fuels should have emissions prices attached based on their sources; for example, gas and oil from shale have much higher emissions than those from onshore wells, with offshore being intermediate.

Recommendations

Apart from a recognition of the above problems, and policies to suit, a new approach to regulation and contracting electricity[112] is needed which will, within the price paid

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110 https://www.storelectric.com/wp-content/uploads/2021/08/Revenue-Stacking-and-Salami-Slicing.pdf

111 https://www.gov.uk/government/publications/valuing-greenhouse-gas-emissions-in-policy-appraisal/valuation-of-greenhouse-gas-emissions-for-policy-appraisal-and-evaluation

112 https://www.storelectric.com/a-21st-century-electricity-system/

(and therefore without need for special financial instruments = market distortions and subsidies), incentivise:

- Minimise total system costs, both capital and ongoing;
- Investment for the long term, including in large-scale flexible technologies;
- Enable large-scale flexible technologies to compete;
- Incentivise cleanness of all technologies without a penny spent on doing so;
- Incentivise the introduction of new technologies, again without a penny spent;
- Make the grid once more one of the world's most reliable, resilient and affordable.

This needs to be matched by other regulatory overhauls such as:

- A correct regulatory definition of storage[113];
- Enabling long-term contracts[114];
- Contracts to cover multiple revenue streams[115], not just from the System Operator but also the Transmission Operator where a project will benefit both[116];
- Enabling projects' benefits to be evaluated and rewarded on their own merits rather than destroying developers' incentives by artificially competing each developer's best ideas[14];
- Revising the OFTO regime to enable offshore energy generators to benefit from onshore investment in relation to both new and existing installations[14].

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[113] https://www.storelectric.com/wp-content/uploads/2021/03/Regulatory-Definition-of-Storage.pdf

[114] https://www.storelectric.com/wp-content/uploads/2021/03/Issues-with-Ever-Shortening-Contract-Durations.pdf

[115] https://www.storelectric.com/wp-content/uploads/2021/08/Revenue-Stacking-and-Salami-Slicing.pdf

[116] https://www.storelectric.com/wp-content/uploads/2021/03/Enabling-Renewables-to-Power-Grids.pdf

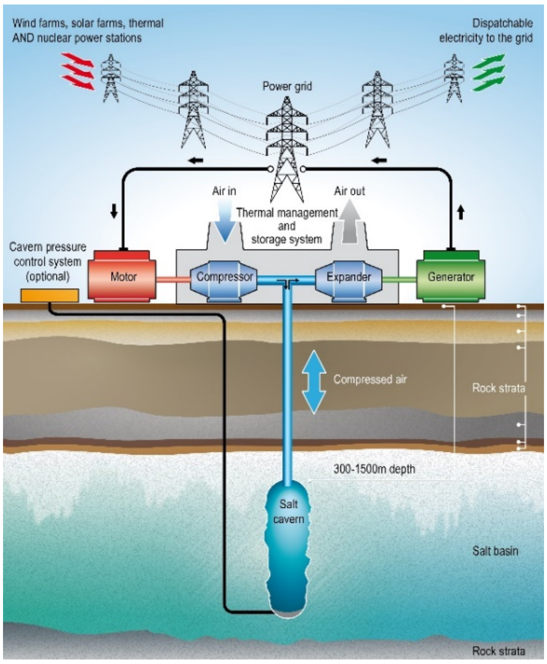
Mark's Blog

Personal blog of Mark Howitt, founding director and CTO of Storelectric Ltd and recognised international expert in the energy transition

About Storelectric

Storelectric (www.storelectric.com) is developing transmission and distribution grid-scale energy storage to enable renewables to power grids reliably and cost-effectively: the world's most cost-effective and widely implementable large-scale energy storage technology, turning locally generated renewable energy into dispatchable electricity, ***enabling renewables to power grids cheaply, efficiently, reliably and resiliently***.

- Innovative adiabatic Compressed Air Energy Storage (Green CAES) will have zero / low emissions, operate at 68-70% round trip efficiency, levelised cost significantly below that of gas-fired peaking plants, and use existing, off-the-shelf equipment.
- Hydrogen CAES technology converts & gives new economic life to gas-fired power stations, reducing emissions and adding storage revenues; hydrogen compatible.
- Storelectric has also patented the use of the heat of compression to catalyse electrolysis, for efficiency and scalability.



Both CAES technologies will operate at scales of 20MW to multi-GW and durations from 4 hours to multi-day, more cost-effective and configurable than any other technology to suit a vast range of applications / use cases, concurrently delivering grid stability based on real inertia. With the potential to store the entire continent's energy requirements for over a week, global potential is greater still. In the future, Storelectric will further develop both these and hybrid technologies, and other geologies for CAES, all of which will greatly improve storage cost, duration, efficiency and global potential.

About the Author

Mark Howitt is Chief Technical Officer, a founding director of Storelectric. He is also a United Nations (UNECE) expert advisor in energy transition technologies, economics, regulation and politics – invitation here. He is also a member of the UK advisory team to the IEA (International Energy Agency), member of the Energy Storage Steering Group of the Renewable Energy Association, and a regular consultee to the British energy ministry, regulator and National Grid.

A graduate in Physics with Electronics, he has 12 years' management and innovation consultancy experience world-wide. In a rail multinational, Mark transformed processes and developed 3 profitable and successful businesses: in commercialising a non-destructive technology he had innovated, in logistics

(innovating services) and in equipment overhaul. In electronics manufacturing, he developed and introduced to the markets 5 product ranges and helped 2 businesses expand into new markets.